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THE INDUSTRIAL MARKET FOR SULFUR DIOXIDE EMISSION CONTROL SYSTEMS: FINAL REPORT

August 1982

Work Performed Under Contract No. AC21-80MC14729

Hagler, Bailly & Company
Washington, D. C.

TECHNICAL INFORMATION CENTER
UNITED STATES DEPARTMENT OF ENERGY

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by

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August 1982

Prepared for

UNITED STATES DEPARTMENT OF ENERGY
Morgantown Energy Technology Center
Morgantown, West Virginia

Technical Project Officer: Louis H. Berkshire
Under Contract No. DE-AC21-80MC14729

ACRONYMS

ACRS	Accelerated Cost Recovery System
AFB	atmospheric fluidized bed
BACT	best available control technology
DOE	U.S. Department of Energy
ECT	emission control technology
EIA	Energy Information Agency
EPA	Environmental Protection Agency
ERA	Economic Regulatory Administration
ERTA	Economic Recovery Tax Act
ESP	electrostatic precipitator
E/T	electric to thermal ratio
FGD	flue gas desulfurizer
FUA	Powerplant and Fuel Use Act
IRS	Internal Revenue Service
ITC	investment tax credit
LAER	lowest achievable emission rate
MEFS	Midterm Energy Forecasting System
METC	Morgantown Energy Technology Center
MFBI	major fuel-burning installation
NAAQS	national ambient air quality standards
NSPS	new source performance standards
O&M	operating and maintenance
ORNL	Oak Ride National Laboratory
PSD	prevention of significant deterioration
PURPA	Public Utility Regulatory Policies Act
RCRA	Resource Conservation and Recovery Act
SAI	Science Applications, Incorporated
SIP	state implementation plan

Contents

Exhibits

Introduction

A major goal of current government policy is to shift our nation's industries from the use of imported oil and gas to the use of domestic coal. The Powerplant and Industrial Fuel Use Act (FUA) mandates the use of coal in major fuel-burning installations (MFBIs). At the same time, the Clean Air Act limits the quantity of air pollutants that can be emitted from coal-burning MFBIs. In particular, the air quality act requires the Environmental Protection Agency (EPA) to develop new source performance standards (NSPS) specifying allowable levels of sulfur dioxide (SO_2) emissions.

The NSPS, which EPA expects to promulgate in 1983, will influence industrial decisions about which type of emission control technology (ECT) to install on coal combustors, and which type of coal to burn. The Morgantown Energy Technology Center (METC), an energy technology center of the U.S. Department of Energy (DOE), is charged with developing and supporting the development of emission control and coal-burning technologies. METC is therefore interested in determining the probable impact of FUA and the NSPS on the industrial use of various SO_2 emission control technologies.

To assist METC in this effort, Hagler, Bailly & Company and Science Applications, Incorporated (SAI), conducted a study to assess the market development among MFBIs of SO_2 emission control systems.

This study comprised two phases. The first phase involved preliminary data collection and development of a computer analysis program to identify the most economically attractive systems and the most promising market sectors. SAI reviewed numerous EPA, DOE, vendor, and user studies and reports to develop consistent cost and performance data for the competing systems.

Four major findings emerged from Phase 1. First, under the postulated energy price scenarios, there will be a significant amount of conversion to coal in the late 1980s to mid 1990s. Based on our estimates, by the year 2000, over 90 percent of the energy used by large MFBIs will be coal. Second, under the postulated Phase 1 system cost and performance scenarios, the atmospheric fluidized bed (AFB) combustor will dominate the market because of its significantly lower capital cost estimate and higher efficiency estimate than competing systems.* Gasifier/boiler combinations were found not to be cost-competitive in the applicable size ranges. Third, the major market for these systems will be in the Southwest region (Texas/Louisiana), which is now heavily dependent on natural gas for industrial boilers. Finally, costs for the various flue gas desulfurization (FGD) technologies were projected to be sufficiently close that the selection of one over another will depend on site-specific factors such as the availability of waste disposal facilities, the demonstrated reliability of the particular systems, and the vendor's reputation.

In the second phase of the study, we refined our estimates of market development through discussions with potential

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*The Phase 2 cost and performance estimates, however, showed that the AFB and FGD options were much closer in costs, and thus the AFB did not dominate this market.

industrial users of the systems, and through a more detailed estimation of system costs and performances conducted by Oak Ridge National Laboratory (ORNL). In addition, we updated our assessments of the impacts of federal regulations such as FUA, NSPS, and tax regulations.

Phase 2 was conducted in six steps. First, in a related study for METC, Foster-Wheeler Development Corporation, under contract to ORNL, developed a detailed comparison of the capital costs, operating and maintenance (O&M) costs, and performances of the various technologies we were evaluating. The following technologies were analyzed:

- Conventional coal boilers with four types of FGD systems (or "scrubbers"): sodium, lime/limestone, dual-alkali, and lime spray drying
- AFB boiler system
- Low-Btu gasifier plus low-Btu gas boiler system
- Conventional oil boiler system
- Conventional gas boiler system.

We also evaluated each of these systems with a steam turbine as a cogeneration system.

Our second step was to project and characterize steam demand from MFBIs between 1980 and 2000. Total MFBI fuel consumption was estimated using projections generated by the Energy Information Agency's (EIA) Midterm Energy Forecast; specifically, its medium world oil price scenario, which projects a world oil price in 1995 of $50 per barrel in (1979$). This forecast was disaggregated by fuel type for each of the 10 DOE regions. In addition, we estimated the distribution of fuel consumption by boiler size (for three size ranges: 100-250 mmBtu/hr, 251-500 mmBtu/hr, and greater than 500 mmBtu/hr), by plant electricity-to-steam-demand ratio (for three ratios: 0.1, 0.2, and 0.3), and by total plant steam demand. Industrial sector fuel prices were also provided on a regional basis for the 1985-1995 period using EIA's medium world oil price scenario.

Next, we examined the laws and regulations that affect coal-fired MFBIs, particularly under FUA and the Clean Air Act's industrial NSPS. FUA determines which market sectors are required to use coal. For our base case analysis, we assumed that no MFBIs will be allowed exemptions from FUA, and that all MFBIs will require SO_2 emission control equipment. These estimates thus represent the maximum possible market for SO_2 ECT, which would be reduced by exemptions from FUA or by relaxation of the NSPS. Although EPA has not yet promulgated the NSPS for industrial boilers, the agency provided us with a set of preliminary standards which we used to calculate the emission control system costs and performances. Other laws and regulations that we considered in comparing the projected economic performance of various ECT systems affected the energy investment tax credits and the depreciation schedules allowed for investments in coal-fired and cogeneration systems.

Fourth, we held discussions with key industrial decision-makers to determine those economic and other factors that affect the use of coal as a boiler fuel and the choice of an ECT. In addition, we discussed the role of federal research and development (R&D) efforts in developing SO2 emission control technologies.

Next, we evaluated the comparative economic performance and market penetration of all the competing ECT systems for each market segment, using the economic techniques and criteria commonly used by industry. Specific factors we analyzed included: type of application (i.e., whether the system is new, a replacement of worn-out equipment, or a retrofit of equipment still having a useful life); technology (e.g., AFB boiler, coal-fired boiler with lime/limestone FGD equipment), and configuration (i.e., steam production only or combined electric power and steam production). This analysis formed our "baseline scenario" of expected market development.

The results of this baseline scenario depend on assumptions made regarding federal regulations such as FUA and NSPS, and on assumptions made regarding the behavior of industrial decision-makers. Accordingly, we used three "sensitivity scenarios" to examine the sensitivity of our findings to variations in the behavior of the industrial decision-makers and to changes in federal fuel choice and environmental regulations. Specifically, we assumed in one analysis that no federal industrial NSPS for SO_x were promulgated, and that the state implementation plan (SIP) standards therefore governed the degree of control required. In another analysis, we also relaxed the FUA requirement for coal use in new MFBIs, and allowed decision-makers to select freely among coal, oil, and natural gas systems. Finally, we incorporated subjective or attitudinal factors to determine their approximate impacts on the market penetrations of various systems.

Several major findings emerged from our discussions and analyses.

First, under the postulated EIA medium world oil price scenario, in which oil prices are projected to rise at a real rate of 2.2 percent per year, coal will represent from 78 to 91 percent of MFBI fuel consumption by the year 2000, up from the present 16 percent. This level of increase will occur even in the absence of FUA, because the cost of coal is substantially lower than the cost of oil or gas. Much of this market will develop in the relatively near to intermediate term (before 1990). Annual installations will be much lower (by about 40 percent) after that period, reflecting a lower overall steam demand growth rate and the fact that much of the discretionary conversion of gas and oil boilers to coal will have been completed. About 22 percent of the sales will be for discretionary conversion of oil and gas boilers still having some useful life; the rest will be for nondiscretionary expansion or replacement of worn-out boilers.

Under the postulated cost and performance estimates for the competing coal-burning technologies, we expect that AFB combustors and lime spray dryer FGD systems will dominate the market, with 42 percent of the market in our base case scenario. If the attitudes of the industrial decision-makers are factored into the analyses, particularly their aversion to FGD systems with wet wastes, the AFB and lime spray dryer technologies will capture as much as 73 percent of the coal-burning market.

In the chapters that follow, we detail the assumptions and methodology we used to derive these results. In Chapter 1, we describe the pertinent regulatory, technical, and market factors we considered in defining the industrial MFBI market sectors. Chapter 2 summarizes our discussions with current and potential industrial users of these systems regarding the economic and other factors affecting their choice of boiler fuels and SO_x emission control systems, as well as their suggestions for future government actions to encourage the clean use of coal in industrial boilers. Chapter 3 presents our projections of baseline market development from 1980 through 2000. In Chapter 4, we discuss how changes in key attitudinal parameters and regulatory policies would affect our baseline estimates of market development.

1

DEFINING THE MARKET

The first step in Phase 2 of our study was to define the important factors that will affect the competitiveness of the systems in each market segment. We focused on:

- Reviewing the regulatory requirements affecting the market

- Estimating the costs and performances of the emission control technologies

- Estimating regional considerations such as energy prices, coal availability, utility buyback and standby rates for cogeneration transactions, and steam demand.

REGULATORY REQUIREMENTS

The market for emission control equipment has been created largely by laws mandating the use of coal in certain kinds of installations and limiting allowable emissions of pollutants from coal-fired systems. The major federal acts that define these requirements are FUA and the Clean Air Act. The market development of ECT systems will also be affected by the Economic Recovery Tax Act (ERTA), the Energy Tax Act, the Crude Oil Windfall Profit Tax Act, the Public Utility Regulatory Policies Act (PURPA), and the Resource Conservation and Recovery Act (RCRA). In the following sections, we review briefly the aspects of each act that affect the market for industrial emission controls.

Powerplant and Industrial Fuel Use Act

FUA prohibits the use of oil or gas in new MFBIs. (An MFBI is defined as a boiler having a design heat input rate of 100 mmBtu/hr or greater.) Initially, FUA also prohibited oil- and gas-fired additions of 50 mmBtu/hr or greater if the aggregate plant capacity after the addition is 250 mmBtu/hr or greater. However this requirement has been dropped by the Reagan administration. FUA also allows DOE to mandate the use of coal or coal/oil mixtures in existing facilities.

Exemptions from the FUA regulations are allowed under five conditions:

- If the cost of a coal-fired plant would "substantially exceed" that of a comparable plant fired by imported oil (assuming a $1/bbl oil price premium above the imported oil price and a 7.7 percent discount rate)*

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*Industrial discount rates are typically 20 percent or higher. The mandated use of a 7.7 percent discount rate and the requirement of a premium on the oil price thus make capital-intensive coal technologies appear more cost-effective than they would seem to industrial firms using their normal criteria and procedures.

- If the plant cannot meet local environmental restrictions using coal
- If the plant uses oil or gas cogeneration, synfuels, coal/oil or coal/gas mixtures, or other "innovative" technologies
- If the plant has limited usage
- If the plant is scheduled for retirement soon.

In the base case scenario for this study, we did not allow for any exemptions from FUA for new MFBI capacity; our estimate thus represents the maximum market size for SO_x ECTs. (In one of the sensitivity scenarios, we eliminate this requirement and estimate the impact on coal use of allowing unrestricted boiler fuel choices; see Chapter 4).

Whether investments are viewed as discretionary or nondiscretionary depends on whether they are required under FUA. The "new" market represents new capacity needed to meet increased steam demand at new or existing plants, including expansion at existing sites. The "replacement" market represents capacity that has reached the end of its useful life and must be retired and replaced. New and replacement investments are nondiscretionary because, under FUA, they must be coal-fired. The "retrofit" market represents capacity that still has a useful life but that can be converted to coal use for economic reasons; accordingly, conversion is considered a discretionary investment.

Although the Economic Regulatory Administration (ERA) has established regulations governing fuel use by industry, the provisions that permit exemptions from these fuel-use restrictions have been modified several times since 1979. In addition, enforcement of the regulations has changed dramatically over the same period. In fact, with only a few exceptions, industrial facilities requesting them have been able to obtain exemptions. Because of the current administration's emphasis on deregulation and the apparent abundant supply of natural gas, industrial decision-makers expect either that the elements of FUA prohibiting natural gas use in certain facilities will be rescinded or that enforcement of the existing law and its regulations will not be strict.

Clean Air Act

The Clean Air Act (together with major amendments adopted in 1970 and 1977) will have major impacts on the costs and use of coal systems in industry, particularly through the associated regulation of SO_x, NO_x and particulate emissions. The major features of the act and regulations affecting industrial coal use require EPA to:

- Develop national NSPS for industrial boilers which set allowable limits on NO_x, SO_x, and particulates.
- Develop national ambient air quality standards (NAAQS).
- Specify prevention of significant deterioration (PSD) areas for regions having air quality

significantly better than the national standards. New sources in these areas are allowed to contribute only a fraction of the difference between the current level of pollutants and the national standard. They are also required to use the "best available control technology" (BACT) to control emissions.

- Specify nonattainment areas for regions in which national standards are not currently being met. New sources must use control technologies that meet the "lowest achievable emission rate" (LAER), and provide offsets in which new emissions are more than compensated for by reductions in emissions from other sources, thus resulting in a net improvement in air quality.
- Require a "percentage reduction" in SO_x emissions, even if a low-sulfur coal can be burned which meets allowable emission levels without scrubbing or using other SO_x reduction processes.
- Have states develop "state implementation plans" (SIPs) presenting in detail their specific strategies for complying with the NAAQS.

NSPS have not yet been issued for industrial boilers under 250 mmBtu/hr fuel input. (Boilers above 250 mmBtu/hr fuel input are now covered by the utility standard of 1.2 lb/mmBtu for SO_2, 0.05 lb/mmBtu for particulates, and 0.6 lb/mmBtu for stoker coal and 0.7 lb/mmBtu for pulverized coal for NO_x.) In addition, a percentage reduction requirement will be promulgated when the final rules are issued.

Most observers believe, however, that it is unlikely that NSPS will be issued before mid-1983, if ever. If no industrial NSPS are promulgated, then the SIPs will govern allowable emission levels within each state.

Congress is currently considering several bills to amend major portions of the Clean Air Act, particularly those relating to the percentage reduction requirement and the PSD requirements. The outcome of these bills is uncertain despite the support of the Reagan administration; the environmental lobbies and high-sulfur coal-producing states are expected to provide significant opposition. One likely compromise is the retention of the percentage reduction requirement for large (above 250 mmBtu/hr) industrial systems, but elimination of the requirement for smaller systems.

We also reviewed the current state regulations for SO_x (see Appendix A). Exhibit 1.a summarizes the regional SO_x control requirements developed for the sensitivity scenarios. We developed these requirements by using the limitations imposed by the states in each region, weighted by the relative amount of industrial activity. In addition, we assumed that states having regions currently in noncompliance with primary NAAQS will require scrubbing on new coal-burning facilities (see Exhibit 1.b). Because the overall relative system costs were not very sensitive to the percent removal required, we assumed that high-sulfur bituminous coal (3.5 percent sulfur) requiring scrubbing would have a 90 percent removal rate, and low-sulfur subbituminous coal (0.7 percent sulfur) requiring scrubbing would have a 70 percent removal rate.

Exhibit 1.a

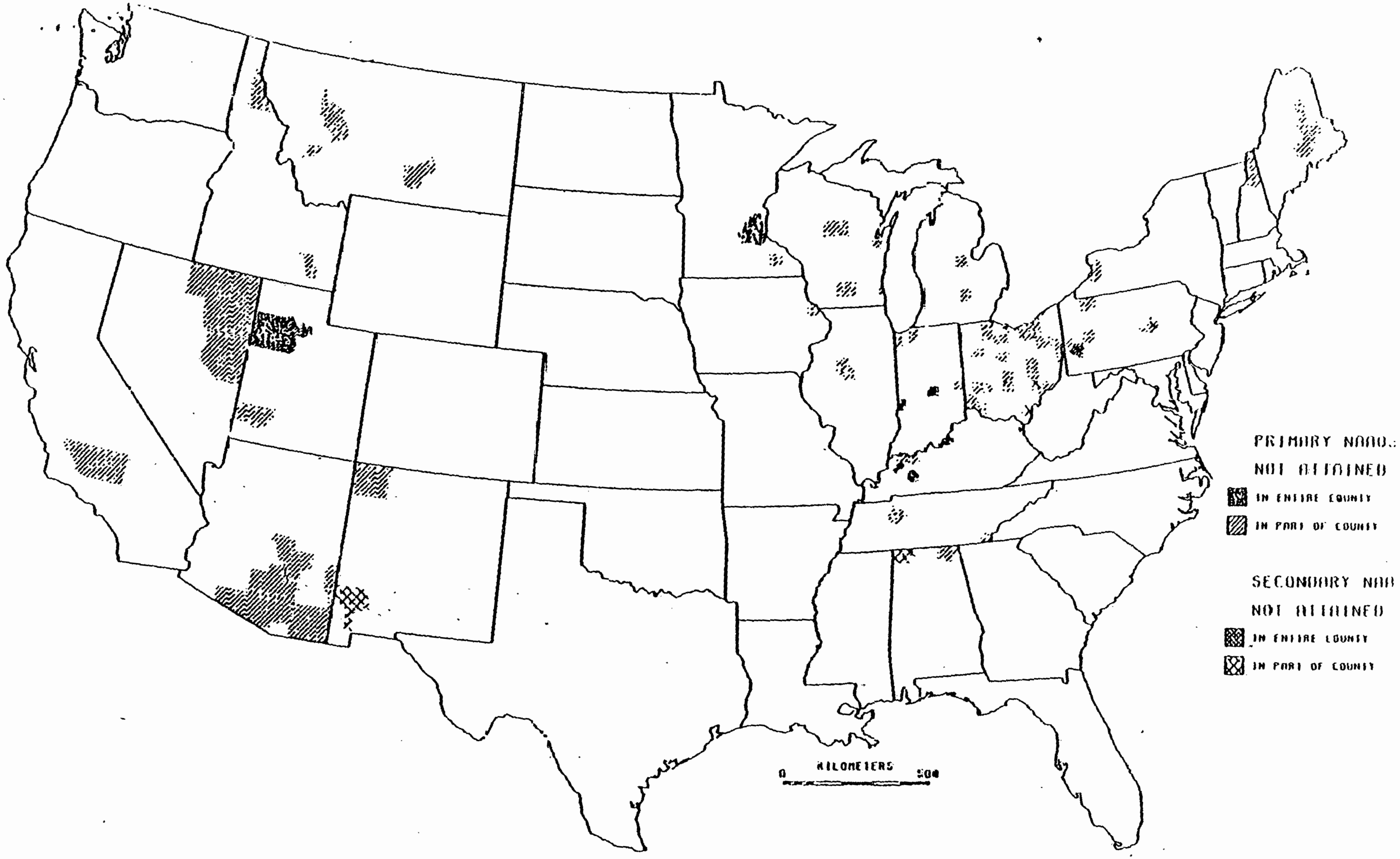
SIP Requirements

DOE Region	Weighted SO_2 MFBI Emission Level (lb SO_2/mmBtu)	Economically Available Coal Types Sulfur Content	 Rank	Control Required?
I New England	1.1	High	Bituminous	Yes
II New York/New Jersey	2.3	High	Bituminous	Yes
		Low	Bituminous	No
III Mid-Atlantic	1.2*	High	Bituminous	Yes
IV South Atlantic	2.0	Medium	Bituminous	Yes
		Low	Bituminous	No
V Midwest	2.1	High	Bituminous	Yes
VI Southwest	2.8	Low	Subbituminous	No
		Medium	Bituminous	Yes
VII Central	2.3	High	Medium Bituminous	Yes
		Low	Subbituminous	No
VIII North Central	1.6	Low	Subbituminous	No
IX West	0.8	Low	Subbituminous	Yes
X Northwest	2.0	Medium	Subbituminous	No

*Not including Pennsylvania, where scrubbing is required in most areas.

Exhibit 1.b

SO_2 Nonattainment Counties – 1981



SOURCE: Environmental Protection Agency, Office of Air Quality Planning and Standards; July 1981.

Economic Recovery Tax Act

The Economic Recovery Tax Act of 1981 (ERTA) includes several business incentive provisions that can enhance the attractiveness of coal-burning systems. In particular, the accelerated cost recovery system (ACRS) replaces the previous complex and varied rules for depreciation, which include asset depreciation ranges and several methods of defining depreciable property. The new law provides four classes of property: 3-year, 5-year, 10-year, and 15-year public utility "recovery" property. Schedules of depreciation are established for property placed in service (a) between December 31, 1980, and January 1, 1985, (b) in 1985, and (c) after December 31, 1985, when the full effect of ACRS depreciation occurs (see Exhibit 1.c for the corresponding depreciation schedules provided by the act).

The Internal Revenue Service (IRS) has not yet established regulations on classification according to these schedules. It is expected that IRS will place all steam-generating equipment (including fuel-handling, waste treatment, and other ancillary equipment) in the 5-year class of property. However, it is uncertain which class electrical generating equipment associated with a cogeneration facility will be placed in; for this study, we assumed it will be 5-year recoverable property.

Energy Tax Act/Windfall Profit Tax Act

The Energy Tax Act of 1978 eliminates the standard 10 percent investment tax credit (ITC) for oil- and gas-fired boilers. At the same time, it provides an additional 10-

Exhibit 1.c

Depreciation Schedule Provided by ERTA

Period Property is Placed in Service	Depreciation Percentage				
	Year 1	Year 2	Year 3	Year 4	Year 5
1981-1984	15	22	21	21	21
1985	18	33	25	16	8
1986 and beyond	20	32	24	16	8

percent ITC to accompany the standard 10-percent ITC for coal-fired and alternative-fueled steam generators. The Crude Oil Windfall Profit Tax Act of 1980 makes available an additional 10-percent ITC (for a total of 20 percent) for cogeneration systems that do not use natural gas or oil as primary fuels (i.e., gas or oil account for less than 20 percent of total fuel use).

The composite ITC incentives provided by both acts (see Exhibit 1.d) are due to expire at the end of 1982, except for the 10-percent additional tax credit for steam generators fueled by biomass, which expires at the end of 1985. However, there are various legislative proposals before Congress to extend the termination date for the additional ITCs. For this study, we have assumed that they will be continued.

Public Utility Regulatory Policies Act

The part of PURPA that is most relevant to our study is Section 201, which requires utilities to interface with cogeneration facilities, to set fair rates for backup and supplemental power for those facilities, and to purchase excess cogenerated electricity at a rate based on the utility's "avoided cost."

The assumptions on these cogeneration standby and buyback rates are summarized later in this chapter.

Exhibit 1.d

INVESTMENT TAX CREDITS UNDER CURRENT LAW*

System/Fuel Type	Oil and Natural Gas	Coal	Waste and Process Residuals
Conventional			
Process steam boiler	0%	10% standard 10% additional through 12/31/82**	10% standard 10% additional through 12/31/85**
Cogeneration			
Boiler/steam turbine	0% for boiler 10% standard for turbine	10% standard 10% additional through 12/31/82**	10% standard 10% additional through 12/31/85** (boilers only)

* Includes Energy Tax Act and Windfall Profit Tax Act

** Windfall Profit Tax Act specifically extends the 10-percent additional tax credit to December 31, 1990 for "long construction projects."

SOURCE: Hagler, Bailly & Company

Resource Conservation and Recovery Act

Certain FGD wastes may be defined as hazardous under RCRA, and therefore will require expensive disposal procedures. However, because none of the systems we examined produces wastes officially considered hazardous, we allowed for no additional expenses for hazardous waste disposal.

COSTS AND PERFORMANCES

The industrial decision-maker has three major options for meeting air emission standards: flue gas desulfurizers (FGDs), which function after the coal has been burned*; atmospheric fluidized beds (AFBs), which operate while the coal is being burned; and gasifiers, which remove sulfur from the coal before it is burned.

In the following sections, we describe each technology option briefly and then compare system costs; more detailed

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*In addition to FGDs, AFBs, and gasifiers, one other possibility for reducing SO_x emissions is the use of cleaned coal. This was not considered a major factor in this study. Coal cleaning uses either chemical or physical processes to remove sulfur and ash. Chemical processes do not now appear to be economically viable with conventional scrubber systems. Significant levels of sulfur removal by physical coal cleaning are possible on only a few types of high-sulfur coal in a few regions, and only about 40 percent or less of the sulfur in those coals is typically removed. At best, cleaned coal will meet state or federal standards only on smaller boilers not under the FUA provisions and thus not within the scope of this study. It may be possible to combine physically cleaned coal with a smaller FGD; our resources did not permit a detailed evaluation of these systems.

descriptions of systems, costs, and performance are presented in the appendices.

Technology Options

Flue gas desulfurizers remove sulfur dioxides from the combustion flue gas after it leaves the boiler, by passing the flue gas through a "scrubber." In the scrubber, the SO_2 in the flue gas reacts with solutions of calcium, sodium, or other salts to form a waste product that can be disposed of as sludge or a dry product. The four FGD systems we examined in this study are sodium throwaway, lime/limestone, dual-alkali, and lime spray drying.

In the sodium throwaway system, a soluble sodium alkali solution absorbs the SO_2. The effluent solution is then partially recycled, with a slipstream going to waste treatment and disposal. It is also possible to use alkaline process waste streams from some industrial processes in place of the sodium solution, or to use the FGD waste stream in certain other industrial processes (such as pulping). Over 80 percent of existing industrial-size scrubbers are of this type, primarily for use in oil field systems burning high sulfur crude oil in California.*

The lime/limestone system uses the calcium salts in lime (CaO) or limestone ($CaCO_3$) to react with the SO_2 to form

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*Dickerman, J. C., "Applicability of FGD Systems to Industrial Boilers," Proceedings: Symposium on Flue Gas Desulfurization, Houston, Texas; October 1980; EPA-600 19-81-019a; April 1981.

a calcium sulfate sludge that must be disposed of, typically by ponding or landfill. This system has been extensively developed for utility applications.

Sodium/calcium dual-alkali systems use soluble sodium for SO_2 absorption and a calcium-based alkali to regenerate the active sodium solution. Thus, they reduce the problems of scaling that lime/limestone systems are claimed to have when scaled down to industrial sizes. The $CaSO_4$ sludge must then be disposed of, typically by ponding or landfill. Other dual-alkali systems are possible (e.g., ammonia or potassium instead of sodium), but the sodium/calcium system is the most highly developed. These systems are assumed to be economically viable only on high-sulfur systems, because combustion of low-sulfur coals results in a high O_2/SO_2 ratio. This promotes oxidation of the sorbent to sodium sulfate, which is not readily regenerable and thus results in excessive operating costs.

