Options, Costs and Strategies for CO$_2$ Reductions in the European Power Sector[*]

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Abstract

Given its high share of total CO$_2$ emissions power generation is a key sector for seeking CO$_2$ reduction options. The purpose of this paper is to provide a power generator eye view of the European power sector's CO$_2$ compliance decision process under a mandatory emissions reduction program. The analysis indicates that in the medium term many European generators are likely to seriously consider options that are based on traditional power technologies such as converting existing coal-fired capacity to burn gas as well, extending the lives of nuclear capacity, and replacing

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old inefficient coal-fired plants with more efficient gas- or even coal-fired units. In the long-term the economic potential of future mitigation options are highly uncertain, and generators are likely to respond to this uncertainty by maintaining flexibility in fuel choices and avoiding large investments that lock them into a specific compliance method before new, more efficient technologies and fuels, have crystallized. Most notably, if the costs of carbon sequestration are expected to go down coal can be considered a sustainable energy source, and there may be weak incentives for generators to switch from coal to other fuels in the medium term. Given the multitude of possible CO_2 mitigation options in the power sector, there is a strong case for emissions trading and for refraining from policies that build on mandatory fuel requirements, higher rates of capital stock turnover and technology standards.

1. Introduction

The international community's adoption of the Kyoto Protocol in 1997 marks a significant step in the process of addressing the problem of global warming and that of CO_2 emissions in particular. For several reasons the power sector will be a likely target for CO_2 reductions (see section 2), but there still exists genuine uncertainty about how electric power generators will choose to comply with the Kyoto obligations and any other (even stricter) climate policy in the future. The primary purpose of this paper is to provide a power generator eye view of the European power sector's CO_2 compliance decision process under a mandatory emissions reduction program. Three broad supply side mitigation options will be discussed: (a) altering the conventional energy mix by converting existing plants and/or by new plant constructions; (b) introducing new carbon-free technology; and (c) carbon removal and sequestration.[1]

When analyzing the different CO_2 reduction options in the power sector and their costs, two issues deserve special attention. *First*, the technological options for CO_2 avoidance are likely to differ depending on the time frame for compliance. The Kyoto Protocol has a *medium-term* impact in that it requires that CO_2 emissions be reduced relative to current trends within less than ten years. Within this relatively brief time frame only today's commercial or near-commercial technology may contribute. However, the Kyoto commitment is not enough if Europe is serious about the global warming issue. Meeting the *long-term* goal of stabilizing the atmospheric CO_2 concentration will require large, additional reductions (e.g., Bolin, 1998). Of course, over the longer term technological progress will play a crucial

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[1] Demand side options, which aim at changing the demand for the underlying service or to meet that demand using less energy, will not be considered.

role, in that many so far non-commercial (or presently unknown) options may provide efficient emissions reduction strategies. From a power generator's perspective both the medium- and the long-term CO_2 reduction strategies must be considered, and any medium-term strategy should not hamper the implementation of potentially more cost effective long-term solutions. Thus, an important part of the generators' compliance decision processes will be to weigh the costs of current compliance methods – not only against each other – but also against the highly uncertain economics of future methods. This article highlights both medium- and potential long-term options for CO_2 reductions, and discusses in what way a cost-minimizing generator will deal with the choice between medium- and long-term strategies.

Second, from a policy standpoint it is very important to ensure that CO_2 emission policies, while attaining their goals, are implemented in a way that maintains flexibility. This clearly precludes policies that lock power generators into specific compliance mechanisms. Instead, environmental pricing, preferably in the context of tradable CO_2 allowances, is the key to an efficient climate policy. The Kyoto Protocol clearly embraces emissions trading as an important element of attaining the set CO_2 reduction targets (Ellerman, 2000), but many national energy policies still tend to mandate certain technologies and/or fuel types (in most cases renewable energy sources). The cost analysis presented in this article builds on the assumption that a system of CO_2 emissions trading is implemented, so that it is up to each generator to weigh different mitigation options against each other. While such an analysis helps us understand the way in which generators are likely to comply with any climate policy target (as well as the cost of that target), it also indicates what the *additional* cost of mandating certain compliance methods may add up to. We stress in particular the often-neglected roles of coal and gas as means to comply with set CO_2 emission targets, especially in the medium-term awaiting the advent of new and more cost efficient technologies such as renewable energy and/or carbon sequestration technologies.

Before proceeding some important limitations of the paper need to be outlined. The paper does not attempt at providing a full-fledged analysis of the entire range of costs of CO_2 avoidance options. Rather it makes use of reasonably realistic cost calculations to discuss likely medium- and long-term CO_2 compliance strategies among power generators in Europe. This implies, for instance, that we neither investigate in detail specific tax and subsidy levels in different European countries and nor do we highlight transmission constraints and other regional variations in Europe. In addition, the analysis ends with some general policy recommendations but we refrain from discussing detailed policy design issues (e.g., auctions versus grand fathering of emissions permits etc.).

Section 2 presents a brief background to the European power sector's contribution to total CO_2 emissions and the current status of the generation mix. In section 3 we discuss some of the theoretical principles of a cost efficient CO_2 reduction policy, and of the economic evaluation of the different mitigation options at the utility level. The remainder of the paper provides an analysis of the specific options facing the European power sector and their costs – both in the medium-term (section 4) and in the long-term (section 5). Finally, section 6 provides some concluding remarks and implications.

2. CO_2 Emissions and the Power Sector in Western Europe

According to the European Commission (2000a, 2000b) the total emissions of greenhouse gases for energy use amounts to around 3400 million tons (Mt) of CO_2 equivalents in the year 2000. Out of this, around 90 Mt stem from methane (CH_4) and 70 Mt from nitrous dioxide (N_2O). Thus, by far the largest contribution to the greenhouse effect results from emissions of carbon dioxide (CO_2). Table 1 shows in turn the contributions of the different sectors of the economy to total CO_2 emissions in the European Union.

Table 1. CO_2 Emissions in the European Union by Sector

Sectors	1990		1996	
	Mt	**%**	**Mt**	**%**
Transport	738	23	825	25
Power Generation	964	30	933	29
Energy Sector	161	5	163	5
Industry	578	18	530	16
Domestic and tertiary	645	20	692	21
Bunkers	108	4	117	4
Total	3194	100	3260	100

Source: European Commission (1999).

The power generation, transport and domestic/tertiary sectors each account for approximately one fourth of total CO_2 emissions. According to the Kyoto Protocol the European Union has agreed to limit its emissions of greenhouse gases by eight percent in the period 2008-2012 compared to 1990 levels. There are at least two reasons why the power-generating sector is likely to be particularly targeted for CO_2 reductions in order to meet the Union's Kyoto commitment. *First*, power generation provides much flexibility in terms of fuel choices and the different fuels have significantly different carbon contents (see also section 4). This is not the case for

other energy uses; the transport sector, for instance, relies almost exclusively on oil products and few substitutes exist. *Second*, emission sources in transport, industry and other sectors are large in number and small in size, whereas the flue gas streams of power plants are concentrated in relatively few and large (and thus easily-identified) facilities.

Table 2 shows the balance for how electric power is produced in Western Europe, as well as the resulting CO_2 emissions. The use of fossil fuels represents about half of total power generation in Western Europe and coal, in particular, plays an important role. In some countries, such as Germany, Ireland and Spain, power generation coal use is not only large but also dominating. However, coal-fired power generation is also the major contributor to CO_2 emissions in Europe and accounts for 74 percent of the total emissions from the power sector, while the corresponding shares for gas and oil are 12 and 14 percent, respectively. The other fuel sources, such as hydropower, nuclear, biomass and wind power, have no CO_2 impacts. The large share of fossil fuels in European power generation in combination with the different carbon intensities of these fuels implies that any carbon abatement strategy has to address the issue of power generation fuel choice.

Table 2.Power Generation and Related CO_2 Emissions in Western Europe (1995)

Fuels	Generation		CO_2 Emissions*	
	TWh	%	Mt CO_2	%
Coal	828	31	813	74
Oil	237	9	149	14
Gas	255	9	129	12
Nuclear	861	32	0	0
Hydro	486	18	0	0
Other sources	10	1	0	0
Total	2678	100	1091	100

* These figures include emissions from combined heat and power plants.
Source: International Energy Agency (1998).

The competitiveness of the combined cycle gas technology (CCGT) has improved rapidly during the last decade. The investment costs have decreased to a level at which few other technologies can compete, and the fuel efficiencies are approaching 60 percent. In addition, the short lead times of the CCGT and the possibility of adding small increments enable power producers to follow demand developments more closely and thus reduce uncertainty and costs. For the above reasons we have witnessed a soar in CCGT capacity additions in Western Europe, and in many cases at the expense of coal-fired power capacity. Given the relatively

low carbon content of gas, the substitution of gas for coal has contributed to the decrease in the power sector's CO_2 emissions during the 1990s (see Table 1).

