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 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. Nuclear power faces four serious challenges: nuclear generating 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 focal concern of the present workshop: the nuclear weapons connection to nuclear power.

Yet nuclear energy offers the potential for power generation with no air pollution and zero greenhouse gas emissions. Such beneficial features of nuclear power led bodies such as the Energy R&D Panel of the President's Committee of Advisors on Science and Technology (PCAST Energy R&D Panel, 1997) to urge that R&D be pursued to see whether the four challenges can be adequately addressed, so that nuclear power might once more become a major option for global energy. More recently various other groups have been calling for revisiting the nuclear option in light of growing concerns about climate change.

The four challenges facing nuclear power were examined in a review of nuclear power technologies carried out as a part of the World Energy Assessment (WEA, 2000).[1] The WEA 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 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

Although the time horizon for business investment decisions is typically less than a decade (determined by the market rate of interest) and that of politicians is the term of office, the climate change challenge is forcing both private- and public-sector decisionmakers to begin to take a much longer (century-scale) perspective relating to energy planning—because of the likelihood that radical technological change in energy technology will be 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 of the Intergovernmental Panel on Climate Change (IPCC, 1994) has been widely used as a framework for trying to understand better the long-term aspects of the climate change challenge. This scenario is often referred to in climate change policy circles as a "business-as-usual"(BAU) scenario representing a plausible course for global energy

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

Box A: Some Dimensions of the Climate Change Mitigation Challenge

One of the potentially serious consequences of the atmospheric buildup of CO_2 is a shutdown of the thermohaline circulation, the south-north turnover of the world's oceans (Stocker and Schmittner, 1997)—with potentially adverse impacts on the European climate (which is presently warmed by the Gulf Stream) and the global food production system (Broecker, 1997) and the prospect that future oceanic uptake of atmospheric CO_2 might be much reduced (Sarmiento and Le Quere, 1996). The shutdown might be permanent if the atmospheric CO_2 level builds up to ~ 1100 ppmv, about four times the pre-industrial level; but even if the CO_2 buildup in the atmosphere could be constrained to a doubling of the pre-industrial level (550 ppmv) it has been predicted that: (*i*) the thermohaline circulation would would slow to about half its current rate for a century or so and then would be only slowly restored during the following 200-300 years (Manabe and Stouffer, 1993; 1994).

Another worrisome impact is sea level rise, with potentially devastating implications for low-lying regions. If the atmospheric concentration of CO_2 were to rise to 1100 ppmv, the rate of sea level rise from sea water thermal expansion would be ~ 0.3 m in 100 years, but, because of seawater's thermal inertia, this expansion would continue for hundreds of years even if the atmospheric CO_2 level remained constant over the long term at 1100 ppmv—reaching 1.8 m in 500 years; over this period there might be an additional 7 m of sea level rise as a result of ice sheet melting, assuming no refreezing; even if only half of meltwater were eventually to run off into the oceans, the total sea level rise over 500 years would be about 5 m; even for the case where the atmospheric CO_2 level is stabilized at 550 ppmv, the sea level rise from thermal expansion of seawater would be about 1 m over 500 years (Manabe and Stouffer, 1994).

under a public policy that gives no consideration to climate change concerns.[2] IS92a also provides a useful framework for trying to understand better long-term aspects of: major societal risks other than climate change posed by fossil fuels, the nuclear weapons connection to nuclear power, and land use and other challenges posed by various 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 (see Table 1); 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 (see Box A), 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. To stabilize the atmosphere at 550 ppmv would require reducing cumulative emissions, 2000-2100, by more than 500 GtC relative to IS92a and to evolve to an energy system emitting no more than about 5 GtC by 2100. To stabilize the atmosphere at 450 ppmv would require reducing cumulative emissions, 2000-2100, by more than 850 GtC relative to IS92a and to evolve to an energy system emitting less than 3 GtC by 2100 (Wigley, Richels, and Edmonds, 1996; Hoffert *et al*., 1998).

[2] But IS92a should not be regarded as a "high emissions scenario." Several of the 40 long-term scenarios generated for the IPCC's Third Assessment Report are characterized by CO_2 emissions in 2100 that are much higher (up to 37 GtC per year) than for IS92a.

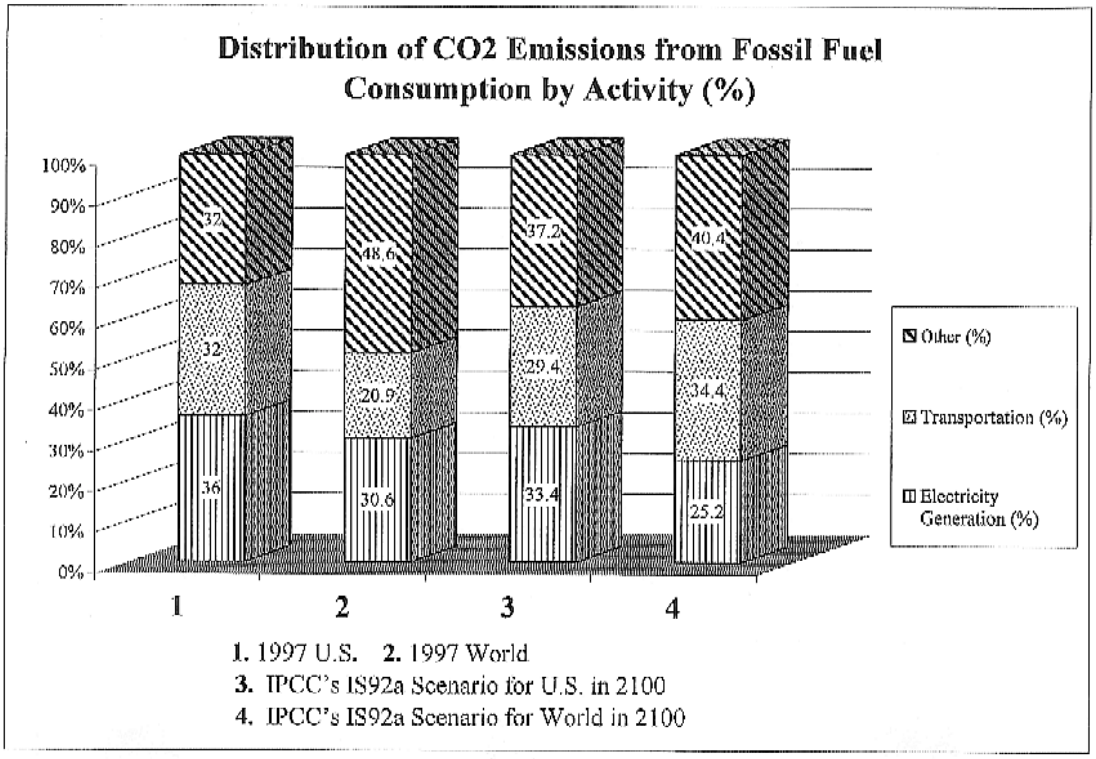

Figure 1: Distribution of CO_2 Emissions from Fossil Fuel Burning by Activity

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) and IS92a projections for 2100 (bars 3 and 4).

The sources for the construction of this graph are the same as for the construction of Table 1.

As an aid to understanding better the formidable challenge of climate change mitigation, it is worth examining some of the details of the IS92a global energy projection to 2100 (see Table 1). Under IS92a, global population grows from 5.9 billion in 1997 to 11.3 billion in 2100, global GDP grows in the period to 2100 at an average rate of 2.23%/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). For IS92a the IPCC projected that during the 21st century, 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). Thus there is rapid growth at the global level in per capita electricity generation [to ~ 6,000 kWh per capita by 2100 (about ½ the use rate in the United States in 1997), up from about 2,300 kWh per capita in 1997], while 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].

Despite the continuing trend to electrification, emissions of CO_2 from the power sector under IS92a decline, from 1/3 of emissions in 1997 to ¼ of emissions in 2100 at the global level; IS92a

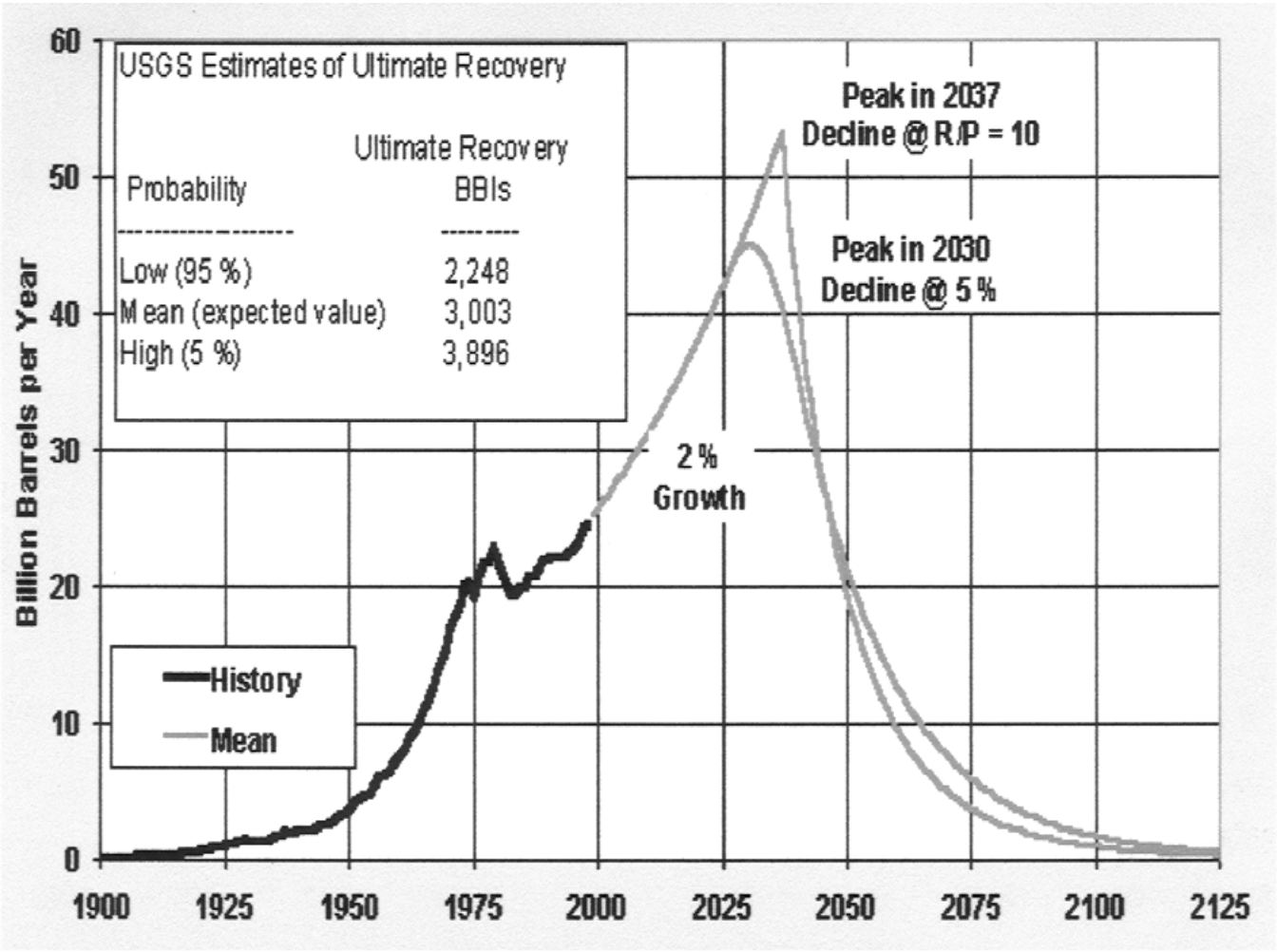

Figure 2: Global Production of Conventional Oil: Historical Data and Alternative Projections

The alternative projections are for the US Geological Survey's expected value of ultimate recoverable conventional oil resources (3,003 billion barrels). The production profile with a sharp production peak involves oil demand growing at 2%/y as long as the ratio of proved reserves (measured in barrels) to production (measured in barrels/y) exceeds 10 years, followed by a production schedule for which the reserve/production ratio is constant at 10 years. The production profile with a rounded (more realistic) peak involves instead a slowing of the production rate from 2%/y to 0%/y as the peak is approached and then increasing the rate of production decline from 0 to 5%/year.

Source: EIA, 2000c.

also projects for the United States a declining share of emissions from the power sector (see Figure 1).

The declining share of emissions accounted for by electricity generation arises in part because of the expectation of growing contributions from non-carbon supplies—from 38% in 1997[3] to 71%

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

in 2100.[4] Another important reason for the declining power sector share of CO_2 emissions under BAU conditions is the expectation of an increase in the carbon intensity of fuels used directly in the latter half of the century as a result of an expected peaking of global production of conventional oil and natural gas during the second quarter of this century[5] (see, for example, Figure 2). Prospective shortfalls in the availability of conventional oil and natural gas can be made up by various unconventional sources. 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 all liquid fuels and ¾ of all gaseous fuels by 2100. Despite a projected relatively large role for biomass (205 EJ/y[6] by 2100), the carbon intensity of fuels used directly is about 30% higher in 2100 than in 1997 (see Table 1).

Nuclear Power in Climate Change Mitigation and Implications for Proliferation

Under IS92a nuclear installed capacity grows from about 350 GW_e in 1997 to about 2,700 GW_e in 2100. Despite the projected large expansion of nuclear capacity, the nuclear contribution to climate change mitigation under this scenario is relatively modest. If there were no nuclear power in IS92a and if all projected nuclear power were provided instead by coal, CO_2 emissions in 2100 would be 24 GtC/year, about a 20% increase.

Nuclear power could potentially play a larger role in climate change mitigation—e.g., by increasing nuclear capacity to the extent that by 2100 would displace *all* coal power by 2100. 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.

Such a nuclear-intensive scenario could be realized only if nuclear power were to become widely acceptable. Under such circumstances nuclear power might also displace future hydroelectric power projects—in light of growing environmental concerns about large hydroelectric plants. Assuming that hydropower expands only to the extent of new plants already under construction, nuclear generating capacity in 2100 under a nuclear-intensive variant of IS92a would be some 5,500 GW_e[7,8] (see Table 1).

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[4] 39% nuclear, 16% hydroelectric, and 45% new renewables.

[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] This is in the mid-range of the practically realizable biomass energy potential for the long term—some 100 to 300 EJ/y, as estimated in the World Energy Assessment (Turkenburg, 2000).

[7] Because the rate of building new nuclear power plants (both net new capacity and replacement capacity, assuming 40-y plant lives and a linear rate of capacity expansion) is so large (~ 100 GW_e/y) if there is to be 5,500 GW_e of installed capacity by 2100, nuclear power technology would probably have to be not just tolerated but enthusiastically embraced by the general public in order to keep capacity expansion on track.

[8] If instead hydropower were at the same level as in IS92a, nuclear capacity in 2100 would be 4,870 GW_e in the nuclear–intensive variant.