The lime spray dryer system uses a slurry of lime to remove the SO_2 from the boiler flue gas, producing a dry particulate in the flue gas. This dry product is removed with fly ash in a fabric filter, thus eliminating the problems associated with handling large amounts of fluid sludges. To date, these systems have been used only with low-sulfur (0.6 percent) and medium-sulfur (2.0 percent) coals. However, it is expected that they can readily be used on high-sulfur (3.5 percent) coals without major design or operating problems.

All of the FGD systems have a particulate removal system: electrostatic precipitators are used in the high-sulfur systems (with the exception of the lime spray dryer), and fabric filters (or "baghouses") in the low-sulfur and high-sulfur lime sprayer systems.

AFB combustors are a newer technology than FGDs. The coal is burned in a bed of noncombustible material by a flow of combustion air which keeps the combustion region in a "fluid" state. If the bed is composed of a reactive material such as limestone, the SO_2 generated will be captured at a potential efficiency of 90 percent or better. AFBs can be smaller and hence less costly than conventional coal-fired boilers, can operate at lower temperatures (thus reducing NO_2 emissions), and may have multi-fuel firing capability. However, they have not been used much in industrial applications, so their performance, cost, and reliability have yet to be thoroughly demonstrated. The AFB systems also have baghouse particulate removal systems for both high-sulfur and low-sulfur coals.

Coal gasification is another technique for SO_2 removal. Air (or oxygen) and steam are injected into a bed of hot coal, producing a gas which, after cleaning, can be used in furnaces designed to burn conventional natural gas with only minor modifications. If air is used in the gasification process, the gas produced is a low-Btu product (100-200 Btu per standard cubic foot, or scf). If oxygen is used, a medium-Btu gas is produced (200-500 Btu/scf). Conventional natural gas is a high-Btu product (1,000 Btu/scf). Because the flame temperature of low-Btu coal gases is considerably below that of natural gas, use of these gases can reduce the effective capacity of the boiler, resulting in a higher boiler cost per unit of output.

Two types of low-Btu gasifiers were selected:

- Stoic gasifier for western subbituminous coal
- Wellman-Galusha agitated gasifier for eastern bituminous coal.

Both systems are currently being sold commercially.

We evaluated only systems sized to provide the total input of a single boiler. Much larger systems may be economically more attractive (in industrial park applications, for example), since gasifiers typically achieve large economies of scale. However, these applications were beyond the scope of this study.

Cogeneration systems, which produce both process steam and electricity, were evaluated as options to supplement these three general ECT technologies. We focused particularly on the most commonly used system: a back-pressure steam turbine used in a topping cycle, in which steam from the boiler goes to a turbine/generator to produce electricity, and hot exhaust from the turbine goes to the process. We analyzed use of this cogeneration system with the FGD, AFB, and gasifier emission control systems.

Relative System Costs

ORNL and Foster-Wheeler Development Corporation estimated costs and performances for a generic set of systems, including:

- Stoker and pulverized coal boilers
- FGD systems (sodium throwaway, lime/limestone, dual-alkali and lime spray dryer)
- AFB/boiler
- Low-Btu gasifier/boiler
- Residual oil boiler
- Medium-Btu gas boiler.

Detailed system design and cost estimates were developed for a 250 mmBtu/hr (absorbed by boiler) system, and scaling equations were developed for the major subsystem components to allow estimates to be made for large and smaller systems.

Estimates were developed for the two major coal types available to industry: a high-sulfur bituminous Eastern coal (3.5 percent sulfur) and a low-sulfur subbituminous western coal (0.5 percent sulfur). These coal types determined the system design requirements. For each range of boiler size, we assumed that all systems would provide the same amount of process steam. Variations in size and cost arose from differences in thermal efficiency, and because cogeneration systems need to be oversized to provide both electrical energy and the required process steam. ORNL developed equations relating system size to system cost, and also estimated the level of system performance. These data are presented in greater detail in Appendix B. Exhibits 1.e and 1.f show system costs for conventional and cogeneration systems for both coal types. Exhibit 1.g compares annualized costs for the various coal-burning system options, using bituminous coal, to produce 250 mmBtu/hr of net steam in the South Atlantic in 1990. To convert the initial capital cost into an annual charge,

Exhibit 1.e

Technology Cost Comparison
(South Atlantic Region, Bituminous coal
1990, 250 mmBtu/hr)

System	Overall Efficiency[1]	Capital Cost $(\$\ 10^6)$[2]	Annual Costs $(\$\ 10^6)$				Relative Cost
			Capital[3]	O & M	Fuel[4]	Total	
Pulverized coal boiler	0.76	31.82	8.38	1.45	7.42	17.65	0.88
PC boiler, sodium	0.73	43.34	11.42	3.66	7.73	22.81	1.14
PC boiler, dual alkali	0.73	37.88	9.98	3.26	7.73	20.97	1.04
PC boiler, lime/limestone	0.73	36.39	9.59	3.33	7.73	20.65	1.03
PC boiler, spray dryer	0.76	36.75	9.68	2.98	7.42	20.08	1.00
AFB boiler	0.73	35.23	9.28	2.64	8.16	20.08	1.00
Low-Btu gasifier/boiler	0.52	80.99	21.34	5.79	10.85	37.98	1.89
Oil boiler	0.73	13.89	5.03	1.10	17.59	23.72	1.18
AFB boiler w/steam turbine	0.70	42.91	11.30	3.08	5.82[5]	20.02	0.99

[1] (Net process + electric energy)/(fuel input energy).

[2] January 1981 dollars.

[3] Capital recovery factors: coal = 0.2635; (which includes effect of 20 percent investment tax credit); oil = 0.3620 (no investment tax credit).

[4] Coal = $\$3.68$/mmBtu plus $\$0.21$/mmBtu for AFB systems for sizing; residual oil = $\$8.38$/mmBtu; electricity = $\$17.04$/mmBtu.

[5] Purchased coal cost = $\$8.69 \times 10^6$; value of cogenerated electricity = $\$2.87 \times 10^6$.

Exhibit 1.f

Technology Cost Comparison
(Southwest Region, Subbituminous coal
1990, 250 mmBtu/hr)

		Capital	Annual Costs ($ 10^6)				
System	Overall Efficiency[1]	Cost ($ 10^6)[2]	Capital[3]	O & M	Fuel[4]	Total	Relative Cost
Pulverized coal boiler	0.72	39.29	10.35	2.04	7.28	19.67	1.03
PC boiler, sodium	0.69	43.15	11.37	3.01	7.60	21.98	1.15
PC boiler, lime/limestone	0.69	43.65	11.50	3.07	7.60	22.17	1.16
PC boiler, spray dryer	0.72	42.18	11.11	2.95	7.28	21.34	1.12
AFB boiler	0.71	34.79	9.17	1.92	7.97	19.06	1.00
Low-Btu gasifier/boiler	0.54	73.90	19.47	6.64	9.71	35.82	1.88
Oil boiler	0.73	13.89	5.03	1.10	17.81	23.94	1.26
AFB boiler w/steam turbine	0.67	42.44	11.18	2.25	4.91[5]	18.34	0.96

[1] (Net process + electric energy)/(fuel input energy).

[2] January 1981 dollars.

[3] Capital recovery factors: coal = 0.2635 (which includes the effect of 20 percent investment tax credit); oil = 0.3620 (no investment tax credit).

[4] Coal = $3.42/mmBtu plus $0.29/mmBtu for AFB systems for sizing; residual oil = $8.48/mmBtu; electricity = $22.44/mmBtu.

[5] Purchased coal cost = $8.69 x 10^6; value of cogenerated electricity = $3.78 x 10^6.

we multiplied it by a capital recovery factor,* which is a function of the required return-on-investment and tax factors that affect cash flows. These exhibits illustrate several points.

First, the AFB and lime spray dryer technologies appear slightly less expensive on an annualized cost basis than the more established FGD technologies. The AFB may even be less expensive than an uncontrolled pulverized coal boiler for subbituminous coal systems.

Second, judging from the same estimates, gasifier systems do not appear cost-effective for process steam applications in single-boiler sizes, due to their high capital and operating costs and the relatively low overall efficiency (estimated at less than 50 percent) of the gasifier/boiler combination.

Finally, cost estimates for the FGD and AFB systems are relatively close; on the basis of economics alone, it appears that no single system is overwhelmingly more or less expensive than other FGD systems. Other, site-specific

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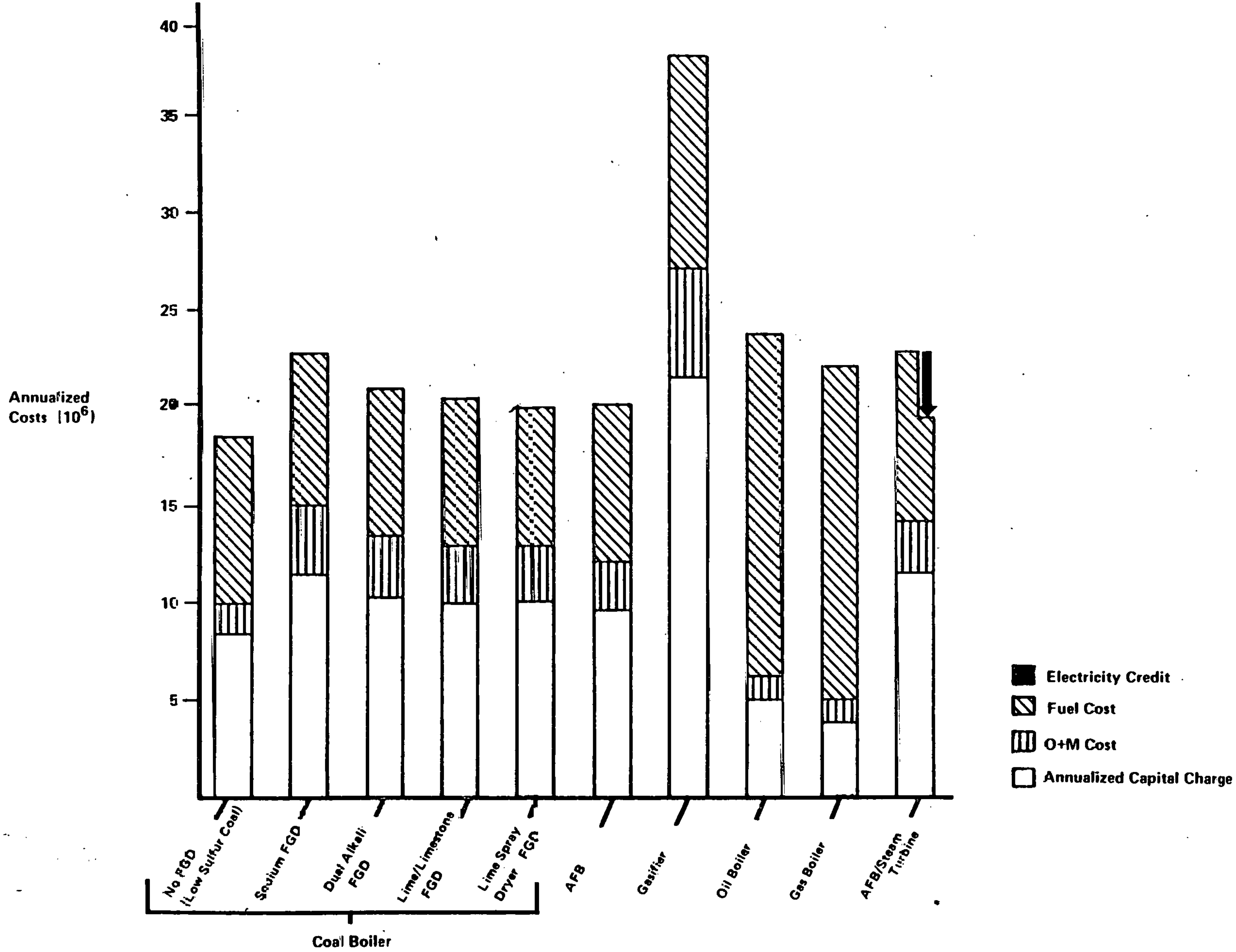
*An account of how this factor was derived can be found in The Cost of Energy from Utility-Owned Solar Electric Systems, by the Jet Propulsion Laboratory (JPL 5040-29, ERDA/JPL-1012-76/3), June 1976. We assumed a return-on-investment (after tax) of 20 percent of capital costs, a system life of 20 years, an ITC of 20 percent for coal systems and 0 percent for gas and oil-fired systems, a tax rate of 50 percent, and a post-1986 ACRS depreciation schedule. On the basis of these assumptions, we calculated a capital charge rate of 0.264 for coal-fired systems and 0.362 for gas- and oil-fired systems. The capital charge rate factor is lower for coal systems because they have a 20 percent investment tax credit, which gas- and oil-fired systems do not.

Exhibit 1.g

Comparative Economic Performance of Coal Burning System Options, South Atlantic Region, 1990



factors will probably determine the actual choice among FGD systems.

REGIONAL CONSIDERATIONS

In defining the market, we also estimated regional energy prices, coal supplies, cogeneration costs, and MFBI steam demand.

Energy Prices

Regional energy prices were developed using the April 1981 computer runs of EIA's Midterm Energy Forecasting System (MEFS).* The MEFS programs are used to forecast national and regional energy supply, demand, and prices for the major energy-consuming sectors. In our analyses, we used the medium world oil price scenario, which projected that world oil prices will reach $50/bbl (in 1979 $) by 1995.

The MEFS model provides industrial sector energy prices for 1985, 1990, and 1995. EIA also provided actual energy prices in each of the 10 DOE regions for the industrial sector for 1979.

DOE's Natural Gas Policy Office felt that the EIA natural gas projections were based on overly optimistic estimates

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*A detailed description of the model's structure and supply and demand assumptions can be found in Annual Report to Congress 1978, U.S. Department of Energy, DOE/EIA-0173-3 and Applied Analysis Model Summaries, U.S. DOE, DOE/EIA-018316.

of "tight sands" gas supplies and costs in the late 1980s and early 1990s. Furthermore, the Phase 1 incremental pricing provisions of the Natural Gas Policy Act specify that the price of industrial natural gas should be equal to or only slightly below (in energy equivalence) the price of residual oil. Accordingly, we set the natural gas price at the higher of the EIA gas price estimate, or 90 percent of the EIA residual oil price estimate. This reflected the current thinking of a number of price forecasting modelers, who generally project natural gas prices to be from 85 percent to 105 percent of the residual oil price.

Exhibit 1.h presents the national average EIA industrial energy price projections to 1995. Electricity prices remain relatively stable after 1990, due primarily to a massive conversion to coal and nuclear power, which together will represent about 95 percent of power generated in 1995. In addition, the EIA projections assume that coal prices remain relatively stable, with less than one percent growth per year in real prices. Additional detail, with regional price projections, is provided in Appendix C.

To calculate energy prices for 1995-2020, we assumed the following:

- Residual oil and natural gas prices will grow at the same rate (in real terms) as world oil prices: 3 percent a year from

Exhibit 1.h

National Average Industrial Energy Prices
(1979 $/mmBtu)

	1979	1985	1990	1995	2020
Medium Price Scenario					
Coal	1.33	2.25	2.55	2.72	3.23
Distillate oil	4.65	7.43	8.28	9.88	15.42
Residual oil	3.06	6.45	7.28	8.62	13.45
Natural gas	1.76	5.29	5.85	6.30	9.83
Electricity	8.02	12.58	12.67	12.68	15.48
World oil price ($/bbl)	32.00	37.00	41.00	50.00	78.00

1995-2000, 2 percent a year from 2000-2010, and 1 percent a year from 2010-2020.*

- Coal prices will increase 0.7 percent a year after 1995. (This is a simple extrapolation of the 1985-1995 trend.)
- Electricity prices will increase 0.8 percent a year after 1995, assuming that the generating mix MEFS determined for 1995 (68 percent coal, 27 percent nuclear power, 5 percent oil and natural gas) is constant beyond 1995, and that the growth rate in electricity prices is proportional to the weighted average growth of prices we assumed for coal and oil/natural gas.

Coal Supplies

Recognizing that system costs are a function of the coal's rank (i.e., bituminous or subbituminous) and sulfur content, we estimated the types and amounts of coal available in each region for industrial use by MFBIs. These estimates are based on a complex coal supply model operated by EIA

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*These estimates were developed based on a review of world oil price forecasts made by a number of government and private sector forecasters (see Fossil Energy Evaluation: Republic of Korea Draft Report, Argonne National Laboratories, May 1980). These forecasts assume development of significant amounts of alternative fuels (including synfuels such as shale oil), expanded use of coal and coal derivatives, and significant conservation efforts by the major industrial countries.

and integrated into the MEFS forecasts which depends not only on regional coal minemouth and transportation costs, but also on assumptions about the development of new mines, expansion of the rail and barge network, and transportation bottlenecks that will effectively limit the types of coal available in each region. The EIA data indicate that seven regions will use primarily medium- to high-sulfur butuminous coals* (New England, New York/New Jersey, Mid-Atlantic, South Atlantic, Midwest, Central, and Northwest) and that the West, Southwest, and North Central regions will use primarily low-sulfur subbituminous coals.

Cogeneration Costs

The buyback rates and standby charges that electric utilities level on cogenerators will significantly affect the economic attractiveness of cogeneration systems.

Buyback rates must be based on the utility's "avoided costs," which are a function of the utility's generation mix and the reliability of the cogenerated power. We developed estimates of these rates based on the EIA energy price projections, reviews of studies in this area, our own analyses developed for utility rate hearings, and published buyback rates. Generally, these rates range from 70 to 125 percent of the retail rate, although in a few cases they are nearly triple that rate. The higher rates occur primarily in the near term, when many utilities are

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*High sulfur -- more than 1.68 lb sulfur per mmBtu; medium sulfur -- 0.67 to 1.68 lb sulfur per mmBtu; low sulfur -- less than 0.67 lb sulfur per mmBtu.

still burning significant amounts of oil and natural gas. As these utilities convert to more coal and nuclear in the future, the buyback rates should come down substantially from today's levels. In addition, we used a standby rate of $65/kW/yr, and assumed that 50 percent of the installed generating capacity has this standby backup.

We also assumed that the industrial cogenerator will negotiate with the utility in the most economically advantageous manner; that is, if the buyback rate is greater than the retail rate, the cogenerator will sell all of its cogenerated power to the utility at the buyback rate while simultaneously buying the power needed at the normal retail rate. If the buyback rate is less than the retail rate, the cogenerator will use its own cogenerated power first to displace purchased power, and sell only the surplus power to the utility.

MFBI Steam Demand

Estimates of overall MFBI steam demand for 1985, 1990, and 1995 were taken from EIA's MEFS forecast. MEFS projects total annual consumption for each of the 10 DOE regions by fuel type, and its projections are consistent with the energy price forecasts. Estimates of 1980 MFBI consumption were taken from EPA's industrial boiler inventory,* which in turn is based on the National Emission Data System (NEDS) data base. State totals by fuel type were aggregated

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*U.S. Environmental Protection Agency, The Population and Characteristics of Industrial/ Commercial Boilers (EPA-600/7-79-178a), May 1979.

to federal regions. EPA's boiler inventory lacked consumption data for certain fuel types in some states (generally states with little or no consumption of that particular fuel type). We estimated the missing data from 1978 consumption figures given in the State Energy Data Report (DOE/EIA-0214(78), April 1980), assuming that MFBI consumption of a particular fuel type in a state is equal to the regional consumption of that fuel by MFBIs times the ratio of the total industrial consumption of that fuel type in the state to the total industrial consumption of that fuel type in the region. Steam consumption for 1995-2000 was extrapolated from estimates of the 1990-1995 growth rate, or 1.7 percent per year. Exhibit 1.i summarizes the regional and national MFBI consumption estimates.

EIA's regional consumption estimates for 1985 indicate that over 70 percent of total industrial fuel consumption by MFBIs will occur in three regions: the Southwest, the Midwest, and the South Atlantic region. This concentration should increase by 1995, when MFBI consumption in those three regions will rise to 75 percent, with over 40 percent of total consumption occurring in the Southwest.

In addition to projecting overall fuel use for steam demand, we estimated the distribution of equipment by boiler size and electricity-to-steam demand ratio.

Data on distribution of industrial boilers by size came from the EPA Industrial Boiler Survey (see Exhibit 1.j). Data from this survey indicate that about 58 percent of overall industrial steam capacity consists of MFBIs (plants that use 100 mmBtu/hr or more).

Exhibit 1.i

REGIONAL MFBI FUEL CONSUMPTION
(10^{12} Btu/yr)

Region	1980	1985	1990	1995	2000
New England	73.7	80.3	83.9	84.0	84.1
New York/ New Jersey	122.5	133.9	140.1	145.6	150.2
Mid-Atlantic	243.5	282.3	217.4	219.1	220.8
South Atlantic	500.5	594.3	645.4	722.2	786.1
Midwest	687.2	796.7	724.7	742.8	757.9
Southwest	987.9	1,145.5	1,487.6	1,746.4	1,961.6
Central	133.0	154.2	152.9	170.8	185.7
North Central	74.2	86.0	96.6	100.5	103.7
West	144.8	175.5	192.2	202.5	210.6
Northwest	122.2	141.7	161.3	181.2	197.7
Total	3,089.5	3,590.4	3,902.1	4,315.0	4,658.4

SOURCE: Department of Energy, Energy Information Agency; May, 1981.

Exhibit 1.j

Distribution of Industrial
Boiler Capacity by Size

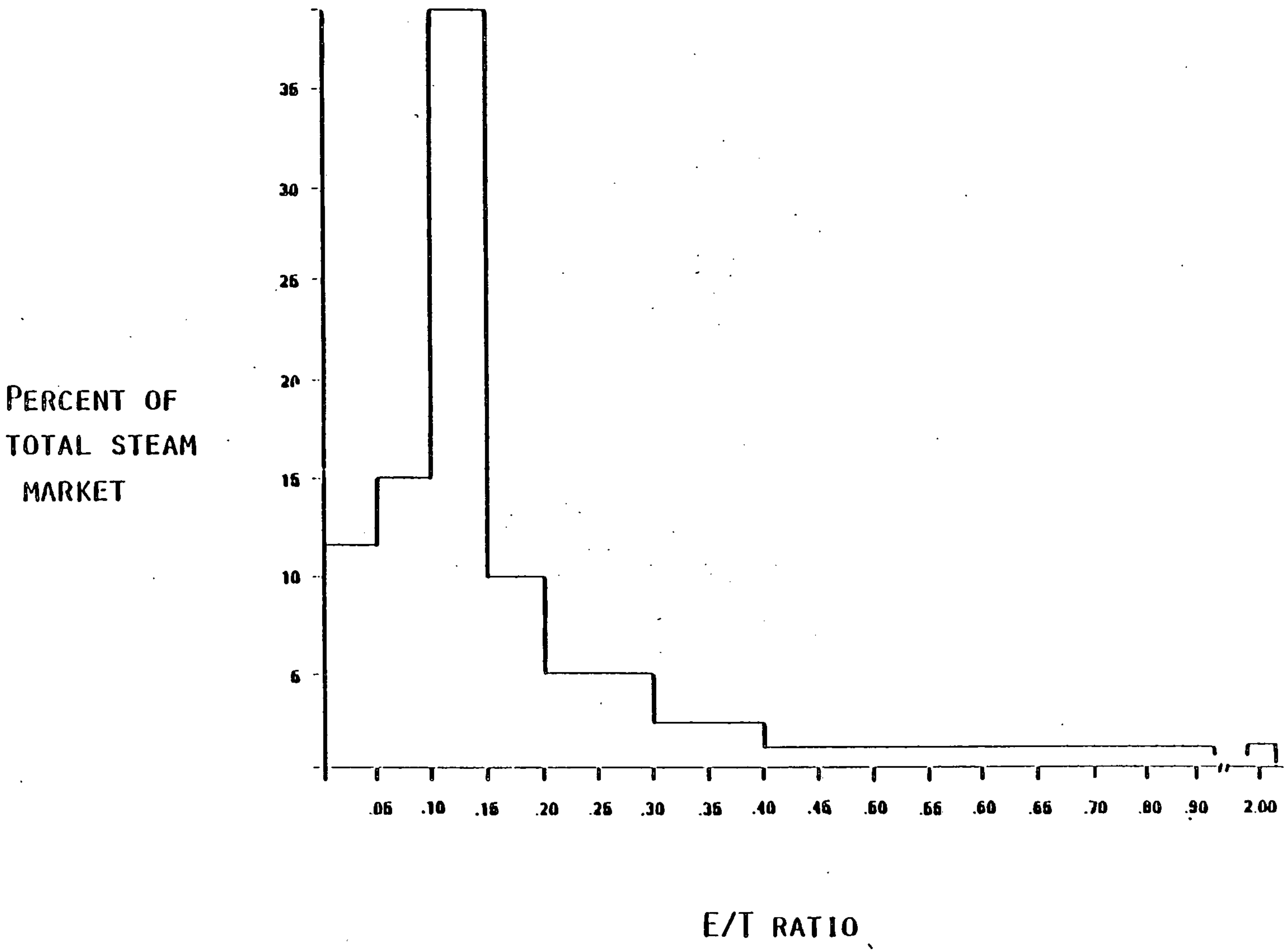
Boiler Size (mmBtu/hr)	Number of Boilers	Total Capacity (mmBtu/hr)	Fraction of Total Capacity (%)
0-49	27,011	506,390	23
50-99	5,640	414,390	19
100-249	3,833	564,220	26
250-500	914	300,600	14
500+	298	393,940	18

SOURCE: The Population and Characteristics of Industrial Boilers, EPA-600/7-70-178a, May 1979.

Knowing a plant's electricity-to-steam ratio is important in estimating the costs and benefits of using a cogeneration system. Our assumptions about the national distribution of these ratios are based on conclusions presented in DOE's Cogeneration Technology Alternatives Study (see Exhibit 1.k).

Exhibit 1.k

Distribution of Electric/Thermal Demand Ratios



SOURCE: Market Development for Advanced Coal-Based Cogeneration Systems; U.S. Department of Energy, October 1980.

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INDUSTRIAL USER DISCUSSIONS

In the course of this study, we held in-depth discussions with representatives of nine industrial firms that are potential users of SO_x emission control systems. Within the constraints of budget and resource limitations and OMB guidelines, we carefully selected nine interviewees representing:

- The major steam-producing industries (e.g., chemicals, petroleum refining, pulp and paper, textiles)

- The regions of the country where the major industrial coal use is expected to occur (i.e., Southwest, South Atlantic, and Midwest)

- Firms that are currently using or seriously considering using coal.

Our initial list, consisting of approximately 50 candidates, was based on industry and regional data banks, a review of recent trade magazine, newspaper, and journal articles, and previous contacts by the study team. The firms contacted were generally very interested in the study and willing to cooperate. (Exhibit 2.a shows the firms interviewed and their pertinent characteristics.)

