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# Environmental Controls for Coal Fired Power Plants

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## I. INTRODUCTION

Coal, with its vast reserves world wide, is likely to continue to furnish a large fraction of the primary energy needed for electricity generation well into the 21st century. Table 1 summarizes the expected global expansion in coal utilization for electric power production (an almost doubling over the next 30 years). But the twin goals of producing useful energy from coal more efficiently, and of minimizing environmental impacts from using coal to generate electricity, will continue to grow in importance as we approach the beginning of a new century. Environmental concerns have grown in many of the most industrialized countries during the past two decades, and developing economies are increasingly recognizing that it can be less costly to protect their environment than to clean up the damage caused by pollution or to live with it.

Great progress has been made and continues to be made in the technical means of preventing pollution for coal use. But successes in overcoming some of coal's environmental problems have been accompanied by identification of new environmental issues, often less obvious and more intractable as to their solution. Also, prevention is often costly, all the more so when the objective is control of pollutants in all environmental media. Nevertheless, coal will have to rise to meet the environmental challenge. The issues are both technological and economic -- in what ways and at what cost can this complex substance be transformed into useful energy while reducing its environmental impact to a level acceptable to society in the long term?

All through the 1980s the environmental debate with the strongest impact on how we use coal has been that on acid rain and related air pollution issues. A substantial number of countries have taken steps to reduce sulfur and nitrogen oxides, precursors of acid rain. In the United States the 1990 Clean Air Act Amendments (CAAA) will require utility power plants to retrofit technologies or switch fuels to meet sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_x$) emissions reduction requirements by the year 2000. These air pollutants are not the only targets of the CAAA. A new feature, compared to previous clean air legislation in the United States, is control of emissions of potentially toxic air pollutant emissions. Electric utilities are not immediately affected by the air toxics emission limits until the results of a three-year utility study by EPA are known; however, air toxics are rapidly becoming a major new focus of concern on the part of coal-burning utilities.

Another growing issue is waste management. The USA produces 70 million tons of coal ash each year; many landfills are reaching capacity limits, and it is increasingly difficult to obtain permits for new disposal capacity. Also, the flue gas desulfurization (FGD) plants, installed to reduce $SO_2$ emissions, in most cases produce large quantities of solid waste that require disposal unless a use can be found for it (e.g., gypsum for wallboard manufacture).

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Improving efficiency of electricity generation (and use) is an effective means of minimizing environmental impacts in all media - air, water and land. Figure 1 shows the U.S. historical trend of increasing electrification while decreasing total energy per unit of economic output. During the economic expansion since 1982, electricity growth has paralleled GNP growth while real electricity price has declined 16% and overall energy efficiency has improved 11%. Continued productive improvement in energy efficiency, through electrification and by other measures, means that the rate of increase in primary energy consumption is expected to shrink, by 2010, to less than half the annual rate of U.S. GNP growth (Starr 1989). As these figures indicate, economic progress, energy efficiency and increased electrification have proceeded hand-in-hand, and continued economic growth is expected to raise electricity use to nearly 50% of U.S. energy consumption by the turn of the century.

Developing countries face hard choices because of the close coupling between the level of economic development and energy use, as indicated in Figure 2. This linkage is likely to increase the political pressure for greater energy efficiency in both the developing and developed world (Blair 1989). It is interesting to note that West Europe and Japan, both at economic levels comparable to North America and well beyond East Europe and the USSR, prosper on about one half of U.S. per capita energy intensity. This is only partially explainable by geographic scale differences. At the other extreme, countries at the bottom of the global economic ladder subsist on less than 10% of our per capita energy consumption.

The potential for improvement in overall energy efficiency, as represented by the energy/GNP ratio, is high in the emerging economies of Eastern Europe, as shown in Figure 3. A significant part of the efficiency gains to be realized over the coming decades will be in the generation and use of electricity, especially from solid fuel resources indigenous to these countries.

## II. MEETING THE ENVIRONMENTAL CHALLENGES: CLEAN COAL TECHNOLOGY

Coal is rising to meet the environmental challenge, both through improved combustion and environmental control in the near term, and through the prospect of a shift in the direction of higher value added and environmentally benign coal processing by the early part of the 21st Century. Solutions which are being developed and demonstrated today or proposed for tomorrow fall under the generic heading of "Clean Coal Technologies." By improving the effectiveness of control technologies and reducing their costs, this concept seeks to reduce the policy conflict between coal use and the environment. Clean Coal Technologies have evolved into a family of precombustion, combustion/conversion, and postcombustion technologies, designed to provide the coal user with added technical capabilities and flexibility at lower cost in terms of environmental control. (EPRI 1988) (EPRI 1989) (DOE 1989) (Torrens 1990)

A major focus of clean coal technology development in the United States is the federal Clean Coal Technology (CCT) Demonstration Program administered by DOE.



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In March, 1986, the Administration requested Congress to commit $2.5 billion over 5 years to support clean coal projects which have matching funds from industry. To date there have been three rounds of project selections. There are now 35 projects funded or in negotiations with DOE, for a total value of $3.0 billion of which $1.2 billion from government and $1.8 billion from industry. Table 2 contains the Program's funding pattern, to date and anticipated (Round IV and V). Technologies being demonstrated under the CCT program include technologies whose purpose is strictly environmental control, and which are suitable for retrofit to existing plants, as well as technologies for repowering and for new coal power generation and industrial use. Table 3 provides a DOE status report for projects in Rounds I, II, and III of the CCT program, as of January 1991.

The U.S. utility industry is heavily involved in the CCT Program and provides host sites for 28 projects. The Electric Power Research Institute has involvement in 18 of these projects, providing total funding amounting to $18 million over the life of the demonstrations, mainly supporting test programs and performance assessments. Of the 28 projects, 12 involve some form of post-combustion $SO_2$ or $NO_x$ (or combined) clean-up. There are two coal gasification and 5 fluidized bed combustion projects.

Clean coal technology development is international in scope, as Figure 4 illustrates. Approximately 100 clean coal demonstrations worldwide, in progress or planned, are aimed at assuring that the highly diversified energy market has an array of coal utilization options which together form the least cost option for eliminating or reducing conflict between coal and the environment.

## III. STATUS OF CLEAN COAL TECHNOLOGIES

This section describes the main features of technologies to reduce pollutant emissions to air, water and land, and their current status. Depending on the specific technology, pollution control can occur before, during or after coal combustion; or combustion may itself be replaced by conversion of the coal into a clean liquid or gaseous fuel. In precombustion technologies, sulfur and other impurities are removed from the fuel before it is burned. Combustion technologies employ techniques to prevent pollutant emissions in the boiler while the coal burns. With postcombustion technologies, flue gas released from a boiler is treated to reduce its content of pollutants.

### 1. Pre-Combustion Cleaning

About 40% of all U.S. coal for utility boilers, and about 70% of eastern and midwestern bituminous coal, receive some cleaning, or beneficiation, prior to combustion. This is essentially all physical cleaning, and its purpose is largely to remove impurities and improve the coal's heat content. Physical cleaning can remove 30 to 50% of pyritic sulfur, or 10 to 30% of total sulfur content. Most physical cleaning processes rely on density differences or variations in other physical characteristics, crushing then washing the raw coal and removing the heavier impurities. Advanced physical cleaning processes are being developed and demonstrated. Most rely on grinding the raw material to much finer sizes, where various techniques specifically designed to separate ultrafine particles can be used. These advanced processes aim to separate up to 90% of the pyritic sulfur.

To remove the sulfur which is organically bound in the coal requires chemical or biological coal cleaning. Those processes are still in development, many of them at the experimental stage. The principal barriers to chemical cleaning are the energy required and cost of reagents, and the management of chemical waste products generated. Biological cleaning involves the use of bacteria or enzymes to "eat" the sulfur in the coal. Researchers are becoming more optimistic that new biotechnologies will make biological coal cleaning economic in the future, with removal of up to 90% of total sulfur.

## 2. $SO_2$ Control

Over 150 flue gas desulfurization (FGD) systems, on approximately 72,000 MW of generating capacity, are currently operating in the U.S. (Dalton, 1990). This represents about 20% of the total coal-fired capacity. Of the FGD systems, about 92% are wet scrubbers and 8% are spray dryers. All new pulverized coal fired units are scrubbed by law, and the 1990 Clean Air Act Amendments require some 9 million tons of $SO_2$ emission reductions from existing utility power plants by the year 2000. By the end of the century, an estimated 27,000 MW of FGD capacity on new plants are expected to come on line.

### (a) Wet Limestone FGD.

Currently the predominant U.S. scrubbing technology of choice by utilities is lime or limestone wet scrubbing with landfill disposal of byproducts. The reagent is prepared (limestone is ground; lime is slaked) and mixed with water in a reagent preparation area. It is then conveyed as a slurry (approximately 10% solids) to an absorber (typically a spray tower) and sprayed into the flue gas stream. Sulfur dioxide present in the flue gas is absorbed in the slurry and collected in a reaction tank where the resulting calcium sulfite and/or sulfate crystals are dewatered.