At such a high level of nuclear power development, the nuclear weapons connection to nuclear power would come into sharp focus.

Consider first the case where uranium resource constraints force a shift sometime during the 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-gigawatt-electric 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 5.5 million kilograms per year. The nuclear weapons connection to 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-megawatt-electric), compact[9] version with a lifetime (15-year) sealed core has been proposed for developing-country applications (Hill *et al*., 1999) as a way to avoid such proliferation capacity-building. 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 could 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 that half of the 5,500 GW_e of nuclear capacity in 2100 were based on such reactors, that there is a linear ramp up of reactor construction throughout the century (adding net incremental capacity at a rate of 55 GW_e/y), and that half of all reactors built after 2040 were of this type. During the period 2040-2100 the average rate of deployment of such modular reactors would be almost 700 per year (about 2 per day).[10]

If uranium could be extracted from seawater at competitive cost (Nobukawa *et al*., 1994; Charpak and Garwin, 1998), a shift to the plutonium economy might be avoided altogether,

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

[10] The deployment rate would be: 275 reactors per year, 2040-2055; 550 per year (275 net new + 275 refurbished), 2055-2070; 825 per year (275 net new + 550 refurbished), 2070-2085; and 1100 per year (275 net new + 825 per year refurbished), 2085-2100.

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.[11] About 2300 such enrichment plants would be needed to support 5,500 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 my being involved recently in a major review of advanced fossil and nuclear energy technologies (Williams, 2000) and in the process becoming sensitised to the shortcomings of alternative "proliferation-resistant" nuclear reactor and fuel cycle technologies, I am coming around 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 their 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.

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

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 (wind, photovoltaic, solar thermal, and biomass), 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

Hydroelectric power accounted for 19% of global electricity generation 1997 (see Table 1). Hydroelectric power is a fully established renewable electric technology with considerable potential for expansion: the technical and economic potentials for hydroelectric power generation are and 5 ½ and 3 times the generation rate in 1997 (Rogner, 2000), and for the IS92a scenario the economic potential is fully exploited by 2100 (see Table 1). However, large hydroelectric power projects are coming under increasing attack on environmental grounds (Rogner, 2000). For all the variants of IS92a presented in Table 1 it is assumed that hydropower expansion ends with plants now under construction (so that less than 40% of the estimated economic potential is exploited by 2100.

New Renewables

Among new renewables, the focus here is on wind and photovoltaic power, although: (*i*) biomass offers significant potential for power generation in regions where land is available for growing biomass in dedicated energy plantations or where biomass residues of agricultural or forest product industries are abundantly available, and (*ii*) high temperature solar thermal-electric technology has promising prospects for regions blessed with good direct normal insolation—e.g., the U.S. Southwest and the Sahara Desert (Turkenburg, 2000). Biomass and high-temperature solar thermal technologies are discussed below as options for making synthetic fluid fuels for a climate-constrained world.

The outlooks for wind power and photovoltaic power are discussed in some detail in Appendices A and C. Here only some highlights are discussed, in the context of the renewable-electric intensive variant of the IS92a scenario presented in Table 1 for which it is assumed that conventional coal and nuclear power each contribute nothing to electricity supplies in 2100 and the total contribution of wind plus PV is three times as large in 2100 as in IS92a.

Wind power. Around 1980 the first modern grid-connected wind turbines were installed. By 1990 about 2,000 MW_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. At the global level, wind power capacity for electric grid-connected applications has been growing at rates in the range 27%/y to 33%/y since 1994 (Turkenburg, 2000).

Costs have fallen sharply since the early 1980s. Currently, the unsubsidized cost of wind electricity is typically less than 5 ¢/kWh; costs are expected to fall to about 3 ¢/kWh in areas of "moderate-quality" wind resources in about a decade's time (see Table 2). The practically realizable global potential for wind development is in the range 20,000-50,000 TWh/y, some 1.5 to 4.0 times the present global electricity generation rate.

Most good wind resources are in areas remote from major markets. This remoteness poses an exploitation challenge, because local populations will be able to consume only a tiny fraction of available supplies. Exploitation would be feasible at acceptable cost with high capacity (GW_e-scale) transmission lines operated at high capacity factor (> 80%) for markets even as distant as thousands of kilometers from generation sites. Such high capacity factors could be realized if wind farms were coupled to compressed air energy storage (CAES), thereby converting wind power into baseload power. CAES is a commercially available energy storage technology that could often provide baseload electricity from wind power for an incremental cost of 1.0 ¢/kWh or less (see Appendix B).

One concern often expressed about wind power is its land-use intensity. The land area occupied by wind farms for the renewable-electric intensive variants of IS92a in Table 1 represents ~ 0.6% of the land area of the inhabited continents. Three considerations are helpful in thinking about the land-use intensity of these variants. 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), the income from wind farm royalties would be a major supplement to farming/ranching income—in the United States typically offering income per acre as great as or greater than net income from farming (see Appendix A for details).

Photovoltaic power. Although PV module costs have fallen by an order of magnitude since the mid-1970s, the generation cost for central-station PV power plants in areas with good insolation at present is eight times the cost of electricity from wind power in regions with good wind resources (see Table 2). For thin-film PV technologies now coming into power generation markets, central-station generation costs are expected to fall more than half by 2005 (see Table 2). Yet even this dramatic reduction would leave PV central-station power generation costly—some 15 ¢/kWh in areas of good insolation—three times the wind electricity cost today.

However, PV technology offers major advantages over wind power and other renewable energy sources in that small PV systems can be sited near users where the power generated is worth

much more than in central-station power plants—e.g., on residential building rooftops, commercial building facades, and roofs of parking garages. Such decentralized generation is feasible because a PV system requires no system operators, has costs per unit of electricity provided that are not especially sensitive to scale, is not noisy, and causes no pollution.

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. PV systems for grid-connected applications are not yet competitive, but installed costs for grid-connected residential rooftop applications have been falling sharply and, sometime during 2005-2010, costs for thin-film 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[12] and where PV systems are financed with home mortgages. For residential rooftop PV system costs that are expected to be realized before 2010, the total potential residential rooftop PV market in the United States is expected to be as much as 40 GW_e (see Appendix C for details).

This initial PV market is expected to provide an enormous stimulus to PV technology development if accompanied by appropriate public policy measures such as net metering and public support for long-term PV R&D. This early market development will plausibly pave the way even to central-station applications of PV technology—especially in the case of thin-film PV technologies. An analysis carried out jointly for the Electric Power Research Institute and the US Department of Energy (see Table 2) projects that between 2005 and 2030 system efficiencies for thin-film PV will roughly double (to almost 14%) and system costs for central station applications will decline roughly three-fold (to less than $\$1/W_{ac}$), so that PV electricity prices by 2030 would be less than 4.5 ¢/kWh in areas of good insolation and about 1 ¢/kWh more in areas of average insolation (see Table 2). These would be attractive market prices, especially considering that PV generation will tend to peak in the afternoon near the time of peak demand in areas and seasons where there are significant air conditioning loads. In areas of low insolation (much of northern Europe) it is not likely that PV would be much deployed in central-station configurations; there most systems would tend to be sited near users in the form of "building-integrated" PV designs—systems for which the electricity generated is more highly valued than central-station electricity and for which some credit can be taken for conventional building materials not needed with such designs. European PV R&D is leading the way toward understanding better the prospects for such building-integrated PV systems.

As in the case of wind power, land use intensity is a concern that has often been voiced about PV technology. The seriousness of the land use constraint depends on where PV systems are deployed. If all future PV systems were in central-station configurations, the total land area required worldwide for the PV projection of about 39,000 TWh/y for 2100 presented in Table 1 for the new renewable-electric intensive/coal-biomass-derived synfuels-intensive variant of the IS92a scenario would be relatively modest—some 320,000 km^2, equivalent to 0.25% of the land area of the inhabited continents or the area of the state of New Mexico. To the extent that PV systems can be sited near users on building rooftops or facades there would be no significant land-use competition issue associated with PV deployment. It is unclear what fraction of ultimate

[12] "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.

PV might be deployed in distributed applications, but the fraction might be significant. Considering that residential rooftop PV systems in the United States will typically have capacities in the range 2-4 kW_{ac}, a per capita PV capacity of ~ 1 kW_{ac} is plausible for regions where distributed PV generation is feasible. This would require that a per capita area of ~ 7 m^2 be available for collectors near users. If, on average at the global level 1 kW_{ac} per capita could be deployed in distributed configurations, the land required for central-station plants would be reduced by half from the above estimate.

Wrapup on wind and PV. A final comment about both wind and PV power relates to their intermittency. Wind and PV systems are dispatched by Mother Nature, not man—making them less valuable, without storage, than dispatchable electricity supplies. But both renewable electric options can provide either baseload or load-following outputs if coupled to suitable electric storage technology. And fortunately, technological breakthroughs with storage technology are not needed for deployment in most regions because of the attractive costs of commercially available CAES technology.

For early applications of both wind and PV technologies (i.e., over the next 2-3 decades) such storage strategies will be little needed, because high reliability of power for grid systems can be assured despite the intermittency, for grid penetration levels by these intermittent renewables of the order of 10-30 percent 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. 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.

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 geological reservoirs, as well as conversion of CO_2 to a harmless carbonate solid that can be stored at the Earth's surface. Although ocean disposal has received the most attention, large uncertainties in its prospects have led to a shift of focus in recent years to give more attention to geological (underground) storage of CO_2, in depleted oil and natural gas fields (including storage in conjunction with enhanced oil and gas recovery), in deep coal beds (in conjunction with coal bed methane recovery), and in deep saline aquifers. CO_2 injection for enhanced oil recovery (Blunt Fayers, and Orr, 1993), enhanced gas recovery (van der Burgt, Cantle, and Boutkan, 1992; Blok *et al*., 1997), and enhanced recovery of deep coal bed methane (Byrer and Guthrie, 1999; Gunter *et al*., 1997; Stevens *et al*., 1999; Williams, 1999a) might

become profitable focuses of initial efforts to sequester CO_2. Enhanced oil recovery using CO_2 injection is well-established technology; one project that began in 2000 in Saskatchewan, Canada, is injecting yearly up to 1.5 million tonnes of CO_2, which is transported 300 km to the injection site from a synthetic natural gas plant in North Dakota.

Sequestration in depleted oil and gas fields is generally thought to be a secure option if the original reservoir pressure is not exceeded (van der Burgt, Cantle, and Boutkan, 1992; Summerfield *et al*., 1993). One estimate of the prospective global sequestering capacity of such reservoirs associated with past production plus proven reserves plus estimated undiscovered conventional resources 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 is wide because reservoir properties vary greatly in their suitability for storage, and because oil and gas recovery may have altered the formations and affected reservoir integrity. Much of the prospective sequestering capacity will not be available until these fields are nearly depleted of oil and gas.

Deep saline aquifers[13] are much more widely available than oil or gas fields. Such aquifers underlie most sedimentary basins, the total areas of which amount to 70 million km^2 (two-thirds onshore and one-third 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). To achieve high storage densities, CO_2 should be stored at supercritical pressures (in excess of 74 bar), which typically requires storage at depths greater than 800 m.[14] The aquifers at such depths are typically saline and not effectively connected to the much shallower (typically less than 300-m) sweetwater 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 globalCO_2 production from burning fossil fuel at the current rate. However, a growing body of knowledge (Gunter, Perkins, and McCann, 1993; Bachu, Gunter, and Perkins, 1994; Holloway, 1996) indicates that many large horizontal open aquifers with good top seals (very low permeability layers) can provide effective storage, if the CO_2 is injected sufficiently far from reservoir 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 (see, for example, Figures 3a and 3b). For large reservoirs, the CO_2 will eventually dissolve in the reservoir water[15] (see Figure 3a). For sandstone reservoirs (but not carbonate reservoirs), the CO_2 will, after dissolving in the water, eventually precipitate out as a carbonate mineral.[16]

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[13] 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.

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

[15] The CO_2 solubility is ~ 50 kg per m^3.

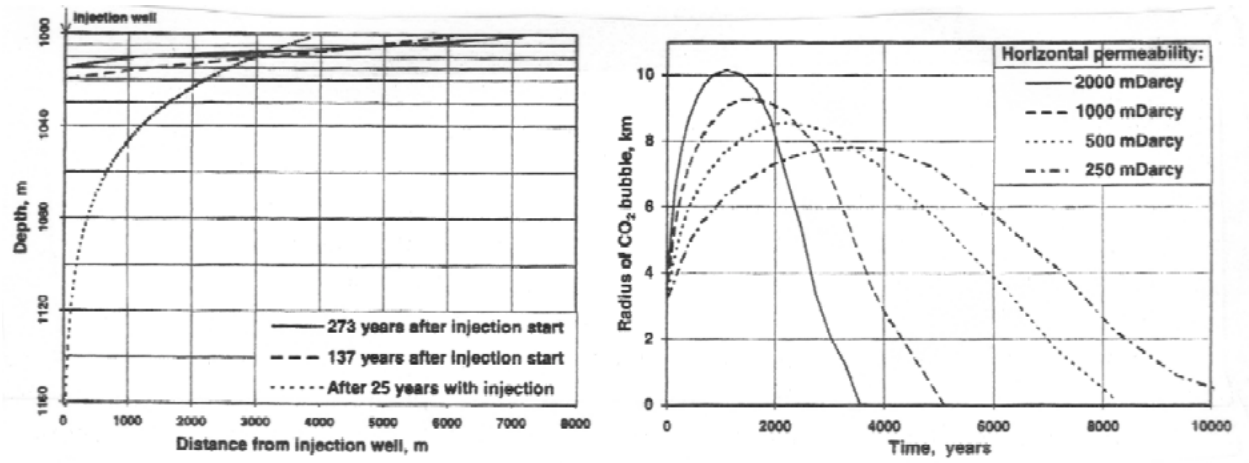

Figure 3a: Evolving CO_2 Plume Front in a Vertical Cross Section of a Disposal Aquifer

These figures represent modeling results by Lindeberg (1997) of the evolving free CO_2 plume front that is formed when CO2 is injected at a rate of 6 million tonnes per year (corresponding to the CO_2 generated by a 1 GW_e coal plant) into the bottom of a flat, 160 m thick aquifer with a 2000 mDarcy horizontal permeability. At the top of the aquifer (1,000 m below the Earth's surface) is a low permeability caprock. The CO_2 is injected over a 25 year period, and then the injection well is sealed off. Less dense (~ 0.7 tonnes/m^3) than water, the CO_2 rises to the top of the reservoir and spreads out. In this modeling exercise, interactions with the rock in the reservoir (which can lead to "mineral trapping" of CO_2) are neglected.

The figure on the left shows a vertical cross-section of the front of the free CO_2 phase at 25 years (when injection stops) and also at 137 years and 273 years after the start of injection. During the injection period, the front at the top of the aquifer advances at an average rate of 42 cm per day. During the next 112 years, the average rate of advance of the plume top is 5.4 cm per day. And during the next 136 years, the average rate of advance of the plume top is 2.4 cm per day. Because of the slow CO_2 migration rates involved, this phenomenon is referred to as "hydrodynamic trapping" of CO_2.

