An evaluation of the direct costs of abatement under the main desulphurisation technologies

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ABSTRACT: This study summarizes the available information on the technical characteristics and costs of those sulphur abatement technologies in operation at present or coming into operation in the near future. Relying on disaggregated source data and using engineering cost functions and various technical and economic assumptions, the least cost curves of sulphur abatement for all the European countries have been derived and some examples are presented. Finally, a sensitivity analysis of abatement strategies and costs to some alternative assumptions about energy futures is presented.

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INTRODUCTION

The generation of electricity from conventional power stations is associated with a number of environmental problems. For example, generation using coal causes significant air pollution due to emissions of sulphur oxides, carbon dioxide, nitrogen oxides and particulates. In the UK a 2000 MW coal fired station operating at 60% load factor burns about 4.4 million tonnes of coal per year and each year emits into the atmosphere about 10 million tonnes of carbon dioxide, 130,000 tonnes of sulphur dioxide, 40,000 tonnes of nitrogen oxides and between 4,000 and 40,000 tonnes of particulate matter depending on how well the stack emissions are cleared before they are released (Highton and Webb, 1980). Particular concern has been expressed about the emissions of sulphur dioxide because the use of tall stacks to disperse emissions can lead to problems of transnational pollution. Approximately 1 tonne of sulphur burned produces 2 tonnes of sulphur dioxide (SO_2) and sulphur is present, in varying quantities, in both oil and coal.

Many abatement technologies are commercially available now (though costly) and that most of those being developed are near- or mid-term technologies and therefore are either on the verge of being commercially available or would be available by the year 2000. Estimates of costs of pollution control systems provide a common language for making international comparisons of emissions control systems. Such abatement cost data could allow environmental policy makers to identify that combination of desulphurization technologies which would achieve a given reduction of sulphur emissions at least cost, i.e. the most cost-effective combination.

The costs used in this study relate to the direct cost of construction, operation and design of sulphur abatement units. A full economic analysis would require also the inclusion of financial factors such as interest payments, subsidies and taxes and an examination of the external costs imposed by the operation of the control unit (for example, waste disposal, etc).

This study summarizes the information on the technical characteristics and costs of the sulphur abatement technologies. Section 1 describes the technical characteristics of the available sulphur control techniques and presents the cost estimates used in this study for the derivation of the European abatement cost curves. Section 2 presents the economic and technical assumptions used in the derivation of the abatement cost curves. Section 3 discusses some of the energy alternative options and section 4 reports on the results obtained. Finally, some concluding remarks are presented. An appendix concerning the results obtained is also attached.

1. ABATEMENT OPTIONS FOR SULPHUR EMISSIONS REDUCTION

Desulphurization processes exist to reduce the sulphur content of the fuel in use. The extent of removal is dependent on the physical and chemical characteristics of the sulphur in the fuel. Control technologies can be classified into three categories: 1. pre-combustion (physical coal washing and oil desulphurization); 2. during-combustion (sorbent injection and fluidized bed combustion); and 3. post-combustion (flue gas desulphurization, FGD). Unfortunately, there has been little commercial operating experience with many of these technologies; therefore, removal efficiencies and costs tend to be uncertain. The choice of the technology will depend upon the characteristics of the fuel being burned and the standards for emissions which must be met. Ease of disposition or ability to reuse waste products was found to be a secondary but important determinant of the technology used, especially as it affects the economics of certain processes. Sub-section 1 hereafter, will describe some of the technical characteristics of the sulphur control methods available now or in the near future; while sub-section 2 will present the cost estimates adopted in this study for the derivation of sulphur abatement cost curves. Also, sub-section 2 will discuss the issue of how easy handling or re-using of by-products produced by the use of the control methods is, as a determinant for the

choice of the control method.

1.1. Technical characteristics of abatement methods used to abate sulphur emissions

Cleaning techniques are relatively simple and well-established. They take place before combustion and their effectiveness depends on the physical characteristics of the specific coal and crude oils which are subject to treatment. Sulphur in coal occurs in two forms: organic and pyritic. Organic sulphur cannot be removed by direct physical separation and comprises from 30 to 70 per cent of the total sulphur of most coals. The proportions vary with different coals although high sulphur content tends to be accompanied by proportionally large pyrite content. As a guide, between 35% and 70% of pyritic sulphur can be removed by physical washing (EPA, 1978). However, the organic sulphur which is not removed by this process may make up between 30% and 70% of the total sulphur content. This suggests that, overall, only about 25% to 30% of the sulphur will be removed (Highton, 1978). In this context it should be pointed out that physical coal washing is applicable to hard coal only. To remove sulphur in the form of pyrite, the coal is crushed, washed and then separated from impurities during a settling process. Further coal washing involves separation of coal into high and low sulphur streams and then processing of the high sulphur stream. This is termed "deep washing" and it is assumed that sulphur content is reduced by 30%. One drawback with coal cleaning is that it produces a large amount of solid waste. On the other hand, it also demands little power plant modification, reduces transport costs, and can be used in conjunction with other combustion or post combustion control methods (Parker, L.B. & Kaufman, A., 1985). Therefore, coal washing will be favoured over other methods when the sulphur content of coal is high, implying a high proportion of pyrites, and when coal is cheap[1]. This technique will also be favoured when transport costs are high.

The desulphurization of oil products takes place before combustion and can be

incorporated into the refining process, where sulphur is obtained as a by-product. The two main candidates for desulphurization are middle distillates (gas oils) and heavy vacuum residues (heavy fuel oil, HFO). The techniques used are normally classified as direct and indirect desulphurization. In the direct method the residue from the initial distillation is reacted with hydrogen at high temperature and pressure in the presence of a catalyst and then reblended with the distillate to produce a lower sulphur oil. This method can remove up to 90% of the sulphur (CONCAWE, 1972; 1982). Capital investment costs are relatively high and they are increased significantly if the process is retrofitted to an existing refinery. Typically the direct process involves about an 8% fuel loss (Highton and Webb, 1980). The hydrogen required for the process can be produced from suitable feedstock such as petroleum gases, naphtha, etc.