The competition between coal and gas is, however, fairly tough. Gas prices are not always competitive and/or important supply constraints exist. In such cases coal may be the preferred fuel (European Commission, 2000b; IEA, 2000a). Coal is a cheap fuel with a high-energy content, and prices tend to be very stable compared to other fossil fuels. Coal use is also considered to be more secure than other fuels because of the much greater extent of geographically widely distributed reserves as well as their location in areas less politically sensitive. In addition, coal benefits from the favorable economics of existing power stations; the lower fixed costs implied by the sunk investments in coal-fired power capacity will in some instances act to support coal as a feedstock (Ellerman, 1996).

Coal combustion technologies are also developing rapidly. Fuel efficiencies are increasing and modern power plants (even those using lignite) have a fuel-to-electricity efficiency of close to 45 percent (IEA, 2000a). These plants are based on supercritical steam conditions and some of the flue gases are cleaned effectively.[2] Coal-fired plants often meet the same environmental requirements as do other plants, and emissions of the 'traditional' harmful substances are not significantly higher than for any other fuel. Catalytic scrubbers and filters can remove nitrogen oxides, sulfur and particulates from the flue gases to very low levels and at reasonably competitive costs. Emissions of polyorganic matter, chlorinated substances and heavy metals can also be eliminated through optimized combustion and flue gas cleaning. In several countries the ash is utilized in other industries. However, in terms of CO_2 emission intensity coal still has a disadvantage since it produces substantially more CO_2 per kWh generated than do both gas and oil.

The alternatives to coal or gas utilization are oil, nuclear power, hydropower, biofuels and other renewable sources such as solar energy and wind power. The traditional competitors to coal and gas in the power sector, hydropower and nuclear, both face serious constraints. Hydropower is only available in some countries and tends to have a very limited expansion potential, at least in the Nordic countries. In addition, it is very hard to get public acceptance even for incremental capacity additions, and the cost of a new small hydropower plant can be very high ranging

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[2]   Supercritical coal-fired boilers are still less expensive than so-called Integrated coal Gasification Combined Cycle (IGCC) power plants. However, the costs of the latter are expected to fall considerably in the future and with respect to CO_2 capture, IGCC technology is considered to be considerably more effective for producing a pure CO_2 stream for capture than supercritical facilities. See, for instance, David and Herzog (2000) for an economic assessment of CO_2 separation and capture at three types of power plants.

from 35 to 100 USD per MWh. Most 'low-cost' sites are often already utilized. Nuclear power also has the advantage of being virtually carbon free, but it faces a number of important economic, social and political obstacles. The key impediments to expanded nuclear power include long lead times, high capital costs for construction and decommissio-ning, waste disposal siting and costs as well as public opposition.

The renewable energy sources have been developing rapidly and especially wind power but also solar cell technologies are becoming cheaper and more effective. The theoretical potential for wind power is likely to be very large. IEA (2000b) estimates that at costs at around 100 USD per MWh[3] the theoretical potential exceeds 15 percent of total demand, while the actual potential may be much lower. In Sweden the theoretical potential has been estimated at about 50 percent of domestic demand (70 TWh), while the potential in practice is believed to be 5 percent (7 TWh) (SOU 1995: 139). Wind power can probably account for a relatively large share of electricity demand in future, and locally along the coasts and offshore it may be very large. The cost of wind power turbines has fallen substantially during the last decade. Nevertheless, in general wind power technologies – as well as solar power technologies – are still not competitive and are normally developed only with the help of subsidies. Biofuels are widely used in several countries. The available supplies are, however, often not adequate. Even in Sweden, with vast forest resources and with one of the world's largest pulp and paper industries, biofuels cannot cover more than approximately 15 percent of domestic electricity demand. The Scandinavian biofuel market is highly developed, but wood fuels based on residues still have more than double the price of coal (exclusive of taxes) and biomass plantation fuels are even more expensive.

Thus, even though renewable energy sources are expected to play a major role in the longer term their potential of meeting the medium-term Kyoto commitments is likely to be relatively limited (e.g., IEA, 2000a; Unander, 2000). Even so, the European Union's White paper (European Commission, 1997) has set a goal that 12 percent (from the present 6 percent) of the energy supply shall be covered by renewable sources in 2012, and many individual countries have formulated similar policy targets for renewable energy. From a pure CO_2 reduction policy standpoint such policies may prove inefficient since they cannot guarantee that the emission targets are met in a least cost manner.

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[3] The corresponding current generation costs (exclusive of taxes and subsidies) for coal- and gas-fired power range between 35 and 60 USD per MWh depending on country and site (NEA/IEA, 1998).

3. The Economic Principles of Cost Effective CO_2 Reduction

CO_2 emissions are a typical example of a (negative) *externality*, i.e., a situation in which the actions of one economic actor – a power generator – create welfare losses for others, but there is no incentive for the generator to take these impacts into account in the decision making process. The reason for this is that environmental resources often are public goods for which property rights are hard to establish. Figure 1 illustrates the externality dilemma. We consider here a power generator with a portfolio of old coal-fired power plants, which give rise to external costs in the form of CO_2 emissions. The level of emission reduction is denoted R. In a free market a profit maximizing generator will have no incentive to pursue any emission reduction activities that draw on the generator's financial resources, i.e., $R = 0$. However, economic efficiency (or social optimality) requires that the marginal benefits of emission reductions, *MB*, equal the value of the marginal costs of emission abatement, *MAC*. In Figure 1 this corresponds to an emission reduction level of R^*. *MB* is essentially the value of the damages avoided by reducing emissions, while *MAC* involves the marginal (least) cost of a combination of emission reduction options such as fuel switching, efficiency improvements and abatement technologies.

Figure 1. The Socially Optimal Level of CO_2 Reduction
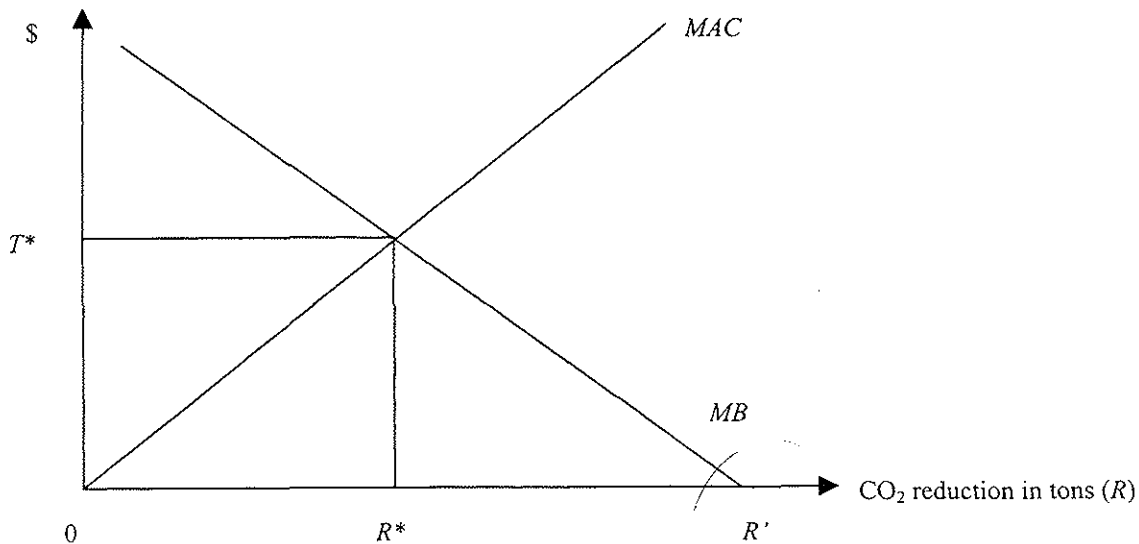
Most environmental economists agree that the above situation calls for governments to intervene in the market place to ensure that the optimal level of emission reductions is attained. The authorities may, for example, set a mandatory emission reduction at R^*. Another approach, however, is to 'put a price' (a tax) on the emissions so that the generator has an incentive to take this, otherwise "invisible", cost into account. In this way the externality is *internalized*. The optimal emission tax, T^*, in our example would be set so that $T^* = MB\ (E^*)$, i.e., it should be equal to the marginal damage at the optimal level of emission reduction. Such a tax is also known as a *Pigovian tax* after the British economist Arthur Pigou (Pigou, 1920). Confronted with this tax the generator will find it profitable to reduce emissions up until the point where $R = R^*$.