Early experience of the U.S. utility industry with "scrubbers" was fraught with difficulties: inadequate understanding of the process chemistry resulted in frequent incidence of plugging and scaling of the scrubber components, corrosion and erosion of the materials of construction, poor handling characteristics and large land requirements for sludge byproducts, and high capital and operating costs. Improved understanding of system chemistry has led to increased reliability, and improved performance. Reliability has reached 98% + for new scrubbed capacity, and additives permit $SO_2$ removal to exceed 90% at an added cost that is not usually prohibitive. Future improvements in conventional lime/limestone FGD can be illustrated using three examples:

- process improvements such as the jet bubbling reactor used in the Chiyoda CT-121 Process;
- application of spray drying to high sulfur coal;



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- an advanced, limestone FGD system producing gypsum with no reheat, and no redundant modules, for use at compact (e.g., space constrained) sites.

Each of these designs can achieve 90 to over 95% $SO_2$ control. The cost and performance advantages of the advanced system are a 20-50% capital cost savings and 20-40% operating cost savings over conventional FGD systems available today. The jet bubbling reactor and advanced limestone/gypsum designs can both make wallboard grade gypsum for sale or disposal.

Engineering and other improvements have succeeded in reducing the cost of wet FGD somewhat, compared to that of a decade ago, but it remains a relatively expensive item. Capital costs for conventional systems will vary depending on a number of factors such as fuel sulfur content and unit size. Preliminary results from the new round of EPRI cost estimation indicate that a state-of-the-art wet FGD system for medium-sulfur coal on a new plant could be built for less than $200/kW with annual operating costs in the range of 5 to 10 mills/kWh (see Figure 6). (Torrens and Radcliffe, 1990)

Depending on the conditions in an existing plant, especially space available and accessibility, retrofitting an FGD system can cost between one and three or more times that of installing it in a new plant. For the different FGD systems now available and a moderately difficult installation (retrofit factor 1.3 - approximately 30% more costly than in a new plant), the range of capital requirements and total levelized costs over 30 years with no inflation are estimated to be, (EPRI GS-7193, 1991).

| 1990 Dollars | Capital $/kW | $/ton $SO_2$ (Constant $) |
|---|---|---|
| Wet FGD (Range of System Types) | 190-230 | 440-500 |
| Spray Dryer | 175 | 450 |

The above figures are subject to a ± 20% level of uncertainty.

(b). Regenerable FGD

Regenerable FGD systems can use diverse physical and chemical principles, but generally recover sulfur byproducts as concentrated $SO_2$, sulfuric acid, or elemental sulfur. The major advantage of regenerable FGD is elimination of waste products. However, it costs 30 to 50% more than the conventional limestone gypsum FGD process, owing to system complexity. (Torrens/Radcliffe, 1990)

(c) Spray-Dry FGD

This is the other principal method of $SO_2$ control used today. Calcium oxide (quicklime) mixed with water produces a calcium hydroxide slurry, which is injected into a spray dryer and dried by the hot flue gas as it reacts to collect $SO_2$.

The dry product is collected both at the bottom of the spray tower and in the downstream particulate removal device where further $SO_2$ removal may take place. Capital costs can be substantially less than for wet systems, especially for low-sulfur coal applications. A total of 17 systems were operating as of mid-1987, all on relatively low-sulfur coal (less than 2%).

High-sulfur spray dryer applications have not been demonstrated over a long at commercial scale. Pilot testing has indicated that $SO_2$ removals in the eight ninety percent range are possible, with over ninety percent achievable under some conditions. However, a fabric filter retrofit may be required to maintain particulate control standards at greater than ninety percent removal, since the mass throughput of solids to the electrostatic precipitator (ESP) - the dominant particulate control technology in existing U.S. power plants - will at least double if a spray dryer is used.

(d) Sorbent Injection

This category of sulfur removal processes involves injection of a calcium-based sorbent directly into the furnace, into a lower temperature zone near the economizer, or downstream of the air pre-heater - in all cases without the addition of a special reaction vessel for $SO_2$ removal.

Furnace sorbent injection (FSI) refers to the injection or calcium-based sorbents (lime or limestone) into the radiant zone of the furnace where they calcine and then react to form $CaSO_4$ in the 1200-900°C temperature region. The sulfated sorbent is then collected along with the fly ash in the precipitator or baghouse. An alternative process, economizer injection (EI), is a similar process in which the sorbent is injected near the economizer at approximately 550°C.

$SO_2$ removal for FSI is a function of sorbent choice and quantity injected, but is typically 20-40% with limestone and 40-60% with lime at injection rates corresponding to calcium to sulfur ratios of two. The process is characterized by low capital costs ($50-100 kW), and simplicity of design and operation. But because of the lower efficiency of removal, the levelized costs expressed in terms of $/ton of $SO_2$ removed are somewhat higher than those typical of wet FGD. EI performance and costs are presently comparable to those for FSI; however, the lower temperatures at the injection location and the extremely fast reaction rates hold promise of performance improvements using sorbent enhancement techniques which are ineffective at FSI temperatures.

Duct sorbent injection refers to those processes where the sorbent is injected into low temperature flue gas downstream of the air preheater. $SO_2$ removal can be accomplished with either sodium- or calcium-based sorbents. In the case of calcium-based sorbents, it is necessary to humidify the flue gas to within 20-10°C of the saturation temperature in order to achieve sufficiently high reaction rates for economical $SO_2$ capture. This can be accomplished either through separate humidification followed by dry sorbent injection, or through slurry injection in the case of in-duct spray drying.

As with furnace sorbent injection, these processes are characterized by moderate sulfur capture (40 to 70% $SO_2$ removal), simplicity of design and operation, low capital cost and attendant savings in levelized removal costs. Several varieties of the basic technology are possible including in-duct spray drying using a slurry, dry duct injection using sodium or calcium sorbents, and a hybrid system which includes retrofit of a fabric filter after the existing ESP (HYPAS). In the last one, a dry calcium sorbent is injected into the clean gas stream following the ESP. All have capital costs of about \$50/kW with the exception of the hybrid system which is about \$100/kW due to addition of the baghouse. However, it is potentially capable of about 70% $SO_2$ removal (versus about 40-50% for the others) resulting in a cost effectiveness of about \$600-650/ton of $SO_2$ removal, which makes it a potentially attractive alternative to other dry systems..

Each of the processes for which pilot-scale development is successful will require full-scale demonstration to resolve operating issues such as particulate control, waste management and disposal, and the severity of duct deposition, plugging, and corrosion. All sorbent injection processes, furnace or duct, increase the quantities and alter the characteristics of solid wastes for disposal, potentially increasing disposal costs due to the presence of unreacted sorbent.

(e) <u>High Sulfur Test Center</u>

The HSTC, located near Buffalo, NY, is the focus of a \$65 Million, 10-year EPRI research program designed to reduce the cost, improve the efficiency, and increase the reliability of environmental control systems. The facility has been in operation since June 1987. Pilot and laboratory research is being conducted in various methods of environmental control including wet, spray dryer and dry sorbent injection FGD; selective catalytic reduction (SCR) for $NO_x$ removal in high-sulfur applications; both reverse gas and pulse jet fabric filters and an electrostatic precipitator for particulate removal; and, the effects of the various combinations of environmental controls on the release of toxic substances in air, water and solids discharges.

The HSTC is jointly sponsored by EPRI, New York State Electric & Gas, Empire State Electric Energy Research Corporation, U.S. Department of Energy and the Electric Power Development Corporation (EPDC) of Japan As the HSTC evolves into an international center for R&D activity on emissions controls, we welcome visitors and would be receptive to inquiries about potential joint research efforts and cofunding from overseas utilities.

3. $NO_x$ Control

(a) Combustion Modification

Combustion modification achieves some $NO_x$ reduction through the redesign of burners or through rearrangement of the fuel and air flows to the furnace (such as overfire air or reburning) in order to control the mixing of the fuel and air in relationship to the local temperature patterns. Maintaining of fuel-rich conditions in the primary flame zone followed by gradual air addition later in the combustion process minimizes NOx formation. This basic approach is characteristic of the low NOx burner and overfire air. Reburning involves the redirection of 10-20% of the total fuel to the upper-furnace region to create a zone for reduction of NOx formed in the primary burner zone. Such methods are applicable to oil and gas units as well as coal.

Achievable reductions are typically 40-60%. Capital costs for retrofit low NOx burners are estimated at $5 to $25/kW with no additional operating costs expec ı. Combustion modification has been widely applied at full scale on new units t ıeet NSPS on coal-fired utility boilers and for both new unit and retrofit applicat on oil- and gas-fired units. Pilot development of retrofit approaches to coal uni .s progressed to the point where technologies are ready for demonstration on a.. ıour major categories of existing boilers (tangentially-fired, wall-fired with circular burners, wall-fired with cell burners, and cyclone-equipped units).

(b) Post-combustion $NO_x$ Control

Postcombustion NOx control refers to flue gas treatment methods for conversion or removal of NOx species after the furnace. The most common processes involve the injection of ammonia or ammonia-like compounds (e.g., urea) into the flue gas with or without a catalyst to promote the reduction of NOx to nitrogen and water vapor. The most extensively developed process is selective catalytic reduction (SCR) in which ammonia is injected into the flue gas at about 440°C in the presence of a vanadium pentoxide catalyst.

NOx reductions of 80% or more are possible with SCR alone and, if used in conjunction with a low-NOx burner achieving 50% initial reduction, a combined efficiency of 90% can be obtained. Costs depend strongly on initial NOx levels, catalyst cost and assumed catalyst life.

