

Carbon emission and mitigation cost comparisons between fossil fuel, nuclear and renewable energy resources for electricity generation

Ralph E.H. Sims^{a,*}, Hans-Holger Rogner^b, Ken Gregory^c

^a Centre for Energy Research, Massey University, Palmerston North, New Zealand

^b Department of Nuclear Energy, International Atomic Energy Agency (IAEA), P.O. Box 100, Wagramerstr. 5, A-1400 Vienna, Austria

^c Centre for Business and Environment, 80 Cecil Park, Pinner, Middlesex HA5 5HH, UK

Abstract

A study was conducted to compare the electricity generation costs of a number of current commercial technologies with technologies expected to become commercially available within the coming decade or so. The amount of greenhouse gas emissions resulting per kWh of electricity generated were evaluated. A range of fossil fuel alternatives (with and without physical carbon sequestration), were compared with the baseline case of a pulverised coal, steam cycle power plant. Nuclear, hydro, wind, bioenergy and solar generating plants were also evaluated. The objectives were to assess the comparative costs of mitigation per tonne of carbon emissions avoided, and to estimate the total amount of carbon mitigation that could result from the global electricity sector by 2010 and 2020 as a result of fuel switching, carbon dioxide sequestration and the greater uptake of renewable energy. Most technologies showed potential to reduce both generating costs and carbon emission avoidance by 2020 with the exception of solar power and carbon dioxide sequestration. The global electricity industry has potential to reduce its carbon emissions by over 15% by 2020 together with cost saving benefits compared with existing generation.

© 2002 Elsevier Science Ltd. All rights reserved.

Keywords: Electricity generation; Carbon emissions; Mitigation potential

1. Introduction

This paper reviews and compares the major technological advances and carbon dioxide mitigation options for the global electricity supply industry. It is a summary of a review study undertaken by the authors for the Third Assessment Report of the Intergovernmental Panel on Climate Change (IPCC, 2001). The IPCC's policy specifically excludes policy prescriptions or commentary. Whether or not liberalised electricity markets are likely to adopt the cost-saving, emission-reducing technologies included in the paper, or whether there are particular institutional obstacles to their adoption is not discussed. Suffice to say that if an investment opportunity exists to increase profit for a privately owned power generating company (or even for a state-owned enterprise), serious consideration will be given. If this same investment would also serve to offset

the threat of a future carbon emissions charge, then it would make good commercial sense to invest.

The paper concentrates on carbon emissions and largely ignores the impacts of other emissions from power generation plants (other than the desulphurisation of flue gases). Other more minor greenhouse gas (GHG) emissions such as nitrogen oxides (NO_x) are detailed in the Third Assessment Report (IPCC, 2001). These, together with other possible emissions from some power plants such as dioxins, whilst certainly needing to be considered in any environmental impact assessment necessary for a resource consent when developing a new plant, were not considered since they have relatively low importance.

The global electricity supply sector accounts for the release to the atmosphere of over 7700 million tonnes of carbon dioxide annually (2100 Mt C/yr), being 37.5% of total CO₂ emissions. Under business as usual conditions, the annual carbon emissions associated with electricity generation, including from combined heat and power cogeneration, is projected to surpass the 4000 Mt C level by 2020 (IEA, 1998). GHG emissions are easier to monitor and control from a limited number

*Corresponding author. Tel.: +64-6-3505288; fax: +64-6-3505604.

E-mail addresses: r.e.sims@massey.ac.nz (R.E.H. Sims), h.h.rogner@iaea.org (H.-H. Rogner), ken.gregory@tinyonline.co.uk (K. Gregory).

of centralised, large power stations than from millions of vehicles, small boilers and even ruminant animals. Therefore the electricity sector is likely to become a prime target in any future world where GHG emission controls are implemented and GHG mitigation is valued.

Several broad methods for mitigation of carbon dioxide emissions exist:

- *More efficient conversion of fossil fuels:* Technological development has the potential to increase the present world average power station efficiency from 30% to more than 60% in the longer term. Also, the use of cogeneration plants replacing the separate generation of power and heat offers a significant rise in the utilisation effectiveness of fuel.
- *Switching to low-carbon fossil fuels and suppressing emissions:* A switch to gas from coal for example allows the use of high efficiency, low capital cost, combined cycle gas turbine (CCGT) technology, resulting in lower carbon emissions per kWh of electricity generated.
- *Decarbonisation of fuels and flue gases, and carbon dioxide sequestration:* Decarbonisation of fossil fuel feedstocks before combustion for electricity generation can be used to make hydrogen-rich secondary fuels which in the longer term can be used in fuel cells. Decarbonisation of flue gases after combustion can become an effective GHG abatement option. In both cases the carbon dioxide can then be stored over geological time frames, for example, in depleted gas fields.
- *Increasing the use of nuclear power:* Nuclear energy could replace baseload fossil fuel electricity generation in many parts of the world if acceptable responses can be found to concerns over reactor safety, radioactive waste transport, waste disposal and proliferation.
- *Increasing the use of renewable sources of energy:* Technological advances offer new opportunities and declining costs for renewable energy technologies which, in the longer term, could meet a greater share of the rapidly growing world energy demand.

Since the onset of the industrial revolution in the mid 19th century, some 290 Gt C have been oxidised from fossil fuels and released to the atmosphere. The known fossil fuel resource base represents a further carbon volume of some 5000 Gt C (excluding methane clathrates) indicating there are good reserves of coal, gas and oil (as well as uranium), although there is still some uncertainty. The technical potential of renewable energy sources is far higher though it currently meets only around 20% of the global energy demand, mainly as traditional biomass and hydro power. Modern renewable energy systems have the technical potential to

provide all global energy services in sustainable ways and with low or virtually zero GHG emissions.

In relation to world electricity production, coal continues to have the largest share at 38% followed by renewables (principally hydro power) at 20%, nuclear at 17%, natural gas at 16% and oil at 9%. Electricity production is expected to almost double by 2020 (Table 1). However average carbon emissions per unit generated will decline over time mainly due to using new technologies with improved conversion efficiencies.