The figure on the right shows the radius of the free CO_2 phase front vs. time for four different permeabilities. Eventually the radius of the plume will reach a maximum and subsequently the plume will shrink back to zero radius by the time the CO_2 is completely dissolved in the reservoir water. For the base case (2000 mDarcy permeability) the modeling predicts that the maximum radius is reached in 1300 years and that 3500 years are required for complete dissolution.[17] For aquifers of lower permeability the maximum radius is less (because the migration rate is lower) and the dissolution time is longer (because of the lower surface area at the free CO_2 plume/water interface).

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[16] For sandstone reservoirs, the calcium-magnesium silicates in the rock will eventually react with CO_2 in the water to form the precipitate calcium carbonate:

$$3\ MgCa(SiO_3)_2 + 3CO_2 + 2\ H_2O \longrightarrow H_4Mg_3Si_2O_9 + 3\ CaCO_3 + 4\ SiO_2,$$

thereby both enhancing reservoir storage capacity by per haps a factor of two compared to the CO_2 storage capacity without taking such rock reactions into account and providing permanent storage of the injected CO_2.

[17] The time required for complete dissolution estimated in this modeling exercise is probably an overestimate, because the model took into account only molecular diffusion of the CO_2 into the water phase. Because the CO_2-rich water near the water/free CO_2 interface is denser than the water below, convective loops will form in the water phase, as the CO_2-rich water sinks and is replaced with CO_2-free water at the interface—thereby increasing the rate of dissolution compared to the situation with molecular diffusion only (Lindeberg and Wessel-Berg, 1997).

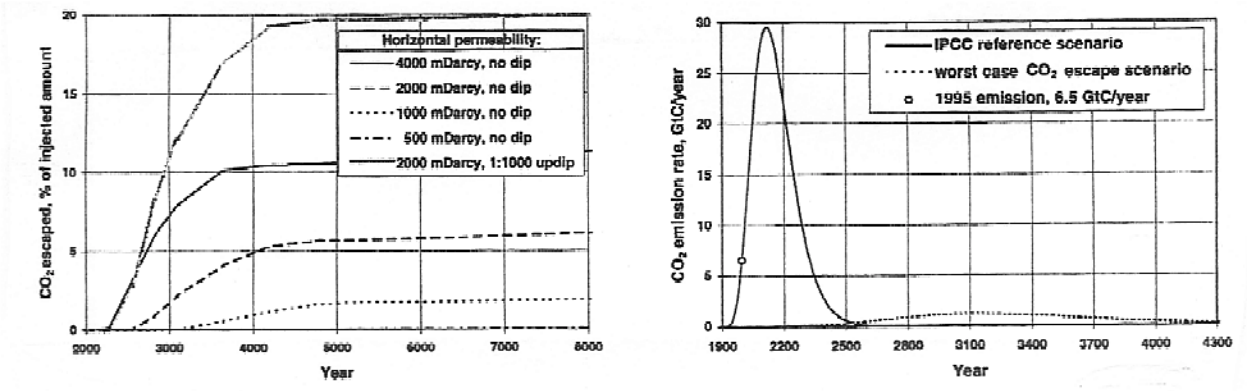

Figure 3b: Escape of CO_2 from an Aquifer with a Spill Point Located 8 km from the Injector

This modeling exercise (Lindeberg, 1997) is an extension of that presented in Figure 3a.

The figure on the left shows the leakage under alternative conditions. The 250 mDarcy case presented in Figure 3a is not represented here because for that case the CO_2 plume never reaches the spill point. Two other cases not presented in Figure 3a are added here: a 4000 mDarcy case and a 2000 mDarcy case with a 1:1000 up dip. For the latter, the "worst case" modeled by Lindeberg, about 20% of the injected CO_2 eventually leaks out.

For the figure on the right, Lindeberg assumed that all estimated remaining recoverable fossil fuels (containing 7,000 GtC) are used up over the next 450 years. The solid curve is for the IS92a scenario, with release of all CO_2 to the atmosphere and for which emissions peak at ~ 30 GtC/y in 2150. For the case represented by the dotted curve it is assumed that the fossil fuel consumption rates are the same as for IS92a, but, beginning now, all CO_2 is sequestered in aquifers whose leakiness characteristics are identical to those for the "worst case" modeled in the figure on the left. For this CO_2 storage case, CO_2 emissions from leakage peak in 3100 at ~ 2 GtC/y.

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 5,000 GtC (Rogner, 2000). The notion that large horizontal aquifers with good top sealscan provide effective sequestration is a relatively new idea that has contributed to the 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).

Experience with aquifer disposal will be provided by two projects involving injection into nearby aquifers of CO_2 separated from natural gas recovered from CO_2-rich gas reservoirs. One is a Statoil project begun in 1996 to recover 1 million tonnes of CO_2 per year from the Sleipner Vest offshore natural gas field in Norway (Kaarstad, 1992). The second, which will commence in 10 years, will involve the recovery of more than 100 million tonnes per year (equivalent to 0.5 percent of total global emissions from fossil fuel burning) from the Natuna natural gas field in the South China Sea (71 percent of the reservoir gas is CO_2) (IEA,1996).

Extensive historical experience with underground gas storage contributes to the growing scientific confidence in the reliability of geological reservoirs for storing CO_2; and regulations that have been evolving for underground gas storage provide a good basis for defining the issues associated with formulation of regulations for CO_2 storage (Gunter, Chalaturnyk, and Scott, 1999). However, more research, field testing, modelling, and monitoring are needed to narrow

the uncertainties relating to CO_2 storage in geological reservoirs. Public acceptability issues are paramount. Fuel decarbonisation with CO_2 sequestration is unfamiliar to most people as a strategy for dealing with the climate change challenge. What will public attitudes be? 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). But more research is needed to clarify the issues.

Even when the limits of geological storage capacity for CO_2 are approached, the fossil fuel era still might not end, because it might prove to be feasible to store CO_2 in the form of solid carbonates by reacting CO_2 with certain abundant minerals such as forsterite or serpentine in exothermic reactions that are favored under ambient conditions.[18] Resources of such minerals are more than what is needed to store as carbonates the carbon in all remaining recoverable fossil fuels. Although about 6 tonnes of mineral (e.g., serpentine) are needed for each tonne of coal processed, the mineral mining costs are low, and overall costs might not be prohibitive; various chemical processes for creating carbonates from CO_2 and serpentine are being investigated (Yegulalp, Lackner, and Ziock, 2000).

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.

Table 3 presents performance and cost calculations[19] for four alternative technologies for CO_2 removal and disposal for coal-fired power systems based on current or near-term (before 2005) technologies. The CO_2 separation and disposal options are compared with three reference technologies for power generation without CO_2 removal and disposal: an ultrasupercritical steam-electric plant, a pressurised fluidised-bed combustion plant, and an integrated coal gasifier combined cycle (IGCC) power plant. Identical capital costs are assumed for these reference plants. Not only is this a reasonable approximation, but also this assumption helps clarify cost differences for CO_2 separation and disposal among alternatives. The cost of avoided CO_2 emissions for each case is calculated relative to the least costly option in the table: the reference IGCC case, with CO_2 venting.[20]

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[18] The reactions are:

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

for foresterite and:

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

for serpentine.

[19] Developed in a self-consistent manner across options.

[20] With the emergence of the latest generation of gas turbine/steam turbine combined cycle technology (characterized by gas turbine inlet temperatures of 1350 ^{o}C and steam cooling of turbine blades), IGCC technology

The 1st CO_2 recovery option presented in Table 3 involves CO_2 scrubbing from the stack gases of an ultra-supercritical steam-electric plant[21] using an amine solution (flue gas scrubbing). The cost of avoiding CO_2 emissions and the power generation cost penalty are relatively high for this option [$134 per tonne of carbon (tC), and 1.9 ¢/kWh], largely because of the high cost penalties associated with recovering CO_2 from the stack gases, where its concentration and partial pressure are low (15% and 0.15 bar, respectively).

The 2nd CO_2 recovery option in Table 3 employs atmospheric pressure O_2 rather than air as oxidant, and recycles the separated CO_2 back to the ultrasupercritical steam plant combustor. This strategy greatly increases the partial pressure of CO_2 in the flue gas. However, cost penalties are comparable to those for flue gas recovery because of the large required quantities of O_2 , which must be obtained by the costly process of air liquefaction.

The 3rd CO_2 recovery entry in Table 3 is for a pressurised fluidised-bed combustion (PFBC) unit[22] that uses pressurised O_2 as the oxidant instead of pressurised air. Pressurization further increases the CO_2 partial pressure in the flue gas and reduces CO_2 removal costs; however, because pressurised O_2 is more costly to provide than O_2 at atmospheric pressure, the savings relative to the ultrasupercritical steam-electric cases is modest.

The 4th entry involves an oxygen-blown coal gasifier with cold CO_2 recovery from synthesis gas for IGCC plants. This option starts with coal gasification to produce syngas (a gaseous mixture for which the main combustible species are CO and H_2).[23] The syngas is then reacted with steam

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is becoming competitive in terms of direct economic costs with conventional coal steam-electric technology technology (see Table 4).

[21] The ultrasupercritical steam plant is a high-efficiency variant of conventional coal steam-electric technology (e.g., an overall efficiency of 43.1%, compared to 35.5% for a conventional subcritical steam plant—compare Tables 3 and 4) that involves increasing peak steam temperatures and pressures to ultrasupercritical conditions by using advanced alloys for steam superheaters and by deploying efficiency-boosting cycle configurations (e.g., double reheating, which increases the average temperature at which heat is added to the cycle). Pollutant emissions will be roughly equal to those for a conventional coal steam-electric plant (see Table 5) reduced by the efficiency ratio (35.5%/43.1% = 0.82). Such pollutant emissions reductions relative to conventional steam-electric are modest relative to what can be achieved with IGCC technology (see Table 5).

[22] Now widely available atmospheric pressure fluidized bed combustion (AFBC) units can burn a wide variety of coals without significant combustor modification and can achieve reduced SO_2 emissions without flue gas desulfurization technology but without efficiency gains relative to conventional coal steam-electric technology. PFBC technology offers efficiency gains as well. But neither AFBC nor PFBC can come close to matching the low air pollutant emissions that are achievable with IGCC technology (see Table 5). Moreover, in contrast to IGCC technology, PFBC technology cannot take advantage of the expected continuing efficiency gains in gas turbine technology that are expected over the next decade or so (Williams, 2000).

[23] Oxygen-blown coal gasification is an exothermic reaction that can be represented, for one type of gasifier operated on Appalachian bituminous coal, approximately as:

$$CH_{0.82}O_{0.06} + 0.27\ H_2O_{(g)} + 0.41\ O_2 \rightarrow 0.85\ CO + 0.15\ CO_2 + 0.68\ H_2.$$

in shift reactors to convert CO into H_2 and CO_2.[24] Subsequently, the CO_2 is separated from the H_2-rich fuel gas using a physical solvent, and the H_2-rich fuel gas is burned in the gas turbine combustor. This option has the least cost penalties of all the near-term options (about $100/tC and 1.5 ¢/kWh). The low cost is realised largely because, when CO_2 is recovered from the shifted syngas in an IGCC, its concentration is high (33%), as is its partial pressure (> 10 bar).

Although the cost penalty for CO_2 removal and disposal with current IGCC technology (1.5 ¢/kWh) represents nearly a 50% cost penalty for coal IGCC plants, the cost penalty for retail consumers would be less than 13% if all coal plants in the US were shifted to present-day IGCC technology with CO_2 sequestration and no credit were taken for the large air-quality benefits that would be associated with a shift to IGCC technology (see Table 5).[25]

Not only does the IGCC option offer the least costly route to near-zero CO_2 emissions with existing technology, but also it is becoming the least-costly option for providing electricity from coal in terms of direct economic cost (see Table 4), and it offers the potential for reducing local environmental damage costs from air pollutant emissions by an order of magnitude relative to what can be achieved via conventional steam-electric technology equipped with best available control technologies—so that in terms of environmental damage costs of air pollution coal IGCC plants are about as clean as natural gas combined cycle power plants (see Table 5).

Such benefits are possible with the IGCC because of a key characteristic of the technology: both CO_2 and conventional air pollutants can be recovered prior to combustion, before the "undesirables" are diluted with N_2 in combustion air that would render their recovery difficult. The key enabling technology that makes these emission benefits possible is O_2-blown gasification technology—a technology that will continue to enable coal to evolve to even lower cost routes to near-zero emissions of both greenhouse gases and conventional air pollutants.

The potential offered by coal technologies involving O_2–blown gasification for dramatic reductions in emissions of air pollutants as well as greenhouse gases is key to making it possible to use coal in environmentally acceptable over the longer term—in light of the likelihood that about an 80-fold reduction in environmental damage costs from air pollutant emissions from

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[24] The water gas shift reaction (in which CO is reacted with steam or "water gas"):

$$CO + H_2O_{(g)} \rightarrow H_2 + CO_2,$$

is slightly exothermic, and the reaction's exothermicity is approximately equal to the latent heat of water, so that the combination of this reaction and the water phase change is approximately autothermic—i.e, there is little net over chemical energy change, but rather the energy content of CO is "shifted" to H_2—hence the reaction's name.

[25] Sequestration would add 1.54 ¢/kWh to the generation cost for an IGCC plant (see Table 3) but a shift from a coal steam-electric plant to an IGCC plant would reduce generation cost by 0.1 ¢/kWh (see Table 4). Since coal accounted for 54% of U.S. generation in 1999, when the transmission and distribution efficiency averaged 0.927, the the average cost penalty at the retail level in 1999 would have been 0.84 ¢/kWh or 12.5% of the average retail electricity price (6.7 ¢/kWh) in 1999.

today's coal conversion technologies would be required in this century in order to keep environmental costs a century from now no higher than at present.[26]

Could nuclear power compete with current IGCC technology with CO_2 sequestration? Competing would be difficult for nuclear with current light water reactor (LWR) technology. A recent survey of capital costs by country for new LWRs indicates that installed costs range from \$1,700/kW_e to \$3,100/kW_e (Paffenbarger and Bertel, 1998). With such capital costs and costs for fuel and for operation and maintenance (O&M) expenses at levels realized recently in the United States, nuclear would be barely competitive only at the lowest installed capital costs in the reported range.[27]

But with advanced nuclear technologies that incorporate some degree of passive safety so as to provide the opportunity for reducing O&M costs, nuclear power might be able to do somewhat better. The only such advanced reactor with real-world experience is the 1300 MW_e advanced boiling water reactor (ABWR) developed by GE/Toshiba/Hitachi—an evolutionary light water reactor that has been built and is in operation in Japan and has been granted design certification in the United States. This technology could be competitive if its O&M costs were at least 30% less than the current average for US plants.[28]

In looking to the future, however, the nuclear industry can expect the fossil energy technology competition for nuclear to become tougher, because of the rapid rate of progress being made with fossil energy technology. To give a flavor for what is in the offing, consider that among advanced technologies H_2 separation membrane reactors employing inorganic membranes that are highly permeable to H_2 but not other gases offer considerable promise in reducing the present relatively large energy and cost penalties associated with gaseous separation for commercial technologies that are designed to realize deep reductions in CO_2 emissions for IGCC-based power systems (Williams, 1999b). One such system under investigation is based on the use of a non-porous dense metal membrane[29] that can in principle provide pure H_2[30] from coal in a

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[26] Suppose that the use of coal and thus the mass of air pollutant emissions (assuming pollutant control technologies are unchanged) increases roughly in proportion to GDP. Environmental damage costs are overwhelmingly dominated by adverse health impacts (Rabl and Spadaro, 2000), which are valued on the basis of the willingness to pay to avoid such damages, which tend to increase in proportion to GDP per capita (GDP/P). Moreover, damage costs also increase in proportion to the density of the exposed population, which can be expected to increase roughly in proportion to the population P. Thus without improvements in air pollutant controls, health damage costs would increase in proportion to GDP*(GDP/P)*P = $(GDP)^2$, or approximately 80-fold during the 21st century under IS92a.

