DOE/EIS-0146

FINAL PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

NOVEMBER 1989

U.S. DEPARTMENT OF ENERGY
Washington, D.C. 20585

COVER SHEET

November 1989

LEAD AGENCY

U.S. Department of Energy (DOE)

COOPERATING AGENCIES

None

TITLE

Final Programmatic Environmental Impact Statement (PEIS), Clean Coal Technology Demonstration Program

CONTACT

Additional copies or information concerning this final PEIS can be obtained from Allyn Hemenway FE-222, Office of Clean Coal Technology, U.S. Department of Energy, Washington, D.C. 20585. Telephone: (202) 586-7162.

ABSTRACT

The proposed action evaluated in this PEIS is to continue the Clean Coal Technology Demonstration Program (CCTDP) involving the selection, for cost-shared federal funding, of one or more clean coal projects proposed by the private sector. The PEIS addresses the potential environmental consequences of the widespread commercialization of the successfully demonstrated clean coal technologies by the private sector in the year 2010. This analysis of programmatic issues, along with additional environmental information and analysis containing business confidential or proprietary information, will be used by DOE in making decisions on specific proposals during the selection process. The PEIS evaluates a no-action alternative, which assumes the CCTDP is not continued and conventional coal-fired technologies with conventional flue gas desulfurization controls would continue to be used, and a proposed action alternative, which assumes that CCTDP projects are selected for funding and that successfully demonstrated technologies undergo widespread commercialization by the year 2010. The analysis of environmental consequences focuses on changes to four parameters of concern; namely, sulfur dioxide (SO_2), oxides of nitrogen (NO_x), carbon dioxide (CO_2), and solid wastes. An upper bound of change to each of these four parameters was estimated for each of 22 clean coal technologies, separately, assuming full penetration of potential markets. Using results from the Regional Emission Database and Evaluation System (REDES), the PEIS shows that repowering and retrofit—New Source Performance Standards (NSPS) capable clean coal technologies could lead to a significant reduction in SO_2 and NO_x relative to the no-action alternative in 2010. Repowering technologies are the only category in which all technologies could lead to a measurable reduction in CO_2. The amount of solid waste generated under the proposed alternative varies with each technology, ranging from a maximum increase of 23% to an equivalent decrease relative to that of the no-action alternative. Commercialization of the clean coal technologies would have a beneficial effect on air quality and could contribute to amelioration of current impacts of acidic deposition. Impacts on CO_2 emissions from clean coal technologies would be a direct function of the quantity of coal burned; thus, if commercialization of clean coal technologies results in changed use of coal resources, the technologies would contribute to a change in CO_2 emissions. Potential effects of the CCTDP on land use, water resources, ecological systems, endangered and threatened species, socioeconomic resources, and human health and safety are also evaluated in the PEIS. This PEIS includes changes made in response to comments received on the draft PEIS (issued July 1989). A copy of the comments received on the draft PEIS and the Department's responses to the comments is included in Appendix C of the PEIS.

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LIST OF ABBREVIATIONS AND ACRONYMS

AFBC	Atmospheric fluidized bed combustion
ANC	Acid-neutralizing capacity
ANL	Argonne National Laboratory
atm	Atmosphere
ASC	Advanced slagging combustor
Btu	British thermal unit
C	Carbon
Ca	Calcium
Ca/S	Calcium/sulfur ratio
CAFB	Circulating atmospheric fluidized-bed combustion
CCT-I	Clean Coal Technology-I; first solicitation
CCT-I	Clean Coal Technology-II; second solicitation
CCT-III	Clean Coal Technology-III; third solicitation
CCTDP	Clean Coal Technology Demonstration Program
CH_4	Methane
CO	Carbon monoxide
COE	Crude oil equivalent
CO_2	Carbon dioxide
CFB	Circulating fluidized bed
CFR	Code of Federal Regulations
CuO	Copper oxide
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EMP	Environmental Monitoring Plan
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic precipitator
FBC	Fluidized bed combustion
Fe	Iron
FE	Fossil Energy
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FR	Federal Register
ft	Foot/feet
GW	Gigawatts
ha	Hectare
HHV	Higher heating value
HSWA	Hazardous and Solid Waste Amendments
ICTAP	Innovative Control Technology Advisory Panel
IGCC	Integrated coal gasification combined cycle
IPP	Independent Power Producers
kg	Kilograms
kj	Kilojoules

km	Kilometers
kWh	Kilowatt hours
lb	Pound
LIMB	Limestone injection multistage burner
LPN	Liquefied petroleum gas
MBtu	Million British thermal units
mg	Milligram
MOI	Memorandum of Intent
MW	Megawatts
MWh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NAPAP	National Acid Precipitation Assessment Program
NAS	National Academy of Sciences
NE	Northeast
NEPA	National Environmental Policy Act
NEPP	National Energy Policy Plan
ng	Nanogram
NOI	Notice of Intent
NOPR	Notice of Proposed Rulemaking
NO_x	Nitrogen oxides
N_2O	Nitrous oxide
NO_2	Nitrogen dioxide
NRC	National Research Council
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NW	Northwest
NWS	National Water Survey
OECD	Organization for Economic Cooperation and Development
OGST	Oil, Gas, and Shale Technologies
O_3	Ozone
OTA	Office of Technology Assessment
Pb	Lead
PCB	Polychlorinated biphenyls
PEIA	Programmatic Environmental Impact Analysis
PFBC	Pressurized fluidized bed combustion
PEIS	Programmatic Environmental Impact Statement
PETC	Pittsburgh Energy Technology Center
PM	Particulate matter
PM_{10}	Particulate matter 10 micrometers in diameter
PON	Program Opportunity Notice
ppm	Parts per million
PURPA	Public Utility Regulatory Policy Act
QFs	Qualifying Facilities
RCRA	Resource Conservation and Recovery Act
REDES	Regional Emission Database and Evaluation System

REED	Regional Emission Evaluation Database
S	Sulfur
SCR	*Selective catalytic reduction*
SE	Southeast
SEB	Source Evaluation Board
sec	Second(s)
SNG	Synthetic natural gas
SO_2	Sulfur dioxide
SW	Southwest
TSP	Total Suspended Particulates
TSS	Total Suspended Solids
μg	Microgram
μm	Micrometer
U.S.	United States
USFWS	U.S. Fish and Wildlife Service
USGS	United States Geological Service
WRC	Water Resources Commission
yr	Year
Zn	Zinc

EXECUTIVE SUMMARY

This final Programmatic Environmental Impact Statement (PEIS) has been prepared by the U.S. Department of Energy (DOE) to support the proposed continuation of the Clean Coal Technology Demonstration Program (CCTDP) involving selection, for cost-shared federal funding, of one or more clean coal projects proposed by the private sector. This PEIS is part of an overall plan for compliance with the National Environmental Policy Act (NEPA). It addresses the projected environmental consequence of the widespread commercialization of the successfully demonstrated clean coal technologies by the private sector in the year 2010. DOE received comments on the draft PEIS from 9 federal agencies, organizations, and interested individuals. Comment letters and responses are contained in Appendix C of this final PEIS. In general, the comments received on the draft PEIS requested clarification or additional consideration of facts related to specific technologies and the overall clean coal program. Where appropriate, text in the final PEIS has been modified to incorporate information provided by the comments to improve the accuracy of the document. The comments did not result in a significant change between the draft and final PEIS. The final PEIS will be available to the Source Evaluation Board and the Selection Official prior to their recommending or making decisions on specific proposals. Additional information and analysis containing business confidential or proprietary information also will be considered by DOE during the selection process but cannot be made available to the public. Site-specific NEPA documentation will be prepared for each project selected by DOE for cost-shared funding and will be made publicly available.

Two alternatives are evaluated in the PEIS: (1) the no-action alternative which assumes that the CCTDP is not continued and that conventional coal-fired technologies with flue gas desulfurization and NO_x controls to meet New Source Performance Standards (NSPS) would continue to be used; and (2) the proposed action which assumes CCTDP projects are selected and funded and that successfully demonstrated technologies would undergo widespread commercialization by the year 2010. Under the proposed action alternative, changes to four environmental parameters of concern [sulfur dioxide (SO_2), oxides of nitrogen (NO_x), carbon dioxide (CO_2), and solid waste] were estimated as a result of the maximum commercialization by the year 2010 of 22 generic clean coal technologies. These environmental parameters were selected because SO_2 and NO_x are believed to contribute to the formation and deposition of acid rain. CO_2 is considered a greenhouse gas which could be influenced by the clean coal technologies. Finally, solid waste is analyzed in order to provide an indicator of the degree to which reductions in air emissions are achieved with a concomitant increase in the generation of solid wastes.

A number of general assumptions were applied to the analysis of the no-action and proposed action alternatives. The long-range energy projections used in the PEIS are consistent with National Energy Policy Plan (NEPP-V). Because projections cannot fully represent important qualitative factors (e.g., political events, economic performance, market behavior, and policy changes) that influence energy markets, the projections incorporate a considerable amount of judgment and are inherently uncertain. The projections reflect a national mix of energy supply components in addition to coal and include liquids, gas, nuclear, renewables, hydro and others. Coal is the only energy supply component of the national energy mix considered in the PEIS. These projections also reflect the effects of increased efficient use of energy. Changes in the national energy mix or the efficiency in the use of energy in 2010 would change the 2010 emission levels of the environmental parameters of concern. While other projections of national energy mix could have been selected, the use of the NEPP-V projection provides a consistent base for this analysis. The coal use projections represent a point of departure to understand possible energy futures associated with the proposed action.

The extent of future commercialization of each of the technologies will depend on its economic competitiveness and the technical suitability to retrofit or repower existing facilities or its use in new facilities. This PEIS does not attempt to predict the economic competitiveness of each of the technologies considered. Further, no attempt has been made to develop scenarios of different mixes of clean coal technologies because it is not known what technologies will be selected for demonstration, and there is no basis for defining a mix of technologies to be commercialized. Rather, maximum commercialization within each applicable market is assumed in order that projected changes in the environmental parameters of interest will not be exceeded by actual changes. While clean coal technologies may achieve higher market shares in some future markets, the potential increase in the use of coal could be offset by the higher efficiencies of some of the technologies (i.e., more energy output per Btu of coal input).

The analysis of environmental impacts is based primarily on information developed from the Argonne National Laboratory (ANL) Regional Emissions Database and Evaluation System (REDES), a computer model specifically designed to aid in environmental evaluations of clean coal technologies. The results are presented in the form of a comparison of emissions projected for the proposed action in the year 2010 to baseline conditions in the year 1985 and to emissions projected for the no-action alternative in the year 2010. In addition to national emission changes resulting from the commercialization of each technology, results were also calculated for each of four geographic quadrants of the United States. It should be noted that the results of this analysis differ to some extent from the analysis contained in the Programmatic Environmental Impact Analysis (PEIA) published in September 1988, which was used as a basis for preparing the PEIS. These differences reflect refinements in environmental characterizations, calculations of applicable markets, and other analytical improvements implemented during the preparation of the PEIS.

The results of the analysis show that under the no-action alternative and under current emission regulations, national emissions from coal-fired utilities and industrial boilers for SO_2 and NO_x are projected to increase by 16 and 67%, respectively, between 1985 and 2010. With respect to acidic deposition, negative impacts on water chemistry from atmospheric deposition of sulfur and nitrogen compounds would continue under the no-action alternative. The northeastern quadrant would continue to be the region of the United States most affected by production of acidic precursors, although a small decrease in the total amount of these materials produced would occur. Increased emissions of SO_2 and NO_x would occur in the other three quadrants, but the total amounts of pollutants produced are small in comparison to those produced in the northeastern quadrant. Carbon dioxide (CO_2) emissions are expected to increase by about 37% under the no-action alternative between the year 1985 and 2010 as a function of the amount of coal burned. The analysis of solid waste generated under the no-action alternative showed that by the year 2010 approximately 4,340 acres/yr would be required to dispose of flue gas desulfurization (FGD) sludge and 2,710 acres/yr for disposal of ash. Current land disposal requirements are estimated to be 570 acres/yr for FGD wastes disposal and 1,440 acres/yr for ash disposal.

The clean coal technologies have been divided into two major categories: repowering technologies and retrofit technologies. Repowering technologies are those that, by replacing a major portion of an existing facility, not only achieve significant emissions reductions but also may provide for the use of a new fuel form, increase facility capacity, extend facility life, and/or improve system efficiency. Retrofit technologies are those which reduce emissions of SO_2 and/or NO_x by modifying existing facilities or their present feedstock or by utilizing new fuel forms. The retrofit category is further divided into three classes. New Source Performance Standards (NSPS) capable technologies are those capable of controlling SO_2 and NO_x emissions to a level equal to or better than NSPS limits. These technologies can be retrofitted on existing plants or installed on new plants. Partial NSPS capable technologies are those that, when applied singly, will control either SO_2 or NO_x to NSPS levels and thus could be retrofitted on existing plants. These technologies could not be applied singly to new plants to meet full NSPS requirements. New fuel forms technologies are those which chemically or physically alter coal with the objective of mitigating emissions of SO_2 and/or NO_x. It should be understood that many of the technologies (e.g., NO_x controls) could be applied with FGD technologies to greenfield plants. However, this PEIS does not consider combinations of technologies, because there is no basis for defining a manageable list of such combinations.

The repowering technologies considered in this PEIS are the atmospheric circulating fluidized bed, pressurized fluidized bed, integrated gasifier combined cycle, and the gasifier fuel cell. For the purpose of this analysis, the available applicable market for repowering technologies may be limited by the demand for new electric power generation (i.e., plants will not be repowered unless additional electricity is needed). When evaluating the impact of repowering technologies, REDES computes the increase in electricity available from the repowered units. This potential increase in electricity is compared with the new electricity demand on a region-by-region basis. If the potential increase from repowered units is greater than the new demand, only a portion of the old units is considered to be repowered, replacing the generation from all new units. If the potential increase in electricity output from repowered units is less than the new demand, all candidate units in the applicable market are considered to be repowered. Only plants older than 30 years are assumed to be candidates for repowering.

The capacity increment (i.e., the percentage increase in generation capacity that can be achieved when repowering an existing power plant) has a significant impact on the applicable market for a repowering technology. The four technologies considered to be repowering technologies in this PEIS have the following capacity increments:

Circulating Atmospheric Fluidized-Bed (CAFB)	15% (DOE 1987a)
Pressurized Fluidized-Bed (PFB)	40% (DOE 1987a)
Integrated Gasifier Combined Cycle (IGCC)	130% (DOE 1987a)
Coal Gasification Fuel Cell (FC)	430% (DOE 1985d)

The structure of the applicable market for each of the four major repowering technologies is shown in Table E-1.

As can be seen, the technologies with higher capacity increment factors (IGCC and FC) actually repower less of the 1985 capacity that still exists in 2010, reflecting the fact that capacity cannot exceed demand based on a region-by-region analysis. Table E-2 shows the environmental characteristics for the repowering technologies evaluated in this PEIS, using the emissions characteristics of the technologies and the applicable market defined in Table E-2.

Table E-1. Structure of the applicable market for repowering technologies

Existing/new generation mix in 2010 (GWh x 10^3)	CAFB	PFB	IGCC	FC
1985 generation repowered	1,064	973	676	426
1985 generation not repowered but still on-line in 2010	21	112	409	659
New 2010 generation satisfied by repowered plants	150	345	666	1,042
New greenfield generation	1,270	1,075	754	378
Total	2,505	2,505	2,505	2,505

Table E-2. Environmental characteristics for the repowering technologies

	Applicable market	Change in national emissions (%)			
	(quads)	SO_2	NO_x	CO_2	Solid waste
CAFB	27.4	-44	-17	-5	+8
PFB	27.4	-48	-17	-8	-4
IGCC	27.4	-37	-17	-6	-5
Fuel cell	27.4	-29	-14	-12	-16

The CAFB affects the largest market share and results in a significant change in 2010 national SO_2 emissions of the repowering technologies. Because the PFB has slightly better environmental performance and a reduced heat rate as compared to the CAFB, the reduction expected in SO_2 is more, even though the PFB does not repower 91,000 GWh of generation that is repowered by CAFB. The reduction in CO_2 and solid waste is directly attributable to the improved PFB heat rate.

Of the repowering technologies, the IGCC and fuel cells have the best environmental performance; however, their impact on 2010 national emissions is somewhat diminished because of the large capacity increment associated with these technologies. Even with the penalty of smaller market shares associated with the capacity increment, the analysis shows that IGCC and fuel cell technologies do lead to significant changes in national emissions relative to the no-action alternative.

The larger percentage change in 2010 national emissions of CO_2 and solid waste associated with the gasifier-fuel cell technology is directly related to the higher efficiency of this clean coal technology. The capacity increment used in the PEIS analysis effectively bounds the minimum market share for each of the technologies. It should be recognized that the IGCC and fuel cell technologies could be deployed in smaller modules and, thus, may capture more of the 1985 capacity that still exists in 2010 than is shown in the analysis. However, there is no basis to analyze the 2010 demand for electricity on a plant-by-plant basis that would be necessary to determine the deployment of modular IGCC and fuel cell plants. The fuel cell and gas turbine could be fueled by the new fuel forms, such as methanol, produced from an indirect liquefaction process. While all possible combinations of fuel and electric power generation technologies could not be analyzed, it is felt that the IGCC and gasifier-fuel cell are representative of these technologies.

The emissions effect of less than 100% availability of the applicable market to repowering technologies depends on the extent to which the demand for new power production already limits the penetration of these technologies. For the fluidized bed technologies, the capacity increment is relatively small; hence, these technologies are not limited by the demand for new power production. Any reduction in the availability of the applicable market, below 75% of the total market, will result in roughly linear reduction in the size of the emissions reductions. For the gasifier technologies, significant expansion of capacity occurs when the technologies are applied. The low demand for new electric generating capacity, particularly in the initial years, naturally limits the application of these technologies. Lower availability of plants in the applicable market for repowering does not appreciably change the size of the emissions effect until the market share falls below 50% for IGCC and 25% for the fuel cell. Of course, the efficiency gains from all of these repowering technologies benefit new plants as well. The emissions reductions of these efficiency improvements are also roughly linear when the application of these technologies is limited in greenfield applications. This impact is small relative to the impact of the direct removal of SO_2 from older, unregulated, repowerable plants.

Retrofit technologies are those which reduce emissions of SO_2 and/or NO_x by modifying existing facilities or their present feedstock or by utilizing new fuel forms. The clean coal technologies in the retrofit–NSPS capable class which have been analyzed include: advanced slagging combustor, copper oxide flue gas cleanup, and the dual-alkali scrubber. The applicable market for all of these technologies is very large and includes the slate of existing unregulated plants still in service in 2010 and all new plants. A maximum market of almost 30 quads has been defined for most of the technologies, with the exceptions of the dual-alkali scrubber that is not applied to plants burning low sulfur coals. Table E-3 summarizes the emissions changes as measured relative to the total national emissions of the no-action alternative in 2010. These technologies can provide comparable environmental performance and reduce SO_2 emissions 30-45%, depending on the applicable market share. All combine SO_2 and NO_x emissions control to some extent. The advanced slagging combustor increases the amount of solid waste generated as a result of controlling SO_2. It should be noted that these wastes for the most part are dry and do not present the sludge disposal problems associated with the no-action alternative. The results presented above represent the applications of the technology to 100% of the market. Application to any other market share would result in a reduction in emissions directly proportional to that reduced market share.

The clean coal technologies in the retrofit–partial NSPS capable class that have been analyzed include: advanced FGD with salable byproduct, spray dryer with lime, limestone injection multistage burner (LIMB), sorbent injection, selective catalytic reduction, low NO_x burner and reburning. Each technology is applied to essentially the same market consisting of 1985 unregulated sources that exist in 2010, which amounts to approximately 12.9 quads of energy use. Table E-4 shows the results of the analysis.

Table E-3. Environmental characteristics for retrofit–NSPS capable technologies

	Applicable market	Change in national emissions (%)			
	(quads)	SO_2	NO_x	CO_2	Solid waste
Advanced slagging Combustor	29.5	-45	-18	<-1	+17
Copper oxide process	29.5	-45	-33	0	-22
Dual-alkali scrubber	18.5	-30	-11	0	-5

Table E-4. Environmental characteristics of retrofit–partial NSPS capable technologies

	Applicable market	Change in national emissions (%)			
	(quads)	SO_2	NO_x	CO_2	Solid waste
Advanced FGD with salable byproduct	12.5	-48	0	0	+9
Spray dryer with lime	12.9	-45	-5	<1	+8
LIMB	12.9	-30	-11	0	+8
Sorbent injection	12.9	-38	0	0	+8
Selective catalytic reduction	12.2	0	-15	0	0
Low NO_x burner	12.6	0	-11	0	0
Gas reburning	12.9	-10	-11	-2	-2

The advanced FGD with salable byproduct and spray dryer with lime have the largest impact on the reduction of SO_2, 48 and 45%, respectively. Solid waste, however, is increased approximately 8-9% for both technologies. The LIMB and sorbent injection can be used to reduce SO_2 emissions in 2010 approximately 30-38%. LIMB can reduce NO_x emissions by approximately 11-30% with respect to the national emissions in the no-action alternative; however, solid waste is expected to increase by approximately 8%. Reburning, selective catalytic reduction, and low NO_x burners are used primarily to reduce NO_x. As can be seen above, 11-15% reduction in NO_x emissions can be achieved if 100% of the unregulated plants in 1985 are retrofitted with these technologies. If these technologies were applied to any other market share, the reduction would be proportional to that share.

The clean coal technologies in the retrofit—new fuel forms class consist of those that chemically or physically alter the form of coal before its use as a fuel. These include advanced physical and chemical coal cleaning, mild gasification, direct liquefaction, indirect liquefaction, coal/oil coprocessing, and coal/water mixtures. Each of these technologies produces a product which, for the purpose of this PEIS, is used in a narrowly defined market. The analysis considered the emissions produced from the new fuel form production facility and its combustion in a boiler. Coal switching was not considered as an option for analysis in this PEIS. Therefore, for the coal cleaning technologies, two cases were considered: cleaning high sulfur coals and using the cleaned high sulfur coal only in the high sulfur coal market, and cleaning medium sulfur coals and using the cleaned medium sulfur coals only in the medium sulfur coal market. Since ultrafine and advanced physical technologies reduce sulfur content by less than 50%, they are assumed to be used only in existing utility and industrial boilers. Chemical cleaning can reduce sulfur content by 90% or more, therefore, it can be used in greenfield boilers that would use high sulfur coal. Table E-5 presents a summary of the emissions changes as measured relative to the total national emissions of the no-action alternative in 2010 for high sulfur coal cleaning.

Table E-5. Changes in national emissions for coal cleaning technologies using high sulfur coal

	Applicable market	Change in national emissions (%)			
	(quads)	SO_2	NOx	CO_2	Solid waste
Ultrafine	0.4	<-1	0	0	+1
Advanced physical	0.4	<-1	0	0	<1
Advanced chemical	8.0	-4	0	0	0

The rationale for defining the market for cleaned medium sulfur coal is the same as that used for defining the market for cleaned high sulfur coal. The changes in national emissions with these technologies are shown in Table E-6.

Table E-6. Changes in national emissions for coal cleaning technologies using medium sulfur coal

	Applicable market	Change in National Emissions (%)			
	(quads)	SO_2	NO_x	CO_2	Solid waste
Ultrafine	4.5	-16	0	0	+12
Advanced physical	4.5	-3	0	0	+10
Advanced chemical	9.9	-26	0	0	+23

Mild gasification, direct and indirect liquefaction, and coal/oil coprocessing produce a fuel that, at a minimum, could be used to displace residual oil in utility and industrial boilers. For the PEIS analysis, the products from these technologies were assumed to replace only high, medium, and low sulfur residual oil. Table E-7 presents a summary of the emissions changes as measured relative to the total national emissions of the no-action alternative in 2010.

Table E-7. Changes in national emissions for new fuel form technologies that could displace residual oil in utility and industrial boilers

	Applicable market	Change in National Emissions (%)			
	(quads)	SO_2	NO_x	CO_2	Solid waste
Mild gasification	4.6	-5	-2	+1	+14
Direct liquefaction	4.6	-9	-3	+1	+9
Indirect liquefaction	4.6	-5	+4	+1	+4
Coal/oil coprocessing	4.6	-4	<+1	+1	+3
Coal/water mixtures	1.1	-2	0	0	+4

Products from these technologies could replace coal in boilers, fuel gas turbines, direct engines, other heat engines, and fuel cells and could be used as refinery and chemical feedstocks and in other applications. An exhaustive analysis of all possible uses of the products from these technologies would not be possible for there is no firm basis to define the market. As expected, SO_2 decreased and solid waste increased. The slight increase in CO_2 is based on the fact that residual oil combustion produces less CO_2 than combustion of coal-derived fuels.

The coal/water mixture technology assumes the use of ultrafine coal preparation technology. The coal/water mixture fuel is used to replace medium and high sulfur residual oil in utility and industrial boilers. Emissions of SO_2 would increase if coal/water mixtures were used in boilers fired with low sulfur residual oil. The applicable market for coal water mixtures was calculated to be 1.1 quads. National emissions changes as measured relative to total national emissions of the no-action alternative in 2010 are -2% for SO_2 and +4% for solid waste.

Appendix B contains a more detailed description of environmental emissions for each of the 22 technologies analyzed in this PEIS. This appendix includes information on the identification of the applicable market, the applicable market characteristics, applicable market baseline emissions, applicable market emissions with clean coal technologies, percentage change in applicable market emissions, percentage change in total national emissions, and percentage change in the emissions in the four quadrants.

A summary of these changes in national emissions represents a range that could potentially be achieved if the technologies in each of the categories were applied independently to 100% of the appropriate applicable market. These ranges represent the maximum projected changes in the environmental parameters of interest.

Under widespread commercialization the repowering and retrofit–NSPS capable technologies could lead to a significant reduction in SO_2 relative to the no-action alternative in 2010. The reduction in the case of repowering ranges between 29 and 48% while the reduction for NSPS capable retrofit technologies is 30 to 45%. The potential emission levels in 2010 range between approximately 15 and 20 million tons per year for both the repowering category and the NSPS capable retrofit technologies. This would be below the 1985 SO_2 levels of approximately 24 million tons per year and the 2010 no-action alternative level of approximately 28 million tons per year. This significant reduction in SO_2 reflects the fact that both of these categories of technologies could be applied to the slate of unregulated plants still in service in 2010 and all new plants put into service between 1985 and 2010. The retrofit–partial NSPS capable technologies are applied only to the unregulated sources which exist in 2010. These technologies could result in SO_2 reductions of between 30% and 48%. It should be noted that some of these retrofit technologies do not control SO_2 and, therefore, would not impact SO_2 emissions. The new fuel forms retrofit technologies could reduce SO_2 emissions up to 26%.

With respect to NO_x and under the assumption of widespread commercialization, the repowering technologies could lead to a reduction of 14 to 17% or approximately 4 to 5 million tons of NO_x per year from the 2010 no-action alternative emission level of approximately 27 million tons per year. NO_x emissions would grow from the 1985 baseline of approximately 17 million tons per year because NO_x controls are not expected to keep pace with the increase in coal use. The NSPS capable retrofit technologies, for which NO_x control is an integral part, could lead to reduction of approximately 33% or approximately 9 million tons per year from the 2010 no-action alternative levels. The NO_x control technologies contained in the retrofit–partial NSPS capable category could lead to a reduction of approximately 15% whereas the new fuel forms retrofit technologies would impact NO_x ±3% relative to the 2010 no-action alternative emission levels.

The repowering technologies are the only category where all technologies could lead to a measurable reduction in CO_2. This reduction is directly attributable to the improved heat rates associated with these technologies, particularly the gasifier fuel cell, integrated gasifier combined cycle and pressurized fluidized bed. Reductions of 5 to 12% from the 2010 no-action alternative level of approximately 7100 million tons of CO_2 released per year could be achieved by the repowering technologies. The gas reburning technology in the retrofit–partial NSPS capable category could lead to a reduction in CO_2 of approximately 2% if it were applied to 100% of its applicable market. The slight increase in CO_2 under the new fuel forms category is based on the fact that combustion of residual oil produces less CO_2 than combustion of coal derived fuels.

Both repowering and NSPS capable retrofit technologies would have an impact on solid waste generation. For the repowering technologies, the change in national emissions relative to the 2010 no-action alternative level of approximately 540 million tons per year ranges between a 16% reduction and an 8% increase. This equates to a 105 to 165% increase in solid waste above the 1985 level of approximately 220 million tons per year and is directly related to the increase in energy use and the fact that reductions in SO_2 are traded off against a potential increase in solid waste. The analysis of the NSPS capable technologies leads to essentially the same results with the range between a 22% reduction and a 19% increase in solid waste. The partial NSPS capable technologies could reduce solid waste by approximately 2% or lead to an increase of approximately 8% over the 2010 no-action alternative level of approximately 540 million tons per year. The new fuel forms retrofit technologies, in most cases, will lead to an increase in solid waste generation. The maximum level of increase is estimated to be approximately 23%, or about 125 million tons per year, over the 2010 no-action alternative level.

Table E-8 summarizes the changes in national emissions for the pollutants of concern relative to the no-action alternative in 2010 as a result of widespread commercialization of the repowering and retrofit technologies. Table E-9 illustrates the minimum level of national emissions which could be achieved under the proposed action.

Table E-8. Comparison of projected national emission for the proposed action and the no-action alternative (2010)

Clean coal technology category	Environmental consequences in 2010 (% change: no-action versus proposed action)			
	SO_2	NO_x	CO_2	Solid Waste
Repowering technologies	-29 to -48	-14 to -17	-5 to -12	-16 to +8
Retrofit technologies:				
NSPS capable	-30 to -45	-11 to -33	0 to <-1	-22 to +19
Partial NSPS capable	0 to -48	0 to -15	0 to <-2	-2 to +9
New fuel forms	<-1 to -26	-3 to +4	0 to +1	0 to +23

In summary, the commercialization of clean coal technologies in the year 2010 would have a substantial beneficial effect on air quality compared to the no-action alternative. The reductions in SO_2 and NO_x emissions could contribute to an amelioration of current impacts of acidic deposition on surface waters, although the degree and rate of recovery is uncertain. Any improvement to acidification would be greatest in the northeastern quadrant of the United States and in southeastern Canada. The clean coal technologies could lead to reduced emissions of CO_2 if higher efficiency technologies, such as the repowering technologies, were employed in the production of electricity since the amount of coal used per unit of electricity produced by these technologies would decrease. The impact of any such decrease on global CO_2 levels, however, would be minor because factors other than U.S. coal combustion dominate the global carbon cycle. The PEIS analysis shows that the amount of solid waste generated by the different clean coal technology categories varies greatly. The impacts of waste disposal on land use could be somewhat less significant than for the no-action alternative since the expected wastes are dry wastes which would be easier to handle and dispose of and would require fewer acres per ton than would wet FGD sludge. Furthermore, several clean coal technologies produce salable byproducts. However, the hurdles these byproducts must overcome to be put to beneficial use include purity requirements, transportation costs, and competition from current suppliers of the materials.

Table E-9. Comparison of national emissions: 1985, 2010 no-action forecast and 2010 proposed action forecast

	National emissions (tons x 10^6/yr)			
	SO_2	NO_x	CO_2	Solid waste
1985 Baseline[a]	23.9	17.0	5180	219
2010 No-action forecast[b]	28.1	27.1	7100	537
Clean coal technology category:	2010 Proposed action forecast[c]			
Repowering technologies	14.6 to 20.0	22.5 to 23.3	6250 to 6750	450 to 580
Retrofit technologies:				
NSPS capable	15.5 to 19.7	18.2 to 27.1	7040 to 7100	420 to 640
Partial NSPS capable	14.6 to 28.1	23.0 to 27.1	7000 to 7100	525 to 585
New fuel forms	20.8 to 27.9	26.3 to 28.1	7100 to 7170	537 to 660

[a] Placet et al. 1986.
[b] Boyd et al. 1988b.
[c] REDES.

Other issues that are addressed in the PEIS include potential effects on (1) land use (potential impacts of new sites on prime farmland, floodplains, wetlands and archaeological, historic, and paleontological sites); (2) endangered and threatened species; (3) terrestrial habitat; and (4) socioeconomic resources. For each of these issues, and other issues as appropriate, a more extensive analysis of the impacts will be made in the project-specific environmental documents to be prepared by DOE when information becomes available on the locations of the proposed project sites.

1. PURPOSE AND NEED FOR ACTION

1.1 INTRODUCTION

This Programmatic Environmental Impact Statement (PEIS) has been prepared by the U.S. Department of Energy (DOE) in compliance with the National Environmental Policy Act (NEPA) to evaluate programmatic environmental issues associated with alternatives related to selecting, for cost-shared federal funding, one or more clean coal projects proposed by the private sector in response to the Clean Coal Technology Demonstration Program (CCTDP) solicitations.

1.2 PURPOSE OF THE CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

1.2.1 Program Goals

The CCTDP is a technology demonstration program jointly funded by the federal government and industry. The program will take the best and most promising of the advanced coal-based utilization, processing, and emission control technologies, and, over the next decade, advance their technical, environmental, and economic performance to the point where the private sector can introduce the demonstrated technologies into the commercial marketplace. These demonstrations will be on a scale large enough to generate all data from design, construction, and operation that is necessary for the private sector to judge their commercial potential and to make informed, confident decisions on commercial readiness.

The goal of the CCTDP is to make available to the U.S. energy marketplace a number of advanced, more efficient, reliable and environmentally responsive coal utilization and environmental control technologies. These technologies will address, and may reduce and/or eliminate, some of the economic and environmental impediments that limit the full consideration of coal as a future energy resource.

Technologies to be demonstrated must be capable of repowering or retrofitting existing facilities. Such existing facilities can be designed to use any conventional fuel (e.g., coal, oil, gas) or a new fuel form and can be either stationary or mobile. A new fuel form is one in which coal has been chemically and/or physically altered with the objective of mitigating emissions of SO_2 and/or NO_x.

Repowering technologies replace a major portion of an existing facility not only to achieve a significant emissions reduction but also to increase facility capacity, extend facility life, improve system efficiency, and/or provide for the use of a new fuel form. Repowering can increase capacity from 10-150% and may be more cost-effective than retiring older units and replacing them with new plants. It also offers the opportunity to efficiently and reliably integrate emissions control and power generation technologies. Repowering technologies include circulating atmospheric fluidized-bed combustion, pressurized fluidized-bed combustion, integrated gasification combined cycle, and integrated gasifier-fuel cell.

Retrofit technologies reduce SO_2 and/or NO_x emissions by modifying existing facilities or their present feedstocks or by utilizing new fuel forms. Retrofit technologies include advanced coal cleaning, advanced combustors, advanced flue gas cleanup, alternative fuels, coal liquefaction, and coal gasification.

1.2.2 Program Strategy

The strategy being implemented to achieve the goal of the CCTDP is to conduct a multiphase effort consisting of at least five separate solicitations for projects (Fig. 1-1), each with individual objectives that, when integrated, will make available technology options on a schedule consistent with the demands of the energy market and responsive to the relevant environmental considerations. A significant common element of this multiphase effort is the capture and transfer to the private sector and international community of sufficient technical, environmental, economic, and operational information to allow potential commercial users to confidently screen the technologies for those which meet their operational requirements.

1.2.2.1 The Clean Coal Technology-I (CCT-I) Solicitation

On December 19, 1985, Congress passed Pub. L. 99-190.[1] Included in this act were provisions for funds to conduct cost-shared, clean coal technology projects for constructing and operating facilities demonstrating the feasibility of future commercial clean coal applications.

Congress directed that the first solicitation for federal cost-sharing (1) be open to all market applications of clean coal technologies, (2) apply to any segment of the U.S. coal resource base, and (3) encompass both "new" and "retrofit" applications. DOE issued a Program Opportunity Notice (PON) on February 17, 1986. Following receipt of 51 proposals by the April 18, 1986, deadline, DOE initiated a rigorous evaluation process that extended over three months. This evaluation resulted in the selection on July 25, 1986, of nine projects for negotiation and the identification of an alternative list of 14 projects to be considered if negotiations could not be successfully completed with any of the initial candidates.

The generic technologies to be demonstrated under CCT-I include:

- Pressurized fluidized-bed combustion
- Limestone injection multistage burner plus sorbent duct injection
- Gas reburning and sorbent injection
- Underground coal gasification
- Slagging combustor and sorbent injection
- Integrated gasifier combined cycle
- Coal/oil coprocessing
- Circulating fluidized-bed combustion (2 projects)
- Advanced slagging coal combustor
- Combustion tests of cleaned coal
- Recovery of fine particles of low sulfur coal from mine waste disposal ponds
- Advanced coal preparation technology for western coal.

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[1] *An Act Making Appropriations for the Department of the Interior and Related Agencies for the Fiscal Year Ending September 30, 1986, and for Other Purposes.*

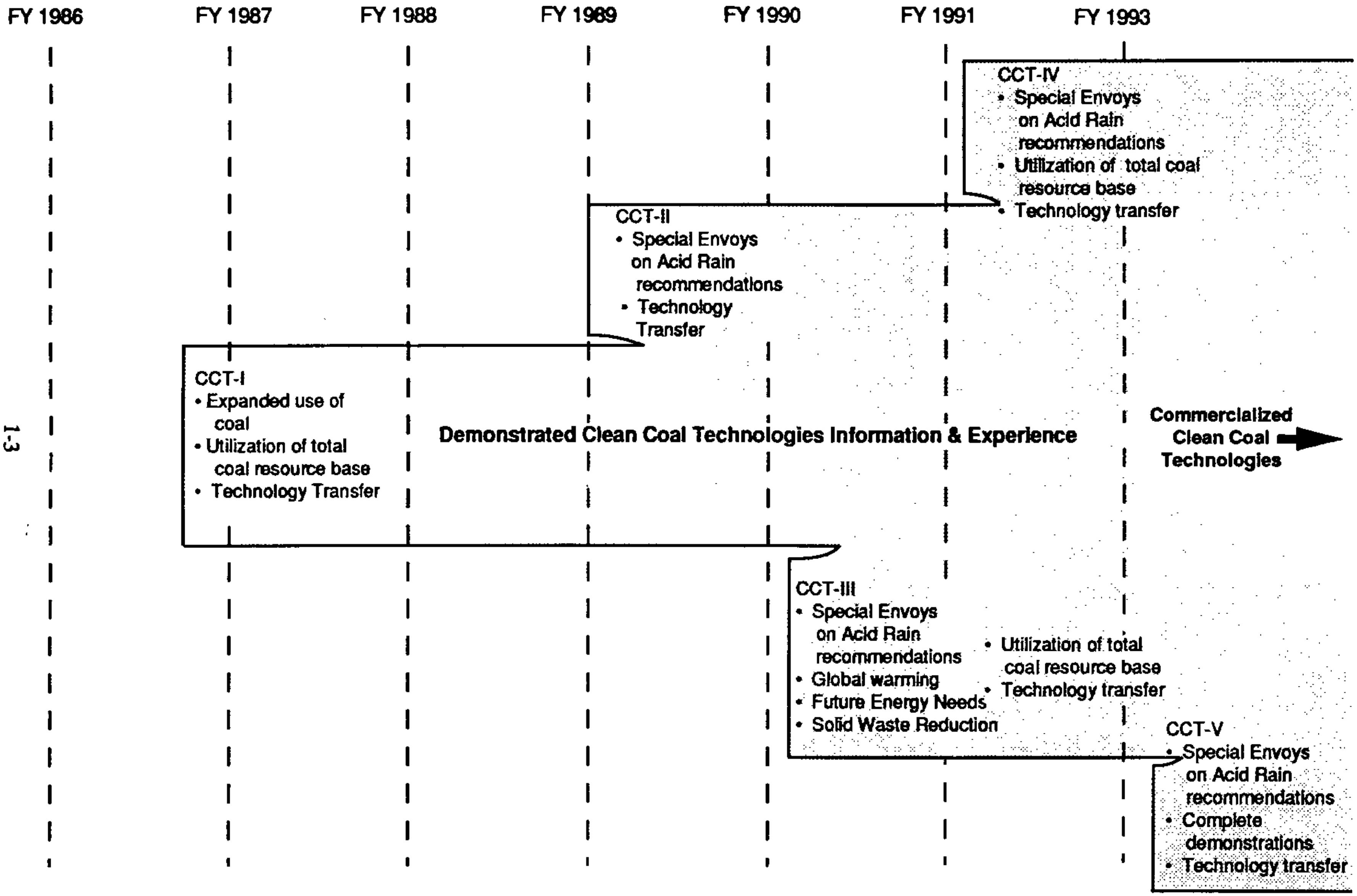

Fig. 1-1. Clean Coal Technology Demonstration Program Strategy.

The goal of the CCT-I will be accomplished through the demonstration of 13 projects. The CCT-I projects will demonstrate six technologies, which can be retrofitted on existing plants, five technologies, which can be used to repower existing plants or used in new plants, and two technologies for conversion of coal to more usable energy forms. While most of the technologies can be applied to any segment of the nation's coal resource base, the use of over 15 different eastern and western coals will be specifically demonstrated.