Coal-fired power generation is projected to have a major increased share by 2020 due to strong growth in countries such as India and China reflecting its importance there, together with steady growth in the USA, but a decline in Western Europe. Gas-fired plant is projected to continue to grow strongly in many world regions reflecting the increasing availability of natural gas whilst oil will lose market share. Nuclear power is projected to decline slightly after 2010 with capacity additions in developing countries and economies in transition roughly balancing plants being retired in OECD countries. Hydropower is projected to grow by around 60%, mainly in China and other Asian countries. New renewables have expanded substantially throughout the 1990s in absolute terms including wind by 21% per year and solar photovoltaics (PV) by 30% per year. Biomass and geothermal projects are also experiencing good growth. So overall, renewables are projected to continue to grow till 2020, but without significant government intervention, they will still only supply less than 2% of the electricity market share.

2. New technological options

2.1. Fossil fuels

The efficiencies of modern thermal power stations using the steam cycle can exceed 40% based on lower heating value (LHV), although the average efficiency of the installed stock world wide is closer to 30%. The cost of a modern coal-fired power station with SO_x and NO_x controls is typically \$US¹ 1300/kW_e but less efficient designs with fewer environmental controls are cheaper and therefore often built in developing countries. Costs vary considerably depending on location. Recently, efficiencies of 48.5% have been reported and, with further development, by 2020 they could reach 55% at costs only slightly higher than current technology (DTI, 1999).

Some new technological options such as CCGTs have the ability to penetrate the market place whereas others, such as new and emerging renewables, need government support by improving market efficiency; by finding new

¹ All costs quoted are in 2000\$US.

Table 1

Past and projected global production from the electricity generating sector (TWh/yr) and average C emissions per kWh due to fuel switching and efficiency gains

	1971	1995	2000	2010	2020
Coal	2100	4949	5758	7795	10,296
Natural gas	691	1932	2664	5063	8243
Oil	1100	1315	1422	1663	1941
Nuclear	111	2332	2408	2568	2317
Hydro	1209	2498	2781	3445	4096
Other renewables	36	177	215	319	433
Total	5247	13,203	15,248	20,853	27,326
Average GHG emissions (g C/kWh)	200	158	157	151	147

Source: Adapted from IEA (1998).

ways to internalise external costs; by accelerating RD&D; and by providing temporary incentives for early market development as such new technologies approach commercial readiness. The efficiency of the best available natural gas-fired CCGTs currently being installed is now around 60% (LHV) and cost around \$450–500/kW_e, including selective catalytic reduction for NO_x. Project costs can be substantially higher in some regions especially where new infrastructure is required. However in general the capital costs have been falling and efficiencies improving. So, together with good availability and short construction times, CCGTs are the highly favoured option where gas is available at reasonable prices. Developments in the liquefied natural gas markets could further expand the use of CCGTs and efficiencies could ultimately rise to 70% (Gregory and Rogner, 1998).

Integrated gasification combined cycle (IGCC) systems utilise the efficiency and low capital cost advantages of a CCGT by first gasifying the solid or liquid fuel. Gasifiers are usually fluidised bed designs, oxygen blown and still at an early commercial stage. Coal and difficult fuels such as bitumens, tar and pyrolysis derived bio-oil can be used as feedstocks. Biomass fuels contain oxygen and little sulphur so can be easier and cheaper to gasify which may lead to improved thermal efficiency. Gas clean up prior to combustion in the gas turbine which is sensitive to contaminants, is one of the key areas needing further development. Based on the latest CCGTs with 60% efficiency, the potential fuel to electricity conversion efficiency of an IGCC system is around 51%, with efficiencies over 60% feasible by 2020. In addition, IGCC offers one of the more promising routes to CO₂ capture and disposal by converting the gas from the gasifier into separate streams of H₂ and CO₂ via a shift reaction then removing the CO₂ before the gas enters the gas turbine or fuel cell.

2.2. Nuclear power

Nuclear power is a mature technology with 434 nuclear reactors totalling around 349GW_e operating in 32 countries in 1999 (IAEA, 2000). Worldwide, the majority of current nuclear power plants are competitive on a marginal generating cost basis in a deregulated market environment because of low operating costs and the fact that many are already fully depreciated. The life-cycle GHG emissions per unit of electricity from nuclear power plants are at least two orders of magnitude lower than those from fossil fueled electricity generation and comparable to most renewables at near zero. Hence nuclear power generation is an effective GHG mitigation option, especially by way of investments to extend the lifetime of existing plants. Whether or not building more nuclear power plants will be accepted depends on new designs becoming economically competitive and on the industry's ability to restore public confidence in its safe use.

The future of nuclear power will therefore depend on whether it can meet several objectives simultaneously—economics, operating safety, proliferation safeguards and effective solutions to waste disposal. While present new nuclear power plants already incorporate unprecedented levels of safety based on in-depth designs, their economics need further improvement to be competitive in most markets. New nuclear power plants at \$1700–\$3100/kW_e cannot compete against natural gas CCGT technology at current and expected gas prices where gas supply infrastructures are already in place (OECD, 1998). However, new nuclear power at generating costs between 3.9 and 8.0 c/kWh can be competitive with coal and natural gas where coal has to be transported over long distances or natural gas pipelines and infrastructures are not in place. Safe waste disposal for approximately 1 million years is claimed to be technically feasible and to add only 0.02 c/kWh to generating costs. Proliferation is primarily a political issue, but can also be addressed by technology.

Technological approaches for safe and long-term disposal of high-level radioactive waste have been extensively studied, one possible solution involving deep geological repositories. In the longer run, fundamentally new reactor configurations may need to be developed based on innovative designs that integrate inherent operating safety features and waste disposal using previously generated radioactive waste as fuel. By way of transmutation, this would also convert nuclear waste or plutonium to less hazardous and short-lived isotopic substances.

Major nuclear reactor vendors have now developed modified reactors that offer both improved safety and lower costs. One of the innovative designs is the pebble bed modular reactor (PBMR) developed by the South African utility ESKOM. The fundamental concept of

the design was to achieve a plant that has no physical process which could cause a radiation induced hazard outside the site boundary. The prospect of a “core melt” scenario is therefore zero. The capital cost of a production of 10 modules of 1000 MW_e was estimated by ESKOM to be around \$1000–1200/kW_e, being cheaper than other designs and giving attractive generating costs with unprecedented safety aspects. As a base load station with a depreciation period of 20 years and at a 10% discount rate, the expected cost of power would be approximately 2 c/kWh including the full fuel cycle and decommissioning (Nicholls, 1998). These costs are far less than typical present nuclear technologies and in part perhaps the result of engineering optimism. Other assessments quote double this generating cost (WEA, 2000).