However, given the difficulties associated with estimating the value of the marginal damage and hence with determining the optimal tax level (e.g., Sundqvist, 2002), environmental policy may be pursued in a more pragmatic manner. Government authorities (or, in the case of climate policy, countries) agree upon a predetermined standard for emissions reduction as a target for environmental quality. The relevant task now is not about identifying the socially optimal level of emissions reduction and then tax accordingly, but rather about choosing the (unique) allocation of means that allows the fulfillment of the emission constraint at least cost. This approach is what Baumol and Oates (1988) refer to as "efficiency without optimality," (p. 159), and one way of achieving this goal is emissions trading. Figure 2 illustrates the basic principles of such a policy.

Figure 2. CO_2 Emission Cap and Cost Efficient Reduction
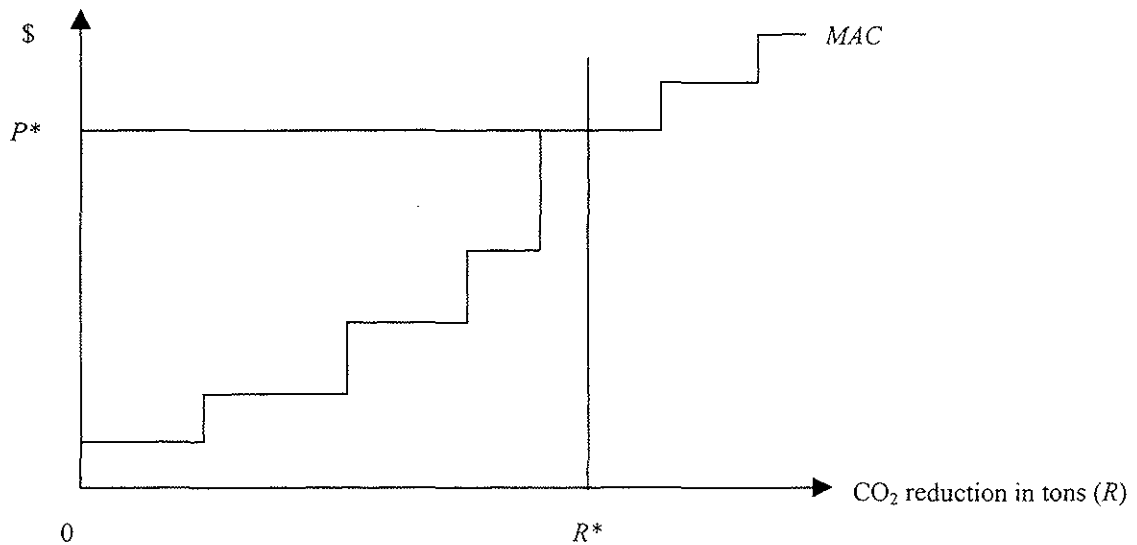
Based on a pre-determined CO_2 reduction target, R^*, the regulator sets a cap on overall emission levels and then issues emission permits to power generators. These permits are fully tradable and a generator that, for example, faces high mitigation costs can buy more permits from another generator with lower mitigation costs. In this way a market for emission permits is created and a price on emissions, P^*, is established. This system has one important advantage; instead of mandating a specific number of compliance methods it encourages the creativity of power generators to search for the least cost compliance path. In addition, an emissions trading program is market-conformed and can easily be implemented in a deregulated electricity market.

Each "step" of the *MAC*-curve in Figure 2 represents the costs of one specific compliance method. Ideally, the *marginal* costs of each CO_2 reduction option should be used in the comparison between the alternative methods, and normally these costs tend to increase with volume due to specific local conditions.[4] For data limitation reasons, however, our cost analysis assumes that all options have constant *average* costs as volumes increase, so that costs at the margin equal average costs. Power generators normally employ discounted cash flow (DCF) techniques to evaluate the economic merits of different technology options. In this paper we use as surrogate of the DCF approach, the levelized cost methodology. This means that (in the case of new plant investment) all power generation costs (i.e., capital, operation and maintenance, and fuel costs) are discounted to a present value and then divided by the total discounted output over the lifetime of the plant. The levelized cost method results thus in an average cost per unit of electricity produced (e.g., Bemis and DeAngelis, 1990; NEA/IEA, 1998). This cost can be compared over different new investment options. For a generator it is also necessary to compare the variable costs of existing plants, without consideration of already-sunk capital costs, and the total levelized cost of a new plant. Such a comparison permits the generator to decide whether it is economical to use existing power stations more intensively by either: (a) extending their lives (in the case of a replacement investment); or by increasing their capacity utilization (when considering capacity additions to meet increases in load growth) (Ellerman, 1996). The generation costs of the above options (new and existing) can then be related to the specific amount of CO_2 emissions avoided for each option in order to obtain the cost per ton of CO_2 mitigated.

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[4]   For example, a wind power plant at the best available site can have a production cost of about 40 USD per MWh. However, if a large amount of windmills are built both onshore and offshore less favorable sites must be used. This may result in 2-5 times higher production costs (IEA, 2000b).

One important shortcoming of all DCF methods, however, is that they permit no explicit consideration of uncertainty and flexibility. For this reason many analysts as well as energy companies have shown an increased interest in real option valuation techniques (Dixit and Pindyck, 1994). An option is an opportunity, i.e., the right but not the obligation to take some action in the future. When an electric utility makes an (irreversible) investment in a new power plant it exercises the option to adjust its power generation mix quickly to changes in technology, and this lost option value is an opportunity cost that should be included as part of the investment. In other words, DCF analyses will not include the value of keeping the option alive, and for this reason it will tend to overstate the economic value of "inflexible" investments (Ibid.). Real option valuation techniques, on the other hand, can be employed to estimate the value of this option.

Even though this paper primarily employs conventional DCF cost analysis, some of the implications of the real options literature for the power generator compliance process will still be emphasized. Generators are today likely to be hesitant about sinking capital because the economics of future technological mitigation options are highly uncertain, and waiting enables them to reduce the risk of being stuck with excess capacity or an obsolete generation mix. In other words, the value of flexibility and thus of keeping options alive tends to be high. This also implies that any medium-term strategy will be influenced by the uncertainty about future options. Given the present uncertainties generators may refrain from investing in the physical and human capital needed to change entirely the company's technology mix. In many cases it will – at least initially – make most sense to invest in flexible solutions and/or refurbish and increase the utilization of existing capacity (Kaslow and Pindyck, 1994).

The fact that many European countries are deregulating (or are in the process of deregulating) their electricity markets strengthens the importance of uncertainty and thus of maintaining flexibility (e.g., Söderholm, 1999). With deregulation and privatization, the risks faced by power generators increase, and for this reason their rate of return requirements increase as well. This favors flexible investment alternatives with short-lead times and low capital requirements. Moreover, deregulation and increased competition also imply that generators are no longer able to pass on cost increases to consumers. There exists in this way a real penalty for making mistakes, and this leads generators to become more cost-conscious and to seek to manage their exposure to changing market conditions more effectively. For instance, in traditional electricity markets it was common for utilities to avoid risks by over-investing in new capacity, while in deregulated markets generators are likely to compare the economics of existing and new capacity more closely. This implies a greater focus on higher capacity utilization, power plant lifetime extension and fuel conversions in existing facilities.

4. Options and Costs of Reducing CO₂ Emissions: Medium-term

The medium-term carbon abatement strategy of a representative power generator is likely to be a combination of investments in new and existing electric power capacity (and of the purchasing of CO_2 allowances). During the last decade the incentives for investing in new power capacity have been few, while fuel conversions as well as extended use of existing capacity have become more common (e.g., Söderholm, 1999). A number of factors have contributed to this situation. The deregulation of the electricity market has generally led to lower prices and in the presence of overcapacity prices have gone down to levels that equal the short-run marginal costs of production, and many generators have not been able to cover capital costs. For example, in the Nordic market the electricity price has occasionally been lower than 2 US cents per kWh, although during 2001 it began to increase substantially (Nordpool, 2001).

Additional reasons for the relative lack of investment in new capacity are: (a) the bias against new plants expressed in new source performance standards; (b) problems of siting; and (c) the fact that new plants have been unable to offer any substantial cost reductions as a result of technical progress (Ellerman, 1998). However, the introduction of a CO_2 allowance market and the related emission cap may create stronger incentives for investing in new capacity, this since one (but certainly not the only) way of complying with the emission target is to replace existing capacity with new less carbon-intensive power-generating technologies.

4.1 Power Generation Cost Structure

In order to permit an analysis of the CO_2 avoidance costs incurred by replacing existing plants with new plants, Table 3 outlines eight representative power generation technologies. Most of these are commonly available in Europe. The old ones are industrial-based plants, and they do not bear any capital burden as the others do. The existing oil-fired plant can also represent a coal-fired unit modified to burn oil. The gas-fired cogeneration plant is however not common. It consists of a modern gas turbine (50 MW) with a heat recovery boiler only, i.e., no combined cycle arrangement. This is probably the most inexpensive combined heat and power (CHP) plant available in Europe today.