Our discussions with the interviewees focused on the economic and other factors affecting their choice of coal as a boiler fuel and their choice of emission control

Exhibit 2.a

Industrial Firms Interviewed

Firm	Location	Annual Sales	Industry	Plant Locations
1. Fiber Industries	Charlotte, N.C.	$1 million	Synthetic textiles	South Atlantic
2. B. F. Goodrich	Akron, OH	$3.1 billion	Chemicals, plastics, rubber	Mid Atlantic, South Atlantic Southwest, West
3. St. Regis Paper Co.	W. Nyack, NY	$2.7 billion	Fiber, paper, oil & gas	All except New England & NY/NJ
4. U.S. Steel Corp.	Pittsburgh, PA	$12.5 billion	Steel	Mid Atlantic
5. Celanese Chemical Co.	Dallas, TX	$3.3 billion*	Chemicals	Southwest
6. Shell Oil Co.	Houston, TX	$20.6 billion	Oil, gas, chemicals	Southwest, Midwest, West
7. J.P. Stevens & Co., Inc.	Greenville, S.C.	$1.9 billion	Textiles	New England, South Atlantic, Southwest, Central
8. Caterpillar Tractor Co.	Peoria, IL	$3.6 billion	Construction equipment, engines	Mid Atlantic, Midwest, Central, West, Northwest
9. General Foods Corp.	Terrytown, NY	$5.6 billion	Food products	All except New England, & North Central

*Total for Celanese Corporation.

technologies, as well as on government actions to promote environmentally acceptable coal use.

SELECTION OF A BOILER FUEL

All of the firms interviewed are either using coal now or are seriously considering it for a facility in the near future. Economics was cited as the primary factor in their decision. Additional factors influencing the decision included concern about the consistency of environmental regulation and the certainty of future gas and oil supplies. Other factors such as FUA and land availability were considered minor factors.

All of the firms interviewed treated coal conversion as a normal capital investment decision. Although several firms had made strategic decisions to shift to coal, the shift would be made only as fast as the economics warranted.

The "hurdle rates" mentioned by our interviewees as necessary for a specific project to be approved were in the range of 15 percent to 40 percent, with most firms in the 20 to 25 percent range (after tax and net of general inflation). These ROI requirements are generally higher for coal conversion (and similar "utility" investments such as energy conservation) than for other types of investments such as plant expansion or new product development. In addition, interviewees mentioned that the ROI required for discretionary coal conversion (i.e., replacing an existing usable gas or oil boiler) is slightly higher than for a new or replacement installation, although they could not quantify this differential.

Only two firms indicated that coal conversion would be carred out if the investment did not meet the firm's normal hurdle rate. Both had had severe problems with fuel availability, one with oil and the other with natural gas. The first indicated that the ROI requirement would be relaxed somewhat for coal conversion, to about 15 percent from a normal 18 to 20 percent. The other indicated that coal conversion was a top priority almost regardless of cost. This firm had built its own low-Btu coal gasifier for process heat applications because it did not feel that natural gas supplies were secure. However, these two firms were the exceptions; all of the other firms felt that natural gas and possibly residual oil supplies were at least as reliable as coal, and would continue to be for the foreseeable future.

The interviewees mentioned two factors as delaying the conversion to coal. The first was the current high interest rates coupled with the recession. This situation appears to be delaying (although probably not eliminating) many previously planned expansions and other capital investment programs, including coal conversion. A second major negative factor is the perceived inconsistency in environmental regulation. Some potential coal users are concerned that the standards will be tightened after their coal-burning facilities are installed, possibly requiring installation of scrubbers or a switch to significantly more expensive compliance coals. This is primarily a state-level problem, with some states (e.g., Illinois) perceived as much more of a problem than others (e.g., Texas).

All of the interviewees considered FUA as having little or no effect on coal use, particularly when the economic factors justify coal use, because exemptions are relatively easy to obtain. Land availability for coal piles or waste disposal was perceived as a problem only in areas of high industrial concentration such as the Houston Ship Channel. For most firms, this was more a question of priorities (current coal, ash, and sludge piles, or future expansion) which could only be resolved on a case-by-case basis.

In general, most firms appear to be moving toward a strategy of flexibility in planning for boiler fuels. Most would consider only multi-fuel (oil/gas) boilers for new installations. One firm is installing coal-capable boilers only, but using oil or gas while the price is low; that firm is switching to coal by installing the required scrubbers and coal- and waste-handling equipment when the economics justify it.

SELECTION OF AN EMISSION CONTROL TECHNOLOGY

All of our interviewees had conducted extensive comparative studies of coal emission control systems within the past year, and thus were quite knowledgable regarding the current costs and performance of commercially available units. Most of the interviewees indicated that if they had to choose an SO_x control system today, they would choose a dual-alkali unit, largely because they feel it would operate effectively in an industrial setting. Lime/limestone systems, which are the most popular systems in utility applications, are not seriously considered by industry because of the severe problems that arise when the utility-sized systems are scaled down (e.g., smaller diameter piping clogs up much faster). However, they are concerned about the sludge-handling problems associated with dual-alkali systems. One interviewee who has been trying to get dual-alkali scrubbers to work properly for several years indicated that he is seriously considering replacing the units with AFB systems, once those have been sufficiently demonstrated. The primary advantage he sees for the AFB is the dry waste, which he feels will eliminate many of the problems his company has been having with the sludges.

Sodium throwaway systems, which are currently the most frequently used FGD systems in industrial applications, are viewed as not being economically competitive except in certain cases, such as the crude oil-pumping systems in California. The major drawback of these systems is the cost of constructing large evaporation ponds in dry climates where this is feasible, or constructing waste water treatment facilities in other areas. There is also concern that the wastes from this system may be declared hazardous and thus require even more expensive treatment. These types of systems may be feasible in certain applications in the chemical, textile, or pulp and paper industries where alkaline waste streams for scrubbing are available and waste water treatment facilities are required anyway, or where the sodium and sulfur can be recovered for use in the process. One pulp and paper plant in Florida is using a sodium system on a coal/wood boiler, and recovering the sodium and sulfur for use in kraft cooking liquor. The process is still experimental, but if it is successful it may be applicable in other pulp and paper industry plants.

Regenerable processes with sulfur or sulfuric acid by-products were generally not considered economically competitive except under very special circumstances. These processes are more complex and thus have higher capital and operating costs. The byproducts usually have little value because they are in relatively small quantities or not of a sufficiently high quality, and thus are difficult to market. If the byproducts could be used on site, the systems would be more attractive, but there is also the question of balancing the plant's requirements with the process outputs. One interviewee had performed a detailed evaluation of a citrate process for a facility that could use the byproducts, and then rejected it on economic grounds.

The lime spray drying system is extremely attractive to industrial users primarily because it has a dry waste. All the interviewees indicated that it would be their top FGD choice as soon as it has been commercially demonstrated. There was particular interest in systems applicable to medium- and high-sulfur coals that could guarantee a 90 percent SO_x removal.

Many of the interviewees felt that AFBs would be the preferred coal systems because of their potentially lower costs (i.e., lower than a conventional coal boiler with an FGD), higher efficiencies, and ability to use a wide variety of fuel types without design changes. However, they are waiting until industrial systems are demonstrated in more installations before they are willing to commit to them. In particular, they want to see how well these systems respond to the cyclic and rapidly changing loads typical of most industrial applications.

Only one of the firms interviewed felt coal gasification was an economically viable option for <u>boiler</u> fuel, and that was primarily for retrofit applications. Another user installed a low-Btu gasification system for process heat applications, because he was extremely concerned about natual gas shortages. Most felt that gasification could be justified only for chemical feedstock. In that case, expanding the gasification facility for process heat or boiler applications might be economically justifiable.

Coal/oil mixtures were not felt to be economically viable for the long term in industrial applications except perhaps where space or environmental limitations were severe. The small savings (10 to 20 percent of the residual oil price) did not appear to justify the conversion expenses. In addition, there did not appear to be any supply advantages since a substantial amount of oil was still required and the user might be restricting itself to a few suppliers, who would then be able to control price.

One participant believed that chemical coal cleaning has major potential for meeting environmental constraints. He claimed that his firm is willing to pay $25/ton (about $1.10/mmBtu) more for its boiler fuel if the need for scrubbers would be eliminated.

GOVERNMENT ACTIONS

The interviewees discussed both government regulatory actions and R&D activities. All of them indicated support for the environmental goals of the Clean Air Act, but felt that the regulations need to be applied more flexibly and consistently. Specifically, they were unanimously opposed to the percentage reduction requirement, preferring that they be allowed to burn low-sulfur coal rather than required to install scrubbers when doing so would meet the emission constraints. In addition, there was major concern that regulations are not being administered fairly or consistently on the state or local level. In particular, the interviewees were concerned that emission levels would be tightened after a plant went on-stream, requiring expensive design changes and retrofits. They would like a moratorium on tightening emission limits for a plant for a period of 5 to 10 years after startup. They feel this would allow for more rational planning and would facilitate their coal conversion efforts.

FUA was considered only a minor influence on fuel choice, since coal use was economically justifiable in most cases anyway, and would be more so with oil and gas price decontrol. In addition, exemptions were relatively easy to justify. One interviewee had obtained 13 exemptions for his company, and did not know of a single request for his or other companies that had ever been denied.

"Pollution offsets," which would allow firms to sell or swap allowed emission levels, were considered a minor factor. Most organizations that had them preferred to retain them for future use, rather than sell them.

Although the respondents expressed many opinions regarding the role of federal R&D on SO_x emission control systems, there was general agreement on several items. First, the interviewees saw a need for a government R&D effort, since they felt the vendor organizations historically had been unwilling or unable to finance R&D into innovative approaches that promise major breakthroughs in costs or efficiencies and to finance early demonstrations of new technologies. One interviewee felt that major progress in this area would come only from a continued government effort, since private R&D would be too cyclic and no firm wants to risk R&D on a technology that could be rendered obsolete by a change in regulations. This interviewee also felt that the federal efforts should concentrate on fully developing a few technolgies, rather than on investigating all possible options superficially.

It was felt that FGD systems would be fully commercialized with little or no future government support needed except perhaps in applying spray dryers to high-sulfur coals. Low-Btu gasification was similarly felt to be a mature technology requiring no major government R&D support. There was some support, however, for having the government fund a full-scale industrial AFB demonstration.

Most interviewees felt there was a role for federal R&D in medium-Btu coal gasification. They cited the long lead time for development (10 years or more), the size of the investment in prototype or pilot scale facilities (hundreds of millions of dollars), and the volatility in conventional gas and oil prices, which means that even if the project is technically successful it may not be commercially viable.

Most interviewees felt that government assistance was useful for accelerating the commercialization of new ECTs because vendors have historically not done so, and none of the potential users were willing to take any financial risk on a full-scale application. About half the companies supported government funding of full-scale demonstrations, as well as innovative financing arrangements in which the government assumes the financial risk of technology failure, and the company pays the government back out of any savings that may accrue.

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PROJECTED MARKET DEVELOPMENT

To establish a baseline scenario for evaluating the economic attractiveness of the ECTs, and to identify the most promising market sectors for SO_x technologies in the period 1982-2020, we made a number of simplifying assumptions:

- No new MFBIs will be allowed exemptions from FUA coal conversion requirements
- Industrial NSPS will be promulgated that will require 90 percent SO_x removal for high-sulfur coals and 70 percent SO_x removal for low-sulfur coals
- The major factor governing choice of ECT technology will be relative economic performance
- Coal will be available to any industrial users who want it, in any region.

We used these assumptions to estimate the maximum coal market size, and thus the maximum market potential for ECTs. We conducted our market evaluation in four steps (see Appendix C for details):

1. Evaluated the cost and performance of each technology by market segment

2. Estimated market shares for each segment

3. Determined market size over time

4. Projected the number of installations.

First, we divided the market into 360 segments, with three categories of boiler size, three categories of electricity-to-steam ratio, 10 regions, two coal types, and two kinds of application (new and replacement, and retrofit). For each market segment, we determined capital cost and annual O&M and fuel costs for each of the competing technologies, using the cost estimates developed by ORNL. Next, we calculated each technology's market share for each market segment. To do this, we determined the after-tax cash flow for the life of each technology, and compared their after-tax ROIs. All systems, both cogenerating and noncogenerating, competed against all other systems, both cogenerating and noncogenerating, on the basis of after-tax lifecycle cost. For example, a coal-fired cogeneration system with a lime/limestone FGD competed with coal-fired cogeneration systems with other types of FGD, as well as with noncogenerating coal-fired systems with all types of FGD. Finally, we estimated how a technology might lag in achieving its market share because of such market diffusion factors as risk aversion among potential customers, and delays in developing manfacturing capacity.

Once we had determined market shares, we estimated the actual size of each market segment (in Btu/yr of consumption). First, we determined the size of the new market (the net addition to total steam demand for the period). Then we determined the size of the retrofit and replacement markets, taking into account that an early retirement in the retrofit market would reduce the later replacement market. Finally, we calculated the expected installations, aggregated by application, technology, and region.

In the following sections, we present our market development results by application, technology, and region. Because these results depend partly on projected costs for technologies that have not yet been commercialized, care must be taken in interpreting and applying them.

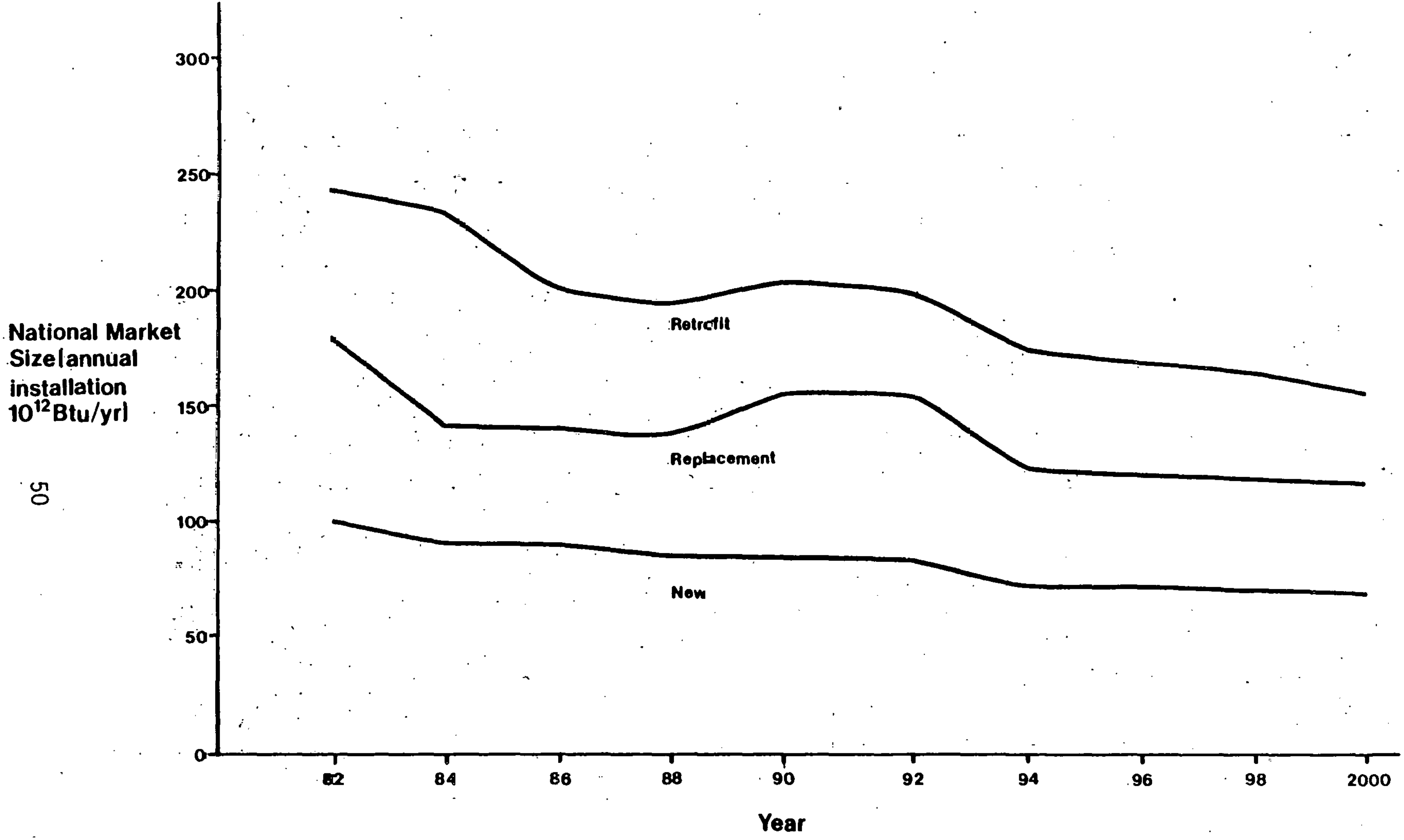
MARKET DEVELOPMENT BY APPLICATION

Exhibit 3.a shows expected market development, for both cogenerating and noncogenerating technologies, by application: new, retrofit, and replacement. The new market represents sales to MFBIs of boilers to meet expanding steam demand. The replacement market represents boilers that have reached the end of their useful economic life and must be replaced. The retrofit market represents gas and oil boilers that are retired before the end of their economic life because of the cost savings available through coal use.

Overall, the market for these systems is expected to decline gradually between now and the year 2000, primarily reflecting a decline in the growth rate of overall industrial steam requirements (as projected by EIA's MEFS model). This slower growth is the result of real increases in energy prices as well as conservation investments, which result in lower net steam demand per unit of output. In addition, the discretionary retrofit of existing oil and

Exhibit 3.a

Expected Market Development: By Application



gas boilers to coal results in their not being available for replacement in subsequent years, thus shifting the sales of these systems to earlier years.

MARKET DEVELOPMENT BY TECHNOLOGY

Exhibit 3.b shows the expected market development by technology. This assessment is based purely on the relative economic performance of the system options, and does not include the effects of the attitudinal factors identified in our discussions with industrial decision-makers. (The impacts of these factors are examined in the next chapter.) The market shares of the AFB and lime spray dryer systems increase over this period, while those of the conventional sodium, lime/limestone, and dual-alkali systems decrease. This difference is attributable to the "diffusion" period required for new technologies to gain market acceptance, and to the overall superior economic performance exhibited by the AFB and spray dryer systems. This is illustrated more clearly in Exhibit 3.c, where the AFB and lime spray dryer technologies increase from about 15 percent to over 60 percent of the market.*

The dual-alkali system market share is lower than might be expected, since its costs and performances are very

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*The low-Btu gasifiers are not shown because their projected market penetration for steam boiler applications is negligible (less than 0.1 percent) due to high capital costs and low overall net efficiency. There may be a significantly greater market for these systems in process heat or chemical feedstock (medium-Btu) applications, which were beyond the scope of this study.

Exhibit 3.b

Expected Market Development: By Technology

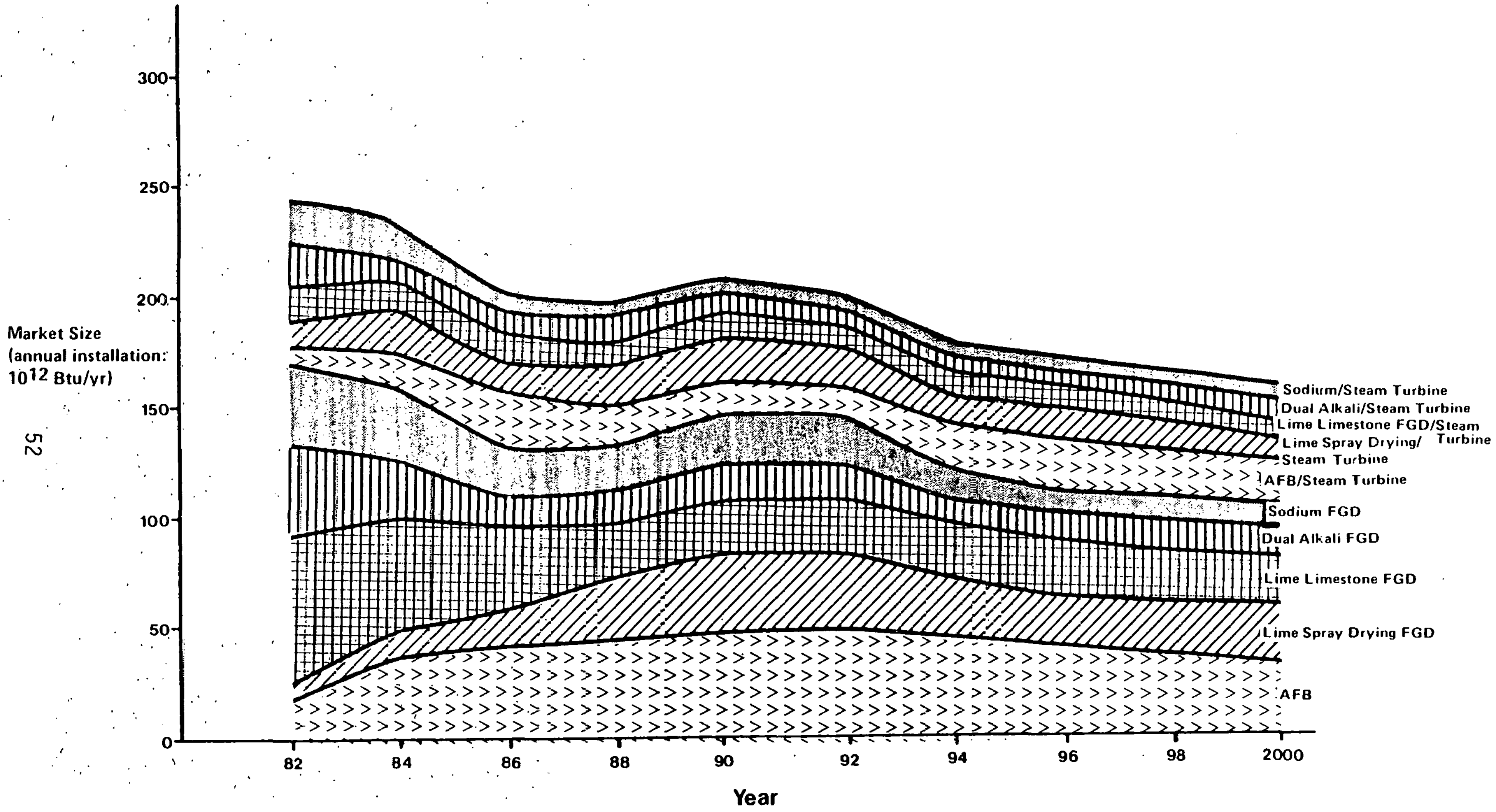
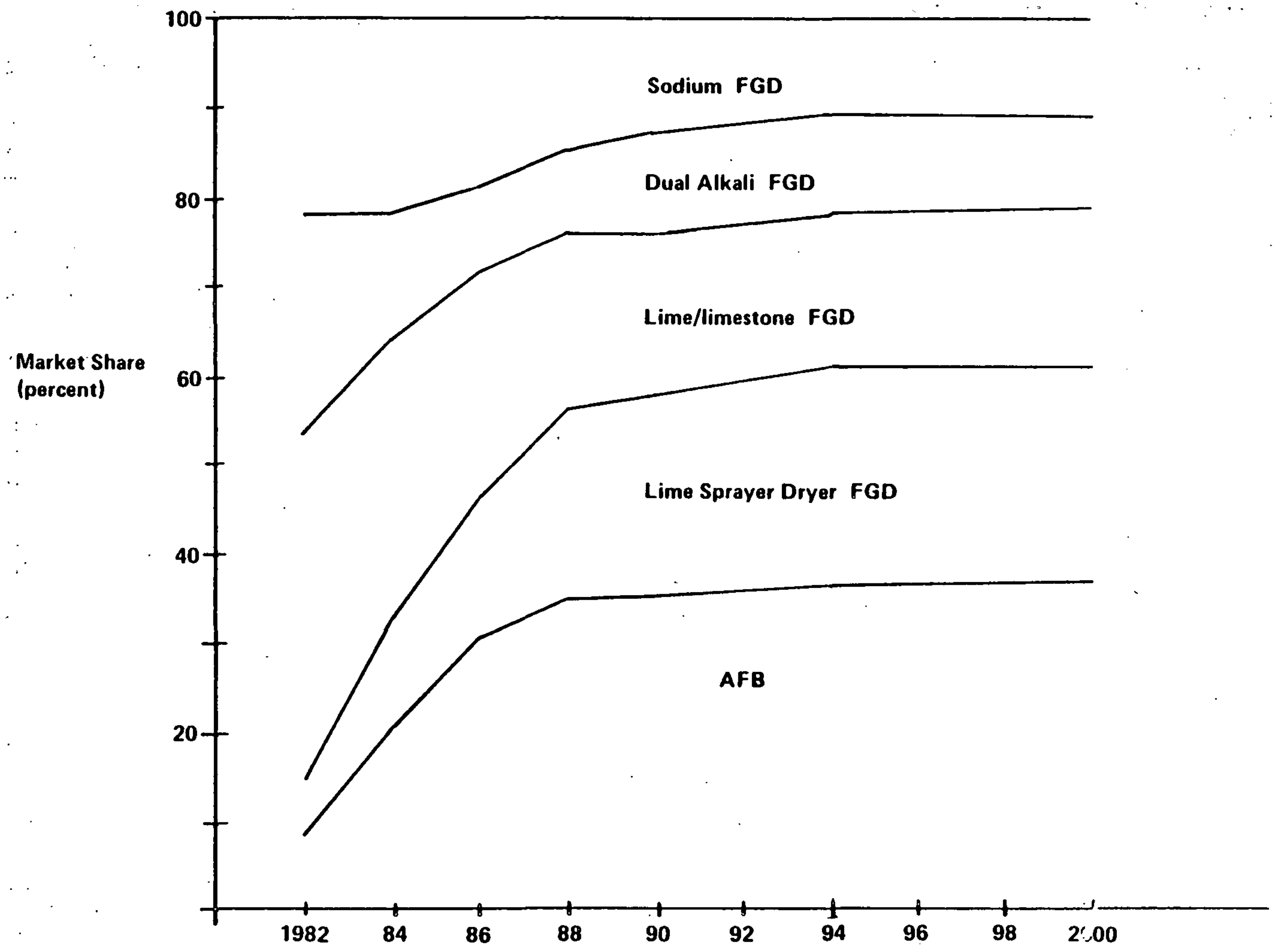


Exhibit 3.c

Expected Market Development: Technology Market Shares*



*Includes both boiler only and boiler/steam turbine (cogeneration) configurations similar to those of the lime/limestone systems. This occurs because we assumed that dual-alkali systems would be applicable only to high-sulfur bituminous coal. Since EIA projects that over 60 percent of the new MFBI coal use between 1985 and 1995 will be low-sulfur subbituminous coal, these systems will be closed out of a significant portion of the market.

Exhibit 3.d shows the technology market shares for two regions, the predominantly low-sulfur subbituminous coal Southwest and the predominantly high-sulfur bitminous coal Midwest. These shares are shown for the year 1995, to illustrate the economic market share for the competing technologies once the AFBs and lime spray dryer systems are fully diffused.

For the subbituminous coal regions, AFBs dominate the market, with over 50 percent of the total. Lime spray dryers are next, with about 21 percent, and lime/limestone and sodium systems each have about 15 percent. In the bituminous high-sulfur regions, the AFB system has only 24 percent of the market, the lime spray dryer has 28 percent, and the dual-alkali and lime/limestone systems each have about 20 percent. The sodium throwaway system is the poorest performer, with about 7 percent of this market sector.

Exhibit 3.e shows the technology market shares by size range. Based on the cost estimates developed by ORNL, AFBs will dominate the larger size ranges (over 250 mmBtu/hr), while the lime spray dryer system will dominate the 100-250 mmBtu/hr. This is contrary to the expectations of our industrial interviewees, who felt that the FGD

Exhibit 3.d

Technology Market Shares By Coal Type* (percent)

	Region** (coal type)	
	Southwest (Subbituminous low sulfur)	Midwest (Bituminous High sulfur)
Boiler Only		
AFB	34	16
Lime Spray Dryer FGD	14	20
Lime/limestone FGD	10	15
Dual-alkali FGD	-	14
Sodium FGD	11	5
Boiler/Steam Turbine		
AFB	18	8
Lime Spray Dryer FGD	7	8
Lime/Limestone FGD	5	6
Dual-alkali FGD	-	6
Sodium FGD	5	2

*Market Shares for 1995.
**Numbers may not add due to rounding.