Their capital costs in Europe are averaging approximately $125/kW. These costs are consistent with EPRI's capital cost estimates for hypothetical retrofit installations which range from $100 to $150/kW. Levelized cost projections for both U.S. and Japanese installations are estimated at 4 to 9 mills/kWh (Cichanowicz, et al, 1990)

SCR has been applied commercially in Japan and Western Europe (primarily Germany and Austria). In particular, Germany now has some 25,000 MW of utility coal-fired capacity retrofitted with SCR. All of this existing and planned SCR application is on lower-sulfur coal, and there are questions as to whether catalyst lifetime may be substantially reduced by sulfur-laden flue gases. There are also issues related to catalyst poisoning by trace metals in the coal. EPRI is cooperating with others in the United States, including the Department of Energy, to investigate the performance of SCR at pilot scale under U.S. coal and boiler conditions.

The United States and Europe are paying increased attention to selective noncatalytic reduction (SNCR) technologies. The principle is similar to that of SCR, but no catalyst is involved. Results with urea injection show the potential for 30 to 50% $NO_x$ reductions, and perhaps up to 75%, with $NH_3$ emissions below 5 to 10 ppm. Capital and operating costs are estimated to be $5 to $15/kW, and less than 3 to 4 mills/kWh, respectively.



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## 4. Combined $NO_x/SO_2$ Control

Combined $NO_x/SO_2$ processes offer the potential to reduce $SO_2$ and $NO_x$ emissions for less than the combined cost of SCR and conventional flue gas desulfurization (FGD). Most processes are in the development stage and are not commercially available, although several have been applied to low sulfur coal-fired boilers.

More than sixty combined $NO_x/SO_2$ processes have been identified in a recent EPRI study. There are six broad categories:

- Solid adsorption/regeneration processes employ physical adsorption of $SO_2$ and $NO_x$ onto a solid material, which is then exposed to high temperature and reducing gas, generating a concentrated $SO_2$ and $NO_x$ stream for production of elemental sulfur or acids.

- Flue gas irradiation delivers a high energy charge to flue gas, forming radical species from $NO_x$ and $SO_2$, which combine at low temperature with a reagent (such as ammonia) to form solid particles, captured by an ESP or fabric filter.

- Wet scrubbing employs additives for conventional lime/limestone scrubbers from solid nitrogen/sulfur compounds which can be precipitated and collected as a solid.

- Gas/solid catalytic operations employ several catalysts to reduce $NO_x$ to $N_2$ by SCR and oxidize $SO_2$ to $SO_3$, the latter for condensation as sulfuric acid.

- Electrochemical operations reduce $SO_2$ to elemental sulfur and $NO_x$ to $N_2$ without reagent by employing an electrically activated catalyst surface.

- Alkali injection uses additives for dry $SO_2$ removal systems to collect $NO_x$ with $SO_2$ as nitrogen/sulfur compounds.

Engineering studies are presently in progress to estimate the capital and operating costs of selected $NO_x/SO_2$ controls that may offer viable alternatives to SCR and FGD. At present, cost analysis accuracy is limited by a lack of significant operating experience at conditions typifying U.S. utility application. Given this uncertainty, most candidate processes appear to require between \$250 and \$350/Kw, and 20-30 mills/KWh total levelized cost.

## 5. Particulate Control

Many utilities will be required to upgrade particulate controls at existing power plants, especially in response to new Clean Air Act Amendments. Existing electrostatic precipitators (ESPs) may have difficulty in meeting future fine particulate and/or air toxic standards, and those designed for use on boilers firing



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high-sulfur coal may not even be able to maintain current emissions if they switch to low-sulfur coal to comply with new $SO_2$ regulations.

Significant savings could be realized in these cases through the use of improved baghouse cleaning methods, replacement of an aging and underperforming electrostatic precipitator (ESP) with a pulse jet baghouse, advanced ESP controls, or improved flue gas conditioning systems. Examples of upgrade technologies that EPRI is developing and/or evaluating follow:

(a) Low Cost, High Performance Electrostatic Precipitators.
Field demonstrations have been, or are being, conducted on four electrostatic precipitator (ESP) upgrade technologies: intermittent energization; wide plate spacing; two-stage precharging; and an agentless flue gas conditioning system. These technologies can be used to improve the performance of existing ESPs or reduce the cost of new units.

(b) Particulate Controls for Advanced $SO_2$ Reduction Processes.
Guidelines are being developed for predicting the performance of particulate controls operating in conjunction with AFBCs, spray dryers, or sorbent injection processes for $SO_2$ control. These guidelines will help a utility engineer determine how well the existing or proposed particulate collector will function in this environment and what countermeasures should be considered if the performance is not expected to be satisfactory. The guidelines will be based on field tests at a variety of sites, complemented by laboratory tests and computer modeling. They are expected to be available in 1993.

(c) Pulse Jet Baghouses for Utility Applications.
Baghouses, or fabric filters, collect fly-ash in the same way that a domestic vacuum cleaner traps dust. They are generally cleaned by mechanical means or using a sonic horn after being taken off line. Pulse-jet baghouses provide a more vigorous cleaning force than conventional baghouses by using short pulses of higher pressure air. The pulse-jet configuration is also unusual because the bags collect ash on the outside rather than the inside. Metal cages on the inside prevent bag collapse. Unlike bags that collect dust on the inside, pulse-jet bags can be cleaned with the compartment remaining on-line. Figure 5 shows a pulse-jet baghouse, including the compressed air cleaning system, bag supports, gas flow patterns, and solids removal port.

Pulse jet baghouses are being evaluated at various utility sites. These tests cover a wide range of flue gas and fly ash characteristics, including products of heavy oil combustion. The demonstrations are being conducted on 1-MWe equivalent pilot baghouses using full-scale components in each compartment. These field tests are demonstrating that pulse jet baghouses, used extensively by domestic and foreign industry as well as foreign utilities, are also applicable and economical under U.S. utility conditions. An EPRI-patented process, the Compact Hybrid Particulate Collector (COHPAC), may become the most cost-effective ESP upgrade when very low emissions and opacities are required. This process takes advantage of the relatively low dust loading, leaving an ESP, even a poorly performing unit, to operate the pulse jet baghouse at 4-6 times normal filtering velocity. The consequent reduction in baghouse size (the same factor of 4-6) results in a very low-cost, yet high performance, upgrade. The first full-scale demonstration of COHPAC will take place in 1992 at a Texas Utilities power plant..

## 6. Air Toxics Control

Air toxics, a relatively new concern for the power industry, feature prominently in the 1990 Clean Air Act Amendments. There is a clear and urgent need to know what amounts of potentially toxic substances are produced and emitted from different plants, how effective today's control equipment is at removing these substances, and how and at what cost controls may be upgraded, if necessary.

In 1988, EPRI initiated the Power Plant Integrated Systems: Chemical Emissions Study (PISCES) to build a comprehensive database and chemical species evaluation model for estimating toxics emissions to all media (air, water, solid waste). Field measurements on two dozen priority chemical substances are in progress at EPRI pilot/demonstration facilities and full-scale power plants of member utilities.

The PISCES project is coordinated with other EPRI research on atmospheric transformations, health/ecological effects, and risk assessment.

## 7. Repowering Technologies

If a power plant is nearing the end of its scheduled life and major expense would be necessary to meet new or emerging emission limits, it may make sense to consider replacing the boiler with a new less polluting and more efficient technology for coal combustion or conversion. This is known as repowering. New technologies for repowering existing boilers include atmospheric or pressurized fluidized bed combustion (AFBC or PFBC), slagging combustors, or integrated gasification combined cycle (IGCC). All of these technologies are of course equally applicable to a new power plant.

### (a) Atmospheric fluidized bed combustion (AFBC)

This is now an established technology for industrial boilers (10 to 25 MW). It is being demonstrated at utility boiler size (75 to 350 MW) in a number of demonstrations in the U.S. and abroad. It relies on jets of air to maintain a mixture of coal and limestone (to capture sulfur) in a turbulent suspension in the boiler while it is being combusted, at temperatures of 1400-1600F, about half of that in a conventional boiler. This reduces $NO_x$ formation. AFBC boilers can meet new source performance standards for both $SO_2$ (at a calcium/sulfur ratio of about 2) and $NO_x$, without additional control equipment. They also permit the combustion of lower grade fuels. However, like FSI, AFBC results in additional waste quantities which may prove difficult to handle in the existing particulate control device.

### (b) Pressurized fluidized bed combustion (PFBC)

PFBC follows the same principle as AFBC except that the boiler operates under 10 atmospheres of pressure. The increased energy of the exit gases can drive both a gas turbine and a steam turbine (combined cycle) potentially boosting generating



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efficiency to over 40%. The relatively small size of PFBC units is well suited to space-constrained sites and modular construction. Four commercial demonstration units each of about 70-80 MWe capacity are being constructed at utility sites in Sweden, Spain and the United States, each repowering an existing plant.

An important issue for PFBC is hot gas clean up, which is needed if the combined cycle is to realize its full potential for improving generating efficiency. Research efforts are in progress to clean the 1500F gases exiting the boiler without cooling them, so that they can drive a gas turbine directly. Various techniques are being tried, such as filtering with ceramic candles, ceramic cross-flow filters or granular beds.

(c) Slagging Combustors
These are cylindrical devices based on the cyclone concept, where combustion takes place in the device and the hot combustion gases pass into the boiler. The combustion temperature is high enough to produce slag instead of ash. Developers claim that the high $NO_x$ levels which would normally be associated with high combustion temperatures are reduced by combustion stoichiometry controls, to less than 250 ppm (0.34lb/MBtu). Also, sorbent injection is claimed to reduce $SO_2$ emissions by 50-80%.