[27] Assuming a 11.5% capital charge rate and an 80% capacity factor, the annual capital charge would be 2.8 to 5.1 ¢/kWh. To this must be added 1.9 ¢/kWh for fuel and O&M costs [which averaged 0.54 ¢/kWh and 1.40 ¢/kWh, respectively, in the United States in 1998 (Williams, 2000)].

[28] The ABWR overnight capital cost is reported by the Nuclear Energy Agency to be \$1582/kW_e (NEA, 2000). Assuming an idealized 5 y construction period and a 10% discount rate, the capital charge would be 3.2 ¢/kWh. Fuel and decommissioning add 0.7 ¢/kWh (Taylor, 2001). Thus cost parity with coal IGCC with CO_2 sequestration could be realized if O&M costs = 0.9 ¢/kWh.

[29] The membrane for which the modeling exercise presented in Figure 4 was carried out is a dense metal alloy (60% palladium, 40% copper). Although this membrane has a hydrogen permeability lower than that for pure palladium, a pure palladium membrane would be quickly destroyed by the H_2S in the synthesis gas derived from

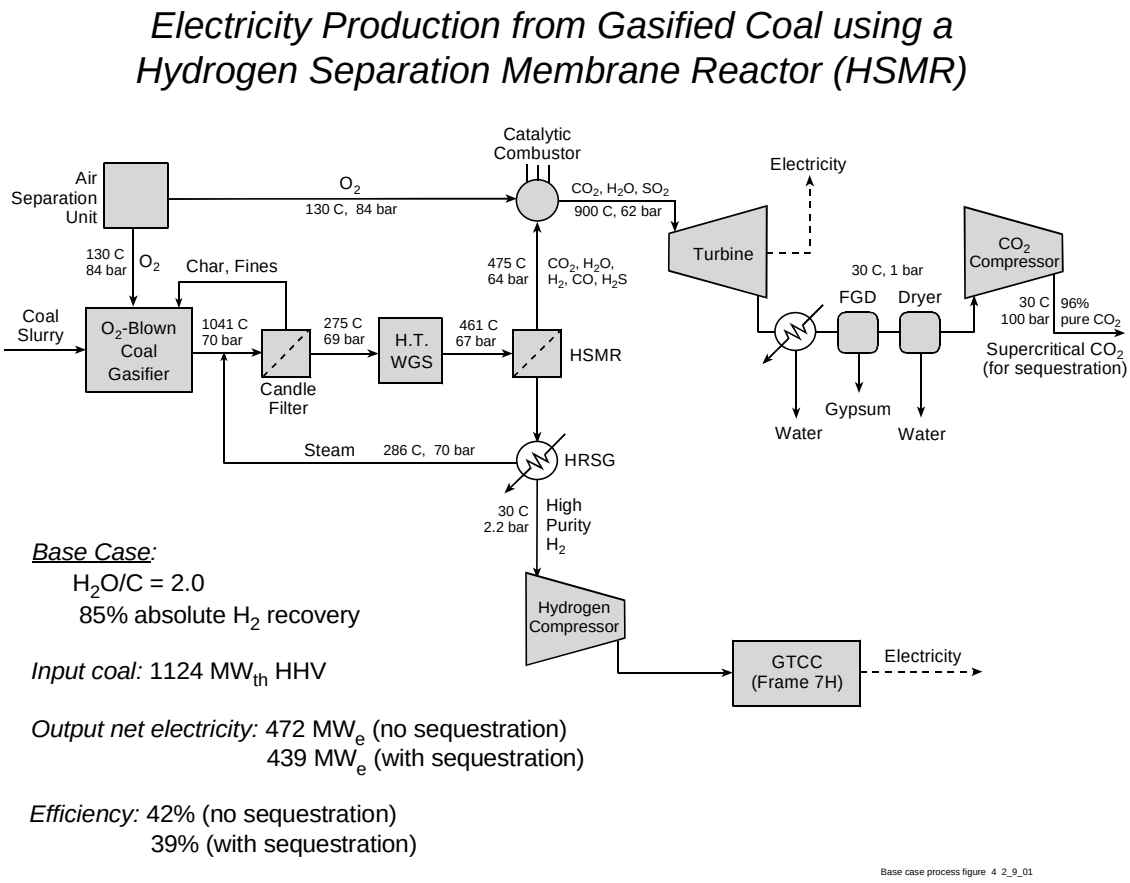

Figure 4: Electricity Production from Coal Using a H_2 Separation Membrane Reactor

In this system coal is gasified in O_2 at high pressure (70 bar), the produced syngas is cooled, cleaned of particles, and reacted with steam in a high temperature water gas shift reactor that converts ~ 85% of the CO in the syngas to H_2. The syngas is then passed through a H_2 separation membrane reactor (HSMR), where most of the rest of the CO is converted to H_2 and most of the produced H_2 is passed through a dense metal membrane, recovered at relatively low pressure (2.2 bar), compressed to 28 bar and combusted, and the combustion product gases are then expanded through the gas turbine of a state-of-the-art combined-cycle power plant (with a Frame 7H gas turbine, as for the natural gas CC and the coal IGCC cases considered in Table 4), which produces most of the electricity (~ 400 MW_e) generated by this system. The residual combustible gases on the high-pressure side of the membrane (H_2, CO, H_2S) are then burned catalytically in O_2, the combustion products of which are expanded through a turbine that produces additional electricity. In the absence of climate concerns SO_2 would be scrubbed from the turbine exhaust and the CO_2-rich gas would be vented to the atmosphere. Turbine exhaust would be treated differently in response to climate concerns: water vapor in the exhaust would be condensed out, SO_2 would be scrubbed out, the CO_2 would

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coal, whereas laboratory experiments have shown that this alloy does not seem to be degraded much by exposure to H_2S. (For the analysis presented in Figure 4 the H_2S is not removed from the synthesis gas before the membrane is exposed to the synthesis gas.) An important role for the palladium in the membrane is to catalyze H_2 dissociation on the feed side of the membrane and H_2 dissociation on the permeate side, since various dense metal membranes are permeable to the flow of atomic hydrogen, not molecular hydrogen.

[30] Because these dense metal membranes are non-porous and permeable to a flux of hydrogen atoms, they can in principle provide pure H_2 from coal or some other fossil fuel. In practice, however, there would be leaks associated with system flaws (e.g., welding flaws at joints), so that the recovered H_2 would not be quite pure.

be compressed to ~ 100 bar and the remaining water removed, and the CO_2 would then sent by pipeline to a site for disposal (e.g., in a geological reservoir).

process that begins with oxygen-blown gasification (see Figure 4). One application of this technology would involve burning the H_2 so produced in a combined cycle power plant to produce electricity. Additional electricity would be produced in a turbine from expansion of pressurized gases on the feed side of the membrane that are heated by burning in O_2 the small amount of combustibles (mainly H_2, CO, and H_2S) remaining in the gases exiting the H_2 separation membrane reactor. After expansion in the turbine, the CO_2 is relatively easily removed from the turbine exhaust so that a stream of nearly pure CO_2 can be provided for disposal. For this system the overall efficiency of making electricity would be 42% if the CO_2 were vented to the atmosphere or 39% if the CO_2 were recovered and sequestered in a geological reservoir. On the basis of a preliminary analysis, the corresponding electricity generation costs would be 3.5 ¢/kWh if the CO_2 is vented or 4.3¢/kWh if the CO_2 is captured and sequestered in a geological formation (Kreutz and Williams, 2001)—so that the total generation cost with CO_2 recovery and disposal would be about 1 ¢/kWh more than for a coal IGCC plant without CO_2 recovery and disposal.

These results are consistent with the general findings of a recent Massachusetts Institute of Technology (MIT) Energy Laboratory study which projected that, with advanced IGCC technology (expected to be commercially available by 2012), the cost penalty for decarbonisation and sequestration would be less than 1.0 ¢/kWh (Herzog, 1999).

Ultimate role of decarbonization/CO_2 sequestration strategies in the energy economy. The essence of the low-cost approaches described above for recovering useful energy from fossil fuels without releasing CO_2 to the atmosphere is to make from fossil fuels H_2, the manufacture of which generates as a natural byproduct a stream of relatively pure CO_2 that can be disposed of in geological reservoirs at relatively low cost.

Absent energy markets for H_2 at present, it is highly likely that initial decarbonization/CO_2 sequestration strategies will emphasize applications in the power sector. However, for the longer term, the principal challenge in the pursuit of an energy future that will not disrupt the global climate will be to find ways to deal with fuels used directly, which in IS92a and in both the nuclear-intensive and the new renewable-electric intensive variants of IS92a described above account for about 15 GtC/y of CO_2 emissions by the year 2100. As will be shown in the next section, the establishment of a H_2 economy based to a large extent on fossil energy-derived H_2 with sequestration of the separated CO_2 is probably the most promising approach for reducing these emissions up to 90% by the end of the century.

Both nuclear and renewable energy technologies are best suited for providing electricity. To the extent that the general public is willing to embrace at least one of these options to decarbonize the power sector, it would seem to make sense to focus fossil energy decarbonization/CO_2 sequestration strategies instead on fuels used directly, where neither nuclear nor renewables are especially well suited for playing major roles (as will be shown). Fossil energy decarbonization/CO_2 sequestration might of course be pursued in the power sector if both the nuclear-intensive and new renewable electric-intensive options fail to take hold. But, as a result,

the need for global CO_2 sequestration capacity (a depletable resource) would be considerably greater than if this strategy were focused mainly on fuels used directly.

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

Fuels used directly in IS92a in 2100 relative to 1997 are up 1.4-fold per capita and 2.7-fold in total, while CO_2 emissions from fuels used directly are up 3.5-fold (see Table 1) because of the expected increase in the carbon intensity of fluid fuels manufacture during this century. As a result, even if the power sector could be completely decarbonized, CO_2 emissions in 2100 would be 15 GtC/y—several times larger than levels required to keep the atmospheric CO_2 concentration at a level of 550 ppmv or less.

In this section a variant of IS9a is presented that could provide deep reductions in emissions for fuels used directly, and the basis for the technology choices underlying this variant is discussed.

A New Renewable Electric-Intensive/Coal-Derived H_2 Intensive Variant of IS92a

The last column of Table 1 presents an IS92a variant in which new renewables are emphasized for power generation and coal-derived H_2 with sequestration of the CO_2 separated out in H_2 manufacture is emphasized for fuels used directly.[31] The only conventional fossil fuels used directly in this variant are coal for iron and steel making and oil for fueling airplanes (see footnote e for Table 1). For this variant, H_2 accounts for about 80% of fuels used directly. To produce from coal the 545 EJ/y of H_2 without CO_2 emissions requires CO_2 sequestration in the amount of 19 GtC/y by 2100.

It is further assumed for this variant of IS92a that biomass residues generated in the agricultural and forest product industries (see Table 6) are the only biomass supplies used for energy—which implies that total biomass energy consumption is about 45% of the level for 2100 in IS92a (see Table 1). In this variant it is assumed that biomass residues are used both to provide carbon-based synthetic fluid fuels (70% of the output energy) and electricity (30% of the output energy). The purpose of this exercise that reduces the use of biomass relative to IS92a is partly pedagogical—to highlight the nature of the land-use issues associated with the growing of biomass in plantations dedicated to energy production—an option that will be discussed later in the biomass energy subsection. In that subsection a variant of the coal H_2-intensive scenario is described that involves restoring the biomass production level to that in IS92a, with the increment dedicated to H_2 production, without and with sequestration of the separated CO_2.

The rationale for focusing on H_2 derived from coal with geological sequestration of the separated CO_2 is the prospect that, with advanced technology, this provides the least-costly route for providing H_2 at large scales without releasing CO_2 to the atmosphere (Williams, 1999b; Williams, 2000; Kreutz and Williams, 2001).

[31] Under this variant, the level of intermittent renewables in 2100 is ~ 20% less than in the previously discussed new-renewables-intensive variant (see Table 1), largely because the generation of some electricity as a coproduct of H_2 from coal reduces the need for power from such sources (see Figure 5).

Hydrogen is the natural fuel for use in fuel cells. 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).

A shift to H_2 as a major energy carrier complementing electricity would go a long way to putting the global energy system on a sustainable path. The new renewable-electric intensive/coal-derived H_2 intensive variant of IS92a is one vision for such a H_2/electricity-based energy economy. If this variant of IS92a could be realized, global CO_2 emissions would be less than 3 GtC/y by 2100, and the evolution of the global energy system would be consistent with achieving an atmospheric CO_2 level ~ 450 ppmv. The air pollution problem associated with fossil fuel burning would be essentially solved.[32] And energy supply insecurity would no longer be a serious concern.

The major residual environmental issues are likely to relate to coal mining and CO_2 disposal (concerns about the safety of disposal practices and about the potential for contamination of fresh water aquifers used by man with CO_2 that might leak out of deep geological reservoirs). These would be the major foci of environmental regulatory activity and environmental engineering relating to energy.

Options for Achieving Deep Reductions in CO_2 Emissions for Fuels Used Directly

To help put the H_2 from coal option into perspective, the major options for achieving deep reductions for fuels used directly are reviewed.

The options for achieving deep reductions in CO_2 emissions for fuels used directly include: (*i*) making H_2 from fossil fuels with CO_2 sequestration, (*ii*) making H_2 electrolytically from either nuclear or renewable-electric sources, (*iii*) making H_2 from nuclear or solar heat using advanced thermochemical cycles, and (*iv*) growing biomass in plantations dedicated to the manufacture of synthetic fuels. In this section each of these options is discussed in turn.