Exhibit 3.e

Technology Market Shares By Size Range* (percent)

	Size Range (mmBtu/hr)		
Technology**	100-250	251-500	501+
AFB	23	45	51
Lime Spray Dryer FGD	31	20	18
Lime/Limestone FGD	21	16	14
Dual-Alkali FGD	12	9	7
Sodium FGD	14	10	9

*For 1995
**Includes both boiler only and boiler/steam turbine configurations

systems would be more competitive in the larger sizes while the AFBs would dominate the smaller sizes.

Exhibit 3.f shows the cumulative market development for industrial MFBIs. By the year 2000, approximately 90 percent of the total MFBI capacity will be coal-fired. The majority of these installations will use some type of FGD, largely because the AFB systems will require time to be widely accepted.

MARKET DEVELOPMENT BY REGION

Exhibit 3.g shows projected the market development for coal-fired MFBI installations by region from 1980 to 2000. Texas and Louisiana in the Southwest are expected to dominate, with 43 percent of installations. Over 75 percent of all installations will be located in three regions: the Southwest, the South Atlantic, and the Midwest.

Exhibit 3.f

Expected Market Development: Cumulative Installations

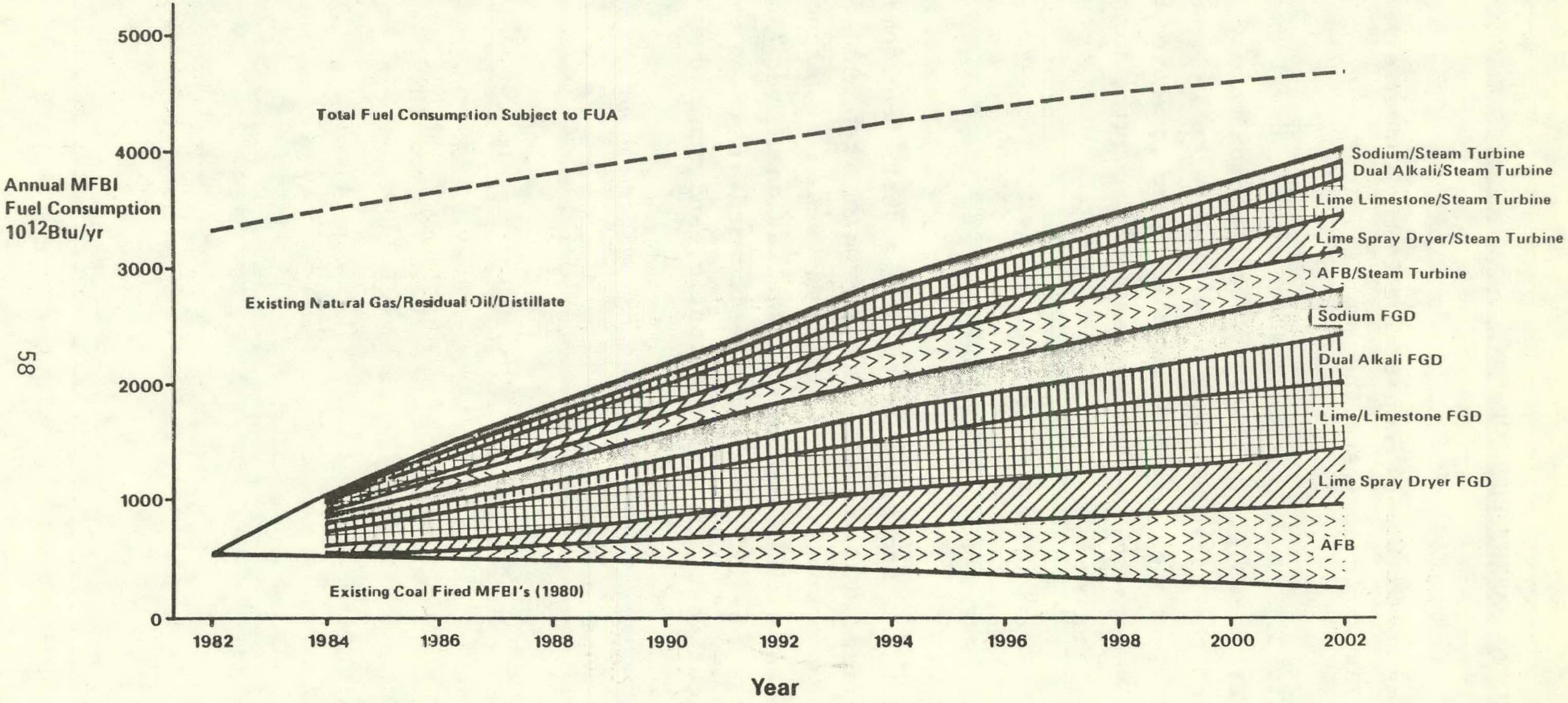
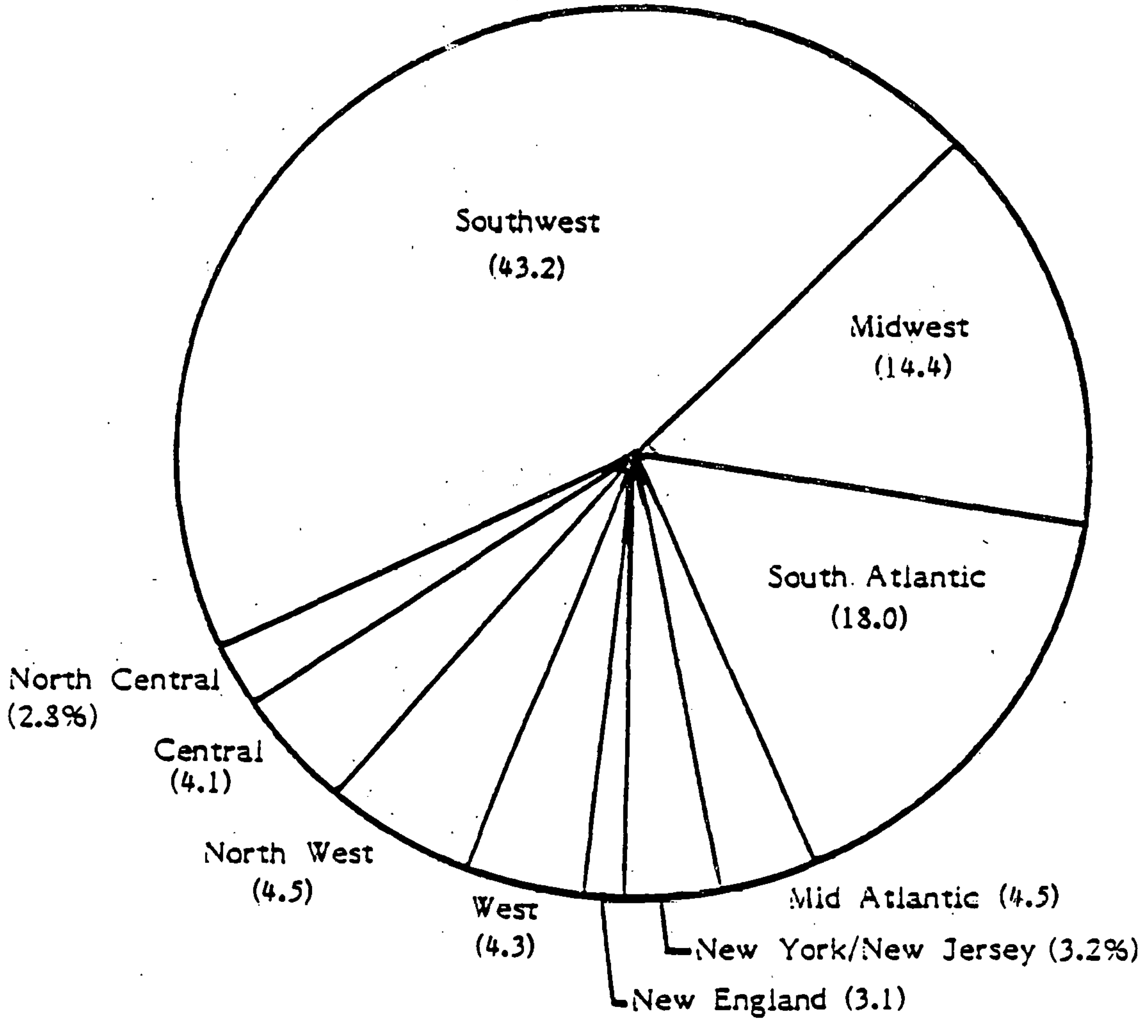


Exhibit 3.g

Base Case Market Development: Region (1982-2000)



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4 SENSITIVITY ANALYSES

We evaluated the sensitivity of our "base case" market scenario to three factors: no promulgation of industrial NSPS, repeal of FUA, and atttiudinal decision factors on the part of the industrial decision-makers. Exhibit 4.a summarizes the characteristics of the base case and the three sensitivity scenarios.

Exhibits 4.b and 4.c compare the estimated sales for coal-burning technologies under the base case and three sensitivity scenarios. The total market size varies from 3,385 x 10^{12} mmBtu/yr to 4,003 x 10^{12} mmBtu/hr, depending on the regulatory assumptions used. Scenario A, which includes a strict application of FUA and more lenient application of environmental regulations, probably represents the maximum realizable coal use under the postulated world oil price scenario; Scenario B, with no FUA, represents the minimum expected coal use. In these two scenarios, coal will represent from 78 to 91 percent of total MFBI fuel consumption. The distribution of technologies in Scenario C (which incorporates attitudinal factors) represents our best estimate of what the expected mix of SO_x control technologies will be, with AFBs and lime spray dryer FGDs representing over 73 percent of the market over the entire period 1982-2001.

Exhibit 4.a

Sensitivity Scenarios

Scenario	Environmental Regulations	Fuel Choice Regulations	Decision Factors
Base Case	NSPS	FUA enforced	economic
A - No NSPS	SIPs	FUA enforced	economic
B - No NSPS, No FUA	SIPs	No FUA	economic
C - Attitudinal	NSPS	FUA enforced	economic/attitudinal

Exhibit 4.b

Total Market Projections For Coal Technologies 1982 - 2001

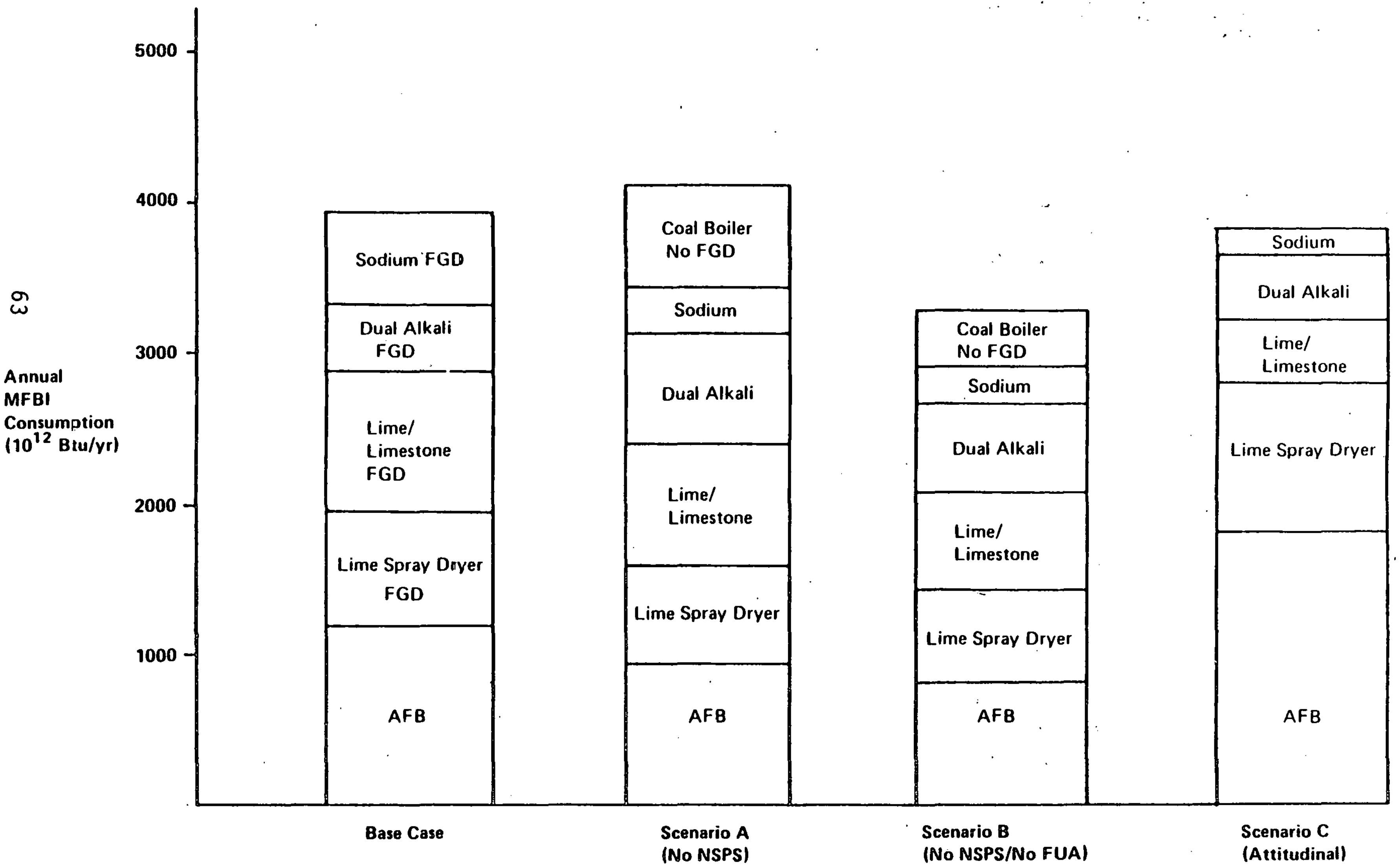
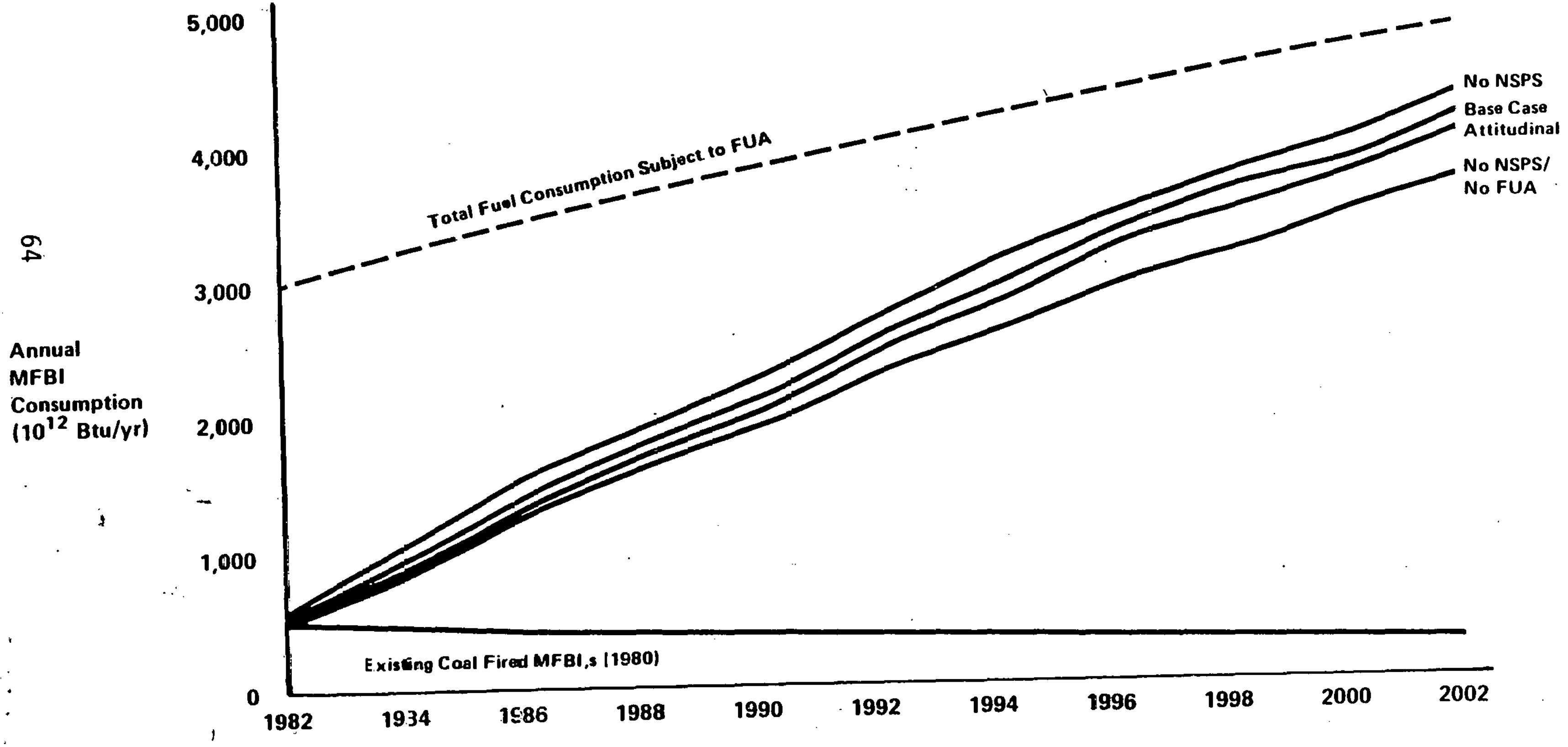


Exhibit 4.c

Expected Market Development: Various Scenarios



SCENARIO A - NO NSPS

Our first sensitivity scenario evaluated the impact of not having federal industrial NSPS, and thus of leaving the environmental control requirements for SO_x up to the individual states through their SIPs. EPA has indicated that industrial NSPS with SO_x emission levels will probably not be promulgated. Thus, SO_x will be governed by the SIPs. At present, none of the SIPs have scrubbing requirements, so in many cases it is possible to meet these requirements by using low-sulfur "compliance" coal.

To evaluate this factor, we evaluated the SIPs in each region, the coal types available in each region, and the SO_x of nonattainment areas in each state. These data are described in Appendices A and D. Exhibit 4.d summarizes the results for the 10 DOE regions. For each region, the average allowable MFBI SO_x emission level is indicated, which equals the state levels weighted by their industrial energy use. Also, the least expensive medium-or high-sulfur coal was chosen, which usually requires scrubbing, and the least expensive low sulfur coal. If the delivered cost of the low-sulfur coal was $2/mmBtu more than the delivered cost of the high-sulfur coal, it was assumed not to be economically competitive and was dropped from consideration. This occurred in the New England, Mid Atlantic, and Midwest regions. For all practical purposes, three other regions had only low or medium sulfur subbituminous coals available: North Central, West, and Northwest. Thus, there was meaningful competition between low-sulfur compliance coals and high-sulfur coals requiring scrubbing in only four regions: New York/New Jersey, South Atlantic, Southwest, and Central.

Exhibit 4.d

SIP Requirements

DOE Region	Weighted SO_2 MFBI Emission Level (lb SO_2/mmBtu)	Economically Available Coal Types: Sulfur Content	Economically Available Coal Types: Rank	Control Required?
I New England	1.1	High	Bituminous	Yes
II New York/New Jersey	2.3	High	Bituminous	Yes
		Low	Bituminous	No
III Mid-Atlantic	1.2*	High	Bituminous	Yes
IV South Atlantic	2.0	Medium	Bituminous	Yes
		Low	Bituminous	No
V Midwest	2.1	High	Bituminous	Yes
VI Southwest	2.8	Low	Subbituminous	No
		Medium	Bituminous	Yes
VII Central	2.3	High	Medium Bituminous	Yes
		Low	Subbituminous	No
VIII North Central	1.6	Low	Subbituminous	No
IX West	0.8	Low	Subbituminous	Yes
X Northwest	2.0	Medium	Subbituminous	No

*Not including Pennsylvania, where discussions with state firms indicate that scrubbing is required in most areas.

Exhibit 4.e compares the market penetrations for competing systems, including a coal boiler with no controls. The uncontrolled coal boiler using compliance coal captures about 15 percent of the market, nationwide.* In addition, the overall market size for coal equipment is about 4 percent larger over the period 1982-2001 (4,004 x 10^{12} Btu/yr in the sensitivity scenario vs. 3,859 x 10^{12} Btu/yr in the base case). This is the result of a 30 percent increase in the size of the discretionary retrofit market (to 1,108 x 10^{12} Btu/yr from 855 x 10^{12} Btu/yr) over the period. This increase is the result of the availablity of a cheaper coal boiler option that can use compliance coal and requres no FGD. Because of the dynamic interaction between the retrofit and replacement markets, however, the size of the replacement market in later years is reduced by these discretionary retrofits, and the net additional coal use is only 57 percent of the apparent increase in the retrofit market size.

Exhibit 4.f shows the market shares of the uncontrolled coal boiler using compliance coal in each region. Its attractiveness is regionally specific, with the South Atlantic region having the largest number of these systems.

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*The market penetration percentage of the dual-alkali FGD system also increases. In this sensitivity scenario, high-sulfur coals were allowed to compete in the Southwest, while in the base case only low-sulfur coals were allowed to compete there. Because the dual-alkali FGD works only on high-sulfur coals, this in effect increased that system's potential market.

Exhibit 4.e

Effect of NSPS on Technology Market Penetration

Technology[***]	Market Share[*] (percent)	
	Base Case: NSPS SO_2 limits promulgated[**]	SIP SO_2 limits (no NSPS)
Coal boiler, no SO_2 control	--	15.3
AFB	30.4	22.8
Lime spray dryer FGD	19.2	16.7
Lime/limestone FGD	23.1	20.1
Dual-alkali FGD	12.0	17.3
Sodium FGD	15.2	7.9

[*] For the period 1981-2000.

[**] With a percentage reduction requirement.

[***] Includes both boiler only and boiler/steam turbine systems.

Exhibit 4.f

Market Share of Compliance Coal Boiler

Region	Fraction of National Market in Region	Percentage of Market Captured by Compliance Coal Boiler
Southwest	0.432	8
South Atlantic	0.180	46
Midwest	0.144	--
Mid-Atlantic	0.045	--
Northwest	0.045	35
West	0.043	--
Central	0.041	6
New York/New Jersey	0.032	46
New England	0.031	--
North Central	0.028	33

SCENARIO B: NO NSPS, NO FUA

The second sensitivity scenario we investigated was elimination of the FUA restrictions on industrial MFBI gas and oil use. This allows the industrial decision-maker to make the most economic choice.

Exhibit 4.g summarizes the overall national market shares of each technology over the 1982-2001 period. Because of their continually escalating prices, gas and oil will capture only 15.4 percent of the MFBI market between now and 2001. This distribution is highly time-dependent, however. In the 1982-1983 period, gas and oil systems capture 29.2 percent of the MFBI market; in 2000-2001, they capture only 6 percent of the market.

The distribution is also very regionally dependent. Exhibit 4.h shows the natural gas and residual oil share of new boiler installations for the 10 DOE regions. Based on the EIA projections, market shares of these noncoal technologies will range from 5 percent to over 60 percent in the 1982-2001 period.

SCENARIO C: ATTITUDINAL FACTORS

The final scenario we investigated was the effect of attitudinal factors on the part of industrial decision-makers in addition to the economic factors. Our interviews with industrial decision-makers indicated that noneconomic factors entered stongly into their decisions. In particular, they were strongly opposed to any system, such as the lime/limestone FGD, that produced a sludge. One

Exhiit 4.g

Comparison of Technology
Market Penetration Estimates:
No FUA, No NSPS

Technology*	Base Case Market Share (percent)	No FUA, No NSPS Market Share (percent)
Coal boiler, no FGD	--	12.7
AFB	30.4	20.2
Lime spray dryer FGD	19.2	14.7
Lime/limestone FGD	23.1	16.3
Dual-alkali FGD	12.0	14.5
Sodium FGD	15.2	6.1
Residual oil boiler	--	3.8
Natural gas boiler	--	11.6

*Includes both boiler only and boiler/steam turbine systems.

Exhibit 4.h

Regional Oil and Gas MFBI
Market Penetration:
No FUA

Region	Fraction of National Market in Region	Oil and Gas MFBI Market Share* (percent)		
		1982-83	2000-01	1982-2001
Southwest	0.432	31.5	5.1	16.4
South Atlantic	0.180	14.2	2.5	7.4
Midwest	0.144	30.9	2.7	9.2
Mid-Atlantic	0.045	23.4	2.0	7.7
Northwest	0.045	89.4	37.1	61.1
West	0.043	82.5	19.3	43.7
Central	0.041	14.8	1.5	5.0
New York/New Jersey	0.032	16.2	2.4	7.7
New England	0.031	34.3	3.9	15.8
North Central	0.028	28.0	1.7	10.9
National		29.2	6.0	15.4

*For new boilers.

interviewee who has operated dual-alkali systems for several years is so dissatisfied because of the associated problems (e.g., finding safe disposal sites, having the equipment operate reliably, maintaining site cleanliness) that he is seriously considering replacing them with AFB systems having a dry waste.

Although our data base is not large enough to quantify these factors in a statistically rigorous manner, we can approximate the effects of these attitudinal factors using information supplied by our interviews with industrial decision-makers to weight the economic market share estimates provided in the model.* To do this, a set of judgments must be made on what the relative market shares of the competing technologies would be if the lifecycle costs were exactly the same. This is done by arbitrarily assigning a weighting factor of 1.0 to the least attractive technology, comparing it to the next least attractive technology, estimating their relative market shares, and setting the relative weighting factor proportional to these market shares. This process is continued until all technologies have been assigned relative weighting factors that are proportional to their relative market shares. Exhibit 4.i illustrates the effect of this factor on the relative market shares of two competing technologies for various sets of weighting factors.