(d) Integrated Gasification Combined Cycle IGCC.
A number of processes are at the demonstration stage in the USA and Europe. The basic principle is synthetic gas production followed by combustion in a turbine generator and recovery of the heat using a steam bottoming cycle to generate additional electricity. Using current technology, such an IGCC plant should be able to reach 42% efficiency.

Environmental protection also depends directly on the gasification process. Sulfur can be recovered chemically from the coal gas in elemental form, which can then be sold. Formation of nitrogen oxides is inhibited during combustion by saturating the coal gas with water vapor to reduce flame temperature. The volume of solid waste produced by a gasification-based plant is less than half that of a conventional coal plant with scrubbers, and the product is an inert slag that can be used as a construction material.

Several U.S. utilities are actively pursuing IGCC projects, following successful demonstration of the concept at EPRI's 100 MW Cool Water facility, which operated from 1984 to 1989. In addition, Destec, a wholly owned subsidiary of Dow Chemical Company, is currently operating a 160 MW IGCC plant, in Plaquemine, Louisiana. Abroad, SEP -- the joint operation authority for electricity production in the Netherlands -- is now constructing a 250 MW IGCC plant based on Shell gasification technology. This plant is scheduled to start operation in 1993. (Torrens 1990)

## IV. WASTE & WATER MANAGEMENT

Utility waste and water management falls into three broad categories:

- high volume wastes re-use and disposal



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- chemical and toxic waste management
- water quality management

### 1. High Volume Wastes

Currently, about 18% of utility fly ash is sold for use in other industries. The most prevalent use is as a substitute for cement in concrete. This application is limited, however, by ash composition and engineering requirements. More than 50 other uses of fly ash have been documented, but many of these are limited by market size, material specifications, or transportation costs.

To help promote ash utilization, one potentially large market for coal ash is highway construction. EPRI has sponsored six demonstrations of fly ash use in highway construction across the nation. Each project was selected to examine a specific type or application of ash. These demonstrations--using both western and eastern coal ash--are proving the effectiveness and value of ash in engineered fill applications (e.g., embankments and pavement base courses). Groundwater monitoring at the sites is verifying the environmental acceptability of using fly ash in roadways.

Design manuals and material specifications developed by the program provide utilities, highway departments, and contractors with guidelines for using fly ash in construction. Videotapes documenting construction applications are also available. The program's fly ash utilization manual helps utilities establish ash marketing programs.

If ash and FGD waste cannot be used, it must be disposed of safely. Today, ponding and landfilling are the predominant means of ash and FGD by-product management. EPRI is helping utilities meet environmental requirements for ponds and landfills through its ash and FGD by-product disposal manuals, site upgrade guidelines, and ASHDAL (ash disposal) and SLUDGECOST (FGD by-product disposal) cost-estimating computer codes.

### 2. Chemical and Toxic Wastes

Utilities handle, store, and discharge chemical substances in the generation of electricity. Regulators are focusing on how these substances are managed and their impact on human health and the environment. They are also investigating cases of potential contamination from other utility operations, such as former manufactured-gas plants and leaking underground storage tanks.

The costs of managing chemical and toxic materials are likely to rise as regulations restricting traditional disposal methods take effect. Materials designated as hazardous will be particularly affected. For these substances, source reduction and recycling, followed by detoxification, stabilization, or encapsulation, may be the only management alternative.

EPRI's PISCES project (see Section III.6) also has a strong water and waste component in the database and field measurement activities. This will provide utilities information on the quantities and fate of chemical substances in waste streams.

Low-volume wastes include a variety of small, intermittent power plant streams, such as boiler and cooling tower blowdown, chemical cleaning wastes, washwaters, process and floordrain wastewaters, coal pile runoff, and used oils. Noncombustion wastes include asbestos, paint cans, antifreeze, spent solvents, and treated wood.

The costs and techniques of managing these wastes vary, depending on whether they are classified as hazardous or nonhazardous. Because disposal costs for hazardous waste can be five to ten times that for nonhazardous waste, classification of only a small minority of substances as hazardous could greatly increase utility disposal costs.

EPRI helps utilities manage low-volume wastes by sampling and characterizing typical power plant streams. Results have been published in a reference manual, which also describes treatment and disposal alternatives and their costs. A similar reference manual exploring innovative minimization, handling, and treatment approaches will be published following an investigation of noncombustion wastes.

### 3. Water Quality Management

Managing water quality is becoming more important as utilities contend with fewer high-quality water sources and stringent wastewater discharge requirements. As a result, many utilities are reducing water consumption. Further, utilities are confronting chlorine discharge limits that can lead to increased condenser biofouling and heat rate penalties.

One of the EPRI's goals is to maximize the efficiency of plant water use while maintaining process performance. It is achieving this goal by developing (1) innovative water management and treatment technologies and (2) methods to detect and minimize condenser scaling, corrosion, and biological fouling.

Integrated water management products include the WATERMAN computer code, which determines water flows and balances throughout a plant. By integrating water flows and by recycling or reusing water, utilities can substantially reduce makeup water needs. In addition, WATERMAN allows utilities to evaluate water recycle and reuse approaches.

Cooling systems are the largest water users in a power plant. Therefore, reducing cooling system makeup water demand is an important element in plant water management. Reduced water use, however, can lead to condenser scaling and corrosion, which can cause heat rate penalties. Proper cooling water chemistry management requires a balance between these two demands. EPRI has developed a family of computer codes to help utilities maintain proper water chemistry in recirculating cooling systems.



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Power plants frequently experience biological fouling (biofouling) of condenser tubes by algae and other microorganisms. This results in increased turbine backpressure, shortened tube life, and increased condenser maintenance.

Utilities traditionally have controlled biofouling by bulk chlorination. However, EPA restrictions on residual chlorine in cooling water discharge are forcing utilities to explore other alternatives. One promising option is targeted chlorination.

In targeted chlorination, chlorine is sequentially injected into various sections of the condenser inlet tubesheet for short durations. The chlorine contact time and concentration are sufficient for biofouling control, yet downstream mixing and dilution enable compliance with EPA discharge limits. A computer code, FOULCOMP, assists utilities in optimizing chlorine use.

### 4. Future Waste and Water Management Strategy

In recent decades, strict regulation of power plant discharges and waste disposal has become routine. EPRI and the utility industry expect this trend to continue. Long-term R&D strategy that will allow future environmental standards to be met at the least possible cost, centers around integrated management systems that possess the following attributes:

- maximum recycling and reuse of wastes
- no detectable toxic waste discharge
- minimal water discharge
- waste processing to extract products of commercial value
- minimal cooling system fouling, scaling, and corrosion
- reliable monitoring techniques for regulated substances
- stabilization and containment of all discharged wastes

With this strategy, EPRI is helping utilities move toward full environmental compatibility, without sacrificing economic competitiveness.

## V. TOOLS FOR SELECTION OF CONTROL TECHNOLOGIES

Section III describes generic categories of clean coal technologies with in some cases an indication of cost ranges. However, when it is a matter of retrofitting an existing power plant, no two situations are identical: fuels, boiler configurations, even space available for new pollution control equipment, all play a role in the decision on how a utility will meet new emission reduction requirements. For example, a decision to install a sorbent injection technology rather than FGD for $SO_2$ reduction may depend not only on the percentage reduction required but also on the space constraints of



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the site, and on the capacity factor of the plant (with a lower capacity factor, the lower capital cost of sorbent injection is advantageous compared to FGD).

To help its member utilities in making these decisions, EPRI has developed or is developing a number of tools, mainly in the form of easy-to-use computer codes. Principal among these are FGDCOST (which compares the cost of different $SO_2$ control technologies applied to a specific plant); FGDPRISM (which simulates wet FGD process chemistry for application to performance, cost and reliability improvement); and $NO_xPERT$ (which helps utilities select a $NO_x$ reduction technology, again adapted to a specific plant configuration). Summary descriptions of these codes follow. They are being integrated with other plant-specific EPRI codes (e.g. CQIM-Coal Quality Impact Model) in a Clean Air Technology (CAT) Workstation, which utilities can use in their strategic planning for response to the 1990 Clean Air Act Amendments.

FGDCOST

EPRI has recently updated its economic evaluations of commercially available FGD systems Revised cost estimates are now available, with technical and commercial evaluations, for up to 26 different FGD processes, including both wet and dry technologies.

FGD Processes Evaluated:

Limestone/Forced Oxidation
Limestone/Wallboard Gypsum
Limestone/Dual Alkali
Lime Dual Alkali
Magnesium-Enhanced Lime
Limestone/Inhibited Oxidation
Limestone/DBA
Pure Air/Mitsubishi
CT-121
Lime Spray Dryer
Furnace Sorbent Injection
Economizer Sorbent Injection
Duct Sorbent Injection
Duct Spray Dryer
Tampella LIFAC
Lurgi CFB
SOXAL
Wellman-Lord
MgO
Saarberg-Holter
NSP Bubbler
Passamoquoddy
ISPRA Bromine
HYPAS
Damp/ADVACATE
NOELL/KRC

A new computer model, FGDCOST, will help utilities tailor cost estimates to specific plant sites. The model is a menu-driven, spreadsheet template (one spreadsheet for each technology) that uses internally stored design information to help users estimate capital, O&M, and total levelized costs. User inputs include economic criteria, boiler/coal characteristics, site conditions, and adjustments for retrofit difficulty. The new model will supersede EPRI's RETROFGD cost-estimating code. Figure 6 shows cost ranges for several FGD technologies calculated by FGDCOST.