In order to calculate the levelized (or discounted average) power generation costs the following assumptions have been made. The real discount rate is set at 7 percent and the economic lifetime of each new plant is assumed to be 20 years.[5] All

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[5] From society's point of view the chosen lifetime is relatively short and the assumed real interest rate is fairly high. However, from a power generator perspective there is uncertainty about the rate of return on the essentially irreversible long-term investment in new power plants, and this justifies the above assumptions.

Table 3. Power Generation Technologies

Plant type	Fuel	Power capacity (MW)	Heat capacity (MW)	Investment cost (USD/kW)	Fuel-to-electricity efficiency (%)	Total efficiency (%)	Status
Power plant	Coal	800	0	1000	45	45	New
CHP	Coal	130	200	1400	35	89	New
CCGT	Gas	400	0	560	57	57	New
CHP	Gas	50	47	740	42	81	New
Power plant	Bio	150	0	1800	40	40	New
CHP	Bio	50	130	2100	29	104	New
Power plant	Coal	150	0	0	31	31	Old
Power plant	Oil	150	0	0	33	33	Old

Sources: Steen (2000) and Strömberg (2001).

power plants are assumed to operate for 7500 hours per year, while the equivalent full load CHP operation time is 4000 hours. The heat sales price will normally vary depending on the local situation. Here the cheapest available alternative, individual gas firing in a separate house or oil firing in own boiler, is assumed. This means that for all considered CHP units the income from heat sales is assumed to be 17.6 USD per MWh. Table 4 summarizes the fuel price and CO_2 contents assumptions made in the analysis. Finally, costs associated with fuel supply infrastructure and the distribution of the electricity, are not included and all costs exclude any taxes or subsidies.

Table 4. Fuel Price and CO_2 Content Assumptions

	Coal	Gas	Oil	Biofuel
Cost of fuel (USD/MWh$_{fuel}$)	5	9	15	13
CO_2 release (kilogram/MWh$_{fuel}$)	339	201	276	0

Figure 3 shows the levelized costs for each of the eight power generation technologies. The four new coal- and gas-fired units show approximately the same net production cost for electricity, around 25-30 USD per MWh. The bio-fueled plants are both much more expensive. This is primarily due to high capital costs relative to coal and gas use because of the lower energy density of fuel systems incorporating biomass. In the Scandinavian countries all coal and oil-fired fired plants have been rebuilt for wooden fuels as a consequence of the investment subsidies and a CO_2 tax for fossil fuels at around 50 USD per MWh (Bärring et al., 2000).

Figure 3. Levelized Power Generation Costs for Selected Technologies

Total gross cost USD/MWh el ▢ Income heat USD/MWh el ▲ Net cost electricity USD/MWh el
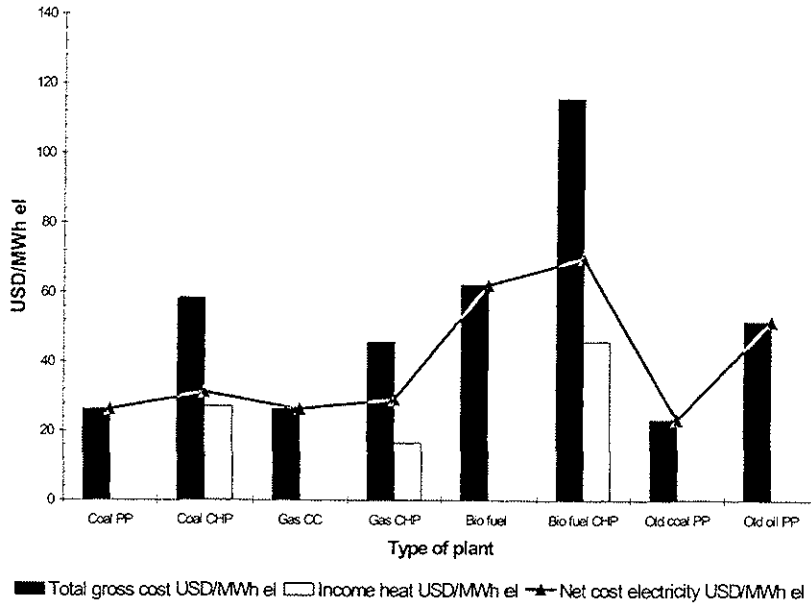
The old, relatively inefficient, coal plant is competitive due to the fact that its investment costs are sunk and it only has to cover its fuel and operation and maintenance costs. Figure 3 also illustrates the fact that no investments in new capacity will be made as long as the variable cost of the existing coal plant is lower than the total cost of a new replacement plant. Figure 4 shows the variable (or marginal) costs for each of the eight power generation technologies. It also shows that the CHP plants generally have the lowest variable costs due to the heat sales.

In sum, there exists a conflict in the fact that the market is liberalized. This creates a situation where some overcapacity exists and owners are forced to sell at marginal costs. As long as there is excess capacity there will be limited incentives for structural change and investment in new plants. The generators have no possibility to introduce either new modern plants with lower specific CO_2 emissions, or any capture and storage equipment. If this is to happen, some governing means must be taken, and they should ideally be equal for all technologies and actors in the market.

**Figure 4. Variable and Total Cost of Power Generation Technologies**

Type of plant

■ Total net cost USD/MWh el □ Marginal cost USD/MWh
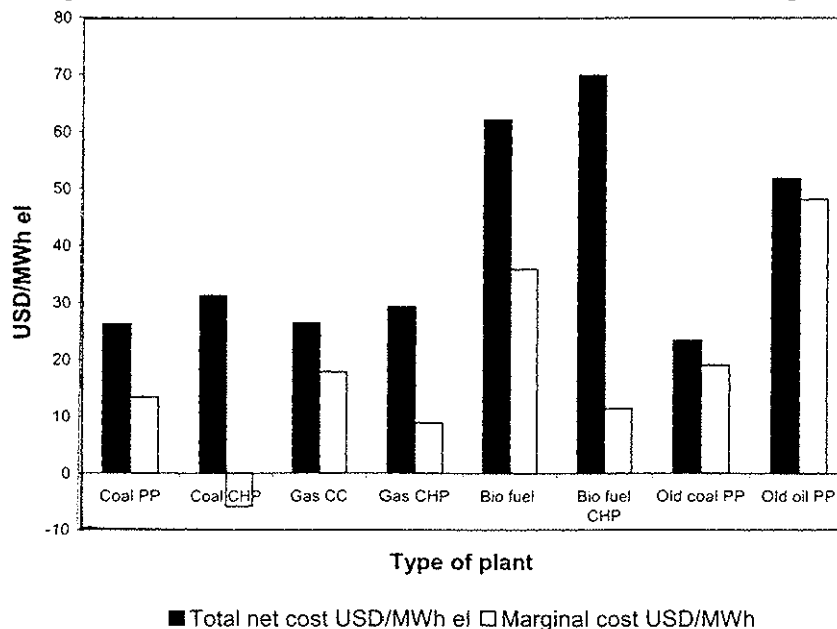
4.2 Costs of CO_2 Reduction

For power generators with few inexpensive CO_2 avoidance options available the purchase of emission permits will clearly be the most rational strategy. For the other, though, a range of possible alternatives may be present. Previous analyses of climate policy compliance strategies in the power sector normally focus on the replacement of old power plants by new and more efficient and less carbon intensive plants (e.g., Steen, 2000; Wang, 2000; Hendriks et al., 2001). This is also the main approach employed in this paper, but before proceeding it is important to also stress the importance of intensified and extended use of existing capacity. As was noted above, as existing capacity (most notably nuclear and coal) tends to have comparatively low variable costs and new power capacity has high investment costs, the incentives for better and more intense use of existing power stations tend to be strong in the power sector (Söderholm, 1999; Ellerman, 1996). Utilizing existing capacity may also turn out to be an important CO_2 compliance strategy. For example, extending the lives of existing nuclear power stations (and thus limiting the need for replacing aging plants) is often a cost-effective CO_2 reduction option in the medium-term. For instance, the levelized costs of investing in nuclear lifetime extension are often considerably cheaper than building a new CCGT plant (e.g., Carnot and Gallon, 2001). In addition, the conversion of an existing coal- or oil-

fired plant to burn gas instead is often inexpensive and can be accomplished within a relatively short time period. Even existing coal-fired power stations could be upgraded – by improving coal quality and fuel efficiencies – so as to lower overall CO_2 emissions (Smith, 2001). The economics of these options tend to vary from case to case, but in general they all help "keeping options alive" and thus in maintaining fuel flexibility.