1.2.2.2 The Clean Coal Technology-II (CCT-II) Solicitation

While CCT-I is directed at demonstrating technologies that can (through increased efficiency and flexibility) increase the role of coal as an energy option, CCT-II is more focused and directed specifically at demonstrating technologies that can overcome the impediments to increased use of coal created by the issues of acid rain. The objectives are derived principally from the efforts and results of the Special Envoys' Report on acid rain (Lewis and Davis 1986) (see Sect. 1.3.2.1).

In March 1986, the President endorsed the Special Envoys' recommendations and set in motion the development of an expanded clean coal technology program that would build on the CCT-I effort, reflect ongoing state and privately funded initiatives, and be fashioned as fully as practicable to meet the recommendations of the Special Envoys. The CCTDP thus became the centerpiece of the initiatives to satisfy the recommendations of the Special Envoys.

Using the recommendations of the Special Envoys and Congressional guidance, a second solicitation was prepared and released on February 22, 1988. On September 28, 1988, 16 additional projects were selected for the CCTDP. Technologies selected for demonstration under CCT-II include:

- Advanced flue gas desulfurization
- Advanced wall-fired combustion techniques
- Selective catalytic reduction
- Advanced tangentially fired combustion techniques
- Dry sorbent injection
- Integrated gasifier combined cycle
- Catalytic reduction of SO_2 and NO_x
- Combined SO2 - NO_x - TSP control technology
- Circulating fluidized-bed combustion
- Pressurized fluidized-bed combustion
- Coal reburning
- Advanced flue gas desulfurization process
- Low NO_x/SO_2 burner
- Coal water slurry production and combustion test
- SO_2 scrubbing system for coal burning cement kilns
- Coke oven gas cleaning.

The selected CCT-II cost-shared projects will demonstrate technologies which are potentially more cost-effective than existing technologies and are capable of achieving significant reductions in emissions of SO_2 and/or NO_x from existing coal burning facilities, particularly those that contribute to transboundary and interstate pollution. Of the 16 projects selected, 13 technologies can be retrofitted on existing coal burning plants, and 3 can be used to repower existing facilities.

1.2.2.3 The Clean Coal Technology-III (CCT-III) Solicitation

Language in the Congressional Report accompanying Pub. L. 100-446[2] established the schedule for the third solicitation. A PON was issued on May 1, 1989, and proposals were submitted on or before August 29, 1989. The Secretary of Energy is to make project selections no later than January 1, 1990, in accordance with Pub. L. 101-45.[3]

On May 1, 1989, DOE released a PON to solicit proposals to conduct cost-shared clean coal technology projects to demonstrate innovative, energy-efficient technologies that are capable of being commercialized in the 1990's. The technologies must be capable of (1) achieving significant reductions in the emissions of SO_2 and/or NO_x from existing facilities to minimize environmental impacts such as transboundary and interstate pollution and/or (2) providing for future energy needs in an environmentally acceptable manner. Candidate technologies must be capable of either retrofitting or repowering existing facilities. Such existing facilities currently may be designed to use any fuel (e.g., coal, oil, gas) and may be either stationary (e.g., power plants) or mobile (e.g., transportation applications). The demonstration projects, however, can be at new facilities, provided that the technology is suitable for retrofitting or repowering applications. The CCT-III solicitation is not intended to support research activities nor to deploy currently available technologies.

1.2.2.4 Future Clean Coal Technology Solicitations

Future solicitations are in the planning stage and, as with the previous solicitations, will be consistent with Congressional guidance and administration policy. This guidance and policy will include implementing the recommendations of: the Special Envoys' Report on Acid Rain, the President's Task Force on Regulatory Relief, and the Innovative Control Technology Advisory Panel (ICTAP). The advice and guidance received from the National Coal Council, potential industrial participants, and states will be used to the maximum extent possible.

1.3 NEED FOR THE CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

1.3.1 The Demand for Increased Use of Coal

Solutions to a number of key energy issues are directly dependent upon the degree to which coal can be considered an available energy option. These issues include (1) long-range requirements

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[2] *An Act Making Appropriations for the Department of Interior and Related Agencies for the Fiscal Year Ending September 30, 1989, and for Other Purposes.*

[3] *An Act Making Supplemental Appropriations for the Department of Veterans Affairs for the Fiscal Year Ending September 30, 1989, and for Other Purposes.*

for increased power demand, (2) need for energy security, and (3) increased competitiveness in the international marketplace.

1.3.1.1 Requirements for increased power

Almost 50% of the current inventory of electrical generating capacity in the United States will be over 30 years old by 1997. The need to replace or refurbish this capacity, plus adding new capacity to keep pace with the rising demand for electricity, means that a major investment in electrical generation capacity should begin by the mid 1990's. Better technologies must be available for use on a commercial basis prior to the year 2000 to avoid the economic and environmental penalties associated with continued investments in only the currently available state-of-the-art commercial technologies.

1.3.1.2 Coal and energy security

Coal's abundance makes it one of the nation's most important strategic resources in building a more secure energy future. Coal can be one of the country's most useful energy sources well into the 21st century and beyond. With current prices and technology, U.S. recoverable reserves of coal could supply the nation's coal consumption at current rates for nearly 300 years. However, if coal is to reach its full potential and be both environmentally acceptable and economically competitive, an expanded slate of advanced clean coal technologies must be developed to provide substantially improved options that are superior to today's choices.

1.3.1.3 Increased competitiveness of coal in the international marketplace

New technology is a major factor in making the coal export package attractive. Such technologies may provide the single most important advantage that the United States could have in the global competition for new markets.

The ability to show a prospective overseas customer an actual operating facility running on U.S. coal, rather than just a drawing-board concept or an engineering prototype, is expected to be a very persuasive inducement. It easily could be the advantage that will sway overseas consumers to buy an American package of coal and the proven clean coal technologies to burn it cleanly and effectively. The opportunity is consistent with and recognizes the increasing demand for safe, effective technology that does not impose further burdens on environmental quality. The development of advanced clean coal technologies also will satisfy the demand for lower cost, more highly efficient energy concepts that will not reverse the recent gains in economic growth by imposing new costs on consumers.

1.3.2 Impediments to the Increased Use of Coal

While substantial deposits of coal exist as a resource suitable for and capable of resolving the critical near-term and long-range energy issues, a number of obstacles exist that not only limit its general availability but also act as a barrier to its increased use. These impediments include (1) concerns about environmental issues, (2) availability of the technology, and (3) performance of the technology.

1.3.2.1 Coal use and acid rain emissions

The combustion of coal results in the generation of a number of gaseous compounds or emissions, among which are SO_2 and NO_x. These emissions are believed to contribute to the formation and deposition of "acid rain."

In March 1985, President Reagan and Canadian Prime Minister Mulroney appointed Special Envoys, Drew Lewis of the United States and William Davis of Canada, to assess the international environmental problems associated with transboundary air pollution and to recommend solutions. The Special Envoys were assigned four specific tasks:

1. pursue consultation on laws and regulations related to pollutants thought to be linked to acid rain;
2. enhance cooperation in research efforts, including research on clean fuel technology and smelter controls;
3. pursue means to increase exchange of relevant scientific information; and
4. identify efforts to improve the United States' and Canadian environments.

The Special Envoys' report on acid rain (Lewis and Davis 1986) resulted from these efforts. In this report, the Special Envoys concluded that acid rain is a serious environmental problem in both the United States and Canada, that acidic emissions transported through the atmosphere undoubtedly are contributing to the acidification of sensitive areas in both countries (a transboundary problem), and that potential for long-term socioeconomic costs is high. Concerning solutions to the acid rain problem, the Special Envoys concluded that there are only a limited number of potential avenues for achieving major reductions in acidic air emissions, and they all carry high socioeconomic costs. In particular, the Special Envoys' report noted that none of the conventional methods now available for controlling emissions provide a simple solution to the problem.

The report contained recommendations to mitigate the problems, including the recommendation that the U.S. government implement a five-year, $5 billion industry/government cost-shared control technology commercial demonstration program in which the federal government would provide up to one-half of the funding for the projects. Industrial sponsors would contribute at least 50% of the funding.

Because this technology demonstration program would be part of a long-term response to the transboundary acid rain problem, the Special Envoys recommended that prospective projects should be evaluated according to the following criteria:

- The federal government should co-fund projects that have potential for the largest emission reductions, measured as a percentage of SO_2 or NO_x removed.

- Among projects with similar potential, U.S. government funding should go to those that reduce emissions at the cheapest cost per ton.

- More consideration should be given to projects that demonstrate retrofit technologies applicable to the largest number of existing sources, especially existing sources that, because of their size and location, contribute to transboundary air pollution.

- Special consideration should be given to technologies that can be applied to facilities currently dependent on the use of high-sulfur coal.

President Reagan approved in 1986 and reaffirmed in 1987 the implementation of the Clean Coal Technology Program as a response to the recommendation of the Special Envoys on acid rain and that the United States should support development of an expanded menu of control options to reduce SO_2 and NO_x emissions. These added options are to be cheaper and more efficient than current controls. As seen at that time, this program would complement both the trend of continuing reduction of these emissions from older plants and the activities of the 10-year interagency National Acid Precipitation Assessment Program (NAPAP).

The NAPAP final report, to be published at the end of fiscal year 1990, will describe the present knowledge of cause and effects relationships, available technologies, and attributes of control programs. In particular, this report will characterize present levels of impacts on freshwater bodies and biota, forests, crops, developed materials, and visibility, and will project how these effects would be likely to change if the levels of emissions are changed.

Additionally, President Bush stated as part of his February 1989 budget revision that the Administration will announce new measures to reduce these acid rain-related emissions. The legislative proposal, when submitted, will call for substantial reductions of emissions from the 1980 levels on a defined time schedule. The process for achieving these reductions will include expanded market-oriented choices to complement the existing "command-and-control" regulatory authorities. The Administration's approach anticipates that successfully demonstrated clean coal technologies will be major contributors to these reductions due to added commercialization incentives as well as the acceleration of full-scale demonstrations due to the program.

If this legislation is enacted, the trends of reduced emissions evidenced in the 1980's will be continued, and in all probability, they will be accelerated through the 1990's. After that time, the introduction of clean coal technologies on an expanded basis for both new facilities and retrofitting or repowering older units would produce emissions levels at much lower levels than occurred in the 1970's and 1980's. Based on current understanding of the atmospheric and geologic processes, the aquatic impacts and material impacts of coal use could be reduced and the other potential damaging impacts may not occur.

Even without legislation, future SO_2 and NO_x emissions should be moderated because of the availability and expected favorable economics of mature, demonstrated repowering technologies. The level of acceptance of retrofit clean coal technologies is less assured, but significant applications are expected due to state legislation, new source reviews of reconstructed facilities, needs to meet ambient air quality standards, etc. Thus, even for many facilities that might be refurbished without change in controls otherwise, there are control authorities that may facilitate their introduction on a case-by-case basis.

One significant issue expected to be addressed in the air emissions legislation is the timing of required reductions. Careful appraisal of the current demonstrations and the planning times for utility operator decisions need to be reflected in the timing provided to meet added emission reduction requirements. If this is not done, the recognized benefits that clean coal technologies can contribute to lessening costs of compliance and to reducing other environmental residuals, such as hard to handle sludge waste and CO_2 emissions, will be lost. The utility operators may perceive that they must add further air emission controls before the success of the new technologies has been adequately demonstrated.

1.3.2.2 Coal use and global warming

One of the critical environmental issues gaining national attention is the possibility of changes in global climate as a consequence of changes in atmospheric concentrations of "greenhouse" gases–most notably CO_2, methane (CH_4), nitrous oxides (N_2O) and chlorofluorocarbons (CFCs). The atmospheric concentration of CO_2 appears to have increased 9.5% between 1960 and 1986. This increase in CO_2 concentration has been mostly attributed to combustion of fossil fuels and global deforestation. In 1986, the United States was responsible for 22% of the global CO_2 emissions from fossil fuel burning. Of this, electric power generation contributes 35%, transportation 30%, and industrial sources 24%. The remaining 11% is contributed by the residential and commercial sectors. It is estimated that approximately 36% of the CO_2 emitted in the United States is attributable to the combustion of coal, and thus, coal use accounts for 8% of global CO_2 emissions.

Clean coal technologies can influence the emissions of greenhouse gases. With respect to CO_2, some of the clean coal technologies improve the efficiency of the conversion of coal to useful energy. Technologies such as pressurized fluidized bed, integrated gasifier combined cycle, and fuel cells will consume less coal per unit of useful energy produced and thus lower the amount of CO_2 emitted per unit of useful energy produced. Other clean coal technologies result in lower net thermal conversion efficiencies and hence, slightly increased rates of CO_2 emissions.

Should global warming be substantiated and reduction in emissions of greenhouse gases becomes a national policy objective, then worldwide commercial deployment of clean coal technologies would assume added significance.

1.3.2.3 The development of technology and improved performance

Since the early 1970's, DOE and its predecessor organizations have pursued a broadly based coal research and development (R&D) program directed toward increasing the nation's opportunities to use its most abundant fossil energy resource while improving environmental quality. This R&D program contains long-term, high-risk activities that support the development of innovative concepts for a wide variety of coal technologies through the proof-of-concept stage.

However, the availability of a technology at the proof-of-concept stage is not sufficient to ensure its continued development and subsequent commercialization. Before any technology can be seriously considered for commercialization, it must be demonstrated. The risk associated with technology demonstration is, in general, too high for the private sector to assume in the absence of strong economic incentives or legal requirements. The implementation of a technology demonstration program has been endorsed by the President, Congress, and the private sector as a way to accelerate the development of technology to meet near-term energy and environmental goals, to reduce risk to an acceptable level, and to provide the incentives required for continued activity in innovative research and development directed at providing solutions to long-range energy supply problems.

A key element in enabling coal to realize its potential in the nation's energy future is to improve the technical performance of coal utilization and conversion technologies. Technical performance is measured in terms of efficiency, reliability, flexibility, and emissions reductions. The CCTDP presents the opportunity to demonstrate improved technical performance, which can lead to significant reductions in the cost of using coal. The fundamental technical improvements demonstrated under the program will allow an effective response to the changing energy markets and a resolution of the conflict between the expanded use of coal and the environmental concerns of such use at the lowest possible cost.

1.4 RELATIONSHIP TO FEDERAL ENERGY POLICY

1.4.1 National Energy Policy Plan—V

The Administration's goal in energy policy, as described in the fifth National Energy Policy Plan (NEPP-V; DOE 1985a), continues to be that the nation should have an adequate supply of energy, maintained at a reasonable cost, and consistent with environment, health, and safety objectives. This goal presupposes three broad objectives: (1) Energy stability describes a situation in which problems of energy availability and price do not destabilize the U.S. economy, and economic growth is promoted. (2) Energy security means that adequate supplies of energy are physically available to U.S. consumers from both domestic and foreign sources and that the United States is less vulnerable to disruptions in energy supply than without the plan. (3) Energy strength derives from energy security, whereby it is possible to utilize effectively the vast energy resource base of the United States.

The CCTDP is consistent with and supports NEPP-V goals. Coal is the most abundant energy resource in the United States, with recoverable reserves estimated to be 935 billion barrels crude oil equivalent (COE). However, petroleum and natural gas, whose proven reserves are estimated to be 28 billion barrels and 35 billion barrels COE, respectively, are the most utilized fossil fuels in the U.S. energy-consuming marketplace, despite their significantly higher costs relative to coal. Coal use is demand driven, and the capacity exists to increase coal supplies to meet significant increases in demand. However, to make coal utilization more attractive, DOE and the private sector have been conducting research, through proof-of-concept, on a wide variety of coal technologies aimed at improving the economics of using coal, improving environmental performance associated with its use, and converting coal into forms that could allow it to be used as a lower-cost substitute for oil and natural gas.

1.4.2 Energy Security

In DOE's examination of domestic energy-related security interests, contained in the Energy Security Report (DOE 1985b), coal was recognized as having substantial potential to reduce dependence on imported oil and to enhance free-world energy security. The report notes that coal supplies are abundant in many countries and subject to widespread competition, and that coal availability is relatively insulated from foreign political manipulation. However, the report recognizes that coal's ability to compete with oil and gas needs to be improved. The report pinpoints five principal areas in which actions are needed:

- *continuing contributions* to the *technological* base for "clean coal" use,
- broadening opportunities to choose coal as a fuel,
- ensuring balanced environmental programs,
- expanding U.S. coal exports, and
- removing barriers to an efficient coal supply chain.

The CCTDP contributes to all recommended areas of activities except the last.

The goal of the CCTDP is to make available to the U.S. energy marketplace a number of more efficient, reliable, and environmentally responsive coal utilization and environmental control technologies. When completed, these demonstration projects will make a major contribution to the technology base by providing sufficient technical, operational, environmental, health, and safety information on a scale large enough to enable the private sector to make rational and confident commercialization decisions. The portfolio of technologies to be demonstrated as part of the CCTDP will expand the potential market applications for coal. The information gained through successful completion of the demonstrations and broad public dissemination of the environmental performance achieved on each project will establish the information base that will help ensure a better balance among legitimate goals in environmental programs. Finally, the CCTDP can lead to improved marketability of U.S. coal technology and open new international markets in the utility, industrial, and commercial sectors. The availability of developed and demonstrated coal technologies that meet environmental objectives of the international community can give the United States a substantial marketing advantage overseas. Further potential exists to link U.S. coal exports with coal technologies to strengthen U.S. competitiveness in both areas.

1.5 DIRECT ACTION

DOE's direct action is the selection, for cost-shared federal funding, of one or more projects to demonstrate clean coal technologies. When completed, it is expected that these CCT demonstration projects will provide sufficient technical, economic, operational, environmental, and health and safety information to encourage private sector commercialization. An important component of the demonstration program is the development of the information base for environmental and health assessments and mitigation of impacts associated with commercialization. The Industrial Participant in the demonstration program is required to develop and execute an environmental monitoring plan (EMP) during the demonstration. The EMP will address two classes of monitoring activities:

- Class I, Compliance Monitoring–monitoring required by other agencies of federal (other than DOE), state, and local governments to satisfy statutes and regulations concerning the environment, occupational and public health and safety, and terms of leases, permits, grants, and other requirements;

- Class II, Supplemental Monitoring–monitoring required in addition to compliance monitoring to establish the environmental characteristics and potential impacts of the clean coal technology and associated facilities, processes, and activities. Supplemental monitoring is intended to satisfy two objectives: to develop the information base for identification, assessment, and mitigation of environmental problems associated with the replication of the technology; and second, to identify and confirm environmental impacts and performance predicted in the NEPA documentation.

1.6 INDIRECT ACTIONS

There are a number of indirect actions that could influence the timing, rate, and extent of the commercialization of clean coal technologies.

1.6.1 Commercialization of Clean Coal Technologies

The goal of the CCTDP will be accomplished by stimulating the development and fostering the commercialization of these technologies through the joint government/industry support of demonstration projects. It has been projected that a window of opportunity will open in the mid-1990's for clean coal technologies. By that time, over one-half of the coal-fired power plants in the United States will be at least 30 years old, and utility companies will have the option of either building new plants to meet increases in demand or applying demonstrated clean coal technologies to existing plants to keep them efficient and within compliance standards. The latter option, which will use existing sites, be less expensive, and require shorter construction times, should be an easy choice for utilities to make. However, to take advantage of the window, two conditions must be met: (1) some existing regulatory barriers to deployment must be eliminated and/or modified; and (2) the technologies must be adequately demonstrated.

1.6.1.1 Regulatory relief

As part of the Special Envoys' agreement, a task force was formed, chaired by then Vice President Bush, to examine regulatory incentives and disincentives for commercializing new technologies and to determine if changes were needed. On January 23, 1988, President Reagan accepted the following recommendations of the President's Task Force on Regulatory Relief:

- Preferential treatment, under the CCTDP, for projects in states that, for rate-making purposes, treat innovative technologies the same as pollution control projects. This treatment would recognize the additional risk inherent in demonstration of innovative technologies.

- A Federal Energy Regulatory Commission (FERC) five-year demonstration program allowing rate incentives for innovative technologies. This program would also recognize the risk inherent in the demonstration of innovative technologies. FERC already provides this type of incentive in certain circumstances.

- A program by the U.S. Environmental Protection Agency (EPA) to: (1) encourage states to consider achieving greater ozone reduction through interpollutant trading and other measures that substitute less-expensive NO_x emissions reductions for more expensive volatile organic compound emissions reductions; (2) encourage the use of "bubbles" between recently built emissions sources; (3) expand commercial demonstration permits for innovative control technologies; and (4) encourage complementary use of emissions "bubbles" and waivers for innovative technology applications.

Further, the Innovative Control Technology Advisory Panel (ICTAP), established by the President to advise the Secretary of Energy on funding and selection of innovative control technology projects, addressed the problems impeding the accelerated commercialization of clean coal technologies and issued a report to the Secretary of Energy in January, 1989 (ICTAP 1989), concerning commercialization incentives.

The report included a number of suggestions to address the problems encountered by clean coal technologies, including economic incentives (tax incentives, loans and grants), regulatory incentives (regulatory reforms, environmental variances, and accelerated administration), and environmental incentives (environmental policy clarifications and waivers). The recommendations have as their objective the removal of impediments to, or in some cases, the provision of incentives for, clean coal technologies prior to full commercial availability. The ICTAP report addresses incentives that could be implemented at both the state and federal levels. These incentives are summarized as follows:

> **Tax incentives** are one method of reducing overall project capital costs. Possible incentives include investment tax credits, accelerated tax depreciation, and property, sales, use or ad-valorem tax reductions or exemptions.
>
> **Loans**, either low interest or zero interest, are a second type of economic incentive.

Grants and subsidies are the most direct method of reducing project costs, and they can be designed to address both economic and regulatory problems. Most typically, grants and subsidies are focused at either (1) the technology's capital costs through provision of a percentage of a project's capital costs or a flat "dollar per kilowatt" capital subsidy, or (2) the technology's total costs or cost-effectiveness in removing pollutants. On the regulatory side, provision of grants and subsidies may reduce the rate recovery uncertainties of the developers.

Regulatory reform can be used to address certain impediments by modifying the existing regulatory framework. A number of reforms are possible, including rolling prudency reviews, modifying the "used and useful" criteria, allowing incentive rates of return, including capital expenses in the rate-base during construction, allowing timely recovery of clean coal technology demonstration expenses through the fuel adjustment clause or comparable rate-setting procedures, and allowing for rapid amortization of innovative pollution reducing technologies.

Acceleration of administration can be used to address both regulatory and environmental impediments to clean coal technology development. Regarding site regulations, for example, states might expedite their siting and project approval processes or adopt "one-stop" approval processes. Similarly, environmental impediments related to permitting lead times and delays might be addressed by accelerating and facilitating permit administration.

Environmental variances could facilitate clean coal technology development by addressing some of the serious environmental impediments faced by these technologies. For example, provision of variances to extend the time period for obtaining required permits, thereby allowing new technologies to "work the bugs out," could encourage clean coal technology development.

Environmental bubbles/waivers could facilitate clean coal technology development by increasing the flexibility in meeting overall environmental goals. "Grandfather" provisions could also serve to mitigate risks regarding potential changes in emission limits in the future.

1.6.1.2 Technical readiness vs commercial deployment

Successful demonstration of a technology does not ensure that the technology will enjoy widespread deployment. DOE is working closely with Industrial Participants to develop plans for technology transfer and commercialization.

Utilities, generally, are risk-averse as a result of current regulatory requirements that severely limit their return on investment regardless of the degree of risk involved or benefits derived from risk taking. The President's Task Force on Regulatory Relief and ICTAP are addressing issues associated with regulatory requirements and identifying incentives to better ensure rapid deployment of the technologies.

In the electric utility industry, reliability of power generation technology is a paramount consideration. A key need of the utility industry is to prove long-term reliability of a technology under utility operating conditions (Yeager 1988). Therefore, realization of commercial potential in the electric utility industry may require several demonstrations of clean coal technology in order to achieve confidence in the new technology. This demonstration of several technologies will establish a learning curve whereby the risk-cost associated with each commercial demonstration is reduced.

The learning curve can be established within the framework of the CCTDP by demonstrating technologies in multiple but different applications rather than by replicating identical plants for identical applications. Widespread commercialization of these technologies can be achieved by demonstrating performance under different conditions (e.g., location, coal type, system configuration). Data produced during the demonstration will be available to ensure that the learning curve will be established to the degree necessary. These data, supplemented with aggressive marketing activities of the Industrial Participants, should allow the private sector to make rational technical, economic, and environmental decisions in a time frame consistent with the window of opportunity in the late 1990's.

1.7 RELATED ACTIONS

This section addresses the changing nature of the nation's energy future between 1986 and 2010 as it may influence the commercialization by the private sector of demonstrated clean coal technologies. The trend in the production of electric power from independent power production and cogeneration is discussed. The trends in the direct use of coal and also in petroleum and natural gas use are described.

1.7.1 Electric Utility Sector

The electric utility sector will account for most of the projected growth in coal demand. Electric utility consumption of coal is forecast to grow from 14.1 quads in 1986 to 28.9 quads in 2010 (DOE 1985c). Coal is projected to provide over 60% of the energy consumed in this sector.

The electric utility industry stands at the threshold of a fundamental change in the power generation technological base, just as the CCTDP is getting under way. By the mid-1990's, many utilities will be increasingly confronted by the dual problem of an aging boiler inventory and the potential long-term need for increasing their power generating capacity. More than half of all coal-fired boilers will be 30 years old or older by the mid-1990's. Utility decision makers will have to make some fundamental choices about many of these units--to retire, refurbish, repower, or replace them.

In this same time frame, demand for electricity will be growing, and reserve margins in generating capacity will be declining. Utility decision makers have been reluctant in recent years to invest in large, conventional baseload plants-either coal or nuclear-fueled. Moreover, uncertainty over anticipated growth in power demand, coupled with uncertainty regarding future environmental regulations, have stalled many construction projects.

Thus, the uncertainty in the timing associated with the anticipated future demand for new facilities, either to meet new demand or as a replacement for older units, plus today's slowdown in construction, has created an opportunity for application of new clean coal technologies in the 1990's and the early twenty-first century. Specifically:

- over 320 gigawatts (GW = MW x 10^3) of additional coal-fired capacity will be required between 1985 and 2010 to satisfy increased demand;

- approximately 59 GW of 1985 generating capacity will be replaced by 2010; and

- up to 248 GW of generating capacity, which will become 30-35 years old between 1995 and 2010, will be candidates for repowering or retrofitting with clean coal technologies.

The last decade has brought substantial changes in traditional electric power generation that must be recognized in the market for clean coal technologies. These changes—independent power production, Qualifying Facilities (QFs), and cogeneration all supported by regulatory provisions—can have a pronounced effect on the market for clean coal technologies.

Independent Power Producers (IPPs) are wholesale producers of electricity that are not affiliated with any utility in the area in which IPPs are selling power and that do not have significant market power. Independent Power Facilities are not regulated on a cost-of-service basis. QFs, as defined under the Public Utility Regulatory Policies Act of 1978 (PURPA), Pub. L. 95-617, are cogenerators and small power producers who sell power to utilities at avoided-cost rates.

Among the Notices of Proposed Rulemaking (NOPR), which FERC proposed in March 1988, was one involving IPPs and another involving bidding programs. The purpose of the first regulation is to streamline FERC regulation of IPPs, while the objective of the second is to allow state regulatory commissions and others to establish bidding procedures for rates in purchasing power from QFs under PURPA. These proposed rules have the potential to increase the availability, diversity, and competitiveness of alternative sources of power purchased by utilities. If these proposed rules are implemented, they could provide a market for new generating technologies.

Coal-fired technologies have not fared well against natural gas-fired technologies in cogeneration markets. The reasons for this are: (1) the need to find relatively large steam loads that are commensurate with economically efficient coal plant sizes; (2) the relatively low capital cost of natural gas-fired systems; and (3) the aggressive marketing strategy of the natural gas industry. Under the proposed rules, FERC anticipates that private power producers would not be constrained by the first reason.

In a draft environmental impact statement on IPPs and QFs (FERC 1988), FERC estimated that without the implementation of these NOPRs, QF capacity will grow modestly (15 GW added between 1990 and 2000 and an additional 8 GW between 2000 and 2005). Natural gas-fired systems will account for over 50% of total QF capacity in 1990, with coal accounting for 10% of this capacity in 1990.

The emergence of IPPs, QFs, and cogeneration have caused the client base for the clean coal technologies to grow beyond the traditional utility industry, thus opening new opportunities. Since these generating facilities are smaller and more dispersed, modular technologies, such as repowering technologies demonstrated under the CCTDP, will be most advantageous.

1.7.2 Direct Coal, Petroleum, and Natural Gas Use in Nonutility Sectors

Coal accounts for less than 16% of the U.S. industrial fuel market today, with oil and natural gas each commanding over 40%. The direct use of coal in the industrial sector is expected to grow at a rate of 1.8% per year, increasing from 1.7 quads in 1986 to 2.9 quads in 2010 (DOE 1985a). Thus, the potential market for coal in this sector is substantial and represents a significant opportunity for clean coal technologies. At present, over 1360 process steam-producing coal-fired boilers are in use by industry in the United States. Clean coal technologies, such as fluidized-bed combustion, appear to be an attractive option for both existing and new industrial applications.

Petroleum will remain the predominant fuel through 2010, contributing over 40% of total national energy consumption. The nation's continued dependence on petroleum is of increasing concern from an energy stability, security, and strength standpoint as projections indicate that the nation, by 2010, will find itself more dependent on imports from less stable regions of the world. Although the CCTDP largely addresses retrofitting and repowering existing coal-fired facilities, important spinoffs can contribute to relieving pressures caused by high oil imports through:

1. substitution of coal-derived liquids and alternative fuels for use in the petroleum consumption sectors. For example, non-energy use of petroleum in the industrial sector is expected to be 4.8 quads, or approximately 50%, of the petroleum consumed in this sector. This represents an important market target for coal-derived liquids as infrastructure impacts would be minimal.

2. providing clean coal technologies that will enable industry, and possibly larger residential and commercial sector users, to switch from oil to coal. These technologies include advanced combustion, alternative fuels, coal liquefaction, coal gasification, fluidized-bed combustion, fuel cells, heat engines, and advanced coal preparation.

Natural gas consumption is projected to increase until 2000 and then remain essentially constant. As in the case of petroleum, clean coal technologies can have significant spinoffs and can contribute to satisfying natural gas demand. For example, in the industrial sector, over 0.5 quad of natural gas is currently used as industrial feedstocks (DOE 1985c). Synthesis gas produced from coal could make a major contribution in this sector if coal gasification technologies are successfully demonstrated and subsequently deployed in the marketplace.

Further, coal gasification technologies can produce synthetic natural gas, which directly displaces natural gas and utilizes the vast network of pipelines that exist in this country.

1.8 SCOPE OF THE PEIS

1.8.1 NEPA Compliance Plan for the CCTDP

This PEIS is part of an overall plan for complying with NEPA consistent with the Council on Environmental Quality regulations (40 CFR 1500-1508) and the DOE NEPA (52 FR 47662) guidelines. For CCT-I, NEPA compliance was documented with (1) a confidential environmental analysis used by the Selection Official, followed by (2) project-specific NEPA reviews and documentation for each project selected. During the CCT-II solicitation a Programmatic Environmental Impact Analysis (PEIA) was prepared to assist the Selection Official by identifying and evaluating programmatic issues related to the technologies under consideration. The present PEIS is based on the PEIA and considers a broader range of clean coal technologies which encompasses all technologies that have been or are likely to be considered during the CCTDP. It should be noted that the results of this analysis differ to some extent from those contained in the PEIA. These differences reflect refinements in environmental characterization, calculations of applicable markets, and other analytical improvements made during the preparation of the PEIS. The draft PEIS was made available for public comment on July 7, 1989, and this final version, which has been modified to reflect comments received on the draft PEIS, will be used to support decisions made by Selection Officials during the third and future solicitations. As plans for additional solicitations are finalized, supplements to the PEIS will be developed as needed to ensure full compliance with NEPA.

The PEIS contains a description of generic technologies that are representative of specific types of technologies to be demonstrated under the CCTDP. From these generic technologies, forecasts are developed which describe potential environmental impacts that could occur from widespread deployment of commercial scale facilities. A second part of the NEPA compliance plan involves the preparation of preselection project-specific environmental review reports prepared by CCTDP Source Evaluation Boards for each solicitation.[4] The Source Selection Official will consider the PEIS, along with the preselection project-specific environmental reviews, as part of the selection process. The third element of the NEPA compliance plan is the preparation of site-specific NEPA documentation for each CCTDP demonstration project selected to receive financial assistance. These site-specific documents will be made available to the public.

The direct action being considered by DOE is the selection, for cost-shared federal funding, of one or more projects to demonstrate clean coal technologies. The indirect impact of the CCTDP is expected to be the widespread commercialization by the private sector of the successfully demonstrated clean coal technologies. It is the environmental consequences of widespread commercialization of these technologies in the year 2010 that is addressed in the PEIS.

The PEIS analysis compares environmental parameters of concern—projected airborne emissions of SO_2, NO_x, CO_2, and solid waste—for each clean coal technology against projected emissions and wastes in the absence of commercialization of any clean coal technology. This analysis assumes

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[4] Because these reports contain business confidential and proprietary information, they cannot be made available to the public.

maximum commercialization of each of the clean coal technologies. This approach is used so that projected environmental consequences will be at least as great as the actual impact. The extent of commercialization of a technology depends on its applicable market and its use in retrofitting or repowering existing facilities or use in new facilities unconstrained by economic competitiveness. Analytical results are presented on both a national and regional (i.e., quadrant) basis.

In this PEIS, 22 generic clean coal technologies are described and analyzed as to their environmental consequences assuming maximum commercialization. The 22 generic technologies are representative of the proposals submitted in response to the CCTDP solicitations. The following analytical bases were used to determine the environmental consequences of widespread commercialization:

- Total utility and industrial coal use was based on the DOE NEPP-V energy projections. (DOE 1985c).
- The characteristics of each technology determined its market application. (See Sect. 2).
- Each technology was analyzed independently in order to establish an upper bound on the environmental impacts that could occur for each technology. No attempt was made to develop scenarios of different mixes of clean coal technologies because: (1) it is not known what technologies will be selected for demonstration, (2) there is no basis for defining a mix of technologies to be commercialized, and (3) addressing all the possible combinations of technologies that could appear in the marketplace is not feasible.

Changes in the analytical bases used could have a significant impact on the projected consequences of the proposed action.

1.8.2 Scoping of the PEIS

On February 7, 1989, DOE published a Notice of Intent (NOI) to Prepare an Environmental Impact Statement for the CCTDP (54 FR 6001). This NOI solicited comments on environmental issues related to the CCTDP and on a Programmatic Environmental Impact Analysis (PEIA) published in September 1988. The NOI stated that the PEIA would be used as the basis for preparing the PEIS.

Comment letters in response to the NOI were received from the EPA, the Department of Health and Human Services, the U.S. Fish and Wildlife Service (USFWS), and the Tennessee Valley Authority (Appendix A). Comments in these letters were considered in determining the scope of the draft PEIS. The draft PEIS was made available to the public on July 7, 1989, and a Notice of Availability soliciting public comment was published in the *Federal Register* by EPA on July 14, 1989. Comments on the draft PEIS were received from 10 agencies, organizations, and individuals and have been considered in preparing the final PEIS. The comment letters and responses to the comments are included in Appendix C of this document.

The approach used in this PEIS is generic, with emphasis on source terms rather than receptors because the latter are highly site-specific and exact locations of deployment are unknown. Emphasis was placed on source terms associated with changes in atmospheric emissions and solid wastes that could change during the period of commercialization for the no-action and proposed action alternatives. The direct effects of changes in emissions of SO_2, NO_x, and CO_2 on air quality and the possible indirect effects of these changes on acidic deposition and global warming are addressed. An evaluation is provided of impacts from changes in solid waste generated under the two alternatives. Other impacts that are considered include those on land use, loss of terrestrial and aquatic habitat, endangered and threatened species, socioeconomic resources, and human health and safety.

The analysis of environmental impacts is based primarily on information developed from the Argonne National Laboratory (ANL) Regional Emission Database and Evaluation System (REDES), a computer model designed to aid in environmental evaluation of clean coal technologies (Boyd et al. 1988a). The regional emission and activity forecast database (REED) provides information on activity, emission factors, and emission projections as part of the REDES system (Boyd et al. 1988b). The REDES considers 22 generic clean coal technologies individually without any mix or summation of impacts from technologies. The results are presented in the form of comparisons to baseline predictions, which are for the no-action alternative in the year 2010. The model is run separately for each technology and assumes full commercialization of that technology in the applicable market without regard to economic competitiveness. Thus, the results represent an upper bound of possible change from the no-action alternative for each technology. No attempt is made to predict scenarios involving mixes of the technologies, because it will only be after the technologies are successfully demonstrated that realistic scenarios can be developed. In addition to national changes resulting from each technology, results are categorized according to four quadrants [Northeast (NE), Southeast (SE), Southwest (SW), and Northwest (NW)] of the United States (Fig. 1-2). The PEIS focuses on the conterminous United States, which includes most (>99%) of the coal-fired electric generating capability in the United States (Alaska has about 50 megawatts (MW) and Hawaii has none). For certain long-range effects such as acidic deposition, impacts on Canada are considered. The analysis provided in the PEIS is further limited by several factors. Because many of the clean coal technologies have not yet been demonstrated, there is little specific information available on the emissions, effluents, and solid wastes that would be produced. Information on where specific technologies would be deployed is not known, and therefore, estimates of where impacts would occur simply reflect the known location of existing power plants and industries.

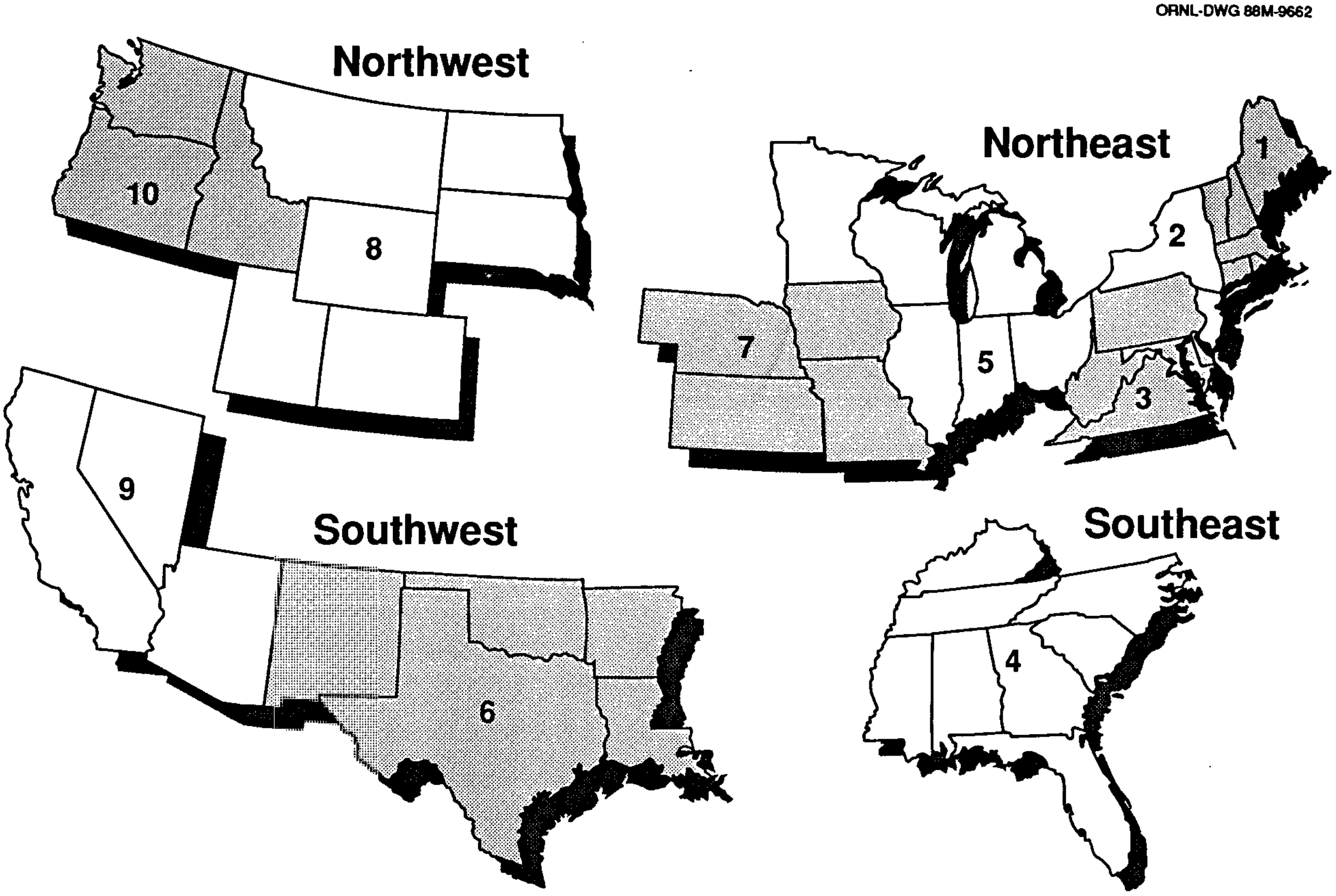

Fig. 1-2. Quadrants and federal regions for the conterminous United States.