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FGDPRISM

Better understanding of FGD chemistry can lead to greater efficiency and reliability in wet scrubber operation. For this reason, EPRI developed the FGD Process Integration and Simulation Model (FGDPRISM), a personal computer program that simulates wet lime/limestone scrubbing chemistry. The model evaluates how changes in the hundreds of variables involved in the scrubbing process affect FGD system performance.

FGDPRISM embodies the results of over 10 years of EPRI research into the fundamentals of FGD process chemistry. It allows purchasers of desulfurization systems to compare the performance of various candidate designs. System designers can refine absorber and reaction tank parameters through performance simulations. Utilities currently operating FGD systems can simulate physical or chemical modifications without full-scale testing. These applications will result in engineering labor, capital, and O&M savings.

$NO_x$PERT

$NO_x$PERT is a PC-based computer model for screening $NO_x$ control technologies. It features the EPRIGEMS standard user interface, and can be used to:

- predict $NO_x$ emissions for individual boilers, plants, and the utility system
- select $NO_x$ controls to meet emissions reduction targets
- provide cost estimates of $NO_x$ reduction retrofits

$NO_x$PERT is based on the best available correlations of $NO_x$ with fuel, boiler/burner type, and other combustion parameters. The model can analyze any of the four major boiler types and accounts for variations in duty cycle, design vintage, and structural constraints.

Technical and cost uncertainties are provided, as is a condensed $NO_x$ control technology tutorial. $NO_x$PERT can help utilities substantially reduce the engineering hours required deciding how best to meet $NO_x$ reduction requirements with their specific plant configurations.

## VI. CONCLUSION

Power plant environmental control is not inexpensive. On the aggregate, environmental systems on a new coal-fired plant are estimated to amount to some 40% of the total capital cost. The U.S. utility industry will be spending some $5-7 billion per year on $SO_2$ and NOx retrofit controls retrofitted to existing plants, when the CAAA compliance program is completed in 2000. Controls on air toxics if utilities are regulated would add to this bill.

In an emerging economy like Poland's, pollution control competes for development capital with badly needed modernization of all industrial plants. It is important therefore to achieve the "biggest bang for the Zloty", in terms of cost-effectiveness and reliability of control equipment to be installed to meet future environmental standards. This implies:

1) careful and impartial evaluation of the technological options, both generically and on a plant-specific basis;

2) translation of the cost basis into Polish cost accounting methods and use of Polish parameters (e.g. labor and materials costs);

3) multi-media planning, for adequate solid waste management and waste water treatment;

4) a sound training program for plant operators and supervisors: a FGD system is a chemical plant and needs to be treated as such if it is to be reliable.

Strategic emission reduction planning should also consider the most cost-effective ways of achieving desired overall goals in a region. For example, is it better to impose 50% $SO_2$ reductions on two power plants or to leave one alone and reduce emissions in the other by 95%? The CAAA in the U.S. provide utilities with options like this by "bubbling" their total required $SO_2$ emission reductions. This is an initial step in a trend towards a more market-oriented approach to pollution reduction.

There are no major technical barriers to reducing pollution from power generation in Poland very substantially. Clearly, the most difficult issue is the availability of scarce financial resources to cope with the retrofit needs of Poland and other emerging Eastern European economies. Development cooperation from abroad, such as the Department of Energy-sponsored retrofit project, provide a beginning. But the total funding available from international development organizations is likely to be far exceeded by the capital needs. Consequently, international investment would appear to be the major potential source for acceleration of the modernization of Poland's power generation sector. How to attract that investment, however, goes beyond the scope of this paper or EPRI's technical expertise.

There has seldom been a time when this phrase "changing world" was more applicable than to the world of 1991. The countries of Eastern Europe are in the center of the political and economic maelstrom. Reaching the level of prosperity of the advanced economies of the OECD will be no easy task.

But if it is to be done, electricity, environment and technological innovation will inevitably play a pivotal role.

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Table 1

## Coal-Fired Generating Capacity Growth

| | 1990 Installed Coal Capacity (GW) | Expected Coal Growth 1990-2000 | | Expected Coal Growth 2000-2020 | |
|---|---|---|---|---|---|
| | | %/Yr | New GW | %/Yr | New GW |
| N. America | 340 | 1.0 | 30 | 2.0 | 180 |
| W. Europe, Japan, Australia | 220 | 2.0 | 40 | 1.5 | 100 |
| E. Europe, USSR | 250 | 1.1 | 30 | 1.5 | 100 |
| China, India, Africa | 200 | 1.3 | 30 | 2.0 | 110 |
| Pacific Rim, S. America | 60 | 7.5 | 60 | 4.7 | 190 |
| TOTAL | 1040 | | 190 | | 680 |

Source: Frisch, J.R., 1986

Table 2

## CLEAN COAL TECHNOLOGY PROGRAM
### Funding Profile
(Basis: FY 1991 Budget Request)

Fiscal Years ($ Million)

| CCT | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | TOTALS |
|---|---|---|---|---|---|---|---|---|---|---|
| I | 99.4 | 149.1 | 149.1 | | | | | | | 397.6 |
| II | | | 50.0 | 190.0 | 135.0 | 200.0 | | | | 575.0 |
| III | | | | | 419.0 | 156.0 | | | | 575.0 |
| IV | | | | | | 100.0 | 250.0 | 250.0 | | 600.0 |
| V | | | | | | | 150.0 | 225.0 | 225.0 | 600.0 |
| TTL: | 99.4 | 149.1 | 199.1 | 190.0 | 554.0 | 456.0 | 400.0 | 475.0 | 225.0 | 2747.6 |

Source: DOE/FE-0219P 1991

TABLE 3

## CCT Demonstration Projects, by Technology Category

| Technology Category | Project Sponsor | Demonstration Project | Solicitation |
|---|---|---|---|
| **Precombustion Cleaning** | | | |
| Coal Preparation | ABB Combustion Engineering, Inc., and CQ, Inc. | Development of the Coal Quality Expert | CCT I |
| | Western Energy Company | Advanced Coal Conversion Process Demonstration | CCT I |
| **Clean Combustion** | | | |
| Advanced Combustion | Alaska Industrial Development and Export Authority | Healy Clean Coal Project | CCT III |
| | The Babcock & Wilcox Company | Demonstration of Coal Reburning for Cyclone Boiler $NO_x$ Control | CCT-II |
| | The Babcock & Wilcox Company | Full-Scale Demonstration of Low-$NO_x$ Cell-Burner Retrofit | CCT-III |
| | The Babcock & Wilcox Company | LIMB Demonstration Project Extension[a] | CCT I |
| | Coal Tech Corporation | Advanced Cyclone Combustor with Integral Sulfur, Nitrogen, and Ash Control | CCT I |
| | Energy and Environmental Research Corporation | Enhancing the Use of Coals by Gas Reburning and Sorbent Injection | CCT I |
| | Energy and Environmental Research Corporation | Evaluation of Gas Reburning and Low-$NO_x$ Burners on a Wall-Fired Boiler | CCT III |
| | Southern Company Services, Inc. | Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler | CCT II |
| | Southern Company Services, Inc. | 180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of $NO_x$ Emissions for Coal Fired Boilers | CCT II |
| | TransAlta Resources Investment Corporation | Low-$NO_x$/$SO_x$ Burner Retrofit for Utility Cyclone Boilers | CCT II |
| Fluidized-Bed Combustion | | | |
| Atmospheric Circulating | The City of Tallahassee | Arvah B. Hopkins Circulating Fluidized-Bed Repowering Project | CCT I |
| | Colorado-Ute Electric Association, Inc. | Nucla CFB Demonstration Project | CCT I |
| Pressurized | The Ohio Power Company and The Appalachian Power Company | PFBC Utility Demonstration Project | CCT II |
| | The Ohio Power Company | Tidd PFBC Demonstration Project | CCT I |
| | Dairyland Power Cooperative | Alma PCFB Repowering Project | CCT III |

[a] Two technologies are being demonstrated in this project: LIMB, which uses sorbent injection in the boiler, and Coolside, which uses sorbent injection downstream of the boiler