Indirect oil desulphurization (or hydro-desulphurization, HDS) is a simple and commercially well established technique. During refining, the light oils (or distillates) produced by the distillation of crude oil are distilled again, this time under vacuum (Persson, 1976). The product of this second distillate is "hydro-treated" so that the sulphur is made to react with hydrogen. This hydro-treated distillate is then blended with the heavy oil to yield a low sulphur fuel oil product. This procedure allows the desulphurization of crudes which are difficult to treat directly. Since only a proportion of the fuel oil is effectively treated, the sulphur content is reduced by 30-42% (CONCAWE, 1982), with an associated fuel loss of about 5% (Highton, 1978). Heavy residue desulphurization is a relatively new process and only limited commercial experience is available. There is almost no desulphurization of heavy residues in Europe at present. Sulphur removal from heavy fuel oil desulphurization is unlikely to be higher than 80% with current catalytic fixed-bed technology (Highton and Webb, 1984; UNECE, 1982; CONCAWE, 1972).

Let us, now, turn to the case where the burning of fuels can be controlled to reduce the amount of sulphur released. New industrial and utility boiler designs are actively being developed to reduce sulphur dioxide emissions. These include in-boiler modifications and also fluidized bed combustion. Sulphur dioxide emission reduction is brought about through injection of sorbents (e.g. lime or limestone) into the furnace. The direct injection of limestone into the furnace does not require the installation of new complex equipment; thus it represents a solution for existing plants with adequate boiler type tube spacing where Flue Gas Desulphurization (FGD) cannot be installed.

In this process limestone is injected into the furnace to capture sulphur dioxide gases in the flue gas streams injected into the power plant and removed via the particulate removal equipment already in use. Where powdered coal is used, an absorbent (usually powdered limestone) is injected into the firebox and the combustion temperature lowered by using special burners. The limestone reacts with the sulphur to convert much of it into gypsum. However, this technique has not yet been applied industrially and presents a few technical uncertainties that will have to be clarified before its adoption at industrial level.

An alternative method, and one which is more favourable to sulphur dioxide absorption, is to employ dry limestone in fluidized bed boilers (FBC). The fluidized bed consists of solid fuel and limestone and is fluidized with air to allow chemical reactions which reduce the SO_2 emissions. Natural gas is injected into the firebox and ignited, then pulverized coal is pushed into the combustion area and burned. After the coal has started to burn well, the natural gas is shut off and the fire is maintained by burning coal. Sulphur oxidized during combustion reacts with limestone or dolomite in the firebox forming calcium sulphate. Calcium sulphate and residual limestone or dolomite from fluidized bed combustion can be

disposed off in landfills or used in construction materials. Another product of the reaction is ash (EPA, 1980). In FBC limestone reacts well with sulphur dioxide (SO_2) at high temperatures and a 80-90% removal efficiency can be achieved. The amount of limestone required is typically about 25% by weight of the coal input (Highton, 1978).

The following FBC technologies have been developed: (1) Atmospheric Fluidized Bed Combustion (AFBC): The construction of an AFBC boiler allows fast inspection and better repair and maintenance. AFBC can be regarded primarily as a technique for burning poor quality coals (or no-coal fuels) rather than for production of low emission level. The AFBC can be divided into two types: (a) Bubbling Bed: In this process the gas velocity is controlled to minimize the entrainment of particles in the gas stream. (b) Circulating Fluidized Bed Combustion (CFBC): It has recently had its commercial breakthrough as a technique to burn various fuels efficiently and with low emissions. The system is not sensitive to fuel quality and sulphur present in the fuel is retained in the circulating bed material in the form of calcium or magnesium sulphate and removed in solid form. (2) Pressurised Fluidized Bed Combustion (PFBC): In addition to the conventional AFBC boiler, there is the PFBC system which passes air onto the combustion bed through the compressor of a gas turbine. An experimental PFBC system was built in the UK in 1985 with funding from that country, the USA and the FRG, but was abandoned in 1988 when it was found that it would not be economical for anything other than very small power stations (McCormick, 1989).

Finally, there is the flue gas desulphurization (FGD) technology which is a post combustion one. FGD is the most commercial technology, and the most commonly used method of removing sulphur oxides resulting from the combustion of fossil fuels. FGD processes result in SO_2 removal by inducing exhaust gases to react with a chemical absorbent as they move through a long vertical or horizontal chamber. The absorbent is dissolved or

suspended in water, forming a solution or slurry that can be sprayed or otherwise forced into contact with the escaped gases. When this slurry comes into physical contact with flue gases the sulphur dioxide reacts with the limestone to produce a sludge[2]. The chamber is known as a scrubber and the process is often referred to as **wet scrubbing**. There are approximately 50 FGD processes but only a few have received widespread use. Removal efficiencies average 90% (80-95%) and the preferred technology varies from country to country.

The FGD processes can be broadly classified into three categories: 1) wet scrubbing - non-regenerable (e.g. limestone, gypsum); 2) wet scrubbing - regenerable (e.g. Wellman-Lord); and 3) spray drying. These processes are either throwaway, in the sense that by-products are useless, or regenerable in the sense that sorbent material is recycled and sulphur or sulphuric acid is recovered as a potentially marketable product. The most widely used type of FGD installations are wet scrubbers. The majority of wet scrubbers use lime or limestone as a sorbent. Economic factors and design improvements have made limestone the preferred sorbent in recent years and increasingly gypsum-producing processes are favoured (Vernon, 1990); only this type of FGD will be considered later on in the derivation of the least-cost control curve. Wet processes using lime/limestone, at 90% removal of sulphur, with sludge fixation and disposal is representative of the typical scrubber in Europe (OECD, 1978; Scharer and Haug, 1987). Sulphur dioxide reacts with the sorption agent in the watery phase. In modern plants the amount of lime/limestone used corresponds to the stoichiometric consumption, i.e. 1.76 tonnes CaO/tonne sulphur and 3.12 tonnes $CaCO_3$/tonne sulphur respectively. Taking an input of hard coal of 30 tonnes per 100 MWh as a basis, with a sulphur content of 1.5% and 5% retention factor, the consumption of CaO and $CaCO_3$ amounts to 1440 Kg/h of CaO and 2540 Kg/h $CaCO_3$ respectively (Scharer and Haug, 1986).