Increased performance and lifetime extension of the currently existing nuclear reactors often present zero cost GHG mitigation options. Current nuclear power plants avoid carbon emissions of 600 Mt/year compared with using coal-fired plant to generate the same quantity of power. However, given current market conditions, new nuclear power plants remain a least-cost alternative only in countries usually characterised by limited indigenous fossil fuel resources or with large distances between energy resource location and demand centres.

2.3. Renewable energy systems

Natural energy flows vary from location to location and make the techno-economic performance of renewable energy conversion highly site specific. Intermittent sources such as wind, solar, tidal and wave energy, require back-up if not grid connected, while high penetration into grids may eventually require storage and/or back-up to guarantee reliable power supply (Ackermann et al., 1999). Therefore, it is difficult to generalise costs and potentials.

Hydro-electricity remains the most developed renewable resource worldwide but is now constrained due to societal and environmental barriers. The market potential resulting from detailed geological, environmental, social and technical evaluations is difficult to establish because societal preferences are inherently uncertain and difficult to predict. Other limitations to further development include the remote locations of many potential hydro sites resulting in high transmission costs, and the high, up front, capital investment cost, which recently privatised power companies are unlikely to accept due to the relatively low rates of return compared with gas or coal. An overall assessment of global economic hydro-power potential is between 7000 and 9000 TWh per year. In addition numerous small (<10 MW_e), mini (<1 MW_e) and micro (<100 kW_e) scale hydro schemes with low environmental impacts continue to be devel-

oped globally for generation costs around 6–12 c/kWh particularly in rural communities currently without electricity. Under certain conditions flooding of land upstream of a hydro dam can cause loss of biological carbon stocks as well as produce methane emissions as the vegetation decays over time. These losses and emissions are very site specific and do not occur with run-of-river schemes so were not considered in this analysis.

Wind power accounts for around 0.3% of the global installed generation capacity due to its relatively recent emergence but, due to its intermittent nature, it supplies around only 0.1% of total global electricity. Capacity reached 13,000 MW_e by 2000, with estimates of increases to over 30,000 MW_e operating by 2005 (EWEA, 1999). Denmark aims to provide 40–50% of its national electricity generation from wind power by 2030 and remains the main exporter of wind turbine technology. To meet future demand, many wind turbines will be sited off-shore, exceed 3 MW_e maximum rated output, have lower operating and maintenance costs, be more reliable, and have a greater content of local manufacture. The need for resource planning consents and limited areas of shallow seas suitable for off-shore wind farms may be constraints.

The cost of wind turbines continues to fall as more new capacity is installed. In high-wind areas, wind power is competitive with other forms of electricity generation at between 3 and 5 c/kWh. The global average price is expected to drop to 2.7–3 c/kWh by around 2020 due to economies of scale from mass production and improved turbine designs. The installed costs will fall from \$1000 to \$635/kW_e and operating costs will fall from 0.01 c/kWh to 0.005 c/kWh (EPRI/DOE, 1997). However, on poorer sites of around 5 m/s mean annual wind speed, the generating costs would remain high at around 10–12 c/kWh (8% discount rate).

Biomass resources include agricultural and forestry residues, landfill gas, municipal solid wastes and energy crops. Since biomass is widely distributed, it has good potential to provide rural areas with a renewable source of energy. The challenge is to provide the sustainable management, conversion and delivery of bioenergy to the market place in the form of modern and competitive energy services. Agricultural and forest residues such as bagasse, rice husks, bark and sawdust often have a disposal cost. Therefore, waste-to-energy conversion for heat and power generation can have good economic and market potential, particularly, in rural industry and community applications where it is widely used. In Denmark, about 40% of electricity generated is from biomass cogeneration plants using wood waste, straw and animal wastes for biogas, and in Finland it is 10% using sawdust, forest residues and pulp liquors. In other countries biomass cogeneration is utilised to a lesser

degree due to unfavourable regulatory practices and limiting structures within the electricity industry. Energy crop feedstocks have less potential in the short term due to their higher delivered costs in terms of \$/GJ of available energy as well as competition for land use.

Biomass fuels are generally easier to gasify than coal and the development of efficient biomass IGCC systems is nearing commercial realisation. Capital investment for a high-pressure, direct gasification combined-cycle plant is estimated to fall from over \$2000/kW_e at present to around \$1100/kW_e by 2020, with operating costs, including fuel supply, declining from 3.98 to 3.12 c/kWh (EPRI/DOE, 1997). By way of comparison, the higher current operating costs of 5.50 c/kWh for traditional combustion boiler/steam turbine technology, (reflecting poorer fuel conversion efficiency compared with gasification), were predicted to lower to 3.87 c/kWh. Capital costs were also predicted to fall from the present \$1965/kW_e to \$1100/kW_e in the same period.

Solar radiation as intercepted at the Earth's surface may be reasonably high in many regions but the market potential for its capture is low due to the current relatively high costs of solar collectors. In addition there are:

- time variations from daily and seasonal fluctuations and hence the need for energy storage;
- geographical variations, areas near the equator receiving approximately twice the annual solar radiation than at 60° latitudes; and
- diffuse characteristics with low power such that large-scale generation from direct solar energy requires significant amounts of equipment and land, even with solar concentrating techniques.

The cost of PV, at around \$5000/kW_e installed, is slowly falling due to manufacturing scale-up and mass production techniques as more capacity is installed. Generating costs are relatively high at 20–40 c/kWh. However, PV is often deployed at the point of electricity use such as buildings, and this can offset the high costs by giving a competitive advantage over power transmitted long distances from central power stations with high losses and distribution costs. Advances in inverters (including incorporation into the modules to give AC output), together with net metering systems and government sponsorship, have encouraged the market uptake of PV panels for grid-connected building integration projects, either in large-scale installations (up to 1 MW_e) or on residential buildings (up to 5 kW_e). Other growing markets for PV power generation systems include off-grid applications for rural locations particularly in developing countries where two billion people still have no access to electricity.