[32] For H_2 used in fuel cells for either mobile or stationary power applications air pollutant emissions are zero. If instead H_2 is burned (e.g., in a gas turbine combined cycle power plant) the only emissions would be NO_x, which can be controlled to very low levels even with commercial technology. For example, for the H_2-burning GTCC power plant shown in Figure 4, NO_x emission levels less than 10 ppmvd (at 15% O_2) can be achieved with commercial products for a fuel consisting of a 50/50 H_2/N_2 mix; the needed N_2 would be obtained from the air separation plant onsite used to provide O_2 for the gasifier and catalytic combustor.

H_2 from fossil fuels.[33] The process of making H_2 from a fossil fuel begins with converting the fossil fuel feedstock into synthesis gas—a gaseous mixture made up largely of CO and H_2. As noted above, synthesis gas can be made from coal via partial oxidation in oxygen.

With current technology making H_2 from coal is more costly than making it from natural gas. Wherever natural gas is readily available it tends to be the preferred feedstock for making H_2 at present. 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 a relatively capital- and energy-intensive process is employed to separate the H_2 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 sequestration) the cost is somewhat higher than for standard practice.

Table 7 presents the performance and H_2 production cost for a large plant (~1000 MW_t of H_2 output capacity) using present technology. The calculation shows that H_2 pressurized to 60 bar can be produced from natural gas priced at $3.4/GJ for a plant-gate H_2 production cost of $5.6/GJ if the CO_2 is vented or $7.0/GJ if 85% of the carbon in the original natural gas feedstock is separated out, compressed to 112 bar, and transported by CO_2 pipeline ~ 100 km for disposal in a depleted natural gas field.

With this currently available technology, the H_2 production cost with CO_2 sequestration is equivalent in terms of energy content to a wholesale gasoline price of $1.0/gallon. At this production cost the cost of H_2 for a consumer owning a fuel cell vehicle would be attractive,[34] but H_2 would not be able to compete so easily in many other markets for which H_2 would be used directly as a fuel.

There is ongoing R&D aimed at finding ways to make less costly H_2. Coal is of particular interest as a feedstock because: (*i*) its cost is low (for average US electric generators its price was half that for natural gas—before the recent fly up in natural gas prices) and declining, with little

[33] 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.

[34] Consider H_2 for a H_2 fuel cell car, which would typically have three times the fuel economy of a gasoline internal combustion engine of comparable performance. The "pump price" of H_2 at the refueling station would be $1.9/gallon of gasoline equivalent without CO_2 sequestration or $2.1/gallon with sequestration (see Table 7b). The fuel cost per mile to the consumer for these two cases would be 2.4 and 2.6 ¢/mile, respectively, for a fuel cell car with a gasoline-equivalent fuel economy of 80 mpg; for comparison, the fuel cost for a 25 mpg gasoline internal combustion engine car would be 4 ¢/mile for gasoline at $1/gallon.

Hydrogen (and Electricity) Production from Gasified Coal using a Hydrogen Separation Membrane Reactor (HSMR)

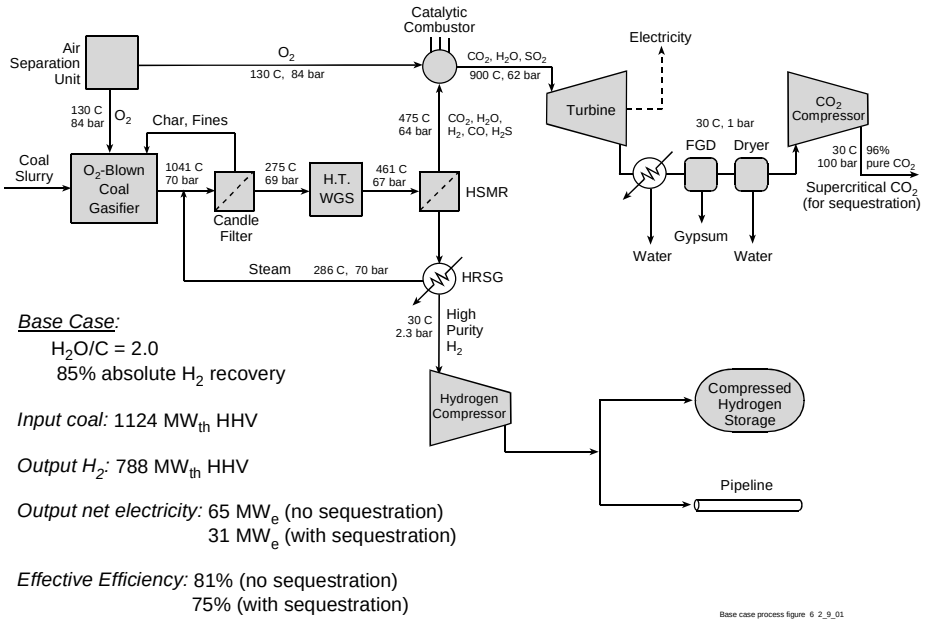

Figure 5: H_2 Production from Coal Using a H_2 Separation Membrane Reactor

The H_2 production system shown here is identical to that presented in Figure 4 except that the produced H_2 is compressed to 60 bar for pipeline transmission to distributed users, and the only electricity generated is that from the turbine that extracts electricity from the fuel gases that are not converted to H_2 and passed through the membrane. The HHV of the H_2 delivered to the pipeline is 70% of the HHV of the coal from which it is derived. The "effective efficiency" of H_2 conversion is higher than this (81% without CO_2 sequestration and 75% with CO_2 sequestration) because credit is taken for "coal saved" by not having to produce the electricity coproduct (at efficiencies of 42% without CO_2 sequestration and 39% with CO_2 sequestration—see Figure 4).

volatility; and (*ii*) it is abundant: estimated exploitable resources worldwide are equivalent to more than 600 years of total global fossil fuel use at the current rate (Rogner, 2000).

Figure 4 presents an advanced technology for making H_2 from coal for use in combined cycle power generation at the H_2 production site. The H_2 so produced could also be delivered to a pipeline for distributed applications as a fuel used directly. Figure 5 is a schematic showing the layout and energy balances for such a plant. A preliminary cost analysis of this system suggests that the cost of the H_2 produced from coal would be 2/3 as much as that shown in Table 7 for H_2 derived from natural gas—both without and with the costs of CO_2 sequestration taken into account (Kreutz and Williams, 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. The requirement of sequestering 19 GtC/y of CO_2 by 2100, as required in the IS92a variant emphasizing coal-derived H_2, would be a daunting challenge. To get an appreciation for the magnitude of the effort involved, consider how the global energy system might evolve to such an intensive level of sequestration. As noted earlier, early sequestration projects will probably be focused to a large

extent on making central station electricity from coal via oxygen-blown gasification (e.g., as shown in Figure 4), with a shift over time toward greater emphasis on H_2 production for distributed uses (e.g., as shown in Figure 5). Suppose that by 2010 the initial CO_2 sequestration projects associated with coal conversion (e.g., as shown in Figure 4) were brought on line, with a total coal power output of 1 GW_e; the associated CO_2 sequestration rate for these projects would be some 1.5 million tonnes of C/y in the form of CO_2 being sequestered in that year (5-6 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 40% per year until 2025,[35] the incremental annual sequestration capacity added by 2025 would be 240 million tonnes of C/y in the form of CO_2. If, after this rapid ramp-up, sequestration were continued at a linear expansion rate of 254 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 720 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 H_2. Alternatively, H_2 might be produced by breaking apart water molecules using electricity from either nuclear or renewable electric supply sources.

Consider first nuclear energy for the situation where the nuclear capacity level of the nuclear-intensive variant presented in Table 1 (5,500 GW_e) is complemented by the amount of additional capacity (21,800 GW_e) required to provide 545 EJ/y of electrolytic H_2.[36] If nuclear capacity were to build up linearly during the century and if plants are replaced every 40 years, the average rate of new nuclear construction would be ~ 490 GW_e/y. In light of proliferation concerns it is hard to imagine the deployment of the nuclear technology required except in large international nuclear parks maintained under tight security.

Or suppose 545 EJ/y of electrolytic H_2 were produced using large photovoltaic arrays. The land area required[37] would be about 1 million km^2—huge but not physically inconceivable, equivalent to 3% of the world's desert area.

But in both cases the economics of H_2 production would be unattractive, considering both current and advanced electrolysis technologies. Assuming baseload (90% capacity factor) electricity, the electricity price would have to be 0.9¢/kWh with commercial electrolyser

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[35] 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 subsequently. 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.

[36] Assuming advanced (90% efficient) electolyzers and 98%-efficient rectifiers, and a 90% capacity factor.

[37] Assuming that PV H_2 is produced in areas of high insolation (2300 kWh/m^2/y), that the DC conversion efficiency is 14% for PV, that advanced (90% efficient) electrolyzers are used, and that the land area required is twice the PV collector areas to account for shading effects.

technology[38] or 1.35 ¢/kWh with advanced electrolyzer technology[39] in order for electrolytic H_2 to be competitive with H_2 produced from natural gas with sequestration of the separated CO_2 using the commercially available technology described in Table 7, and lower breakeven prices are likely with advanced fossil energy conversion technologies such as that shown in Figure 5.

Such low electricity prices are not likely to be achievable with either nuclear or renewable electric technologies. Offpeak hydroelectric power prices are typically this low, however, and variable nuclear costs are plausibly 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. That is not the situation here, because the energy content of the H_2 in this IS92a variant is 2.2 times the total electricity generation rate in energy-equivalent terms (see Table 1), 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 H_2 production from water. An alternative to electrolysis for splitting the water molecule is to dissociate water by the application of heat to produce H_2. If this were done directly, temperatures of the order of 4000 ^oC 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 temperatures lower than for this brute-force approach—using either nuclear heat [(e.g., heat that can be provided by an HTGR (Yoshida, 1983; Yalçin, 1989)] or high-temperature solar heat that could be provided with collectors that concentrate sunlight (Steinfeld and Palumbo, 2001).

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,[40] one

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[38] From a study by Foster Wheeler (1996), the cost C_{EH} ($/ GJ, HHV) of electrolytic H_2 produced from electricity at a price P_E (in $/kWh) and a 90% capacity factor for the electrolysis system is, with commercial technology, $C_{EH} = \$3.52 + P_E/(\eta*0.0036$ GJ per kWh), where $\eta = 0.739$ = efficiency of converting electricity into H_2. To provide H_2 at a cost competitive with H_2 derived from natural gas with sequestration of the separated CO_2 and current technology ($7/GJ—see Table 7), the electricity generation cost would have to be less than 1¢/kWh.

[39] For advanced H_2 production systems [based on Ogden and Nitsch (1993)] operated at 90% capacity factor the cost of H_2 $C_{EH} = \$2.72 + P_E/(\eta*0.0036$ GJ per kWh), where $\eta = 0.882$ = efficiency of converting alternating current electricity into H_2 (an overall electrolytic efficiency of 90% and a rectifier efficiency of 98%).

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

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

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 estimated that the overall efficiency of converting nuclear heat into H_2 would be 45% (HHV basis) and that the production cost would be $35/GJ (Tadokoro *et al*., 1997)—five times the cost of making H_2 from natural gas with current technology, taking into account costs for CO_2 separation and geological sequestration (see Table 7).

One reason for the high cost is that nuclear heat is expensive, accounting for nearly 60% of total production cost. However, if the nuclear heat were "free," the cost of H_2 would still be $12.5/GJ—about 80% more than the cost of H_2 from natural gas with current technology and CO_2 sequestration (see Table 7).

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;[41] assuming this heat cost and a free 50%-efficient conversion technology the production cost for H_2 would be $18/GJ, which is far too high for the technology to be competitive.

Still, one might argue that in the future: (*i*) HTGR heat costs will come down substantially [as would be the case if recent very optimistic projections of capital and busbar generation costs of $1,000/kW$_e$ and 2.6 ¢/kWh (Taylor, 2001) were to be realized for the PBMR], and (*ii*) thermochemical conversion costs will also come down. Assuming that: (*i*) these very optimistic cost estimates for the PBMR can be realized in practice, (*ii*) 40% of the capital cost of the PBMR is for power generating equipment, and (*iii*) the PBMR is 43% efficient in converting nuclear energy into heat, the cost of nuclear heat would be ¼ of the value estimated in Tadokoro *et al*. (1997), and, for some unknown future 50%-efficient process, the contribution of nuclear heat to the H_2 production cost would be $4.5/GJ. To meet a total H_2 production cost target of $7/GJ (see Table 7) would require reducing the non-nuclear component of the total H_2 production cost to 1/5 of the estimate of Takodoro *et al*. (1997)! Competing with advanced coal-to-H_2 processes (see Figure 5) that are likely to be able to provide H_2 at lower cost than for commercial technology for making H_2 from natural gas (Kreutz and Williams, 2001) would be even more challenging economically.

In light of its poor economic prospects, thermochemical H_2 would be considered seriously only if 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

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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.

[41] Tadokoro *et al*. (1997) estimate that nuclear heat will cost 3.8 Yen per 1000 kcal = $9.0/GJ (assuming an exchange rate of 101 Yen/$, the average for 1995-96).

thermochemically using high-temperature solar thermal processes. Overall land requirements for producing H_2 via the latter processes are not much different from those estimated earlier for providing electrolytic H_2 from PV systems.[42]

Plantation biomass energy. The growing of biomass on a sustainable basis leads to no net buildup of CO_2 in the atmosphere, because the CO_2 released in combustion is balanced by the CO_2 extracted from the atmosphere during photosynthesis.

A detailed review of biomass energy options carried out for the World Energy Assessment 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 (Turkenburg, 2000). The study also concluded that the practical global potential for biomass production for energy is 100 to 300 EJ per year—some 10 to 210 EJ more than the amount of biomass assumed for the coal H_2 variant of IS92a. Thus, at most, biomass could displace about ¼ of the emission-free fuel targeted for this IS92a variant in the form of H_2 derived from coal.[43]

The amount of biomass included in IS92a (205 EJ per year) is in the midrange of what the WEA judged is feasible and is perhaps a reasonable target for bioenergy. Restoring the total bioenergy consumption rate to the IS92a level would require adding ~ 113 EJ/year of biomass energy from dedicated plantations. Assuming an average productivity of 12 dry tonnes per hectare per year would require land for such plantations in the amount 4.7 million km^2 (3.6% of the land area of the inhabited continents.[44]

One interesting possibility would be to make H_2 out of this biomass via gasification (Williams *et. al.*, 1995), perhaps in some of the same facilities that would make H_2 from coal. (Biomass/coal cofiring is now common practice in some regions, such as Scandinavia.) If the CO_2 coproduct of manufacturing H_2 from biomass were sequestered in geological formations, the CO_2 emission rate for the system would be negative—because the growing of biomass extracts CO_2 from the atmosphere. Thus making some H_2 from biomass with CO_2 sequestration in regions where sequestration is convenient would make it possible "to make room in the atmosphere" for some coal-derived H_2 without sequestration in some other regions that are distant from suitable storage reservoirs. Each EJ/y of H_2 produced from biomass with CO_2 sequestration would not only reduce the need for coal-derived H_2 by one EJ/y but also so doing would make it feasible to not

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[42] Consider a solar conversion system consisting of a set of heliostats (moving mirrors that track the sun) that reflect incident sunlight onto a central receiver where the solar energy is recovered as high-temperature heat in a region of high direct normal insolation (assumed to be 2500 $kWh/m^2/y$). Typically, about 40% of the solar energy incident on the collectors is recoverable as heat in the solar receiver (Spiewak, 1992; Williams and Wells, 1998), and, for such systems, the ratio of land to heliostat (collector) area would be about 5.5 (DeLaquil *et al*., 1993). Assuming a 50% efficiency for converting heat recovered in the receiver into H_2, the land area required for making 545 EJ/y of H_2 (see Table 1) is 1.7 million km^2 or 5% of the world's desert areas—not much different from the 1 million km^2 area estimated earlier for H_2 produced electrolytically from PV power sources.