1.2 Abatement cost estimates for different control methods

The cost of cleaning coal before combustion is a function of the level of cleaning, per cent energy recovery, washability and physical characteristics of the coal, plant configuration and waste treatment. Each plant must be considered individually due to location, terrain, cleaning objectives, raw coal delivery arrangements etc (UNECE, 1982). The OECD has estimated that if all the hard coals (coals other than lignite) used in Western Europe were washed, SO_2 emissions could be reduced by about a million tonnes a year at an annual cost of $350 million (1986 US$; McCormick, 1989). Operating costs mainly arise from thermal losses. 60% removal of pyrites may involve thermal losses of up to 25% which would probably make FGD cheaper at coal prices in excess of $23 per tonne (Prior M., 1977). Furthermore, FGD can effectively remove up to 90% of total sulphur. In some cases it may be economic to combine physical washing with FGD.

Regarding the desulphurization of oils, costs depend mainly on the size of the refinery, the degree of desulphurization obtained and the nature of the initial crude. Apfsen et al. (1986) calculate the cost of switching from high to low sulphur heavy fuel oil as $333 per tonne of SO_2 removed when moving from 2.15% to 1% HFO and $722 when moving from 1% to 0.7% HFO ($ 1985). Due to the energy requirement at an oil desulphurization unit, operating costs are very sensitive to changes in energy prices. Oil prices are also important since the direct process involves 8% fuel loss and the indirect process 5% loss (Highton, 1978). From CONCAWE (1986) it can be seen that the total capital cost of plant with 1.46 million tonnes/year output capacity is equal to $245.2 million ($1985). This number has to be adjusted for country variations in capital and construction costs. Variable operating and maintenance costs (O and M) consist of the catalyst chemicals cost, the energy consumption cost and hydrocarbon losses and equals approximately $17 per tonne product (CONCAWE, 1986).

Additionally the fixed O and M cost is equal to $9 per tonne product adjusted to the labour cost factor for country differences.

The study by CONCAWE (1984) assumes that for a gas diesel oil desulphurization (GDOD) unit the average capital cost with usable capacity of 0.59 million tonnes per year is $26.5 million (in 1985 $). The variable O and M cost of a GDOD unit consists of energy consumption cost and the costs of hydrogen and catalyst used and equals approximately $3.5 per tonne gas oil. Additionally, the fixed O and M cost equals $3 per tonne of gas oil used. To adjust for international differences this number is multiplied by the cost for labour.

Moving to the case of controlling sulphur emissions during combustion, a review of international developments and cost estimates regarding the sorbent injection technique was reported by Schweers (1986). Based on survey information, representative cost ranges were developed for a hypothetical 500 MW power plant burning either a low (1%) or high (3%) sulphur coal. Capital costs were estimated to range from $50 to $150 per KW (in mid-1985 US $), with an overall cost-effectiveness ranging from $350 to $1340 per tonne SO_2 removed for the low sulphur coal and $165 to $650 per tonne SO_2 removed for the high sulphur coal. Barrett (1986) based on a 4x500 MW plant using limestone, concluded that a maximum of about 35% reduction in SO_2 could be achieved at a capital cost of $111.5 million and an operational cost of $17.3 million per year (in 1985 $). The primary advantage of these systems is that they are relatively simple and easier to retrofit at existing power plants when compared to larger more complex conventional dry and wet scrubbing systems[3]. Less new equipment would be needed than for FGD, the capital costs would be expected to be relatively low and it would also seem less difficult to fit the system to an existing plant.

One major problem with the direct limestone injection (DLI) is the fact that abatement efficiency is not well established. Burdett et al. (1985) assumed an abatement efficiency of

35% and concluded that a single 4x500 MW FGD plant removes as much SO_2 as 11x500 MW limestone injection units. Assuming an increase in abatement efficiency of DLI from 35% to 40%, a delivered price of $8.6 per tonne and an average disposal cost of $2.86 per tonne, concluded that it would reduce the operating costs of the limestone injection equivalent system from $514 to $343 per tonne SO_2 removed. Hence, although the capital and operating costs per station fitted with limestone injection appear at present to be less than for a wet FGD, the former process operates at a considerably higher cost in terms of cost-effectiveness ($/tonne SO_2 removed).

A Fluidized Bed Combustion (FBC) unit tackles pollutant emissions at source in the furnace; high and low-grade coal can be used. An FBC boiler takes up less space than boilers with other firing systems, construction is simple, personnel requirements are low, and overall investment costs are low (McCormick, 1989). Two types of FBC systems have been developed: the Atmospheric (AFBC) and the Pressurized (FFBC). Estimates of SO_2 control costs typically include only the added costs of reagent, energy and waste disposal. On this basis Houvilainen (1986) reports a cost of $234 per tonne of SO_2 removed for a 34 MW AFBC boiler burning a 1% sulphur content fuel. Total energy losses amount to approximately 0.5-1.0%. The raw material costs of limestone and dolomite are generally low, although these can be increased by local shortages and high transport costs. However, bubbling-bed AFBC units require more sorbent than the scrubber FGD to remove the same amount of sulphur. Capital costs are not greatly affected by sulphur dioxide removal, although operating costs are increased in a number of ways. The main elements in operating cost are operation and maintenance, energy costs of the process, limestone/dolomite raw material costs and waste disposal. PFBC disposal costs are nearly twice that of AFBC due to the additional volume of waste. Energy costs arise from electrical requirements for material preparation and feeding as

well as removal and gas clean up.