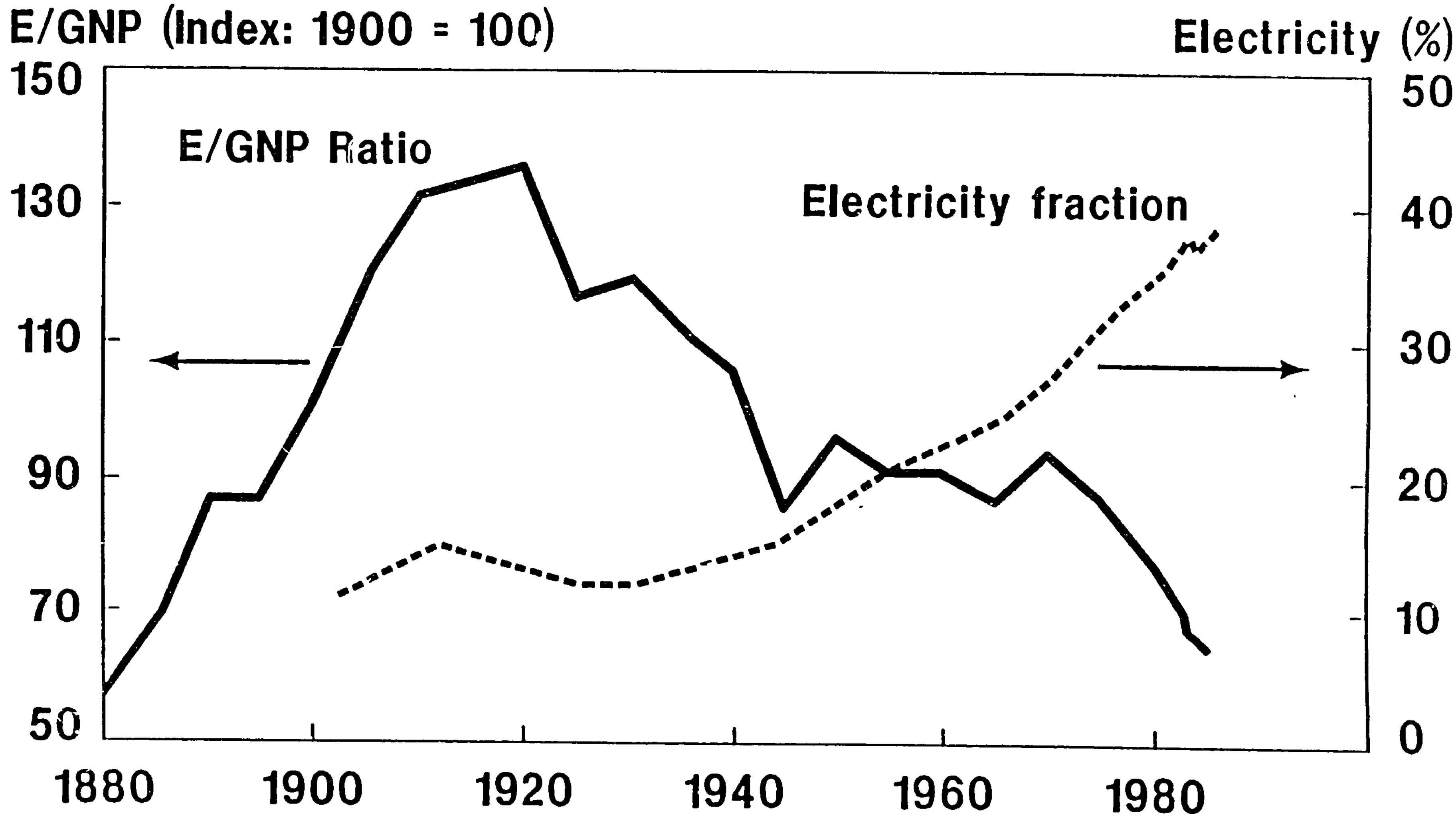
TABLE 3 (continued)

## CCT Demonstration Projects, by Technology Category

| Technology Category | Project Sponsor | Demonstration Project | Solicitation |
|---|---|---|---|
| **Postcombustion Cleaning** | | | |
| Flue Gas Cleanup—Combined $SO_2/NO_x$ Control | ABB Combustion Engineering, Inc. | WSA-SNOX Flue Gas Cleaning Demonstration Project | CCT-II |
| | The Babcock & Wilcox Company | LIMB Demonstration Project Extension (Coolside Only)* | CCT-I |
| | The Babcock & Wilcox Company | SOX-NOX-ROX Box Flue Gas Cleanup Demonstration Project | CCT-II |
| | MK-Ferguson Company | Commercial Demonstration of the NOXSO $SO_2/NO_x$ Removal Flue Gas Cleanup System | CCT-III |
| | Public Service Company of Colorado | Integrated Dry $NO_x/SO_2$ Emission Control System | CCT-III |
| Flue Gas Cleanup—$NO_x$ Control | Southern Company Services, Inc. | Demonstration of Selective Catalytic Reduction Technology for the Control of $NO_x$ Emissions from High-Sulfur-Coal-Fired Boilers | CCT-II |
| Flue Gas Cleanup—$SO_2$ Control | Airpol, Inc. | 10-MW Demonstration of Gas Suspension Absorption | CCT-III |
| | Bechtel Corporation | Confined Zone Dispersion Flue Gas Desulfurization Demonstration | CCT-III |
| | Bethlehem Steel Corporation | Innovative Coke Oven Gas Cleaning System for Retrofit Applications | CCT-II |
| | LIFAC–North America | LIFAC Sorbent Injection Desulfurization Demonstration Project | CCT-III |
| | Passamaquoddy Tribe | Cement Kiln Flue Gas Recovery Scrubber | CCT-II |
| | Pure Air on the Lake, L.P. | Advanced Flue Gas Desulfurization Demonstration Project | CCT-II |
| | Southern Company Services, Inc. | Demonstration of Innovative Applications of Technology for the CT-121 FGD Process | CCT-II |
| **Coal Conversion** | | | |
| Gasification Combined-Cycle Systems | ABB Combustion Engineering, Inc. | Combustion Engineering IGCC Repowering Project | CCT-II |
| | Clean Power Cogeneration Limited Partnership | Air-Blown/Integrated Gasification Combined-Cycle Project | CCT-III |
| Mild Gasification | ENCOAL Corporation | ENCOAL Mild Coal Gasification Project | CCT-III |
| Coal Liquefaction | Air Products and Chemicals, Inc., and Dakota Gasification Company | Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH®) Process | CCT-III |
| | Ohio Clean Fuels, Inc. | Prototype Commercial Coal/Oil Coprocessing Plant | CCT-I |
| Direct Coal Use in Iron Making | Bethlehem Steel Corporation | Blast Furnace Granulated-Coal Injection System Demonstration Project | CCT-III |

FIGU[redacted]1

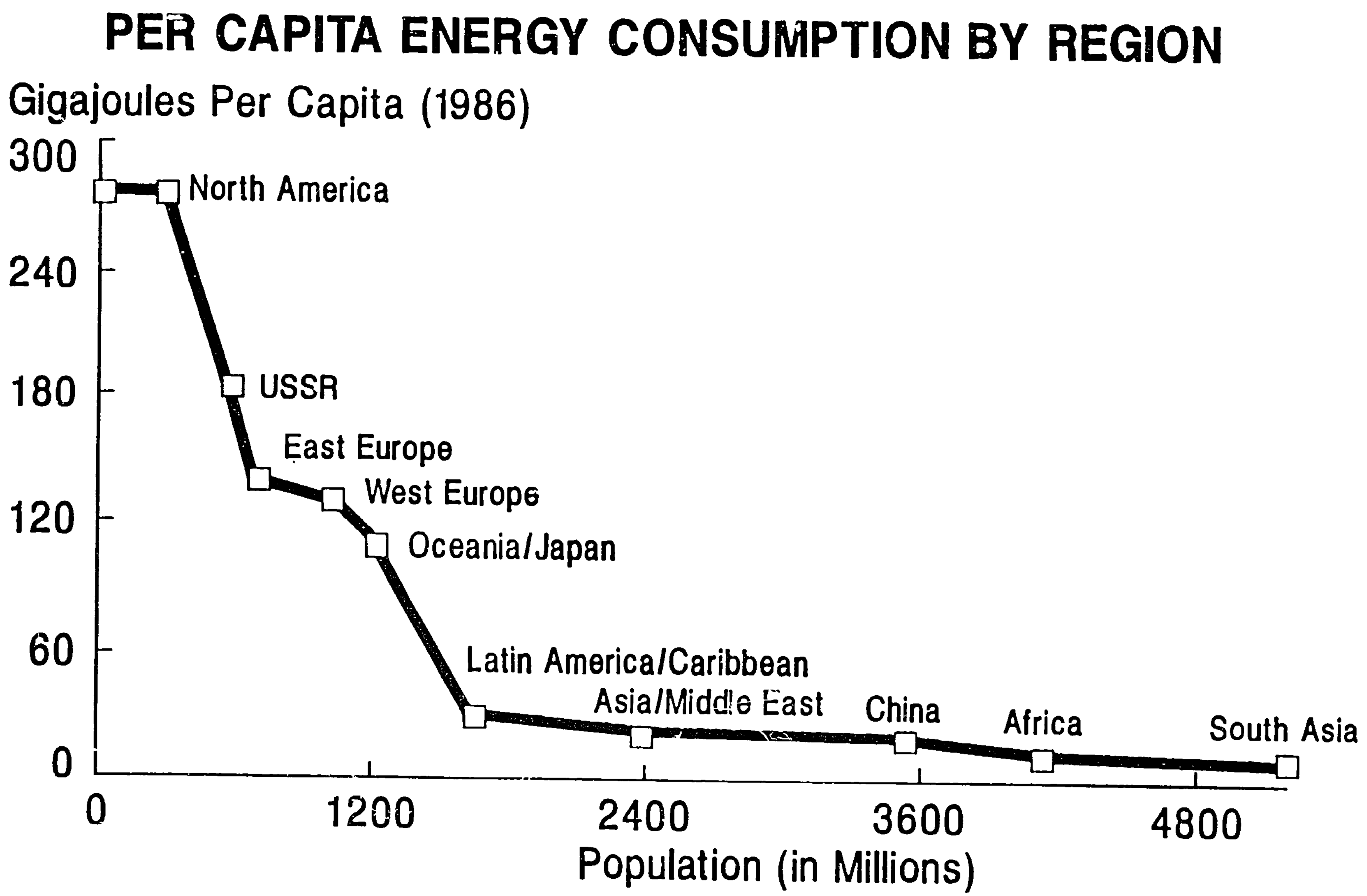
# U.S. ENERGY/GNP RATIO & ELECTRICITY FRACTION 1880-1985




-90

35968.