[43] Assuming a 70% efficiency for converting raw biomass into synthetic fluid fuel.

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

sequester CO_2 in conjunction with production of approximately an additional EJ/y of H_2 produced from coal.[45]

At the global level with advanced technology it might be feasible to produce ~ 80 EJ/y of H_2 from 113 EJ/y of biomass by 2100, thereby reducing the need for coal-derived H_2 by this amount, obviating, with CO_2 sequestration, the need to sequester 2.8 GtC/y associated with an additional 80 EJ/y of coal-derived H_2, and reducing the total sequestration requirement for 2100 (for coal plus biomass) from 19.3 to 16.5 GtC/y.

Although the amount of plantation biomass considered here is not likely to pose serious conflicts with food production, according to the WEA (Turkenburg, 2000), some would argue that it would be 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. Plantation-based bioenergy is likely to be the most contentious of the renewable energy options.

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.

Major concerns often voiced about renewables are high costs, intermittency, and land-use intensity. But costs have been falling rapidly, and there are good prospects that both wind and

[45] Conversion processes for biomass similar to that shown for coal in Figure 5 would probably involve producing H_2 in an amount that is about 70% of the heating value of the biomass feedstock, and the required CO_2 sequestration rate would be about the same as for H_2 derived from coal (35-36 kg C per GJ of H_2).

PV technologies will become widely competitive over a period of 1-2 decades. No new technological developments are needed to deal effectively with the intermittency challenge. And although renewables are the most land-use intensive of these electric technology options, overall land requirements would be quite modest 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 markets and markets that use fuels directly. With technology available today, coal power plants characterized by near-zero emissions of both greenhouse gases and air pollutants would be competitive in terms of cost with present nuclear power technologies, and there are substantial opportunities for improving performance and reducing cost with advanced technologies. There is growing confidence in the scientific community that several thousand gigatonnes of carbon 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.

Initial efforts aimed at fossil fuel decarbonization/CO_2 sequestration will be focused largely on power plants. But over the longer term, the focus of this activity will probably shift to markets for fuels used directly, because of: (*i*) the enormity of the challenge of dealing with fuels used directly in mitigating climate change, (*ii*) the availability of other non-carbon options for dealing with the climate challenge in the power sector, (*iii*) the fact that geological CO_2 sequestration capacity is a finite resource, and (*iv*) the scarcity of alternative low-cost options for achieving deep reductions of CO_2 for fuels used directly.

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.

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 fossil fuel decarbonization/CO_2 sequestration technologies and strategies—which are still largely unfamiliar to most people. 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—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 viewed 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 in the general public to be decisively better than the 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 this issue is not on most people's radar screens today, it would come into sharp focus in a world with much more nuclear 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.

Table 1: Global Energy: Actual 1997 + IS92a Projection for 2100 and Variants					
	1997[a]	2100			
		IS92a[b]	Variants of IS92a Formulated by the Author		
			Nuclear-Electric-Intensive[c]	New Renewable-Electric-Intensive; Alternative Options for Fuels Used Directly:	
				Coal/Biomass-Derived Synfuels-Intensive[d]	Coal-Derived H_2-Intensive w/CO_2 Storage[e]
Electricity Generation (TWh/y)					
Coal	4,818	15,480	0	0	0
Oil	1,244	531	531	531	2,158
Natural gas	2,246	915	915	915	3,685
Synthetic liquids/gases from coal	-	3,017	3,017	3,017	0
Byproduct of H_2 from coal w/CO_2 storage	-	-	-	-	5,953
Hydroelectric	2,574	7,660	3,065	3,065	3,065
Wind	192	20,405	20,405	20,000	20,000
Photovoltaic				39,175	28,748
Biomass		1,381	1,381	1,381	4,475
Nuclear	2,266	18,695	38,770	0	0
Subtotal	13,340	68,084	68,084	68,084	68,084
CO_2 emissions, power sector (GtC/y)	1.9	4.9	1.3	1.3	0.9
Fuels Used Directly (EJ/y, HHV basis)					
Coal	43.2	132.7	132.7	132.7	25.8
Oil	142.7	94.6	94.6	94.6	58.8
Natural gas	63.0	37.3	37.3	37.3	0
Synthetic liquids/gases from coal	0	276.5	276.5	276.5	0
Synthetic liquids/gases from biomass	0	126.5	126.5	126.5	38.3
Coal-derived H_2 w/CO_2 storage	0	0	0	0	544.8
Subtotal	248.9	667.7	667.7	667.7	667.7
CO_2 emissions, fuels used directly (GtC/y)	4.3	14.9	14.9	14.9	1.7
Primary energy requirements (EJ/y, HHV basis)					
Coal	97.9	718	567	567	849
Oil	156.9	100	100	100	87
Natural gas	88.5	47	47	47	38
Biomass	-	205	205	205	92
Total CO_2 emissions (GtC/y)	6.2	19.8	16.1	16.1	2.6
CO_2 sequestration rate (GtC/y)	0	0	0	0	19.3

Notes to Table 1:

[a] Global data for 1997 are from EIA (2000a).

[b] IS92a is the reference ("Business As Usual") global energy scenario of the Intergovernmental Panel on Climate Change (IPCC, 1994). For an 80% average capacity factor, the installed nuclear capacity in 2100 is 2,666 GW_e.

[c] The nuclear-intensive variant differs from IS92a in two respects: (*i*) by 2100 all coal power is replaced by nuclear power; (*ii*) because of growing opposition to dam-building there is no expansion of hydroelectric power beyond what is already under construction (Rogner, 2000), with the difference made up by building more nuclear plants. For an 80% average capacity factor, the installed nuclear capacity in 2100 is 5,528 GW_e.

[d] The new renewable-electric-intensive + coal/biomass-derived synfuels-intensive variant differs from IS92a in two respects: (*i*) by 2100 all coal and nuclear power plants are replaced by wind and photovoltaic power plants; (*ii*) there is no expansion of hydroelectric power beyond what is already under construction, with the difference made up by building additional wind and photovoltaic plants. The level of wind power generation (20,000 TWh) is the long-run practical potential level of global wind power development as estimated in a major World Energy Council study (WEC, 1994)—see Appendix A. A discussion of the projected level of photovoltaic power development is presented in Appendix C. Fuels used directly are provided in the same manner as in IS92a and the nuclear-intensive variant of IS92a.

[e] The new renewable-electric-intensive + coal-derived H_2-intensive with CO_2 storage variant differs from IS92a in several respects: (*i*) by 2100 all coal and nuclear power plants are replaced by wind, photovoltaic, and bipower plants, as well as plants producing electricity as a coproduct of H_2 manufacture from coal with CO_2 storage; (*ii*) there is no expansion of hydroelectric power beyond what is already under construction, with the difference made up by building additional wind and photovoltaic plants; (*iii*) biomass is developed for energy only for residues according to the prescription in Table 2; (*iv*) all fuels used directly are provided by H_2 derived from coal with CO_2 storage, except for biofuels from residues (see Table 2), coal for iron/steel manufacture, and jet fuel derived from oil for airplane use. It is assumed that: (*i*) 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 required coal is 5.9 GJ/tonne of steel (Worrell, 1995); (*ii*) 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. It is assumed that global jet fuel requirements for airplane use in 2100 is $GJF_{2100} = (USJF_{1998})*GGDP_{2100}/USGDP_{1998}/(1.007)^{102} = 58.8$ EJ/y, where $USJF_{1998}$ is the US rate of jet fuel consumption in 1998 (3.59 EJ) (EIA, 2000b), $GGDP_{2100}$ is the global GDP in 2100 (284.5 trillion 1996 $, for IS92a), $USGDP_{1998}$ is the US GDP in 1998 (8.52 trillion 1996$), and 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. The EIA projects an average aircraft energy efficiency improvement rate of 0.74%/year for the United States for the period 1998-2020 (EIA, 2001). 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 jet fuel from crude oil, so that in 2100 the primary oil energy needed for airplanes is 65.3 EJ/y. The net efficiency of H_2 manufacture from coal is 75.5%, taking credit for fuel savings from generating the electricity coproduct @ 39% efficiency—see text discussion.

Table 2: Projected Levelized Lifecycle Electricity Cost for Central-Station Wind and Photovoltaic Technologies[a]												
	1997		2000		2005		2010		2020		2030	
Wind												
Wind farm capacity (*MW*)	25		37.5		50		50		50		50	
Installed capital cost (*$/kW*)	1000		750		720		675		655		635	
Wind power class[b]	4	6	4	6	4	6	4	6	4	6	4	6
Annual average capacity factor (%)	26.2	35.5	30.2	40.4	35.1	45.3	36.2	46.4	37.6	47.9	38.3	48.7
Lifecycle cost of electricity generation (*¢/kWh*)	6.6	4.8	4.5	3.4	3.4	2.7	3.2	2.5	3.0	2.4	2.9	2.3
PV (*thin-film*)												
Plant capacity (*MW*)	0.02		3		10		20		20		20	
System efficiency (*%*)	4.8		7.2		8.8		11.2		12.8		13.6	
Installed capital cost (*$/kW*)	9,300		5,300		2,900		1,500		1,110		880	
Insolation ($kWh/m^2/y$)	1800	2300	1800	2300	1800	2300	1800	2300	1800	2300	1800	2300
Lifecycle cost of electricity generation (*¢/kWh*)	61.3	48.1	34.4	27.0	18.7	14.6	9.7	7.7	7.1	5.6	5.6	4.5

[a] Source: Based on EPRI/OUT (1997), with capital charges in each case calculated assuming a 10% cost of capital, a 25-year plant life, and an insurance charge of 0.5% per year. Corporate income and property taxes are neglected. Thus the annual capital charge rate is 11.5%.

[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—see Table A1.

Table 3: Alternative Technologies for Reducing CO_2 Emissions from 400-MWe Coal Plants (current technologies)[a]						
Technology	Efficiency (%, HHV)	Capital cost ($/kW$_e$)	Generation cost (¢/kWh)	O_2 require-ments (tonnes/h)	CO_2 emissions (gr C/kWh)	Cost of avoiding CO_2 emissions ($/tC)
Ultrasupercritical pulverised coal steam turbine plant						
Reference, CO_2 vented	43.1	1,114	3.24	0	196	-
CO_2 recovery from flue gases	34.3	1,812	5.15	0	36.8	132
O_2 firing, CO_2 recovery from flue gases	32.0	1,661	5.20	339	0	109
Pressurised fluidised-bed combustion plant						
Reference, CO_2 vented	43.1	1,114	3.24	0	196	-
O_2 firing, CO_2 recovery from flue gases	35.4	1,675	5.09	307	0	103
Integrated gasifier–combined cycle plant						
Reference, CO_2 vented	45.9	1,114	3.20	80	184	-
Cold CO_2 recovery from synthesis gas	36.1	1,514	4.72	108	23.9	95

[a] From Table 8.9 in Williams (2000). Based on calculations by Dale Simbeck, SFA Pacific. Engineering and contingencies are 10 percent of process capital equipment costs; general facilities are 10 percent of process capital equipment costs. The annual capital charge rate is 11.5 percent. The coal price is $0.93/GJ, the average price projected for electric generators in the United States in 2020 (EIA, 2000b). The annual average capacity factor is 80 percent. All options involving CO_2 separation and disposal include the cost of compressing the separated CO_2 to 135 bar plus a cost of $5 per tonne of CO_2 ($18 per tC) for pipeline transmission and ultimate disposal.

Table 4: Performance, Generation Costs, and CO_2 Emission Rates for Alternative Conventional Fossil Fuel Power Plants

Performance, costs, emission rates[a]	Pulverised coal steam-electric plant w/FGD	Coal IGCC plant		Natural gas combined cycle (NGCC) plant	
		Air-cooled turbine	Steam-cooled turbine	Air-cooled turbine	Steam-cooled turbine
Plant capacity (MW_e)	500	500	400	506	400
Efficiency (%, HHV basis)	35.5	40.1	43.8	50.2	54.1
Installed capital cost ($/ kW_e)	1090	1320	1091	468	445
Generation cost elements (¢/kWh)					
Capital charges[b]	1.79	2.17	1.79	0.77	0.73
Fixed O&M	0.23	0.28	0.30	0.23	0.23
Variable O&M	0.20	0.20	0.21	0.15	0.15
Fuel	0.94	0.83	0.76	2.44	2.26
Total generation cost (¢/kWh)	3.16	3.48	3.06	3.59	3.37
CO_2 emission rate (gr C/kWh)[d]	238	210	193	98	91

[a] Plant capacities, installed capital costs, operation and maintenance costs, and plant efficiencies are from Todd and Stoll (1997). Combined cycle plants [both natural gas combined cycle (CC) and coal integrated gasifier combined cycle (IGCC)] with air-cooled and steam-cooled gas turbine blades involve use of General Electric Frame 7F (commercial) and Frame 7H (near commercial) gas turbines, respectively.

[b] Capital charges are calculated assuming a 10 percent discount rate, a 25-year plant life, and an insurance rate of 0.5 percent per year, and neglecting corporate income taxes, so that the annual capital charge rate is 11.5 percent. It is assumed that all power plants are operated at an average capacity factor of 80 percent.

[c] Coal and natural gas prices of $0.93/GJ and $3.40/GJ, respectively, the average prices projected for electric generators in the United States in 2020 (EIA, 2000b).

[d] The carbon contents of coal and natural gas are assumed to be 23.4 kg C/GJ and 13.7 kg C/GJ, respectively.

Table 5: Emission Rates For And Estimated Costs Of Environmental Damages From Air Pollutant Emissions of Fossil Fuel Power Plants *(Low Valuation for Typical European Conditions)*

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

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

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

[c] In 1990, PM_{10} emissions from U.S. electric utility coal power plants amounted to 245,000 tonnes (Spengler and Wilson, 1996), when these plants consumed 17.1 EJ of coal (EIA, 1998), so that the PM_{10} emission rate was 14.34 gr/GJ—the assumed emission rate for all steam-electric cases in this table.