The size of the world market for PV rose to 300 MW_e/yr in 2000 with anticipated growth to over

1000 MW_e/yr by 2005. Conversion efficiencies of silicon cells continue to improve in the laboratory, though commercial monocrystalline based modules are still obtaining only 13–17% efficiency and multicrystalline 12–14%. Recent studies showed a \$660 M investment in a single factory capable of producing 400 MW_e (5 million panels) a year would reduce manufacturing costs by 75% as a result of economies of scale (KPMG, 1999). Possible further cost reductions from project learning experience could be offset by predicted higher cost of silicon wafers in future. Neij (1997) calculated a \$100 billion investment in manufacturing capacity would be needed in order to reach an acceptable generating level of 5 c/kWh (excluding back-up supply or storage costs).

Several types of high temperature, solar thermal, independent and utility-owned grid connected power stations have also been demonstrated. Dish systems giving concentration ratios up to 2000, and therefore performing at temperatures up to 1500°C, can supply steam directly to a standard steam turbine generator. Capital costs are projected to fall from around \$4000/kW_e now to \$2500/kW_e by 2030 with other estimates even lower (AGO, 1998).

Wave power, ocean currents and tidal power are other renewable energy technologies but these are unlikely to find significant markets by 2020 and were not considered in this analysis. Geothermal generation was also not included.

2.4. Carbon sequestration

Carbon sequestration technologies have become much better understood during the past few years, so they can now be seriously considered as GHG mitigation options alongside the better established options. They include the use of biological sinks such as plantation forests but only physical sequestration is discussed here. Once proven, the potential for generation of electricity from fossil fuels linked with the capture and storage of CO₂ is unlikely to be constrained by either the availability of resources of fossil fuels or by the capacity for storage. The technology is mature and readily available for both piping CO₂ over large distances, and for providing underground storage.

Carbon dioxide exists naturally in underground reservoirs in various parts of the world and some is often released during oil, gas and geothermal extraction. Hence potential sites for the storage of captured CO₂ are underground reservoirs such as depleted oil and gas fields or deep saline reservoirs. Also CO₂ injected into coal measures may be preferentially absorbed, displacing methane from the coal (which would be captured for commercial use) such that sequestration would be achieved providing the coal is never mined. Another possible storage location for captured CO₂ is in the deep ocean, but this option is at an earlier stage of

development than underground reservoirs. So far only small-scale experiments for preliminary investigation have been carried out.

Physical carbon sequestration is best suited to dealing with the emissions of large point sources of CO₂ such as power plants. It can be captured either from the fuel gas before combustion in, for example, an IGCC or steam methane reforming process or from the flue gas stream after combustion using regenerable amine solvents or other systems. The concentration of CO₂ in power station flue gas is between about 4% (for gas turbines) and 14% (for a pulverised coal-fired plant). These low-concentrations mean that large volumes of gas have to be handled and powerful solvents therefore have to be used, resulting in high-energy consumption for solvent regeneration. However, 80–90% of the CO₂ in a flue gas stream can be captured by such techniques. Other CO₂ capture techniques available or under development, include cryogenics, membranes and adsorption. After capturing the CO₂, it is pressurised, typically up to 100 bar, before transportation to storage areas using high-pressure pipelines or even by ship.

Carbon dioxide capture and compression imposes a penalty on the thermal efficiency of a power generation plant estimated to be 8–13%. The cost of CO₂ capture in power stations is estimated to be approximately \$30–50/t CO₂ of emissions (\$110–180/t C), being equivalent to an increase of about 50% in the cost of electricity. The cost of CO₂ transport depends greatly on the transport distance and the capacity of the pipeline but is approximately \$1–3/t CO₂ per 100 km. The cost of underground storage, excluding compression and transport, would be approximately \$1–2/t CO₂ stored. The overall cost of transport and storage for a transport distance of 300 km would therefore be about \$8/t CO₂ stored, equivalent to about \$37/t of carbon emissions avoided. Hence the overall cost of CO₂ capture and storage would be around \$150–220/t C emissions avoided. As with most new technologies, there is scope to reduce these costs in future through technical developments and wider application.

If CO₂ storage is to be used as a basis for emissions trading, or to meet national commitments under the UN Framework Convention for Climate Change, it will be necessary to establish the quantities of CO₂ stored in a verifiable manner and to ensure a retention time sufficient to avoid any adverse effect on the climate. Most verification requirements for geologically stored CO₂ can be achieved with technology available today but the permanency of storage is yet to be determined. Validation of CO₂ storage in the ocean would be more difficult but it should be possible to verify quantities of CO₂ stored in concentrated deposits on the seabed.

3. Technological and economic potential of power generation systems

Several electricity generation technologies were analysed and compared for both their costs and carbon mitigation potential. Previous studies attempted to compare power generation technologies on cost alone (US DOE/EIA, 2000; WEA, 2000; OECD, 1998). The OECD data resulted from a survey of power stations due for completion between 2000 and 2005 in a wide cross-section of countries. It showed that costs can vary considerably between projects due to national and regional differences including the need for additional infrastructure, the trade-off between capital costs and efficiency, the ability to run on baseload and the cost and availability of various fuels. The costs of reducing GHG emissions will also vary because of local variability in the costs of the baseline generation technology chosen (pulverised coal or CCGT) and the alternative technologies available. This large variation in local circumstances prevents specific generating costs from being used even within the boundaries of one country. In addition, it was not always possible to accurately account for the varying assumptions made for each of the variables used in each study when comparing the technologies in this analysis. Costs and mitigation potentials are highly location-dependent and consequently ranges had to be used.

This paper presents typical CO₂ emissions and costs/kWh from conventional pulverised coal-fired power generation plants and compares them with alternative types of generation and also with GHG mitigation technologies expected to be firmly in place by 2010. These include natural gas-fired CCGT, CO₂ capture and storage, nuclear power, hydro, wind, biomass, PV and solar thermal. Two principle sources of data were used: OECD, 1998 (Tables 2–5) and US DOE/EIA, 2000 (Table 6) for a single country in an attempt to reduce some of the variability in costs seen in multi-country studies. The OECD (1998) survey of power stations provided data on actual projects due to come on stream during 2000–2005 in 19 countries including Brazil, China, India and Russia, together with a few projects for 2006–2010 based on more advanced technologies. Additional data from other sources were used where necessary and are identified in the text.