In this study, we arrived at the relative weighting factors through the following process. First, based on our

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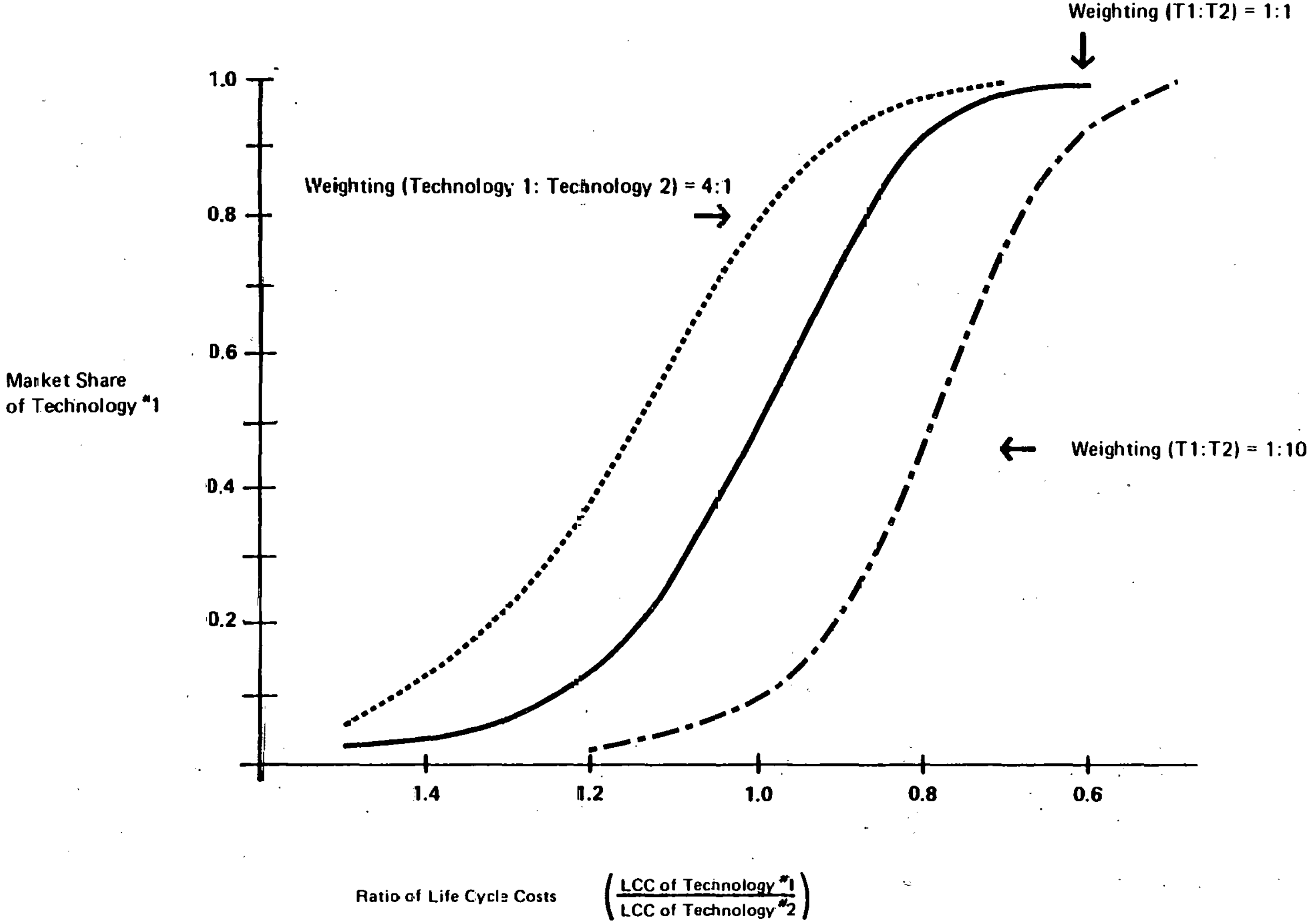
*A detailed description of the mathematics involved is provided in <u>The Energy-Economy Interaction Model</u> and is summarized in Appendix C.

Exhibit 4.i

Effect of Judgmental Weighting Factors on Market Shares



discussions with industrial decision-makers, the least attractive SO_2 control technology is the sodium FGD system. This is because it requires large settling ponds in dry climates or extensive waste treatment facilities. While the system may be feasible in some applications having alkaline waste streams or that can use the effluent (such as certain chemical processes or in the pulp and paper industry), these situations appear limited. Finally, our interviewees expressed concern that the wastes may be declared hazardous, in which case they will be extremely expensive to dispose of. This system is given a weighting of 1.

The next least attractive system is the lime/limestone FGD. Our interviewees were extremely adverse to handling the sludges generated by this system, and the system has a bad reputation in industrial-size applications. However, there is much more experience with these systems than with sodium systems in various regions of the country based on their utility applications. Therefore, these systems are given a relative weighting of 2.

The dual-alkali systems are very similar to the lime/limestone systems because they have a sludge waste. However, they do not have the scaling and plugging problems of the lime/limestone systems and thus are perceived as much more acceptable in industrial applications. These are given a weighting of 4.

Lime spray dryer FGD systems have a dry waste that can be handled similarly to normal ash wastes, thus eliminating the major drawbacks of the other FGD systems. These systems are therefore given a relative weighting of 8.

AFB systems also have a dry waste, and in addition have several advantages over the lime spray dryer FGD. Specifically, they are a more compact unit, are simpler to operate, and can handle a wider variety of fuels than a coal boiler with an FGD. These are therefore given a relative weight of 16.

Although we do not have an uncontrolled coal boiler in this scenario (because we are assuming a federal NSPS with a percentage reduction requirement), such a boiler would have a weighting similar to the AFB, since it has a dry waste. However, these boilers generally cannot handle the variety of fuels that an AFB can, and thus will be slightly less attractive, with a weight in the range of 12 to 15.

Oil boilers do not require the extensive coal and waste-handling facilities that the coal systems require, are more compact, are easier to operate, and can generally operate more flexibly with quicker response to fluctuating loads and better turndown ratios. However, there is concern about the reliability of supply and stability of price of this fuel in regions such as New England that rely heavily on imports. This system is given a relative weighting of 18.

Finally, natural gas is the most attractive fuel, since it does not require extensive emission controls and is similar to oil in its operating flexibility. There is some concern about its availability, but this concern is waning with price decontrol and the potential repeal of certain regulatory barriers to its use such as the Natural Gas Policy Act. This system was given a weighting of 20.

Gasifiers have a very low relative weighting, 0.5 or less. This is because they (1) have byproducts (tars and oils) that are difficult to handle, (2) are highly sensitive to the type of coal, thus reducing the user's flexibility in supply sources, and (3) are complicated to install and operate. These factors further reduce a very small economic market share to a negligible one.

These attitudinal factors will affect the market projections in two ways. First, the relative market shares of the technologies are changed. Exhibit 4.j illustrates the changes for high-sulfur and low-sulfur coal regions (the Southwest and South Atlantic) in the year 2000, when distortions caused by the need for new technologies such as AFBs and lime spray dryer FGDs to become accepted and fully diffused into the marketplace have disappeared. The estimated sales of the AFB and lime spray dryer FGD systems increase by 30 to 40 percent over that estimated by a purely economic comparison. The sales of the lime/limestone and sodium throwawav FGD technologies are reduced by 60 to 80 percent, with the estimated sales of the dual-alkali system down only about 15 percent.

These attitudinal factors will also affect the size of the projected market, as shown in Exhibit 4.k. While the overall size of the new market is unaffected by these attitudinal factors, the discretionary retrofit market is reduced by approximately 20 percent; industrial firms will prefer to retain their oil and gas burners rather than convert to coal even when coal conversion meets their ROI requirements. About a third of these lost discretionary conversions will be picked up in later years when worn-out oil/gas boilers are replaced with coal units; thus,

Exhibit 4.j

Impact of Attitudinal Factors on Expected Market Shares*

- Southwest Region (Low-Sulfur Subbituminous Coal)

	Market Share (percent)	
Technology	Economic	Economic/Attitudinal
Sodium FGD	16.0	3.2
Lime/Limestone FGD	14.8	5.8
Lime Spray Dryer FGD	20.8	24.5
AFB	48.3	66.5

- South Atlantic Region (High-Sulfur Bituminous Coal)

	Market Share (percent)	
Technology	Economic	Economic/Attitudinal
Sodium FGD	7.9	1.7
Dual Alkali FGD	19.3	16.3
Lime/Limestone FGD	20.6	8.7
Lime Spray Dryer FGD	28.1	35.9
AFB	24.2	37.4

*Market share estimates for the year 2000

Exhibit 4.k

Impact of Attitudinal Factors on Market Application*

Application	Economic Market Size (10^{12} Btu/yr)	Economic/Judgmental Market Size (10^{12} Btu/yr)
New	1,608	1,608
Retrofit	855	677
Replacement	1,396	1,457
Total	3,859	3,742

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*For the entire period 1982-2001

the effect on the overall market size is small, with a net reduction of about 3 percent.

Appendix A STATE SO_2 REGULATIONS

We reviewed the state SO_x emission requirements for MFBI systems of 100 mmBtu or greater*. These are summarized in Exhibit A.1, together with each state's 1979 industrial energy consumption and an indication of whether portions of the state are not complying with the primary NAAQS SO_2 standard**. (The MFBI emission limit shown is that for a 100 mmBtu/hr fuel input boiler. Most states have the same limitation for all boilers over 100 mmBtu/hr.)

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*Sedman, C.B. "New Source Performance Standards for Industrial Boilers." Symposium on Flue Gas Desulfurization. Houston, Texas, October, 1980.

**Environmental Protection Agency. Office of Air Quality Planning and Standards. Durham, N.C.

Exhibit A.1

SIP SO_x Regulations for New Coal-Fired Boilers

	Total 1979 Industrial Energy Consumption (10^9 mmBtu/yr)	MFBI Emission Limit (lb SO_x/mmBtu)	Are Portions of State Exceeding Primary SO_x NAAQS Standard?
Region 1			
Maine	140	2.85	Yes
New Hampshire	45	1.50	Yes
Vermont	27	3.17	--
Massachusetts	242	0.28	--
Connecticut	212	0.55	--
Rhode Island	38	0.55	--
Region 2			
New York	1,140	2.80	Yes
New Jersey	684	1.50	--
Region 3			
Pennsylvania	1,999	8.90	Yes
Maryland*	428	0.95	--
Delaware	80	1.58	--
Virginia	396	1.06	--
West Virginia	435	1.60	--
District of Columbia	42	0.79	--
Region 4			
North Carolina	621	1.60	--
South Carolina	404	2.30	--
Georgia	551	1.90	--
Florida	564	6.17	--
Alabama	1,002	1.80	Yes
Mississippi	421	2.40	--
Tennessee	694	1.60	Yes
Kentucky	635	1.69	Yes

*Specifies "low sulfur" coal; this limit is for 0.5 percent sulfur coal, 12,000 Btu/lb.

Exhibit A.1 (continued)

SIP SO_x Regulations for New Coal-Fired Boilers

	Total 1979 Industrial Energy Consumption (10^9 mmBtu/yr)	MFBI Emission Limit (lb SO_x/mmBtu)	Are Portions of State Exceeding Primary SO_x NAAQS Standard?
Region 5			
Ohio	2,072	1.00	Yes
Indiana	1,396	4.68	Yes
Illinois	1,430	1.80	Yes
Michigan	1,052	2.40	Yes
Wisconsin	495	2.38	Yes
Minnesota	529	2.38	Yes
Region 6			
Louisiana	2,083	Ambient Regulations	--
Arkansas	371	Ambient Regulations	--
Oklahoma	570	1.20	--
Texas	4,642	3.00	--
New Mexico	151	No Regulation	Yes
Region 7			
Missouri*	373	1.25	--
Kansas	494	No Regulation	--
Iowa	426	5.00	Yes
Nebraska	198	3.96	--
Region 8			
Colorado*	253	1.25	--
Utah	218	1.58	Yes
Wyoming	264	No Regulation	--
South Dakota	68	3.00	--
North Dakota	94	3.00	Yes
Montana	178	1.00	--

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*Standard is 500 ppm; for 3 percent sulfur coal, 500 ppm SO_2 in stack gas = 1.25 lb SO_2/mmBtu fired.

Exhibit A.1 (continued)

SIP SO_x Regulations for
New Coal-Fired Boilers

	Total 1979 Industrial Energy Consumption (10^9 mm/Btu/yr)	MFBI Emission Limit (lb SO_x/mmBtu)	Are Portions of State Exceeding Primary SO_x NAAQS Standard?
Region 9			
California*	1,639	0.79	Yes
Arizona	236	0.80	Yes
Nevada	75	0.70	Yes
Hawaii	69	3.17	--
Region 10			
Oregon	290	1.58	--
Washington	573	2.50	--
Idaho	135	1.58	Yes
Alaska	137	1.25	--

*Standard is 200 lb/hr, 0.2 percent SO_2 by volume, 1,000 ppm, or 0.5 percent sulfur.

SOURCE: Sedman, C.B., "New Source Performance Standards for Industrial Boilers," Symposium on Flue Gas Desulfurization; Houston, Texas; October, 1980.

Appendix B ESTIMATING COSTS AND PERFORMANCES FOR EMISSION CONTROL SYSTEMS

A consistent set of capital cost, O&M costs, and performances was developed by Foster Wheeler Development Corporation (with minor modifications by ORNL).*

Costs were developed for the following systems:

- Stoker and pulverized coal boilers
- Sodium throwaway FGD
- Lime/limestone FGD
- Dual-alkali FGD
- Lime spray dryer FGD
- AFB combustor
- Low and medium-Btu on-site and central coal gasifier
- Residual oil boiler
- Low- and medium-Btu gas boiler.

Conceptual cost estimates were developed for each major subsystem of a reference plant sized to provide 250 mmBtu/hr heat absorbed in the boiler. Exhibit B.1 summarizes the general design conditions.

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*These systems and cost estimates are described in more detail in: A Comparative Assessment of Industrial Boiler Options Relative to Air Emission Regulations, Oak Ridge National Laboratory (in preparation), and Industrial Steam Supply Systems Characteristics Program: Phase I - Conventional Boilers and Atmospheric Fluidized Bed Combustor; Phase II - Low- and Medium- Btu Gas Fired Boilers with Associated Gasification Plants, Foster Wheeler Development Corporation, August 1981 (FWDC No.9-41-8903).

Exhibit B.1

Steam System Design Parameters

Heat absorbed:	250 x 10^6 Btu/h
Steam pressure:	650 lb/in^{2}g
Steam temperature:	750°F
Feedwater temperature:	250°F
Feedwater makeup:	50 percent
Condensate return:	50 percent
Plant availability:	90 percent
Turndown ratio:	4.1

Exhibit B.2

Coal Properties

Component/Property	Eastern High-Sulfur Bituminous Coal	Western Low-Sulfur Subbituminous Coal
Proximate Analysis (wt%, wet):		
Volatile matter	35.2	32.5
Fixed carbon	43.2	30.7
Ash	10.3	5.0
Moisture	11.3	31.8
Ultimate Analysis (wt%, dry):		
Carbon	69.33	69.3
Hydrogen	4.30	5.2
Nitrogen	0.86	0.9
Chlorine	0.04	---
Sulfur	3.61	0.5
Oxygen	9.64	16.8
Ash Analysis (wt%, dry):		
P_2O_5	0.05	---
SiO	45.73	28.8
Fe_2O_3	18.38	9.0
AL_2O_3	19.40	13.0
TiO_2	1.30	0.7
C_aO	5.50	25.0
MgO	0.95	6.5
SO_3	6.63	18.0
K_2O	1.53	0.4
Na_2O	0.02	1.2
Undetermined	0.02	---
Higher Heating Value (Btu/lb):		
As received	11,026	8,164
Dry	12,432	11,970
Ash Fusion Temperature		
(Reducing/oxidizing (^oF):		
Initial deformation	1950/2270	2140/2160
Softening temperature:		
Spherical	2140/2380	2180/2190
Hemispherical	2160/2400	2200/2210
Fluid	2250/2500	2280/2370

Designs were developed for two reference coal types: a high sulfur (3.6 percent) eastern bituminous, and a low-sulfur (0.5 percent) western subbituminous. These are representative of the major coal types available in the United States. Exhibit B.2 summarizes the coal characteristics.

In addition to the cost estimates for the reference-sized system, scaling factors were developed for each cost component to allow extrapolation of these costs to other size systems. The cost of each component is given by the equation: $C = A \quad (S/S_r)^b$

where:

C = capital cost of component
A = capital cost of reference system
S = size of desired system
S_r = size of reference system
B = component cost scaling factor.

Detailed cost estimates were developed for the following component cost categories:

- Site work
- Boiler plant
- Boiler support
- Coal handling
- General support facilities
- Indirect costs
- Flue gas desulfurizer
- Particulate removal.

The total capital cost is the sum of these cost components. The indirect costs comprise field indirects and home office costs. Field indirects are 130 percent of indirect labor. Home office costs are 13.37 percent of the sum of field indirects and total direct costs. The cost estimates for FGD particulate removal systems include the indirect costs. Costs for conventional boiler, FGD, and particulate systems include a 20 percent contingency allowance; costs for AFBs and gasifiers include a 25 percent contingency.

Exhibit B.3 summarizes these capital cost equations for this study. High-sulfur systems were assumed to have a 90 percent sulfur removal requirement; low-sulfur, a 70 percent sulfur removal requirement. High-sulfur stoker and pulverized coal systems (except for the lime spray dryer FGD) and oil boiler systems used an electrostatic precipitator (ESP) for particulate removal; low-sulfur stoker and pulverized coal, lime spray dryer FGD, and AFB systems used baghouses. (The cost of the AFB baghouse is included in the AFB boiler support facility costs.) The exhibit also summarizes the relative efficiencies of the systems. It shows the gross efficiency (heat absorbed in boiler divided by fuel input) and boiler house losses (fraction of heat absorbed needed for fans, etc.). The overall efficiency is the gross efficiency times 1.0 minus boiler house losses.

The nonfuel O&M costs are divided into a fixed and variable portion. The fixed portion does not change with plant operating factor; the variable portion is proportional to energy production.

Exhibit B.3

Boiler and Emission Control Technology (ECT) Capital Costs for Systems Using High-Sulfur, Bituminous Coal[1]
(Millions of 1981 dollars)

			Boiler Plant		Site Work		Boiler Support		General Facilities		Coal Handling		Indirect Costs		FGD Costs		Particulate Control	
Technology	Gross Efficiency	Other Losses	C_1	C_2	C_3	C_4	C_5	C_6	C_7	C_8	C_9	C_{10}	C_{11}	C_{12}	C_{13}	C_{14}	C_{15}	C_{16}
Stoker Systems																		
No FGD	0.845	0.107	9.54	0.67	0.36	0.60	1.60	0.38	0.65	0.61	5.36	0.53	6.11	0.65	0.00	0.00	2.11	0.60
Sodium	0.845	0.139	9.54	0.67	0.36	0.60	1.60	0.38	0.65	0.61	5.36	0.53	6.11	0.65	9.71	0.66	2.11	0.60
Dual alkali	0.845	0.139	9.54	0.67	0.36	0.60	1.60	0.38	0.65	0.61	5.36	0.53	6.11	0.65	4.09	0.66	2.11	0.60
Lime/limestone	0.845	0.139	9.54	0.67	0.36	0.60	1.60	0.38	0.65	0.61	5.36	0.53	6.11	0.65	3.41	0.66	2.11	0.60
Lime spray dryer	0.845	0.107	9.54	0.67	0.36	0.60	1.60	0.38	0.65	0.61	5.36	0.53	6.11	0.65	3.34	0.66	3.08	0.60
Pulverized Coal Systems																		
No FGD	0.857	0.107	12.28	0.70	0.36	0.60	1.60	0.38	0.65	0.61	5.36	0.53	7.38	0.69	0.00	0.00	1.97	0.60
Sodium	0.857	0.141	12.28	0.70	0.36	0.60	1.60	0.38	0.65	0.61	5.36	0.53	7.38	0.69	9.71	0.66	1.97	0.60
Dual alkali	0.857	0.141	12.28	0.70	0.36	0.60	1.60	0.38	0.65	0.61	5.36	0.53	7.38	0.69	4.09	0.66	1.97	0.60
Lime/limestone	0.857	0.141	12.28	0.70	0.36	0.60	1.60	0.38	0.65	0.61	5.36	0.53	7.38	0.69	3.41	0.66	1.97	0.60
Lime spray dryer	0.857	0.107	12.28	0.70	0.36	0.60	1.60	0.38	0.65	0.61	5.36	0.53	7.38	0.69	3.34	0.66	3.08	0.60
AFB	0.859	0.143	12.00	0.62	0.38	0.60	5.84	0.39	0.68	0.61	5.36	0.53	8.49	0.58	0.00	0.00	0.00	0.00
Gasifier[2]	0.621	0.156	26.63	0.81	0.00	0.00	4.54	0.70	6.68	0.45	7.23	0.75	15.13	0.74	0.00	0.00	0.00	0.00
Low-Btu gas boiler	0.791	0.107	7.20	0.63	0.09	0.60	0.11	0.60	0.51	0.62	0.00	0.00	3.88	0.63	0.00	0.00	0.00	0.00
Medium-Btu gas boiler	0.837	0.107	6.08	0.63	0.09	0.60	0.11	0.60	0.51	0.62	0.00	0.00	3.34	0.63	0.00	0.00	0.00	0.00
Oil-fired boiler	0.861	0.107	6.40	0.63	0.18	0.60	0.31	0.60	0.59	0.66	0.00	0.00	3.85	0.62	0.00	0.00	1.61	0.60

---

[1] High sulfur = 3.5 percent sulfur.
Turnkey capital cost = $C_1M^{C_2} + C_3M^{C_4} + C_5M^{C_6} + C_7M^{C_8} + C_9M^{C_{10}} + C_{11}M^{C_{12}} + C_{13}M^{C_{14}} + C_{15}M^{C_{16}}$.
M = ratio of gross steam requirements = (S/S_R).
Sulfur removal = 90 percent.

[2] Total gasifier system capital cost is computed by adding gasifier cost and low-Btu gas boiler capital costs.

Exhibit B.3

Boiler and Emission Control Technology (ECT) Capital Costs for Systems Using Low-Sulfur, Subbituminous Coal[1]
(Millions of 1981 dollars)

			Boiler Plant		Site Work		Boiler Support		General Facilities		Coal Handling		Indirect Costs		FGD Costs		Particulate Control	
Technology	Gross Efficiency	Other Losses	C_1	C_2	C_3	C_4	C_5	C_6	C_7	C_8	C_9	C_{10}	C_{11}	C_{12}	C_{13}	C_{14}	C_{15}	C_{16}
Stoker Systems																		
No FGD	0.798	0.107	11.67	0.67	0.36	0.60	1.52	0.38	0.65	0.61	6.39	0.53	6.97	0.65	0.00	0.00	3.08	0.60
Sodium	0.798	0.143	11.67	0.67	0.36	0.60	1.52	0.38	0.65	0.61	6.39	0.53	6.97	0.65	2.42	0.66	3.08	0.60
Dual alkali	0.798	0.143	11.67	0.67	0.36	0.60	1.52	0.38	0.65	0.61	6.39	0.53	6.97	0.65		0.66	3.08	0.60
Lime/limestone	0.798	0.143	11.67	0.67	0.36	0.60	1.52	0.38	0.65	0.61	6.39	0.53	6.97	0.65	2.87	0.66	3.08	0.60
Lime spray dryer	0.798	0.107	11.67	0.67	0.36	0.60	1.52	0.38	0.65	0.61	6.39	0.53	6.97	0.65	2.68	0.66	3.08	0.60
Pulverized Coal Systems																		
No FGD	0.808	0.107	15.37	0.70	0.36	0.60	1.52	0.38	0.65	0.61	6.39	0.53	8.82	0.69	0.00	0.00	3.22	0.60
Sodium	0.808	0.147	15.37	0.70	0.36	0.60	1.52	0.38	0.65	0.61	6.39	0.53	8.82	0.69	2.42	0.66	3.22	0.60
Lime/limestone	0.808	0.147	15.37	0.70	0.36	0.60	1.52	0.38	0.65	0.61	6.39	0.53	8.82	0.69	2.87	0.66	3.22	0.60
Lime spray dryer	0.808	0.107	15.37	0.70	0.36	0.60	1.52	0.38	0.65	0.61	6.39	0.53	8.82	0.69	2.68	0.66	3.22	0.60
AFB	0.828	0.145	12.00	0.62	0.38	0.60	4.41	0.39	0.68	0.61	6.39	0.53	8.01	0.58	0.00	0.00	0.00	0.00
Gasifier[2]	0.635	0.147	22.51	0.75	0.00	0.00	4.71	0.68	5.57	0.15	8.36	0.75	13.56	0.69	0.00	0.00	0.00	0.00
Low-Btu gas boiler	0.791	0.107	7.20	0.63	0.09	0.60	0.11	0.60	0.51	0.62	0.00	0.00	3.88	0.63	0.00	0.00	0.00	0.00
Medium-Btu gas boiler	0.837	0.107	6.08	0.63	0.09	0.60	0.11	0.60	0.51	0.62	0.00	0.00	3.34	0.63	0.00	0.00	0.00	0.00
Oil-fired boiler	0.861	0.107	6.40	0.63	0.18	0.60	0.31	0.60	0.59	0.66	0.00	0.00	3.85	0.62	0.00	0.00	0.00	0.00

---

[1] Low sulfur = 0.6 percent sulfur.
Turnkey capital cost = $C_1M^{C_2} + C_3M^{C_4} + C_5M^{C_6} + C_7M^{C_8} + C_9M^{C_{10}} + C_{11}M^{C_{12}} + C_{13}M^{C_{14}} + C_{15}M^{C_{16}}$.
M = ratio of gross steam requirements = (S/S_R).
Sulfur removal = 70 percent.

[2] Total gasifier system capital cost is computed by adding gasifier cost and low-Btu gas boiler capital costs.

These costs are divided into six subcost categories:

- Manpower
- Electricity
- Waste disposal
- Maintenance
- Water
- Desulfurization
- Coal handling
- Particulate removal.

The total O&M costs are determined by summing the individual subcost categories. The equations for these are summarized in Exhibit B.4. Exhibit B.5 summarizes the coefficients.

Adjustments were made to these costs to develop costs for cogeneration systems using a conventional back-pressure steam turbine topping cycle, in which steam from the boiler is taken through the turbine and used to generate electricity. The turbine exhaust is then used for process.

The electric-to-thermal ratio (E/T) of the system was taken to be 0.11. The overall efficiency loss is approximately 5 percent greater than that of a conventional noncogenerating system. Since these systems typically require a higher pressure than conventional systems (850 psig/825°F compared with the 650 psig/750°F used in the ORNL estimates), the boiler capital costs were increased by 2 percent*.

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*The variation of boiler capital costs with pressure and other factors is discussed in "Estimating Industrial Steam Costs," Coffin, B.D., Power, April 1979, pp. 106-111.

Exhibit B.4

Nonfuel O&M Cost Equations

Manpower $= P_1 \ (F/F_R)^{0.2}$

Electricity $= P_2 \ (F/F_R)^{CCSF} \ P_3 \ (F/F_R) \ (AU/AU_R) \ (R/R_R)^{P4}$

Waste Disposal $= P_5 \ (F/F_R) \ (AU/AU_R)$

Maintenance $= P_6 \ (F/F_R)^{CCSF}$

Water $= 0.0232 \ (F/F_R)$ for boilers

$= P_7 \ (F/F_R) \ (AU/AU_R) \ (R/R_R)^{P8}$

Desulfurization $= P_9 \ (F/F_R) \ (AU/AU_R) \ (R/R_e)^{P10}$

Particulate Removal $= P_{11} \ (F/F_R)^{0.60}$

Coal Handling $= 0.143 \ (F/F_R)^{0.53}$ for bituminous coal systems

$= 0.169 \ (F/F_R)^{0.53}$ for subbituminous coal systems

$= 0.336 \ (F/F_R)^{0.53}$ for bituminous gasifier

$= 0.388 \ (F/F_R)^{0.53}$ for subbituminous gasifier

where:

$P_1 - P_{11}$ = O&M cost parameters, Exhibit A.5.

(F/F_R) = ratio of system net-steam-to-process to net-steam-to-process of reference system.

(AU/AU_R) = ratio of annual utilization to reference annual utilization (AU_R = 1.0).

(R/R_R) = ratio of desired removal efficiency to reference removal efficiency.
R_R = 0.90 for Eastern high-sulfur coal
R_R = 0.70 for Western low-sulfur coal.

CCSF = capital cost scaling factor.