2. ALTERNATIVES INCLUDING THE PROPOSED ACTION

2.1 INTRODUCTION

This section contains a description of the two alternatives evaluated in the PEIS: (1) the no-action alternative, which assumes that the CCTDP is not implemented and conventional coal technologies continue to be used and (2) the proposed action, which assumes one or more clean coal technology projects are selected for cost-shared federal funding and that successfully demonstrated technologies undergo widespread commercialization by 2010. Included in the discussion are the general assumptions made for both the no-action and proposed action alternatives, descriptions and environmental characteristics of the conventional coal technologies assumed in the no-action alternative, and descriptions of 22 generic clean coal technologies, which cover the range of technologies that are anticipated for the proposed action.

A number of general assumptions were applied to the analysis of the no-action and proposed action alternatives. The long-range energy projections used in the PEIS are consistent with NEPP-V. Because projections cannot fully represent important qualitative factors (e.g., political events, economic performance, market behavior, and policy changes) that influence energy markets, the projections incorporate a considerable amount of judgment and are inherently uncertain. The projections reflect a national mix of energy supply components in addition to coal, including liquids, gas, nuclear, renewables, hydro, and others. Coal is the only energy supply component considered in the PEIS. These projections also reflect the effects of increased efficient use of energy. Changes in the national energy mix or the efficiency in the use of energy in 2010 would change the 2010 emission levels of the environmental parameters of concern. While other projections of national energy mix could have been selected, the use of the NEPP-V projections provides a consistent base for this analysis. The coal-use projections represent a point of departure for understanding possible environmental futures associated with the proposed action. The widespread commercialization of clean coal technologies assumed in the PEIS enables an analysis of environmental futures that would not be exceeded by actual events. While clean coal technologies may achieve higher market shares in some future markets, the potential increase in the use of coal could be offset by the higher efficiencies of some of the technologies (i.e., more energy output per Btu of coal input). The reference energy projection is shown in Table 2-1 (Placet et al. 1986). The following are the most significant general assumptions associated with coal-fired electric utility generation:

- Changes in coal-fired generating capacity between 1985 and 2010 are as follows:
  - 1985 capacity still on line in 2010 = 248 GW,
  - 1985 capacity retired and replaced by 2010 = 59 GW
  - new capacity added between 1985-2010 = 320 GW

Table 2-1. Reference case: Energy consumed by the U.S. economy

Source	1989 (quads)	2010 (quads)
Coal	17.2	35.9
Oil	31.1	33.2
Natural gas	18.2	18.2
Nuclear	3.6	8.7
Renewables	6.4	14.5
Net electricity imports	0.1	0.3
Total	76.6	110.8

- Capacity factors for pre-New Source Performance Standards (NSPS) plants remain at the 1985 levels.

- Fuel switching from oil and gas may occur at some point in the future because of the relative economics of oil, gas, and coal, but the amount cannot be predicted. For the purposes of this PEIS, the impact of fuel switching is analyzed for the new fuel form technologies.

- Additional coal switching will not occur for pre-NSPS power plants because of economic and performance reasons.

The above coal-fired electric generating assumptions were based on the REDES.

With respect to the industrial sector, industrial feedstock use of coal (mainly coking coal) is not expected to increase between 1985 and 2010 and will remain at 0.1 quad. Coal use for industrial heat and power applications is expected to increase from 2.8 quads in 1986 to 5.1 quads in 2010 (DOE 1985c). Coal consumption for power generation in the industrial sector is restricted primarily to very large cogenerators or to particular circumstances where coal is readily available. Between 1986 and 2005, coal consumption for cogeneration is expected to increase by 23 GW (FERC 1988). Coal consumption for other services is limited by industrial process requirements. Consumption of coal for other industrial services is expected to remain constant at approximately 0.2 quad through 2010 (DOE 1985c).

Another general assumption made in the analysis is that there will be no changes in environmental regulations pertaining to coal-fired facilities before 2010. This is an important assumption particularly as it affects the impacts of the no-action alternative. If stricter emission limitations were imposed on existing coal-fired power plants through new EPA standards, acid rain control legislation or other policy choices of technologies, retirement decisions, and refurbishing action might be significantly affected. Depending on the nature and timing of such limitations and technologies available, plants might be retired earlier and replaced with new facilities rather than refurbishing them. Another alternative would be to repower the plant or add retrofit technologies not considered in the no-action alternative. Under the proposed action, retrofit and repowering with clean coal technologies is assumed. This might remain unchanged under the assumption of more stringent emission limitations if the time table of limitations allows for commercialization of these technologies. The precise outcomes and the relative differences between the no-action and proposed action alternatives, therefore, depend on exactly how such emission limitations are imposed.

If new emission regulations were assumed, it is generally expected that the no-action alternative would be affected the most and the relative difference between the no-action and proposed action would be reduced somewhat insofar as the environmental parameters of concern. However, some environmental effects would be increased under the no-action alternative. Since existing methods of control, such as coal cleaning and wet limestone flue gas desulfurization (FGD), tend to generate large quantities of solid waste, it is expected that solid waste generation would be larger than under either alternative as analyzed with the assumption of no new emission regulations. Hence, the effect of changing the assumption concerning new emission regulations generally would be to shift the environmental advantage of the proposed action alternative from reduction of SO_2 and NO_x toward reducing solid waste generation. However, the detailed results depend on the particular clean coal technology (if only one is assumed) and on the specific details of the emission limitation policy. In part, for these reasons, it was deemed impractical to analyze in a simple, clear manner the impacts under changing environmental regulations.

A final general assumption made in the definition of alternatives is that economic competitiveness cannot be predicted. Costs of technologies, fuels, and other factors cannot be predicted easily or precisely as far ahead as 2010; thus this complication was not deemed amenable to analysis in a reliable manner in this PEIS. Consideration of evaluating emission changes beyond 2010 was not done because neither the DOE projections nor adequate data on which to base such projections was available. A discussion of trends beyond 2010 can be found in NAPAP (1987a).

2.2 ALTERNATIVE 1–NO ACTION ALTERNATIVE

2.2.1 Introduction and Overview

Under the no-action alternative, no additional CCTDP projects are funded, and the CCTDP is discontinued because conventional coal technologies continue to be used. It is assumed that commercial readiness of clean coal technologies is not achieved and commercialization will not occur until after 2010, if at all. The utility and industrial sectors will utilize existing technologies for new and replacement capacity. Private sector development and demonstration of clean coal technologies could be expected to continue but at a significantly reduced pace and on a more limited set of technologies. Widespread commercialization could not be expected by 2010.

Under the no-action alternative, it is assumed that electric utilities will meet 248 GW of power demand during the 1995-2010 time period by extending the life of existing power plants through improved maintenance procedures. Because of the high cost of new capacity and the need for increased reliability and availability, the utility industry has become increasingly interested in refurbishing existing plants as a cost-effective option to replacing old plants with new, high-cost plants. This life extension option can be achieved either through an ongoing enhanced plant maintenance program or a single refurbishment where the unit is taken out of service while major components such as steam generators, turbines, electrostatic precipitators or other components are replaced or upgraded. In the case where a plant is refurbished extensively, the plant may have to go through new source review and may be required to meet NSPS. By adopting a comprehensive life extension program, utilities can add as much as 10 to 20 years to an existing plant originally designed for 30 to 40 years of service.

For the purposes of this PEIS, it is assumed that 100% of new and replacement coal-fired capacity required to satisfy electricity demand would be satisfied by building new pulverized coal-fired plants with FGD units. These units could also use physically cleaned coal in conjunction with FGD as part of a least-cost strategy for reducing acid rain precursor emissions and meeting NSPS for new electric power plants.

Two precombustion control techniques are available to utilities—coal cleaning and coal switching. Both are proven techniques for emissions reduction and have been adopted by a variety of facilities since the passage of the Clean Air Act in 1970. The average sulfur content of coals burned in electric utilities in the United States has dropped from 2.2% in 1975 to 1.4% in 1985 (GRI 1987). This shift to lower average sulfur content reflects the combined effects of coal switching, coal cleaning, and relatively more construction of low sulfur coal plants in the West.

Coal cleaning is a proven way to reduce the sulfur content of coal prior to combustion. However, commercial coal cleaning techniques are limited in their removal efficiencies to about 10 to 30% of the total sulfur in the coal. Prohibitive cost increases associated with high Btu losses generally rule out higher levels of sulfur removal using conventional techniques.

Through physical coal beneficiation technologies, the undesirable components from coal, such as ash and sulfur, are reduced significantly. This reduction leads to decreased transportation cost (on a Btu basis) and reduced boiler operational problems such as slagging, fouling, and corrosion.

Currently, over 50% of all domestic coal is cleaned. While low sulfur western coals generally are not cleaned, approximately 95% of the coals from the Appalachian and Illinois basins are cleaned to some extent (GRI 1987). During the period 1988 to 2010, it is assumed that coal cleaning will keep pace with coal demand, and significant changes in conventional cleaning performance or in percentages of coal cleaned will not occur except in combination with FGD.

Switching to a lower sulfur coal has been one of the cheapest options available to a utility plant faced with requirements to reduce SO_2 emissions. However, it is assumed that significant additional coal switching will not occur between 1988 and 2010. When NSPS were first promulgated in 1971, a ceiling of 1.2 lb/10^6 Btu was imposed on SO_2 emissions from major new coal-fired plants, and the use of "compliance coal" having potential uncontrolled emissions less than 1.2 lb/10^6 Btu increased dramatically. Revisions of the NSPS in 1979, however, eliminated this strategy by adding a requirement of 70-90% removal of SO_2 emissions. However, fuel switching remained a cost-effective technique for units that were operating or under construction prior to September 1978. There are a number of drawbacks to the widespread adoption of coal switching, including:

- strain on coal transportation networks from the West to the Midwest and out of the mountainous Appalachian region;
- high transportation costs (up to two-thirds the delivered cost of coal);
- displacement of coal miners in high-sulfur coal fields and socioeconomic disruption in rapidly expanding low-sulfur coal fields;
- the need to upgrade particulate control devices and to cope with additional boiler slagging and fouling problems in boilers designed for eastern bituminous coal; and, possibly,
- the need to upgrade coal handling equipment because western subbituminous coals can be more difficult to pulverize, and because of their lower heating values, greater quantities are required to generate an equivalent amount of electricity.

Because of these drawbacks, it is assumed significant additional coal switching will not occur between 1988 and 2010. It is also assumed that current environmental standards for new industrial boilers will not change between 1988 and 2010 and, therefore, present coal combustion and environmental control technology will continue to be used in existing and new industrial applications.

The remainder of this section discusses conventional coal technology, defined for purposes of the no-action alternative as the pulverized-coal firing with wet lime/limestone FGD technology.

2.2.2 Pulverized Coal Firing with Flue Gas Desulfurization

2.2.2.1 Description

To comply with 1979 NSPS, a typical new plant would be equipped with particulate matter control, such as an electrostatic precipitator (ESP) or a baghouse, and a FGD system capable of removing 70%(low sulfur coal) to 90% (high sulfur coal) of the SO_2 generated. While there are a number of FGD process designs, including wet, dry, nonregenerable and regenerable, the utility industry, historically, has had a strong preference for nonregenerable, calcium-based, wet slurry processes that produce a waste product for disposal (i.e., the lime/limestone scrubbing process).

In this process, the SO_2 in the flue gas comes in contact with and chemically reacts with a recirculating lime or limestone slurry in the scrubber to form a precipitate or sludge. The reacted lime or limestone slurry from the scrubber goes to a reaction tank where calcium sulfite and calcium sulfate precipitate as hydrated solids upon addition of fresh lime or limestone. To avoid the buildup of solids in the system, a portion of the slurry from the reaction tank is sent to a solid liquid separator which may be a centrifuge, filter, or a holding pond. The waste sludge is composed of calcium sulfite, calcium sulfate, unreacted lime, or limestone, and fly ash is withdrawn to a disposal area while the liquor is returned to the process. Makeup water is added to the process to compensate for evaporative losses and water lost with the waste sludge. The cleaned flue gas is reheated above its dew point and released through the stack.

A number of improvements to the basic process, described above, are needed in order to improve SO_2 removal and increase system availability. Varying the chemical composition of the limestone FGD system or the use of organic additives can improve SO_2 removal. Other improvements in FGD usage have been realized—scrubber redundancy (required to ensure availability) and elimination of reheat cycle and system reliability concerns. These have been substantially reduced or mitigated through extensive operating experience and technology improvements (NAPAP 1987a). It is recognized that these improvements could impact system availability; however, the analysis considers a constant capacity factor of 65% for both the no-action and proposed action alternatives.

2.2.2.2 Environmental characteristics

The most significant environmental emission from lime/limestone scrubbing is the generation of solid waste. Currently, solid wastes from a typical 500 MW plant using 2.5% sulfur, 12% ash, midwestern bituminous coal amount to about 160,000 tons/yr of ash and 135,000 tons/yr (dry basis) of FGD waste (impure gypsum) (NAPAP 1987a). FGD wastes are sludges comprised primarily of calcium sulfate solids that must be contained by the walls of a dike or pond for ultimate disposal, due to its slowly settling characteristics. Quantities of these materials will vary according to the sulfur and ash content of the coal. The environmental characteristics of pulverized coal firing with wet lime/limestone FGD are shown in Table 2-2. Three coals were selected for use in calculating the environmental characteristics discussed in Sects. 2.2 and 2.3. The selections were made primarily to provide a range of sulfur and ash contents to illustrate the expected performance of the various clean coal technologies, which are the subject of the PEIS. Illinois No. 6 represents a high sulfur, medium ash coal; Upper Freeport represents a medium sulfur, high ash coal; and Wyoming Powder River represents a low sulfur, low ash coal. Table 2-3 shows some of the properties of these coals.

2.2.2.3 Market application

The pulverized coal fired power plant with lime/limestone flue gas scrubber can be applied to all new and replacement power plants. It is estimated that approximately 380 GW of new and replacement capacity will be required in the United States by the year 2010. The technology

Table 2-2. Summary of environmental characteristics for pulverized coal firing with wet lime/limestone flue gas desulfurization.[a]

Applicable coal sulfur content	High[b]	Medium[b]	Low[b]
SO_2 removal (%)	90	90	70
NO_x formation reduction (%)	0	0	0
Solid waste:[c]			
Bottom ash (lb/10^6 Btu)	15.8	28.2	8.0
FGD sludge (lb/10^6 Btu)	31.1	19.4	4.1
Total suspended particulates	0.03	0.03	0.03
Heat rate (Btu/kWh)	9770	9770	9770
Capacity factor (%)	65	65	65

[a] Poch et al. 1988.
[b] See Table 2-3.
[c] ANL 1977.

Table 2-3. Properties of three coals used in calculating environmental characteristics[a]

Coal	Ash (%)	Sulfur (%)	Carbon (%)	Heating value (Btu/lb)
Illinois No. 6	16.0	4.0	57.5	10,000
Upper Freeport	29.8	2.5	60.1	10,570
Powder River	6.4	0.5	47.8	8,200

[a] Boyd et al. 1988a,b; Poch et al. 1988.

could be retrofitted technically to existing pre-1979 NSPS power plants. FGD can be used by industrial boilers in much the same way as in utilities, although the choice of specific FGD technologies may be different. A number of conventional lime/limestone FGD systems are in operation on many industrial boilers (NAPAP 1987a).

2.3 ALTERNATIVE 2–PROPOSED ACTION AWARDING FUNDS TO ONE OR MORE PROJECTS

2.3.1 Introduction and Overview

DOE's proposed action is the continued selection, for cost-shared federal funding, of one or more clean coal projects to demonstrate the technical feasibility, economic viability, and environmental acceptability of those technologies represented by the project(s) chosen. These emerging clean coal technologies can be used commercially to retrofit or repower existing power plants or used in new facilities in such a manner that they control more effectively and efficiently the discharge of suspected acid rain precursor pollutants. The proposed action may result in the widespread commercialization by 2010 of one or more of the technologies awarded funds under the CCTDP. It is the environmental consequence of the widespread commercialization of successfully demonstrated clean coal technologies which is addressed in the PEIS, not the individual demonstration projects themselves. The extent of future commercialization of the clean coal technologies will depend on their economic competitiveness and technical suitability to retrofit or repower existing facilities or to their use in new facilities. The PEIS does not attempt to predict the economic competitiveness of each of the technologies considered. Further, no attempt has been made to develop scenarios of different mixes of clean coal technologies, because it is not known which technologies will be selected for demonstration, and there is no basis for defining a mix of technologies to be commercialized. The analysis of the proposed action assumes each technology independently achieves maximum commercial potential in its applicable market. This assumption will ensure that the projected environmental consequence will be at least as great as the actual impact.

Twenty-two generic clean coal technologies have been identified as encompassing the slate of technologies expected to be proposed by the private sector under the CCTDP. Table 2-4 identifies these technologies along with some of the key market and application attributes. A more extensive discussion of the applicable markets for the technology as used in this PEIS is presented in Sect. 4.1 and a description for each technology is given in Appendix B.

The remainder of this section provides a brief description of 22 generic clean coal technologies, their environmental characteristics, and their market application. These 22 generic technologies are representative of the technologies that are anticipated to be demonstrated under the CCTDP.

The environmental characterization of the clean coal technologies were based in large measure on Environmental Profiles of Selected Clean Coal Technologies (Poch et al. 1988). The parameters were characterized for use in the Regional Emission Data Base and Evaluation System (REDES), which was developed to assist DOE in analyzing the potential environmental impacts of techno-

Table 2-4. Summary of market applications

Technology[a]	Coal Sulfur content[b] HS	MS	LS	Market Util.	Ind.	Boiler size[c] S	M	L	Application Repowering	Greenfield	Retrofit
					Repowering technologies						
CAFB	X	X	X	X	X	X	X	X	X	X	
PFB	X	X	X	X			X	X	X	X	
IGCC	X	X	X	X			X	X	X	X	
Fuel cells	X	X	X	X	X	X	X	X	X	X	
Gas turbine	X	X	X	X	X	X			X	X	
Diesel engine	X	X	X	X	X	X			X	X	
					Retrofit technologies—NSPS capable						
ASC	X	X	X	X	X	X	X	X		X	X
Copper oxide	X	X	X	X	X	X	X	X		X	X
Dual alkali	X	X	X	X	X		X	X		X	X
					Retrofit technologies—partial-NSPS capable						
Advanced FGD with salable byproduct	X	X	X	X	X		X	X			X
Spray dryer	X	X	X	X	X	X	X	X			X
LIMB	X	X	X	X	X	X	X	X			X
Sorbent injection	X	X	X	X	X	X	X	X			X
Gas reburning	X	X	X	X	X	X	X	X			X
SCR		X	X	X	X	X	X	X		X	X
Low NO_x burner	X	X	X	X	X	X	X	X		X	X
					Retrofit technologies—new fuel forms						
Ultrafine coal cleaning	X	X		X	X	X	X	X			X
Advanced physical coal cleaning	X	X		X	X	X	X	X			X
Advanced chemical coal cleaning	X	X		X	X	X	X	X		X	X
Mild gasification	X	X		X	X	X	X	X		X	X
Direct liquefaction	X	X	X	X	X	X	X	X		X	X
Indirect liquefaction	X	X	X	X	X	X	X	X		X	X
Coal oil coprocessing	X	X	X	X	X	X	X	X		X	X
Coal/water mixture	X	X		X	X	X	X	X			X

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[a] It is assumed for this analysis that multiple technologies are not applied to the same plant.
[b] Sulfur content designated as high (HS), medium (MS), or low (LS).
[c] Boiler size designated as small (S), medium (M), or large (L).

logies submitted under the CCTDP (Sect. 1.8). Additional sources of information were used, when available, to verify the output of the REDES model.

In many instances REDES contained percentage changes for emission and heat rate (efficiency) values for the 22 technologies rather than absolute values. Absolute values have been calculated using a reference uncontrolled pulverized coal-fired power plant characterized in Table 2-5. The clean coal technologies have been divided into three general classes: repowering technologies, retrofit technologies, and coal upgrading and new fuel form technologies.

2.3.2 Repowering Technologies

Repowering technologies replace a major portion of an existing facility not only to achieve a significant emissions reduction but also to increase facility capacity, extend facility life, improve system efficiency, and/or provide for the use of a new fuel form. This group of clean coal technologies includes concepts such as fluidized-bed combustion and gasification combined cycle, as well as advanced options such as gasification with fuel cells, direct coal-fired turbines and diesels. A repowered coal-fired plant would retain much of its existing solids handling equipment and virtually all of its steam cycle, electrical generating, and power conditioning hardware.

From an environmental standpoint, repowering opens the door to a future of sustained deep reductions in nationwide emissions of SO_2, one of the chief pollutants thought to contribute to acid rain. Repowering concepts are among the cleanest of coal burning options. Fluidized-bed combustors can eliminate 90-95% of the potential sulfur pollutants during the combustion process itself, eliminating the need for post combustion sulfur controls. Combined-cycle coal gasification systems can remove more than 99% of sulfur emissions from coal-derived gases.

Repowering of a generation facility would improve its emissions control capability, boost energy production efficiency, and enhance the cost-effectiveness of operation. Further, these repowering technologies can be used in new plants that will be constructed to satisfy future growth in electric power demand.

Table 2-5. **Summary of environmental characteristics for a baseline, uncontrolled pulverized coal-fired power plant**[a]

Applicable coal sulfur content	High[b]	Medium[b]	Low[b]
SO_2 removal (%)	0	0	0
SO_2 emission rate (lb/10^6 Btu)	7.9	4.7	1.2
NO_x removal (%)	0	0	0
NO_x emission rate (lb/10^6 Btu)	1.0	1.0	1.0
Solid waste—Ash (lb/10^6 Btu)	15.8	28.2	8.0
Total suspended particulates (lb/10^6 Btu)	0.03	0.03	0.03
Heat rate (Btu/kwh)	9400	9400	9400
Capacity factor (%)	65	65	65
Coal specifications:			
Sulfur content (%)	4.0	2.5	0.5
Ash content (%)	16.0	29.8	6.4
Heating value (Btu/lb)	10,000	10,570	8,020

[a] ANL 1977.

[b] See Table 2-3.

2.3.2.1 Atmospheric Fluidized-Bed Combustion

Description. In a fluidized-bed design (Fig. 2-1), coal and limestone are fed into a bed of hot particles (1400-1600°F) fluidized by upflowing air. The SO_2 formed during combustion reacts with the limestone to form calcium sulfate. The relatively low combustion temperature limits NO_x formation, reduces ash fusion problems, and optimizes sulfur capture. There are two major types of atmospheric fluidized-bed technologies: the dense or bubbling bed and the dilute or circulating atmospheric fluidized-bed (CAFB). The fundamental distinguishing feature between the two is the velocity of air through the unit. Bubbling beds have lower fluidization velocities, about 5-12 ft/sec, while CAFBs have velocities as high as 30 ft/sec.

Environmental characteristics. The environmental characteristics of the CAFB were used in the PEIS analysis. However, it is also representative of the atmospheric bubbling fluidized-bed technology. With a calcium-to-sulfur (Ca/S) ratio of 1.5, SO_2 removal efficiency for the CAFB is estimated to be about 90%. Maximum potential SO_2 reduction is 95%. With staged combustion, NO_x emissions are estimated to be reduced by 60%. On the other hand, CAFB technology may produce between 1.5 and 2 times as much solid waste as a conventional, uncontrolled pulverized coal plant. The solid wastes consist of a dry and benign solid sulfate and coal ash that are suitable for disposal in a landfill or possible beneficial use such as construction aggregate and agricultural fertilizer. A summary of typical CAFB environmental characteristics is shown in Table 2-6.

Market Application. CAFBs have good potential for both the industrial and utility sectors in repowering existing coal-fired plants or constructing new facilities. This analysis considered CAFB's use in repowering and new utility plants. In repowering applications, CAFB is assumed to have a capacity increment of approximately 15% (DOE 1987a). Coal of any sulfur content can be used. Since any type or size of boiler can be repowered by CAFB using the existing plant area, coal and waste handling equipment, and steam turbine equipment, the life of the plant can be extended.

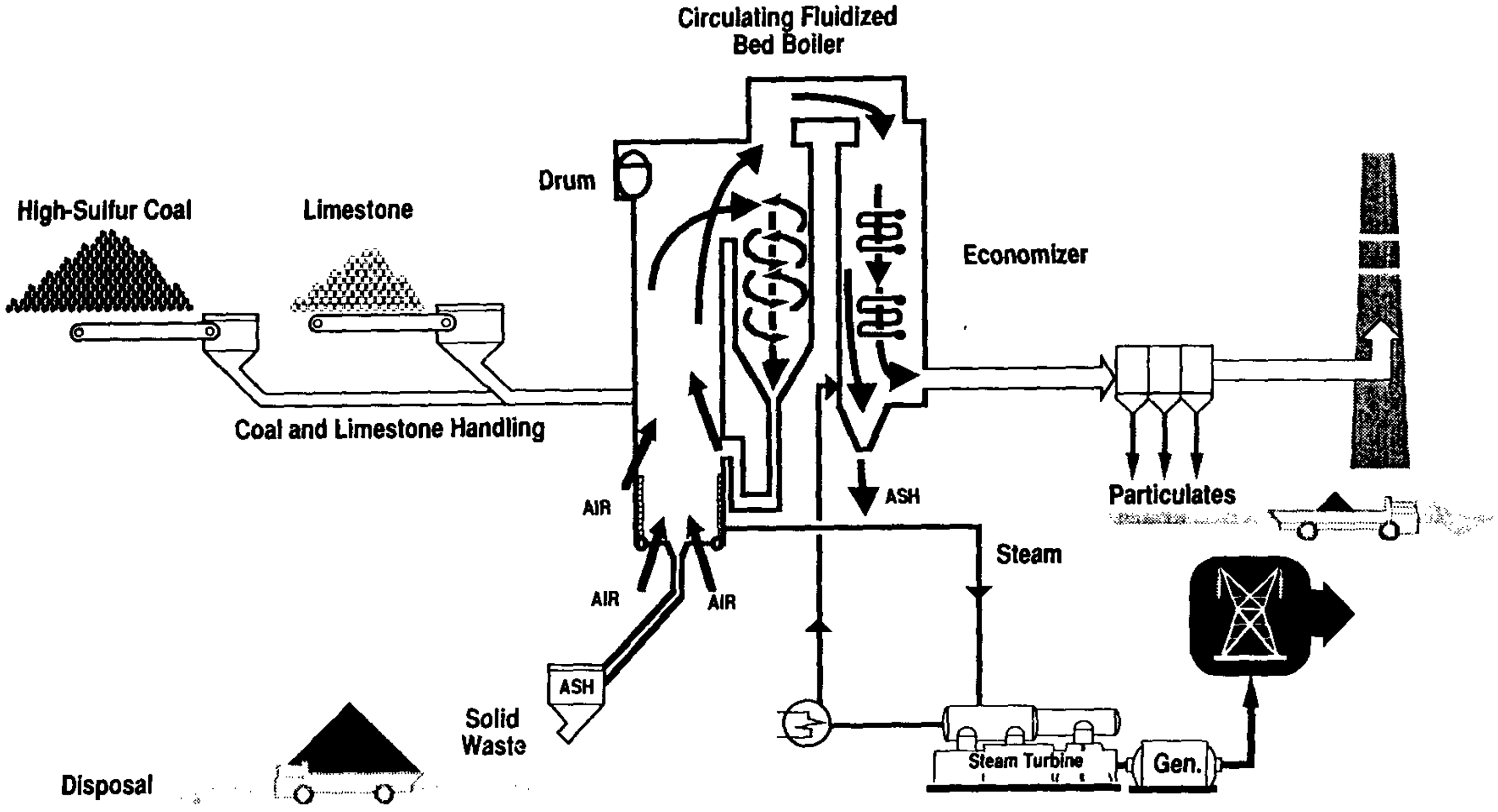

Fig. 2-1. Atmospheric fluidized bed boiler. (Source: DOE 1989)

Table 2-6. Summary of environmental characteristics for atmospheric fluidized-bed combustion[a]

Applicable coal sulfur content	High[c]	Medium[c]	Low[c]
SO_2 removal[a] (%)	90-95	90-95	90-95
NO_x formation reduction[a] (%)	60	60	60
Solid waste:[b]			
Ash (lb/10^6 Btu)	15.8	28.2	8.0
Sorbent (lb/10^6 Btu)	21.3	12.7	3.3
Total suspended particulates (lb/10^6 Btu)	0.03	0.03	0.03
Heat rate (Btu/kWh)	9400	9400	9400
Capacity factor (%)	65	65	65

[a] DOE 1987a.

[b] Based on Ca/S ratio of 1.5; ash and sorbent are removed as a single mixed stream. Higher level of SO_2 removal can be achieved with higher Ca/S ratio.

[c] See Table 2-3.

2.3.2.2 Pressurized Fluidized-Bed Combustion

Description. In pressurized fluidized-bed (PFB) combustion, the combustor operates at considerably higher pressure (6-15 atm) than a combustor used in CAFB (Sect. 2.3.2). Typically, PFB operates in a combined cycle mode. In the combined cycle plant (Fig. 2-2), gases from the boiler drive a gas turbine generator before discharge to the stack. Water-filled coils within the PFB bed generate steam that is utilized in a conventional steam turbine cycle to produce additional power.

Environmental characteristics. The sorbent in the fluidized bed captures most of the sulfur emissions during the combustion process itself, which greatly reduces or completely eliminates the need for expensive downstream sulfur control equipment. The SO_2 is expected to be 90-95% (for a dolomite to sulfur ratio of 1.5), and NO_x removal is expected to be 70%. NO_x reductions result from lower operating temperatures. Combined cycle PFB produces a dry solid waste that is suitable for disposal in a landfill. A summary of typical environmental characteristics is shown in Table 2-7.

Market application. Combined cycle PFB permits the combustion of a wide range of coals, including high-sulfur coals. It can be used to repower oil- and gas-fired boiler units, while switching them to high-sulfur coal, to repower coal-fired power plants, and to build new PFB units. Combined cycle PFB technology appears to be best suited for electric utility applications for medium (100-400 MW) and large (>400 MW) plants. In fact because of modular construction capability, PFB generating plants will permit utilities to economically add increments of capacity to match load growth and to reduce utility financing requirements. Plant life can be extended by repowering with PFB using the existing plant area, coal and waste handling equipment, and steam turbine equipment. PFB is assumed to have a capacity increment of 40% (DOE 1987a).

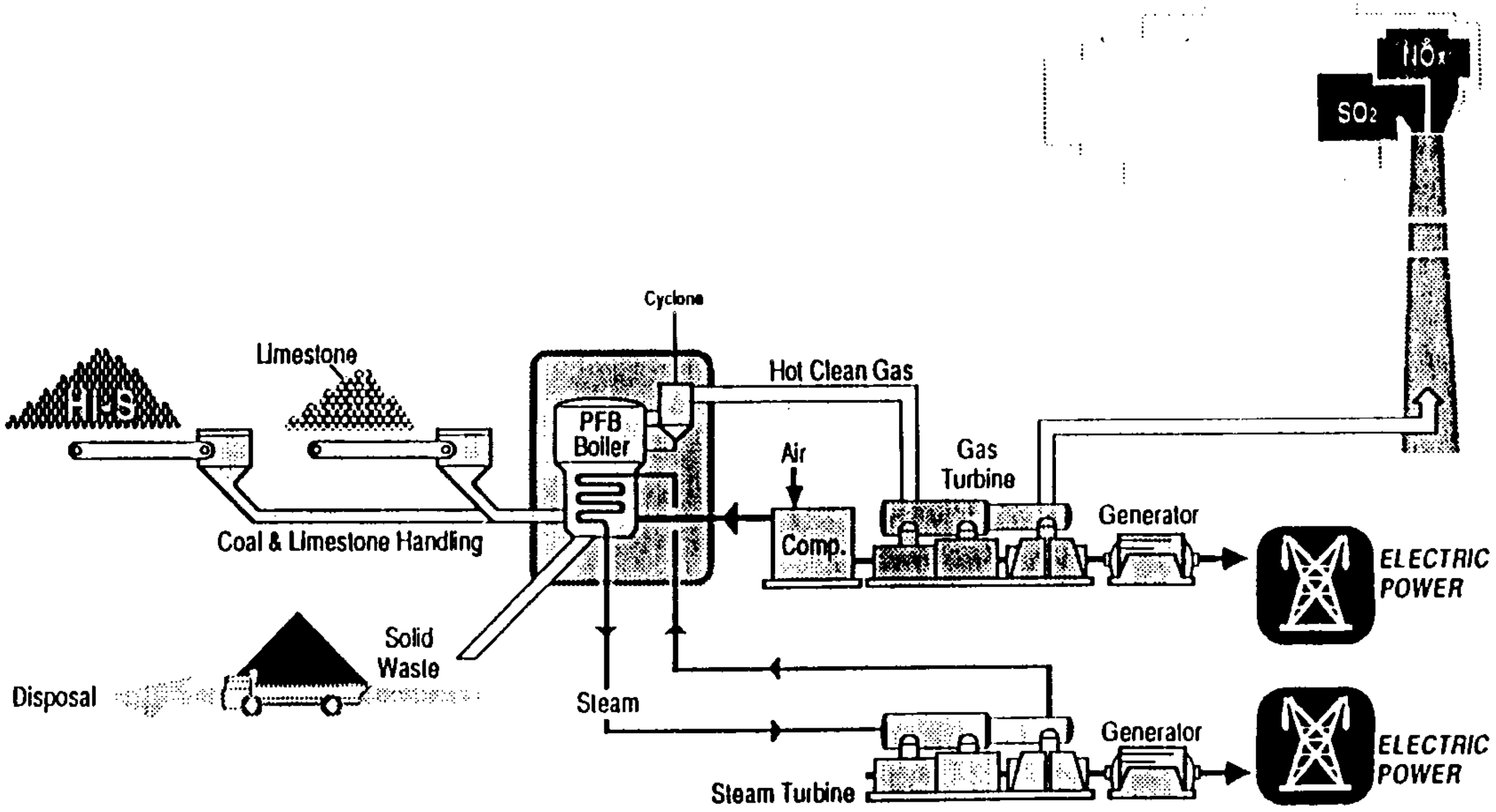

Fig. 2-2. Pressurized fluidized bed boiler. (Source: DOE 1987b)

Table 2-7. Summary of environmental characteristics for pressurized fluidized-bed combustion[a]

Applicable coal sulfur content	High[c]	Medium[c]	Low[c]
SO_2 formation reduction[a] (%)	90-95	90-95	90-95
NO_x formation reduction[a] (%)	70	70	70
Solid waste:[b]			
Ash (lb/10^6 Btu)	15.8	28.2	8.0
Sorbent (lb/10^6 Btu)	21.3	12.7	3.3
Total suspended particulates (lb/10^6 Btu)	0.03	0.03	0.03
Heat rate (Btu/kWh)	8510	8510	8510
Capacity factor (%)	65	65	65
Capacity increment (% increase)	40	40	40

[a] 1987 National Acid Precipitation Assessment Program Estimates: SO_2 = 90-95% removal; NO_x = 80-90% removal (NAPAP 1987a).

[b] Based on dolomite/sulfur ratio of 1.5; ash and sorbent are removed as a single mixed stream. Higher level of SO_2 removal can be achieved with a higher dolomite/sulfur ratio.

[c] See Table 2-3.

2.3.2.3 Integrated gasification combined cycle

Description. Integrated gasification combined cycle (IGCC) is an alternative to conventional coal-fired electric power generation with postcombustion emission controls. Because of its overall design, emissions of sulfur and nitrogen oxides and particulates from IGCC facilities are projected to be significantly lower than from existing technologies. The four major processes of an IGCC facility are (1) converting coal (via partial oxidation and gasification) into a fuel gas, (2) cleaning the fuel gas, (3) using the clean fuel gas to fire a gas turbine generator and using the hot turbine exhaust to make steam which drives a steam turbine generator, and (4) treating waste streams generated. Figure 2-3 shows a typical arrangement.

Environmental characteristics. Emission levels are all well below NSPS limits. An IGCC plant produces only about 40% of the solid waste produced by a comparable pulverized coal plant. Elemental sulfur can be recovered from the process and sold, thus reducing the operating cost. The solidified slag particles, which have the texture of coarse sand, are recognized by the test procedure of the California State Department of Health as nonhazardous and considered environmentally benign for disposal. A summary of typical environmental characteristics are shown in Table 2-8.

Market application. With recent successful demonstrations and continued research/demonstration activities, IGCC has become a rapidly emerging alternative for new electricity generating plants. Such plants require 15% less land area than pulverized coal plants with FGD. Repowering is another viable option, where a gasifier, gas stream cleanup unit, gas turbine, and waste heat recovery boiler are added to replace the existing coal boiler. The remaining equipment is left in place, including the steam turbine and electrical generator. The IGCC is assumed to have a capacity increment of approximately 230% (DOE 1987a).

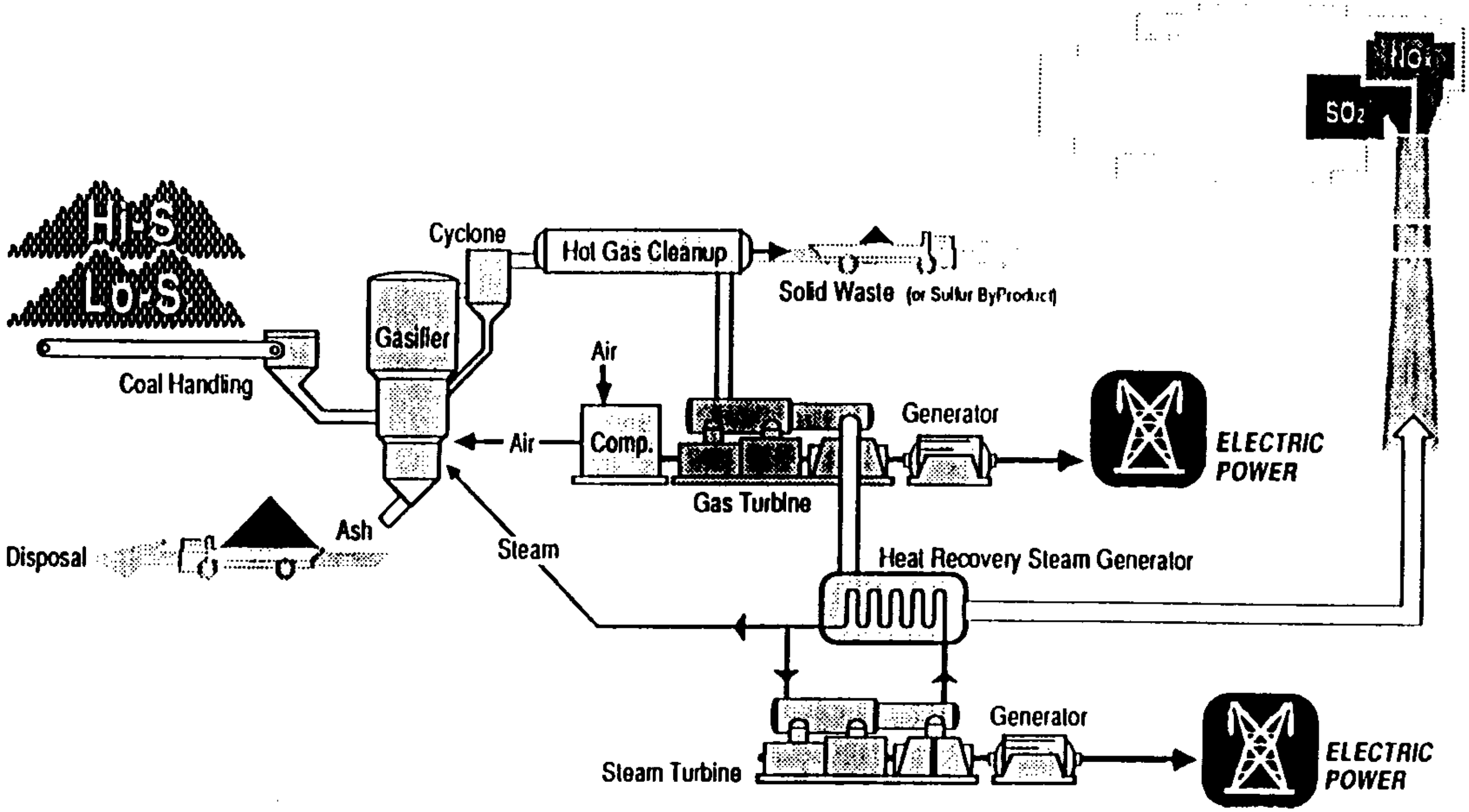

Fig. 2-3. Integrated gasification combined cycle. (Source: DOE 1987b)

Table 2-8. Summary of environmental characteristics for integrated gasification combined cycle[a]

Applicable coal sulfur content	High[b]	Medium[b]	Low[b]
SO_2 removal[a] (%)	92-99	92-99	92-99
NO_x formation reduction[a] (%)	92	92	92
Solid waste—Ash (lb/10^6 Btu)	15.8	28.2	8.0
Total suspended particulates (lb/10^6 Btu)	0.01	0.01	0.01
Sulfur removal by-products (lb/10^6 Btu)	3.8	2.3	0.6
Heat rate (Btu/kWh)	9010	9010	9010
Capacity factor (%)	65	65	65
Capacity increment (% increase)	230	230	230

[a] 1987 National Acid Precipitation Assessment Program estimates for advanced, commercial applications: SO_2 = 97-99% removal; NO_x = 95% removal (NAPAP 1987a).