Pulverised coal, steam turbine technology was used as the baseline for comparative purposes (Tables 2 and 3) but for regions where natural gas is the first choice of generation, a second comparison was made with the baseline technology assumed to be CCGT (Tables 4 and 5). New generation plant investment costs differ between Annex I (developed) countries (Tables 2 and 4) and non-Annex I countries (Tables 3 and 5) as defined in the UN Framework Convention on Climate Change. Costs and carbon emissions of the coal baseline were

Table 2

Cost estimates of alternative mitigation technologies in the power generation sector compared to baseline coal-fired power stations and potential reductions in C emissions to 2010 and 2020 for Annex I countries

Technology	PF + fgd, NO _x , etc.	IGCC and super- critical	CCGT	PF + fgd +CO ₂ capture	CCGT +CO ₂ capture	Nuclear	Hydro	Wind turbines	Biomass IGCC	PV and solar thermal
Energy source	Coal	Coal	Gas	Coal	Gas	Uranium	Water	Wind	Biofuel	Solar
Generating costs (c/kWh)	4.90	3.6–6.0	4.9–6.9	7.9	6.4–8.4	3.9–8.0	4.2–7.8	3.0–8	2.8–7.6	8.7–40.0
Emissions (g C/kWh)	229	190–198	103–122	40	17	0	0	0	0	0
Cost of C reduction (\$/t C avoided)	Baseline	–10–40	0–156	159	71–165	–38–135	–31–127	–82–135	–92–117	175–1400
Reduction potential to 2010 (Mt C/yr)	Baseline	13	18	2–10		30	6	51	9	2
Reduction potential to 2020 (Mt C/yr)	Baseline	55	103	5–50		191	37	128	77	20

PF, pulverised fuel; fgd, flue gas desulphurisation; IGCC, integrated gasification combined cycle.

Table 3

Cost estimates of alternative mitigation technologies in the power generation sector compared to baseline coal-fired power stations and potential reductions in C emissions to 2010 and 2020 for non-Annex I countries

Technology	PF + fgd, NO _x , etc.	IGCC and super- critical	CCGT	PF + fgd +CO ₂ capture	CCGT +CO ₂ capture	Nuclear	Hydro	Wind turbines	Biomass IGCC	PV and solar thermal
Energy source	Coal	Coal	Gas	Coal	Gas	Uranium	Water	Wind	Biofuel	Solar
Generating costs (c/kWh)	4.45	3.6–6.0	4.45–6.9	7.45	5.95–8.4	3.9–8.0	4.2–7.8	3.0–8	2.8–7.6	8.7–40.0
Emissions (g C/kWh)	260	190–198	103–122	40	17	0	0	0	0	0
Cost of C reduction (\$/t C avoided)	Baseline	–10–200	0–17	136	62–163	–20–77	–10–129	–56–137	–63–121	164–1370
Reduction potential to 2010 (Mt C/yr)	Baseline	36	20	0		36	20	12	5	0.5
Reduction potential to 2020 (Mt C/yr)	Baseline	85	137	5–50		220	55	45	13	8

Table 4

Cost estimates of alternative mitigation technologies in the power generation sector compared to gas-fired CCGT power stations and the potential reductions in C emissions to 2010 and 2020 for Annex I countries

Technology	CCGT	PF + fgd +CO ₂ capture	CCGT +CO ₂ capture	Nuclear	Hydro	Wind turbines	Biomass IGCC	PV and solar thermal
Energy source	Gas	Coal	Gas	Uranium	Water	Wind	Biofuel	Solar
Generation costs (c/kWh)	3.45	7.6–10.6	4.95	3.9–8.0	4.2–7.8	3.0–8	2.8–7.6	8.7–40.0
Emissions (g C/kWh)	108	40	17	0	0	0	0	0
Cost of C reduction (\$/t C avoided)	Baseline	610–1050	165	46–421	66–400	–43–92	–60–224	500–3800
Reduction potential to 2010 (Mt C/yr)	Baseline		2–10	62	3	23	4	0.8
Reduction potential to 2020 (Mt C/yr)	Baseline		5–50	181	18	61	36	9

Table 5

Cost estimates of alternative mitigation technologies in the power generation sector compared to gas-fired CCGT power stations and the potential reductions in C emissions to 2010 and 2020—non-Annex I countries

Technology	CCGT	PF + fgd +CO ₂ capture	CCGT +CO ₂ capture	Nuclear	Hydro	Wind turbines	Biomass IGCC	PV and solar thermal
Energy source	Gas	Coal	Gas	Uranium	Water	Wind	Biofuel	Solar
Generation costs (c/kWh)	3.45	6.9–8.7	4.95	3.9–8.0	4.2–7.8	3.0–8	2.8–7.6	8.7–40.0
Emissions (g C/kWh)	108	40	17	0	0	0	0	0
Cost of C reduction (\$/t C avoided)	Baseline	507–772	165	46–421	66–400	–43–92	–60–224	500–3800
Reduction potential to 2010 (Mt C/yr)	Baseline		0	10	9	5	1	0.2
Reduction potential to 2020 (Mt C/yr)	Baseline		5–50	70	26	21	6	4

taken from the average of several coal-fired projects under construction as surveyed in the OECD database. Flue gas desulphurisation (fgd) was assumed to be

included in all Annex I plants and in around 20% of the non-Annex I cases. Due to this additional cost, and also reflecting the lower efficiencies of older power station

Table 6
Estimated costs of alternative baseline and mitigation technologies in the USA power generation sector, in idealised conditions

Technology	PF + fgd, NO _x , etc.	IGCC	CCGT	PF + fgd +CO ₂ capture	IGCC +CO ₂ capture	CCGT +CO ₂ capture	Nuclear	Wind turbines	Biomass	Biomass	PV and solar thermal
Energy source	Coal	Coal	Gas	Coal	Coal	Gas	Uranium	Wind	Residues	Crops	Sunlight
Generating costs (c/kWh)	3.3–3.7	3.2–3.9	2.9–3.4	6.3–6.7	5.7–6.4	4.4–4.9	5.0–6.0	3.3–5.5	4.0–6.7	6.4–7.5	9.0–25.0
Emissions (g C/kWh)	247–252	190–210	102–129	40	37	17	0	0	0	0	0
Cost of C reduction compared to pulverised coal steam cycle (\$/t C)	Baseline	–80–168	–53–8	141–145	93–148	30–70	52–102	–16–85	12–138	107–170	210–880
Cost of C reduction compared to natural gas CCGT (\$/t C)			Baseline	326–613	250–538	134–176	124–304	–8–245	47–373	233–450	434–2167

designs currently being built in non-Annex I countries, the baseline coal technology was cheaper in these regions (4.45 c/kWh, Table 3) than for Annex I countries (4.9 c/kWh, Table 2). However CO₂ emissions were higher at 260 g C/kWh compared with 229 g C/kWh from the most modern, more efficient power plant designs. Other generation and carbon mitigation technologies were then compared to the baseline data using costs from the OECD database and other sources as referenced in the sections above.