Exhibit B.5

Boiler and Emission Control Technology Nonfuel O&M Costs for Systems Using High-Sulfur, Bituminous Coal
(Millions of 1981 dollars)

Technology	Capital Cost Scaling Factor	Manpower	Electricity			Waste Disposal	Maintenance	Water		Desulfurization		Particulate Removal
		P_1	P_2	P_3	P_4	P_5	P_6	P_7	P_8	P_9	P_{10}	P_{11}
Stoker Systems												
No FGD	0.65	0.735	0.049	0.014	0.00	0.098	0.408	0.023	0.000	0.000	0.00	0.004
Sodium	0.66	0.420	0.000	0.089	0.48	0.000	0.029	0.007	0.078	1.200	1.00	0.004
Dual alkali	0.66	0.347	0.000	0.153	0.56	0.368	0.069	0.003	0.160	0.319	1.00	0.004
Lime/limestone	0.66	0.421	0.000	0.184	0.56	0.453	0.054	0.003	0.190	0.217	1.00	0.004
Lime spray dryer	0.66	0.309	0.000	0.204	0.90	0.181	0.046	0.002	0.600	0.235	1.00	0.004
Pulverized Coal Systems												
No FGD	0.69	0.789	0.049	0.114	0.00	0.095	0.515	0.023	0.00	0.000	0.00	0.036
Sodium	0.66	0.420	0.000	0.092	0.48	0.000	0.029	0.008	0.77	0.204	1.00	0.036
Dual alkali	0.66	0.347	0.000	0.161	0.56	0.368	0.069	0.003	0.12	0.319	1.00	0.036
Lime/limestone	0.66	0.421	0.000	0.190	0.56	0.453	0.054	0.003	0.06	0.217	1.00	0.036
Lime spray dryer	0.66	0.309	0.000	0.215	0.88	0.228	0.046	0.002	0.73	0.235	1.00	0.036
AFB	0.58	0.911	0.049	0.047	0.00	0.309	0.649	0.023	0.00	0.578	0.52	0.000
Gasifier	0.74	1.596	0.192	1.309	0.00	0.182	1.403	0.184	0.48	-0.018	1.00	0.000
Low-Btu gas boiler	0.63	0.487	0.046	0.003	0.00	0.000	0.226	0.023	0.00	0.000	0.00	0.000
Medium-Btu gas boiler	0.63	0.487	0.046	0.003	0.00	0.000	0.039	0.023	0.00	0.000	0.00	0.000
Oil boiler	0.62	0.487	0.046	0.003	0.00	0.000	0.242	0.023	0.00	0.000	0.00	0.000

Exhibit B.5

Boiler and Emission Control Technology Nonfuel O&M Costs for Systems Using Low-Sulfur, Subbituminous Coal
(Millions of 1981 dollars)

		Manpower	Electricity			Waste Disposal		Maintenance	Water		Desulfurization		Particulate Removal
Technology	Capital Cost Scaling Factor	P_1	P_2	P_3	P_4	P_5	P_6	P_7	P_8	P_9	P_{10}	P_{11}	P_{12}
Stoker Systems													
No FGD	0.65	0.735	0.049	0.021	0.00	0.095	0.00	0.490	0.023	0.00	0.000	0.00	0.074
Sodium	0.66	0.420	0.000	0.078	0.73	0.000	0.00	0.025	0.003	0.30	0.139	1.00	0.074
Lime/limestone	0.66	0.421	0.000	0.169	0.53	0.056	1.00	0.046	0.003	0.18	0.024	1.00	0.074
Lime spray dryer	0.66	0.309	0.000	0.169	0.86	0.041	0.30	0.043	0.002	0.64	0.023	1.00	0.074
Pulverized Coal Systems													
No FGD	0.69	0.789	0.049	0.152	0.00	0.084	0.00	0.643	0.023	0.00	0.000	0.00	0.077
Sodium	0.66	0.420	0.000	0.092	0.73	0.00	0.00	0.025	0.003	0.28	0.139	1.00	0.077
Lime/limestone	0.66	0.421	0.000	0.184	0.53	0.056	1.00	0.046	0.003	0.06	0.024	1.00	0.077
Lime spray dryer	0.66	0.309	0.000	0.202	0.87	0.069	0.17	0.043	0.002	0.73	0.023	1.00	0.077
AFB	0.58	0.911	0.049	0.045	0.00	0.087	0.00	0.490	0.023	0.00	0.053	0.52	0.000
Gasifier	0.69	1.596	0.196	2.056	0.00	0.133	0.00	1.288	0.086	0.11	-0.015	1.00	0.000
Low-Btu gas boiler	0.63	0.487	0.046	0.003	0.00	0.000	0.00	0.270	0.023	0.00	0.000	0.00	0.000
Medium-Btu gas boiler	0.63	0.487	0.046	0.003	0.00	0.000	0.00	0.226	0.023	0.00	0.000	0.00	0.000
Oil boiler	0.62	0.487	0.046	0.003	0.00	0.000	0.00	0.242	0.023	0.00	0.000	0.00	0.000

In addition, the boiler and ancillary equipment needed to be oversized by a factor of 1.17 (= (1.0 + 0.11)/0.95) to allow for the additional fuel needed for the power generation and the additional efficiency losses.

Based on a review of cost quotations for steam turbines ranging in size from 1 MW to 73 MW, we developed the following formula for estimating the total installed cost of the turbine/generator package:

$$\text{cost (millions of 1980\$)} = 0.769\ (\text{MW})^{0.727}$$

Annual O&M costs for the turbine/generator were estimated at 3 percent of the installed capital costs.

Finally, the capital costs for the systems were adjusted to reflect regional cost differences. These adjustments are given in Exhibit B.6, which was provided by Foster-Wheeler.

Exhibit B.6

Regional Cost Multipliers

Region	City	Cost multiplier[a]
1	Boston	1.17
2	New York	1.22
3	Philadelphia	1.17
4	Altanta	1.02
5	Chicago	1.17
6	Dallas	1.05
7	Kansas City	1.13
8	Denver	1.08
9	San Francisco	1.27
10	Seattle	1.21

[a] Ratio of capital investment cost in subject region to base cost in reference city(New Orleans).

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Appendix C METHODOLOGY FOR PROJECTING THE MARKET

Our methodology for estimating the market potential for SO_2 emission control technologies involved four steps:

1) Identifying market segments by categorizing the market for steam demand in terms of factors that influence steam supply and demand

2) Determining the relative economic attractiveness of each technology in each market segment

3) Calculating the expected market share for each technology in each market segment

4) Translating market shares into projected steam demand for each market segment.

In this appendix, we explain the purpose and methodology of each step and state our underlying assumptions.

STEP ONE:
IDENTIFYING MARKET SEGMENTS

The purpose of this step was to divide the steam market into specific segments so that we could simulate the investment needed for SO_2 ECTs. With this segmentation of the market, it was possible to determine the market potential for each ECT, given the technical and financial performances in each segment.

We identified 360 market segments in each of 10 time periods by segmenting the market by:

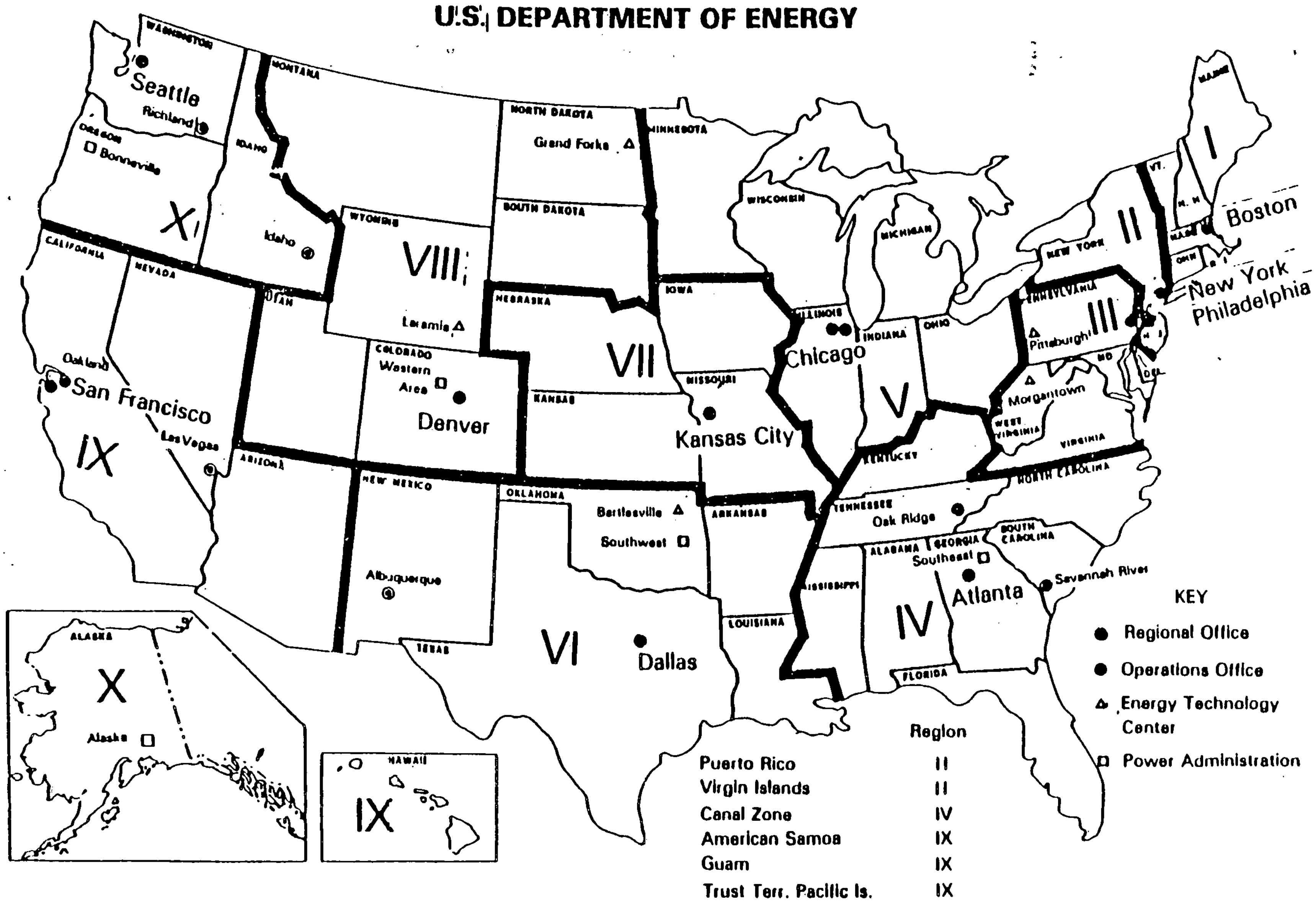
- DOE region
- Type of investment (new, replacement, or retrofit)
- Boiler size
- Electric to thermal load ratio for industrial applications
- Current fuel used (for retrofit markets)
- Time period (1982-2001) in two-year intervals.

DOE Region

By dividing the steam market into DOE regions (see Exhibit C.1), we could incorporate three important variables into our model: regional fuel prices, regional steam demand and growth, and fuel availability. Exhibit C.2 summarizs our assumptions about regional fuel prices, which were based on data provided by EIA's Mid-Term Energy Forecasting System using the medium world oil price scenario. Exhibit C.3 projects MFBI boiler consumption to 2000. The EIA data also projected the types of coal that would be available for new coal-fired installations in each region: primarily medium- to high-sulfur coals in the New England, New York/New Jersey, Mid-Atlantic, South Atlantic, Midwest, Central, and Northwest regions; and primarily low-sulfur coals in the Southwest, West, and North Central regions.

Exhibit C.1

DOE Regions



	Region
Puerto Rico	II
Virgin Islands	II
Canal Zone	IV
American Samoa	IX
Guam	IX
Trust Terr. Pacific Is.	IX

Exhibit C.2

Region: I (New England)
(1979 $/mmBtu)

	1979	1985	1990	1995	2020
Coal	1.79	2.69	2.96	3.07	3.65
Distillate oil	4.87	7.42	8.27	9.83	15.34
Residual oil	3.45	6.56	7.32	8.65	13.50
Natural gas	2.95	6.11	6.82	8.17	12.75
Electricity					
Retail	11.31	19.73	18.10	14.73	17.98
Buyback	13.57	23.66	22.08	16.20	12.59
Buyback/retail	1.20	1.20	1.22	1.10	0.70

Region: II (New York/New Jersey)
(1979 $/mmBtu)

	1979	1985	1990	1995	2020
Coal	1.47	2.25	2.51	2.59	3.08
Distillate oil	4.71	7.49	8.33	9.89	15.44
Residual oil	3.28	6.72	7.48	8.81	13.35
Natural gas	2.69	6.27	6.98	8.33	13.00
Electricity					
Retail	1015	16.49	15.04	14.66	17.89
Buyback	10.15	16.49	13.39	13.05	12.52
Buyback/retail	1.00	1.00	0.89	0.89	0.70

Exhibit C.2 (continued)

Region: III (Mid-Atlantic)
(1979 $/mmBtu)

	1979	1985	1990	1995	2020
Coal	1.26	1.91	2.17	2.22	2.64
Distillate oil	4.67	7.66	8.51	10.08	15.73
Residual oil	3.25	6.86	7.62	8.95	13.97
Natural gas	2.24	6.40	7.11	8.46	13.20
Electricity					
Retail	8.95	12.23	13.15	13.69	16.71
Buyback	11.72	16.02	14.60	13.14	11.70
Buyback/retail	1.31	1.31	1.11	0.96	0.70

Region: IV (South Atlantic)
(1979 $/mmBtu)

	1979	1985	1990	1995	2020
Coal	1.40	2.74	3.19	3.31	3.94
Distillate oil	4.59	7.66	8.51	10.13	15.81
Residual oil	2.91	6.49	7.26	8.59	13.41
Natural gas	1.93	6.04	6.76	8.11	12.66
Electricity					
Retail	7.90	10.81	11.71	12.34	15.06
Buyback	9.01	12.32	14.75	15.42	10.54
Buyback/retail	1.14	1.14	1.26	1.25	0.70

Exhibit c.2 (continued)

Region: V (Midwest)
(1979 $/mmBtu)

	1979	1985	1990	1995	2020
Coal	1.36	1.99	2.21	2.26	2.69
Distillate oil	4.69	7.27	8.12	9.75	15.21
Residual oil	2.93	6.52	7.29	8.55	13.35
Natural gas	2.11	6.07	6.79	8.07	12.59
Electricity					
Retail	8.40	11.70	12.53	11.88	14.99
Buyback	7.81	10.88	13.78	14.26	10.49
Buyback/retail	0.93	0.93	1.10	1.20	0.70

Region: VI (Southwest)
(1979 $/mmBtu)

	1979	1985	1990	1995	2020
Coal	1.43	2.66	2.95	3.20	3.81
Distillate oil	4.76	7.41	8.26	9.89	15.44
Residual oil	2.87	6.54	7.32	8.69	13.56
Natural gas	1.21	4.62	5.39	5.55	8.66
Electricity	1.21	4.62	5.39	5.55	8.66
Retail	7.29	16.69	14.89	15.38	18.76
Buyback	8.02	18.36	19.36	13.69	13.13
Buyback/retail	1.10	1.10	1.30	0.89	0.70

Exhibit c.2 (continued)

Region: VII (Central

(1979 $/mmBtu)

	1979	1985	1990	1995	2020
Coal	1.31	1.69	1.87	1.94	2.31
Distillate oil	4.73	7.21	8.06	9.69	15.13
Residual oil	2.89	6.56	7.33	8.59	13.41
Natural gas	1.69	6.10	6.83	8.09	12.63
Electricity					
Retail	8.28	13.59	12.36	12.81	15.63
Buyback	3.97	6.50	12.11	14.86	10.94
Buyback/retail	0.48	0.48	0.98	1.16	0.70

Region: VIII (North Central)

(1979 $/mmBtu)

	1979	1985	1990	1995	2020
Coal	1.04	1.33	1.35	1.44	1.71
Distillate oil	4.50	7.28	8.12	9.74	15.20
Residual oil	2.82	6.32	7.07	8.45	13.19
Natural gas	1.49	4.35	5.26	5.41	8.44
Electricity					
Retail	5.48	11.46	8.20	7.64	9.32
Buyback	1.37	2.87	5.00	8.55	6.52
Buyback/retail	0.25	0.25	0.61	1.12	0.70

Exhibit c.2 (continued)

Region: IX (West)
(1979 $/mmBtu)

	1979	1985	1990	1995	2020
Coal	1.29	2.85	3.09	3.26	3.88
Distillate oil	4.54	7.01	7.85	9.41	14.69
Residual oil	2.96	6.22	6.97	8.29	12.94
Natural gas	2.36	5.77	6.46	7.81	12.19
Electricity					
Retail	9.74	16.22	15.33	15.02	18.32
Buyback	11.20	18.65	20.24	14.42	12.82
Buyback/retail	1.15	1.15	1.32	0.96	0.70

Region: X (Northwest)
(1979 $/mmBtu)

	1979	1985	1990	1995	2020
Coal	1.36	1.89	2.19	2.50	2.98
Distillate oil	4.33	7.01	7.85	9.41	14.69
Residual oil	2.92	6.17	6.92	8.25	12.87
Natural gas	2.01	6.32	6.70	7.74	12.08
Electricity					
Retail	2.24	3.51	4.94	4.49	5.48
Buyback	3.43	5.37	5.09	8.35	3.84
Buyback/retail	1.53	1.53	1.03	1.86	0.70

Exhibit C.3

REGIONAL MFBI FUEL CONSUMPTION
(10^{12} Btu/yr)

Region	1980	1985	1990	1995	2000
New England	73.7	80.3	83.9	84.0	84.1
New York/ New Jersey	122.5	133.9	140.1	145.6	150.2
Mid-Atlantic	243.5	282.3	217.4	219.1	220.8
South Atlantic	500.5	594.3	645.4	722.2	786.1
Midwest	687.2	796.7	724.7	742.8	757.9
Southwest	987.9	1,145.5	1,487.6	1,746.4	1,961.6
Central	133.0	154.2	152.9	170.8	185.7
North Central	74.2	86.0	96.6	100.5	103.7
West	144.8	175.5	192.2	202.5	210.6
Northwest	122.2	141.7	161.3	181.2	197.7
Total	3,089.5	3,590.4	3,902.1	4,315.0	4,658.4

Type of Investment

We considered three types of investment in the steam market: new, retrofit, and replacement.

New demand represents the increase in steam demand each year. On the assumption that all new steam demand must be met, and must be met using coal, we treat advanced ECT systems for the new market as nondiscretionary investments.

Replacement investment is made when a steam generator's useful economic life has ended. We calculated replacement investments by multiplying the base year (1980) steam demand by the phase-out ratio. We calculated the phase-out ratio using the average vintage of the MFBI steam generator population. (We explain this process in more detail in our explanation of Step 4.) Replacement investments are treated as nondiscretionary because we assume that steam generators have reached the end of their economic life and must be replaced.

Retrofit investments involve the retirement and replacement of steam generators before the end of their useful economic lives. The existing gas- or oil-fired boiler is either scrapped, with a scrap value equal to the disassembly costs, or put on standby. Then a new coal-fired system is installed, capital costs for which must be justified by the incremental fuel savings. Because retrofit investments are not necessary, they are treated as discretionary investments.

Boiler Size

We segmented the boiler market by size to examine the probable effect on market shares of technologies that offer significantly different costs and performance for units in different size ranges. To codify the distribution of unit size, we relied on EPA data on the population of industrial boilers.* We divided our industrial boilers into three size ranges, based on net steam to process: 100-250 mmBtu/hr, 250-500 mmBtu/hr, and greater than 500 mmBtu/hr. These represent 45, 24, and 31 percent of the MFBI market, respectively.

Electric to Thermal (E/T) Load Ratio

Our purpose in segmenting the steam market by E/T ratio (see Exhibit C.5) was to take into account the diversity of demand among manufacturing processes and to characterize differences in economic performance among cogeneration systems at different E/T ratios. We divided the market into three sectors: 0-0.1, 0.1-0.2, and greater than 0.2. These represent 27, 50, and 23 percent of the market, respectively.

Current Fuel Use

We further divided the retrofit market according to current fuel use. We assumed that those parts of the retrofit market that now use critical fuels (natural gas, or distillate or residual oil) are candidates for retrofit

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* EPA, The Population and Characteristics of Industrial/Commercial Boilers.

Exhibit C.4

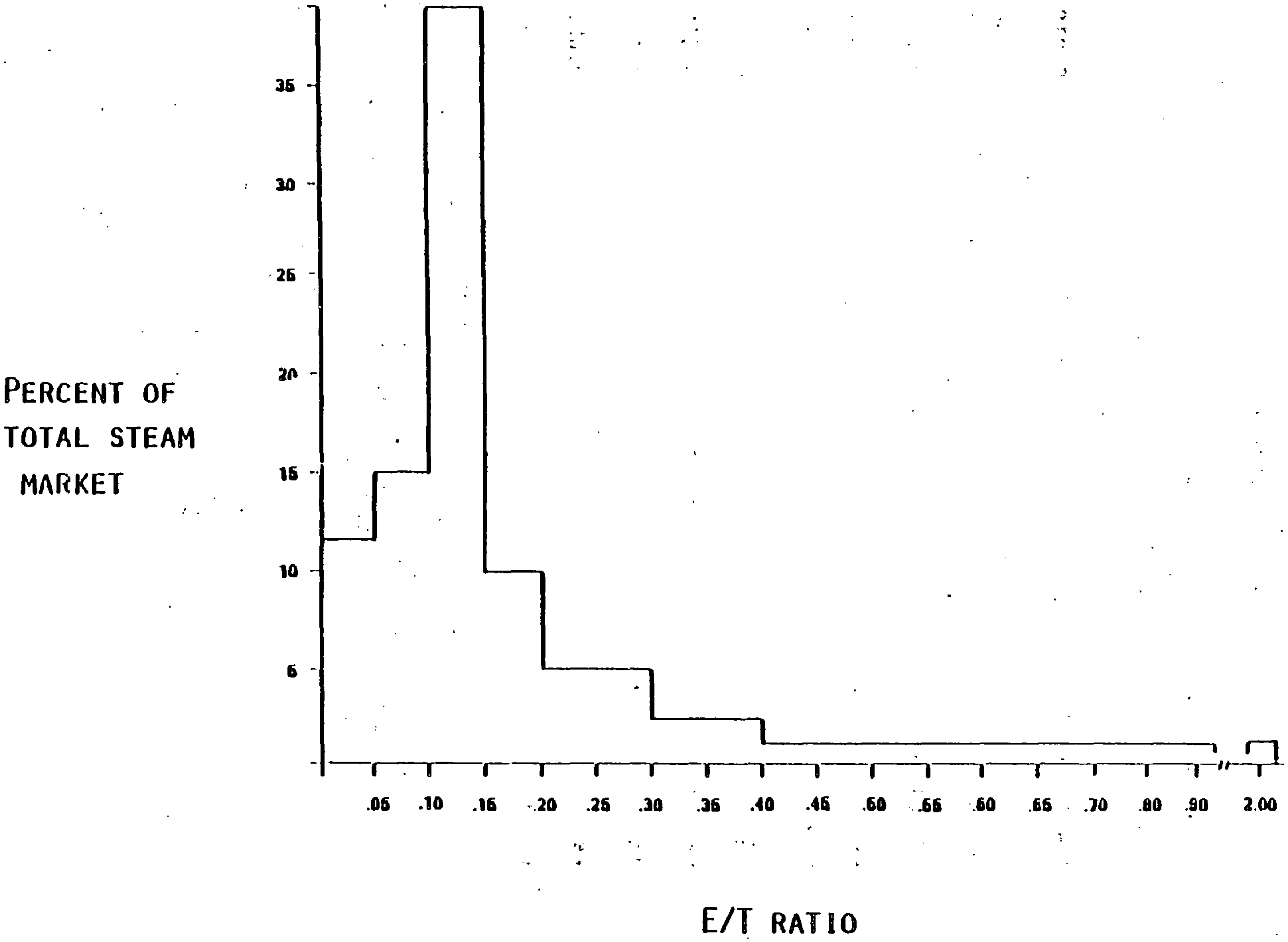
Summary of 1980 MFBI Fuel Use
(fraction of total regional demand)

Region	Natural Gas and Residual Oil	Distillate Oil	Coal
New England	0.874	0.116	0.010
New York/ New Jersey	0.684	0.018	0.298
Mid-Atlantic	0.621	0.055	0.324
South Atlantic	0.798	0.052	0.150
Midwest	0.688	0.032	0.280
Southwest	0.933	0.051	0.016
Central	0.637	0.048	0.315
North Central	0.894	0.028	0.078
West	0.923	0.055	0.022
Northwest	0.890	0.004	0.106

SOURCE: EPA's The Population and Characteristics of Industrial Boilers; State Energy Data Report; DOE/EPA-0214(78), April 1980.

Exhibit C.5

Distribution of E/T Demand Ratios



SOURCE: Market Development for Advanced Coal-Based Cogeneration Systems; U.S. Department of Energy, October 1980.

investment (see Exhibit C.4). We did not characterize new and replacement investments in terms of current fuel use because they will be subject to FUA and must use coal.

Time Periods

Several time-dependent variables affect the market for SO_2 emission control systems. These include demand growth over time; market penetration over time; changes in fuel prices over time; and the date new technologies are introduced commercially. To account for these changes, we analyzed the market in two-year intervals from 1982 until 2001.

STEP TWO:
DETERMINING RELATIVE ECONOMIC ATTRACTIVENESS

To compare the relative economic performance of technology options available to each market segment, we used procedures that duplicate industrial decision-making as closely as possible. For each of three boiler sizes (with steam production of 80 mmBtu/hr, 140 mmBtu/hr, and 200 mmBtu/hr), we calculated capital costs and O&M costs (see Exhibits C.6 and C.7). The capital costs for each region were multiplied by the regional multiplier in Appendix B. Using the thermal efficiencies and E/T ratios for each technology, we then calculated their fuel requirements and electricity production (if any). The annual after-tax cash flows for each technology option in each market segment (e.g., boiler size, E/T ratio, region, investment) were then determined for the estimated plant life (20 years). These cash flows included the annual O&M costs, purchased fuel costs, depreciation allowances (using sum-of-the-

Exhibit C.6

Costs and Thermal Efficiencies of Technologies Using High-Sulfur Bituminous Coal, Oil, and Gas

Technology	Size as output (million Btu/hr)	Capital cost* (thousands)	O&M Cost* (thousands)	Thermal Efficiency
Coal Boiler, No FGD	100	17,072	1,126	0.754
	250	30,041	1,755	0.765
	500	46,917	2,527	0.765
Sodium FGD	100	23,857	2,173	0.727
	250	40,931	3,468	0.736
	500	64,120	5,473	0.736
Dual-Alkali FGD	100	20,151	1,963	0.727
	250	35,066	3,089	0.736
	500	54,853	4,760	0.736
Lime/limestone FGD	100	19,702	2,022	0.727
	250	34,356	3,155	0.736
	500	53,731	4,836	0.736
Lime spray Dryer FGD	100	19,222	1,790	0.754
	250	34,701	2,828	0.765
	500	54,200	4,302	0.765
AFB	100	21,754	1,728	0.736
	250	31,943	2,499	0.736
	500	47,048	3,799	0.736
Gasifier with Gas Boiler	100	46,434	4,523	0.524
	250	76,367	6,531	0.524
	500	126,263	9,882	0.524
Oil-fired Boiler	100	8,508	783	0.768
	250	13,108	1,045	0.768
	500	20,196	1,434	0.768

*1980 dollars.