Finally, the costs of controlling sulphur emissions after combustion and by using a wet FGD vary with the different processes and with local needs and conditions but investment comes to about 15-20% of the total cost of a power plant. The cost of FGD per tonne of sulphur abated will vary between $629 per tonne and $1057.3 per tonne, depending on the process adopted; the average being about $786.3 per tonne sulphur abated (Barrett, 1986). The operating cost for all these FGD units would range from $610-720 /metric tonne of sulphur removed for oil-fired plants. The costs are much higher for FGD on hard coal fired plants because of the relative high sulphur content of European hard coals. The FGD costs for new plants are usually much higher than coal cleaning costs, which range from $560-$860 per metric tonne of sulphur removed (Remmers and Rentz, 1986; Barrett, 1986). Capital costs are highly sensitive to plant size. The most important determinant of cost is the fuel sulphur content. Some USA studies cited a 40% increase in capital costs for 4% sulphur compared with 2% sulphur coal (Vernon, 1989). For low sulphur coals (0.6% sulphur content) capital costs of FGD systems ranged from $90 to $180 per kW with certain regenerable systems costing up to $300 per kW. Annual costs were mostly in the range of $4-6 millions/kWh. For high sulphur coals (up to 5% sulphur content) capital costs were $120-300 per kW and annual costs $7-12 millions per kWh (or $12-15 millions per kWh for some regenerable systems).

The biggest disadvantage with wet FGD systems is the sludge they produce, which is difficult to store and handle. A 500 MW boiler would produce about 600 tonnes per hour. In a typical 1,000 MW plant, burning coal with 3.5% sulphur, wet FGD produces about 225,000 tonnes of sludge annually (Regens and Rycroft, 1988). Barrett (1986) gives an output of 520,000 tonnes of gypsum for a 2,000 MW plant, while Highton (1978) gives an output of 200,000 tonnes of gypsum annually for an 800 MW plant. The annual sludge production from

a 2,000 MW power station could exceed 300,000 m^3 (Elsworth, 1984). Lime/limestone FGD processes produce a waste sludge comprising calcium sulphite and calcium carbonate or lime in various proportions. The sludge is difficult to dewater which makes it difficult to dump. Opportunities for sales in the FRG and Japan have always favoured the production of gypsum, rather than calcium sulphite sludge, as an end product (Dacey and Cope, 1986). The sludge fixation and disposal cost was estimated to be \$12.5 /tonne of dry waste in \$ 1985 (Barrett, 1986). The lime/limestone process can be regarded as suitable for areas with a large disposal site. For example a 500 MWe plant operating at an average load factor of 50% and aiming at 90% SO$_2$ removal using limestone absorbent, depending on the sulphur content of coal, produces between 4000 and 7500 acre-feet of waste over a thirty year period (Highton, 1980). It is estimated that a new 500 MWe station burning 3.5% sulphur content coal, with 90% removal of SO$_2$, requires 8.0 acres of land for sulphur dioxide and ash removal. In the case of the lime/limestone process on-site waste disposal would increase investment costs by approximately 18% and operating costs by about 7% (Highton, 1978).

Certain by-products may be marketable, e.g. sulphur, sulphuric acid and gypsum. But this must be weighted against the capital and operating costs of any extra items required to bring the by-products to marketable quality. Sulphur and sulphuric acid are basic industrial chemicals used in the paper industry, rubber processing, pesticides, fertiliser etc. The UK imports about 1.4 million tonnes of sulphur per year compared with a possible output of 500,000 tonnes from FGD. This quantity could easily be absorbed into the UK market and help reduce imports. Sulphur is easily transported and stored, and even dumped with little environmental damage. Sulphuric acid is expensive to transport, cannot be dumped and has fewer industrial uses. UK production of sulphuric acid in 1976 was 3.3 million tonnes compared with a potential output from FGD of 1.5 million tonnes annually. Gypsum is a fairly

common naturally occurring mineral which is obtained by mining and used in the manufacture of plaster, plasterboard and cement. It is of low value, bulky and hence expensive to transport. It is, however, a more desirable by-product than sludge. It is easier to handle and almost certainly less damaging to the environment (Highton, 1978).

2. ASSUMPTIONS USED IN THE DERIVATION OF THE ABATEMENT COST CURVES

Given the generic engineering capital and operating control cost functions for each efficient abatement technology, total and marginal costs of different levels of emission reduction at each individual source (power plant, industrial boiler, petroleum refinery) and in the national (country) level can be constructed. The previous section summarized the available information on the technical characteristics and costs of those abatement technologies in operation at present to reduce the sulphur content of fuels in use. We have seen that abatement technologies differ both as to cost and applicability (depending on the physical and chemical characteristics of the fuel used and on the size of abatement plant). It is assumed that control costs are independent of order of introduction and that abatement technologies are scale specific. Each abatement technology is efficient over a defined range of sulphur removed; we have constant returns to scale over the range of abatement at which each technology is potentially efficient. In other words, each technology reduces emissions by some proportion, called the "abatement efficiency", which is assumed to be fixed for each control method at the plant size at which the method is efficient. For example, an FGD unit has an abatement efficiency of 90% at the efficient plant size. Also, it is assumed that the objective of private users is to minimize the costs of abating a given level of emissions. Further, fuel use and costs are assumed given independently of abatement policy. For the purposes of this

exercise, then, abatement by means of reducing the output of electricity or other industrial output is ruled out[4]. Finally, another basic assumption of the cost module is that there is a competitive market for sulphur abatement technologies accessible to all European countries.

It is assumed that the regulatory authority seeks to maximize abatement subject to a budget constraint: a cheaper option will always be preferred over a more costly one. It would be economically inefficient to introduce relatively costly control options unless opportunities for using cheaper alternatives had already been exhausted. The relative economic efficiency of alternative options is compared by reference to "cost-effectiveness" which, for a given option at a given site, is the total annualized cost divided by the annual tonnes of pollutant removed. This type of cost function is potentially useful to policy-makers because it indicates the maximum level of emission abatement that can be achieved with a given budget constraint. That is, we look for an efficient frontier or a minimal cost envelope, which will give us the optimal total abatement cost function; i.e. the corresponding point on the marginal cost curve specifies the set of country control options which minimize total abatement costs (Halkos, 1992, 1994; Rubin et al., 1986; Mäler, 1990). If the objective function is to maximize abatement subject to a budget constraint then it will never be optimal to use a less efficient technology. Table 1 presents the applicability requirements, the abatement efficiencies and the capital and operating costs of each possible abatement option, as well as an estimate of the cost-effectiveness.