[d] It is assumed: that the new coal steam-electric plant is 35.5% efficient; that the sulfur content of the coal is 454 gr/GJ (1.08% sulfur by weight), the average for U.S. coal power plants in 1997 (EIA, 1998b); that SO_2 emissions are reduced 95%, a commercially feasible rate; that the NO_x emission rate is 86 gr/GJ—achievable with advanced low-NO_x burners that will be commercially available shortly;

[e] It is assumed: that the coal integrated gasifier combined cycle (IGCC) plant is 43.8% efficient, based on use of steam-cooled gas turbines (see Table 4); that the emission rates equal the measured values for the Buggenum coal IGCC plant (Netherlands):10.0 and 0.3 gr/GJ of coal, for NO_x and particulates, respectively, as well as 99% sulfur recovery (data presented by Co van Liere, KEMA, at the Gasification Technologies Conference in San Francisco, 17–20 October 1999); and that the sulfuer content of coal is 454 gr/GJ.

[f] It is assumed: that the natural gas combined cycle (NGCC) plant is 54.1% efficient, based on use of steam-cooled gas turbines (see Table 4); that the NO_x emission rate is 9 ppmv (dry volume basis, at 15% O_2), corresponding to an emission rate of 0.092 gr/kWh.

Table 6: Potential Global Energy Supplies from Biomass Residues for 2100			
	Primary Energy[a] (EJ/year)	Fluid Fuel (EJ/year)	Electricity (TWh/year)
Dung[b]	18.9	15.1	-
Sugar cane[c]	13.3	-	1,345
Industrial residues[d,e]	11.7	4.6	618
Forest residues[d,f]	3.2	1.2	169
Cereals[d,g]	14.0	5.5	739
Urban refuse[d,h]	30.4	11.9	1,604
Total	91.5	38.3	4,475

[a] Projections of potential biomass residue supplies on a region-by region basis for the years 2025, 2050, 2075, and 2100 were made in conjunction with the preparation of Chapter 19 (Energy Supply Mitigation Options) for the Second Assessment Report of Working Group II (Impacts, Adaptation, and Mitigation Options) of the Intergovernmental Panel on Climate Change (IPCC, 1996); the residue supply estimates compiled for that report are presented here, based on Williams (1995).

[b] Dung generation rates are based on projections of production of meat and dairy products by region. It is assumed that 1/8 of total dung generated is recoverable for methane generation via anaerobic digestion at 80% conversion efficiency.

[c] It is assumed that sugar cane production by region increases in proportion to population, that all of bagasse (residue left after crushing sugar cane to extract sugar) and 2/3 of the cane tops and leaves are recoverable for energy. It is assumed that residues are gasified in air-blown gasifiers and the gas used to produce electricity and process heat via biomass integrated gasifier/combined cycle power plants (technology that is currently being demonstrated). The effective efficiency for converting residues to electricity for export from sugar factories (electricity produced in excess of onsite needs) is expected to be ~ 36% for next-generation biomass integrated gasifier/combined cycle technology—the value assumed here (Larson *et al*., 2001).

[d] For these residues it is assumed that dimethyl ether (DME) plus electricity are produced from biomass-derived synthesis gas using a once-through liquid phase reactor. It is assumed that 39% of the biomass energy is converted to DME and 19% to electricity (HHV basis)—conversion efficiencies expected to be characteristic of current technology for manufacturing these energy carriers from coal via oxygen-blown gasification (Air Products, 1993). (For biomass, synthesis gas can be produced via gasification in steam using indirectly heated gasifiers—obviating the need for the air-separation plant needed for making synthesis gas from coal).

[e] It is assumed that industrial (mill) residues in the forest product industry increase by region in proportion to population and that 3/4 of mill residues are recoverable.

[f] It is assumed that forest (logging) residues in the forest product industry increase by region in proportion to population and that 1/2 of logging residues are recoverable.

[g] It is assumed that grain residues are produced at a rate of 1.3 tonnes per tonne of harvested grain (the global average rate for 1983) and that ¼ of these residues are recoverable for energy purposes.

[h] It is assumed that urban refuse is generated at a rate of 300 kg/capita per day with a heat value of 12.7 MJ/kg (current average value for OECD Europe) and that 3/4 of residues generated are recoverable

Table 7a: Production of 60 Bar H_2 from Natural Gas, at 1000 MW_t of H_2 Output Capacity[a]		
	Without CO_2 Sequestration	With CO_2 Sequestration[b]
H_2 Output/NG Input (%)	81	78
CO_2 Emission Rate (kg C/GJ H_2)	17.56	2.74
CO_2 Sequestration Rate (t CO_2 /h)	-	204
Capital Investment w/o CO_2 Disposal ($ million)	262	429
Capital for CO_2 Pipeline ($million)	-	36
Lifecycle Cost ($/GJ)		
Capital (except CO_2 Pipeline)[c]	1.20	1.97
Capital for $_{CO2}$ Pipeline	-	0.21
O&M (except for CO_2 Disposal)	0.24	0.39
O&M for CO_2 Disposal	-	0.07
NG input[d]	$1.235*P_{NG}$	$1.282*P_{NG}$
Total[d]	$1.44 + 1.235*P_{NG}$	$2.64 + 1.282*P_{NG}$
Table 7b: Delivered Cost of H_2 from Natural Gas (*$/GJ*)		
Production Cost (for P_{NG} = $3.40/GJ[e])	5.64	7.00
Central H_2 plant compression from 870 psia (60 bar) to 1000 psia for storage or pipeline transmission ($/GJ)[f]	0.03	0.03
Central H_2 plant buffer storage cost ($/GJ), storage capacity = 1/2 day output of H_2 plant[f]	0.41	0.41
H_2 pipeline distribution system[f]	1.58	1.58
Refueling station[f, g]	5.61	5.61
Total cost of delivered H_2	$13.27/GJ ($1.9/gallon, gasoline equivalent)	$14.63/GJ ($2.1/gallon, gasoline equivalent)
Cost of CO_2 Pipeline and CO_2 Disposal[h]		$5.0/t CO_2
Cost of Avoided CO_2 Emissions	-	$92/tC

[a] From a study prepared for Statoil and the IEA GHG Programme by Foster Wheeler (FW, 1996) except that the FW results are presented here with all energy quantities expressed on a HHV basis (whereas the original FW report presented energy quantities on a LHV basis). For these systems all energy requirements for H_2 production are provided from natural gas.

[b] 85% of the CO_2 in the feedstock is recovered, compressed to 112 bar, and transported by pipeline to a disposal site in a depleted natural gas field 105 km from the H_2 production plant site.

[c] For an 80% capacity factor and an annual capital charge rate of 11.5%.

[d] Here P_{NG} is the natural gas price (in $ per GJ, HHV basis).

[e] The natural price projected for U.S. electric generators in 2020 by the U.S. Energy Information Administration (EIA, 2000b).

[f] From studies by Joan Ogden at Princeton University's Center for Energy and Environmental Studies: high auto density case (1600 cars per square mile)—equivalent to half the cars in Los Angeles area being H_2 FC cars.

[g] For a refueling station dispensing H_2 (345 bar) to FC vehicles at a rate of 1 million scf H_2/day.

Appendix A: Outlook for Wind Power

Wind power is the most mature of the new renewable electric technologies. Worldwide installed wind power capacity has been growing rapidly—from 7.4 GW_e in 1997 to 13.6 GW_e in 1999, when wind power provided 24 TWh/y of electricity—about 0.2% of total generation. Rapid growth has been catalyzed by promotional programs (esp. in Germany, Denmark, and Spain) and increasingly favorable costs. Currently, the unsubsidized cost of wind electricity in areas of moderate-quality wind resources (wind class 4—see Table A1) is typically less than 5 ¢/kWh; costs are expected to fall to near 3 ¢/kWh for such wind resources by decade's end (see Table 2).

Without storage, the intermittency of wind power makes it less valuable than power from dispatchable thermal power plants. 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 (Kelly and Weinberg, 1993). Without storage much lower penetrations 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 wind (as well as other intermittent renewables) represent competitive rather than complementary power technologies in grid applications.

Grubb and Meyer (1993) estimated that the practically exploitable global onshore windpower potential is 53,000 TWh/y, whereas a World Energy Council study (WEC, 1994) estimated this potential to be 20,000 TWh/y; [46] the author's estimate is 43,000 TWh/y.[47] For comparison, worldwide electricity generation in 1997 totaled 13,000 TWh/y.

The estimates of the global wind energy potential by Grubb and Meyer (1993) and WEC (1994) start from the same estimate of a gross electric generation potential of 500,000 TWh/y on the 23% of the land area of the inhabited continents associated with average wind speeds in excess of 5 m/s at 10 m off the ground.[48,49] The differences between these estimates reflect differing

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[46] This is twice the U.S. wind electric potential estimated in Table A1.

[47] The author's estimate of the practically exploitable global wind energy potential is 43,000 TWh/y, obtained as follows. First, the author restricts his estimate to the wind resources at least as good as Class 4 resources (average wind speeds at 10 m of at least 5.6 m/s. Second, the exploitable potential is estimated for 100 m hub height, which is expected to be routinely exploitable with technology available by 2030 (EPRI/OUT, 1997); at this hub height, the net annual electricity generation rate with 2030 technology is estimated to be 1412, 1566, and 1797 kWh/m^2 of wind intercepted by 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 km2 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.

[48] For Wind Classes 3 and above—according to the U.S. convention for measuring wind resources; see, for example, Table A1, which shows wind resource estimates for the United States in Classes 4-6.

judgments as to what is practical vis a vis accessibility constraints, environmental constraints, and land-use competition constraints (including aesthetic considerations). The author's estimate reflects, in addition, more recent estimates of the potential technical performance of wind turbines in the 2030 time frame (EPRI/OUT, 1997).

Most of the good wind resources are in areas remote from major markets (Grubb and Meyer, 1993). Examples: (*i*) in the United States, over 95% of the high-quality wind resources are concentrated in the 12 states of the Great Plains[50] (see Table A1), 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 1800 TWh/y (Lew *et al*., 1998)—about twice the thermal electricity generation rate in China in 1998.

The remoteness of many good wind resources poses an exploitation challenge, because local populations will be able to consume only a tiny fraction of available supplies. Exploitation might be feasible at acceptable cost with high capacity (GW_e-scale) transmission lines operated at high capacity factor (> 80%) for markets even as distant as 1,000-3,000 km from generation sites.

Cavallo (1995a) has shown that, without adding electrical storage capacity, the cost of electricity at the end of a long transmission line will decline as wind turbine capacity is added above a wind farm capacity matched to the transmission line capacity up until the transmission line capacity factor reaches a level somewhat in excess of 50% (up from ~ 35% for a system with wind farm and transmission line capacities equal)—because the economic gain from increasing the capacity factor on the transmission line will be greater than the economic losses from "electron spillage" associated with the infrequent high-speed winds that provide power at rates in excess of transmission line capacity.

To achieve transmission line capacity factors of 80-90%, however, requires that wind farms be coupled to appropriate storage technology (Cavallo, 1995a). Compressed air energy storage (CAES—see Table A2) stands out as being especially promising for helping provide baseload electricity from large wind farms. In Appendix B calculations are presented indicating that baseloading wind power in large wind farms using CAES would add ~ 0.5 to 1.0 ¢/kWh to the cost of wind power, thereby making baseload wind power only marginally more costly than coal or natural gas power, with system CO_2 emissions in the range 14% and 7% of those for natural gas combined cycle and coal integrated gasifier combined cycle power plants, respectively (see Table 5 and Appendix B).

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[49] The Grubb/Meyer (1993) calculation is for a 50 m hub height, a scaling of wind speeds as the 1/7 power of height, a Rayleigh distribution of wind speeds (so that $\langle v^3 \rangle = (6/\pi)^* \langle v \rangle^3$), an average turbine efficiency $\eta = 0.35$, an array/system loss rate of $\lambda = 0.25$, and down-wind/cross-wind turbine spacings of 10 and 5 turbine blade diameters (D), respectively, so that the power density per unit of land area is $\pi^*\eta^*(1 - \lambda)(D/2)^2/(5D^*10D) = 0.0041$ times the power density for the wind intercepted by the turbine blades.

[50] Colorado, Iowa, Kansas, Minnesota, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming.

For the renewable-electric-intensive variants of the IPCC's IS92a scenario presented in Table 1, the wind generation rate in 2100 is assumed to be 20,000 TWh/y [equal to the WEC (1994) estimate but less than half of the author's estimate of the practically exploitable wind electric potential onshore]. The corresponding area occupied by wind farms is ~ 0.6% of the land area of the inhabited continents. Three considerations are helpful in thinking about the land-use intensity of these variants.

First, only about 5-10% of the land on which wind turbines are deployed is actually used for turbines and their foundations, access roads, electrical substations, and other infrastructure(EPRI/OUT, 1997),[51] so that most of the land is can be used for other purposes such as farming and ranching.

Second, people in the remote areas where most wind resources are concentrated are likely to be concerned much less than people in densely populated areas about aesthetic impacts of large wind farms, if wilderness areas are avoided (as is the case for the U.S. wind resource estimate presented in Table A1).

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), the income from wind farm royalties would be a major supplement to farming/ranching income[52]—providing a powerful incentive for

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[51] For the 12 states of the U.S. Great Plains, using all the exploitable wind resources (see Table A1) would involve establishing wind farms on 14% of the land area of these states, but most of this land could simultaneously be used for other purposes (e.g., farming and ranching) because only 0.7 to 1.4% of the land area of these states would actually be needed for wind power equipment and infrastructure (EPRI/OUT, 1997).

[52] For Class 4 winds, wind power generation costs in the United States in 2005 are projected to average 4.0 ¢/kWh in 2005, when the net power 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 about $80/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.

landholders to make their lands available for wind farms without jeopardizing their capacity for farming/ranching.

Table A1: Estimated Recoverable Wind Resources and Projected Costs by Wind Power Class in the US			
	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 resources	9,200 TWh/y	690 TWh/y	490 TWh/y
Resources in 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 & urban areas, 50% of forest lands, 30% of farm lands, &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/m2/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.

Table A2: Capital Costs for Electricity Storage[a] *(1997 Dollars)*				
Technology	Component Capital Cost		Total Capital 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 Robert B. Schainker (Electric Power Research Institute), presented to the PCAST Energy R&D Panel, 14 July 1997.

Appendix B: Incremental Cost of CAES in Creating a Baseload Wind Farm

Compressed air energy storage (CAES) is a proven, commercially available, low-cost technology (Shainker *et al*., 1993) that can enable high penetrations on electric grids with intermittent renewable energy technologies. Firming up intermittent renewable electricity requires of the order of a day or more of storage. As indicated by the calculations presented in Table A2, CAES is the only storage technology offering low-costs at such high levels of storage. 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.