Exhibit C.6 (continued)

Costs and Thermal Efficiency of technologies
Using High-Sulfur Bituminous Coal, Oil, and Gas

Technology	Size as output (million Btu/hr)	Capital cost* (thousands)	O&M Cost* (thousands)	Thermal Efficiency
Gas-Fired Boiler	100	6,672	700	0.706
	250	10,318	916	0.706
	500	15,957	1,227	0.706
Coal Boiler with Steam Turbine, No FGD	100	21,253	1,308	0.716
	250	37,360	2,075	0.747
	500	58,718	3,049	0.727
Sodium FGD with Steam Turbine	100	28,920	2,576	0.716
	250	49,669	4,177	0.727
	500	78,163	6,690	0.727
Dual-alkali FGD with Steam Turbine	100	24,731	2,338	0.691
	250	43,039	3,742	0.699
	500	67,688	5,865	0.699
Lime/limestone FGD with Steam Turbine	100	24,224	2,398	0.691
	250	42,224	2,398	0.699
	500	66,420	5,945	0.699
Lime Spray Dryer FGD with Steam Turbine	100	23,684	2,143	0.691
	250	42,615	3,446	0.699
	500	66,930	5,343	0.699
AFB with Steam Turbine	100	26,289	1,976	0.716
	250	39,035	2,910	0.727
	500	58,167	4,494	0.727
Gasifier/Boiler with Steam Turbine	100	57,168	5,105	0.497
	250	94,172	7,492	0.497
	500	155,876	11,498	0.497

*1980 dollars.

Exhibit C.6 (continued)

Costs and Thermal Efficiency of Technologies
Using High-Sulfur Bituminous Coal, Oil, and Gas

Technology	Size as output (million Btu/hr)	Capital cost* (thousands)	O&M Cost* (thousands)	Thermal Efficiency
Oil-fired Boiler	100	11,679	940	0.730
with	250	18,236	1,296	0.730
Steam Turbine	500	28,498	1,837	0.730
Gas-fired Boiler	100	9,622	848	0.671
with	250	15,110	1,152	0.671
Steam Turbine	500	23,747	1,607	0.671

*1980 dollars.

Exhibit C.7

Costs and Thermal Efficiency of Technologies Using Low-Sulfur, Subbituminous Coal

Technology	Size as output (million Btu/hr)	Capital cost* (thousands)	O&M Cost* (thousands)	Thermal Efficiency
Coal Boiler, no FGD	100	20,293	1,172	0.712
	250	37,089	1,885	0.721
	500	58,052	2,739	0.721
Sodium FGD	100	22,409	1,797	0.683
	250	40,737	2,759	0.689
	500	63,813	4,014	0.689
Lime/limestone FGD	100	22,706	1,824	0.683
	250	41,209	2,808	0.689
	500	64,558	4,102	0.689
Lime spray Dryer FGD	100	22,018	1,710	0.712
	250	39,815	2,696	0.721
	500	62,359	3,978	0.721
AFB	100	21,409	1,349	0.707
	250	31,530	1,786	0.707
	500	46,561	2,439	0.707
Gasifier with Gas Boiler	100	43,388	4,746	0.540
	250	69,764	6,936	0.540
	500	112,552	10,643	0.540

*1980 dollars.

Exhibit C.7 (continued)

Costs and Thermal Efficiency of Technologies
Using Low-Sulfur, Subbituminous Coal

Technology	Size as output (million Btu/hr)	Capital cost* (thousands)	O&M Cost* (thousands)	Thermal Efficiency
Coal Boiler with	100	24,876	1,359	0.676
Steam Turbine,	250	45,326	2,220	0.685
No FGD	500	77,818	4,977	0.685
Sodium	100	27,264	2,134	0.676
FGD with Steam	250	49,449	3,343	0.685
Turbine	500	78,661	5,077	0.685
Lime spray	100	26,826	2,045	0.649
Dryer FGD with	250	48,407	3,284	0.654
Steam Turbine	500	76,175	4,952	0.654
AFB with Steam	100	25,931	1,540	0.676
Turbine	250	38,597	2,086	0.685
	500	57,654	2,921	0.685
Gasifier/Boiler	100	53,454	5,360	0.513
with Steam	250	86,211	7,957	0.513
Turbine	500	139,471	12,378	0.513

*1980 dollars.

years-digits depreciation), tax rate (50 percent), investment tax credits (20 percent for coal-fired systems), and utility standby charges (if applicable). For cogeneration systems, the electric energy produced was treated as a credit to the annual pre-tax cash flow. If excess power was produced (i.e., if the E/T ratio of the technology was greater than the plant's demand ratio), it was treated as being sold back to the utility at the buyback rate.

We then discounted the after-tax cash flows for each technology at a nominal industrial sector discount rate of 20 percent to yield the lifecycle cost of each technology in a particular market segment. This 20-percent discount rate, developed from previous interviews with industrial decision-makers, represents the ROI expected from an industrial energy conservation investment to allow it to capture half of the total market. Retofit investments were discounted at a 25-percent rate, to simulate the slightly higher discount rates used for these discretionary investments.

STEP THREE:
CALCULATING MARKET SHARES

In this step, we evaluated the probable market response to the selected technologies and projected the rates of market penetration. Recognizing that site-specific factors vary greatly and can significantly affect the relative economic attractiveness of a technology, we did not assume that the technology with the lowest lifecycle cost will capture the entire market segment.

To allocate the probable market for each technology on the basis of its lifecycle cost, we used a market share elasticity model.* Incorporating other factors into our computer model (e.g., market lag resulting from risk aversion on the part of the customers, which delays the development of manufacturing capacity and distribution networks), we used the computer to estimate each technology's market share as a function of its relative economic performance and the number of years it has been available on a commercial basis (not counting the availability of demonstration or prototype models).

The probable market share of each technology on the basis of its lifecycle cost can be estimated using the equation:

$$MS_i = \frac{LCC_i^{-GAMMA}}{\sum_{j=1}^{N} LCC_j^{-GAMMA}}$$

Where: MS_i = market share of technology i
LCC_i = lifecycle cost of technology i
GAMMA = parameter dependent on specific market characteristics
N = number of technologies competing in the market.

The value of GAMMA is dependent on the behavior characteristics of the specific market sector being examined. Exhibit C.8 shows the effect of differing values of GAMMA in a two-technology market. The larger the GAMMA value, the more competitive the market will be and the larger share the more cost-effective technology will capture.

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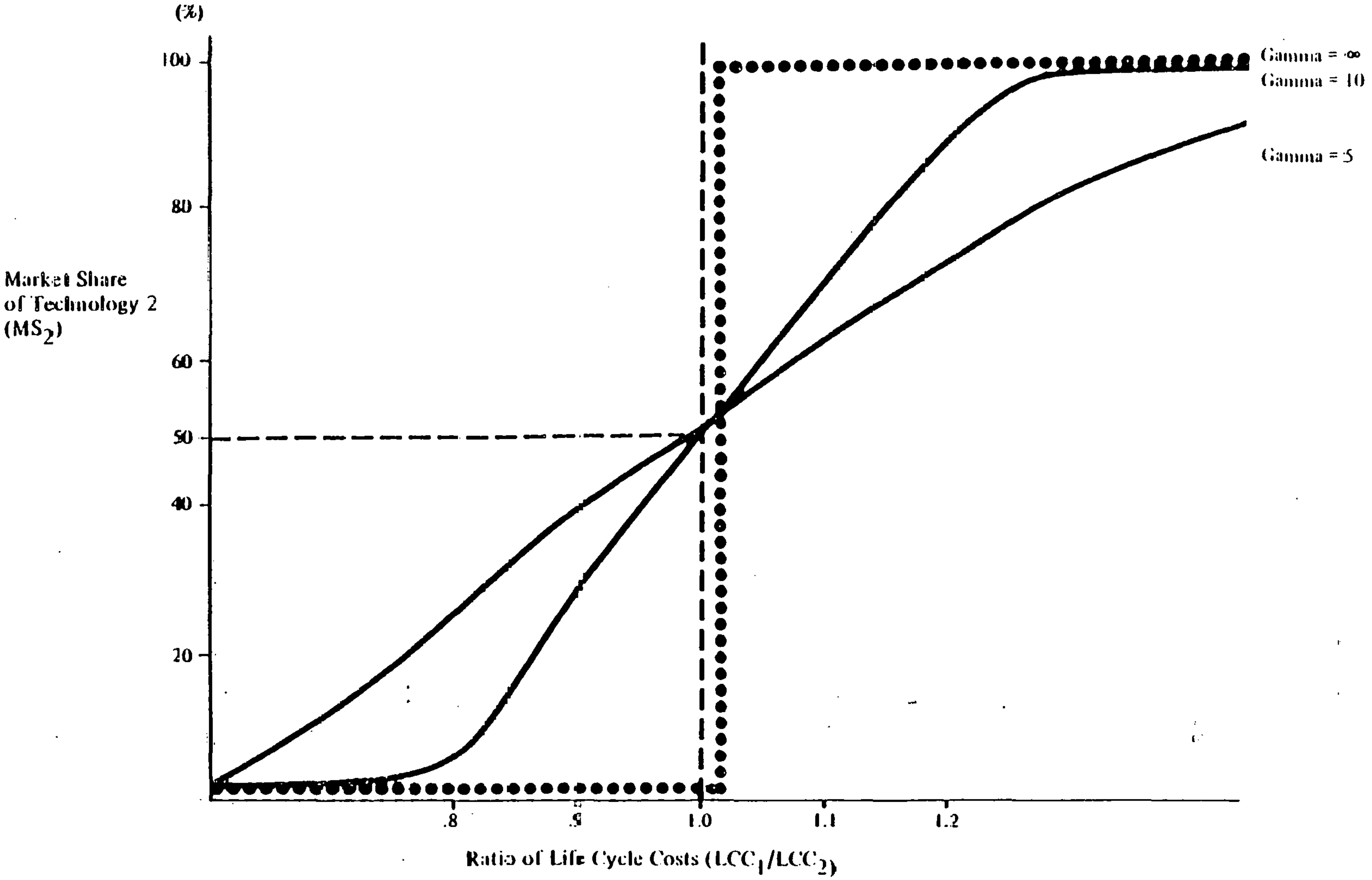
* This model is discussed more fully in The DFI Energy-Economy Modeling System, Department of Energy, Contract WO-CR-03-70313, 1978.

Exhibit C.8

Effect of Gamma in a Two Technology Market



The value of GAMMA can be estimated from:

$$\text{GAMMA} = \frac{N}{N-1} \quad \text{EPSILON}$$

Where: N = number of technologies competing in the market
EPSILON = market share elasticity.

Market share elasticity is defined as the percentage increase (decrease) in market share resulting from a one-percent decrease (increase) in the LCC. This value can be estimated from a market response curve and from the cost characteristics of the technologies.

The formula for calculating elasticity can be rewritten as:

$$\text{EPSILON} = \frac{\Delta\,\text{MS/MS}}{\Delta\,\text{LCC/LCC}} = \frac{\Delta\,\text{MS/MS}}{\Delta\text{ROI/ROI}} * \frac{\Delta\text{ROI/ROI}}{\Delta\text{LCC/LCC}}$$

Where: ROI = return on investment.

The market share as a function of ROI $\left(\frac{\Delta\text{MS/MS}}{\Delta\text{ROI/ROI}}\right)$ was developed in a previous study* of industrial cogeneration systems, and through extensive industry interviews. By using the results of that study, we developed a composite curve that represents all industry (see Exhibit C.9). This curve can be approximated by the equation:

$$\text{MS} = \frac{e^x}{1-e^x}$$

Where: $x = 3.76 + 11.17 * \text{ROI} + 29.52 * \text{ROI}^2$.

By differentiating MS with respect to ROI, and calculating the value of the differential at MS = 0.5, ROI = .21, we

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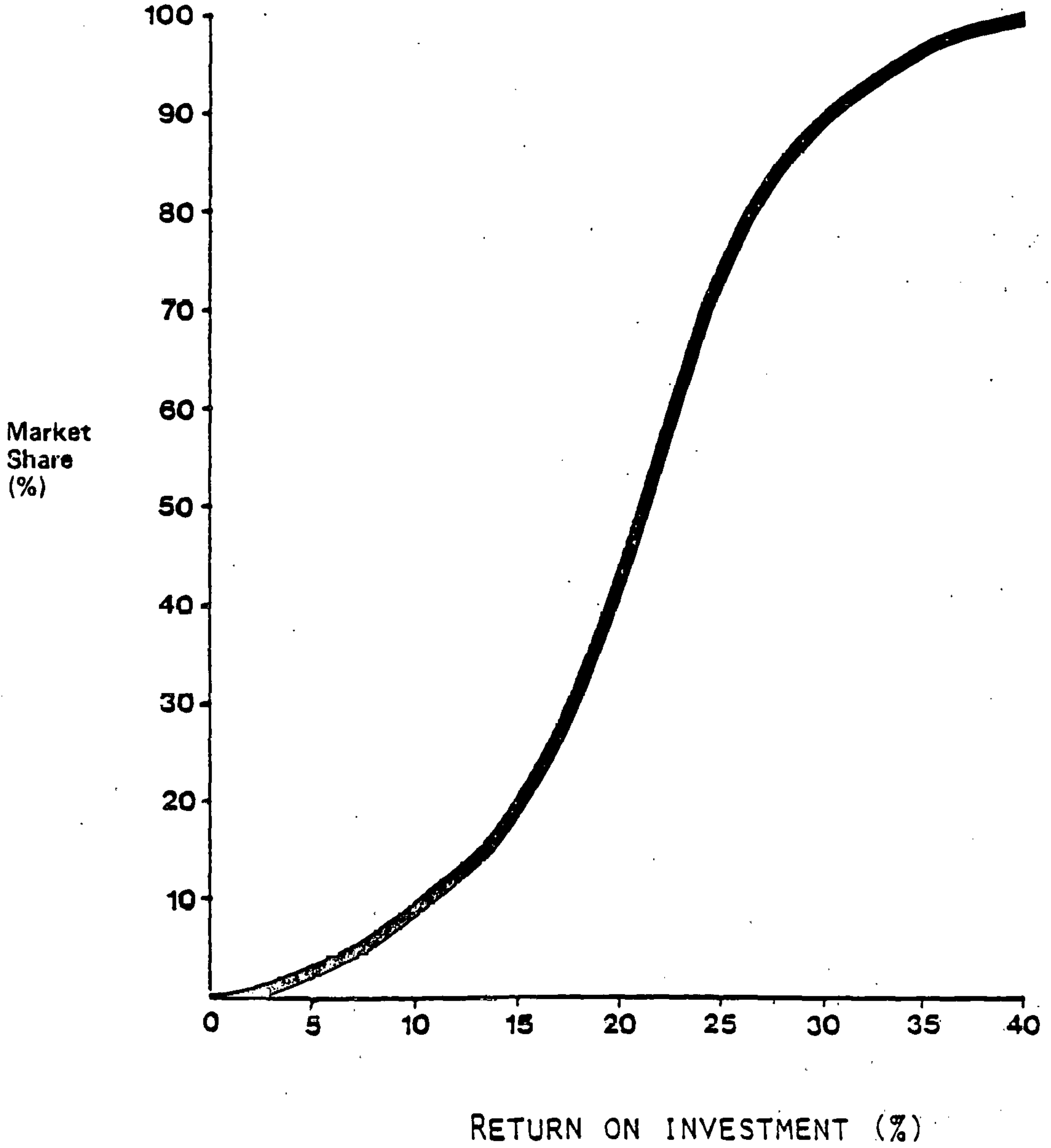
* <u>The Potential for Cogeneration Development in Six Major Energy Consuming Industries</u>, Department of Energy, 1977.

Exhibit C.9

Estimated Market Share as a Function of Return-on-Investment



find the value for the first term in the equation for EPSILON as $\Delta MS/MS / \Delta ROI/ROI = 2.56$.

We can find the approximate value of the second term,

$$\frac{\Delta ROI/ROI}{\Delta LCC/LCC},$$

by considering at the cash flow of two systems, such as a conventional sodium FGD and a cogeneration sodium FGD. First, we must separate the lifecycle cost into capital costs (which are not dependent on the discount rate) and yearly costs (where net present value is dependent on the discount rate). By assuming values for the change in capital cost (e.g., 10 to 40 percent of the initial capital cost), and by assuming different ROIs for these additional costs (e.g., 19, 20, and 21 percent), we can calculate the LCCs and determine $\frac{\Delta ROI/ROI}{\Delta LCC/LCC}$ numerically.

For the system above, $\frac{\Delta ROI/ROI}{\Delta LCC/LCC}$

was approximately 3.7. This gives EPSILON a value of 9.4, and GAMMA a value of 10.0.

A value of 10.0 for GAMMA indicates a relatively competitive market.

This procedure considered only relative economic performance, disregarding site-specific and attitudinal factors, which in many instances will actually determine a purchase decision.

The impacts of attitudinal factors on market penetration can be simulated by using weighting factors in the market share equation:

$$MS_i = \frac{(W_i)(LCC_i)^{-GAMMA}}{\overset{N}{\underset{j=1}{}}(W_i)(LCC_j)^{-GAMMA}}$$

where MS_i = market share of technology i
LCC_i = lifecycle cost of technology i
GAMMA = market elasticity parameter
W_i = market share weighting factor
LCC_i = life cycle cost of technology i.

W_i is a weighting parameter which can be developed in a number of ways. The simplest is to use it to develop the "equal price" market shares. That is, if two technologies have exactly the same lifecycle cost, they will split the market according to the relative values of their respective weighting factors. Exhibit C.10 shows the effect of this weighting factor in a two-technology market segmnt.

We used the Bass diffusion model* to simulate market development for newly introduced technologies. This model assumes that, on the whole, the probability that a buyer will invest in a new technology increases as the number of persons already using that technology increases. Bass assumed that only a small number of buyers, the innovators, are not influenced by others in their initial purchase. Most buyers are imitators; the probability of their pur-

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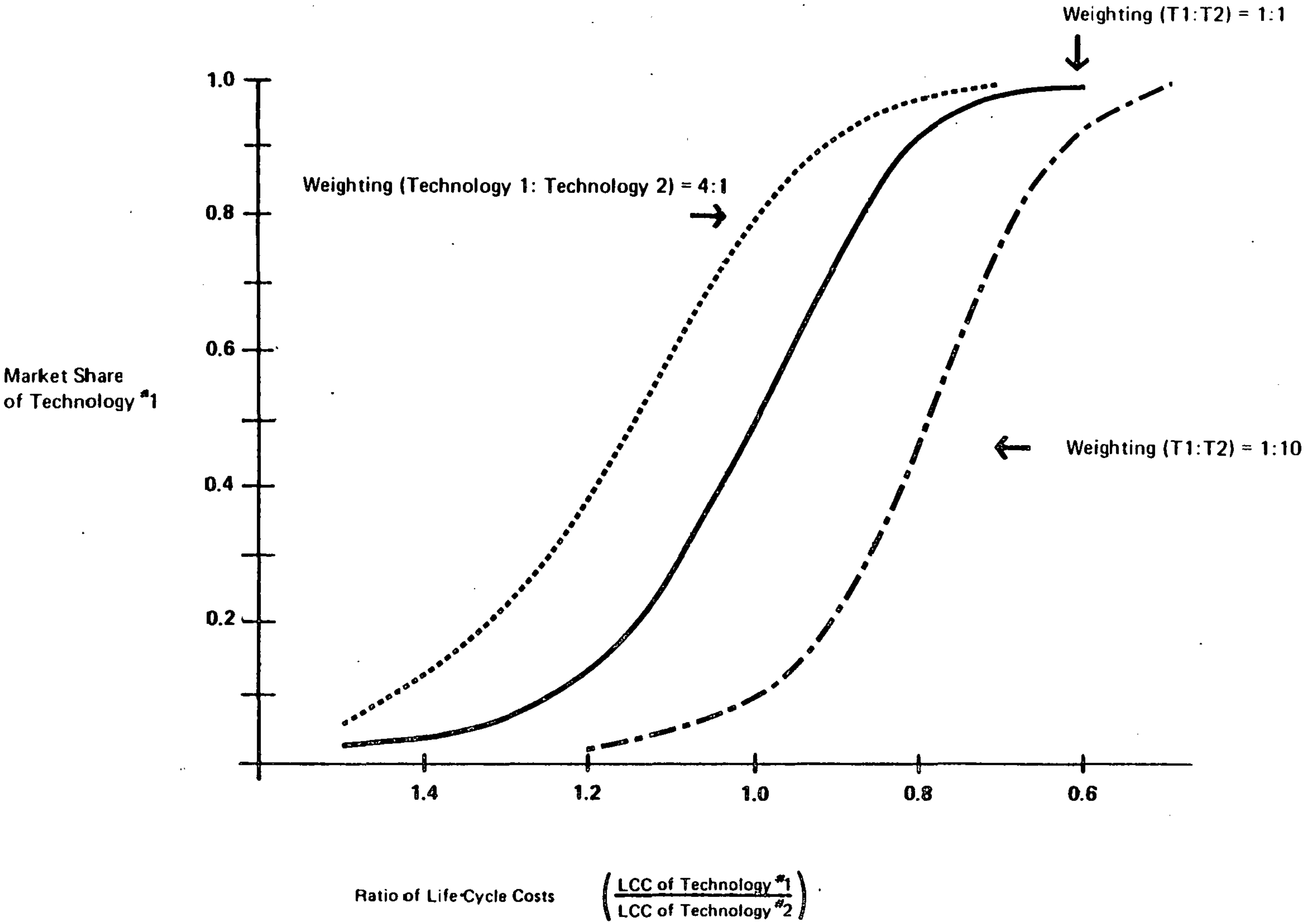
* Frank M. Bass, "New Product Growth Model for Consumer Durables," Management Science, January 15, 1969.

Exhibit C.10

Effect of Judgmental Weighting Factors on Market Shares



chasing a new technology depends on the number of buyers who have already purchased it. The diffusion model requires a coefficient of innovation (P) and a coefficient of imitation (Q). These values are used in an exponential function to calculate the cumulative percentage of the market that has been penetrated by any given time. Bass assumed that the coefficients of innovation (P) and imitation (Q) are constant over time. The higher P is, the more importance innovators assume. We estimated these coefficients using a multiple regression technique, based on data about investment in coal-fired steam generators and cogeneration systems. Exhibit C.11 shows the diffusion effects of different P and Q coefficients over time. In this study, a value of P of 0.015 was used; of Q, 0.6. This results in a diffusion of 90 percent in about 10 years.

The equation relating the fraction of the market captured by a new technology to its economic market share is:

$$MS = \frac{1-EXP(-(P + Q)T)}{1 + (Q/P)(EXP(-(P + Q)T)}$$

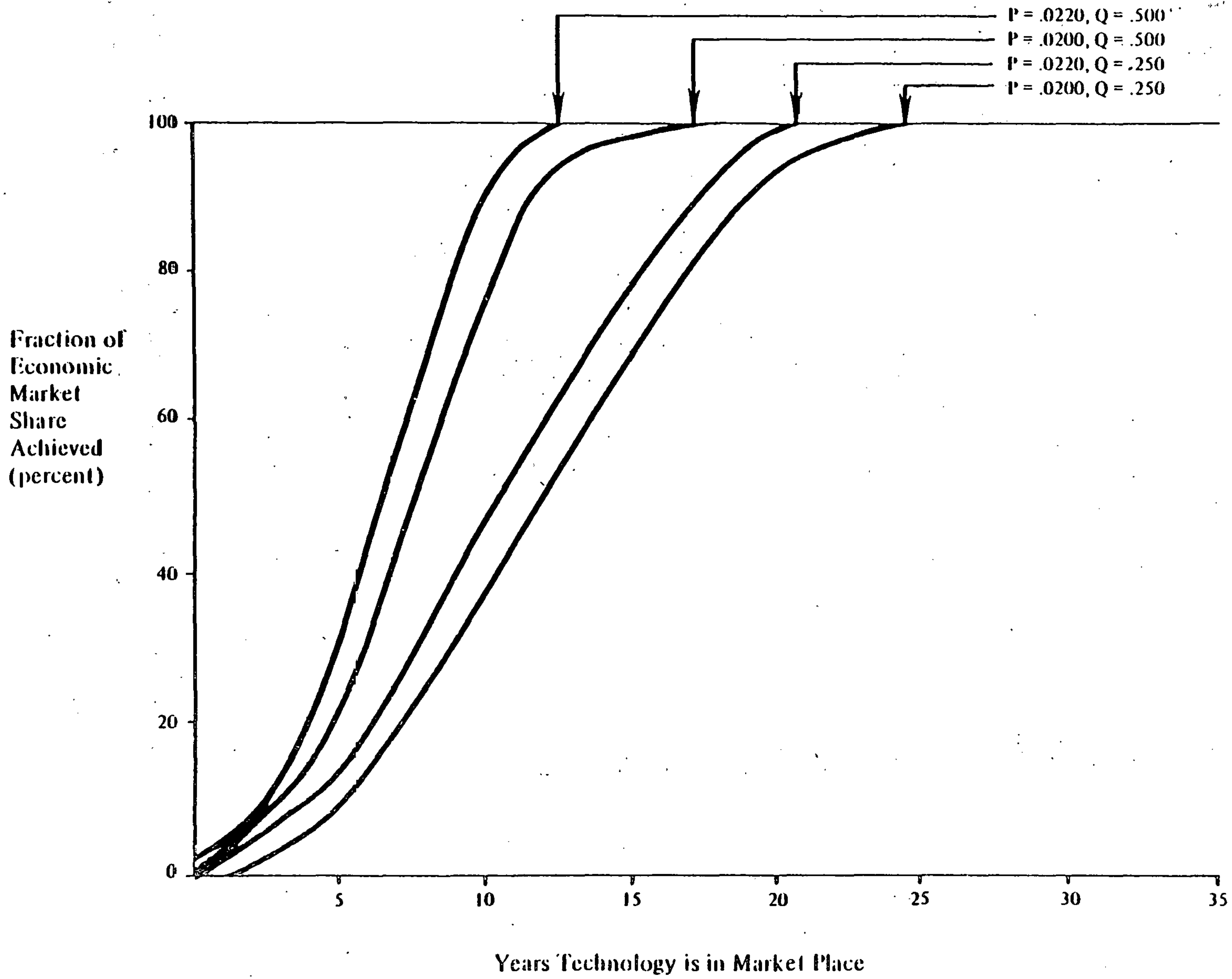
where:

MS = fraction of economic market share captured
P = innovator coefficient
Q = imitator coefficient
T = time since introduction of new technology (years).

The effect of diffusion on market response is then calculated by multiplying the market response by the diffusion percentage.

Exhibit C.11

The Effects on Market Diffusion of Different Coefficients for Innovation (P) and Imitation (Q)



STEP FOUR:
TRANSLATING MARKET SHARES INTO STEAM DEMAND

In this step, we translated the market share computed for each technology (in Step 3) into projected steam demand for each market segment. To allocate steam demand among the technologies, we had to project total MFBI steam consumption for the 1982-2000 period within each region. We derived these data from EIA's Mid-Term Energy Forecasting Model.