The actual control costs of each abatement technology are defined by national circumstances and the abatement cost curves depend on the energy scenario adopted. Such abatement costs differ considerably among countries even for the same technology, mainly due to sulphur content of fuels, capacity utilization and boiler sizes of installations. At present cost estimates for each technology take into account a wide range of site and plant specific factors,

e.g. plant size, fuel type, initial sulphur content of fuel, load factor and new or retrofit application (remaining life). It is recognized that it is more expensive to retrofit an abatement technology to an existing plant than it is to design it into a new plant. Retrofit of equipment systems is usually assumed to carry out a cost penalty of 10% to 40% over the cost of installation with new plants. Here, an average approximation of 25% higher capital cost than the equivalent at a new plant is used.

The cost of an emission abatement option is given by the total annualized cost (TAC) of an abatement option, including capital and operating cost components:

$$TAC = [(TCC) * (r / (1-(1+r)^{-n}))] \ VOMC + FOMC$$

where TCC is the total capital cost ($), VOMC and FOMC are the variable and fixed operating and maintenance costs ($) respectively and $(r/(1-(1+r)^{-n})$ is the capital recovery factor at real discount rate r, which converts a capital cost to an equivalent stream of equal annual future payments, considering the time value of money (represented by the discount rate, r); n represents the economic life of asset (in years). The estimation of the annual operating and maintenance costs requires a great deal of information (for example, the sulphur content of fuel used, the annual operating hours, removal efficiencies of the control methods, etc) and consists of a fixed portion that is dependent on the use of the plant (e.g. maintenance and labour costs) and a variable portion dependent on the prices for electricity, labour, sorbents and waste disposal and the specific demand for energy due to abatement process. Table 2 in the appendix presents the fuels used by each sector and to which we apply the available abatement technologies, while table 3 presents the control technologies applied to each fuel type[5].

The economic efficiency of alternative abatement options (expressed as $ per tonne pollutant removed) depends on site specific conditions and a least cost emission control

function for each source can be estimated by ranking alternative options in order of increasing marginal cost of control. The set of source-specific emission reduction opportunities can be merged in order of increasing marginal cost to yield a least cost emission reduction function for each country[6]. Marginal costs increases are due to the effect of switching between technologies as the scale or level of abatement rises. The marginal cost curve has a staircase shape (i.e. it is a discontinuous step function) with each step representing a particular discrete abatement technology. The level of each step indicates the incremental cost of a technology relative to the maximum incremental amount of sulphur removed by introducing that technology. The sequence of efficient technologies gives us the long run marginal cost of abatement. At the low end of the curve the least expensive strategies are presented; the greater the percentage of pollutant removed the higher will be the cost of removing an additional amount. In the first step in ranking the technologies used in each plant (boiler) we take the lowest marginal cost equal to the average cost for the first technology used and then, we add up extra technologies to get the maximum feasible abatement that can be achieved by the plant/boiler under consideration. Building up the source cost functions we eliminate any technology choices which yield non-convex regions of the cost curve. National cost curves therefore will exhibit non-decreasing marginal costs and the most cost-effective techniques will be the proper abatement techniques for the national decision maker. In the final national cost curve each step represents an abatement measure that achieves an emission reduction of an extra unit at the least cost. The national cost curve consists of a large number of very small steps. In view of the differences between countries, with regard to both present and future energy demand, energy mix and fossil fuel qualities, this "optimization" must be carried out on a country-by-country basis.

3. ENERGY ALTERNATIVES TO POLLUTION CONTROL

The selection of appropriate strategies to reach and implement pollution control objectives is of crucial importance to planners. Because of the existing differences between countries in energy-use patterns, emissions, source locations and other economic factors, it is unlikely that a single, uniform program of secondary abatement will be appropriate in all countries. To reduce sulphur emissions the national decision maker may set a maximum allowable rate of pollution output for each generic type of source (electricity generating, industry, petroleum refineries and transport) by type of pollutant. Furthermore, fuel quality regulations can be structured around the types of fuels in use (e.g. coal, oil etc) and can be limited by the technical possibilities and the costs of cleaning process for the different fuels.

Sulphur emissions can be also reduced by reducing energy consumption through either conservation or energy improvements. The latter can be achieved for instance by reducing energy consumption through more efficient generation, use of combined heat and power, etc. Denmark, Norway and Sweden are the only OECD countries that continue to increase energy taxation since the 1980s aiming to encourage energy conservation. On the other hand, IEA claims that inconsistency of taxation and energy policy is evident in the UK which actually discourages efficiency by charging VAT on home-insulation products. IEA suggests that the potential for demand reductions for the UK, the Netherlands, Austria, the EEC and Western Europe in the industrial sector in 2000 can be as high as 25%, 21%, 10%, 25% and 30% respectively. At the same time Sweden can achieve demand reductions of 50% in its residential sector and 40% in its commercial sector. The EEC countries and the Netherlands can achieve an average of approximately 30% and 21% savings through cost-effective means in the residential and commercial sectors respectively. A 30% increase in energy efficiency can reduce energy requirements by 25% which is equivalent of more than 1200 million tonnes oil

equivalent per year in 2000 (IEA, 1987).

Low sulphur coal may be a good way to reduce emissions where emission standards are met by using coal within a specific range of sulphur content. For instance, a standard of 2000 mg/m^3 is equivalent to approximately 1% sulphur content of coal, as the cut-off level above which sulphur abatement technologies would be used. Emission standards between 1000 and 2000 mg/m^3 are equivalent to coal sulphur content of 0.5-1% and there is no percentage removal requirement. Plants facing these standards can use either low sulphur content coal alone, or in conjunction with a limited-efficiency abatement technique (Vernon, 1989).

The use of low sulphur coal is a function of its availability and its cost relative to other control methods. Obviously, if the demand for low sulphur coal increases then both price and availability will change. Technical barriers exist to using low sulphur coal because it has a low calorific value and different ash characteristics which affect the operation of electrostatic precipitators. A political barrier is when there are no local supplies and government energy policies restrict by import quotas the import of supplies from elsewhere (Germany, Spain).