In Tables 2–5, the first column gives the generation costs of the baseline technology in c/kWh and the emissions of carbon dioxide as g C/kWh. The subsequent columns give a range of the costs and emissions for alternative technologies that could be used to reduce carbon emissions over the next 20 years or so by displacing the baseline technology. The costs of reducing carbon dioxide emissions in the mitigation options (\$/t C avoided) vary because of variability in the costs of both baseline and alternative technologies. Hence a range is given.

Estimates of the CO₂ reduction potential (Mt C/yr) in 2010 and 2020 are provided for each of the alternative mitigation options. These were derived mainly from projections of world electricity generation from different energy sources by IEA (1998) as presented in Table 1. IEA data were chosen in preference to various IPCC scenarios because of the shorter time horizon and the higher technology resolution provided.

In Tables 2 and 3 it was assumed that a maximum of 20% of currently proposed coal baseline capacity would be replaced by either gas, nuclear or renewable technologies during 2006–2010 and 50% during 2011–2020. These assumptions allowed for a 5-year lead time for decisions on the alternatives to be made and construction to be undertaken. It was assumed the alternative generation investment options to coal would ramp up only slowly over several years and hence this would limit the maximum capacity that could be displaced by 2010. After 2010, it was assumed there will be practical reasons why half the proposed new coal capacity could not be displaced so these plants will be built.

Based on similar assumptions as used for the coal baseline, it was assumed in Tables 4 and 5 that a maximum of 20% of proposed new baseline gas capacity during 2006–2010 could be displaced by improved mitigation options and 50% during 2011–2020.

The rate of developing and building gas or nuclear power stations that would be required using these assumptions was considered to be realistic. For nuclear power, the rate of building between 2011 and 2020 would be less than that seen at the peak of construction of new nuclear plant in the 1970s. For gas, the gas turbines are factory-made so no supply constraints should arise from the anticipated increase in demand. Less equipment and construction effort would be required than the coal capacity replaced in terms of boilers, steam turbines and cooling towers.

For hydro, wind, biomass and PV technologies, estimated penetration rates applied to displace new coal (Tables 2 and 3) or gas capacities (Tables 4 and 5) were derived from the well researched and publicised Shell sustainable growth scenario (Shell, 1996). For wind and PV, these penetration rates imply substantial growth until 2020, but this is less than the current rate of expansion of 20–30% per year. For biomass, most of the fuel was assumed to be agricultural, wood process or forest residues though some purpose grown crops would also be used as in the 10 MW_e Yorkshire ARBRE project which uses 2200 ha of coppiced *Salix* (Pitcher, 2000).

The introduction of CO₂ capture and storage technology for coal or gas plants would require similar construction processes as for conventional power plant. The CO₂ separation facilities would need additional equipment but, in terms of physical construction, this would involve no more effort than, say, the establishment of a similar scale of biomass gasification plant. CO₂ storage facilities would be constructed using available oil/gas industry technology so this was not seen to be a limiting factor. Storage of the carbon would be in saline aquifers or depleted oil and gas fields. It was assumed that pilot plants, first developed in Annex I countries, could be operational before 2010 and that the

annual mitigation potential would be 2–10 Mt C each for coal and for gas technologies. In 2020, the total mitigation potential was therefore put at 40–200 Mt C, split equally between coal and gas and between Annex I and non-Annex I countries. This was somewhat arbitrary but reflected the potential to move forward with the technology if no major problems are encountered, and if more pilot schemes were to be extended. It was assumed for simplicity that fuel switching, from coal to gas or vice versa, would not occur in addition to CO₂ capture and storage, although in reality this would be an extra option for a power generation company.

Costs for coal, gas and nuclear were derived from OECD (1998) data using \$1.70/GJ for coal and \$3.20/GJ for gas in Annex I countries. (These costs were the anticipated long-run real prices, though actual prices may fluctuate widely in the short term as for USA natural gas prices which varied in 2000 between \$2 and \$11/GJ.) The additional costs of CO₂ capture and disposal were derived from the IEA GHG R&D programme (Audus, 2000). For coal, the costs for CO₂ capture and storage were assumed to be for retrofitting to pulverised fuel (PF) power stations. Data for hydro-power costs were taken from WEA (2000) and the IPCC (1996) Second Assessment Report. Wind power data were based on recent project costs (Walker et al., 1998) and projected future costs in IPCC (1996). For biomass, the technology used was IGCC (rather than combustion/steam cycle) with capital and operating costs assumed to be similar to those for coal IGCC. Biomass fuel costs ranged between \$0 and 2.7/GJ, based on either wood process residues or sugar-cane bagasse being free by-products produced on-site (perhaps even with a negative cost for disposal) or on forest arisings or crop residues such as cereal straw needing collection. PV costs, taken from the World Energy Assessment (WEA, 2000), were based on present day costs of \$5000 per peak kW_e capacity lowering to \$1000/kW_e predicted after 2015. A 10% discount rate was used throughout.

3.1. Carbon emissions reductions

When estimating the maximum CO₂ mitigation each technology could achieve, it was assumed that only proposals for new coal or gas power stations or old plant would be displaced since early retirement of existing plant and equipment assets is only likely to occur in practice under exceptional circumstances. In all cases, the reduction potential in 2020 is substantially higher than in 2010. This follows from the assumptions used for the rate of plant uptake and demand growth, reflecting the time taken to make decisions and, especially in the case of renewables and CO₂ capture and storage, to build up manufacturing capacity, to learn from experience and to reduce costs.

As a general rule, increasing the amount of carbon abatement to be achieved will require moving to higher cost options, the “low hanging fruit” being picked first. This applies particularly to renewables since to achieve additional capacity will eventually require constructing plants on sites with less favourable conditions such as those with lower mean annual wind speeds or slower growth of energy forests.