[b] See Table 2-3.

2.3.2.4 Fuel cells

Description. A fuel cell electrochemically converts the chemical energy of a fuel into electrical energy without the inherent efficiency limits of heat engines. Fuel cells can be used in integrated power production facilities where a coal gasifier supplies the fuel gas for the fuel cell system, as shown in Fig. 2-4.

Environmental characteristics. A very important characteristic of the fuel cell is its capability to use domestic fossil fuels as an energy input with minimal deleterious environmental impact. High electrical conversion efficiencies lead to reduced environmental impact over the entire fuel cycle chain from extraction to point of use, per unit of usable energy generated. Air emissions for key pollutants range from negligible for SO_2 to nonexistent for NO_x and particulates, since there is no combustion. Only the secondary effluents from the gasifier have potential environmental implications, and the high system efficiency of the fuel cell makes this a potentially superior application of gasifier technology. The solid waste primarily consists of dry coal ash that is suitable for disposal in a landfill. A summary of environmental characteristics for an integrated system using a Texaco type gasifier and molten carbonate fuel cells in a repowering application is shown in Table 2-9. Other types of fuel cells which may be integrated with gasifiers include phosphoric acid fuel cells (if CO_2 is removed from the fuel gas) and solid oxide fuel cells. The environmental characteristics would be essentially the same for any of these fuel cell technologies.

Market application. Fuel cell technology is applicable to the industrial and commercial sectors and to the electric power generating industry. Fuel cells are especially suitable for repowering applications because of their significantly higher conversion efficiency of fuel to electricity, modular construction, high efficiency at part load, minimum siting restrictions, potential for cogeneration, and low production of pollutants. Fuel cells are assumed to have a capacity increment of 430% (DOE 1985d).

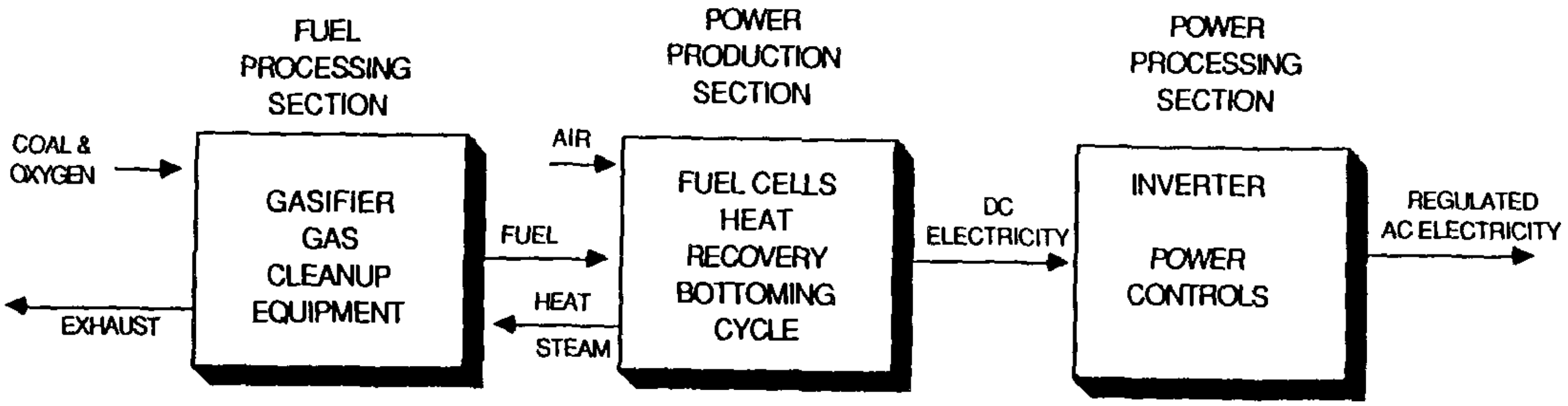

Fig. 2-4. Integrated coal gasifier fuel cell system.

Table 2-9. Summary of environmental characteristics for fuel cells

Applicable coal sulfur content	High[c]	Medium[c]	Low[c]
SO_2 removal[a] (%)	92-99	92-99	92-99
NO_x formation reduction (%)	92	92	92
Solid waste[b]—Ash (lb/10^6 Btu)	15.8	28.2	8.0
Total suspended particulates (lb/10^6 Btu)	0.01	0.01	0.01
Sulfur by products (lb/10^6 Btu)	3.8	2.3	0.6
Heat rate[b] (Btu/kWh)	6825	6825	6825
Capacity factor (%)	65	65	65
Capacity increment (% increase)	430	430	430

[a] DOE 1987a.
[b] Emission rates in lb/10^6 Btu of product gas.
[c] See Table 2-3.

2.3.2.5 Gas Turbine

Description. The gas turbine converts part of the energy of a hot gas stream to a shaft horsepower, which can be used to generate electricity, pump liquids or gases, and drive vehicular or marine propulsion systems. Normally, waste heat released by the gas turbine can produce steam for direct use (cogeneration) or generate additional electricity through a steam cycle (combined cycle). A direct coal-fueled turbine system uses dry pulverized coal or a coal slurry as the fuel. The coal is burned directly in the combustor and the gases are expanded in the turbine. The combustor is external to the turbine and contaminants must be removed from the gases between the combustor and the turbine inlet. Major advantages of a direct coal-fired turbine system are the simplicity of the technology and the potential for using a wide range of fuels.

Environmental characteristics. Presently, it is believed that particles and sulfur compounds are the contaminants that represent the most significant control problem. Slagging combustors and sorbent injection are used to meet or exceed NSPS requirements for particulates, and SO_2 reduction in the range of 85-95% can be achieved. Sulfur removal can be accomplished either at high temperatures (1800°-2250°F) following coal combustion, at intermediate temperatures between the expander and heat recovery steam generator, or at a relatively low temperature after heat is recovered from the products of combustion by the steam cycle. In either case, SO_2 emissions can be reduced by 85 to 95% using the ZnFe sulfur removal system (DOE 1985e, 1987c). The particulate tolerance limits for a gas turbine is 0.01 grains/scf. In general, the gas turbine is extremely sensitive to compounds of sodium, potassium, calcium, sulfur, vanadium, lead, and other elements. Fuel specifications for high-efficiency modern turbines operating at high temperatures (1900-2200°F) restrict these impurities to a few parts per million. The particulate emissions are typically reduced to well below the NSPS limits of 0.03 lb/10^6 Btu by the application of two-stage cyclones and cross-flow filters (DOE 1985e, 1987c). At the present time, there are no standards for NO_x from coal-fueled gas turbines. Current indications are that direct coal-fueled gas turbines with two-stage combustors potentially will meet the required standards for NO_x. A summary of typical environmental characteristics is shown in Table 2-10.

Market Application. Gas turbines have several inherent advantages in efficiency, size, capital cost, procurement time, operational flexibility and system adaptability, thus making them extremely desirable for utilities and industry.

The main application of gas turbines in the energy producing sector is for peak power generation by electric utilities. Coal-fueled turbine power could be competitive in peaking, repowering, or new combined-cycle applications.

Table 2-10. Summary of environmental characteristics for coal-fueled gas turbines

Applicable coal sulfur content	Any
SO_2 removal[a]	85-95%
NO_x[b]	0.2-0.3 lb/10^6 Btu
Total suspended particulates[c]	0.01-0.003 lb/10^6 Btu
Solid waste	11.8 lb/10^6 Btu
Sulfur removal byproducts	Not Applicable
Heat rate	8,460 Btu/kWh

[a] Based on utilization of sorbent injection.

[b] With two-stage combustion, NO_x emission rates would be well below NSPS requirement of 0.6 lb/10^6 Btu.

[c] Based on utilization of Venturi scrubber and ammonia and selexol absorbers for cold gas cleaning system and two-stage cyclones and a ceramic crossflow filter for the hot gas cleaning system.

2.3.2.6 Diesel engine

Description. The diesel engine is a high-compression, sparkless internal combustion engine. Unlike the spark-ignition, gasoline-fired, internal combustion engine, the diesel burns lower cost fuel oils (No. 2 diesel fuel). The diesel also accepts, with suitable engine design modifications, heavier petroleum distillates, natural or medium-Btu gas, or liquid fuels (coal-water slurry) derived from coal provided they are thoroughly de-ashed and free of deleterious impurities. The diesel engine offers major benefits in efficiency, load following capability, durability, compactness, and capital cost. The operation of diesel engines with coal-based fuels offers a potential economic advantage by replacing conventional diesel fuel with a relatively low cost fuel derived from coal. The coal-based fuels being considered for use in diesel engines include coal slurries, micronized coal, coal-derived liquids, and gaseous fuels.

Environmental characteristics. The diesel engine requires extremely clean coal for proper operation; therefore, effective coal cleaning technologies are critical to their development. The ash content of feed coal must be reduced to 1% or less by advanced coal cleaning processes such as the ultrafine process. Diesel engines in general generate relatively higher levels of NO_x, SO_2, hydrocarbons, soot, and particulate emissions as compared to alternative combustion technologies such as boilers (DOE 1985e, undated). The diesel's tolerance for ash concentration, ash size, and alkalis has yet to be determined. Presently, there are no emission regulations pertaining to diesel engines. Since there is no opportunity to clean the working fluid within the engine, final cleanup must be accomplished by use of exhaust cleanup devices. A summary of typical environmental characteristics is shown in Table 2-11.

Market application. The coal-fueled diesel engine is targeted for the railroad locomotive and stationary power plants. The locomotive market would utilize a medium speed engine operating at approximately 1000 rpm. The stationary plant market can utilize the same engine as the locomotive, but slower speed engines under 500 rpm must also be applied. The slower speed engine is generally larger in physical size and can be more expensive, however; it has advantages of slightly higher efficiency and lower maintenance costs. Under the stationary power plants, two major market applications are identified: (1) industrial cogeneration installations (400-1000 MW/yr) and (2) modular electric power plants up to 50 MW size (500-2000 MW/yr).

Table 2-11. Summary of environmental characteristics for coal-fueled diesel engines

Applicable coal sulfur content	Low, medium
SO_2 removal[a] (%)	80
NO_x reducton[b] (%)	50
Total suspended particulates[c] (lb/10^6 Btu)	0.03
Solid waste	Not applicable
Sulfur removal byproducts	Not applicable
Heat rate (Btu/kWh)	7520
Capacity factor (%)	65

[a] Sulfur removal to 0.5% in the coal water mixture is accomplished by advanced physical coal cleaning methods (ultrafine). Reduction of SO_2 level in the engine exhaust stream to the NSPS is accomplished using available commercial technology.

[b] Test results show that the NO_x emission level in the exhaust of a diesel engine burning coal-water mixture is about half of that of a similar engine burning No. 2 diesel fuel.

[c] With 1% ash content in the coal-water mixture, particulate emissions are reduced by 96% in the exhaust system by utilizing a combination of high efficiency cyclone, ceramic bag, and crossflow filter.

2.3.3 Retrofit Technologies

Retrofitting is the process of adding environmental control equipment to a coal-using facility originally designed to perform without such equipment. Retrofit technologies reduce SO_2 and/or NO_x emissions by modifying existing facilities or their present feedstocks or by utilizing new fuel forms. Although some may be less able to reduce sulfur emissions than conventional flue gas scrubbing, these retrofit technologies can reduce levels sufficiently to meet possible future environmental requirements for existing plants. Retrofit technologies include advanced combustors, advanced FGD, combined SO_2 and NO_x control, and advanced NO_x control. These technologies used separately or in combinations can control both SO_2 and NO_x.

Of increasing interest is the ability of many retrofit technologies to be operated as combined systems. Benefits of such operation can include greater reductions in SO_2 and NO_x emissions as well as costs. The relative benefits of combined systems depend mainly on the sulfur content of the coal and the efficiency of sorbent utilization in the control system. For example, furnace sorbent injection has a comparatively low sorbent utilization rate; the economics of pollutant reduction are significantly improved when the coal is cleaned first to reduce its sulfur content. In another case, advanced FGD technology, which is being developed to address reliability, operability, and waste disposal issues, can be used in combination with NO_x reduction technologies.

Either by themselves or in combination, the advanced technologies have the potential to meet the wide variety of site-specific needs of individual utilities. This includes meeting NSPS and other regulatory requirements such as State Implementation Plans.

The retrofit technologies are divided into the following three classes for purposes of the PEIS: (1) Retrofit–NSPS capable – those technologies that, when applied singly, will control emissions of SO_2 and NO_x to NSPS levels and thus can be retrofitted on existing plants and used on new plants; (2) Retrofit–partial NSPS capable – those technologies that, when applied singly, will control emissions of either SO_2 or NO_x to NSPS levels and thus could be retrofitted on existing plants where SO_2 or NO_x controls are required, but could not be applied singly to new plants to meet full NSPS requirements; and (3) those technologies that chemically or physically alter the state of coal to produce a new fuel form that would meet the objective of mitigating emissions of SO_2 and/or NO_x. A more detailed discussion of these classes of technologies is presented in Sect. 4.1.5.

2.3.3.1 Retrofit–NSPS capable

2.3.3.1.1 Advanced slagging combustor

Description. The advanced slagging combustor (ASC) can replace the standard burner or combustor that is attached to the outside wall of the boiler. As shown in Fig. 2-5, the ASC mixes coal, sorbent (limestone), and air; provides ignition; and removes ash before discharging the hot combustion products to the boiler. Sulfur oxides are controlled by limestone injection into the combustor, and NO_x is controlled by staged combustion.

Environmental characteristics. Ash removal efficiencies in the combustor range from 90-95%. Because of this, flue gas cleanup should not be required. The ASC results in no derating of the boiler, no added fly ash handling capability, and no degradation of boiler tube surfaces. Much of the coal's ash content is removed as a molten slag by cyclonic action in the combustor and, when cool, is a dry, coarse solid suitable for landfill disposal. A summary of typical environmental characteristics is shown in Table 2-12.

Market application. This technology has a wide range of applications. It is appropriate for any size utility or industrial boiler in new and retrofit uses. It can be used not only in coal-fired boilers but also in oil-and gas-fired boilers because of its high ash removal capability. Cyclone boilers may be the most amenable to retrofit with an ASC because of the limited supply of high-Btu, low sulfur, low-ash-fusion-temperature coal that cyclone boilers require. Furthermore, coal of any sulfur content can be used as long as the minimum ash content is 5%. Pulverized coal is also required.

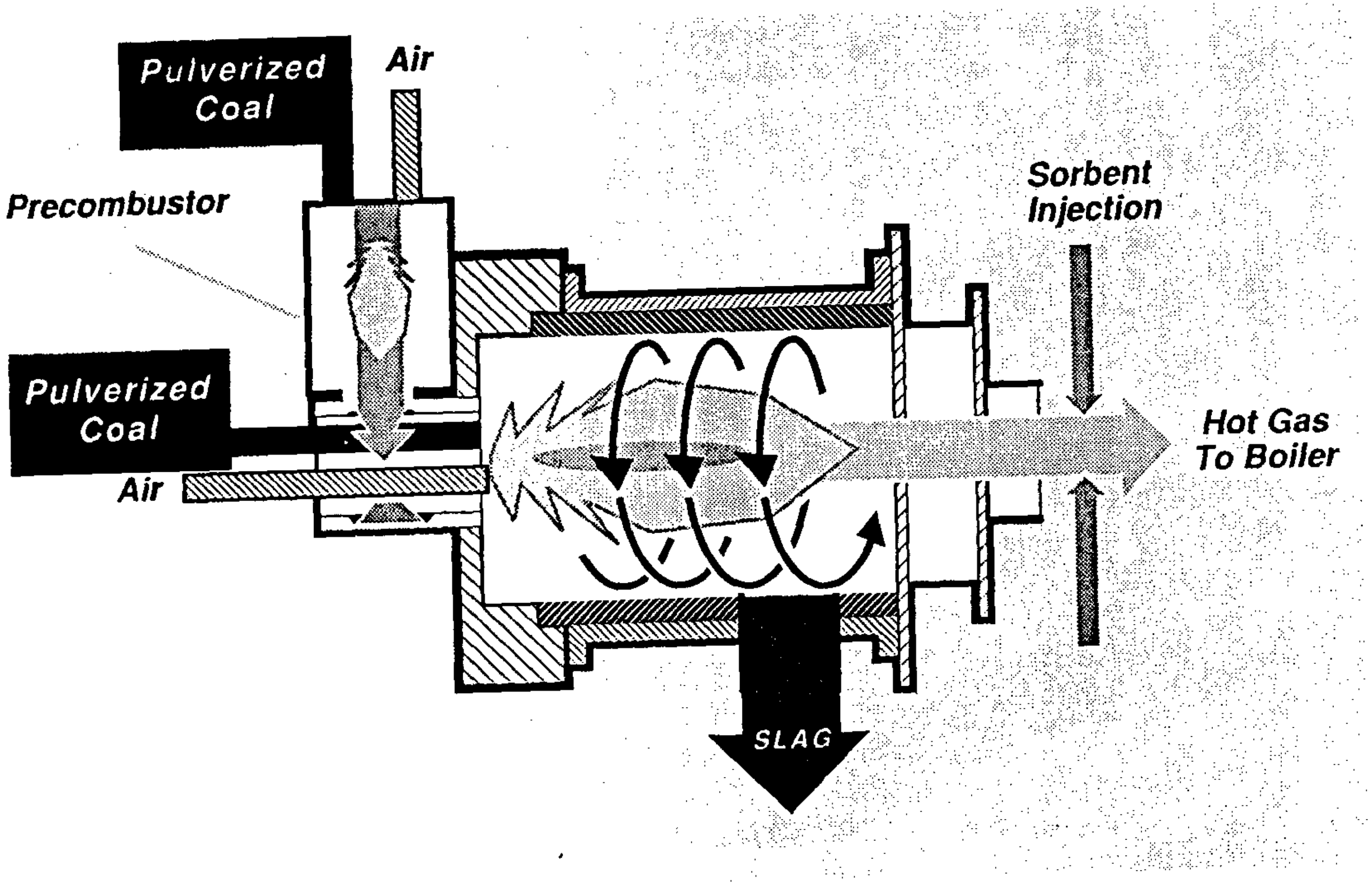

Fig. 2-5. Advanced slagging combustor. (Source: DOE 1989)

Table 2-12. Summary of environmental characteristics for advanced slagging combustor[a]

Applicable coal sulfur content	High[d]	Medium[d]	Low[d]
SO_2 removal[a] (%)	60-90	60-90	60-90
NO_x formation reduction[a] (%)	50 (max.)	50 (max.)	50 (max.)
Solid waste:[b]			
Ash (lb/10^6 Btu)	15.8	28.2	8.0
Sorbent (lb/10^6 Btu)	29.7	17.7	4.7
Total suspended particulates[a,c] (lb/10^6 Btu)	0.06	0.06	0.06
Heat rate[a] (Btu/kWh)	9440	9440	9440
Capacity factor (%)	65	65	65

[a] Information provided by staff at the Pittsburgh Energy Technology Center.
[b] Ash and sorbent are removed as a single mixed stream.
[c] Assumes electrostatic precipitators for additional particulate control.
[d] See Table 2-3.

2.3.3.1.2 Copper oxide process

Description. The copper oxide (CuO) process is representative of an advanced, combined SO_2 and NO_x removal technology. It is based on the absorption reaction of CuO and SO_2 to form copper sulfate ($CuSO_4$). The $CuSO_4$ (and to a lesser extent, the CuO) catalyzes the selective reduction of NO_x to N_2 in the presence of ammonia. Spent $CuSO_4$ is sent to a second vessel for regeneration by a reducing gas. Sulfur in the resulting concentrated SO_2 steam can then be economically recovered as a salable byproduct. Two CuO processes have been developed. Shell Oil's version (Fig. 2-6) uses a set of specially designed, parallel-passage, fixed-bed reactors containing CuO bonded to an alumina substrate. The other version uses a fluidized bed of CuO-impregnated alumina pellets. Improved performance over the fixed-bed design occurs as a result of more intimate gas-solids contact.

Environmental characteristics. Initial tests by DOE's Pittsburgh Energy Technology Center (PETC) indicate that 90% of the SO_2 and NO_x in coal-generated flue gas can be removed (Poch et al. 1988). The SO_2 removed can be converted to either elemental sulfur or concentrated sulfuric acid and sold as a byproduct to offset operating costs.

The CuO in the absorber can also be regenerated, lowering the project's overall costs even further. During the six months of testing at PETC, the sorbent lost just 0.05% of its absorptive ability each cycle. Additionally, the process does not produce any significant or environmentally deleterious byproducts. A summary of typical environmental characteristics is shown in Table 2-13.

Market application. The CuO process is applicable to any size utility or industrial coal-fired boiler. It is also applicable to coal of any sulfur content. New boilers using this technology can be designed; however, like other retrofit FGD applications, the CuO process is limited to retrofitting installations in which suitable duct geometries and space are available. Furthermore, the process is rather complex and requires a high absorber temperature.

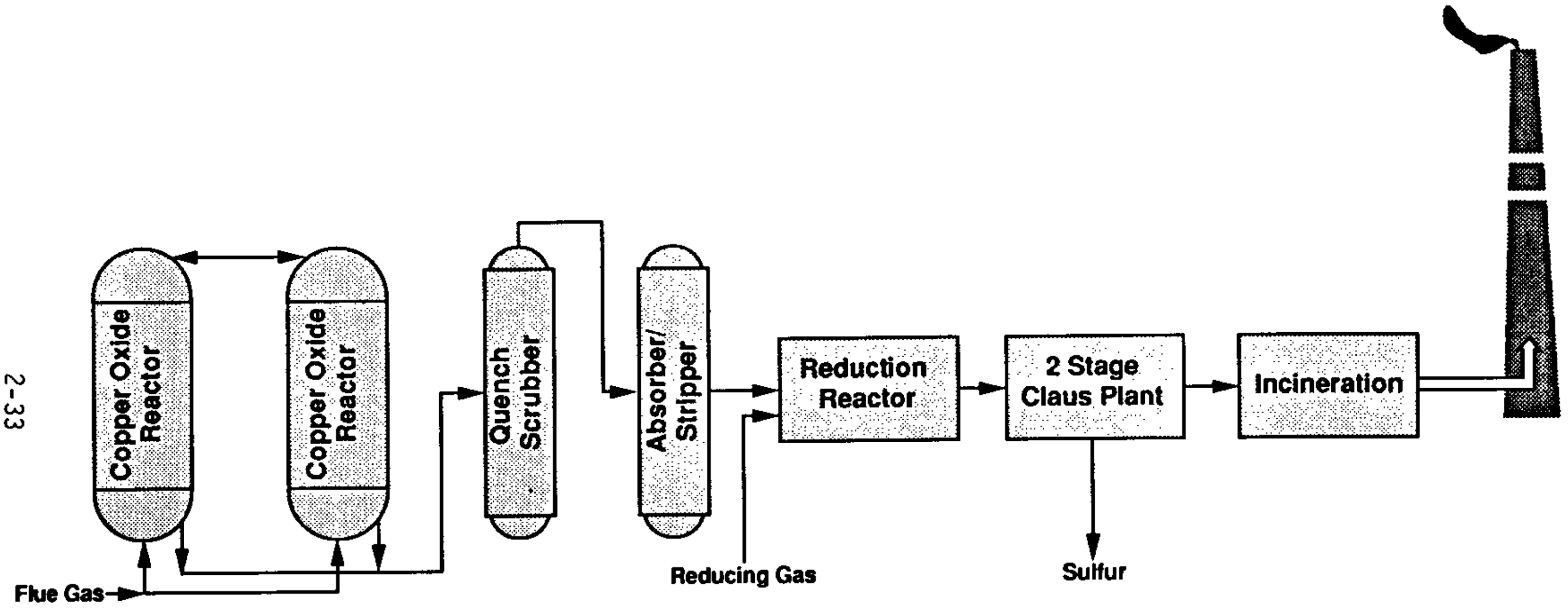

Fig. 2-6. Copper oxide process. (Source: EPRI 1984a)

Table 2-13. Summary of environmental characteristics for copper oxide process[a]

Applicable coal sulfur content	High[b]	Medium[b]	Low[b]
SO_2 removal[c] (%)	90	90	90
NO_x removal[c] (%)	90	90	90
Solid waste:			
Ash (lb/10^6 Btu)	15.8	28.2	8.0
Sulfur removal byproducts (lb/10^6 Btu)	3.6	2.1	0.6
Total suspended particulates (lb/10^6 Btu)	0.03	0.03	0.03
Heat rate (Btu/kWh)	9400	9400	9400
Capacity factor (%)	65	65	65

[a] ANL 1977.
[b] See Table 2-3.
[c] Information provided by staff at the Pittsburgh Energy Technology Center.

2.3.3.1.3 Dual-alkali process

Description. Dual-alkali scrubbing (Fig. 2-7) was developed to avoid the problems of erosion, scaling, and solids deposition found with wet-limestone FGD. As the name implies, two alkalis are used: a solution (generally sodium sulfite) in the absorber followed by the addition of lime in the reaction tank to regenerate the spent solution for recycle to the absorber. The resulting calcium sulfite/sulfate sludge is then dewatered and landfilled. Makeup sodium (typically soda ash) is added to the regenerated solution to replace residual sodium lost in the filter cake.

Environmental characteristics. Removal of 90% of the SO_2 is common using dual-alkali scrubbing. This process generally has no NO_x removal capability, but a system with this capability has been developed and tested on a laboratory scale by researchers at Argonne National Laboratory. The system involves retrofitting a metal-chelate, NO_x-control technique into a dual-alkali scrubbing process. Levels of NO_x removal ranging from 50% to more than 90% have been observed for extended periods in the laboratory, while SO_2 removal has been simultaneously maintained or enhanced (Poch et al. 1988). The dual-alkali process produces waste sludges primarily consisting of calcium sulfate that are suitable for landfill disposable. A summary of typical environmental characteristics is shown in Table 2-14.

Market application. The process is applicable to any size utility or industrial coal-fired boiler. Because of technical considerations, the process is most applicable to medium- and high-sulfur coals. With low-sulfur coals, the need to increase lime utilization makes this process more expensive than wet-limestone scrubbing. The process can be used for new boilers and for retrofit onto old boilers. The complexity and cost of the retrofit naturally depend on the ductwork geometry of the boiler to be retrofitted. Dual-alkali scrubber outages affect system reliability by about 1-5%.

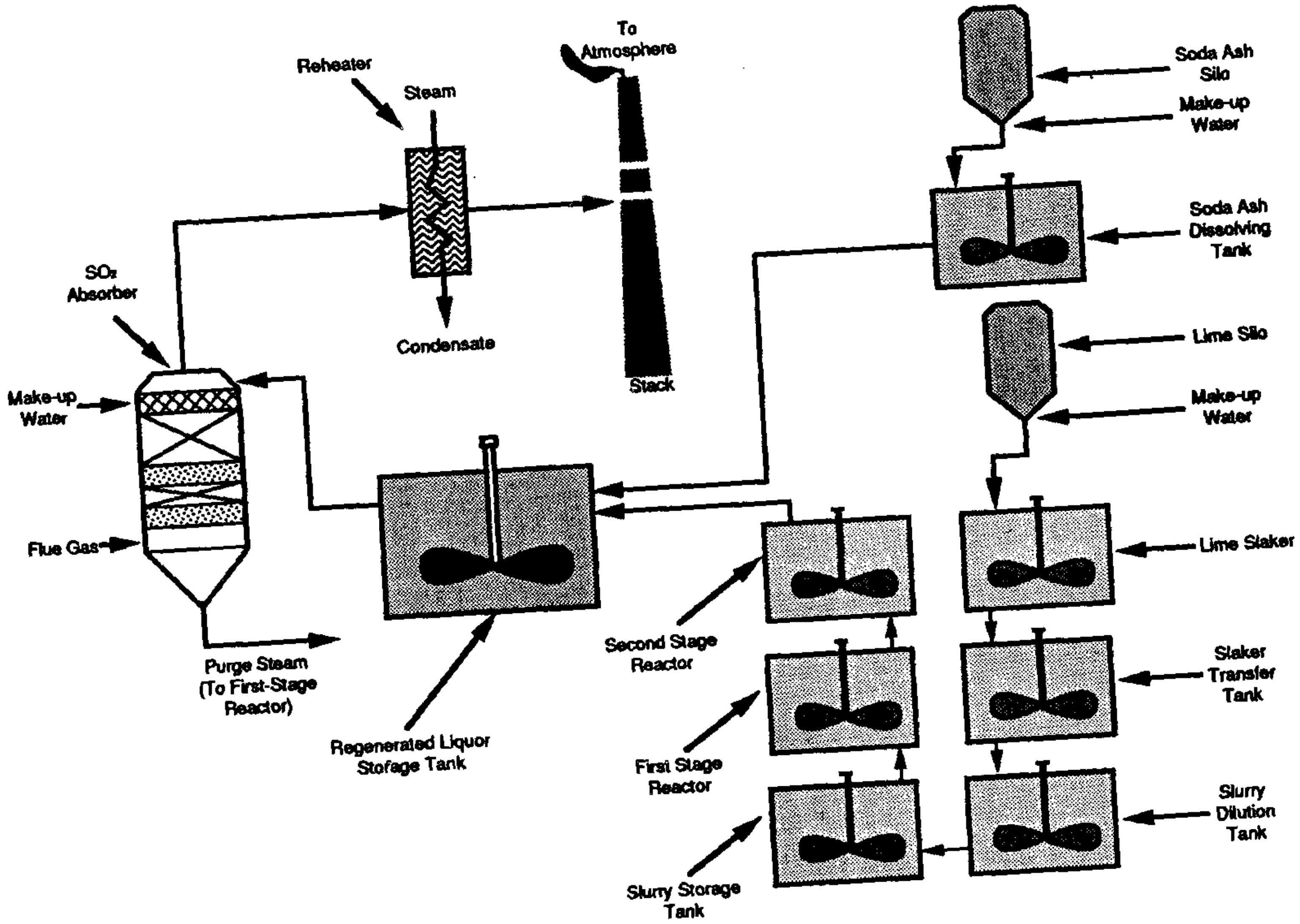

Fig. 2-7. Dual-alkali process. (Source: EPRI 1984a)

Table 2-14. Summary of environmental characteristics for dual-alkali scrubbing[a]

Applicable coal sulfur content	High[b]	Medium[b]
SO_2 removal (%)	90	90
NO_x removal (%)	50-90	50-90
Solid waste:		
Ash (lb/10^6 Btu)	15.8	28.2
Sorbent (lb/10^6 Btu)	16.7	10.0
Total suspended particulates (lb/10^6 Btu)	0.03	0.03
Heat rate (Btu/kWh)	9580	9580
Capacity factor (%)	65	65

[a] Poch et al. 1988.
[b] See Table 2-3.

2.3.3.2 Retrofit—partial NSPS capable

2.3.3.2.1 Advanced flue gas cleanup with salable byproduct

Description. The Chiyoda Thoroughbred-121 (CT-121) process is an example of the advanced FGD with salable byproduct technology. The CT-121 process is unique in that it integrates the absorption, oxidation, and gypsum crystallization processes in one vessel called a jet bubbling reactor (JBR) (Fig. 2-8). The vessel operates under weak acid conditions to minimize gypsum scaling and to maximize sorbent utilization. Oxidation air is injected at the bottom of the JBR (EPRI 1984a). Quick and complete oxidation is required for efficient SO_2 removal. Because the system operates at a relatively low pH, any sulfite not oxidized quickly raises the SO_2 back pressure and limits the removal. With sufficient air and adequate mixing, the sulfite concentration remains very low. Consequently, the gypsum produced is very pure and suitable for byproduct utilization.

Environmental characteristics. The CT-121 process does not remove NO_x from the flue gas. Tests for the 23 MW prototype evaluation program conducted by the Electric Power Research Institute (EPRI), which included a fixed throat Venturi, showed particulate removal efficiencies of 99.7% (EPRI 1984a, Bechtel 1981). The Venturi is not normally specified in Chiyoda's commercial designs.

The CT-121 process utilizes limestone very efficiently, resulting in minimum solid waste production. The gypsum produced was successfully tested for byproduct utilization, specifically, for wallboard manufacturing, as a cement additive, and as a soil conditioner. However, if the gypsum is not sold, it will require a disposal site. A summary of typical environmental characteristics is shown in Table 2-15.

Market application. The CT-121 process is mechanically and chemically simpler than conventional FGD processes and can be expected to exhibit lower cost characteristics. In addition, due to the compact design feature of the jet bubbling reactor (which combines limestone FGD reactions, forced oxidation, and gypsum crystallization in one vessel), a favorable utility application is foreseen.

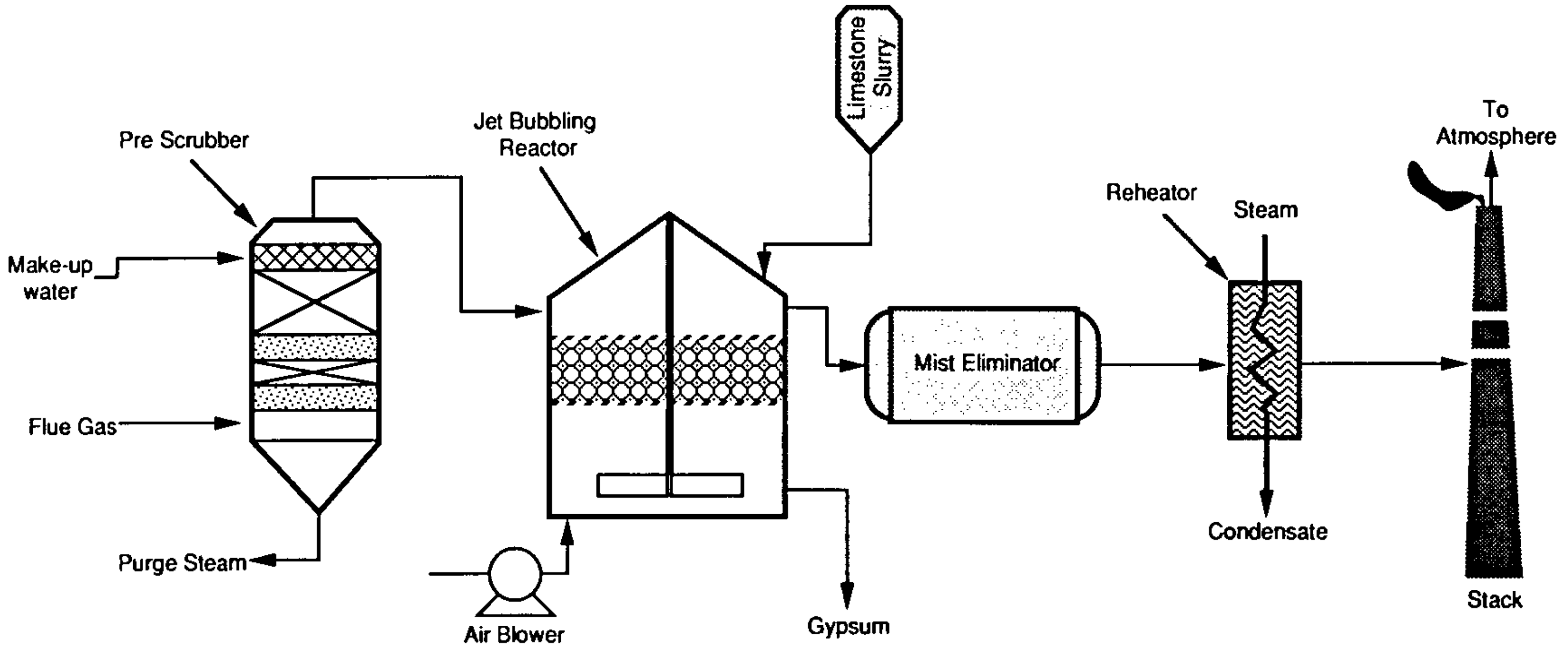

Fig. 2-8. Advanced flue gas desulfurization with salable byproduct. (Source: Klingspone and Cope 1985)

Table 2-15. Summary of environmental characteristics for advanced flue gas cleanup with salable byproduct[a]

Applicable coal sulfur content	High[b]	Medium[b]	Low[b]
SO_2 removal (%)	90-99	90-99	90-99
NO_x removal (%)	0	0	0
Solid waste:			
Ash (lb/10^6 Btu)	15.8	28.2	8.0
Sulfur removal byproducts (lb/10^6 Btu)	24.4	14.5	2.9
Total suspended particulates (lb/10^6 Btu)	0.01	0.01	0.01
Heat rate (Btu/kWh)	9708	9708	9708
Capacity factor (%)	65	65	65

[a] Bechtel 1981.
[b] See Table 2-3.

2.3.3.2.2 Spray dryer with lime

Description. A mixture of lime and recycled solids is slaked and the resulting slurry is injected into the spray dryer. Slurry atomization is accomplished either by a rotary device or by nozzles; the degree of atomization and the vessel dimensions are such that the water in the slurry evaporates before it strikes the wall. The flue gas passes through the spray dryer, a fabric filter, and then the stack. Part of the dried solids (ash plus reaction product, collected both in the fabric filter and the spray dryer) is recycled to increase lime utilization, while the remainder becomes byproduct for reuse or disposal.

It is also possible and feasible to remove NO_x using this system. This is accomplished by raising the spray dryer outlet temperature to 80-90°C (normal temperature is 65-75°C) and adding caustic soda (NaOH) to the primary lime sorbent.

Environmental characteristics. Sulfur dioxide removal efficiencies as high as 95% have been achieved and NO_x removal efficiencies have reached 55%. Fabric filters contribute 20-30% to the overall SO_2 removal. Because of this SO_2 removal in the fabric filter, systems designed with electrostatic precipitators do not have as great SO_2 removal capability. The solid waste consists of dry solids (ash and sorbent) that are suitable for landfill disposal. A summary of typical environmental characteristics is shown in Table 2-16.

Market application. The process is applicable to any size utility or industrial coal-fired boiler. Spray drying is generally considered to be an established technology in low sulfur applications; however, successful tests have been run with high sulfur coals also. The process can be used for new boilers and for retrofit onto old boilers if there is sufficient land near the boiler and if ductwork geometry is suitable. A dry, rather than a wet, scrubbing system should be easier to retrofit onto an existing power plant, because of smaller equipment and a less complex process. The spray dryer process also uses about 1-2% of the electrical output of the generating plant to power the equipment.

Table 2-16. Summary of environmental characteristics for spray dryer with lime[a]

Applicable coal sulfur content	High[d]	Medium[d]	Low[d]
SO_2 removal[a,c] (%)	70-90	70-90	70-90
NO_x reduction[b,c] (%)	20-30	20-30	20-30
Solid waste:			
Ash (lb/10^6 Btu)	15.8	28.2	8.0
Sorbent (lb/10^6 Btu)	20.7	12.3	3.3
Total suspended particulates (lb/10^6 Btu)	0.01	0.01	0.01
Heat rate[c] (Btu/kWh)	9550	9550	9550
Capacity factor[c] (%)	65	65	65

[a] Removal is 20-30% lower if an electrostatic precipitator is employed instead of a bag house.

[b] NO_x reduction is possible if NaOH is added to the lime solution and the temperature is increased.

[c] Information provided by staff at the Pittsburgh Energy Technology Center.

[d] See Table 2-3.

2.3.3.2.3 Limestone injection multistage burner

Description. The limestone injection multistage burner (LIMB) process produces SO_2 by injecting dry sorbent into the boiler at points above the burners (Fig. 2-9). The sorbent then travels through the boiler and is removed along with the fly ash in either an electrostatic precipitator (ESP) or a baghouse. Additional dry sorbent and gas humidification are also included to enhance SO_2 removal and ESP performance.

Environmental characteristics. LIMB technology reduces SO_2 and NO_x but makes particulate control more difficult because the ash load may increase by a factor of 2 to 3, the ash resistivity may increase by 100-fold, and the mean particle size will be lowered. Dust collection equipment may also account for 50% of the capital cost of a LIMB retrofit. The solid waste streams consist of sorbent and fly ash materials, both of which are dry and readily disposable.

EPA and others are trying to produce a salable product from the LIMB waste, with the aim of reducing process costs. A summary of typical environmental characteristics is shown in Table 2-17.

Market application. The LIMB process is applicable to any size utility or industrial coal-fired boiler. It is also applicable to coal of any sulfur content. New boilers can be designed utilizing this technology; however, the SO_2 emissions will not meet NSPS. The practicality of LIMB as a retrofit technology depends on its compatibility with existing boiler systems. Major factors influencing compatibility of LIMB appear to be coal properties and designs of the boiler furnace, convection system, and ash removal systems.