Substitution of fossil fuels by nuclear power and natural gas is also possible. But nuclear and hydropower have seen opposition on environmental grounds while other non-fossil fuel sources have been under-developed. Public pressure may increase the demand for gas fired power plants. High capital cost and costs of decommissioning mean that the nuclear plants have no advantage over coal-fired plants with secondary emissions control. The costs of NO_x and SO_2 controls on coal-fired plants are similar to those of gas firing plants. A range of $36-$50 m per kWh (US $1987) for coal-fired plants with full environmental control compares with $44-$48 m per kWh for a natural gas plant meeting similar standards (assuming a coal price of $40-60 per tonne and a relative gas price of $160 per tonne coal equivalent)

(IEA, 1988). Newbery (1993) cites that, if FGD investment is coordinated with gas then capital costs of a gas burning Combined Cycle Gas Turbine (CCGT) will be £360-£500/kW compared with FGD capital costs of £150-£175/kW capacity. According to the same source, at the 1993 import parity price of coal, FGD was cheaper than new CCGT stations. This implies that FGD can be competitive against CCGT.

4. EMPIRICAL RESULTS

In order to compare the abatement costs between countries the least cost combination of abatement options for each emission reduction level from zero reduction up to the technical feasible limit is derived. Cost estimates for each technology are influenced by fuel type, plant size, sulphur content of fuel, new or retrofit application and labour, construction and electricity cost factors. The slopes of the total abatement cost curves differ from country to country and if the slope of the total abatement cost curve for one country is steeper than for another, for any given abatement level, then the abatement cost in the first country is higher than in the second. Given projections of uncontrolled emissions, estimates can be made of the potential for their reduction using available abatement technologies and of the likely cost. Following the procedure described in section 2, total and marginal abatement cost curves can be derived for each European country. Figures 1 and 2 present the total abatement cost curves for FRG and UK[7]. The potential of the abatement technologies for reducing emissions in a particular country depends on the existing pattern of energy use. Table 4 presents the unconstrained emissions in the year 2000[8], the maximum feasible national emission abatement levels through the use of all available technologies and combination of technologies and the associated cost of achieving this maximum abatement in each country, as well as the total costs of achieving 30%, 50% and 60% sulphur emissions reduction. It can be seen that, for example in Turkey, a 50% sulphur emissions reduction costs $510 million while a 57% (the

maximum that can be achieved in Turkey) requires an amount of $1,395 million and which shows how more expensive is the reduction of just seven more percent, when a certain level of abatement is reached. Similarly, for Sweden a 60% reduction requires $79 million, while a 74% reduction requires $1,051 million and, for Italy, a 60% reduction costs $720 million and an 85% reduction costs $2,629 million and so on.

Similarly, the total cost of 50% reduction varies from $5 million in Luxembourg to $943 million in Russia[9]. The UK has a total cost of $605 million at this percentage level while Greece has a cost of $106 million, FRG has a total cost of $346 million, Austria of $15 million and Norway of $12 million. Similarly, we can find the total costs for all the European countries and for four different percentages (30%, 50%, 60% and maximum feasible abatement). The final interesting conclusion of table 4 is that the total cost for all European countries of achieving these different percentage reductions uniformly increases drastically as the reduction is moved from 30% to the maximum feasible abatement. A 30% reduction requires a cost of $2,939 million, a 50% of $6,642 million, a 60% of $8,157 million and the maximum of $35,965 million. But would a massive program of sulphur control have a large effect on the prices which consumers pay for electricity? Highton and Webb (1984) showed that the price to the consumer of a 50% reduction in Central Electricity Generating Board of England and Wales (CEGB) emissions of sulphur would be about 4% in electricity costs. Besides, for large industrial consumers the effect would be an increase of slightly over 5%. Of course, this percentage increase in the electricity cost will vary across countries due to different domestic unrestricted tariffs or different industrial tariffs.

Forecasts of energy demand in a given future year depend crucially on the forecaster's assumptions about economic growth, the rate of conservation, energy policy objectives and the availability and price of fuels. As a result energy forecasts are subject to periodic

reassessment. In order to test the sensitivity of abatement strategies and costs to alternative assumptions about energy futures, a small number of energy variants have been developed:

1. Base case: energy projections used according to the latest government energy forecasts regarding the fossil fuel consumption for the year 2000.

2. Nuclear phaseout: nuclear power generation is assumed to be phased out by the year 2000. Countries which currently plan to introduce nuclear power during the period are assumed to cancel these plans. In this scenario, the output from conventional thermal stations is increased to compensate for the extra demand for electricity resulting from the 'nuclear phaseout' assumption. That is, we expect a higher fossil fuel consumption.

3. Increased natural gas consumption: The European Community and IEA studies (Guilmot et al. 1986, IEA 1986) have recently identified the possibility of up to 25% increases in gas demand in Western Europe by the year 2000 over and above current official forecasts, particularly if gas reserves in former USSR are more fully utilized and if gas prices are relatively low. Natural gas competes primarily against coal and oil in the industrial market and in electricity generation and other sectors. In this scenario we assume a 25% increase for gas over forecast levels in each sector and demand for fossil fuels is reduced proportionately.

Using FRG as an example, table 5 presents the cost of achieving different percentage levels of emissions reduction under each of the different scenarios; while figure 3 gives a graphical presentation of the "estimated" total abatement cost curves in each different case. It is notable that the abatement cost curve derived from the base case coincides with the one derived under the "increased natural gas" scenario, while it is substantially different from the abatement cost curve derived according to the non nuclear scenario.

Finally, the abatement cost curves derived in this way represent a "hypothetical" situation, as far as it is assumed that countries apply a number of technologies in each fuel

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used and in the most cost-effective way. However, the reality is different. Table 6 in the appendix presents the current level of abatement (if any) in each European country. In this table the first column represents the abatement reductions (if any) for every European country in levels and as a percentage of emissions at the end of 1989; the second column shows the future abatement (after 1990) in these countries, again in levels and percentage, and the last column presents the total emission reductions according to current and future plans. The main sources of this table are IEA Coal Research (1990 and personal communication) and Vernon (1989), which provide information on the number of control units installed in each European country (if there are any) at the end of 1989, and the future plans for control equipment instalment; also, the same sources present the number of control technologies used in each country (i.e. how many of these control units are SI, FGD etc) and their capacity (in MWe), as well as the number of control units which are retrofitted and/or installed on new power plants/boilers and their capacity in MWe (see Halkos, 1992).