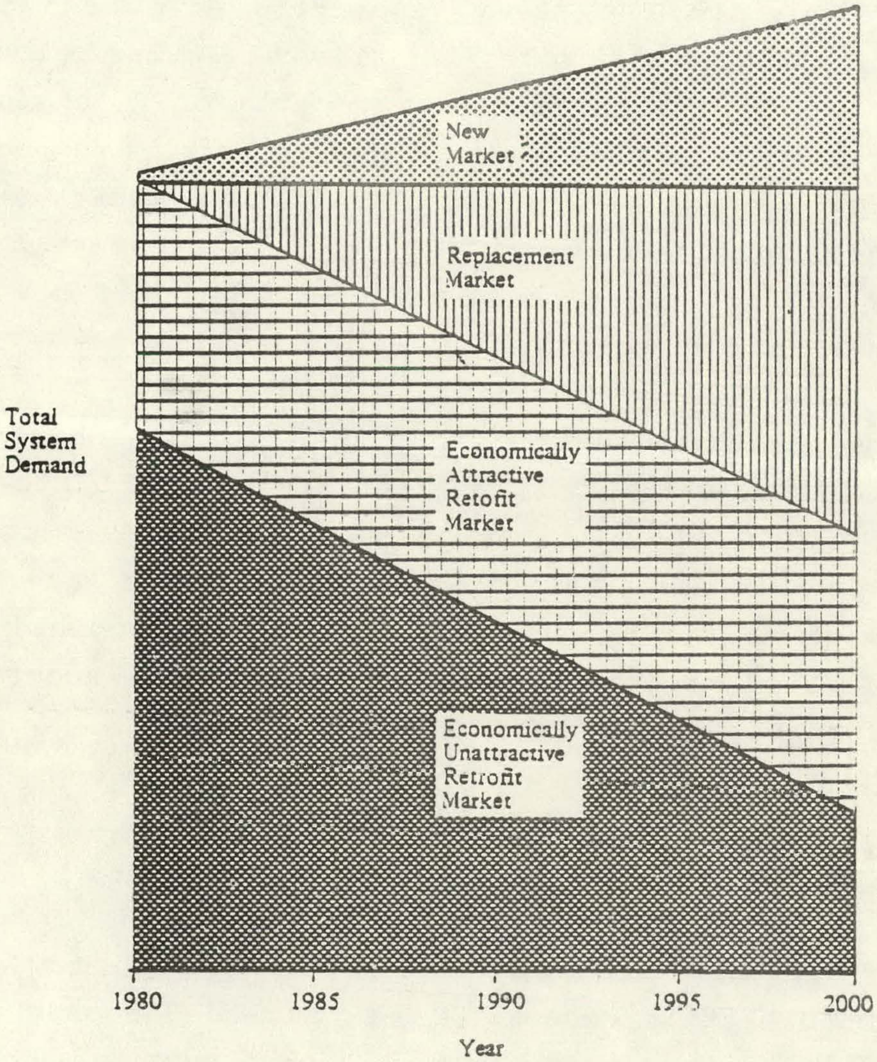
We allocated all growth in steam demand to the new market, because FUA requires use of coal in all new installations. We allocated changes affecting existing capital stock of steam boilers either to the retrofit or the replacement market. Exhibit C.12 shows typical allocation of steam demand in a region where steam demand grows. If steam demand is projected to decline, the amount of that decline is subtracted from that segment's retrofit market.

Allocating the Replacement Market

We calculated the replacement market by identifying 1980 steam demand in each market segment and multiplying it by the "phase-out ratio." The phase-out ratio reflects the percentage of steam generators that will be required in a particular year. Typically, we predict replacement of steam generators as proportional to the current inventory, the assumption being that a constant percentage of steam generators is retired every year. Thus, projected replacement depends upon the phase-out ratio chosen and the growth rate of steam consumption.

Exhibit C.12

Typical Allocation of Steam Demand in a Region Where Steam Demand Increases



Using this approach, we would tend to overestimate the replacement market in market segments with high growth in steam demand and underestimate it where steam demand grows very little or declines. To adjust for this factor, we used a vintaging methodology* based several principles. First, the phase-out ratio is dependent on the sizes of existing industrial boilers (both packaged and field-erected). Second, the replacement rate is dependent on the use to which the steam generators have been put. Equipment operated at a moderate, steady rate lasts longer than equipment operated at full throttle or in a highly cyclical mode. Finally, the replacement rate is dependent on the present age profile of existing industrial steam generators. The replacement rate will be greater if industry's capital stock is 80 percent old and 20 percent new rather than 20 percent old and 80 percent new.

Adjusting for these factors, we found that the phase-out ratio would escalate from 2.2 percent initially to 6.8 percent in 2000. By multiplying the yearly phase-out percentage by projected 1980 steam demand, we calculated the replacement market by 1980 for each market segment. We then allocated this market among technologies according to their respective market shares.

Allocating the Retrofit Market

The retrofit market exists where steam generators are replaced before their economic life has ended because the availability of a new and superior technology, or a change

---

* This methodology is described in Industrial Sector Technology Use Model (ISTUM), Department of Energy, 1979.

in energy prices, makes premature retirement of the old equipment economically attractive. Allocating demand in the retrofit market required five steps. First, because coal-fired steam generators were not considered viable candidates for retrofit, we removed coal-based steam consumption from the 1980 steam market. Second, as an alternative to retrofit ECT investments, we included a zero-capital-cost boiler, fired by the fuel currently being used for steam generation. Third, in regions where steam demand declined (because of conservation, for example, or plant closings), we subtracted that decline from the retrofit market. Fourth, we subtracted from the retrofit market that portion of the steam market projected to have been replaced in the preceding 2-year period because equipment became obsolete (the replacement market). Finally, that portion of the retrofit market projected to have been retrofitted to coal in a given 2-year period was subtracted from the potential retrofit market for the following 2-year period. We then allocated total steam demand for the retrofit market among the technologies according to their estimated market shares.

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Appendix D METHODOLOGY FOR DETERMINING REGIONAL COAL PRICES AND AVAILABILITY

For each demand region in the United States, it was necessary to determine the lowest cost high-sulfur and low-sulfur (compliance) coals.

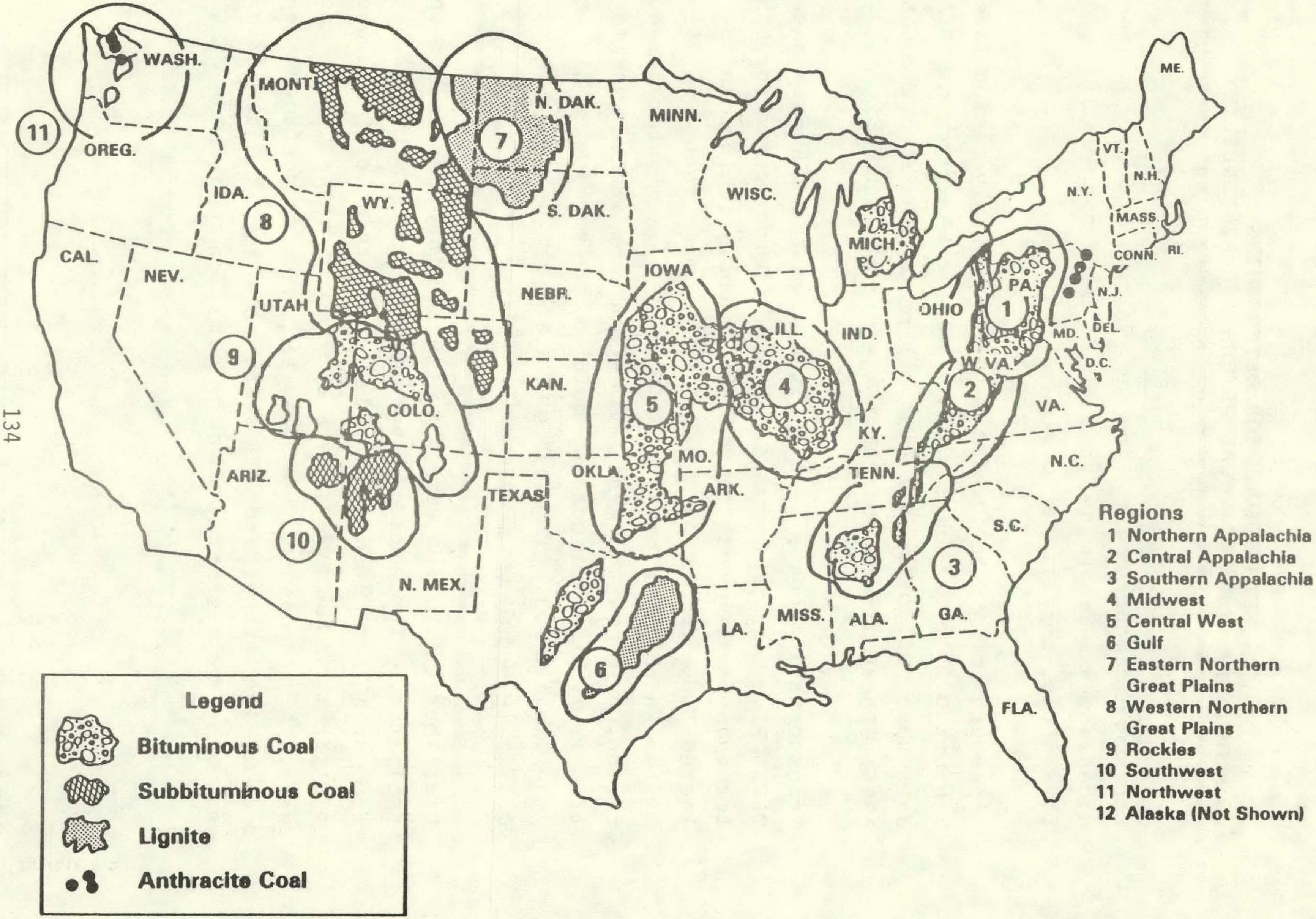
Minemouth coal price forecasts for each supply region (see Exhibit D.1) and each coal type were taken from the EIA data base reflecting a medium oil price scenario through 1995. These minemouth prices are shown in Exhibit D.2.

Transportation costs were derived from the EIA data base TRCLLPRC, which estimates single-car freight costs per ton for transporting coal between coal supply regions and selected U.S. cities. In cases where more than one city listed in the data base is located in a particular demand region, average costs were derived using estimated consumption rates for areas corresponding to the particular cities (see Exhibit D.3). These figures are depicted in Exhibit D.4 in 1975 dollars.

Distribution charges were also figured into the coal price estimates. These costs represent local retail markups from single-car loads to smaller quantity sales. Average distribution fee multipliers applied to minemouth prices were 1.12 for deep-minded coal, and 1.17 for surface-mined coal. For stoker and AFB systems, an additional $5/ton was added for sizing, based on information supplied by ORNL.

Exhibit D.1

MEFS Coal Regions



Regions

1 Northern Appalachia
2 Central Appalachia
3 Southern Appalachia
4 Midwest
5 Central West
6 Gulf
7 Eastern Northern Great Plains
8 Western Northern Great Plains
9 Rockies
10 Southwest
11 Northwest
12 Alaska (Not Shown)

Exhibit D.2

1985 F.O.B. Mine Price Summary
(1979 $/ton)

Coal Types	Supply Regions* C1	C2	C3	C4	C5	C6	C7	C8	C9	CA	CB
Premium (27 mmBtu/ton)	55.21	49.70	56.73		72.23				89.16		
Bituminous (23.80 mmBtu/ton)	33.68	37.32	41.71	31.92	32.41			25.43	21.61		
Low sulfur	48.38	42.67	46.66		43.30			25.43	21.70		
Medium sulfur	35.90	36.54	40.75	39.78	37.89				21.48		
High sulfur	29.64	33.70		26.23	29.50						
Mid-Bituminous (21.80 mmBtu/ton)	26.65			23.44	26.85			21.09	17.89	19.08	37.93
Low sulfur				44.10				21.26	17.89	19.59	37.93
Medium sulfur	36.32			35.74				20.99	17.89	17.70	
High sulfur	26.58			22.57	26.85						
Subbituminous (18.33 mmBtu/ton)								8.95			25.49
Low sulfur								9.40			
Medium sulfur								8.05			25.49
Lignite (13.00 mmBtu/ton)						6.34	6.29				
Low sulfur							6.70				
Medium sulfur						6.34	6.21				

*Supply Regions:

C1 Northern Appalachian
C2 Central Appalachian
C3 Southern Appalachian
C4 Midwest
C5 Central West
C6 Gulf
C7 Northeast Great Plains
C8 Northwest Great Plains
C9 Rockies
CA Southwest
CB Northwest

Sulfur Contents:

Low = less than 0.67 lbs./mmBtu (premium is low sulfur). Medium = 0.67 to 1.68 lbs./mmBtu. High = more than 1.68 lbs./mmBtu.

SOURCE: DOE, Energy Information Agency, Mid-term Energy Forecasting System; Medium World Oil Price Scenario; April 1981.

Exhibit D.2

1990 F.O.B. Mine Price Summary
(1979 $/ton)

	Supply Regions*										
Coal Types	C1	C2	C3	C4	C5	C6	C7	C8	C9	CA	CB
Premium (27 mmBtu/ton)	62.38	56.76	63.34		75.24				92.69		
Bituminous (23.80 mmBtu/ton)	38.70	47.05	52.97	34.64	36.83			31.07	26.39	26.41	
Low sulfur	54.89	48.87	54.60		43.93			31.07	26.91	26.41	
Medium sulfur	41.21	46.56	51.67	45.17	42.42				25.45		
High sulfur	34.92	44.47		31.03	32.89						
Mid-Bituminous (21.80 mmBtu/ton)	31.81			27.52	29.04			25.41	22.76	21.30	44.57
Low sulfur				44.53				26.37	22.76	21.30	44.57
Medium sulfur	37.53			40.66				24.68	22.76	21.30	
High sulfur	31.77			26.79	29.04						
Subbituminous (18.33 mmBtu/ton)								8.85	15.74		29.56
Low sulfur								9.40			
Medium sulfur								8.05	15.74		29.56
Lignite (13.00 mmBtu/ton)						7.10	6.70				
Low sulfur							6.70				
Medium sulfur						7.10	6.70				

*Supply Regions:

C1	Northern Appalachian	C4	Midwest	C7	Northeast Great Plains	CA	Southwest
C2	Central Appalachian	C5	Central West	C8	Northwest Great Plains	CB	Northwest
C3	Southern Appalachian	C6	Gulf	C9	Rockies		

Sulfur Contents:

Low = less than 0.67 lbs./mmBtu (premium is low sulfur). Medium = 0.67 to 1.68 lbs./mmBtu. High = more than 1.68 lbs./mmBtu.

SOURCE: DOE, Energy Information Agency, Mid-term Energy Forecasting System; Medium World Oil Price Scenario; April 1981.

Exhibit D.2

1995 F.O.B. Mine Price Summary
(1979 $/ton)

Coal Types	Supply Regions* C1	C2	C3	C4	C5	C6	C7	C8	C9	CA	CB
Premium (27 mmBtu/ton)	73.02	66.49	74.35		75.24				94.07		
Bituminous (23.80 mmBtu/ton)	43.05	55.39	59.82	36.64	41.23			33.04	28.41	31.72	
Low sulfur	64.38	55.75	68.10		47.65			33.04	29.40	31.72	
Medium sulfur	45.69	55.05	69.40	46.94	44.21				25.96		
High sulfur	38.44	55.05		33.94	36.71						
Mid-Bituminous (21.80 mmBtu/ton)	35.01			29.57	31.15			26.75	24.98	24.55	54.15
Low sulfur				50.82				28.04	25.15	24.83	54.15
Medium sulfur	42.20			42.25				25.22	23.19	23.80	
High sulfur	35.01			28.92	31.15						
Subbituminous (18.33 mmBtu/ton)								9.09	15.74		34.36
Low sulfur								9.40			
Medium sulfur								8.68	15.74		34.36
Lignite (13.00 mmBtu/ton)						23.36	7.52				
Low sulfur							8.11				
Medium sulfur						23.36	7.48				

*Supply Regions:

C1	Northern Appalachian	C4	Midwest	C7	Northeast Great Plains	CA	Southwest
C2	Central Appalachian	C5	Central West	C8	Northwest Great Plains	CB	Northwest
C3	Southern Appalachian	C6	Gulf	C9	Rockies		

Sulfur Contents:

Low = less than 0.67 lbs./mmBtu (premium is low sulfur).

Medium = 0.67 to 1.68 lbs./mmBtu.

High = more than 1.68 lbs./mmBtu.

SOURCE: DOE, Energy Information Agency, Mid-term Energy Forecasting System; Medium World Oil Price Scenario; April 1981.

Exhibit D.3

Fraction of Regional Industrial Demand in Each Demand Center

Coal Demand Region	Coal Demand Center 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
New England	1.00																		
New York/New Jersey		1.00																	
Mid-Atlantic			0.80		0.20														
South Atlantic				0.40		0.30	0.30												
Midwest								0.25	0.45	0.10	0.10								
Southwest													0.35	0.45					0.20
Central										0.65		0.35							
North Central															1.00				
West																0.65	0.35		
Northwest																		1.00	

Coal Demand Centers:

1 Boston
2 New York
3 Baltimore/Washington/ Philadelphia
4 Miami
5 Pittsburgh
6 Atlanta
7 Cincinnati
8 Detroit
9 Chicago
10 St. Louis
11 St. Paul
12 Kansas City
13 Houston
14 Dallas
15 Denver
16 Los Angeles
17 San Francisco
18 Seattle
19 New Orleans

Blank space signifies not applicable.

SOURCE: DOE, Energy Information Agency, Mid-term Energy Forecasting System; Medium World Oil Price Scenario; April 1981.

Exhibit D.4

1985 Transportation Cost Estimates
(1975 $/ton)

Coal Production Region	Coal Demand Center 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Northern Appalachian	22.82	14.15	9.03	48.31	2.05	27.98	11.41	12.06	17.88	22.84	31.27								44.65
Central Appalachian	30.00	21.33	14.25	38.12	21.05	13.91	10.36	19.08	19.86	21.79	33.25								30.58
Southern Appalachian	45.17	36.50	30.21	31.56	34.61	7.35	23.92	32.64	27.51	17.91	40.90								13.71
Midwest	43.89	35.22	29.37	50.47	20.38	26.26	9.69	18.41	11.48	7.29	24.87								42.93
Central West	53.89	45.22	40.79	54.59	45.21	30.38	21.11	26.22	19.28	9.68	15.55	1.60	24.30	16.63	20.08	59.06	63.21		34.85
Gulf		60.09	55.29	49.34	39.56	32.94	35.98	41.09	34.15	24.55	32.87	18.92	5.72	3.89	28.16	46.32	59.98		16.27
Northeast Great Plains	63.11	54.44	50.65		51.64	48.55	33.23	32.93	23.73	33.33	10.34	26.57	49.27	41.60	19.73	62.20	55.62	29.46	59.82
Northwest Great Plains			62.09		54.33	51.68	40.41	45.84	36.64	30.98	23.25	22.90	37.57	30.65	9.70	34.87	36.47	38.98	48.12
Rockies			64.78		60.11	54.37	45.10	50.21	43.26	33.67	32.86	25.59	39.05	31.38	7.11	25.75	26.61	32.11	49.60
Southwest						53.68	50.88	55.99	49.05	39.45	40.38	33.11	26.45	18.79	14.63	25.98	39.64	63.41	37.01
Northwest									66.34		52.95				48.47	43.99	29.94	2.28	

Coal Demand Centers:

1 Boston
2 New York
3 Baltimore/Washington/ Philadelphia
4 Miami
5 Pittsburgh
6 Atlanta
7 Cincinnati
8 Detroit
9 Chicago
10 St. Louis
11 St. Paul
12 Kansas City
13 Houston
14 Dallas
15 Denver
16 Los Angeles
17 San Francisco
18 Seattle
19 New Orleans

Blank space signifies not applicable.

SOURCE: DOE, Energy Information Agency, Mid-term Energy Forecasting System; Medium World Oil Price Scenario; April 1981.

Exhibit D.4

1990 Transportation Cost Estimates
(1975 $/ton)

Coal Production Region	Coal Demand Center 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Northern Appalachian	25.74	15.87	10.10	54.74	2.09	31.51	12.75	13.48	20.10	25.76	35.34								50.58
Central Appalachian	33.91	24.04	15.98	43.15	23.72	15.50	11.56	21.49	22.37	24.57	37.61								34.57
Southern Appalachian	51.17	41.30	34.14	35.68	39.15	8.13	26.99	36.91	31.07	20.14	46.31								15.37
Midwest	49.71	39.84	33.19	57.20	22.98	29.65	10.89	20.72	12.83	8.06	28.07								48.62
Central West	61.21	51.35	46.31	62.01	34.42	34.46	23.92	29.73	21.84	10.91	17.65	1.63	27.69	18.88	27.85	67.60			39.80
Gulf		68.46	62.95	56.17	51.53	37.51	41.03	46.84	38.95	28.02	37.57	21.55	6.43	4.30	32.16	53.02	68.70		18.54
Northeast Great Plains		61.99	57.68		45.06	55.29	37.86	37.52	27.05	37.98	11.81	30.28	56.34	47.53	22.73	71.49	64.09	34.06	68.45
Northwest Great Plains					59.91	65.16	52.71	52.37	41.90	41.60	26.66	32.33	47.78	38.97	11.11	59.87	60.63	44.72	59.89
Rockies					62.06	62.10	51.56	57.37	49.48	38.55	37.61	29.27	44.72	35.91	8.05	29.73	30.72	37.13	52.83
Southwest					68.87	61.53	58.37	64.18	56.29	45.36	46.35	38.01	32.45	21.64	16.79	29.99	45.67		42.56
Northwest											60.61				54.23	48.09	32.41	2.38	

Coal Demand Centers:

1 Boston
2 New York
3 Baltimore/Washington/ Philadelphia
4 Miami
5 Pittsburgh
6 Atlanta
7 Cincinnati
8 Detroit
9 Chicago
10 St. Louis
11 St. Paul
12 Kansas City
13 Houston
14 Dallas
15 Denver
16 Los Angeles
17 San Francisco
18 Seattle
19 New Orleans

Blank space signifies not applicable.

SOURCE: DOE, Energy Information Agency, Mid-term Energy Forecasting System; Medium World Oil Price Scenario; April 1981.

Exhibit D.4

1995 Transportation Cost Estimates
(1975 $/ton)

Coal Production Region	Coal Demand Center 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Northern Appalachian	27.78	17.07	10.81	59.24	2.12	34.15	13.69	14.48	21.66	27.80	38.19								54.73
Central Appalachian	36.64	25.93	17.19	46.67	25.58	16.78	12.39	23.16	24.12	26.50	40.65								37.36
Southern Appalachian	55.38	44.67	36.90	38.57	42.33	8.68	29.14	39.91	33.56	21.70	50.09								16.53
Midwest	53.79	43.08	35.86	61.91	24.75	32.02	11.56	22.33	13.77	8.60	30.30								52.60
Central West	66.36	55.65	50.18	67.21	37.28	37.32	25.88	32.18	23.63	11.77	19.12	1.66	30.08	10.47	24.80	73.59			43.28
Gulf		74.35	68.34	60.99	55.98	40.74	44.58	50.88	42.33	30.47	40.87	23.41	6.95	4.60	34.98	57.72	74.82		20.16
Northeast Great Plains	78.04	67.33	62.65		48.96	60.06	41.15	40.77	29.42	41.28	12.89	32.93	61.34	51.74	24.94		70.19	37.45	74.55
Northwest Great Plains					65.12	70.90	57.31	56.93	45.58	45.35	29.05	35.24	52.08	42.48	12.10	65.26	66.09	48.74	65.29
Rockies					67.50	67.54	56.10	62.40	53.85	41.99	40.97	31.88	48.72	19.12	8.74	32.65	33.75	40.82	61.93
Southwest					75.12	67.13	63.72	70.02	61.47	49.61	50.62	41.53	33.34	23.74	18.39	32.94	50.04		46.55
Northwest											65.98				59.03	52.33	35.23	2.49	

Coal Demand Centers:

1 Boston
2 New York
3 Baltimore/Washington/
Philadelphia
4 Miami
5 Pittsburgh
6 Atlanta
7 Cincinnati
8 Detroit
9 Chicago
10 St. Louis
11 St. Paul
12 Kansas City
13 Houston
14 Dallas
15 Denver
16 Los Angeles
17 San Francisco
18 Seattle
19 New Orleans

Blank space signifies not applicable.

SOURCE: DOE, Energy Information Agency, Mid-term Energy Forecasting System; Medium World Oil Price Scenario; April 1981.

Total regional costs were then determined for each type in each demand region by adding minemouth prices, transportation costs, and distribution charges. In cases where more than one possible source for high- or low-sulfur coal was available in a particular demand region, the lowest cost alternative was chosen. Estimated coal production figures for each supply region were studied to ensure that supply was adequate to meet anticipated demand in each demand region. If a lowest cost coal alternative already chosen could not supply coal in adequate quantites, the next lowest cost alternative was chosen.

In certain regions, no compliance coal use is feasible because states have strict SO_x regulations, or low-sulfur coal was determined to be overly expensive. (This was assumed to be so if the cost of the low-sulfur coal was $2/mmBtu greater than high-sulfur coal.)

In these regions, only high-sulfur coals were included in the analysis. In certain other regions, only one type of coal is economically and technically viable because of the types of coals mined locally and/or excessive transportation link costs.

Six demand regions were determined to have only one coal type available. Total regional prices (per million Btu) for these areas were taken from EIA average price projections. In the other four regions, both high- (or medium) and low-sulfur coals were considered practical. These prices were calculated using our per-ton total costs divided by the estimated Btu content for the particular coal types studied to yield prices per million Btu.

Estimates of 1979 prices for each of those regions having both high- and low-sulfur coal types were devloped from the EIA estimates by assuming that the differential between high- and low-sulfur prices projected for 1985 was the same as in 1979. Projections of 2020 coal prices were made by assuming that the 1995 prices escalated in real terms by 0.7 percent per year.

Estimated regional coal prices for 1979, 1985, 1990, 1995, and 2002 in each of the 10 demand regions are shown in Exhibit D.5.

Exhibit D.5

Regional Coal Prices
(1979$/mmBtu)

Demand Region	Supply Region	Coal Type	1979	1985	1990	1995	2020
1 New England	North Appalachian	high sulfur bituminous	1.79	2.69	2.96	3.07	3.65
2 New York/ New Jersey	North Appalachian	high sulfur bituminous	1.27	2.8	2.50	2.73	3.25
	Central Appalachian	low sulfur bituminous	2.49	3.17	3.61	4.03	4.80
3 Mid-Atlantic	North Appalachian	high sulfur bituminous	1.26	1.91	2.17	2.22	2.64
4 South Atlantic	South Appalachian	medium sulfur bituminous	1.26	2.29	2.84	3.23	3.85
	South Appalachian	low sulfur bituminous	1.73	2.74	3.19	3.31	3.94
5 Midwest	Midwest Appalachian	high sulfur bituminous	1.36	1.99	2.21	2.26	2.69
6 Southwest	Southwest	medium sulfur subbituminous	1.43	2.66	2.95	3.20	3.81
	NW Great Plains	low sulfur subbituminous	2.22	3.33	4.08	4.40	5.24
7 Central	Central west	high sulfur midbituminous	1.23	1.45	1.56	1.67	1.99
	NW Great Plains	low sulfur subbituminous	1.92	2.26	2.95	3.16	3.76
8 North Central	NW Great Plains	low sulfur subbituminous	1.04	1.33	1.35	1.44	1.71
9 West	NW Great Plains	low sulfur subbituminous	1.29	2.85	3.09	3.26	3.88
10 Northwest	Northwest	medium sulfur subbituminous	1.36	1.89	2.19	2.50	2.98

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