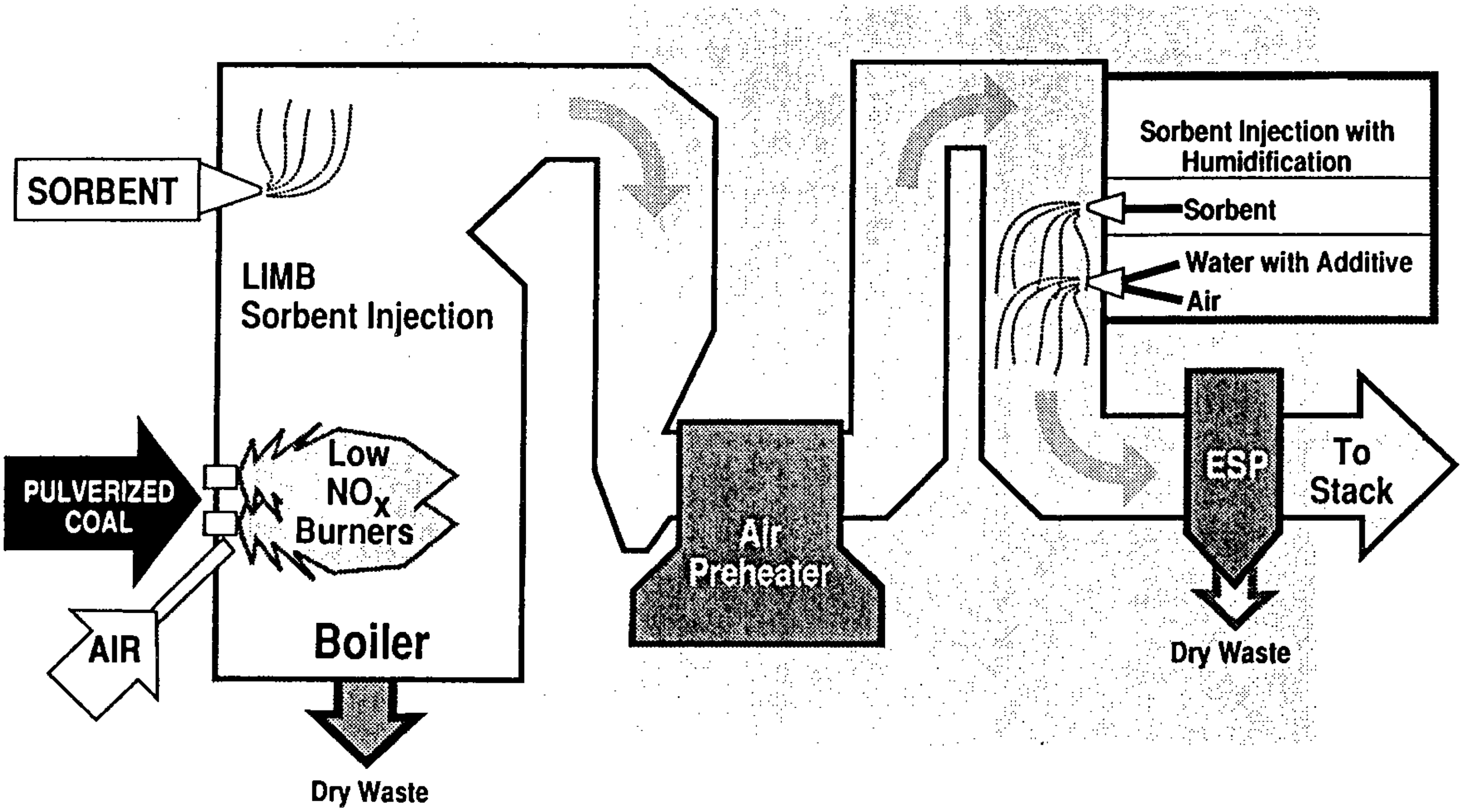

Fig. 2-9. Limestone injection multistage burner (LIMB). (Source: DOE 1989)

Table 2-17. Summary of environmental characteristics for limestone injection multistage burner[a]

Applicable coal sulfur content	High[c]	Medium[c]	Low[c]
SO_2 removal[a] (%)	50-60	50-60	50-60
NO_x formation reduction[a] (%)	45-60	50-60	50-60
Solid waste:[b]			
Ash (lb/10^6 Btu)	15.8	28.2	8.0
Sorbent (lb/10^6 Btu)	19.8	10.7	3.1
Total suspended particulates (lb/10^6 Btu)	0.03	0.03	0.03
Heat rate[a]	9430	9430	9430
Capacity factor (%)	65	65	65

[a] Information provided by staff at the Pittsburgh Energy Technology Center.
[b] Ash and sorbent are removed as a single mixed stream.
[c] See Table 2-3.

2.3.3.2.4 Sorbent injection

Description. In-duct sorbent injection (Fig. 2-10) involves the spray injection of calcium-based sorbents close to the center of the duct and downstream from the combustion zone. The direction of the injection is concurrent with the gas flow; as the cone of spray expands, the gas within the cone cools and the SO_2 is rapidly absorbed by the spray droplets. The finer the sorbent droplets, the more reactive they are. Several in-duct sorbent injection processes are under development. The mode of spraying, the position of the spray mechanism in the duct, and the nature of the sorbent may vary depending on the process. However, the basic principles of all processes are similar. Captured as dry calcium sulfate particles, SO_2 is removed in the downstream particulate collection equipment along with the fly ash and the unreacted sorbent.

Environmental characteristics. SO_2 reduction is in the range of 55 to 75% and thus can satisfy the NSPS level of SO_2 reduction for low sulfur coals. The volume of solid waste is considerably increased but the waste is dry, nontoxic, and easily disposed of. A summary of environmental characteristics is shown in Table 2-18.

Market application. Sorbent injection is applicable to most utility and industrial coal-fired units and can be retrofitted with modest capital investment and down time.

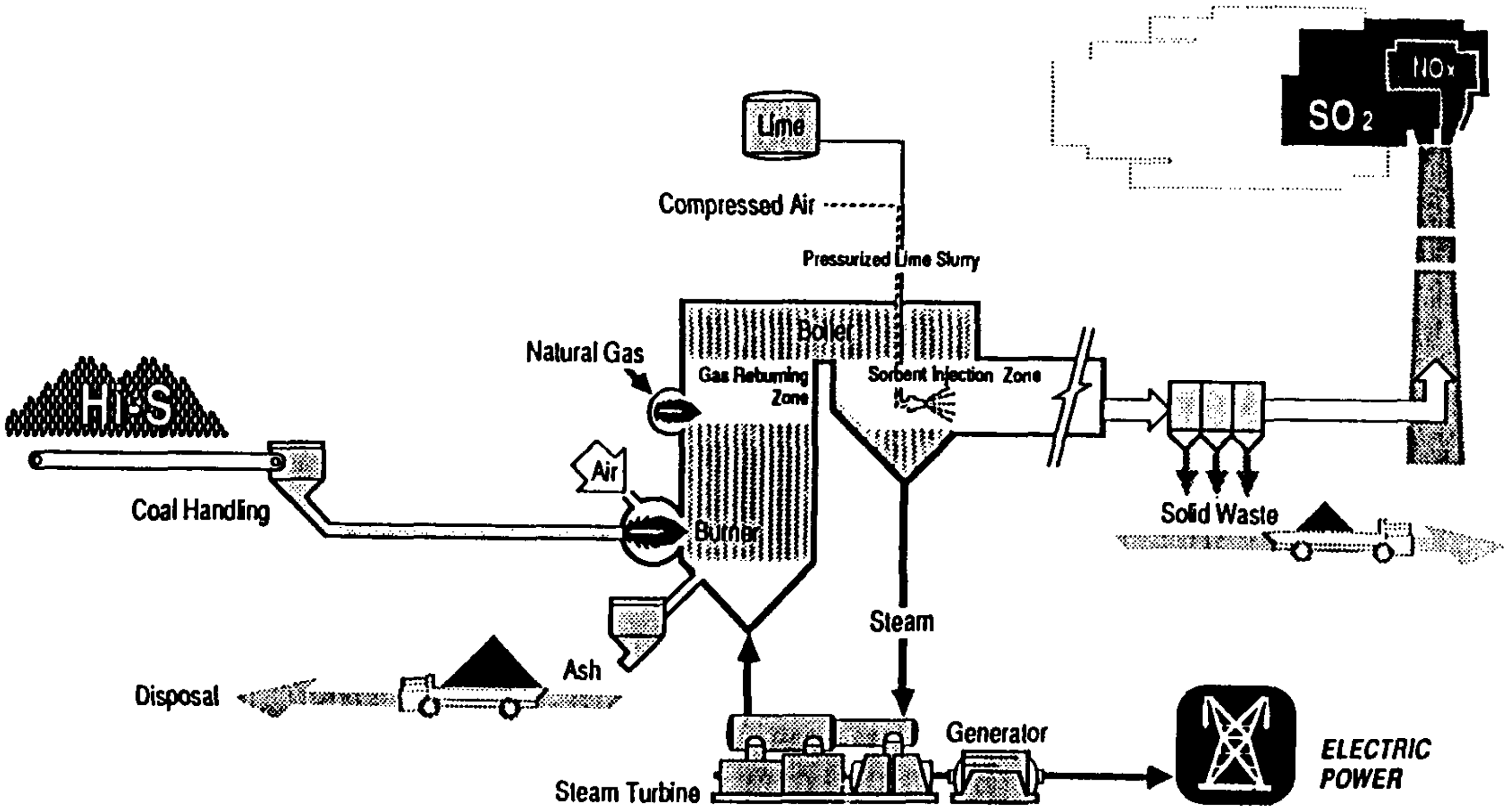

Fig. 2-10. Gas reburning and in-duct sorbent injection. (Source: DOE 1987b)

Table 2-18. Summary of environmental characteristics for sorbent injection[a]

Applicable coal sulfur content	High[b]	Medium[b]	Low[b]
SO_2 removal[c] (%)	55-75	55-75	55-75
NO_x reduction[c] (%)	0	0	0
Solid waste:			
Ash (lb/10^6 Btu)	15.8	28.2	8.0
Sorbent (lb/10^6 Btu)	19.8	10.7	3.1
Total suspended particulates (lb/10^6 Btu)	0.01	0.01	0.01
Heat rate[d] (Btu/kWh)	9550	9550	9550
Capacity factor (%)	65	65	65

[a] ANL. 1981. p. 2-4. (Coal adjusted to base case ash and sulfur content.)
[b] See Table 2-3.
[c] 1987 National Acid Precipitation Assessment Program Estimates: SO_2 = approximately 70% removal; NO_x = about 60% if sorbent injection is used in conjunction with reburning (NAPAP 1987a).
[d] Information provided by staff at the Pittsburgh Energy Technology Center.

2.3.3.2.5 Gas reburning

Description. Gas reburning is another postcombustion technology and was developed primarily for the removal of NO_x (Fig. 2-10). Fuel is bypassed around the main combustion zone and injected above the main burners to form a reducing zone in which NO_x is converted to reduced nitrogen compounds. About 15-20% of the fuel is injected into this reburning zone. Any fuel can be used for reburning. However, pilot studies in the United States indicate that fuels with little or no fuel-bound nitrogen can achieve greater NO_x reductions. In this way, natural gas is probably the best reburning fuel because of its low fuel-bound nitrogen.

Environmental characteristics. NO_x reduction capability is 60% when using 15-20% natural gas as a reburning fuel. An additional benefit of using natural gas as a reburning fuel is the reduction of SO_2 emissions and ash by 20%. The use of oil and coal as reburning fuels results in less NO_x reduction and increased carbon content in fly ash. Tests using low-nitrogen oil as a reburning fuel achieved 50% NO_x reduction. Reburning produces no waste products nor does it seem to affect the heat rate or capacity factor of the unit. A summary of typical environmental characteristics is shown in Table 2-19.

Market application. Reburning technology is applicable to any size utility or industrial coal-fired boiler. This process can be used in new boilers as well as in retrofit applications. Natural gas reburning is applicable to a wide range of wall-, tangential-, and cyclone-fired boilers. For retrofit applications, adequate space (and residence time) between the top burner row and the furnace exit must be available for the additional levels of fuel and air injection. If adequate space is not available, a loss of NO_x reduction performance and/or boiler output at full load would likely be incurred. FGD techniques should be able to be used in conjunction with reburning.

Table 2-19. Summary of environmental characteristics for gas reburning[a]

Applicable coal sulfur content	High[b]	Medium[b]	Low[b]
SO_2 removal[a,c]	10-20	10-20	10-20
NO_x reduction[c] (%)	60	60	60
Solid waste—Ash (lb/10^6 Btu)	12.6	22.6	6.4
Total suspended particulates (lb/10^6 Btu)	0.03	0.03	0.03
Heat rate[d] (Btu/kWh)	9400	9400	9400
Capacity factor (%)	65	65	65

[a] Total emissions from coal-fired plant using reference coal.
[b] See Table 2-3.
[c] Due to 20% replacement fuel, natural gas.
[d] Information provided by staff at the Pittsburgh Energy Technology Center.

2.3.3.2.6 Selective Catalytic Reduction

Description. Selective catalytic reduction (SCR) is a flue gas treatment process for removal of NO_x only. In utility applications, an SCR system is placed between the economizer and air preheater of a power plant, where temperatures are suitable for the chemical reactions involved. Inside the SCR system, ammonia is first mixed with flue gas and then passed through a catalytic reaction chamber. At the catalyst surface, NO_x is reduced by ammonia to form elemental nitrogen and water.

Environmental characteristics. SCR systems generally reduce NO_x emissions by 50 to 80%, although 90% reduction has been demonstrated under carefully controlled conditions. Overall costs of using SCR depend heavily on catalyst life. Experience in Japan has shown that the SCR catalyst can last 4-5 years in a coal plant. The limiting factor on catalyst life appears to be the onset of air preheater fouling. At the end of its useful life, the SCR catalyst can be returned either to the manufacturer for recycle or disposed of as a hazardous waste. A summary of environmental characteristics is shown in Table 2-20.

Market application. The SCR process should be applicable to any size utility or industrial coal-fired boiler that burns either low or medium sulfur coal. SCR systems are well-suited for installation on new boilers but can be retrofit to existing boilers in limited applications only; retrofits require flow modifications and additional ductwork to divert and return flue gas to the existing boiler system. An FGD system to reduce SO_2 emissions can be used in conjunction with an SCR system.

Table 2-20. Summary of environmental characteristics for selective catalytic reduction[a]

Applicable Coal Sulfur Content	Medium[b]	Low[b]
SO_2 removal (%)	0	0
NO_x reduction[a] (%)	80-90	80-90
Solid waste - Ash (lb/10^6 Btu)	28.2	8.0
Total suspended particulates (lb/10^6 Btu)	0.03	0.03
Heat rate[c] (Btu/kWh)	9600	9600
Capacity factor (%)	65	65

[a] 1987 National Acid Precipitation Assessment Program Estimates: NO_x reduction = 50-80%, with 90% possible under carefully controlled conditions (NAPAP 1987a).

[b] See Table 2-3.

[c] Information provided by staff at the Pittsburgh Energy Technology Center.

2.3.3.2.7 Low NO_x burner

Description. Low NO_x burners are replacements for standard burners and are used solely to reduce NO_x emissions. These burners reduce NO_x emissions by promoting a more gradual mixing of fuel and air to reduce flame temperature, and they use a richer fuel-air mixture to reduce oxidation of nitrogen in the fuel. Of the four principal boiler types considered for retrofit NO_x (i.e., tangentially fired, wall-fired with circular burners, wall-fired with cell burners, and cyclone), pilot-scale tests have already been successfully completed for all except cyclones.

Environmental characteristics. Reductions in NO_x emissions are about 60%, and a flue gas cleanup system can be used with low NO_x burners if SO_2 emissions are still above acceptable levels. Other than coal ash, which is a dry material, no solid wastes are produced by the burners. A summary of typical environmental characteristics is shown in Table 2-21.

Market application. Low NO_x burners have a wide range of applications. They are appropriate for any size utility or industrial coal-fired boiler in either new or retrofit uses. Coal of any sulfur content can be used with low-NO_x burners.

Table 2-21. Summary of environmental characteristics for low NO_x burners[a]

Applicable coal sulfur content	High[b]	Medium[b]	Low[b]
SO_2 removal (%)	0	0	0
NO_x formation reduction[a,c]	45-60	45-60	45-60
Solid waste - Ash (lb/10^6 Btu)	15.8	28.2	8.0
Total suspended particulates (lb/10^6 Btu)	0.03	0.03	0.03
Heat rate[c] (Btu/kWh)	9450	9450	9450
Capacity factor (%)	65	65	65

[a] 1987 National Acid Precipitation Assessment Program estimates: NO_x = 45-60% formation reduction (NAPAP 1987a).

[b] See Table 2-3.

[c] Information provided by staff at the Pittsburgh Energy Technology Center.

2.3.3.3 Retrofit—new fuel forms

Coal preparation is used to upgrade the coal by extracting a significant percentage of the ash and sulfur. The extent to which the ash and sulfur can be reduced depends on the characteristics of the coal itself and the way it is processed.

There are two major coal preparation technologies: physical and chemical cleaning. Physical cleaning processes can remove up to 60% of the ash and sulfur, depending on the surface coal characteristics. Chemical methods are needed to remove organically bound sulfur and very finely dispersed (i.e., 40% or less) inorganically combined sulfur. Some advanced chemical extraction methods may have the potential of separating up to 90% of the ash and sulfur. The advanced coal preparation process is illustrated in Fig. 2-11.

Coal preparation can be used in a number of ways in conjunction with many coal utilization and conversion technologies. In the case of directly fired steam coals, the lowered sulfur and ash reduces scrubbing and waste disposal costs and mitigates ash fouling. The enhanced heating value and improved consistency benefit boiler operation and performance. Coal preparation may also be used in the preparation of coal/oil and coal/water mixtures to realize the full economic potential of these combustion technologies.

New fuel form technologies have the capability of producing liquid and gaseous fuels from coal for use in industrial, commercial, residential, and transportation sectors. Surface and underground coal gasification can produce clean fuels and chemical products for use in industrial or utility applications. Coal liquefaction processes fall into four categories: direct liquefaction, indirect liquefaction, coal/oil coprocessing, and pyrolysis. Direct liquefaction involves conversion of coal into liquids by reacting with a slurry of coal, a process-derived solvent, and hydrogen. The liquid product can be refined to produce a full range of refinery products, including gasoline and industrial and home heating oil. Indirect liquefaction processes first convert coal to liquid products by gasifying coal into a mixture of carbon monoxide and hydrogen and then causing these gases to react in the presence of a catalyst to form liquid products. A wide range of fuel and chemical products can be produced for use in all energy sectors. In coal/oil coprocessing, coal is slurried in residual fuel oil, and both coal and petroleum residuals are converted to high-quality fuels in subsequent processing steps. Pyrolysis involves heating coal in the absence of air or oxygen to obtain heavy oil, light liquids, gases, and char. Alternative fuels involve suspensions or slurries of coal or coal-derived solids in water or combustible liquids. The alternative fuels include coal/water, coal/oil, and coal/methanol mixtures.

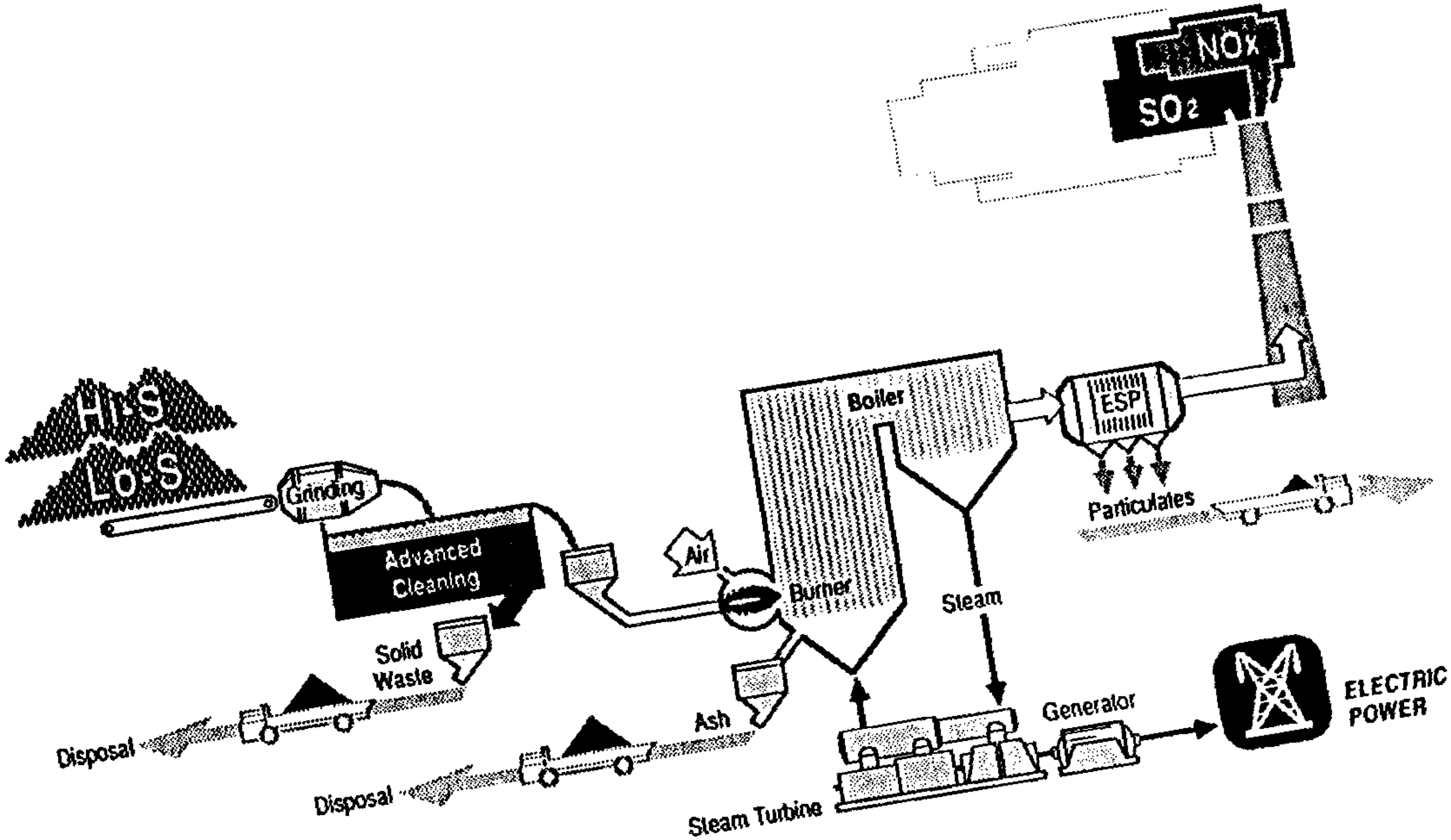

Fig. 2-11. Advanced coal preparation process.

2.3.3.3.1 Ultrafine coal cleaning process

Description. The ultrafine coal cleaning processes involve the crushing, grinding, sizing, and separation of the ultrafine size (finer than 325 mesh) coal product from its impurities. The process is designed to remove the ash-forming materials and pyritic sulfur but not the chemically bound organic sulfur. A number of techniques are available or under development to separate the impurities from the coal product. In the heavy-liquid cyclone technique, a heavy liquid (typically an organic chemical) is used to effect the separation of mineral matter in a cyclone. Virtually all coal particle sizes are amenable to separation with this technology. The selective agglomeration process takes advantage of the difference in surface properties between coal and its impurities to agglomerate coal while its impurities remain suspended in the water. At the ultrafine coal sizes, the liberation of impurities is extensive. The third technique is electrostatic separation. This technique imports electrostatic charges of opposite polarity to the ultrafine ground coal and its impurities to effect separation. Force vectors acting on the charged articles as they pass through an electric field cause separation of the particles.

Environmental characteristics. The combustion of the product from the ultrafine coal cleaning processes lead to emission rates of SO_2 of 1.1 lb/10^6 Btu for Upper Freeport coal and 2.8 lb/10^6 Btu for Pittsburgh No. 8 coal. A FGD system also may be required to meet SO_2 emission regulations. This process removes 90% of the ash in both kinds of coal. Solid wastes consist of coal fines and minerals that are suitable for landfill disposal. No hazardous wastes are produced in the beneficiation process. A summary of typical environmental characteristics is shown in Table 2-22.

Market application. The product from the ultrafine coal beneficiation process is suitable for any size utility or industrial boiler and can be used in new and retrofit boiler applications.

Table 2-22. Summary of environmental characteristics for ultrafine coal cleaning process[a]

	Coal type and sulfur content	
	Upper Freeport medium (2.5% S)	Pittsburgh No. 8 high (3.6% S)
SO_2 removal[b] (%)	77	49
NO_x reduction (%)	0	0
Solid waste removal (%)	90	90

[a] Values shown represent pounds of emission product per million Btu burned at the end-use facility. The only exception is solid waste, which is in terms of pounds of waste removed at the coal cleaning facility per million Btu in the cleaned product coal.

[b] 1987 National Acid Precipitation Assessment Program Estimates: SO_2 removal = up to 65% (NAPAP 1987a).

2.3.3.3.2 Advanced physical coal cleaning process

Description. Advanced physical coal cleaning is an extension of commercially used flotation techniques. Flotation techniques exploit surface property differences between coal and its impurities, but they differ in the variation of process configurations and types of chemicals they use. The process characterized is an advanced multistage flotation process. In the process, the first-stage rougher flotation cells are operated to separate out the high-ash, least-floatable materials as refuse. The froth product from the rougher stage is then reprocessed in cleaner cells in which a pyrite depressant is used in addition to a coal collector. The froth product of this stage is low in ash and sulfur and becomes the final product. The rejects from the cleaner cells are combined with the rougher stage refuse for disposal.

Environmental characteristics. Emission rates of SO_2 from the combustion of the product from this technology are 2.1 lb/10^6 Btu for Upper Freeport coal and 3.4 lb/10^6 Btu for Pittsburgh No. 8 coal (approximately a 66% and a 38% reduction, respectively). A FGD system may be required to meet SO_2 emission regulations. This process removes 65% of the ash in Upper Freeport coal and 53% of the ash in Pittsburgh No. 8 coal. Solid wastes consist of coal fines and mineral matter that are suitable for landfill disposal. No hazardous wastes are produced in the beneficiation process. A summary of typical environmental characteristics is shown in Table 2-23.

Market application. The production from this coal beneficiation process is suitable for use in any size utility or industrial boiler and can also be used in new and retrofit boiler applications.

Table 2-23. Summary of environmental characteristics for advanced physical coal cleaning process[a]

	Coal type and sulfur content	
	Upper Freeport medium (2.5% S)	Pittsburgh No. 8 high (3.6% S)
SO_2 removal[b] (%)	66	38
NO_x removal (%)	0	0
Solid waste removal (%)	65	53

[a] Values shown represent pounds of emission product per million Btu burned at the end-use facility. The only exception is solid waste, which is in terms of pounds of waste removed at the coal cleaning facility per million Btu in the cleaned product coal.

[b] 1987 National Acid Precipitation Assessment Program Estimates: SO_2 removal = 10-30%; costs rise rapidly over 30% removal but up to 50% removal is possible (NAPAP 1987a).

2.3.3.3.3 Advanced chemical coal cleaning process

Description. Organic sulfur is chemically bound to the coal necessitating a chemical reaction to separate it from the coal matrix. In the chemical coal cleaning process, finely ground coal particles are exposed to a molten caustic of either sodium hydroxide or potassium hydroxide at a temperature of 375 - 425 °C. This exposure results in chemical leaching that removes over 90% of the total (organic and inorganic) sulfur and mineral matter from the coal. The cleaned coal is subsequently separated from the spent caustic and impurities though water washing and filtration. The spent caustic is separated from the contaminants and regenerated for reuse. An integrated test circuit has been designed, constructed, and operated for 700 hours to produce a clean coal product.

Environmental characteristics. Combustion of the products from the chemical cleaning process results in SO_2 emission reductions of 90% for Upper Freeport coal. Although no hazardous wastes are produced in the beneficiation process, volatile matter is generated during the desulfurization process and sludges are produced from treatment of wastewaters. Dewatered sludges are disposed of in landfills. A summary of typical environmental characteristics is shown in Table 2-24.

Market application. This coal beneficiation process is suitable for new and retrofit applications on any size utility or industrial boiler, with the exception of cyclone boilers. An ash removal efficiency of approximately 99% reduces the amount of slag formed during combustion of the product coal in cyclone boilers.

Table 2-24. Summary of environmental characteristics for advanced chemical coal cleaning process[a]

	Coal type and sulfur content	
	Upper Freeport medium (2.5% S)	Pittsburgh No. 8 high (3.6% S)
SO_2 removal[b] (%)	90	90
NO_x removal (%)	0	0
Solid waste (lb/10^6 Btu)	42	34

[a] Values shown represent pounds of emission product per million Btu burned at the end-use facility. The only exception is solid waste, which is in terms of pounds of waste removed at the coal cleaning facility per million Btu in the cleaned product coal.

2.3.3.3.4 Mild gasification

Description. The mild gasification process (Fig. 2-12) takes an alternative approach to pyrolysis coal liquefaction by driving off the condensable, volatile hydrocarbon matter and leaving behind carbon in lieu of converting the entire charge of coal.

Mild gasification processes generate multiple products by medium temperature treatment of coal. The products generated are characterized as coal-derived liquids, gases, and chars depending on the operating conditions. The char can be beneficiated further to remove both ash and pyritic sulfur, mixed back with the coal-derived liquids into a stable suspension in a 50-50 ratio and can be burned in both coal- and oil-fired boilers.

Environmental characteristics. Utilizing a chemical beneficiation process developed specifically for char, 90% of the sulfur (and consequently the SO_2 from combustion) can be removed (Poch et al. 1988; Wolfe 1986). The process also removes 90% of the nitrogen. If one assumes that 70-80% of the NO_x emissions comes from fuel-bound nitrogen, NO_x removal efficiency is 70% (further assuming that there is no nitrogen in either of the coal liquids). Finally, beneficiation reduces the ash content in the char by 99%. If the beneficiation process does not reduce emissions to acceptable levels, a FGD system could be used with the combustion technology using liquid coal. The solid waste produced in this process consists of coal and char fines/ash which can be disposed of in landfill sites. A summary of typical environmental characteristics is shown in Table 2-25.

Market application. A slurry of coal-derived liquids and beneficiated char is a very versatile fuel. It can be burned not only in coal-fired boilers but also in any oil-fired boiler. If the char is beneficiated to a high degree, even coal with a high sulfur content can be used. The fuel can also be used in both utility and industry applications and in any size boilers. Use of liquid coal is not expected to alter the heat rates or the capacity factors of any of the generating plants.

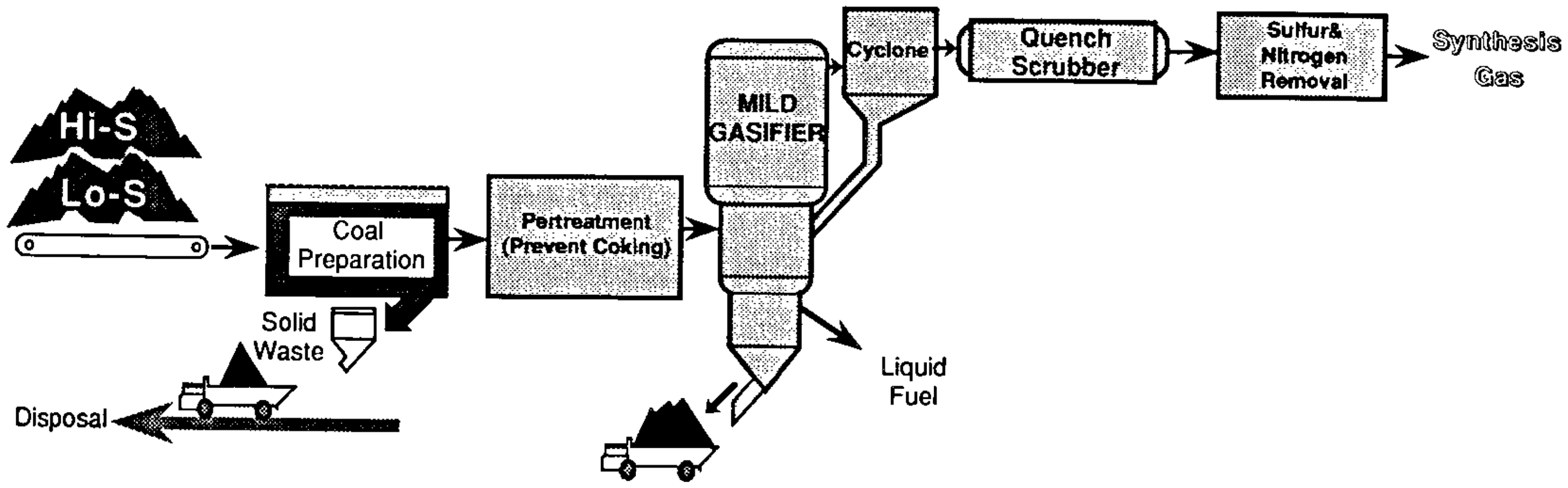

Fig. 2-12. Mild gasification. (Source: DOE 1989)

Table 2-25. **Summary of environmental characteristics for mild gasification**

Applicable coal sulfur content	High[a]	Medium[a]
Fuel production facility		
SO_2 reduction[b] (%)	90	90
NO_x reduction[b] (%)	70	70
Solid waste[b]—Ash (lb/10^6 Btu)	15.8	28.2
Thermal efficiency[c] (%)	65-80	65-80
End-use oil-fired boiler		
SO_2 emission rate (lb/10^6 Btu)	0.5[d]	0.5[e]
NO_x emission rate[f] (lb/10^6 Btu)	0.3	0.3
Solid waste	Negligible	Negligible
Total suspended particulates (lb/10^6 Btu)	0.03	0.03
Heat rate	Not applicable	Not applicable
Capacity factor (%)	65	65
End-use coal-fired boiler		
SO_2 emission rate	0.5[d]	0.5[e]
NO_x emission rate[f]	0.3	0.3
Solid waste	Negligible	Negligible
Total suspended particulates	0.03	0.03
Heat Rate	Not applicable	Not applicable
Capacity factor (%)	65	65

[a] See Table 2-3.

[b] Sulfur and ash removals of 90% and 99%, respectively, are achievable by using advanced chemical methods for coal cleaning.

[c] Thermal efficiency of 65% with conductive heat transfer system and up to 80% with combined conductive-convective heat transfer system.

[d] Sulfur content of char is 0.25% weight, sulfur content of coal-derived liquid fuel is also 0.25% weight, heating value of char-oil mixture is 15,466 Btu/lb.

[e] Sulfur content of char is 0.4% weight sulfur content of coal-derived fuel is also 0.4% weight, heating value of char-oil mixture is 15,460 Btu/lb.

[f] For tangentially fired boilers.

2.3.3.3.5 Direct liquefaction

Description. The two-stage direct liquefaction process (Fig. 2-13) is the most technologically advanced direct liquefaction process currently under development. The technology uses a catalytic process to convert coal to a high quality liquid fuel. Pulverized coal is slurried in a recycle solvent, mixed with hydrogen, preheated, and passed through two close-coupled ebullated bed reactors.

The products from the reactors are separated by distillation to recover the liquid products, part of the recycle solvent stream, and ash. The ash-containing material is sent to a critical solvent de-ashing unit to reject the ash and unreacted coal from a solvent recycle stream. The ash and unreacted coal are gasified, along with fresh coal, to produce the required hydrogen.

The products of the two-stage process are transportation fuels, synthetic natural gas (SNG), and liquified petroleum gas. Byproducts are primarily sulfur, phenols, and ammonia.

Environmental characteristics. Disposal of solid wastes is a major environmental concern with the two-stage process. The major wastes are ash, slag, and sludges from the water treatment. Other solids effluents include spent catalysts and sludge from evaporated aqueous process condensates.

Liquid waste streams contain tar, oils, phenols, ammonia, particulates, CO_2, hydrogen sulfide, chloride, sulfate, cyanide, and ferrocyanide. Atmospheric emissions from the end-use oil fixed utility boiler primarily contain SO_2, NO_x, and particulates. Table 2-26 presents a summary of environmental characteristics for direct liquefaction.

Market application. The two-stage process is designed to maximize the production of liquid fuel products. The principal products to be made are liquefied petroleum gas, naptha, diesel fuel, jet fuel, and turbine fuel. The products are all high quality products that have a high hydrogen content and a low nitrogen and sulfur content.

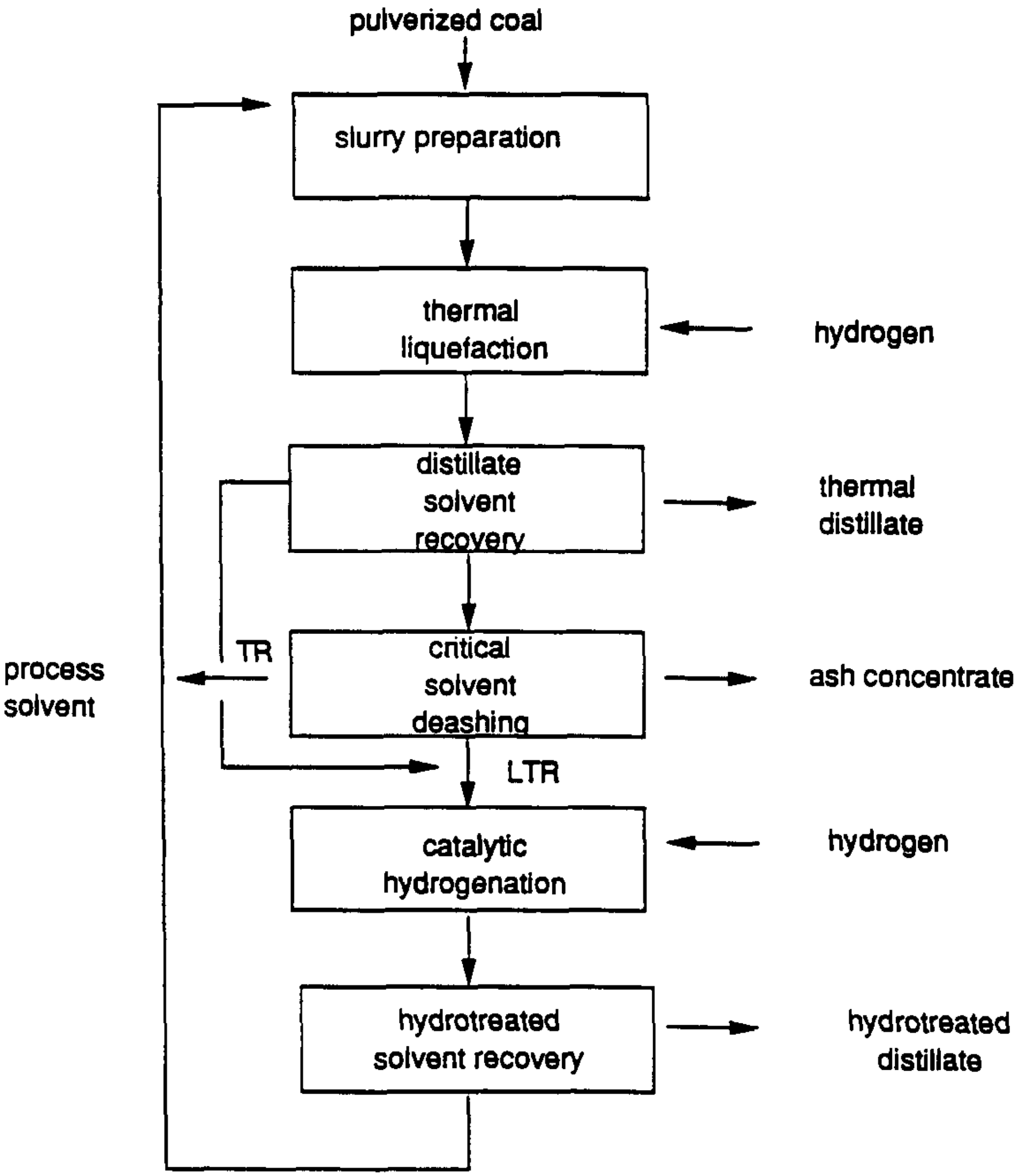

Fig. 2-13. Two-stage direct liquefaction process. (Source: PETC)

Table 2-26. Summary of environmental characteristics for direct coal liquefaction[a]

Fuel production facility	
Applicable coal sulfur content	Any
SO_2 emission rate	0.05 lb/10^6 Btu
NO_x emission rate	0.03 lb/10^6 Btu
Total suspended particulates	0.01 lb/10^6 Btu
Solid waste	14 lb/10^6 Btu
Thermal efficiency	70%
On stream factor	92%
End-use oil-fired utility boiler	
SO_2 emission rate	0.01 lb/10^6 Btu
NO_x emission rate	0.3 lb/10^6 Btu
Total suspended particulates	NA
Solid waste	NA
Heat rate	9,400 Btu/kWh
Capacity factor	65%

[a] DOE 1983, as modified by information provided by staff at Pittsburgh Energy Technology Center.