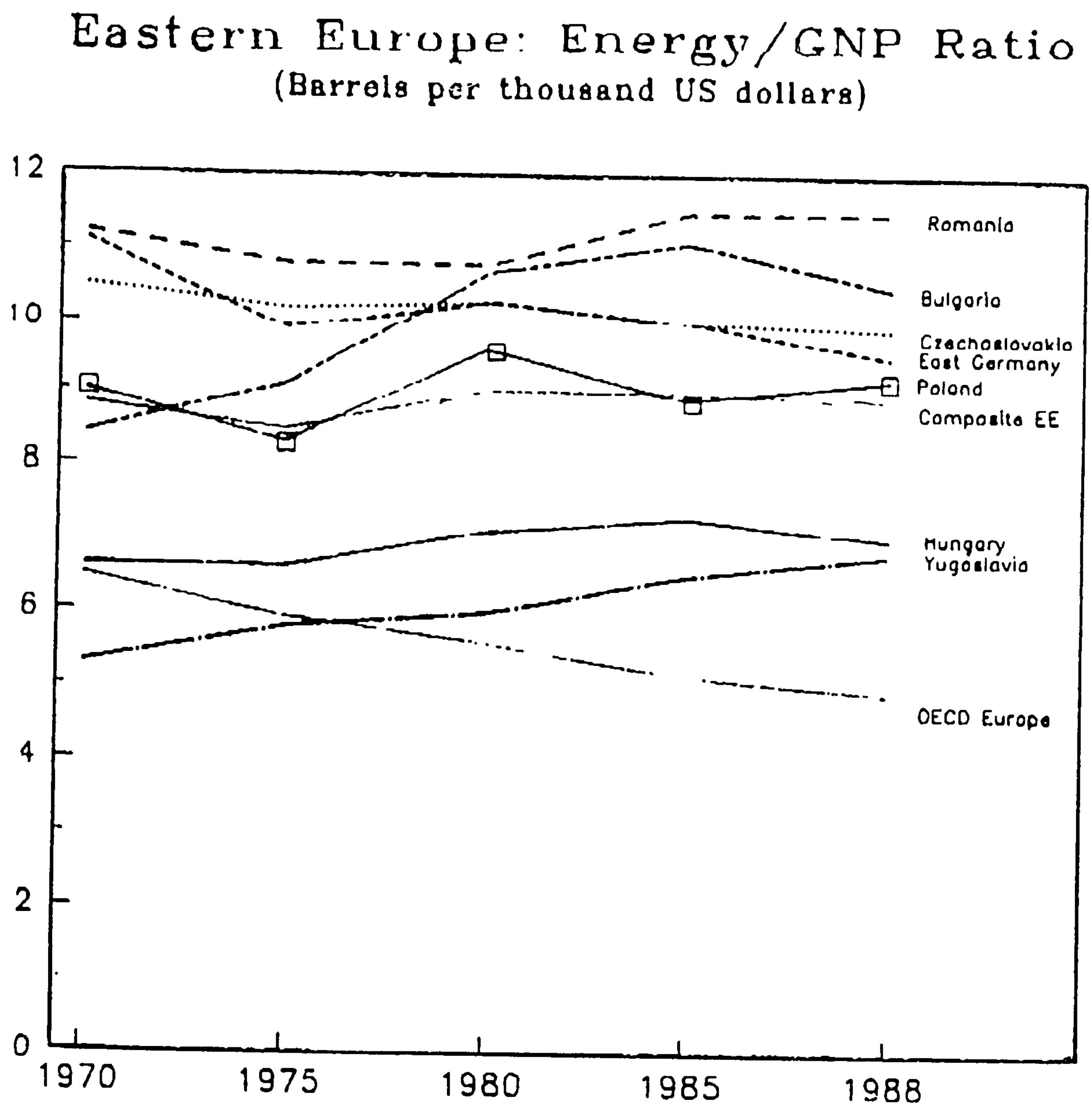
FIGURE 2




Source: World Resources 1989; RFF analysis

0386.08

FIGURE 3

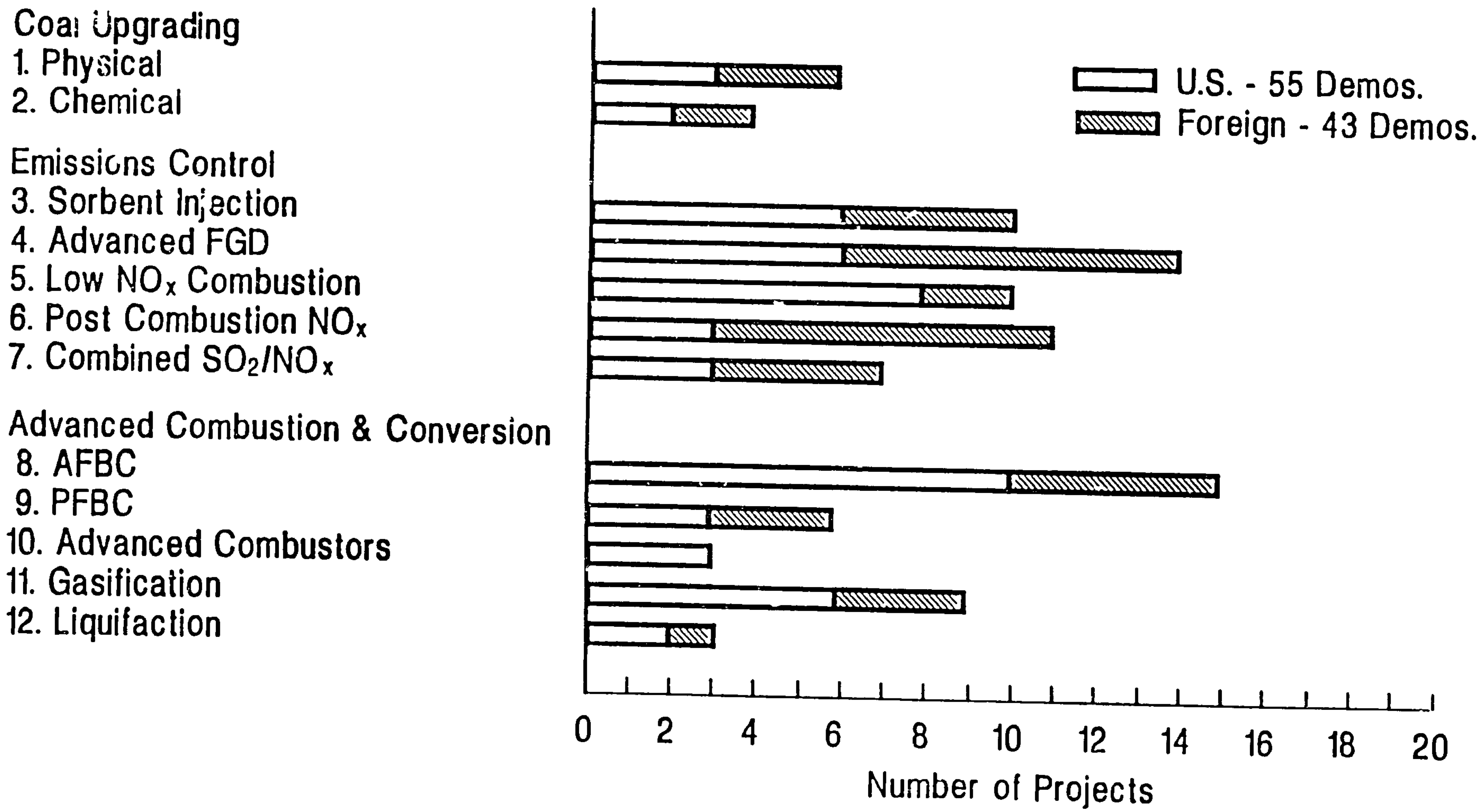



GNP data represented in 1988 US dollars.