It is evident that each of the mitigation technologies presented can contribute to reducing emissions in terms of Mt C/yr with nuclear, where considered to be socio-politically desirable, having the greatest potential. Replacement of coal by gas (Tables 2 and 3) can make a substantial contribution as can CO₂ capture and storage. Each of the renewables can also make a significant contribution to displacing proposed or replacement coal-fired power plants, although solar power will be limited due to the high investment costs constraining its uptake.

The potential reductions within each table are not additive since each of the technologies assessed will be competing with each other to displace new coal and gas power stations. Based on the assumption about the maximum displacement of new coal and gas power stations being 20% for the 2006–2010 period and 50% by 2020, the maximum mitigation that could be achieved would be around 140 Mt C in 2010 and 660 Mt C in 2020. These avoided emissions can be compared with the projected global CO₂ emissions from power stations of around 2400 Mt C in 2000, 3150 Mt C in 2010 and 4000 Mt C in 2020 (IEA, 1998). In practice, a combination of technologies could be used to displace coal and natural gas-fired generation and the choice will often depend on local circumstances. Not shown in the tables, oil-fired generation could also be displaced. Based on similar assumptions, this would give a further mitigation potential of 10 Mt C by 2010 and 40 Mt C by 2020.

Not all of the mitigation options are likely to achieve their potential for a variety of reasons such as unforeseen technical difficulties, investment cost limitations in non-Annex I countries, and socio-political barriers in Annex I countries. Conversely the uptake of renewable energy projects due to the Clean Development Mechanism is hard to predict at this stage. Therefore the total mitigation potential for the electricity supply sector using mitigation options for all three fossil fuels and allowing for potential constraints, was estimated to be between 50–150 Mt C by 2010 and 350–700 Mt C by 2020.

3.2. Costs of carbon mitigation

Where the investment cost to avoid one tonne of carbon emissions is negative, the project can be assumed to be an economic option regardless of any emission

reductions. There are a range of win/win opportunities which can reduce emissions at either zero cost or with cost savings. Where gas infrastructures are in place and CCGT is a lower cost option than coal, it was assumed that natural gas would be the fuel of choice (Tables 2 and 3). Hence no negative cost reduction options exist for natural gas to displace coal. Where additional investment costs are involved compared with the baseline cases, the level is an indication of the carbon value needed for a project to proceed if and when carbon trading occurs. For example in Table 4 in areas of Annex 1 countries where both hydro and gas resources exist, building hydro power plants instead of CCGT would be unlikely unless the carbon offset value exceeds \$66/t C.

Hydro, wind and biomass power generation projects all have the potential on good sites to avoid carbon emissions by displacing coal-fired plants and in some specific cases, investment in the technologies can generate power at lower costs (Tables 2 and 3). It is also possible for some wind and biomass projects to profitably displace natural gas CCGT plants (shown as negative values within the \$/t C avoided ranges in Tables 4 and 5). These will be located on sites where high mean annual wind speeds or cheap wood processing or agricultural residues are available. Hydro plants would not compete with CCGT without a carbon offset value being included. In fact, as shown by the ranges of costs, for the majority of sites, all renewable energy projects are more costly and generation would be more expensive than using CCGT.

Under the assumptions made, nuclear power is theoretically a zero cost mitigation option in terms of \$/t C reduced. If the projected generating costs for PBMR plants can be realised in practice, this would certainly imply negative mitigation costs were possible. For new nuclear plants using state-of-the art designs, a possible value between \$30 and 40/t of carbon avoided would put them more on a par with IGCC coal-fired electricity stations (Tables 2 and 3). However, it would take a carbon value of over \$46/t (Tables 4 and 5) for nuclear power to break even with natural gas combined cycle electricity.

3.3. Analysis of USA data

The ranges of the data presented in Tables 2–5 reflect the large variations of local circumstances for a specific project resulting in a wide range of mitigation costs (\$/t C avoided) for each technology option. Therefore, to narrow down these variations, project costs were also analysed for USA alone, mainly based on data used in the USA Annual Energy Outlook (US DOE/EIA, 2000) as presented in Table 6. A 10% discount rate was used for all options. In this US DOE/EIA study, a narrower range of future cost estimates was used for PV and solar

thermal (9–25 c/kWh) than was used in Tables 2–5. The range of wind costs from 3.3 to 5.5 c/kWh were taken from high and low cases in the same study and the costs of biomass derived electricity were based on a fuel cost of \$2.7/GJ for purpose grown crops, and a cost range of \$0–\$2/GJ for agricultural and forest residues.

The USA electricity generating costs were based on national projections of utility prices for coal of \$1/GJ and for natural gas of \$2.7/GJ. Capital costs and generating efficiencies were assumed to be dynamically improving depending on their respective rates of market penetration. Overall, the generation costs were at the lower end of the ranges for Annex 1 countries (Table 2) for all technologies. Compared with the costs for Annex 1 countries (Tables 2 and 4), carbon mitigation costs in the USA tended to be lower for IGCC coal, CCGT gas, PF + CO₂ capture, CCGT + CO₂ capture, and PV and in the mid to high end of the ranges for nuclear, biomass and wind. Once sufficient capacities have been adopted in the market place, coal-fired IGCC power stations would have similar costs but lower emissions than the baseline pulverised coal power station due to their higher efficiency. Gas-fired CCGT power stations offer lower cost generation than coal at current gas prices and produce around only half the CO₂ emissions. Data on CO₂ capture and storage were again taken from IEA GHG R&D Programme studies (Audus, 2000). This technology could reduce emissions by about 80% for additional costs around 3 c/kWh for pulverised coal, 2.5 c/kWh for coal IGCC and 1.5 c/kWh for gas CCGT. Nuclear power is more expensive than coal-fired or gas-fired generation but can be a cheaper option than CO₂ capture and storage. Wind power can be competitive with conventional coal and gas power generation at sites with high mean annual speeds of 9–10 m/s. Biomass can also contribute to carbon mitigation, especially where forest or agricultural residues are available at very low or negative costs. Where biomass is more costly (either because in-forest residue material used requires collection or because purpose-grown short rotation forest energy crops are used), or where wind conditions are poorer, the technologies will be less competitive for reducing emissions. PV and solar thermal technologies remain relatively expensive for large-scale power generation, but will be increasingly attractive in niche markets or for off-grid generation as capital costs fall.