In order to evaluate the CO_2 reduction costs incurred by replacing an old plant with a new less carbon intensive one we first need information about the extra cost of producing power, i.e., the difference between the total cost of the new plant and the variable (fuel and operating) costs of the existing plant. This additional cost should then be divided by the avoided CO_2 emissions per unit electricity produced (e.g., Hawk, 1999). We will consider a *base case that involves replacing an old coal-fired plant* with the new plants identified above. Let us first consider the CO_2 release calculated as kilogram CO_2 per MWh electricity produced for the different types of plants. Figure 5 presents these CO_2 emission intensities using Eurostat data.

Figure 5. CO_2 Emissions per Unit Power Generated (kg CO_2/Mwh)
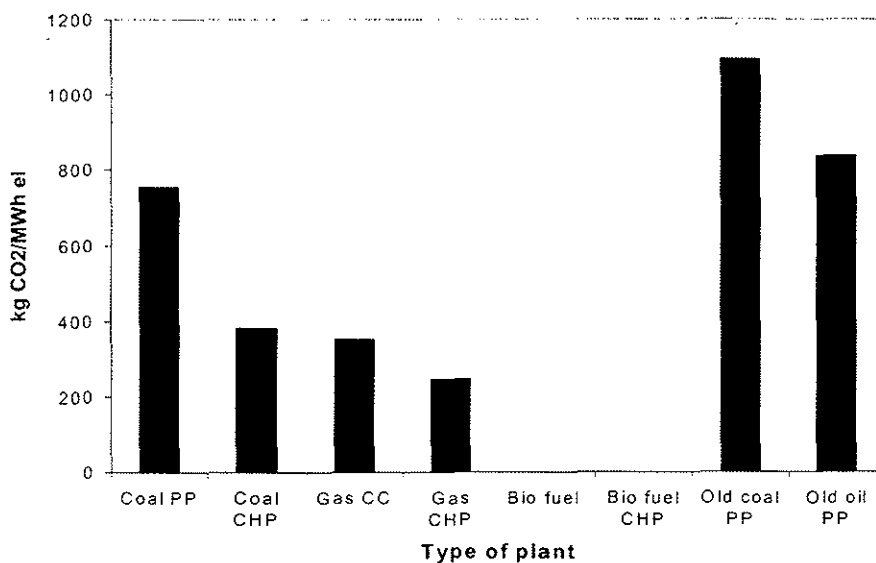
For the CHP plants the fuel consumption has been divided between the electricity and the heat outputs. The fuel consumption for the heat has been estimated as the amount needed for heat-only production in the best available plant.

The remainder of the consumption has been attributed to electricity generation. As anticipated, the old coal plant with its low efficiency emits most CO_2. The biofuels, however, do not give rise to any net amount of CO_2.

Figure 6 shows the costs of CO_2 avoidance in USD per ton CO_2. This figure illustrates that even though the bio-fueled plants are very attractive in terms of CO_2 release their high production costs make them a less attractive alternative from a CO_2 avoidance perspective. The cost of reducing the old coal plant's CO_2 release by building a new bio-fueled plant is in the order of 40 USD per ton CO_2. Based on our figures the four options involving new coal or gas plants are the cheapest CO_2 reduction alternatives. In these cases the costs are between 5 and 10 USD per ton of CO_2. The low cost of using coal-fired power as a CO_2 compliance strategy is somewhat surprising (given the high emission intensity of coal). However, the potential for this option is likely to be limited to those cases where old and very inefficient coal-fired plants can be replaced by much more modern ones at *existing* sites.[6]

It is also interesting to note that the CHP plants do not show any significant advantage over the power only plants. The case of the old oil plant is included to exemplify the option to switch over to oil in a coal-fired plant, since oil burning emits less CO_2 than does coal. Technically this is easy, but from Figure 6 it is clear that the CO_2 emissions will decrease only at a very high unit cost.

Since other carbon-free renewable energy sources (wind, solar etc.) generally are more expensive than the bio-fueled options considered here, we can conclude that for an electric utility with a portfolio of coal-fired plants the best medium-term strategy tends to be either to: (a) convert the existing plant to burn gas instead; or (b) replace the old coal plants with a new (more efficient) coal plant or CCGT.

Furthermore, a cost effective emission reduction strategy also implies that the oldest, and hence most inefficient, plants should be replaced first. In addition, in the case of an old plant there is no capital burden but for a more modern plant there is still a capital cost, and any new plant has to carry this cost. The capital burden during a representative coal-fired plant's lifetime is illustrated in Figure 7. Specifically, Figure 7 shows the capital burden and the annual costs as percentages of the present actual investment cost.[7] It should be read so that, for instance, a 13-year-old plant has a capital burden of about 50 percent of the present new

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[6] This is often referred to as *repowering*, and indicates a situation in which a generator adds new capacity by taking advantage of existing infrastructures and fuel supplies.

[7] From a purely economic theoretical point of view, once the investment is made the capital costs are sunk and should not affect future decisions about plant replacement. Still, for the generator these annual expenses (whether sunk or not) may affect these decisions since financing constraints are common in the industry.

investment cost, and an annual capital cost of about 7-8 percent of that same investment cost. A typical coal-fired plant is written off in 20-25 years, but it also gets retrofitted at different intervals during its lifetime. In Figure 7 it is assumed that the depreciation time is 20 years and reinvestments are made every fifth year and they equal a sum equivalent to 10 percent of the new investment cost at the specific time. The annual inflation rate is assumed to be 3 percent and the real interest rate is 6 percent.

Figure 6. CO_2 Reduction Cost Analysis
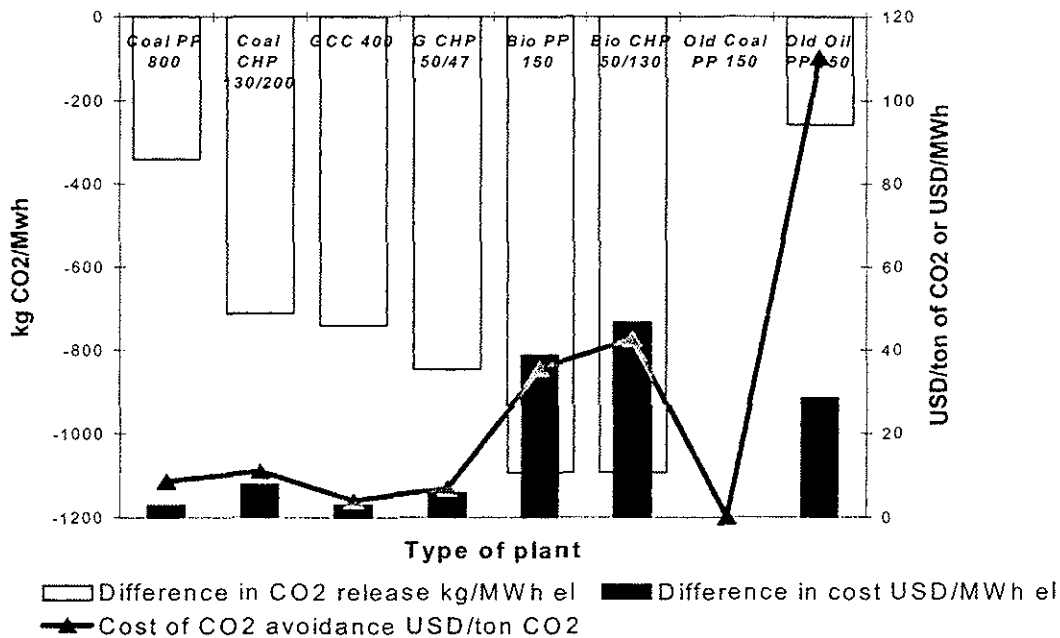
By taking the capital burden into consideration and also the fact that the fuel-to-electricity efficiency is better in a newer plant, Figure 8 has been constructed. The most favorable CO_2 reduction option, namely to replace an old coal-fired plant with a new CCGT plant, is used as the reference case here. For the coal-fired plant the efficiency is assumed to be typical for an industrial plant. The efficiency conditions are generally worse for a power plant, but the size 150 MW (see Table 3) suggests that it is an industrial plant that we are considering. Figure 8 shows that the cost of CO_2 avoidance increases with the youth of the replaced coal plant. A very old plant will incur a cost of about 4 USD per ton of CO_2 avoided, while the replacement of a newer plant will give rise to a cost about three to four times higher than that.