Source: International Energy Agency

FIGURE 4

# CLEAN COAL DEMONSTRATIONS




0392e.37

FIGURE 5

# TYPICAL PULSE JET FABRIC FILTER CONFIGURATION

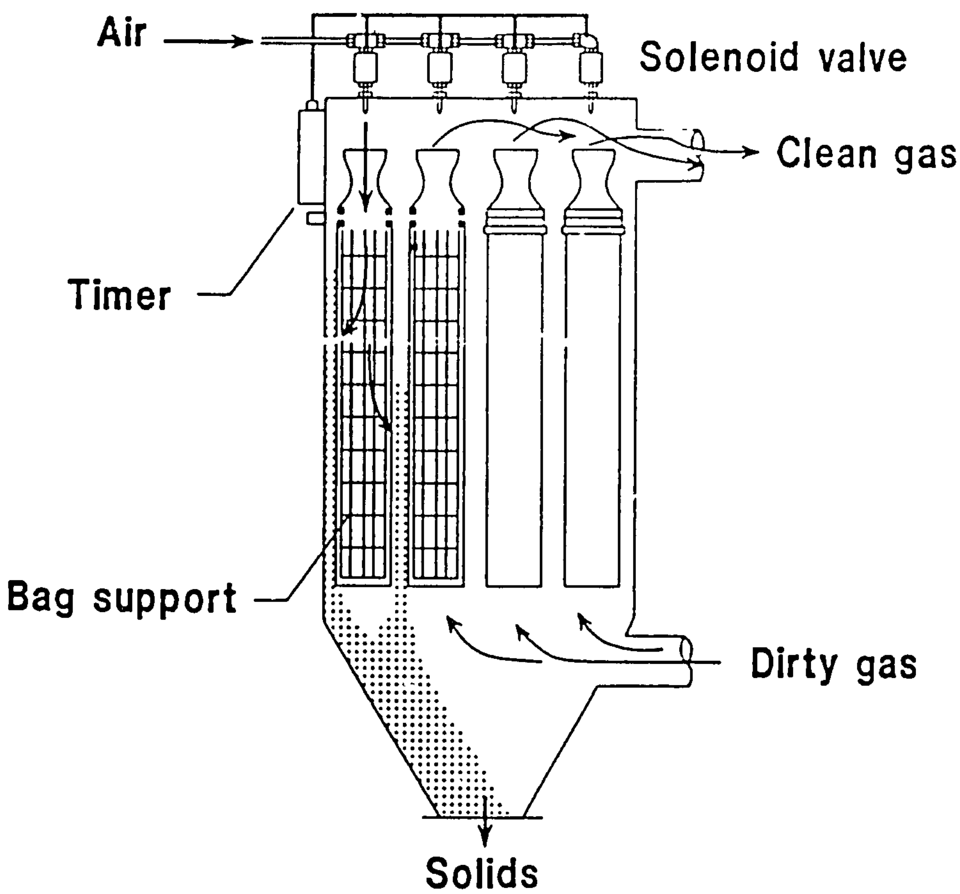
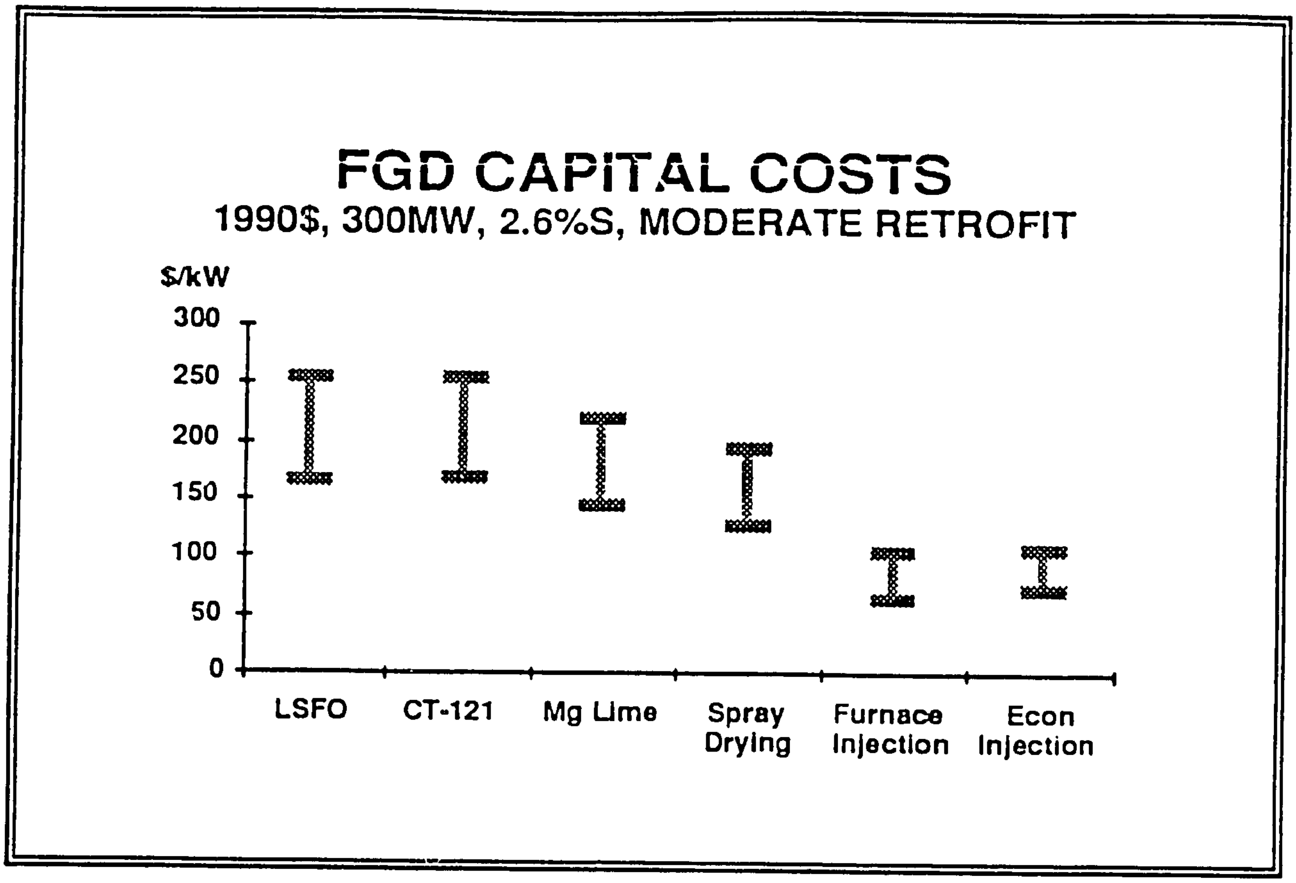
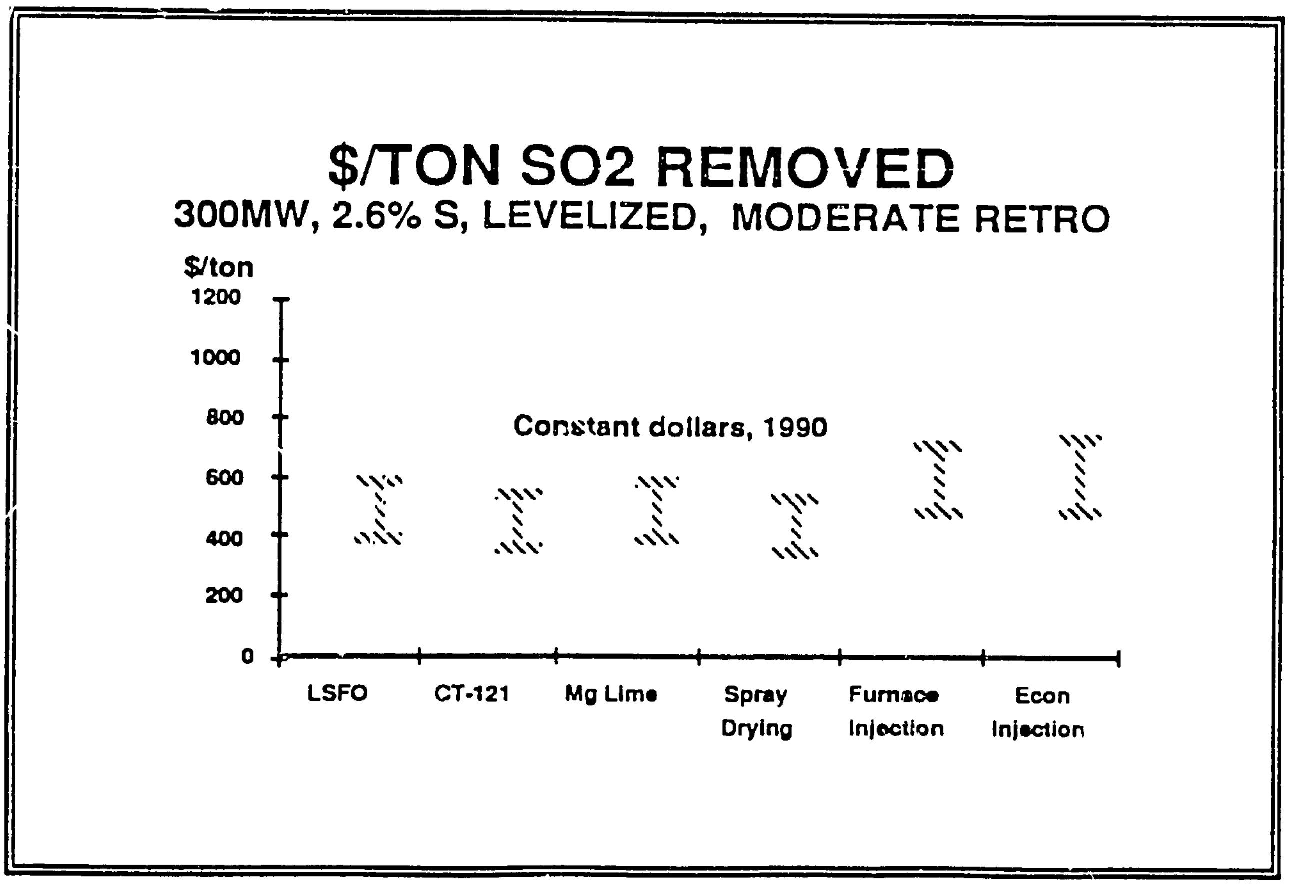


FIGURE 6


FGD CAPITAL COSTS
1990$, 300MW, 2.6%S, MODERATE RETROFIT
$/kW
300
250
200
150
100
50
0
LSFO
CT-121
Mg Lime
Spray Drying
Furnace Injection
Econ Injection


$/TON SO2 REMOVED
300MW, 2.6% S, LEVELIZED, MODERATE RETRO
$/ton
1200
1000
800
600
400
200
0
Constant dollars, 1990
LSFO
CT-121
Mg Lime
Spray Drying
Furnace Injection
Econ Injection

95