CONCLUDING REMARKS

Currently available technologies for SO_2 have been classified into three categories: pre-combustion, during combustion and post combustion. Fuel cleaning techniques are relatively simple and well-established but their effectiveness depends on the physical characteristics of the specific coals and crude oils which are subject to treatment. Fluidized bed combustion (FBC) can only be used for new installations and could only have an effect on total emissions over a long period. It is not possible to define abatement costs precisely since air pollution control is an integral part of the FBC boiler design. Sorbent injection could be a low cost retrofit option in cases where only moderate SO_2 emission reductions are required. FGD is the

most commercially developed technology and the only one available for achieving very high removal efficiency at all types of installation, new or retrofit. The general trend is for sorbent injection to have the lowest capital costs, with pre-combustion technologies, FBC and spray-dry scrubbers next, followed by wet scrubbers with regenerable processes having the highest capital costs.

In order to minimize the costs for a given reduction of sulphur emissions, the different desulphurization technologies can be used in the least-cost combination. It was shown that the greater the percentage of pollutant already removed, the higher the cost of removing an additional amount. In the beginning those sources of pollution are eliminated that can be removed most cheaply and easily. Further reductions in pollution will usually prove more than proportionately costly and difficult. This means that there is a maximum marginal quantity of sulphur removed and that, after this point, the pool of technologies starts to be less efficient, i.e. the marginal quantity of sulphur removed decreases progressively. This implies the rise in marginal costs which is evident from the curves. The important point is how steeply marginal cost rises with each successive increase in pollution control objectives. Obviously, there exist countries where abatement is cheaper. As the transboundary nature of the acid rain problem requires cooperation between countries in order to achieve environmental targets, this implies that an optimization must be carried out (for more details see Halkos, 1993, 1994).

Finally, it was also shown that the control cost curve derived for the base case of the official energy projections coincides with the one derived under the "increased natural gas" scenario and it is quite different from the control cost curve derived according to the nuclear phaseout scenario. It was, also, explained that the situation under which the abatement cost curves were derived is hypothetical in so far as it is assumed that countries use all the available

control methods for sulphur emissions reduction. The actual current level of sulphur emissions abatement was presented and it was obviously quite different from the maximum feasible abatement level that can be achieved if countries use all the available abatement techniques.

NOTES

(1) The most significant cost is generally coal loss and hence the price of coal is very influential. The extent of loss depends on the intensity of washing and the type of coal used.

(2) It is possible to convert the sludge to gypsum which may be saleable.

(3) In order to compare the costs for a limestone injection operating at 35% removal efficiency with those already published for a conventional wet FGD plant operating at 90% removal efficiency, the limestone injection costs should increase by a factor of 90/35=2.57, to provide equivalent capacity for sulphur removal (Burdett et al, 1985).

(4) Other types of abatement options that are omitted in this approach are abatement through energy conservation in its broadest sense (energy demand suppression, fuel switching, efficiency measures) and fuel substitution.

(5) Ten individual fossil fuel types consumed by 5 economic sectors have been taken under consideration. The fuel types include hard coal and derivatives, coke, brown coal and derivatives, other primary solid fuels such as peat and wood, heavy oil products (refinery fuel oil and residual fuel oil) and middle distillates (gas oil and diesel oil) in which the available abatement technologies are applied and natural gas. The economic sectors identified include thermo-electric plants (including district heating), industry (split between iron and steel, process emissions and others), energy sector (split between refineries and others), transportation and other sectors (including residential, commercial and agriculture).

(6) For this reason a program in Basic has been constructed by the writer. The program consists of five separate algorithms, each corresponding to each single sector. The results of all algorithms are merged in a unique output file.

(7) The data on which these estimates are based are projections made prior to the unification of Germany. For this reason the report refers to the Federal Republic of Germany, not Germany. It turns out, however, it is useful to work with 'old data'. It does not make much sense to aggregate FGR and GDR simply for the sake of using current boundaries simply for the reason that historic policies in the two areas have been so different.

(8) The estimates of the unconstrained sulphur emissions used in this paper are based on early work undertaken by the Stockholm Environment Institute (SEI) at York. They should, however, be regarded as indicative only. Obviously, subsequent revisions to estimates of energy balances and fuel sulphur content for the year 2000 will lead to revisions of the cost estimates. Later estimates by the SEI, to be published shortly, may be more realistic.

(9) Russian Federation within the EMEP area, Kola-Karelia and St Petersburg included. Also, the Baltic Region comprises Estonia, Latvia, Lithuania and Kaliningrad.

Table 1: Sulphur emission abatement options and costs (costs in $ million 1985)
     Costs are based on a new 500 MW power plant, using hard coal of 2% sulphur content, 70% load factor and 5% retention factor.

Abatement Method	Applica-bility	Sulphur removal efficiency (%)	Capital Cost	Operating and Maintenance cost		Cost-effective ness
				FIXED	VAR	$/t SR
Fuel switching (e.g. oil to gas)	All users	Up to 99	-	-	-	(1)
Physical coal cleaning	All users	25	-	-	-	635-1625
Heavy fuel oil desulphurization (HFOD)	All users	80	7.775	6.32	12.28	2100-2930
Sorbent injection (SI)	All users	50	0.344	0.22	2.59	485-750
Atmospheric Fluidized Bed Combustion (AFBC)	Power plants and indust-rial boilers	80	3.259	0.16	2.71	238-446
Circulating Fluidized Bed Combustion	New plants only	85	7.061	0.35	4.77	529-835
Flue Gas Desulphuri-zation (FGD)	Power plants, indust-rial boilers and process emis-sions	90	29.462	1.67	4.02	650-1200
Gas Oil Desulphurization	All users	90	1.918	1.93	2.2	2900-3740

(1) Depends on relative price and sulphur content

TABLE 2: Fuels in which control technologies are applied in each sector

Fuels Sectors	Hard Coal	Brown Coal	Brown Coal Briquettes	Heavy Fuel Oil	Gas Diesel Oil	Peat	Refinery Fuel Oil
Electricity Generating	*	*	*	*	*	*	
Industry	*	*	*	*	*	*	
Energy							*
Transport	*			*	*		
Others	*			*	*		