Figure 7. Capital Burden and Annual Capital Costs During the Lifetime of a Plant
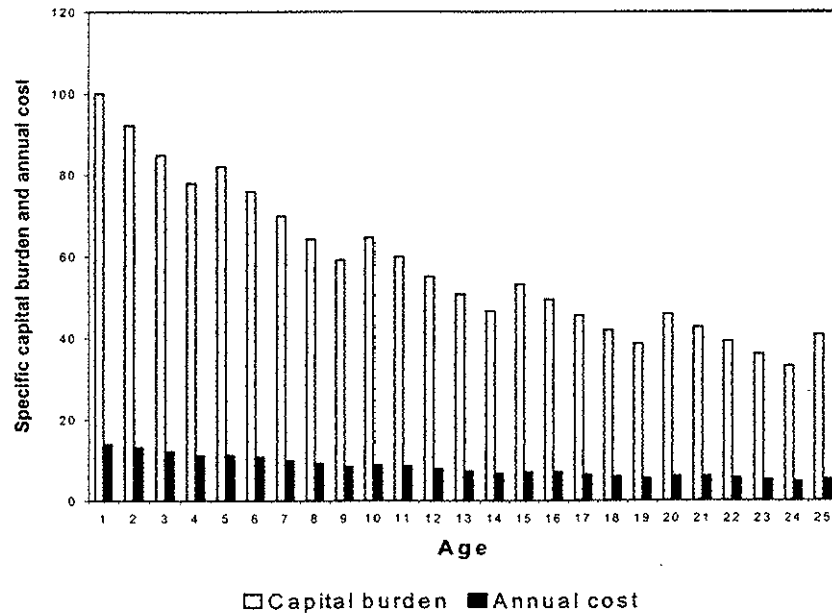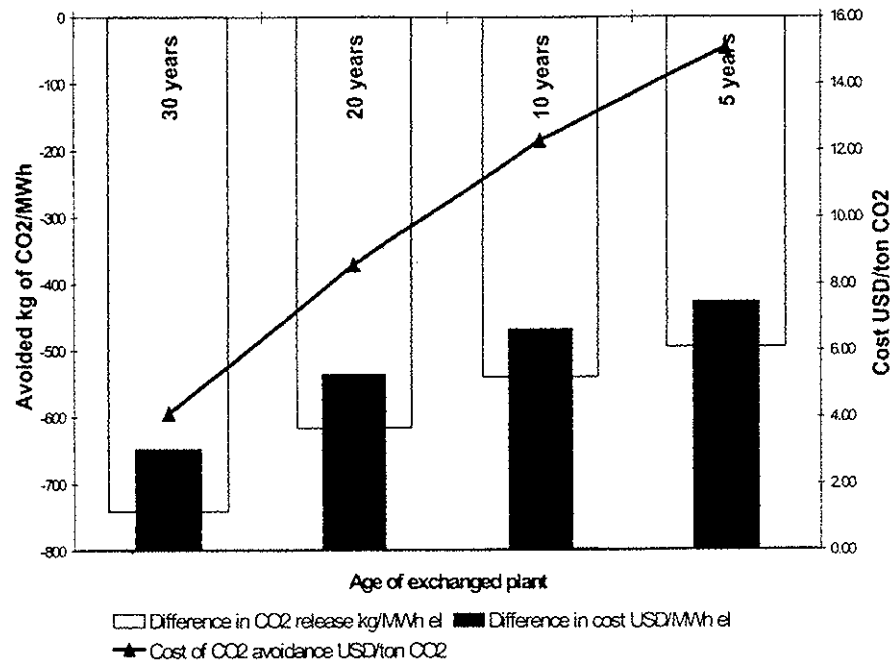

☐ Capital burden ■ Annual cost

Figure 8. CO_2 Avoidance Costs for Different Vintages of Coal-fired Plants

☐ Difference in CO2 release kg/MWh el ■ Difference in cost USD/MWh el
▲ Cost of CO2 avoidance USD/ton CO2

Thus, the age structure of the existing coal-fired plants to be replaced will be an important determinant of the utilities' financial cost of CO_2 avoidance. Smith (2001) shows that in Western and Central Europe over one third of the installed coal-fired power capacity has been built after 1980 and many of these are likely to still bear a capital burden. This shows the importance of replacing the oldest (and the least efficient) coal-fired plants with newer and more efficient ones first. Furthermore, the analysis also illustrates the fact that government policies, which attempt at speeding up the energy capital stock turnover (e.g., IEA, 2002), are not necessarily cost effective even though they may increase the rate at which new technologies are introduced. Any justification for policy activism must be based on evidence of some failure in the market under consideration, and the case for such market failures in the capital market is not easily made. Instead slow turnover is often instead due to *policy failures*. Most notably, environmental regulations for new power capacity are often stricter than the corresponding regulations for existing plants (Ellerman, 1998). Again, a price-based policy targeted towards the most important market failure in this case, CO_2 emissions, would encourage power generators to find the optimal balance between continued use of existing plants and the building of new ones.

In sum, this sub-section has evaluated a number of medium-term supply side CO_2 mitigation options. Based on this it is probably fair to conclude that even though many alternatives appear favorable from a pure CO_2 emission impact view, their real economic costs, in terms of USD per ton CO_2 avoided, may be relatively high. It is also clear that the avoidance costs depend on many factors such as the cost of new power plants, fuel efficiencies and the age structure of exiting plants. For this reason it will be very difficult for regulators to "pick" the most efficient reduction strategies. All in all this strengthens the case for the introduction of environmental pricing and emissions trading, and for refraining from policies that build on mandatory fuel requirements, higher rates of capital stock turnover and technology standards.

4.3 Some Consequences of Substituting Gas for Coal

We have so far only considered marginal investments in new capacity, and have thus assumed that, for instance, a shift from coal to gas will have no impact on fuel prices. However, since a large number of generators are likely to invest in new gas-fired combined cycle plants due to its high efficiency, flexibility and low costs, and especially so if an ambitious cap on CO_2 emissions should be introduced, there is likely to be a large impact on fossil fuel markets. Given the existing fuel mix in the European energy supply system it can easily be estimated how much a certain shift from the existing coal (black coal and lignite) plants in Europe would increase the corresponding power generation gas consumption. This type of simulation exercise

permits us to gain an understanding of how much coal needs to be removed in order to achieve a given reduction in CO_2 emissions. In order to perform such an evaluation, the following assumptions have been made:

1. The average efficiencies for each power plant are drawn from the European Commission (2000c). A range is estimated from 30 percent efficiency for the worst up to 43 percent for the best lignite-based plants. Similar assumptions have been made for the other plants.
2. The new power plants are assumed to be gas-fired combined cycle plants with an average efficiency of 55 percent.
3. The CO_2 emissions are calculated using Eurostat figures (see also Figure 5).
4. Electricity consumption is assumed to remain constant.
5. No other capacity, such as nuclear units, is shut down.

Figure 9 shows the amount of coal to be abandoned to reduce CO_2 emissions, and how much gas is needed to replace the existing coal-fired units. In order to reduce the CO_2 emissions by 20 percent it would be necessary to shut down close to 55 percent of all coal-fired plants in Europe. This means that not only the least efficient coal plants are affected but several of the high-performing units also. Furthermore, it would also imply that both lignite and black coal plants are shut down, and that some countries have to abandon coal more or less completely.

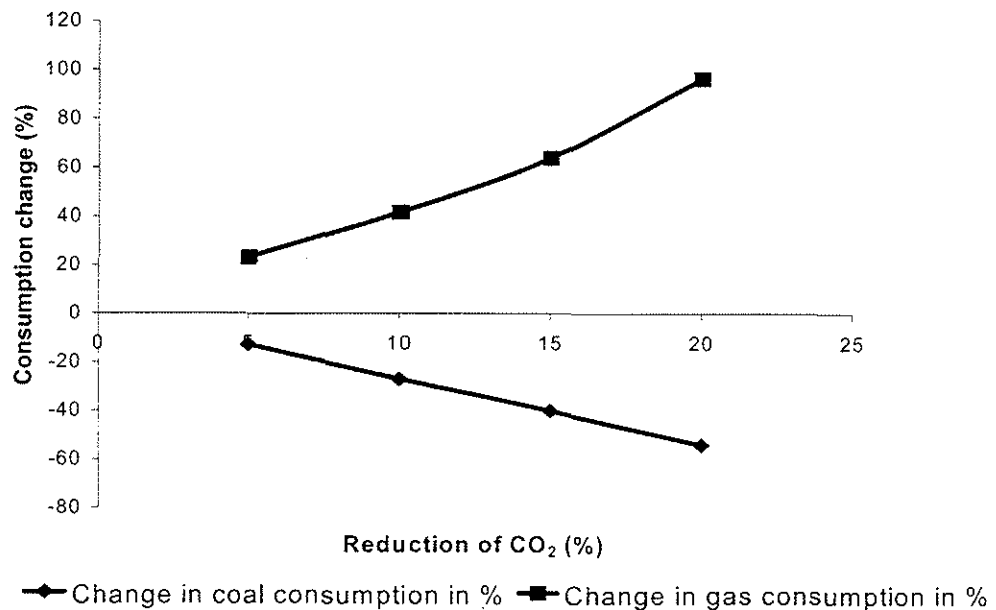**Figure 9. Fuel Consumption Consequences of Substituting Gas for Coal in Europe**

Reduction of CO_2 (%)

—◆—Change in coal consumption in % —■—Change in gas consumption in %

Figure 9 also shows that gas use will increase considerably. A CO_2 reduction of 20 percent can be achieved if the use of gas in the European power sector is doubled (100 percent increase). Naturally, if we relax the assumption of constant nuclear energy capacity and assume instead that this capacity shall be exchanged with gas (as is planned in countries such as Germany and Sweden), the results become even more dramatic.