2.3.3.3.6 Indirect liquefaction

Description. Indirect liquefaction (Fig. 2-14) is characterized by a Fischer-Tropsch-type process in which all the coal is gasified to yield synthesis gas, which is then catalytically converted to produce not only gasoline but also jet fuel, diesel oil, middle distillates, heavy oil, waxes, and a variety of chemical products. The catalysts used determine the products obtained in the process. Other indirect liquefaction processes produce methanol, which can be used directly as a fuel or in a feedstock to produce chemicals and gasoline.

Environmental characteristics. Virtually all of the sulfur (>99%) can be removed in the manufacturing process and converted into salable elemental sulfur or sulfuric acid. Nitrogen compounds (principally ammonia) are generated in the gasification process, but they are easily removed by cleanup systems and subsequently recovered as salable ammonia for fertilizer manufacture. The principal solid waste from the gasifier is coal ash, which is suitable for landfill disposal. A summary of typical environmental characteristics is shown in Table 2-27.

Market application. Because of the variety of fuel products the indirect liquefaction process produces, the technology can be used to supply fuels for a wide range of applications in the utility or industrial sector. Virtually any size boiler that uses coal, distillate, residual oil, or natural gas can use the fuels. The technology can be used in both new and retrofit applications.

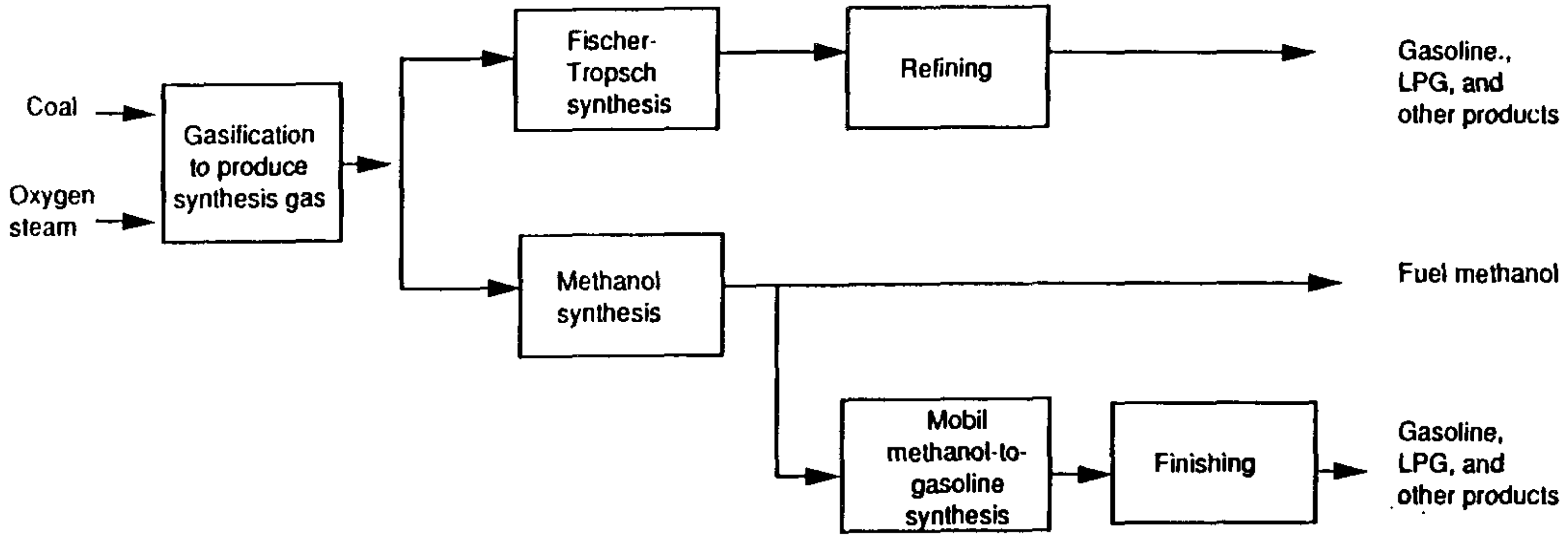

Fig. 2-14. Indirect liquefaction. (Source: DOE 1983)

Table 2-27. Summary of environmental characteristics for indirect liquefaction[a]

Fuel production facility[b]	
Applicable coal sulfur content	Any
SO_2 emission rate	0.3 lb/10^6 Btu
NO_x emission rate	0.3 lb/10^6 Btu
Solid waste	35 lb/10^6 Btu
Total suspended particulates	0.02 lb/10^6 Btu
Thermal efficiency	60%
On stream factor	90%
End-use oil-fired utility boiler[c]	
SO_2 emission rate	0.01 lb/10^6 Btu
NO_x emission rate	0.3 lb/10^6Btu
Solid waste	None
Total suspended particulates	Negligible
Heat rate	9,400 Btu/kWh
Capacity factor	65%

[a] Data DOE 1983, as modified by information provided by staff at Pittsburgh Energy Technology Center.

[b] Rates are in pounds of emissions per million Btu of product produced.

[c] Removal of SO_2 and NO_x occurs in the fuel production facility. Rates are in pounds of emissions per million Btu fed to end-use boiler.

2.3.3.3.7 Coal/oil coprocessing

Description. The final liquefaction technology characterized is coal/oil coprocessing (Fig. 2-15). In this process, coal is slurried in residual fuel oil rather than recycle solvent, and both coal and petroleum residuals are converted to high quality fuels in subsequent processing. The immediate benefit of coprocessing is better operating economies because less hydrogen is required and the need for a process-derived recycle solvent is eliminated.

Environmental characteristics. The environmental characteristics of the fuels produced by coprocessing should be quite good. Desulfurization of coal up to 90% may be achieved, which means SO_2 removal efficiencies should be 90%. Nitrogen removal of up to 80% may be achieved. Assuming 80% of NO_x emissions are from fuel-bound nitrogen, then a net 60% reduction in NO_x emissions is possible. Demetalization of 95% may be achieved with the high metals petroleum residuum. Most of the metals may be removed with the unreacted coal solids. The solid waste consists of coal ash and fines that are suitable for landfill disposal. A summary of typical environmental characteristics is shown in Table 2-28.

Market application. Because of the variety of fuel products coprocessing can produce, the technology can be used to supply fuels for a wide range of applications in the utility and industrial sectors. Virtually any size boiler that uses coal, distillate, residual oil, or natural gas can use the fuels. The technology can be used in new, retrofit, or repowering applications.

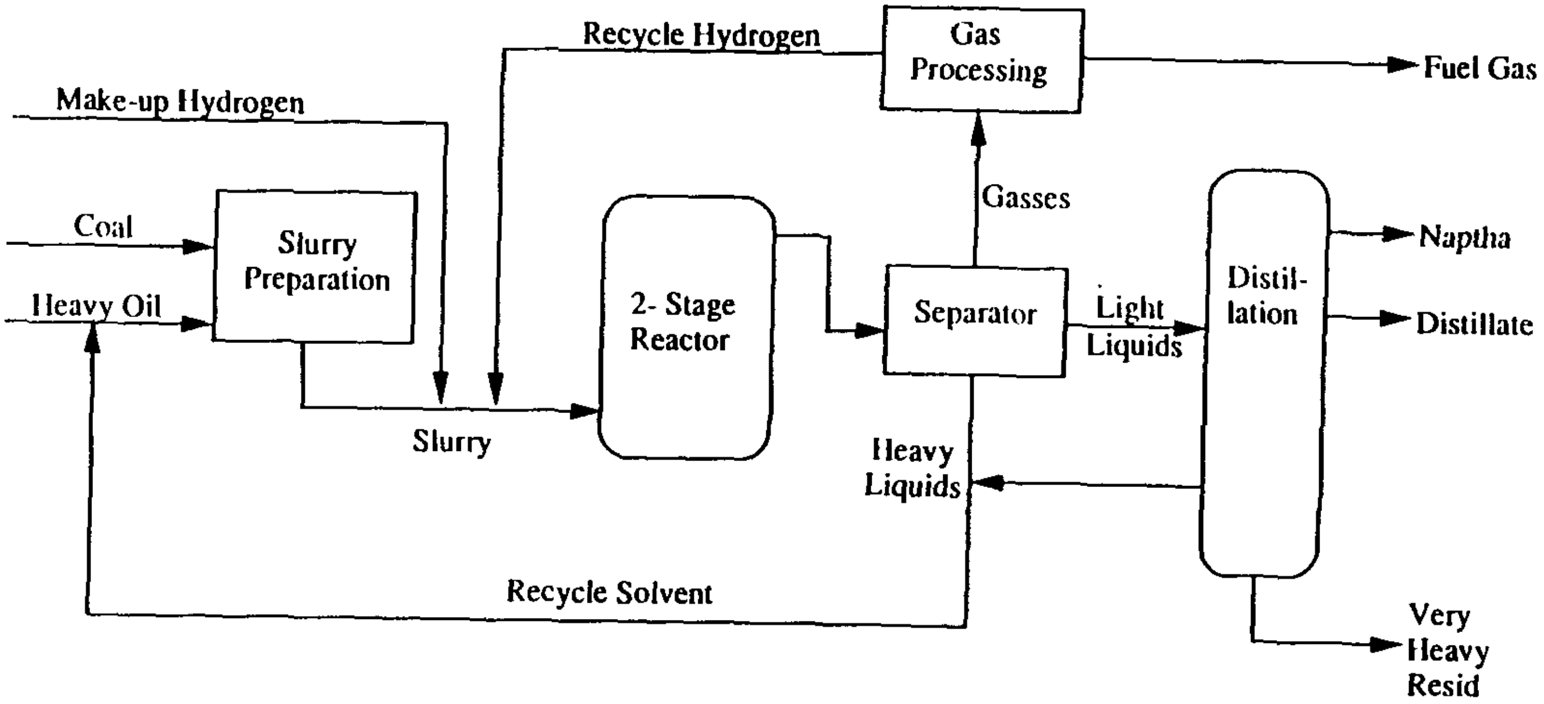

Fig. 2-15. Simplified process flow diagram coal/oil coprocessing area. (Source: PETC)

Table 2-28. Summary of environmental characteristics for coal-oil coprocessing[a,b]

Fuel production facility[b]	
Applicable coal sulfur content	Any
SO_2 emission rate	0.3 lb/10^6 Btu
NO_x emission rate	0.2 lb/10^6 Btu
Solid waste	6.3 lb/10^6 Btu
Total suspended particulates	N/A
Heat rate	N/A
Capacity factor	N/A
End-use oil-fired utility boiler[c]	
SO_2 emission rate	0.4 lb/10^6 Btu
NO_x emission rate	0.3 lb/10^6 Btu
Solid waste	N/A
Total suspended particulates	N/A
Heat rate	9,400 Btu/kWh
Capacity factor	65%

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[a] Data from Argonne National Laboratory and DOE Energy Technology Characterization Handbook, March 1983. (Adjusted for reference case coal and Fisher-Tropsch product quality.)

[b] Rates are in pounds of emissions per million Btu of product produced.

[c] Rates are in pounds of emissions per million Btu fed to end-use boiler.

2.3.3.3.8 Coal/water mixtures

Description. Coal/water mixtures (CWM) consist of a suspension of pulverized (200 mesh) coal in water, plus about 1% additives necessary to maintain the suspension and reduce the viscosity of the mixture. A typical CWM contains 70% coal and 30% water that is fed directly to a boiler and burned. By contrast, pipeline transport of coal typically uses a 50/50 mixture of coarsely ground coal and water that must be de-watered and pulverized upon arrival at a power plant.

Environmental characteristics. CWM alone is not a pollution reduction technology. However, conventional physical coal cleaning, which is normally a part of all CWM systems can lead to reduced emissions, particularly of SO_2. The level of cleaning will dictate the types of environmental controls that must be added or refurbished to meet appropriate emission limitations. Reductions of up to 35% in sulfur and 50% in ash may be attained with conventional cleaning of many coals. Higher levels of sulfur removal (up to 60%) and ash removal (up to 90%) may be obtained with "deep cleaning," depending on coal type. The solid waste stream consists of coal ash and fines that can be disposed of in landfill sites.

FGD equipment may also be required if emissions are not within acceptable levels. Derating (from nameplate capacity) of oil-fired boilers may also be necessary because of conversion to CWM. The extent of the derating could be as high as 60% and will depend on the specific design of the boiler, the extent of the modifications made, and the quality of the coal used. A summary of typical environmental characteristics is shown in Table 2-29.

Market application. Since CWM can replace existing fuel (coal, oil, or gas), this technology has potential applications in a number of areas including retrofitting coal- and oil-fired boilers. Any size boiler in both the industrial or utility sector could use CWM. If coal-cleaning techniques reduce ash levels to 3% or less, CWM can also be used in existing oil- or gas-fired boilers.

Additionally, use of CWM entails special handling procedures. Storage tanks will have to be equipped with agitators to keep the slurry mixed. Care will have to be taken to prevent both changes in pH and bacterial growths in the slurry. Finally, slurries from different vendors may not be compatible because of the different chemical additives used. When incompatibility is found, the entire handling system will have to be flushed out thoroughly before changing from one slurry to another.

Table 2-29. Summary of environmental characteristics for coal/water mixtures[a,b]

Applicable coal sulfur content	High	Medium
SO_2 removal[c] (%)	49%	77%
NO_x removal[d] (%)	0	0
Solid waste[c] (lb/10^6 Btu)	90%	90%
Total suspended particulates (lb/10^6 Btu)	90%	90%

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[a] Environmental Profiles of Selected Clean Coal Technologies, Argonne National Laboratory, December 1987.

[b] Retrofits to previously oil-fired boilers may require derating by as much as 60%.

[c] Coal cleaning prior to CWM preparation can remove 35 to 60% of the sulfur and up to 90% of the ash.

[d] NO_x reduction could be achieved by low-NO_x burners, etc.

2.3.4 Industrial processes

Description. The industrial sector of the energy-consuming marketplace offers significant potential for the development of innovative approaches or technologies to use coal as a more efficient and environmentally responsive energy option. The clean coal technologies discussed in this document have wide application in industries such as iron, cement, paper, and acid manufacturing. For example, the practicality of ironmaking by the traditional method of reducing iron ore material in a coke-fed blast furnace has been severely impacted due to environmental problems. The problems result principally from the coke-manufacturing operation generating emissions and effluents that have proven to be exceedingly difficult to control to levels that meet environmental regulations. One new ironmaking process replaces the two-step coke oven/blast furnace approach to producing pig iron from iron ore and metallurgical coal with an integrated two-component system capable of operation on a variety of U.S. coals (Fig. 2-16). The system consists of an upper "reduction shaft" and a lower "melter-gasifier" component. Iron ore, along with an appropriate flux (e.g., limestone), is fed into the top of the reduction shaft where it is reduced to sponge iron by the off-gas from the lower melter-gasifier section into which it is then introduced along with coal. This lower section is an oxygen-blown, fluidized-bed gasifier. In this lower section, the sponge iron is melted and the resulting pig iron and slag are separated and tapped as in a blast furnace. The low- to medium-Btu, sulfur-free off-gas from the process (sulfur is captured by the limestone and remains in the slag) is scrubbed to remove particulates and is available for site use.

Environmental characteristics. Control technologies similar to those used by utility and industrial boilers can be applied to industrial processes, which generate SO_2, NO_x, and particulates, and will achieve similar reductions in many cases. In the example above, the process, by eliminating the coking step, is environmentally superior to established ironmaking methods and has the ability to operate on a wide range of coal and iron feedstocks.

Emissions of NO_x are often due to the high temperatures required by a particular process. In such cases, technologies such as low-NO_x burners may not be applicable since NO_x control is achieved by lowering combustion temperatures. In general, solid wastes consist of de-watered sludges, solids, and intermediate products that could be salable or suitable for disposal in landfills.

Market application. In addition to the application of clean coal technologies to the ironmaking process discussed above, fluidized-bed combustion and advanced combustors have application in steam production and cogeneration and gasification in production of clean fuel or as a feedstock for the production of highly valued chemicals. Direct heating technologies are used in process heat applications in which the combustion products directly impinge on the manufactured product. For indirect heating applications, a tube wall prevents the combustion products from impinging on the manufactured product as in the case of fired heaters in petroleum refining. The limitations to coal use in direct and indirect heating include product contamination and flame stabilization.

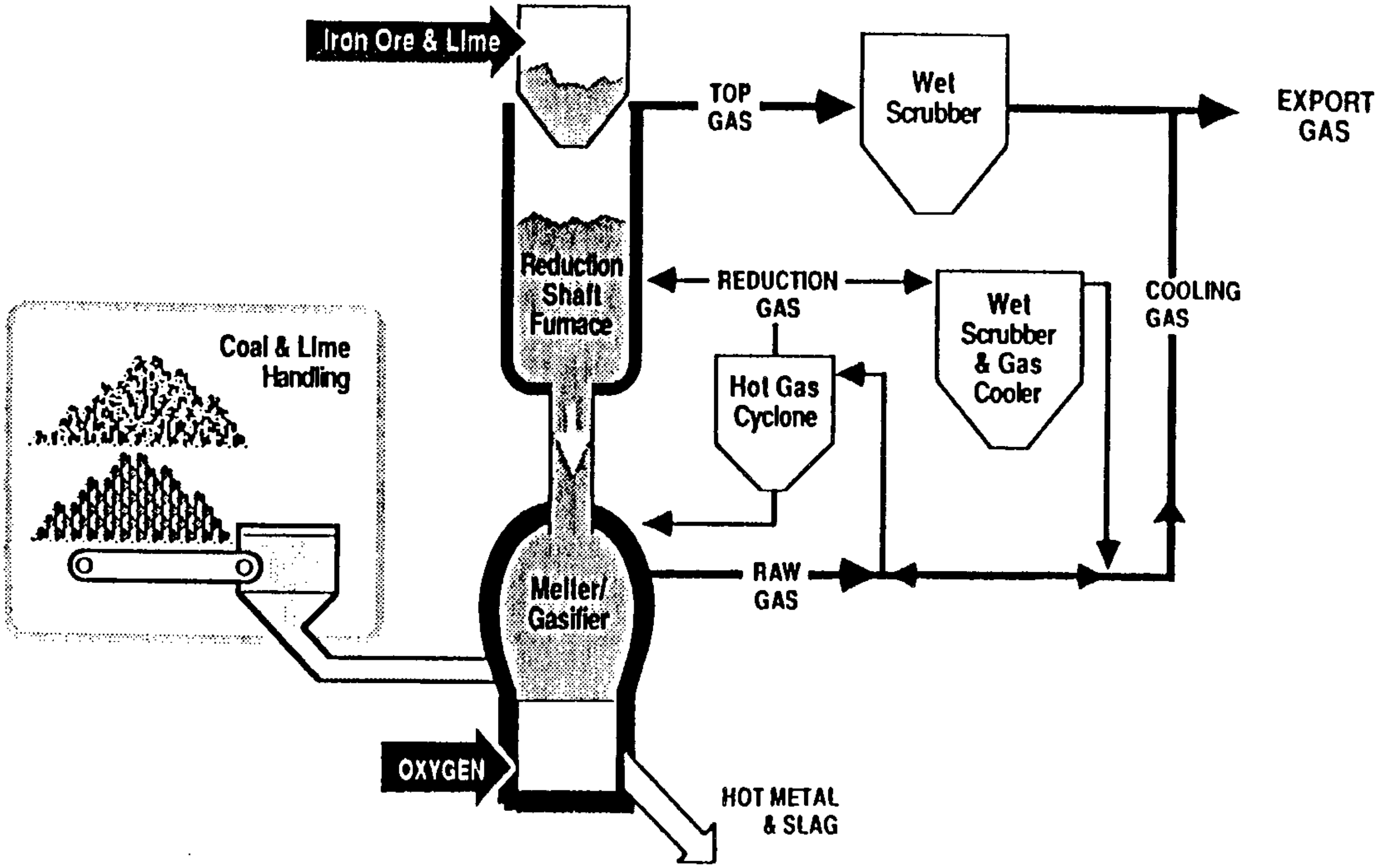

Fig. 2-16. Integrated iron production.

3. AFFECTED ENVIRONMENT

3.1 POTENTIAL REGIONS FOR COMMERCIALIZATION OF CLEAN TECHNOLOGIES

Three important factors in identifying potential regions of commercialization of the clean coal technologies are the locations of coal-fired power plants, coal energy consumed, and coal sulfur content. Figure 3-1 shows the locations of existing coal-fired power plants in the United States for each of the four quadrants used in this study (Fig. 1-2, Sect. 1.8.2). As can be seen, the Northeast (NE) quadrant has the greatest number of facilities, followed by the Southeast (SE), Northwest (NW), and Southwest (SW) quadrants. From the standpoint of energy use (and ultimately the release to the environment of air emissions, water effluents, and solid wastes), the electric generating capability is of principal interest, because coal use is primarily related to electricity generation. Figure 3-2 illustrates the 1985 distribution of coal-fired electric generating capability for the conterminous United States by state and quadrant. The figure shows that the NE quadrant is the greatest area of coal-fired generating capability, followed by the SE, SW, and NW quadrants. Note that the State of Texas is shown as having high generating capabilities as a consequence of its large size. Summary data (1985 operable capacity, generator nameplate in megawatts) on which this map is based are as follows (EIA 1986):

NE Quadrant:	165,605 MW
SE Quadrant:	78,632 MW
SW Quadrant:	41,919 MW
NW Quadrant:	22,276 MW

The locations of existing coal-fired power plants and the regional distribution of coal-fired generating capacity help to illustrate the potential for commercialization of the clean coal technologies in each of the four quadrants. An important component of this potential is the actual 1985 and projected 2010 coal-fired energy consumption used as input to the REDES. Table 3-1 summarizes coal energy use in 1985 by market sector and quadrants based on information from the Regional Emissions Evaluation Data Base (REED), which is the data spreadsheet for the REDES systems (Sect. 1.8). As can be seen, electric utilities and industrial boilers dominate the total coal use in 1985 for each of the major sectors and for the U.S. total. Utilities used about 94% of the energy from coal combustion in 1985. A final consideration is the sulfur coal content in coal demand areas because clean coal technologies would be commercialized to help reduce SO_2 emissions. Figure 3-3 shows the distribution of coal sulfur content in the United States. In general, coal sulfur content is highest in portions of the NE and SW quadrants (midwestern coal demand regions).

The data from the REED, which provide the basis for the numerical estimates of potential changes in air emissions, water effluents, and solid waste generation resulting from commercialization of the clean coal technologies, generally agree with other data published by the Energy Information Administration (EIA), showing that the NE quadrant has the greatest potential of being affected. Commercialization could also occur at facilities not yet constructed (additional units to meet growing demand and replacement of units operating in 1985). As discussed in Sect. 2, new and replacement coal-fired nameplate capacity (i.e., rated capacity of equipment) is estimated to be

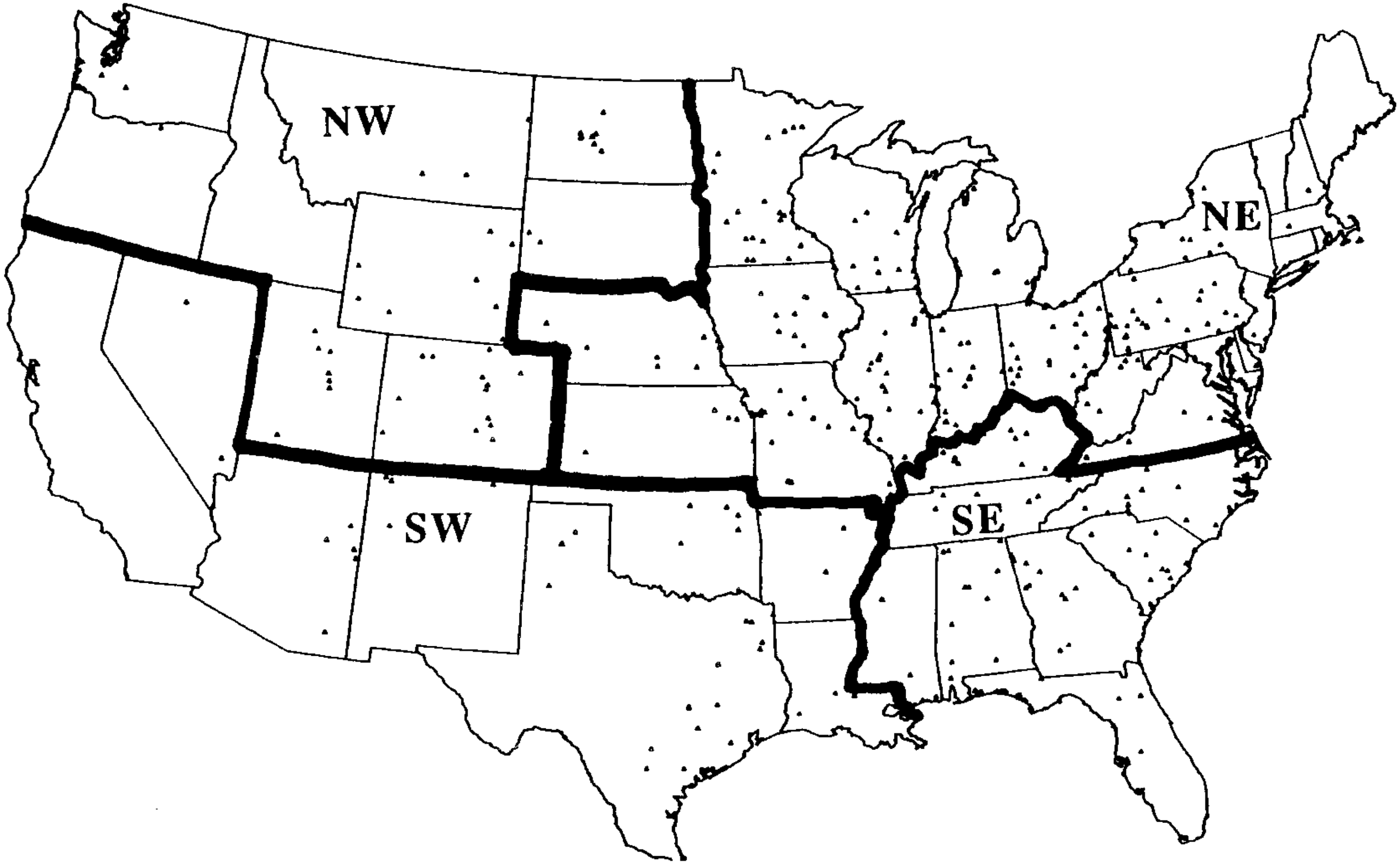

Fig. 3-1. Locations of coal-fired power plants in the conterminous United States. Sources: ORNL Generating Unit Reference File 1985; EPA. 1985. National Emissions Data System (NEDS) Data Base.

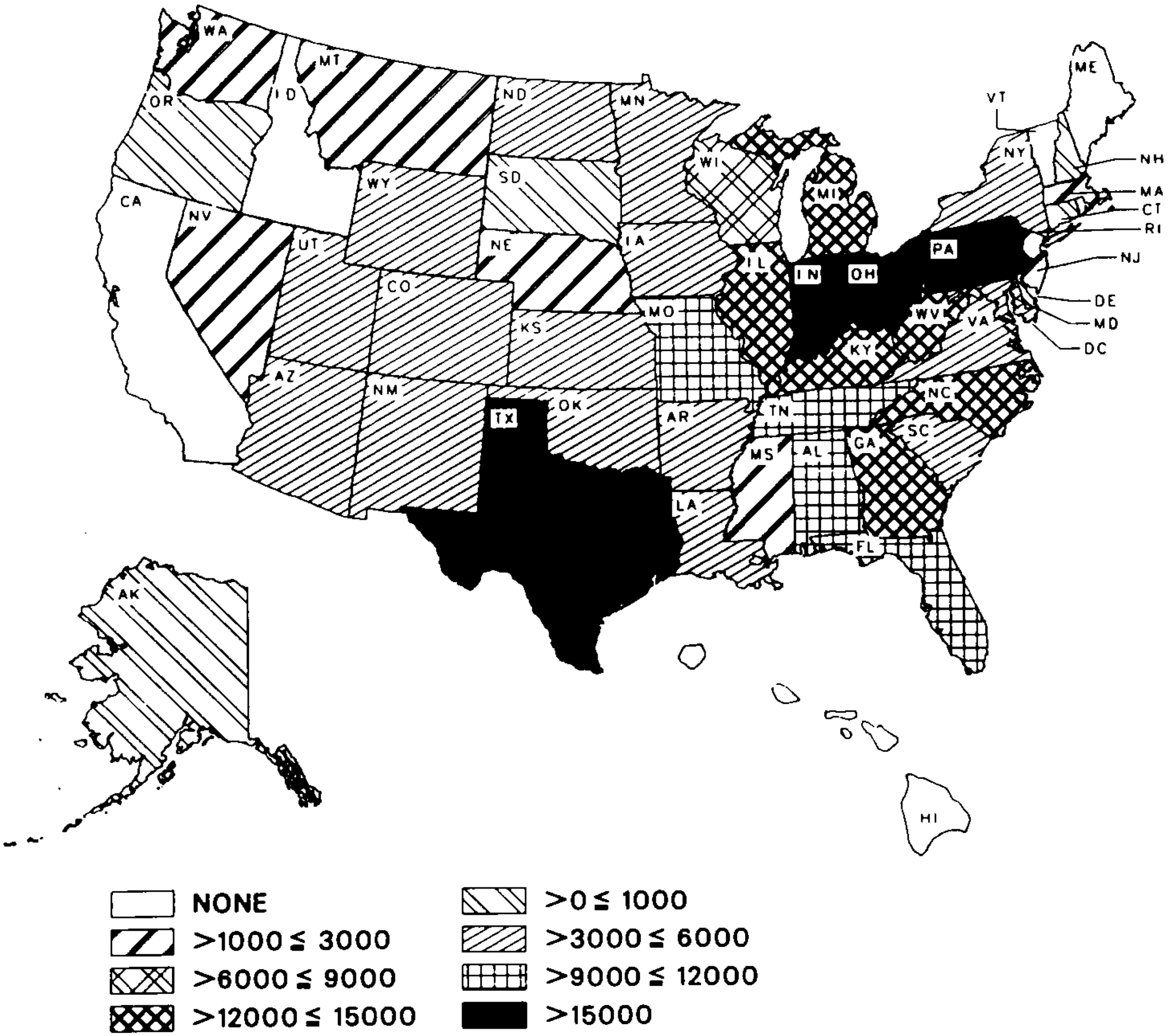

Fig. 3-2. Coal-fired electric generating capability, as of December 31, 1985 (megawatts), in the conterminous United States. (Source: Energy Information Administration, Form EIA-860, Annual Electric Generator Report.

Table 3-1. Coal use activity levels by quadrant and market sectors[a] for calendar year 1985

	1985 Coal energy use by sector (millions of Btus)		
Quadrant	Electric utilities	Industrial boilers	Industrial processes[b]
Northeast	7.86x10^{9}	0.64x10^{9}	4.04x10^{3}
Southeast	3.61x10^{9}	0.20x10^{9}	1.01x10^{3}
Southwest	2.20x10^{9}	0.01x10^{9}	2.40x10^{3}
Northwest	0.95x10^{9}	0.05x10^{9}	0.23x10^{3}
Totals	1.5x10^{10}	0.9x10^{9}	7.7x10^{3}

[a] The database does not include coal energy use for the residential/commercial and transportation sectors.

[b] Data for industrial processes represent the energy content of all fuels (coal, oil, natural gas, etc.) used as feedstock and for process heat; data disaggregated by fuel type for this sector are not available.

Source: Staff computations based on information from the REED database.

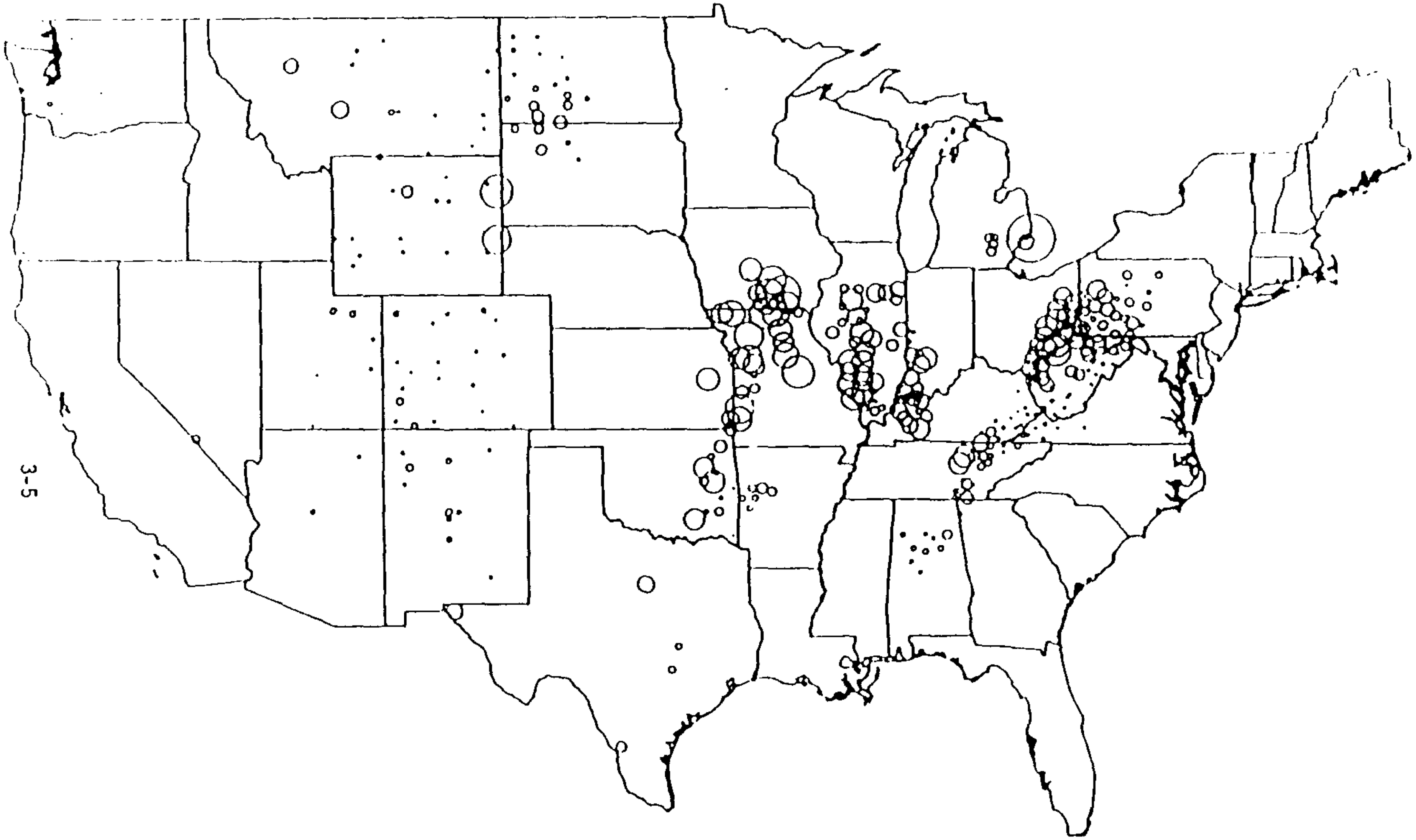

Fig. 3-3. Sulfur content of United States coals. Sulfur content (0.1-8.9% dry) is proportional to circle size. (Source: National Energy Technology Data Center, U.S. Department of Energy, Pittsburgh Energy Technology Center)

about 380 GW for the period 1985-2010. Projections from REED for where the new and replacement units will be built and operated are as follows:

NE Quadrant: 156,000 MW
SE Quadrant: 104,000 MW
NW Quadrant: 23,000 MW
SW Quadrant: 96,000 MW

The addition of these values to those presented for 1985 (Table 3-1) shows that the 1985 ranking of the quadrants in terms of level of coal-fired activity is still projected to be valid for the year 2010.

In summary, the regional quadrant with the most coal-fired level of activity during the 1985 baseline year is the NE, which represents about 55% of the total coal energy used in 1985 for the United States. The remaining 45% is divided among the other three regional quadrants. The NE quadrant incorporates a significant portion of the population and industrial/commercial base and most of the eastern coal fields and their associated users. The NE quadrant thus represents the most likely area of activity for commercialization of the clean coal technologies, followed by the SE, SW, and NW quadrants.

3.2 REGIONAL RESOURCES

3.2.1 Air Resources

3.2.1.1 Air quality

The existing air resources environment that is likely to be affected by commercialization of clean coal technologies is most readily evaluated in terms of existing levels of criteria pollutants in the ambient air. The levels are compared with National Ambient Air Quality Standards (NAAQS), which the EPA established as a result of the Clean Air Act. The NAAQS define maximum allowable ambient concentrations for six criteria pollutants: SO_2, NO_2, ozone (O_3), carbon monoxide (CO), total suspended particulates (TSP), and lead (Pb). In July 1987, EPA replaced the standards for TSP with standards governing particulate matter having aerodynamic diameters $\leq$10 micrometers (PM-10; a size of particle that can easily be inhaled). This document, however, evaluates the existing environment and project impacts to the environment in terms of TSP for which data and projections are more readily available. The standards for the pollutants are established for average concentrations during periods ranging from 1 hr to 1 yr and are categorized according to primary and secondary standards. Primary standards ensure protection of public health, while secondary standards protect public welfare (vegetation, visibility, building materials, etc.).

Based on comparisons of ambient concentrations with the NAAQS, EPA has designated all areas of the United States as either in attainment or nonattainment for each criteria pollutant. Nonattainment areas have been shown by monitored data or by a combination of monitoring data and air quality modeling to violate a NAAQS for a particular pollutant. Figures 3-4 to 3-8 (Loughe et al. 1987) indicate counties in the United States in which all or part of the county is in nonattainment of a primary and/or secondary standard for SO_2, NO_2, TSP, CO, and O_3, respectively, as of September 1987 (the darkened counties are in nonattainment). A figure is not

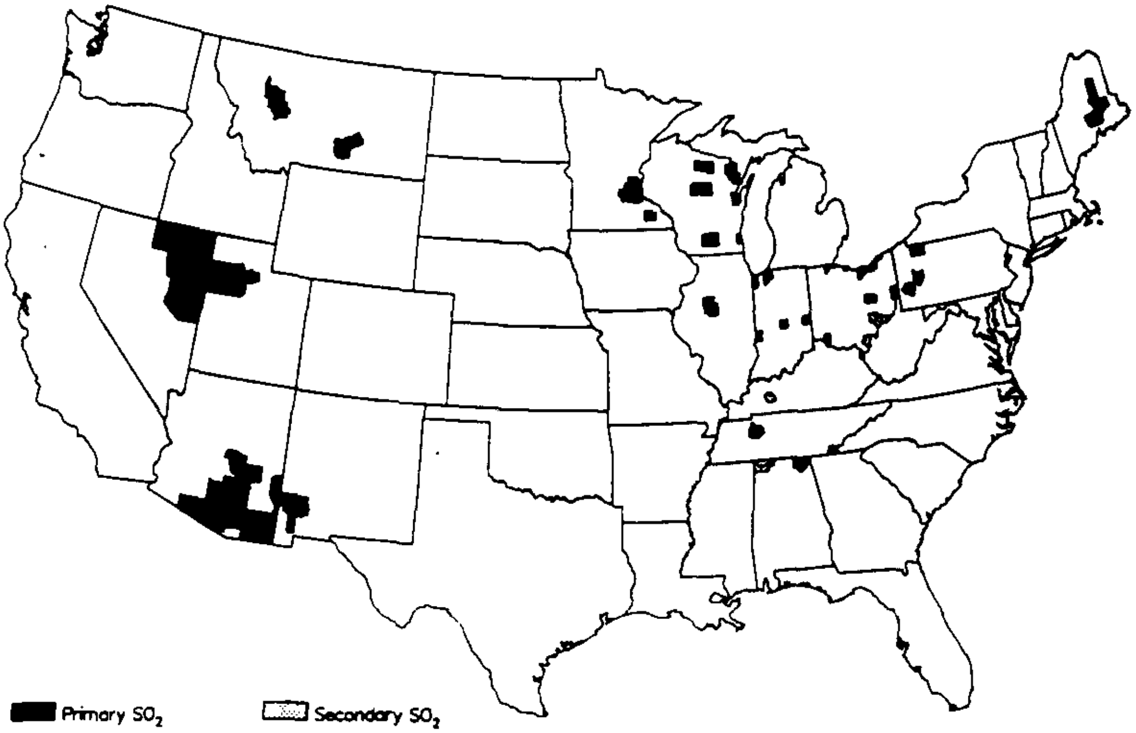

Fig. 3-4. National SO_2 nonattainment counties, as of December 31, 1987. (Source: Loughe et al. 1987)

Fig. 3-5. National NO_2 nonattainment counties as of December 31, 1987. (Source: Loughe et al. 1987).