Carbon dioxide emissions and mitigation costs were compared to both the coal-fired pulverised fuel power station and the gas-fired CCGT (Table 6). Compared with the coal base-case, it was projected that in 2010 under assumptions of improved fossil fuel technologies, an IGCC plant would offer a small reduction in emissions at positive or negative costs depending on the specific circumstances. A gas-fired

CCGT would generally have negative mitigation costs compared with the coal-fired baseline, reflecting its lower generating costs. Carbon dioxide capture and storage options would enable significant reductions in emissions from coal-fired generation but the cost would be between \$100 and 150/t C depending on the technology used. Gas-fired CCGT with CO₂ capture and storage appears more attractive, principally because switching to CCGT is attractive in the first place wherever natural gas production and delivery infrastructures exist. Nuclear power mitigation costs are in the range \$50–100/t C versus coal but \$125–300/t C versus gas. It is uncertain whether there would be sufficient capacity available for wind or biomass to deliver as much electricity as could be produced by fossil fuel-fired plants, but certainly the installed capacities would be limited at the low costs shown due to a scarcity of good sites.

When compared with the gas-fired CCGT baseline under USA conditions, most of the mitigation options were found to be considerably more expensive with the exception of wind on good sites. Carbon dioxide capture and storage appeared relatively unattractive for both coal or gas-fired plants, but could achieve significant reductions in emissions if carbon was valued at \$150/t C or above. Biomass and nuclear were attractive options under certain circumstances whereas PV and solar thermal were again expensive mitigation options.

4. Conclusions

Compared with burning coal or gas in conventional power generating plant designs, there are several alternative technological ways to generate electricity and reduce greenhouse gas emissions cost effectively. They include using plant designs which offer more efficient power generation conversion of fossil fuels, greater use of renewable energy or nuclear power, and the capture and disposal of CO₂. The choice, in terms of cost savings and carbon emission reduction benefits, is very site specific and the least-cost option in terms of \$/t C avoided will differ from case to case. Most of the technologies considered in the discussion have a role to play since, for each, it is possible to obtain both cost and carbon emission reductions under certain circumstances. The exceptions are solar power and carbon dioxide sequestration, though this new concept gives future opportunity for costs to be reduced with further experience. Compared with business as usual, the global electricity sector has the potential to lower its carbon emission reductions by between 1.5–4.7% by 2010 and 8.7–18.7% by 2020 based on the current literature and the range of assumptions used in this analysis.

Acknowledgements

The secretariat of Working Group III of the IPCC Third Assessment Report agreed for this section of the report to be published in this revised and condensed form. The other co-authors of Chapter 3 are acknowledged, several having provided useful reviews of this analysis during the preparation of the IPCC report.

References

- Ackermann, T., Garner, K., Gardiner, A., 1999. Wind power generation in weak grids—economic optimisation and power quality simulation. Proceedings of the World Renewable Energy Congress, Perth, Australia, Murdoch University, pp. 527–532. ISBN 0-86905-695-6.
- AGO, Australian Greenhouse Office, 1998. Renewable energy showcase projects. Australian Greenhouse Office, Canberra. www.greenhouse.gov.au/renewable/renew3.html.
- Audus, H., 2000. Leading options for the capture of CO₂ at power stations. Proceedings of the Fifth International Conference on Greenhouse Gas Control Technologies, Cairns, Australia, 13–16 August.
- DTI, Department of Trade and Industry, 1999. New and emerging renewable energy prospects for the 21st century, Department of Trade and Industry Report DTI/Pub 4024/3K/99/NPURN99/744 London, United Kingdom.
- EPRI/DOE, 1997. Renewable energy technology characterizations, Electric Power Research Institute and US Department of Energy Report EPRI TR-109496, December.
- EWEA, 1999. Wind energy—the facts European Wind Energy Association Report prepared for the Directorate-General XVII-Energy, European Commission.
- Gregory, K., Rogner, H.-H., 1998. Energy resources and conversion technologies for the 21st century. Mitigation and Adaptation Strategies for Global Change 3, 171–229.
- IAEA, 2000. Nuclear power reactors in the world. International Atomic Energy Agency Reference Data Series No. 2, April Edition, Vienna, Austria.
- IEA, 1998. World Energy Outlook—1998 Update. International Energy Agency Report, IEA/OECD, Paris, France.
- IPCC, 1996. Second Assessment Report. United Nations Intergovernmental Panel on Climate Change. Cambridge University Press, England.
- IPCC, 2001. Third Assessment Report. United Nations Intergovernmental Panel on Climate Change, Working Group III, Cambridge University Press, England (Chapter 3).
- KPMG, 1999. Solar energy—from perennial promise to competitive alternative. Project Number 562. KPMG Bureau voor Economische Argumentatie, Hoofddorp, Netherlands, p. 61.
- Neij, L., 1997. Use of experience curves to analyze the prospects for diffusion and adoption of renewable energy technology. Energy Policy 23, 1099–1107.
- Nicholls, D.R., 1998. Status of the pebble bed modular reactor. ESKOM Report, South Africa.
- OECD, 1998. Projected costs of generating electricity: update 1998. Organization for Economic Cooperation and Development (OECD). International Energy Agency (IEA) and Nuclear Energy Agency (NEA) Joint Report, Paris, France.
- Pitcher, K., 2000. Turning willow into megawatts—the ARBRE project. Renewable Energy World 3 (6), 34–45.
- Shell, 1996. The evolution of the world's energy systems. Shell International Limited report, Shell Centre, London SE1 7NA, UK, 7pp.

US DOE/EIA, 2000. International energy outlook 2000. US Department of Energy Information Administration, Report No. DOE/EIA-0554(2000), Washington, DC.

Walker, D., Botha, P., White, G., 1998. Tararua wind farm. Proceedings of the 36th Annual Conference, Australian and New Zealand Solar Energy Society, Christchurch, November, pp. 637–641.

WEA, 2000. World Energy Assessment: energy and the challenge of sustainability. United Nations Development Programme (UNDP), UN Department of Economic and Social Affairs (UNDESA) and World Energy Council (WEC) Joint Report, New York, USA.