TABLE 3: Technologies applied by fuel used

Existing plants	HARD COAL Hard Coal Washing (HCW) Sorbent Injection (SI) Flue Gas Desulphurization (FGD) Combination of HCW and SI Combination of HCW and FGD
New plant (less or equal to 500 MWe)	All the above technologies and additionally: Atmospheric Fluidized Bed Combustion (AFBC) Circulating Fluidized Bed Combustion (CFBC) Combination of HCW and AFBC Combination of HCW and CFBC
Existing plants	BROWN COAL Sorbent Injection (SI) Flue Gas Desulphurization (FGD)
New plants	All the above technologies and additionally: Atmospheric Fluidized Bed Combustion (AFBC) Circulating Fluidized Bed Combustion (CFBC)
	HEAVY FUEL OIL Heavy Fuel Oil Desulphurization (HFOD) Flue Gas Desulphurization (FGD) Combination of HFOD and FGD
	GAS DIESEL OIL Gas Diesel Oil Desulphurization (GDOD) Flue Gas Desulphurization (FGD) Combination of GDOD and FGD
	PEAT AND BROWN COAL BRIQUETTES Sorbent Injection (SI) Flue Gas Desulphurization (FGD)

Table 4: Total cost and sulphur removed of maximum abatement (TC of max ab) (costs in m US $ 1985 and abatement in 1000 t S)

Countries	Provisional emissions	Sulphur Max ab	% sulphur max ab	TC of max ab
Albania	200	120	60	181.9
Austria	187	142	76	330.1
Belgium	329	269	82	689.8
Bulgaria	961	692	72	530.5
Former CSFR	1216	775	64	630.9
Denmark	143	124	86	362.5
Finland	270	196	72	900.4
France	765	629	82	1950.8
FRG	1556	1275	82	2949.3
Former GDR	2099	1363	65	2569.2
Greece	450	395	88	519.1
Hungary	467	286	61	236.4
Ireland	83	61	73	179.4
Italy	1715	1282	75	2628.8
Luxembourg	15	9	61	29.0
Netherlands	242	192	80	813.0
Norway	69	52	76	259.3
Poland	2182	1433	66	1409.9
Portugal	218	168	77	378.9
Romania	1374	1051	76	779.6
Spain	2573	2387	93	2270.9
Sweden	248	184	74	1050.7
Switzerland	50	39	78	276.0
Turkey	2203	1263	57	1394.3
UK	1844	1448	79	2987.6
Russia Belarus Baltic R Ukraine	6172 737 563 4286	3913 464 383 2486	63 63 68 58	5036.1 456.9 382.2 2858.6
Yugoslavia	1891	1329	70	922.6
TOTAL	35108	24410	72	35965

Table 4: (continued) Total costs (TC) of different percentage levels (m $ 1985)

Countries	TC of a 30% reduction	TC of a 50% reduction	TC of a 60% reduction
Albania	14.3	47.7	158.3
Austria	0.97	15.3	27.2
Belgium	17.1	52.4	85.7
Bulgaria	73.4	128.0	163.0
Former CSFR	123.4	218.0	302.0
Denmark	12.0	31.3	52.7
Finland	43.5	95.0	167.4
France	127.5	296.7	405.2
FRG	146.0	346.0	637.9
Former GDR	228.0	398.0	634.0
Greece	55.0	106.0	142.0
Hungary	41.0	73.0	173.0
Ireland	1.2	10.8	33.0
Italy	271.5	528.7	719.7
Luxembourg	1.2	5.0	16.4
Netherlands	27.0	56.7	95.8
Norway	5.0	12.0	33.9
Poland	243.0	455.3	629.9
Portugal	33.5	78.4	114.1
Romania	100.7	185.0	229.4
Spain	188.2	317.0	400.0
Sweden	4.8	30.8	78.9
Switzerland	4.6	45.0	60.0
Turkey	210.0	509.6	no feasible
UK	285.0	604.4	887.0
Russia Belarus Baltic R Ukraine	228.8 2.8 2.2 275.0	942.5 57.6 41.5 637.0	1265.0 170.6 76.1 no feasible
Yugoslavia	172.6	317.0	398.0
TOTAL	2939.3	6641.7	8156.8

Table 5: Different percentage levels of sulphur reduction, level of sulphur emission reductions (SR, in thousand tonnes) and associated total abatement costs (TC, in million $ 1985) under different energy scenarios

Sulphur reduction (%)	SR Base case	SR Nuclear phase-out	SR Gas increase	TC Base case	TC Nuclear phase-out	TC Gas increase
10	155.6	192.92	141.75	2.68	3.3	2.45
30	466.8	578.77	425.25	146.0	156.3	137.0
50	778	964.62	708.75	346.0	370.0	293.0
60	933.6	1157.54	850.5	638.0	468.8	479.0
70	1089.2	1350.46	922.24	1100.0	920.0	835.0
maximum	1274.8	1716.9	1245.7	2949.0	3685.8	2518.7

Table 6: Current levels of abatement reductions (in 1000 t)

Countries	1989 Level	(%)	Post 1990 Addition	(%)	Post 1990 Total	(%)
Austria	29	15.51	5.31	2.84	34.31	18.35
Belgium	2.482	0.8	1.635	0.5	4.117	1.3
Denmark	14.18	9.92	18.565	12.98	32.745	22.9
Finland	8.139	3.0	10.601	4.0	18.74	7.0
France	1.945	0.25	1.418	0.2	3.363	0.45
FRG	651.7	41.9	49.82	3.2	701.5	45.1
Italy	3.422	0.2	139.56	8.2	142.98	8.4
Netherlands	34.989	14.46	15.215	6.3	50.204	20.76
Spain	0.06	.0023	7.013	0.27	7.073	0.272
Sweden	8.419	3.4	0.973	0.4	9.392	3.8
UK	7.236	0.4	198.975	10.8	206.211	11.2
Turkey	-	-	37.13	1.7	37.13	1.7
Former CSFR	26.422	2.2	16.985	1.4	43.407	3.6
Former GDR	15.083	0.72	-	-	15.083	0.72
Ireland	0.357	0.43	-	-	0.357	0.43

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