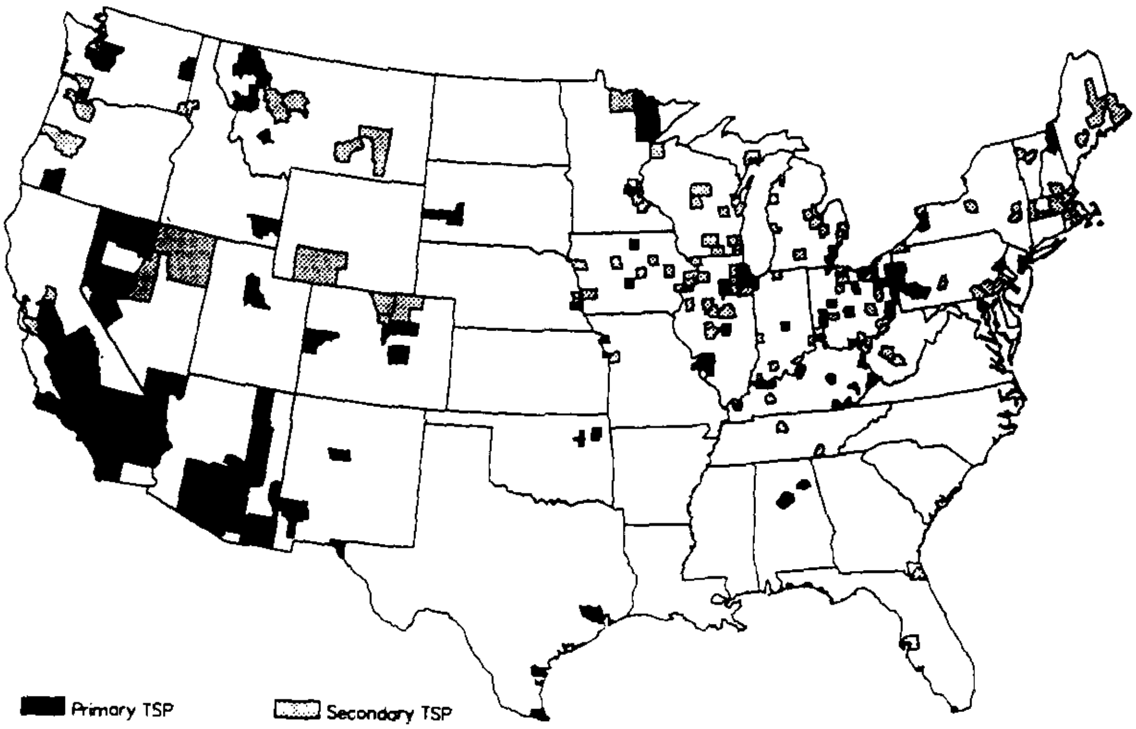

Fig. 3-6. National TSP nonattainment counties as of December 31, 1987. (Source: Loughe et al. 1987).

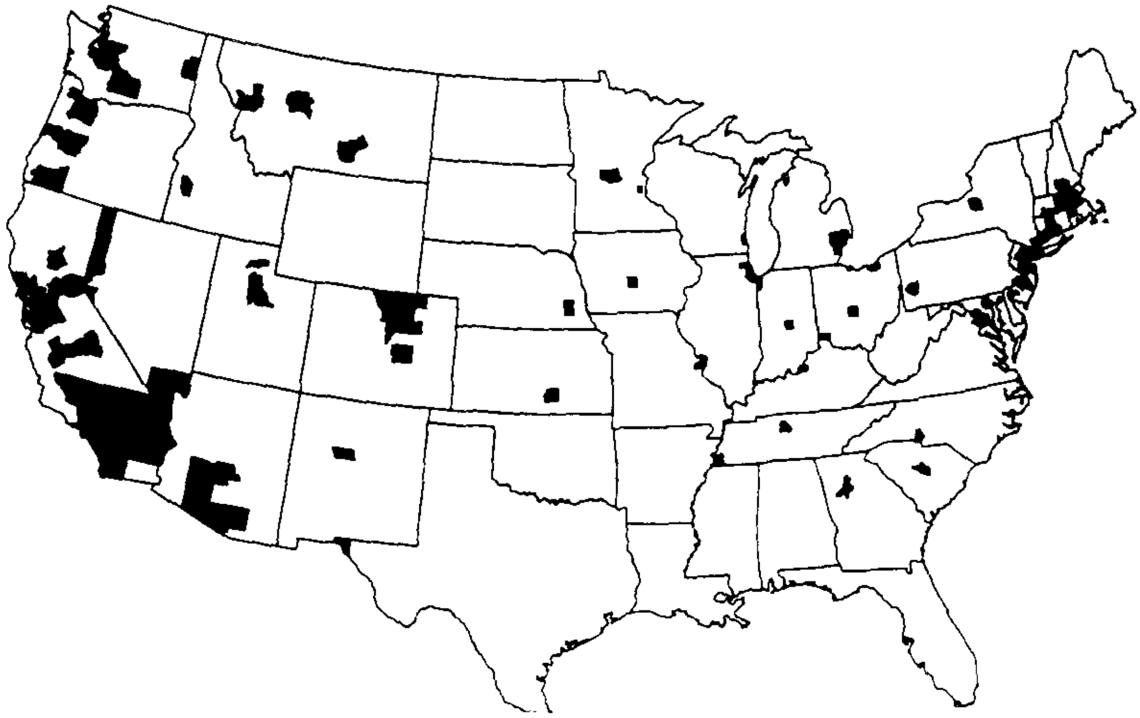

Fig. 3-7. National CO nonattainment counties as of December 31, 1987. (Source: Loughe et al. 1987).

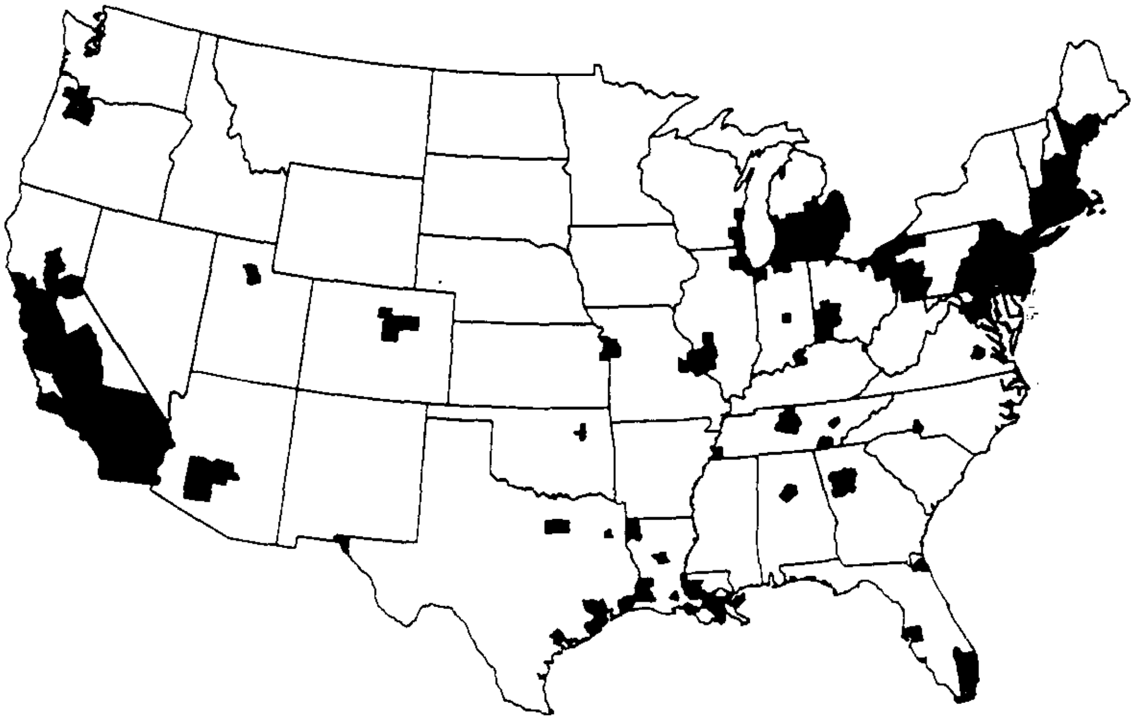

Fig. 3-8. National O_3 nonattainment counties as of December 31, 1987. (Source: Loughe et al. 1987).

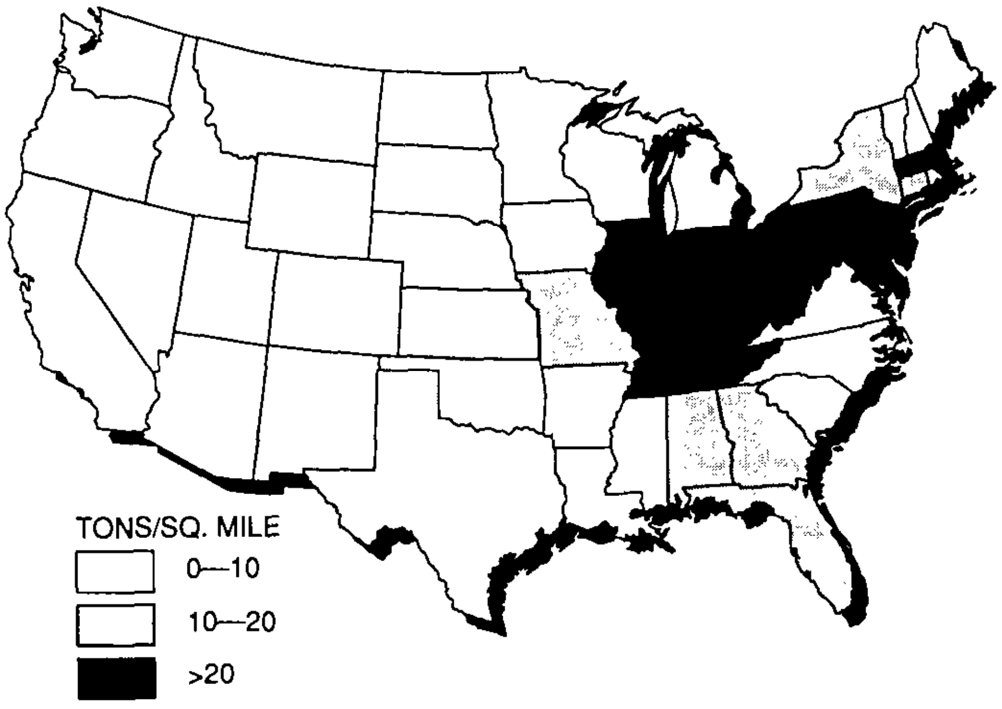

Fig. 3-9. 1985 NAPAP Emissions Inventory, SO_2 emissions density. (Source: Unpublished 1985 NAPAP Emissions Inventory, version 2.0. U.S. Environmental Protection Agency)

included for lead because there are no designated nonattainment areas for lead. The figures provide a general indication of regions in the United States that have air quality problems.

Because emphasis is placed in this document on regions that would be most directly impacted by commercialization of clean coal technologies, the following discussion of existing air quality focuses on regions and criteria pollutants that would be most affected.

Fossil fuel combustion in stationary sources is the major source of SO_2 in the United States, contributing 80% of total national emissions in 1983; coal combustion accounted for 90% of that 80% (Placet et al. 1986). Therefore, baseline conditions of SO_2 are extremely important. Figure 3-9 displays annual SO_2 emissions in the United States for 1985. Emissions tend to be greater in the NE quadrant and, to a lesser degree, in the SE quadrant as compared with the two western quadrants. Examination of Fig. 3-4 reveals that SO_2 nonattainment areas in 1985 also tend to be concentrated in the NE quadrant of the United States, reflecting existing heavy use of coal in this quadrant, especially in the region from Pennsylvania to Illinois. Some nonattainment areas are also located in the SE quadrant in Kentucky, Tennessee, and Alabama—another region of relatively high coal use. Clearly, the above areas are potentially most likely to be impacted by commercialization of clean coal technologies because of their current use of coal and air quality problems associated with SO_2 emissions. Nonattainment areas in the NW and SW quadrants tend to be caused by other sources such as smelters.

Coal combustion is also a major source of NO_x; stationary sources burning fossil fuel produced 50% of national NO_x emissions in 1983 (Placet et al. 1986). Mobile sources (mainly gasoline-powered automobiles) are the other major source for NO_x, generating nearly all of the remaining NO_x emissions. Figure 3-10 displays annual NO_x emissions in the United States for 1985 Emissions tend to be greater in the NE and SE quadrants as compared with the two western quadrants. Figure 3-5 indicates, however, that the only nonattainment areas for NO_x are located in southern California, reflecting emissions from sources other than coal combustion. Thus, NO_x emissions from coal combustion are below levels which would cause violations of NAAQS that trigger nonattainment in the ambient air.

Stationary sources burning fossil fuel generated about 30% of TSP emissions in the United States in 1983 (Placet et al. 1986). Figure 3-6 depicts the nonattainment areas for TSP. The areas tend to be concentrated in the NE quadrant and the two western quadrants. High concentrations in the western United States generally are caused by windblown dust in the more windy and arid areas. Nonattainment areas in the NE quadrant tend to reflect emissions from industries and from fossil fuel combustion in stationary sources.

Emissions from fossil-fueled stationary sources are not as much a factor in ambient concentrations of lead and CO as they are for ambient concentrations of the other regulated air pollutants. Mobile sources emit the majority of lead and CO emissions in the United States, contributing almost 90% and 70%, respectively (Placet et al. 1986). Stationary sources contribute relatively small amounts of these pollutants.

The role of stationary sources in regional ozone formation is still being investigated. Ozone forms via a complicated series of photochemical reactions involving hydrocarbons and NO_x. While stationary sources emit relatively small amounts of hydrocarbons, emissions of NO_x by stationary

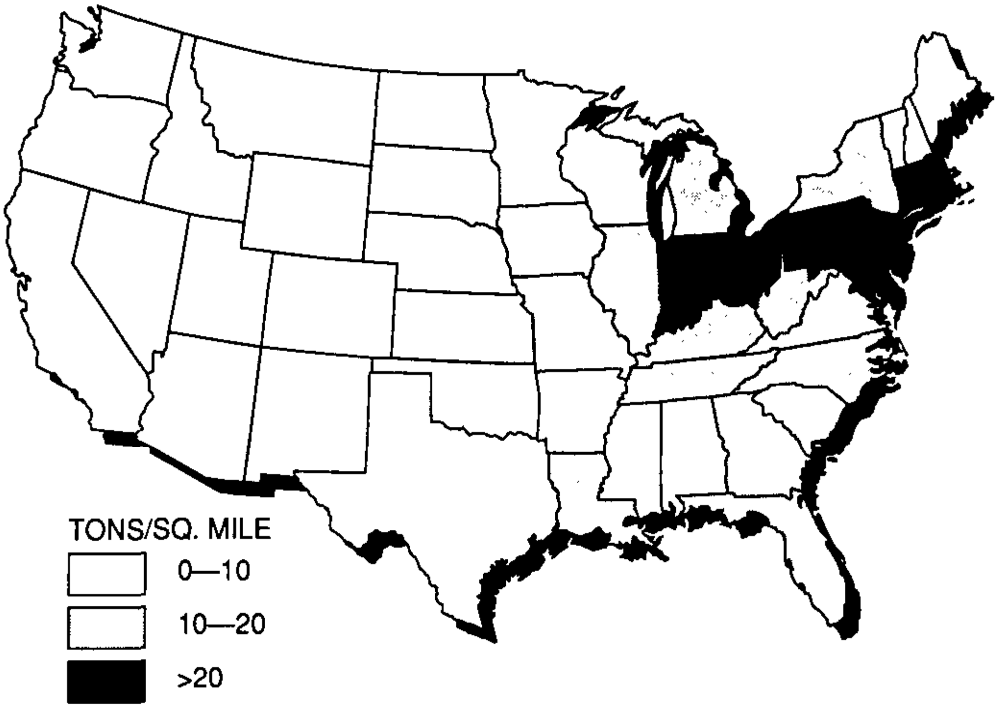

Fig. 3-10. 1985 NAPAP Emissions Inventory, NO_x state emissions density. (Source: Unpublished 1985 NAPAP Emissions Inventory, version 2.0. U.S. Environmental Protection Agency)

sources in some areas might contribute substantially to ozone formation. Generally, ozone nonattainment areas are found in large regions adjoining metropolitan areas throughout the country and correlate well with mobile sources, a large contributor to hydrocarbon emissions.

In addition to examining existing levels of criteria pollutants, it is very important to identify regions that currently are experiencing wet and dry acidic deposition from the atmosphere. Wet deposition, more commonly called acid rain or acid precipitation, refers to precipitation (e.g., rain, snow, and sleet) that is more acidic than normal as a result of exposure to acid-forming pollutants in the atmosphere (Placet et al. 1986). Although the mechanisms of acid rain formation are not well understood, it is believed that SO_2 and NO_x are the major precursors that are transformed via complex chemical reactions into sulfate and nitrate ions in the precipitation. Other substances, including hydrocarbons, chlorides, O_3, and trace metals, also contribute to acid rain formation (Placet et al. 1986). While natural sources such as carbonic acid, salt spray, dust, and volcanic emissions lower the pH of rain to about 5.0-5.2 in some eastern U.S. areas (a pH of 7 is neutral and 5.6 is the level when distilled water is chemically stabilized at one atmosphere of ambient air), the additional acidity of precipitation in parts of North America (pH as low as about 4) is almost certainly caused by combustion of fossil fuels, especially coal (DOE 1979).

Establishment of a clear source-receptor relationship for acid rain is hampered by long travel times between sources of acid rain precursors and occurrence of acid rain. The long travel times translate into long distances between sources and receptors because the emissions are advected by the wind from one region to another. Figure 3-11 depicts the annually averaged pH of precipitation in North America in 1982. As the figure indicates, acid rain in North America presently is occurring in the eastern United States (roughly east of the Mississippi River) and southeastern Canada. The phenomenon is widespread throughout this large area, with the greatest acidity found in a continuous area consisting of eastern Ohio, western and central Pennsylvania, western and northern New York, southeastern Ontario, and the southern edge of Quebec. The major source region for acid rain precursors (SO_2 and NO_x) is suspected to be in the Midwest, centered around Illinois, Indiana, and Ohio. Prevailing winds at levels of pollutant transport are generally from the southwest or west-southwest during periods prior to acid rain, suggesting a general transport of pollutants in an east-northeasterly direction from the Midwest to the region that experiences the greatest acidity. Although potential concern also exists for areas in the western United States, lower emission levels of SO_2 and NO_x are present in most of this part of the country.

Acidification also may occur through dry deposition of acidic nitrogen and sulfur compounds. Dry deposition, which occurs at a fairly constant rate over time in contrast to the episodic deposition of acid rain, may damage plants and materials directly and adds to the acid loading of watersheds. Generally, areas near emission sources receive substantial proportions of acidic deposition via dry deposition, while areas removed from emission sources obtain most deposition from acid rain (OTA 1984). The contribution from wet and dry deposition is estimated to be about equal over most of the eastern United States that is not too remote from emission sources (OTA 1984). Because an air mass contains nitrogen and sulfur compounds from many sources at widely varying distances away, source-receptor relationships are extremely difficult to establish.

Finally, conventional and clean coal technologies emit small quantities of other substances to the atmosphere, including chlorine, ammonia, fluorine, lead, mercury, beryllium, sulfuric acid mist, and uranium. Because emission levels, in general, are extremely low and no impacts to human health and the environment are expected, atmospheric emissions of these substances are not discussed further. Descriptions of health effects from concentrations exceeding threshold values for these and other compounds potentially present in clean coal technologies are presented in Sect. 4.3.6 of this document.

3.2.1.2 Carbon dioxide and other greenhouse gases

One of the critical environmental issues confronting mankind is the possibility of significant changes in the global climate as a consequence of changes in the atmospheric concentration of "greenhouse" gases—most notably CO_2 but also including N_2O, CH_4, and the CFCs. Although there are many uncertainties in our understanding of the climatic effects of greenhouse gases, most scientists agree that increasing concentrations of CO_2 in the atmosphere will result in a warmer Earth and in regional impacts (of unknown magnitude and direction) on temperature, precipitation, and other climate variables (DOE 1985f-j). The importance of climate change will depend on how large the changes are, how rapidly changes occur, and what changes occur in specific regions; all things that are not now well known. Recent DOE testimony stated that global climate change may alter weather patterns, disrupt food crops, forests and other vegetation, as well as negatively affect

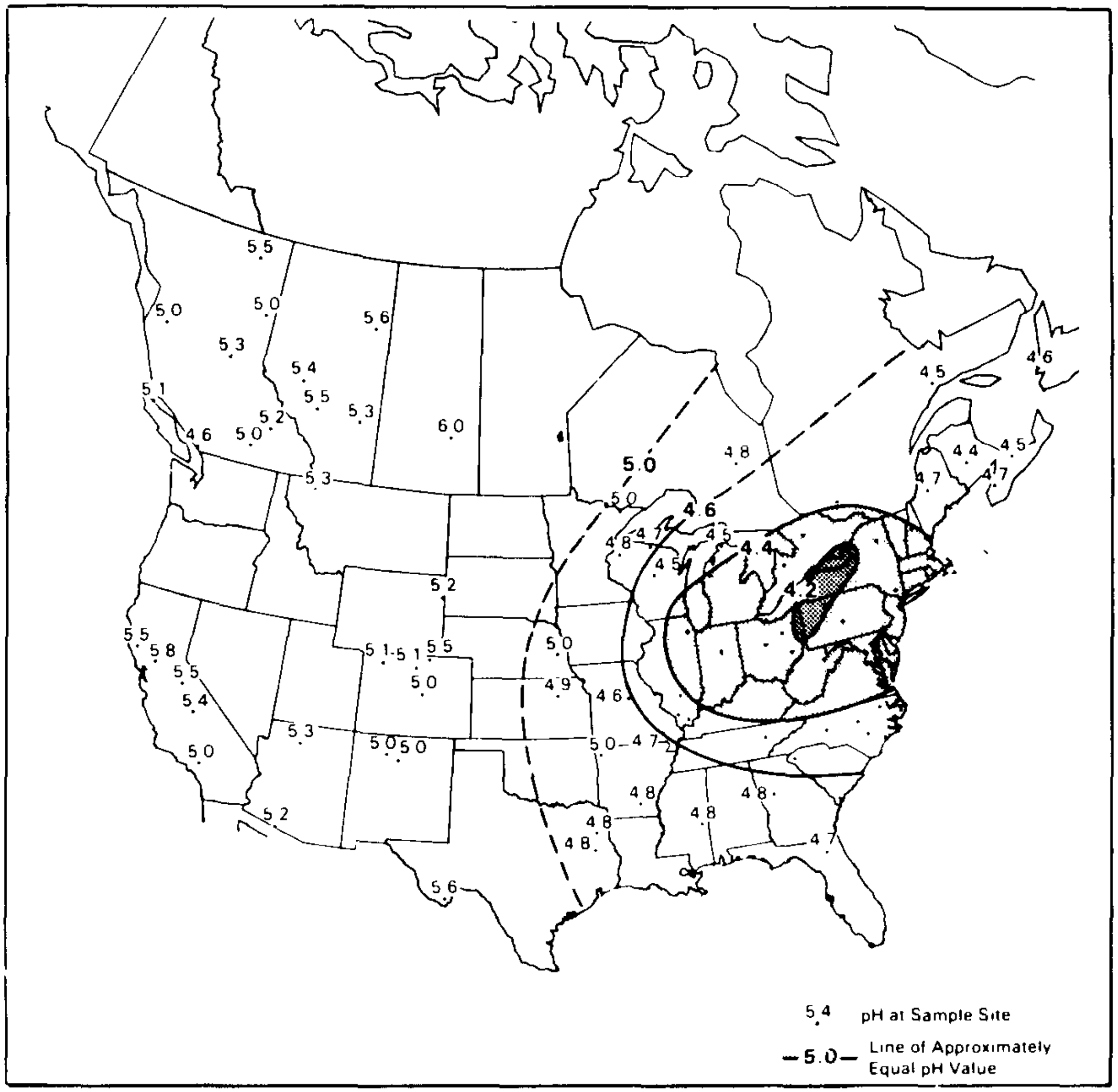

Fig. 3-11. 1983 pH of wet deposition (precipitation-weighted annual average); based on NTN, NADP, and CANSAP data. (Source: NAPAP 1984)

wildlife distribution patterns. It may cause sea levels to rise, destroying coastal wetlands, valuable property, and entire communities. (DOE 1989b).

The atmospheric concentration of CO_2 increased 9.5% between 1960 and 1986. It is generally agreed that fossil fuel burning is the primary contributor and that global deforestation is also a contributing factor. Any action that alters the pattern of fossil fuel burning has the potential to affect the flux of CO_2 to the atmosphere and thus the concentration of CO_2 in the atmosphere. This is true whether the change involves (1) the total amount of energy derived from fossil fuels, (2) the efficiency of use of energy from fossil fuels, or (3) the relative quantities of solid, liquid, and gaseous fuels burned. On a global scale, the burning of fossil fuels averages roughly 32.1 lbs $C/10^6$ Btu in the form of CO_2 for gas fuels, 45.8 lbs $C/10^6$ Btu for liquid fuels, and 55.5 lbs $C/10^6$ Btu for solid fuels. The differences are largely attributable to the varying carbon-to-hydrogen ratios in the fuels.

Because of its stability in the atmosphere, CO_2 is essentially uniformly mixed throughout the troposphere and stratosphere, and the climatic impact does not depend on the geographic location of sources. As a consequence, any action taken in the United States is effective in altering CO_2 concentrations only to the extent that the United States contributes to the global total of fossil fuel burning. For purposes of this evaluation, it is assumed that the program will only impact fuel use in the United States, although it is recognized that the CCTDP could affect emissions elsewhere by the export of the technologies to other countries.

Data from 1986 indicate that the United States is responsible for about 22% of the global total CO_2 emissions from fossil fuel burning. This share has been shrinking as other regions have been experiencing higher growth rates. In 1950 the U.S. share was 42.5% of the global total. Of the 1.31×10^9 tons of carbon discharged from U.S. fossil fuel burning in 1986, 36.7% came from coal. Consequently, about 8% of global CO_2 emissions from fossil fuel burning comes from coal burning in the United States. It is this component that could be affected by commercialization of clean coal technologies in the United States.

Another greenhouse gas that might be produced by burning fossil fuels is nitrous oxide (N_2O). The atmospheric concentration of N_2O is currently about 300 ppb and is increasing at a rate of about 0.65 ppb/yr. It has been suggested that a contributor to the observed increase has been fossil fuel burning. Nitrous oxide has been reported in burners as a function of both burner conditions and fuel nitrogen content. It is destroyed in the stratosphere by photodissociation and by reaction with singlet oxygen, but its mean atmospheric lifetime is estimated to be about 150 yrs.

Hao et al. (1987) concluded that combustion of coal in large boilers accounted for more than 25% of current global inputs of N_2O to the atmosphere. Other data have suggested that the N_2O production rate is directly correlated with the NO_x production rate and that low NO_x burners would produce lower N_2O emissions as well. Some very recent studies have called into question the N_2O analytical procedures and, hence, much of the emission data. Muzio et al. (1989) suggest that coal-fired combustion may not be an important source of N_2O and that information to the contrary is based on faulty analyses. It appears, nonetheless, that measures taken to reduce NO_x emissions from coal-fired boilers would also constrain N_2O emissions. Thus, clean coal technologies that control NO_x emissions are likely to reduce emissions of N_2O.

3.2.2 Land Use

Use of coal for utilities or by industry involves a variety of disturbances to existing land use. Coal combustion plants require substantial land areas (up to or exceeding 1000 acres) for handling and burning the coal, air and water pollution control, cooling equipment, administration needs and other ancillary facilities. Ash and sludge disposal often requires large land areas, either on or off the plant site. Most coal burning electric plants built in the past 10 years use wet limestone FGD to meet air pollution control requirements. These plants consume large quantities of limestone, the supply of which involves additional disturbance to land.

Over 80% of the country's coal production is consumed by electric utilities. It is extremely difficult to estimate the extent to which coal-related land use by nonutility sectors of the economy differs from electric utility coal-related land use. The discussion which follows addresses land use by coal-related electric utilities. Much of the information on land use in this section is based on Robeck et al. (1980).

3.2.2.1 Wastes from coal processing

The cleaning of coal generates large quantities of waste. Wastes from cleaning surface-mined coal are often returned to the open cut, but wastes from cleaning underground coal are usually not returned to the mine workings. Little coal is cleaned in the western states, but in the Appalachian region, 50% or more of the coal mined underground is cleaned, and as much as half a ton of refuse can be generated for each ton of clean coal produced. Present regulations require planned disposal of these wastes.

3.2.2.2 Power plant land use

New coal-fired electric power plants are typically built on sites of 500 to 1000 acres. At a typical site, land is needed for the power plant, coal storage piles, other ancillary facilities, access roads, and landscaping. Physical structures for a 2000-MW power plant might consume less than 100 acres. Topographic considerations may make parts of a power plant site unusable, but most coal-fired power plants built in the past 20 years have substantial areas of usable but unused land on the site. In some cases, this unused land would be suitable for use in repowering projects, while in other cases, it would not. Older power plants are frequently located in urban areas and are more likely to have little room for expansion. In many cases, repowering may not be feasible on these older sites because insufficient land is available. Estimates of direct land use by coal-fired power plants for the ten federal regions (Fig. 1-2, Sect. 1.8.2) are shown in Table 3-2.

Loss of prime farmland is an issue of national concern. Because power plants require large quantities of cooling water, they and their associated waste disposal areas are frequently located on prime farmland near rivers and lakes. Prime farmlands are those lands that have the best combination of physical and chemical characteristics for producing food, feed, fiber, forage, oilseed, and other agricultural crops with minimum inputs of fuel, fertilizer, pesticides, and labor, and without intolerable soil erosion. Prime farmland includes land that possesses these characteristics but is being used currently to produce livestock and timber. It does not include land already in, or committed to, urban development or water storage (Pub. L. 97-98). Annual loss of cropland to nonagricultural uses has been estimated at 3 million acres/yr (Reed et al. 1983). Table 3-3

Table 3-2. Estimated direct land use by existing coal-fired power plants in 1986

Quadrant and Federal Region	Generating capacity[a] (MW)	Land used[b] (103 acres)
Northeast		
1	3,190	1.6
2	5,460	2.7
3	48,660	24.3
5	84,400	42.2
7	25,670	12.8
Subtotal	167,380	83.6
Southeast		
4	75,850	37.9
Southwest		
6	38,300	19.1
9	7,800	3.9
Subtotal	46,010	23.0
Northwest		
8	21,490	10.7
10	1,330	0.7
Subtotal	22,820	11.4
National total	312,050	155.9

[a] Based on coal-fired power plants above 100 MW capacity reported in the UDI (Utility Data Institute, Inc.) Edison Electric Institute Power Statistics Database for the year 1986.

[b] Based on 50 acres/100 MW (Systems Consultants, Inc. 1981).

Table 3-3. Prime farmland in 1982 (10^3 acres)[a]

Quadrant and Federal Region	Irrigated cropland	Total prime farmland
Northeast		
1	19	2,569
2[b]	173	6,227
3[c]	130	11,537
5	596	85,063
7	7,745	56,529
Subtotal	8,663	161,965
Southeast		
4	952	47,921
Northwest		
8	3,815	24,177
10[d]	4,024	7,657
Subtotal	7,839	31,834
Southwest		
6	11,684	92,885
9[e]	6,955	7,592
Subtotal	18,640	100,477
National total	36,094	342,198

[a] Non-federal rural land

[b] Includes figures for the Caribbean (Puerto Rico and the Virgin Islands are within Region 2)

[c] Excludes D.C.

[d] Excludes Alaska

[e] Excludes American Samoa and Guam

Source: USDA 1982.

shows a current estimate of the amount of irrigated cropland and prime farmland by quadrant and federal region.

Activities that affect wetlands or take place in floodplains are also national concerns. Power plant sites are frequently located at least partially in floodplains for reasons discussed above, but power plant facilities are generally located above the 100-yr flood level to avoid flood damage or are protected by flood control structures. Historically, wetlands have frequently been used as sites for cooling ponds or waste disposal areas, but these practices are generally discouraged currently where practicable alternatives exist.

Under the conservative assumption that all existing coal-fired power plants are located on prime farmland, the information in Table 3-2 suggests that currently as much as 150 thousand acres of prime farmland have been converted to power plant use.

3.2.2.3 Solid waste disposal

The three main methods used to dispose of coal combustion wastes are landfills, surface impoundments (primarily for wet slurries), and mine disposal. Materials may be treated prior to disposal so that they are compatible with the particular waste disposal method used and applicable regulations. Wastes from over half the coal-fired electric utility generating units in the United States are disposed in landfills.

Practically all coal-fired combustion facilities require land for disposal of solid wastes, including bottom ash, fly ash, scrubber waste, and sludge from water treatment. The amount of waste from water-treatment processes is much smaller (more than two orders of magnitude) than the wastes from the other three sources. Therefore, only solid wastes from bottom ash and fly ash removal and flue-gas scrubbers are discussed here.

Coal ash is the noncombustible solid residue of coal. In a coal-fired boiler, some of the ash remains inside the boiler and is known as bottom ash. Fly ash is the fraction that is too small to settle out in the combustion chamber; it becomes suspended in the high-velocity flue gas. Air pollution regulations require electric-utility and industrial boilers to be equipped with particulate control devices to prevent fly ash from entering the ambient air.

The control of SO_2 emissions from stationary sources required under the Clean Air Act has led to the installation of FGD systems at many electric power and industrial plants. At present, a large majority of FGD units in the country are of the lime or limestone wet scrubbing type, which produces solid waste in the form of sludge. The lime/limestone scrubber wastes contain calcium sulfite and/or calcium sulfate and fly ash, but the proportions of the solids vary widely. FGD sludge also contains a myriad of trace elements originating in the coal.

Table 3-4 indicates that current generation of ash at coal-fired electric utility power plants is about 80 million tons/yr, and generation of FGD waste is about 15 million tons/yr. Land requirements for solid waste disposal have been estimated to be 19 acres/million tons of ash and 38 acres/million tons of FGD waste (Robeck et al. 1980). Using this information, current land disposal requirements are estimated to be 1520 acres/yr for ash disposal and 570 acres/yr for FGD waste disposal.

Table 3-4. Estimated ash and flue gas desulfurization (FGD) sludge generation by coal-fired power plants in 1990 (10^6 tons/yr)

Quadrant and Federal Region	Ash[a]	FGD sludge[b]
Northeast		
1	1.0	0.2
2	1.3	1.0
3	10.8	2.0
5	19.2	2.6
7	5.7	1.0
Subtotal	38.0	6.8
Southeast		
4	19.3	2.7
Southwest		
6	15.4	5.2
9	3.0	0.3
Subtotal	18.4	5.5
Northwest		
8	6.4	0.4
10	0.8	0.1
Subtotal	7.2	0.5
National total	82.9	15.5

[a] Source: EPA 1988a.

[b] Source: Placet et al. 1986.

Ash and FGD sludge generation are not evenly distributed across the federal regions (Table 3-4). Ash generation follows coal-fired electric power generation closely, but FGD sludge does not. Power plants burning low sulfur western coal may produce as little as 15% of the amount of FGD sludge produced at a comparable plant burning eastern coal. In addition, many older power plants produce little, if any, FGD sludge because they are not required to meet the NSPS. Estimated land requirements for ash and FGD sludge disposal are presented in Table 3-5 for the ten federal regions in 1990. Although landfills are located throughout the country, most are found in the NE quadrant (Federal Regions 3 and 5), a region of high coal consumption. While landfills increasingly are being built on the power plant site, nearly all (95%) of the off-site disposal is in landfills. Wastes generated in Federal Regions 1 and 2 tend to be disposed in off-site landfills.

Surface impoundments, used for about 44% of the generating units nationwide, are most frequently found in the NE and SE quadrants (Federal Regions 4 and 5). Such impoundments are used for nearly 70% of the generating units practicing on-site waste disposal. Because facilities in the SE quadrant rely heavily on surface impoundments, the highest percentage of on-site waste disposal is found in this quadrant.

Mine disposal of wastes, used for only 3% of the generating units, is most frequently encountered in the NW quadrant (Federal Region 8). The mines used for waste disposal tend to be located adjacent to or near the power plant sites (EPA 1988a).

Wastes and waste byproducts from coal-fired power plants can be recovered and reused. These processes typically take place on the power plant sites. Recycled wastes may be used on the power plant site or sold for off-site use; prior to such use, these wastes may be stored at the site. Recent trends indicate that recovery and reuse of wastes are increasing. For instance, while 18% of all coal ash produced annually was reused between 1970 and 1980, over 27% of the coal ash generated in 1985 was recycled. About 21% of the combination of fly ash, bottom ash, boiler slag, and FGD sludge from coal combustion wastes was reused or recovered in 1985. However, current FGD sludge waste recovery and reuse processes are inefficient; less than 1% of the volume of such wastes produced was recycled.

3.2.2.4 Limestone mining

In 1985, 1.4 million tons of limestone (Tepordei 1985) and 1.3 million tons of lime (Pelham 1985) were used in FGD. Lime is a manufactured product made by oxidizing limestone or other high calcium materials. Assuming all lime used for FGD is made from limestone, an estimated 2.8 to 3.0 million tons of limestone were mined in 1985 for FGD purposes. This limestone constitutes less than one-half percent of the 685 million tons of crushed limestone produced in 1985.

Limestone is a plentiful mineral mined in every state in the Union. No estimates of land use requirements of limestone production are available but it is clear that, at the national level, limestone production for FGD systems is an insignificant part of overall land use for limestone production. Because it is a widely mined and low-cost mineral, limestone will almost always be mined near its point of use.

Table 3-5. Estimated annual landfill requirements for ash and flue gas desulfurization (FGD) sludge disposal of coal-fired power plants in 1990 (acres/yr)

Quadrant and Federal Region	Ash	FGD sludge
Northeast		
1	19	8
2	25	38
3	205	76
5	365	99
7	108	38
Subtotal	722	259
Southeast		
4	367	103
Southwest		
6	293	198
9	57	11
Subtotal	350	209
Northwest		
8	122	15
10	15	4
Subtotal	137	19
National total	1,596	590

Source: Based on Table 3.2.2-3 and landfill requirement estimates of 19 acres/10^6 tons for ash and 38 acres/10^6 tons for FGD sludge from Robeck et al. 1980.

3.2.3 Water Resources

Regional water resources are currently affected by the use of coal-fired utility and industrial boilers in many ways. These ways include (1) nonconsumptive use (i.e., use with nearly complete return to the waterbody) to cool steam condensers (steam electric plants), (2) consumptive uses such as evaporative cooling towers and boiler makeup water, (3) addition of contaminants in direct discharges such as ash pond overflow or coal pile runoff, and (4) deposition of materials released to the air, such as SO_2, NO_x, or fly ash that eventually find their way into water bodies. The environmental costs of fuel extraction (e.g., water quality degradation from coal mining) and processing (e.g., water discharges from coal cleaning) are also important existing impacts.

The scale of impacts of a coal-fired facility varies from local to regional. Local impacts of cooling water discharges and other effluents historically have received the most attention. Because airborne contaminants can be transported many hundreds of kilometers, the area affected by any deposition to watersheds and surface waters may include a wide region that extends across states and across the border between the United States and Canada. The transboundary effects have been the subject of considerable controversy and international agreement in the form of the United States-Canada Memorandum of Intent (MOI) on Transboundary Air Pollution (MOI 1983) and the Joint Report of the Special Envoys on Acid Rain (Lewis and Davis 1986).

The most comprehensive sources of information on the general quality of water in major U. S. river basins are the Second National Water Assessment (WRC 1978) and the National Water Summary 1985—Hydrologic Events and Surface-Water Resources (USGS 1986). Water quality naturally differs along a gradient from small mountain streams and lakes (which are usually nutrient-poor and low in dissolved minerals) to large rivers and lakes that contain abundant dissolved and suspended material. Quality also varies on a local scale as a result of human influences. In addition, there are other regional trends that are important considerations for potential commercialization of clean coal technologies. These relevant trends and the mechanisms behind them are discussed below.

3.2.3.1 Water consumption

Conventional coal-fired power generation consumes large amounts of water. Steam-electric generation requires water for boiler water makeup (water used for steam), boiler blowdown, and cooling. Conventional plants that use coal cleaning or wet scrubbers to reduce SO_2 and NO_x emissions consume additional water in these processes.

Consumption of water in steam-electric generation, except for cooling and flue gas scrubbers, is estimated to be about 690 acre-feet (1.1×10^9 liters) per 10^{12} Btu of energy produced, or 82 cubic feet (2300 liters) per MWh (DOE 1983; estimates for coal-fired power plants using eastern coal). Power plants can use either once-through cooling (in which heated water is discharged back to the water body, where evaporation occurs at the water surface) or cooling towers that recirculate water, some of which is lost through evaporation in the towers. When cooling towers are used, they are estimated to consume about 55 cubic feet (1500 liters) of water per MWh (Dvorak et al. 1978).

Coal cleaning (beneficiation using current technology) requires about 3.7 acre-feet (4.5×10^6 liters) per 10^{12} Btu of cleaned coal produced (DOE 1983). Using the heat rate for the baseline power plant of 9400 Btu/kWh (Table 2-3), the water consumption for coal cleaning is about 1.5 cubic feet (42 liters) per MWh.