Even though Figure 9 provides a very rough and "mechanical" view of the impact of fuel switching on gas and coal use, it raises some important concerns. Most importantly, rapid increase in the use of gas could lead to substantially higher prices in the short-run for natural gas and, in some countries, to concerns over energy security and diversification as gas becomes the dominant fuel (Söderholm, 2001). Over the longer-term, however, the relative price of coal versus gas and all other fuels will be determined mostly by relative productivity improvements and capacity adjustments in the respective energy industries. It is beyond the scope of this paper to analyze the ultimate outcome of this "productivity race". An investment in a new power plant (more or less regardless of the fuel burnt) is a long-term investment with an economic lifetime of at least 20-25 years, and an electric utility has to consider both short- and long-term fuel price developments. In the end this involves a projection of future technological improvements. For instance, investments in new gas-fired power may very well be hampered by short-run gas price increases but may still be stimulated if future technological improvements are expected to be gas promoting.

5.   Options and Costs of Reducing CO_2 Emissions: Long-term

In previous sections we have pointed out that the present uncertainties about future technological options for CO_2 mitigation as well as about the exact design of climate policy, induce power generators to maintain flexibility and not to lock themselves into a specific infrastructure and capital stock that cannot make use of alternative fuels. We have not yet, however, dealt with the question of what technical solutions may be available in the longer-term. In this section we discuss the technical and economic potentials of a number of promising – but yet non-commercial – CO_2 mitigation options. Of course, in contrast to our previous analysis of medium-term options this discussion will be highly tentative, not the least when it comes to assessing the economics of CO_2 avoidance over the longer term. Still, a careful consideration of the long-term options is important not only because even more strict policies than the Kyoto agreement are needed to level out the CO_2 concentration in the atmosphere, but also since the actions of today's generators are likely to have a decisive effect on the future course of technological innovation and adoption.

The academic literature has long recognized the difficulties involved in predicting the outcome of technological competition. However, a relatively safe bet is that the outcome of the competitive process in the power industry will be *path dependent*, i.e., any given change in the power generation mix and/or CO_2 mitigation technologies will be strongly dependent on pre-existing technologies and institutions (e.g., Arthur, 1994; Rosenberg, 1994). The existing electricity companies have invested in a lot of technology-specific human and physical capital, and they will have an incentive to direct future innovation activities toward technical solutions that can make use of this capital. However, the picture gets more complicated by the fact that in some cases the industry moves away from the historical path of technological change due to substantial technical breakthroughs (in some cases spurred by government R&D activities). The efficiency improvements and the soar in CCGT during the late 1980s represent one example of such a breakthrough (Islas, 1997). At present, most governments are hoping to be able to induce (if not a fundamental but) at least a modest switch from fossil-fueled power to renewable energy sources.

In sum, when considering if, how and when to invest in different CO_2 mitigation options, many power generators are not simply passively "keeping options alive" and waiting for a new technological breakthrough to drop down from the sky. They are also taking an active role in influencing the direction of future technical change. Whatever the case, there are strong reasons to believe that existing power generation technologies will be favored. As we browse through some of the different long-term options of CO_2 compliance methods, it will become clear that many of these build on improvements in and/or developments of existing fossil-fueled and nuclear power technologies and represent thus not only renewable energy alternatives. The most important example of this is, perhaps, the carbon sequestration technology, which involves capturing and storing the CO_2 in natural reservoirs rather than allowing it to build up in the atmosphere (e.g., Herzog et al., 2000). If this technology – which already exists – is commercialized coal can be considered a sustainable energy source, and there may be weak incentives for utilities to switch from coal to alternate fuels. Section 5.1 outlines a mix of promising technologies to reduce future CO_2 emissions, while we devote section 5.2 entirely to carbon sequestration.

5.1 Potential Future Options for CO_2 Reduction in the Power Sector

Table 5 summarizes the International Energy Agency's recent assessment of the most promising technologies for CO_2 mitigation in the future. In section 2 we presented the current status of power generation technologies in Europe, and Table 5 shows that many of the promising developments in terms of CO_2 reduction strategy are derived from traditional energy sources. Efficiency improvements in coal- and gas-fired plants are expected to lead to substantial CO_2 savings. In other

words, although the costs of new power sources, such as fuel cells, wind and solar, continue to decrease, the competitive disadvantage of these sources remains as the costs for the traditional power sources continue to decline as well. Thus, the declining costs of conventional power generation constitute a "moving target" against which renewable energy has to compete (McVeigh et al., 2000). In addition, extended and intensified use of existing (carbon-free) power generation options, such as hydro and nuclear, can also provide effective compliance strategies. Thus, while constructions of *new* nuclear and hydro power plants are facing serious constraints due to siting problems, high capital costs and public opposition, more effective utilization of *existing* plants avoids these obstacles.

Biomass firing and solar and wind power are also very promising – more or less established – technologies but they still face serious cost constraints, which limits their current possibilities of increasing considerably their share of total power generation (see Section 2). Two of the most promising power technologies, fuel cells and CHP, deserve additional attention. Some of these applications may also be able to supply so-called distributed power where the electricity is generated close to the place where it is used, instead of generating at large centralized facilities and then transmitting the power to the end users.

A fuel cell is operated with hydrogen or methanol as the fuel (but with methanol use efficiency drops). It is estimated that a fuel efficiency of 70 percent can be reached in the future for the cell itself and this provides a potential for CO_2 reductions. Since hydrogen, or for that matter methanol, are not naturally available fuels they have to be manufactured somehow. At present, hydrogen is produced either from oil or gas or from water using electricity. The efficiency for this production must be included in the total efficiency for the fuel cell. In order to provide substantial CO_2 emissions savings the hydrogen or methanol must be produced from biological processes or using solar energy. In both cases it may, however, be the case that it is more efficient to use these processes directly instead of making hydrogen for a fuel cell in a stationary system. Fuel cells have been developed for many decades, but most are still at the R&D phase and are thus not competitive for power generation purposes due to high investment costs. At present the driving force for development comes mainly from the automotive industry where huge development efforts are made.

CHP (or cogeneration) is one of the most promising technologies for reduction of CO_2, even in the shorter-term (IEA, 2000a). In some regions CHP technologies are already competitive. A conventional power plant with a fuel-to-electricity efficiency of some 35 percent can achieve some 90 percent of total efficiency if built as a CHP plant. However, the potential is in many cases limited, partly since one barrier to the use of CHP is the difficulty of matching heat and electricity loads.

Table 5. Some Promising Technologies to Reduce CO_2 Emissions in the Power Sector

Technologies	Description	Development status	Reduction Potential
Natural gas	Efficiency improvements in combined-cycle technology and conversion of existing coal-fired plants to operate on gas.	Already competitive and can be put in place rather quickly.	CO_2 emissions are often 50 percent lower than those from conventional coal-fired power.
Coal	New and more efficient technologies such as the integrated coal-gasification combined-cycle (IGCC) technology.	Some new technologies are already commercially available, though operating experience may be limited. IGCC technology is mainly on the demonstration project stage, and is not yet competitive.	By 2020 high-efficiency coal technologies could reduce CO_2 emissions substantially, especially in Eastern Europe.
Biomass	Forestry and wood residues, agricultural and crop processing residues, and dedicated energy crops.	In the short-run, co-firing with coal is the most effective method, while in the long-run prospects are good for new conversion technologies such as biomass gasification.	Has no CO_2 emissions impact, and can replace up to 15 percent of the total input energy to a coal-fired plant.
Wind	Large, grid-connected wind turbines as well as smaller stand-alone turbines.	Has developed rapidly since 1980, but despite falling costs wind energy is still not competitive except in some niche markets.	Is a potential major option for emissions reduction. In regions where wind conditions are favorable up to 10-20 percent of the total power capacity could be supplied by wind turbines.