An important application of CAES will be to make baseload electricity out of wind power to facilitate the exploitation of large, good wind resources that are remote from major markets (Cavallo, 1995a; Cavallo, 1996; Lew *et al*., 1998). In regions where wind supplies show significant seasonal power variability, even interseasonal storage might be considered in order to provide baseload power; if porous media (e.g., aquifer) storage is available in such regions, interseasonal storage is feasible and can be economically attractive in appropriate circumstances (Cavallo, 1995b).

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). According to the EPRI Technical Assessment Guide (EPRI, 1993), 85% of the area of the United States has one or more suitable geologies for CAES (see Figure B1).

In what follows a cost analysis is presented of applications of CAES technology to the production of "baseload" wind power, based on Cavallo (1995a).[53] The Cavallo analysis is for a system consisting of a large wind farm plus CAES located hypothetically in Kansas and designed so as to minimize the cost of transport to distant markets via a high voltage transmission line. To realize favorable transmission costs, a large (2 GW_e) line and a 90% transmission line capacity factor are assumed. Cavallo's modelling for the Kansas wind regime indicates that the required installed capacities are 6 GW_e for the wind farm (with a 36% capacity factor) and 1.4 GW_e plus 20 hours of storage for the CAES system. The busbar cost of electricity BCOE (in $/kWh) for this system is given by:

$$BCOE = (1 - \beta)*WFLC + \beta*CSLC,$$

where:

WFLC = levelized cost of electricity for the wind farm (in $/kWh),
CSLC = levelized cost of electricity from compressed air energy storage (CAES) (in $/kWh),
β = fraction of electricity delivered to the transmission line from CAES,

[53] As presented here, the Cavallo calculation is modified as follows: costs are updated from 1992$ to 1999$ (by multiplying Cavallo's costs by a GDP deflator of 1.145); the natural gas prices is assumed to be $3.40/GJ, the average price for U.S. electric generators projected for 2020 (EIA, 2000b) instead of $4.33/GJ assumed by Cavallo; the capital charge rate of 0.115 is assumed (instead of the 0.107 value assumed by Cavallo, to make the calculation consistent with the other cost calculations presented in this paper).

$$CSLC = [CCR*(PCC + SCC*h_s) + FOM]/(CF_s*8766) + HR*PF + WFLC*ER + VOM, \text{ and}$$

CCR = capital charge rate = 0.115
PCC = power-related specific capital cost for the CAES system (in $/kW),
SCC = storage-related specific capital cost for the CAES system (in $/kWh),
h_s = storage capacity of the CAES system (in hours),
FOM = fixed operation and maintenance costs for the CAES system (in $/kW-year),
VOM = variable operation and maintenance cost for the CAES system (in $/kWh),
CF_s = capacity factor for the CAES system,
HR = the heat rate for the CAES discharge sub-system (in GJ/kWh),
PF = price of fuel consumed by the CAES discharge subsystem = $3.40/GJ,
ER = electricity input/output ratio for the CAES.

For the system modelled by Cavallo:

h_s = 20 hours of storage
$\beta = 0.219$
$CF_s = 0.28$
PCC = $640/kW, SCC = $3.45/kWh
FOM = $1.38/kW-year, VOM = $0.00171/kWh,
HR = 0.004326 GJ/kWh
ER = 0.67,

so that

$$CSLC = 0.050 + 0.67*WFLC, \text{ and } BCOE = 0.928*WFLC + 0.0109.$$

Assuming WFLC = $0.03/kWh, CSLC = $0.070/kWh and BCOE = $0.039/kWh. Thus the cost penalty associated with increasing the system capacity factor from 36% to 90% with CAES is ~ $0.009/kWh, assuming Cavallo's estimates of CAES costs. With the more recent lower CAES costs projected by Shainker (PCC = $350/kW and SCC = $1/kWh—see Table A2), the cost penalty associated with "baseloading" wind power would be lower, ~ $0.005/kWh (CSLC = $0.054/kWh; BCOE = $0.035/kWh).

CO_2 emissions from the CAES subsystem are (13,500 gr/GJ)*HR = 58 gr/kWh with natural gas firing [64% of the emission rate for state of the art (Frame 7H) natural gas combined cycle and 30% of the emission rate for a coal IGCC plant (see Table 5)]. The emission rate for the entire wind farm/CAES system (the more appropriate measure) is β*58 gr/kWh = 13 gr/kWh, corresponding to 14% and 7% of the of the emission rates for natural gas combined cycle and coal IGCC plants, respectively (see Table 5).

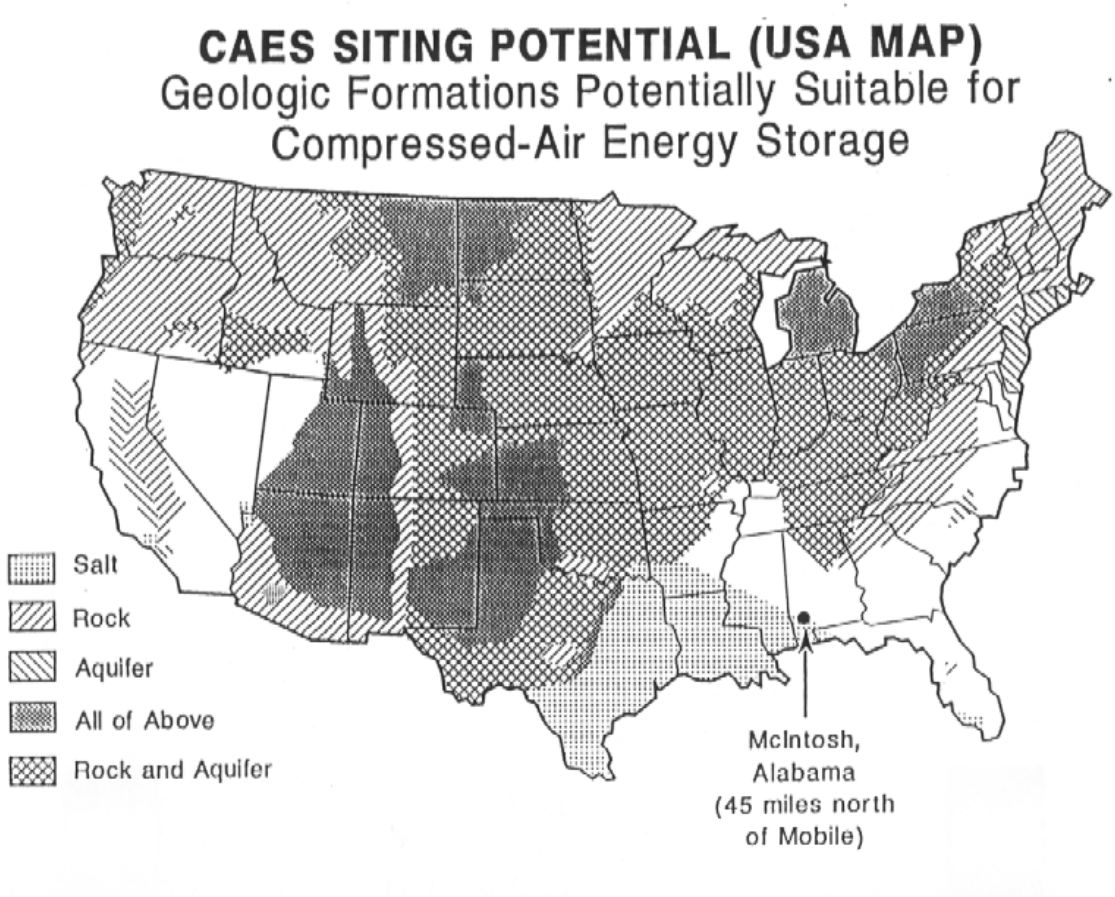

Figure B1: Regions of the United States with Potentially Suitable Sites for Compressed Air Energy Storage

Source: Cohn and Louks (1991).

Appendix C: The Outlook for Photovoltaic Technology

As a result of advances from R&D[54] and early market experience, photovoltaic (PV) module costs have declined by more than an order of magnitude since 1976 (PCAST Panel on International Cooperation in ERD[3], 1999). Still, when considered for central-station power applications, photovoltaic (PV) technology lags considerably behind wind power. Today the cost of generating PV electricity in areas with good insolation is about 8 times the cost of wind electricity in regions with good wind resources (see Table 2). For thin-film PV technologies now coming into power generation markets, central-station generation costs are expected to fall by more than half by 2005 (see Table 2). Yet even this dramatic reduction would leave PV central-station power generation costly—some 15 ¢/kWh in areas of good insolation—three times the cost of wind generation today.

However, PV technology offers major advantages over wind power and other renewable energy sources in that small PV systems can be sited near users where the power generated is worth much more than in central-station power plants—e.g., on residential building rooftops, commercial building facades, and roofs of parking garages. Such decentralized generation is feasible because a PV system requires no system operators, has costs per unit of electricity provided that are not especially sensitive to scale, is not noisy, and causes no pollution.

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 fallen from $\$17/W_{ac}$ in 1984, to $\$9/W_{ac}$ in 1992 and $\$6/W_{ac}$ in 1996 (PCAST Energy R&D Panel, 1997). Several PV vendors have indicated that installed costs for residential systems could reach $\$3/W_{ac}$ before 2005 (Forest and Braun, 1997; Lawry, 1996).[55]

Photovoltaic (PV) technology has reached a crossroads at which appropriate public policies could open up large-scale fully commercial markets for distributed grid-connected power.

Various thin-film PV technologies[56] offer good prospects for achieving very low costs and moderate (and probably adequate) efficiencies. Detailed "bottom up" analysis of two competing amorphous silicon thin-film PV technologies (Payne, Duke, and Williams, 2001) shows that residential PV system costs of less than $\$3/W_{ac}$ are indeed feasible in this time frame—if module production is scaled up from current 5-10 MW_p/y plants to 100 M W_p/y plants, if PV system efficiencies of 6.4%-7.7% are realized (based on what has been proven for submodules becoming the norm for commercial product), and if current manufacturing and installation costs are "learned out" as a result of a rapidly growing volume of cumulative production. With home

[54] For example, the US federal PV R&D investment totaled $2.4 billion (1999$), 1974-1999.

[55] This cost level for residential systems is consistent with projections by the Electric Power Research Institute and the US Department of Energy for central-station PV systems in this time period (see Table 2).

[56] Very low costs for thin-film PV technologies are potentially realizable 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.

mortgage financing and "net metering" provisions,[57] such PV systems for module production plants that would be built in ~ 2005 could provide PV electricity at costs of less than 10 ¢/kWh in areas of good insolation and less than 12 ¢//kWh in areas of moderate insolation—costs that would make such systems cost-competitive for the consumer in those regions (e.g., southern California, the greater New York metropolitan area) where retail electricity rates exceed these costs (Payne, Duke, and Williams, 2001). Marney *et al*. (1997) have estimated that at an installed system cost of $\$3/W_{ac}$ the total potential U.S. residential PV market that would be cost effective to the consumer with home mortgage financing and net metering provisions is 40,000 MWp (10 million US homes at 4 kW_p each). Even if all this potential market could be exploited it would make only a minor contribution (~ 2%) to US electricity supply at current demand levels, but the availability of this market (equivalent to 200 times annual world PV module production at present!) could be an enormous stimulus to PV technology development with appropriate public policy supporting measures such as net metering and public support for long-term PV R&D.

Cadmium telluride, copper indium diselenide and thin-film crystalline PV are other thin-film PV technologies that offer the potential for low cost, along with amorphous silicon. All will soon be competing with amorphous silicon in commercial PV markets.

An analysis carried out jointly for the Electric Power Research Institute and the US Department of Energy (EPRI/OUT, 1997) projects that between 2005 and 2030 system efficiencies for thin-film PV will roughly double (to almost 14%) and system costs for central station applications will decline roughly three-fold (to less than $\$1/W_{ac}$), so that PV electricity prices by then would be less than 4.5 ¢/kWh in areas of good insolation and about 1 ¢/kWh more in areas of average insolation (see Table 2). These would be attractive market prices, especially considering that PV generation will tend to peak in the afternoon near the time of peak demand in areas and seasons where there are significant air conditioning loads. In areas of low insolation (much of northern Europe) it is not likely that PV would be much deployed in central station configurations; there most systems would tend to be sited near users in the form of "building-integrated" PV designs—systems for which the electricity generated is more highly valued than central station electricity and for which some credit can be taken for building materials not needed with such designs. European PV R&D is leading the way toward understanding better the prospects for such building-integrated systems.

Concerns that have often been voiced about PV technology are: (*i*) at best PV can make only modest contributions to overall electricity needs in light of the intermittency of PV electricity; (*ii*) the time required to pay back the energy required for manufacture and install PV systems is so long as to make generating net energy difficult; and (*iii*) prohibitively large areas would be required for PV systems.

The challenge of intermittency. As in the case of wind power, high reliability of power for grid systems can be assured despite the intermittency of PV electricity, for grid penetration levels by PV of the order of 10-30 percent 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

[57] "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.

hydroelectric power (Kelly and Weinberg, 1993). And, as in the case of wind power, very high levels of grid penetration (up to 100%) can be realized by coupling PV (or PV plus wind) to compressed air energy storage systems that can compensate for the intermittency of renewables at potentially low incremental cost.

Energy payback. PV systems are expected to last 20-25 years. The time required to pay back the energy invested in manufacturing and installing PV systems must be a small fraction of such system lifetimes if PV is to make substantial net contributions to energy supplies.

For current grid-connected rooftop crystalline silicon and thin-film systems, payback times are in the range 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).

Land requirements. To the extent that PV systems can be sited near users on building rooftops or facades there would be no significant land-use competition issue associated with PV deployment. Considering that residential rooftop PV systems in the United States will typically have capacities in the range 2-4 kW_{ac}, a per capita PV capacity of ~ 1 kW_{ac} [58]is plausible for regions where distributed PV generation is feasible. This would require[59] that a per capita area of ~ 7 m^2 be available for collectors near users.

If all future PV systems were in central-station configurations, the total land area required worldwide for the PV projection of about 39,000 TWh/y for 2100 presented in Table 1 for the new renewable-electric intensive/coal-biomass-derived synfuels-intensive variant of the IS92a scenario[60] would be relatively modest—some 320,000 km^2, equivalent to 0.25% of the land area of the inhabited continents or the area of the state of New Mexico.

It is unclear what fraction of ultimate PV might instead be deployed in distributed applications, but the fraction might be significant. If, on average, 1 kW_{ac} per capita could be deployed in distributed configurations the land required for central-station plants would be reduced by half.

[58] In areas of average US insolation (1800 $kWh/m^2/y$) this much capacity would provide 45% of average US residential electricity requirements or 15% of average US total electricity requirements (at 1998 demand levels) or 30% of average world electricity requirements projected for 2100 in the IS92a scenario.

[59] Assuming the PV system efficiency indicated in Table 2 for 2030.

[60] This estimate is based on the PV system efficiency indicated in Table 2 for 2030, an average insolation of 1800 kWh/m^2 /year (the US average), and a factor of two increase over the collector area to account for shading effects of other collectors.

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