Table 5 (cont'd)

Technologies	Description	Development status	Reduction Potential
Nuclear	Life extension and optimisation of existing nuclear power plants and new nuclear technologies.	Life extension already used but development activities needed to increase the potential for this option. New technologies (such as fission reactors) still at the development stage.	Nuclear power is virtually carbon-free, but its expanded use is constrained by high capital costs and concerns about waste management.
Fuel cells	Generate power through the chemical reaction between hydrogen (or a hydrogen-rich fuel such as natural gas) and air.	One group of fuel cells (so-called PAFCs) are available while others are still at the development stage.	There is potential for CO_2 savings since fuel cells are much more efficient than other power technologies.
CHP	The joint production of heat (steam) and electricity, in some cases in small engines.	Highly efficient lower-temperature CHP is well-developed, but high-temperature CHP is still in its infancy.	Large potential to reduce CO_2 emissions given its high overall conversion efficiency (80-90 percent).
Solar	Photovoltaic power systems	Still uncompetitive but cost reductions are expected from development of new materials and large-scale manufacturing.	Major potential for emissions reduction but considerable uncertainty about future costs.

Source: IEA (2000a).

According to the European Commission (1995, 1998) CHP plants cannot theoretically provide more than between 30 and 40 percent of the electricity used in a country. This is true even for the cold Nordic countries; in Sweden the theoretically possible power generation from industrial and domestic cogeneration has been estimated at below 20 percent of total demand (SOU 1995:139). However, in the longer-run micro-turbine CHP is also discussed. This involves providing heat and electricity with a small engine, or fuel cell, on a very local level. The benefits are that the distribution system losses can be eliminated, the modular character of the turbine and their ability to add new capacity incrementally and adjustably to changes in electricity demand (Edinger and Kaul, 2000). The impacts on CO_2 reduction are, though, still uncertain and have to be studied in more detail.

In sum, it is very hard to predict the long-run outcome of the technological competition between different power technologies. At present the costs of renewable energy based power generation will have to come down considerably to be able to compete with the traditional power sources. Although the economics of the next generation of, in particular, biomass energy, wind power and fuel cells are likely to be more favorable (IEA, 1997), substantial efficiency improvements also occur in coal, gas and nuclear power generation, and the ultimate outcome of this productivity race is highly uncertain. It is also noteworthy that natural gas may well become the fuel of choice in many of the emerging technologies – fuel cells and micro turbines – as it already offers a ready delivery system (Pfeifenberger et al., 1997). This clearly illustrates the path dependency of energy systems.

5.2 Capture and Sequestration of CO_2

Carbon sequestration involves two essential steps.[8] First the CO_2 must be removed from flue gas streams by methods analogous to what is used for sulfur dioxide removal. Second, there is the problem of disposal or, more aptly, sequestration. Technologies for both capture and storage of CO_2 exist already today (Herzog et al., 2000; Lyngfelt and Azar, 1999). However they are not optimized for power generation purposes and are still expensive. A huge development effort has, however, been initiated in many countries, and these have been described and summarized extensively within the IEA Greenhouse Gas Program (IEA, 2001).

Separation of CO_2 from flue gases is at present based on an adsorption process, and this method is well established and is used industrially. To de-carbonize the fuel is somewhat simpler but requires more energy. This loss of efficiency implies that the costs for both methods are calculated at 30-50 USD per ton CO_2, and the costs of carbon capture is cheaper in IGCC power plants than in Pulverized Coal (PC)

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[8] We do not consider here the case of forest sequestration, which implies forestation programs that allow new power plant constructions to be delayed. See, however, Newell and Stavins (2000).

plants or Natural Gas Combined Cycle (NGCC) plants (Herzog, 2001; David and Herzog, 2000). This implies that today's CO_2 capture technology adds about 1.5-2.0 US cents per kWh to the cost of electricity (for an IGCC plant). The total cost of permanently getting rid of the CO_2 is dominated by the separation process; CO_2 transportation and injection adds about 10 USD per ton of CO_2 avoided (Ibid.). Scrubbing and membranes can also be employed for CO_2 removal in power generation but just as for the adsorption process the costs of using these methods remain a major obstacle, mainly because the volumes to be removed are so large. For this reason research has been initiated to develop new processes to separate the CO_2 from the process.

After the CO_2 has been removed from the flue gases it can either be pumped into underground geologic formations or it can be "bubbled" directly into the ocean. Permanent storage in porous layers in the ground has been used for 25 years. It is a well-established technology and large-scale experience is available. CO_2 has already been used to enhance oil recovery from oil wells. Another reason is that natural gas contains naturally more or less CO_2, which is not accepted by the customers, and it is therefore separated from the gas and pumped back into the ground. It is also a method with large enough capacity, the geology of many reservoirs is fairly well known and they are "proven traps because they have held hydrocarbons for millions of years," (IEA, 1998, p. 407). The costs for drilling and pumping are also well known, and amount to 5-10 USD per ton of CO_2. Apart from oil and gas reservoirs other geological formations that can be used for CO_2 disposal are deep coal beds and saline aquifers.

The potential of large-scale storage of CO_2 in oceans is very large, and is more than enough for the needs in the world. Physically CO_2 acts so that if it is pumped down to 500-700 m under the sea surface it remains liquid. There the density is somewhat less than of the water, while at depths of more than 1500 meters it is denser than water. This means that it can form liquid pools on the bottom of the sea, and it would take a very long time before it would return to the atmosphere. Concerns for environmental effects (such as the pH of the water) and related life in sea due to these pools will probably, however, rule out this possibility.

The total costs of carbon capture and sequestration in the power sector are of course very uncertain. According to a recent analysis by the IEA (2001), however, the cost can come down to about 50 USD per ton of CO_2 (both separation and storage included). If so, this method could provide a less expensive CO_2 removal option than many renewable power sources (Strömberg, 2001). Herzog et al. (2000) summarize what is needed before carbon sequestration becomes common practice:

> "First, researchers need to verify the feasibility of the various proposed
> storage sites in an open and publicly acceptable process. Second, we

need leadership from industry and government to demonstrate these technologies on a large enough scale. Finally, we need improved technology to reduce costs associated with carbon dioxide separation from power plants."

The most significant opportunities for future cost reductions are gains in heat rates and reductions in the amount of energy required by the separation (David and Herzog, 2000). Given the present dominance of fossil fuels within the energy industry, power generators are likely to have an incentive to push this technology forward. Still, given the large projects involved, collaboration between governments and industry will be critical to mobilizing the investment and expertise needed to make substantial technology breakthroughs. And just as governments should not discriminate between different existing CO_2 reduction options, they also have few reasons to bias their energy R&D support in any direction (unless there are strong ethical reasons for doing so or the option under consideration is not likely to contribute to the political goal of CO_2 reductions).

6. Concluding Remarks

This paper has illustrated that for the power sector there exist a multitude of ways of complying with a mandatory cap on CO_2 emissions, regardless of whether it is a medium-term Kyoto cap or a tighter longer-term cap post-Kyoto. The avoidance costs facing a generator depend on, for instance, the cost of new and existing power plants, fuel efficiencies and the age structure of the plants to be replaced. For this reason it will be difficult for regulators to "pick" the best reduction CO_2 strategies. This strengthens the case for the introduction of emissions trading, and for refraining from policies that build on mandatory fuel requirements, higher rates of capital turnover and technology standards. A tradable permit system for CO_2 emissions will ensure that the emission cap is not violated but leaves it to the power generators to decide on the method of compliance. They will then carefully consider all available mitigation alternatives and their costs. Our cost analysis indicates that in the medium term many European utilities are likely to seriously consider options that are based on technologies that dominate today such as (a) converting existing coal-fired capacity to burn gas as well; (b) extending the lives of nuclear capacity; and (c) replacing old inefficient coal-fired plants with more efficient gas-or even coal-fired units.

In the long-term the economic potential of future mitigation options are highly uncertain, and generators are likely to respond to this uncertainty by staying flexible in terms of fuel choices and, for as long as possible, avoiding large investments that lock them into a specific compliance method before new, more efficient

technologies and fuel, have crystallized. The theoretical literature provides little support for the notion that this represents a market failure, which should be explicitly addressed by technology policy (Jaffe et al., 2000). The costs associated with uncertainty are as real as those of material, labor and capital.

In sum, there exist important CO_2 reduction strategies that rely on efficiency improvements in the traditional power stations, which as a part of a multi-option strategy offer promise in reducing overall emissions. This proposition is in some contrast to many policy initiatives, which focus on the commercialization of, primarily, renewable energy sources. Clearly, in many instances a market-push policy that creates a secure market for, say, wind power or biomass, is motivated by the existence of learning-by-doing effects and the ensuing cost reductions. However, an energy policy that solely postulates quantitative targets such as "20 percent of all power generation must stem from renewable energy sources" is good for nothing unless it is logically derivable by analysis of more basic objectives and values and of the relevant costs and constraints. Similarly, government-sponsored research efforts that are targeted towards specific fuel sources and policies that aim at increasing capital stock turnover may hamper the use of even more cost effective compliance methods. In the case of CO_2 policy, the emissions as such (in tons) represent *the* problem (not fossil fuels or delayed investment), and the methods employed for reducing CO_2 emissions must be of secondary importance.

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