Existing power plants using wet limestone scrubber technology to remove sulfur from flue gas require in the range of 8-10 cubic feet (230-280 liters) per MWh, depending on the quality of the coal (EPRI 1980).

The environmental effects of water uses by coal-fired utility and industrial plants depend greatly on the regional water resources available. Many impacts are less severe where water is abundant, underutilized, and of good quality than where it is scarce, highly subscribed, and of marginal quality for intended uses. Water availability differs markedly among regions of the United States and Canada. In general, eastern North America has high rainfall and high runoff in rivers and streams compared to the arid West (except the heavy rainfall area of the Pacific Northwest coast). Abundant natural lakes in the glaciated northeastern United States and Canada provide both ample supplies for use in power generation and a widespread resource that may be affected by atmospheric deposition. In contrast, long periods of dryness characterize much of the West, which results in high evaporation, relatively few lakes, and salt buildup in alkaline soils. Water use varies greatly among regions of the United States (Solley et al. 1983). Irrigation is the greatest use of water in the arid West, whereas other uses, especially industrial, predominate in the East. Water resources throughout North America are used heavily for recreational boating, swimming, and fishing.

3.2.3.2 Acidification of surface waters

Deposition of acid from SO_2 and NO_x released by coal-fired plants has significant effects on water quality (e.g., Schindler 1988). There are fundamental differences among regions of North America that affect susceptibility of surface waters to acidification. These differences are due in part to differences in rainfall and in part from the underlying rock and soil types. Many waters of the arid western states tend to be alkaline and to contain high concentrations of minerals and, therefore, are less susceptible to acidification. In contrast, many waters in the eastern states and in mountainous areas of the West are much less mineralized (Brakke et al. 1988; Eilers et al. 1988a, 1988b; Landers et al. 1988). This difference has important implications for neutralization of any acidic materials that are added. Susceptibility of lakes and streams to acidification has been mapped in the United States (Fig. 3-12); surface waters with low alkalinity (a low content of ions such as bicarbonate which can neutralize acid) are shown with average pH of precipitation (Malanchuk and Turner 1987). Figure 3-13 indicates areas of southeastern Canada with low surface water alkalinity (Jefferies in press; acidification is primarily a concern in the southeastern provinces).

Within the last half-century there has been acidification of some upland lakes and streams in eastern Canada, the northeastern United States, and the upper United States Midwest (NAPAP 1987b). This acidification is generally attributed to deposition of acidic sulfur and nitrogen materials derived in part from the burning of fossil fuels (National Academy of Sciences 1984, National Research Council 1986, NAPAP 1987b, Mohnen 1988). Atmospheric transformations that may lead to acidic deposition are described in Sect. 3.2.1.1. The cause and effect relationships of surface water acidification are not well understood and continue to be debated (Lefohn and Krupa 1988). Some scientists believe that what has been attributed solely to acidic deposition from power plant emissions could instead arise from a combination of anthropogenic and natural processes

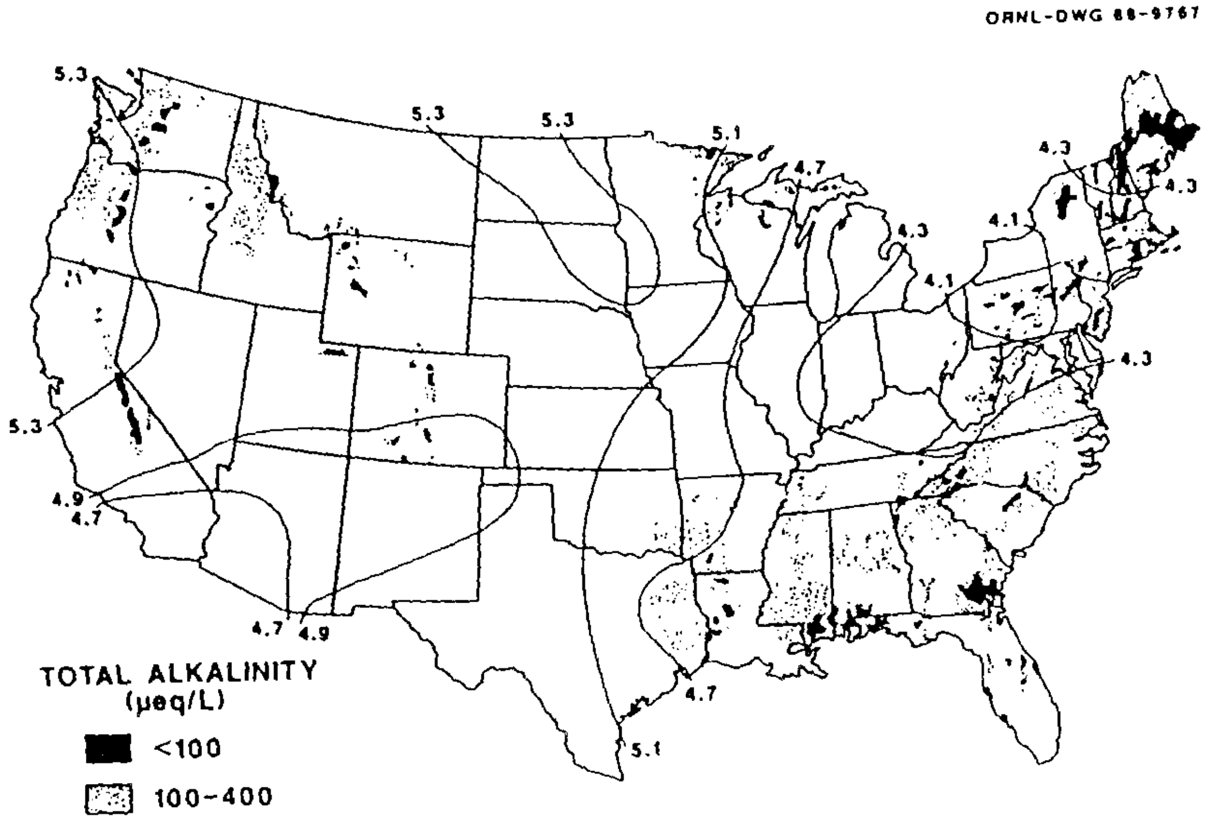

Fig. 3-12. Regional patterns of surface water alkalinity in the United States, that delineate zones that are sensitive to acidification. Adapted from Malanchuk and Turner (1987).

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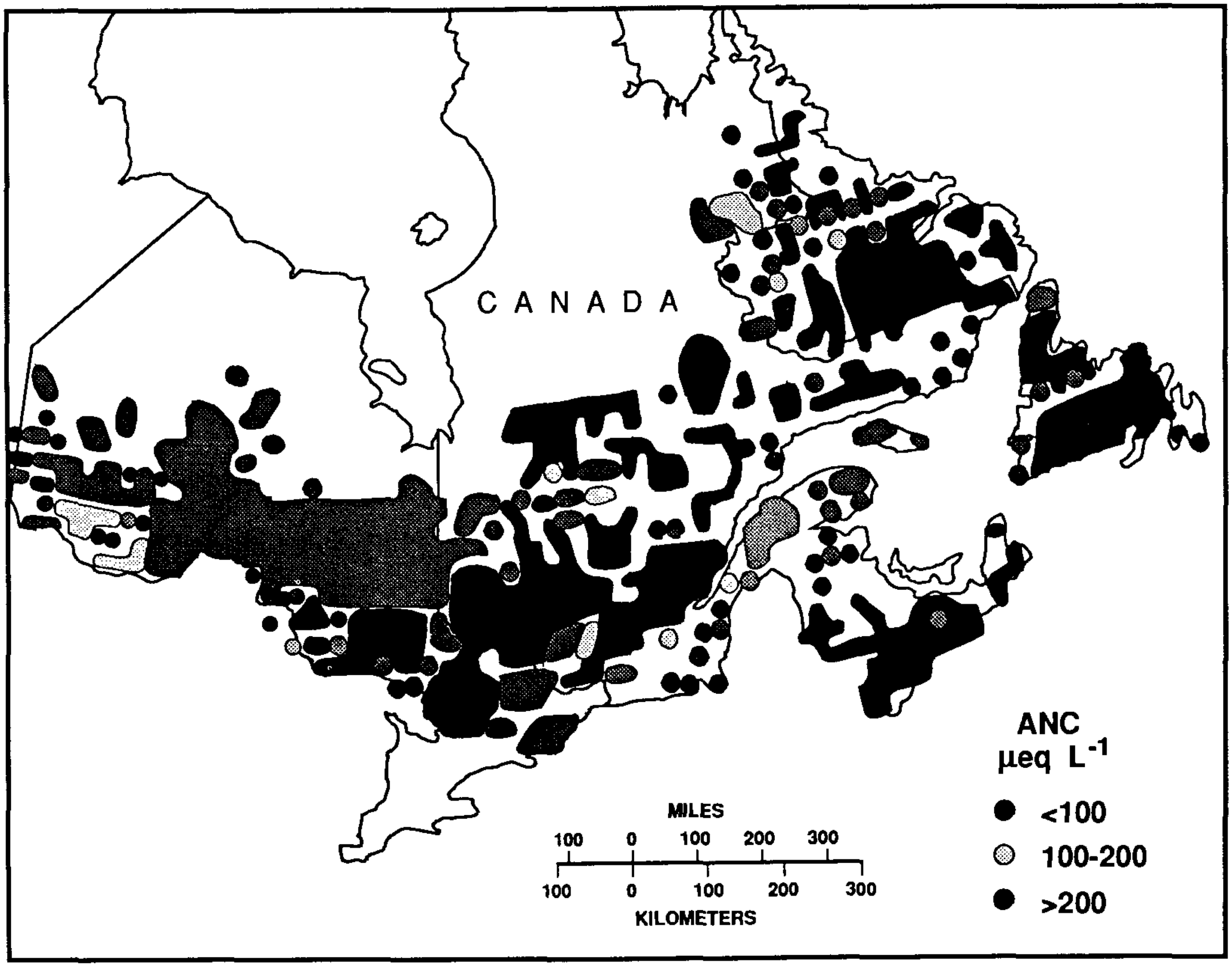

Fig. 3-13. Regional alkalinity in lakes of Eastern Canada; shaded areas represent grid patterns having a common ANC range. (Modified from Jefferies in press.)

(Lefohn and Krupa 1988). Ameliorating the presumed contribution to acidification from coal-fired facilities is a major impetus behind the CCTDP (Lewis and Davis 1986).

The current extent and magnitude of acidifying chemical changes in surface waters that can be attributed to atmospheric deposition are difficult to determine. Regional acidic deposition of anthropogenic origin, particularly in the eastern states, probably began before the turn of the century and reached a peak in the early 1970s (Malanchuk and Turner 1987). Emissions of SO_2 and NO_x peaked about 1975 and declined to the mid 1980s (Sect. 4.1). No historical records exist of changes in atmospheric deposition or changes in surface water chemistry over the past 100 years, and relationships can only be inferred.

Recent paleoecological studies (reviewed by Charles et. al., in press) analyzed subfossil diatoms (algae accumulated in sediments) in lakes to infer past pH levels and the sources of pH changes. Such studies indicate that recent lake acidification as a result of acid deposition has occurred in the Adirondack Mountains, northern New England, Ontario, Quebec, the Atlantic provinces of North America, and in Europe. The pH decreases inferred by this method to have occurred as a result of changes in atmospheric deposition are commonly in the range of 0.5 to 1.5 units, although changes vary regionally and are greater in Europe than in North America. Most of the lakes studied are highly acidic, so actual regional effects of deposition are expected to be less than the changes shown in these studies. Smaller changes in pH occur in lakes with higher acid neutralizing capacities.

Relationships utilizing available data have been developed through the use of models created to estimate the regional impacts of current or altered levels of acidic deposition on water chemistry (Hendricksen 1979, 1980; Minns 1981; Thompson 1982; Wright 1983). These models are tentative and controversial.

Over the past 10 years, however, a consensus among European and North American scientists has emerged about the various processes (atmospheric, watershed, and aquatic) that mediate surface water chemistry in site-specific studies (Galloway et al. 1983; Mason and Seip 1985; Church and Turner 1986; Malanchuk and Turner 1987; Cook 1988). Figure 3-14 illustrates the primary processes thought to control surface water chemistry. These processes have been reported in numerous technical publications, and their interrelationships have been summarized in publications such as Altshuller and Linthurst (1984); Cosby et al. (1985a); Driscoll and Newton (1985); Mason and Seip (1985); EPA (1985b); Galloway et al. (1983); Goldstein and Gherini (1984); Johnson et al. (1985); Jones et al. (1987); Marmorek et al. (1987); NAS (1984); NRC (1986); and Turner et al. (1986).

The processes involve the dynamics of wet and dry deposition and foliar interception (the interception of cloud droplets by needles and leaves), movement of water and acids to and through soils where chemical reactions take place, mixing of surface water and ground water in streams, and interactions with the organisms and sediments in the streams and lakes. The acid-base chemistry of a water body depends on the balance among the acid deposition or natural acid formation processes and processes that regenerate acid neutralizing capacity through biological activity and soil and rock weathering. Some areas, such as coastal areas of the eastern United States, have naturally acidic waters due to sandy soils with little acid neutralizing capacity and wetlands that

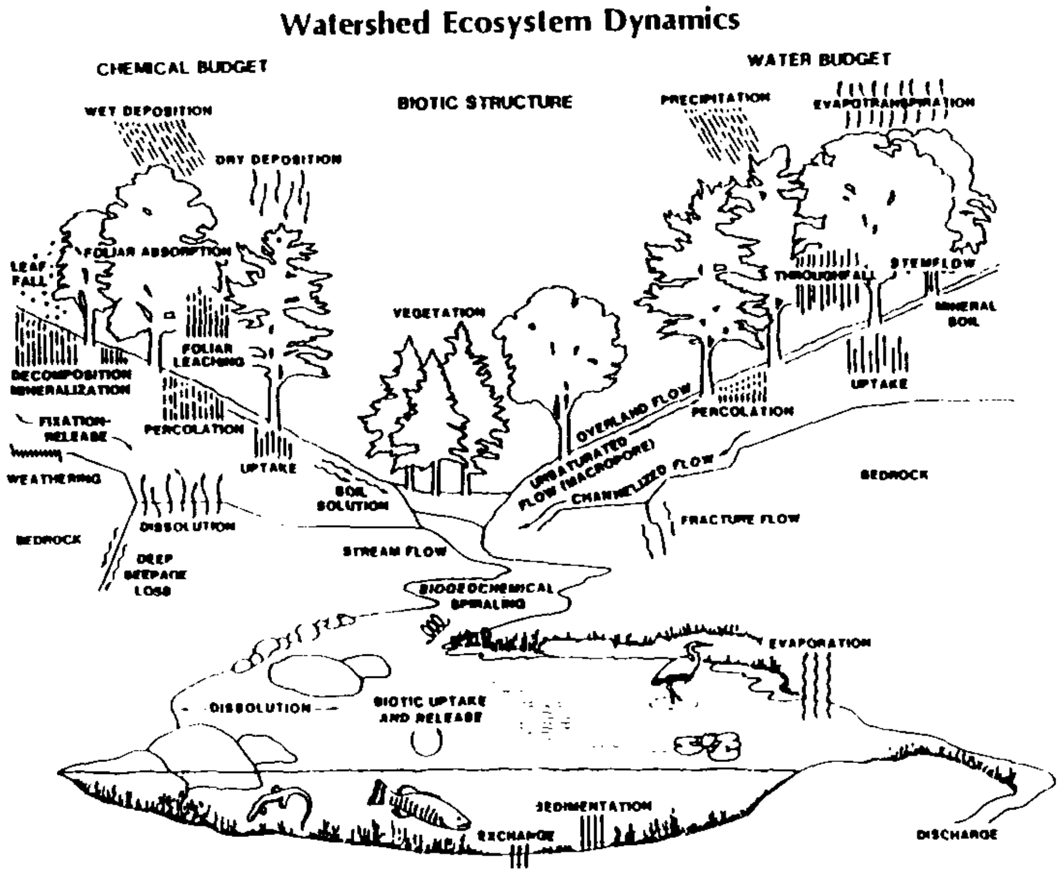

Fig. 3-14. Schematic diagram of a watershed, showing key hydrologic and biochemical processes that affect deposition and its impact on water chemistry and biotic effects. From Cook 1988.

generate organic acids (Eilers et al. 1988b; Lee and Schnoor 1988). It is not currently known how many of the acidic waters in areas receiving acidic deposition may have been naturally acidic. Although it is known that land-use changes such as deforestation can induce acidity in surface waters, the historic extent of these changes is poorly understood.

This conceptual framework of atmosphere-soil-water processes is the basis for process-level studies in watersheds and for mechanistic computer models that mathematically link acidic deposition inputs to changes in surface water chemistry. These models (e.g., Schnoor et al. 1984, Chen et al. 1983, Cosby et al. 1985b) can give a quantitative estimate of changes in water chemistry in a watershed from changes in atmospheric inputs. For example, by using a mechanistic model Rustad et al. (1986) estimated that if sulfur deposition decreased by 50% in the watershed of one lake, then the pH during snowmelt would increase by 0.2 to 0.5 units. Such conclusions will differ among lakes, however. Fendick and Goldstein (1987) modeled two watersheds in the Adirondack region of New York and predicted that outflow pH and alkalinity change little with reductions or increases in NO_x deposition.

Modeling studies indicate that the response of a watershed and lake to changes in acid deposition are highly dependant on the paths that water takes through the watershed as well as the acid neutralizing capacity of the different watershed elements. Watersheds with little acid neutralizing capacity and short hydraulic residence times tend to respond more quickly to acid deposition than do systems that are larger and more buffered (Huckabee et. al. 1989).

There remains considerable uncertainty in predicting on a regional or national scale the environment that would exist in the year 2010 without implementing commercialization of clean coal technologies. Factors that contribute to this uncertainty include questions about the degree to which studies of local situations represent regional waters, the unknown bias in lakes that have been selected for study, the absence of consideration of all chemical or watershed variables that influence chemical and biological effects, the difficulty in comparing data collected in the past by different and sometimes unknown methods, and the inconsistent documentation of data quality (Landers et al. 1988).

Attempts by various groups to estimate the impacts of increasing or decreasing SO_2 emissions have exposed the importance of differing assumptions about direct or delayed responses of waters to acidification (Marmorek et al. 1988). Some analyses, especially of lakes in Canada, emphasize the potential for increasing acidification even under steady deposition. However, the NAPAP Interim Assessment did not find much evidence for a delayed (cumulative) response in the U. S., except in the Southern Blue Ridge Province. Marmorek et al. (1988) summarizes the controversy as it applies to parameterizing acidification models, including a review of uncertainties. It seems likely that the mechanisms could differ among regions of North America. An ongoing EPA project (Direct-Delayed Response Project) is attempting regional extrapolations from process models run on 145 statistically representative watersheds in the northeastern United States to resolve this issue, but results are not yet available.

A recent approach to assessing the status of the acid-base chemistry of surface waters of the United States has been to inventory the chemistry of lakes and streams in the areas that are thought to be potentially sensitive to acidic inputs (Landers et al. 1988). The National Surface Water Survey (NSWS) of the NAPAP includes a regional survey of lake chemistry, a more intensive sampling of a subset of these lakes, and a survey of stream chemistry. Areas sampled are shown in Fig. 3-15. Surveys of Canadian lakes have also been conducted, but these did not use the rigorous statistical sampling framework used in the NSWS. Acid-sensitive areas are present in all four of the United States quadrants (Figs. 1-2 and 3-12) and much of eastern Canada. The combination of high sensitivity and recent low rainfall pH is centered for the most part in the NE quadrant of the United States (especially the upper Midwest, the northern Appalachians, the Adirondack Mountains of New York, and New England), and eastern Canada. The percentage of sampled lakes in the United States whose acid-neutralizing capacity is zero or less (such lakes usually have a low pH and limited aquatic life) is relatively high in these same areas (Fig. 3-16). For example, the NSWS found 11% of the lakes sampled in the Adirondacks to have acid neutralizing capacity less than zero. The highest percentage of lakes with low acid neutralizing capacity was in Florida, where deposition is not as high as elsewhere in the United States.

New research programs in the United States are planned to study the intensity and frequency of episodes of acidity in streams and lakes due to transient runoff. Another program is intended to monitor long-term changes in lake chemistry. These efforts offer the potential to monitor changes in atmospheric deposition and water chemistry as new coal technologies are commercialized (NAPAP 1989a,b).

3.2.3.3 Nutrient enrichment

Inland and coastal waters, especially in the East, are receiving large inputs of nutrients (especially nitrogen),, which cause excessive growth of algae, loss of oxygen and light to the water, and the long-term decline of aquatic life due to a process called cultural eutrophication. Although the major sources of nitrogen from human activities are generally thought to be runoff of fertilizer and animal waste from agricultural land and outfalls of sewage treatment plants and industries, recent analyses show that atmospheric nitrate deposition may be another major source along the eastern seaboard (Fisher et al. 1988). For example, these workers estimate that about one fourth of the nitrogen contributed by human activity to the Chesapeake Bay region is estimated to originate from atmospheric sources, exceeding either sewage or animal waste sources. The uncertainties in such estimates require additional research attention, however.

A survey of water quality trends in the nation's rivers during the period 1974 to 1981 documents widespread increases in nitrate concentrations (Smith et al. 1987). Total nitrogen increases at USGS network stations were strongly associated with high levels of atmospheric nitrate deposition, particularly in the Ohio, mid-Atlantic, Great Lakes, and Upper Mississippi basins. Increases outnumbered decreases four to one and were most common in the East. Trends in total nitrogen appear more related to nonpoint sources (including atmospheric deposition) than to point sources. In New Hampshire, annual weighted nitrate concentrations in precipitation in the mid-1970's were 2 to 3 times greater than they were in the mid-1960's (Likens et al. 1977). Western basins also receive substantial amounts of atmospheric nitrogen. Precipitation contributes 1 to 2 kg/ha of inorganic nitrogen each year to Lake Tahoe, California (a lake undergoing eutrophication), whereas, only 10 to 33% of these precipitation inputs are flushing from the lake. In all western basins, nitrate deposition from the atmosphere is now ten times the basin yield of nitrate, suggesting that atmospheric sources are the predominant factor in nitrogen enrichment (Fisher et al. 1988).

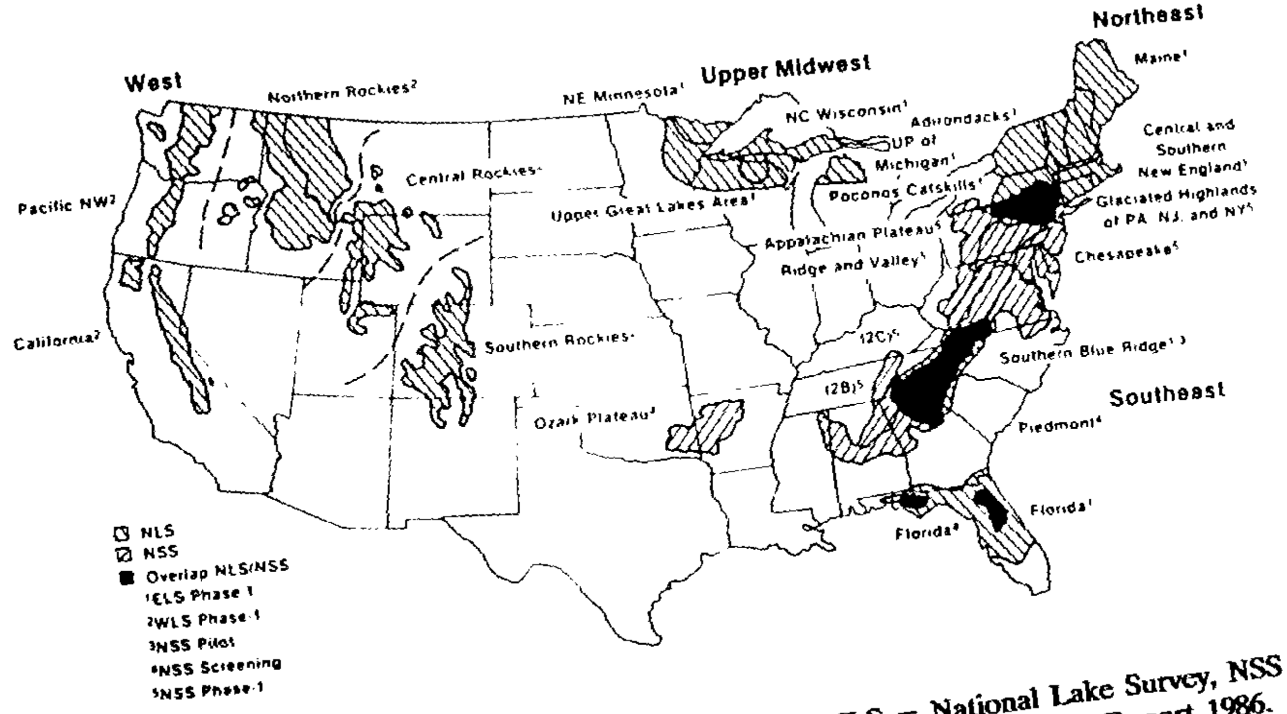

Fig. 3-15. Regions of study for the U.S. National Surface Water Survey. NLS = National Lake Survey, NSS = National Stream Suvey, ELS = Eastern Lake Survey, WLS = Western Lake Survey. (Source: NAPAP Annual Report 1986.

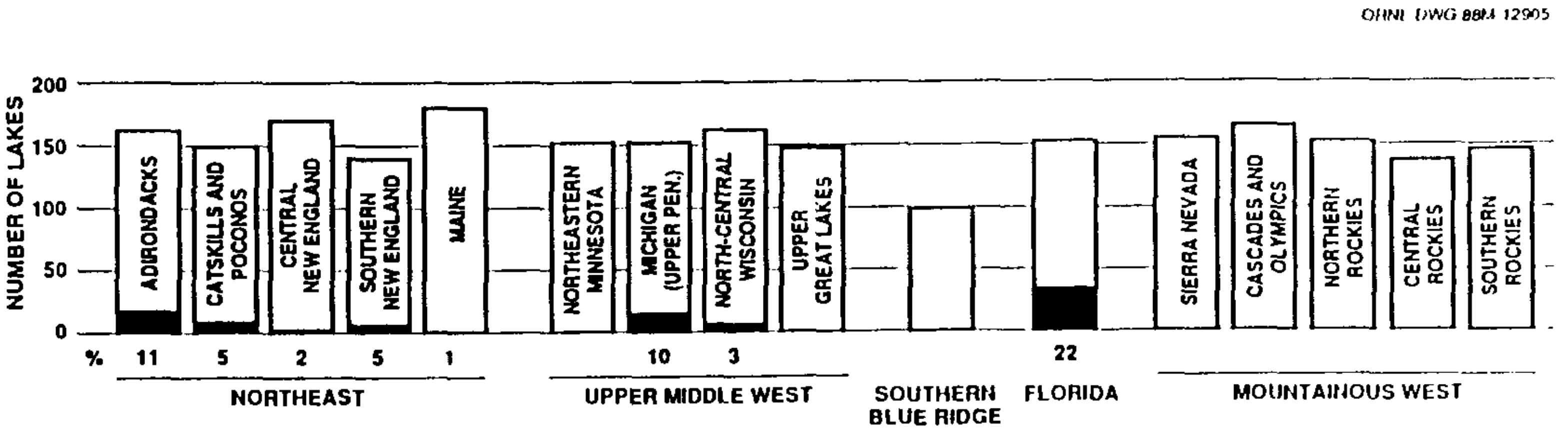

Fig. 3-16. Number of lakes sampled by region in the U.S. Environmental Protection Agency's National Surface Water Survey. Dark portion of each bar indicates the percentage of lakes in which the content of bicarbonate and other acid-neutralizing ions (acid neutralizing capacity: ANC) is less than zero. (Source: Kanciruk et al. 1986, and Eilers et al. 1987)

Atmospheric nitrate deposited on land and water surfaces arises from natural sources and the combustion of all fossil fuels. The primary sources include motor vehicles and power plants. In 1984, these sources were nearly equal, with 36% and 32% of the NO_x emissions, respectively (Fisher et al. 1988). Nitrogen oxide emissions from all sources have increased more or less continuously since 1900, according to Fisher et al. (1988), although there was a small decrease between a peak near 1977 and 1980, producing a generally steady increase in nitrate concentrations in surface waters of the eastern United States. Estimates of the airborne component of nutrient additions to waterways are complicated, however, by the extensive processing of nutrients by watersheds before there is addition to surface waters. This watershed processing is in contrast to more direct sources, such as sewage or agricultural runoff.

3.2.3.4 Other water quality characteristics

There is a general trend toward cleaner waters in many industrial areas due to intensified regulatory activity, especially through the EPA's National Pollutant Discharge Elimination System (NPDES). Recent decline in heavy industrial activity in some areas has also contributed to reduction in polluting discharges (e.g., in the upper Ohio River basin where the steel industry has declined and fish populations have improved markedly; Pearson and Krumholz 1984). These improvements have led to an improved public awareness about the value of water resources and increased use of waters for recreation. Because of cumulative natural and anthropogenic addition of acid-neutralizing materials as waters flow from upland streams to the lowlands, these larger systems are less susceptible to acidification.

Experience with solid wastes from existing coal combustion technologies indicates that leaching can occur from the waste disposal sites to adjacent ground and surface waters (e.g., Coutant et al. 1978). Water in the ash slurry or from rainfall on the compacted ash percolates through the deposits and accumulates iron, sulfur compounds, and trace metals. The mobilization is enhanced by anaerobic conditions and microbiological activity. The leaching can cause noticeable degradation of nearby waterways by discharge of highly acid water, soluble iron, and toxic metals. There can also be surface runoff of suspended solids from solid waste handling facilities. Leachates require site-specific control measures.

3.2.4 Ecological Resources

3.2.4.1 Aquatic ecosystems

The kinds and numbers of aquatic organisms in a water body depend on the water quantity and quality found there (Sect. 3.2.3). As quantity and quality change, so will the biological components of the aquatic ecosystem. These biota are often important directly for recreational or commercial fisheries or indirectly for sustaining the biological community on which the fisheries depend.

There is great variation in the types and abundance of aquatic communities in North America because of the variety of aquatic habitats in which they are found. Summaries of the types of fishes in various regions are available in standard references. Of most importance to commercialization of clean coal technologies are the inhabitants of acid-sensitive areas.

Areas in the NE quadrant of the United States and eastern Canada that are sensitive to acidification from atmospheric deposition (Sect. 3.2.3) have populations of cold-water salmonids (lake, brook, rainbow and brown trout, Atlantic salmon) and cool-water species (walleye, smallmouth bass, yellow perch, and rock bass) (Lee et al. 1980), which are important for recreational fisheries. Atlantic salmon populations have been the subject of considerable restoration efforts in New England and coastal Canada (Beland 1984) as have populations of lake trout in the upper Midwest. Brook trout, a product of both natural reproduction and stocking, were a dominant resource in many of the lakes and streams that are alleged to have become acidified in recent years. Many of these populations have been lost (EPA 1986; NAPAP 1987b). Some lakes in the sensitive areas (Figs. 3-12, 3-13) are now devoid of fish or have reduced populations, which is attributed by most analysts to acidic deposition (EPA 1986). Species differ in their sensitivity to low pH; lake trout and Atlantic salmon, for example, are especially sensitive, whereas, brook trout and yellow perch are more tolerant (Elwood 1988).

Other acid-sensitive areas in North America also tend to have cold-water and cool-water fish species. Mountainous areas of the southern Appalachians and the western states have several species of trout as the dominant sport fish. Rainbow, brown, and brook trout are present in all of these areas, and cutthroat trout are important in the West. The southern Piedmont and coastal plain lakes and streams that are susceptible to acidification (organic, brown-water systems) are dominated by warm-water fish species. There is evidence that many coastal streams that are important for spawning of anadromous fishes (those that migrate from the sea for spawning in freshwater rivers and streams, such as striped bass, alewife, blueback herring, and American shad) may be acidified at critical spawning times in spring and that these episodes reduce survival of larval stages (Hall 1984).

Results of laboratory bioassays, bioassays in the field, and field surveys tend to corroborate the fact that acidification can cause changes in populations and communities of organisms and has probably contributed to the decline in living resources. The evidence linking loss of fish and other organisms in some poorly buffered lakes and streams to declining pH is unequivocal (Malanchuk and Turner 1987, Elwood 1988) (Figs. 3-17 and 3-18). Historical records of species' richness and relative abundance of fish in streams and rivers, particularly in the Adirondack Mountains and southeastern Canada, begin to show a decline in the numbers of species and a reduction in the relative abundance of selected species as pH has declined below about 6, although the pH record is poor. Paleolimnology, the reconstruction of past history of lakes by use of evidence in the sediments, is contributing to an understanding of the past pH regimes (Sect. 3.2.3.2). The relationships between water chemistry and biology are most conclusive in site-specific studies in which acidity has been altered experimentally (e.g., Schindler et al. 1985). Surveys of lakes and streams across a wide range of pH values show a trend of decreasing richness of phytoplankton, zooplankton, benthic invertebrate, and fish species with decreasing pH. How much of the pH change and biological effects in such waters is due to emissions from coal-fueled boilers is uncertain, however.

3.2.4.2 Terrestrial ecosystems

Existing impacts of coal-fired utility and industrial plants on terrestrial ecosystems range from the possible effects of atmospheric emissions and subsequent deposition to destruction or disruption of habitat associated with siting new or expanded facilities such as solid waste disposal areas. Land

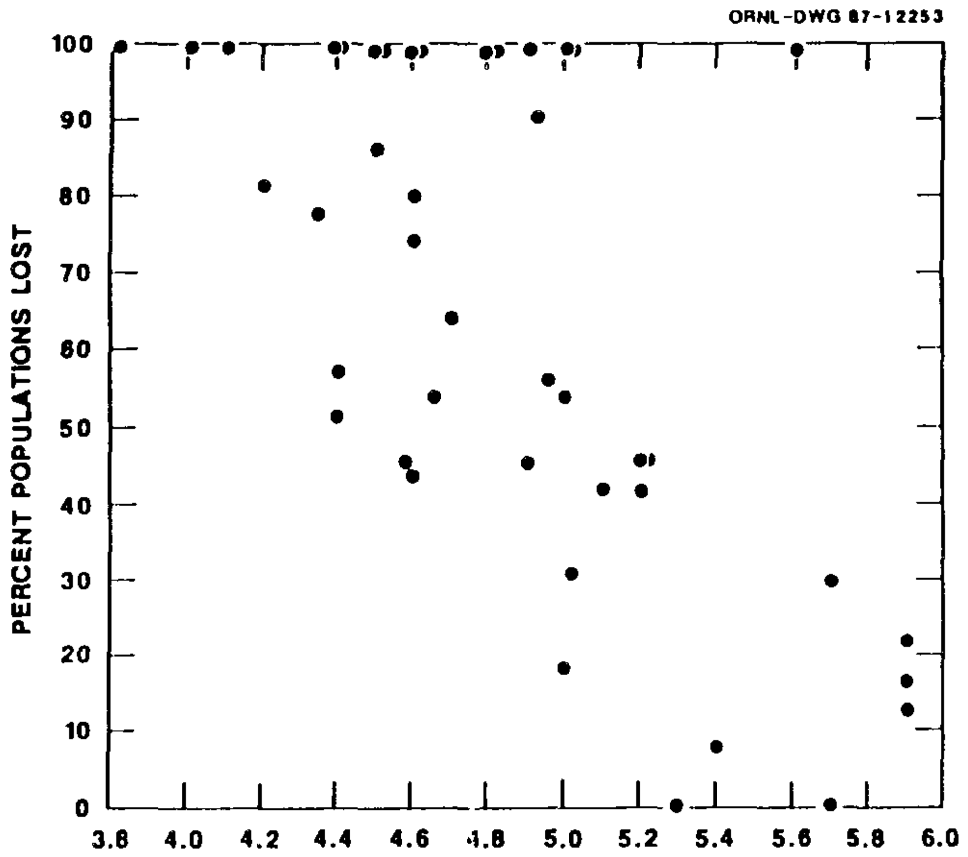

Fig. 3-17. Calculated percentage of the fish species lost from 50 lakes with pH less than 6.0 in the LaCloche Mountains as a function of pH. The lost populations were calculated as a fraction of the expected number of species in a given lake estimated from a regression model of lake area and number of fish species. (Source: Harvey and Lee 1982, as modified by Elwood 1988)

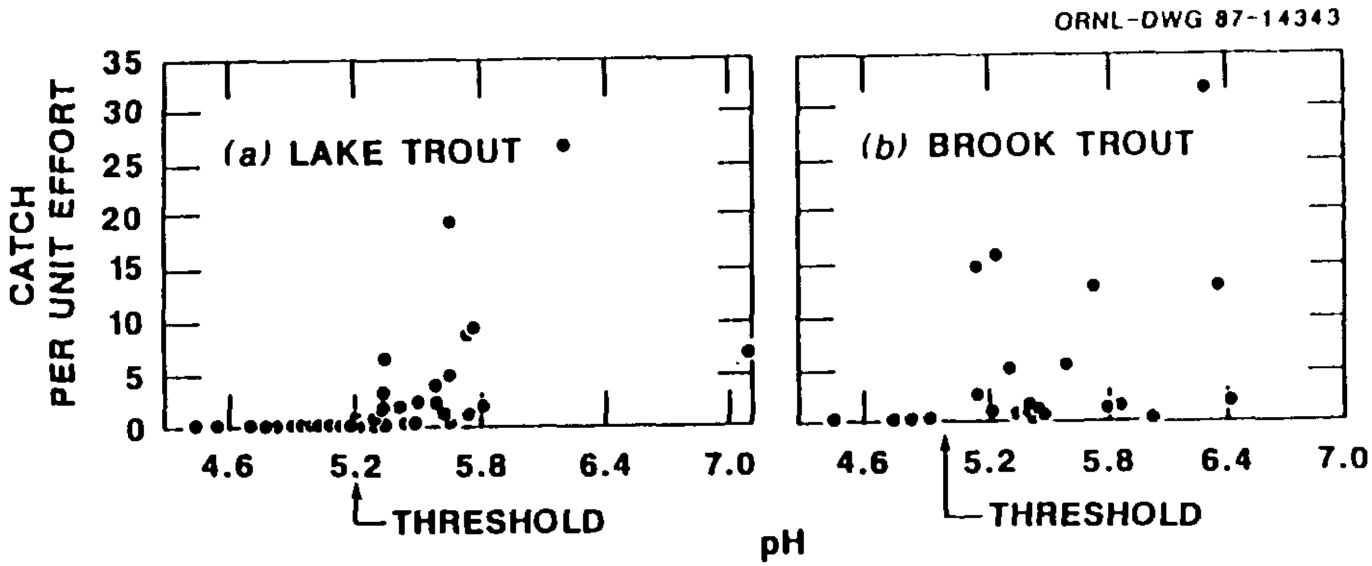

Fig. 3-18. Relationship between catch per unit effort of native lake and brook trout and midlake summer epilimnetic pH in 24 lakes in Ontario known to have contained lake trout in the part. (a) Values for native lake trout (salvelinu namavcush); (b) Values for native or char (Salvelinis fontinalis). The threshold value is the pH below which the catch per unit effort is 0 for these study lakes. (Source: Beggs and Gunn 1986, as modified by Elwood 1988)

areas, including former terrestrial habitat, for existing power plants and disposal areas are tabulated and discussed in Sect. 3.2.2.

Gaseous and particulate combustion products emitted from the stacks of coal-fired plants are eventually deposited on land and water surfaces. The effects of deposition of acidic materials (SO_2, NO_x, O_3, and associated acidic substances) on terrestrial ecosystems are a current area of environmental concern. The decline of forest productivity, especially at higher elevations, changes in species composition of wetlands, and effects of habitat loss and food chain modifications on wildlife have been attributed to present acidic deposition levels in some countries and have been postulated to impact these resources in others. Reductions in crop yields have been related to ozone for some crop species.

It is generally agreed that the most likely explanations for impacts to terrestrial ecosystems involve the interaction of multiple stress factors, both anthropogenic and natural, which combine to reduce the vigor or overall condition of terrestrial ecosystems. Such stress may be reflected in reduced growth and productivity and ultimately, in mortality of sensitive species, which may in turn, result in destabilizing the ecosystem (Hain 1987). Changes in physical and chemical characteristics of plants and soil due to acidic deposition have been documented, and long-term, cumulative effects have been hypothesized but presently are not well understood.

Acids, metals, and gaseous pollutants originating from both local sources and long distance transport are deposited on ecosystems as both wet and dry deposition. Nearby sources tend to produce more dry deposition than wet deposition. Acidic deposition affects terrestrial ecosystems through direct injury or impact to the vegetation occurring from one or more pollutants acting with or without other natural stresses. Indirect effects of acidic deposition on forest ecosystems involve relationships among acidic deposition, soil characteristics, and the physiology of forest organisms. Over the past 25 years, air pollution has been suggested as the cause of at least eight cases of apparent decline in regional forests in the United States (Fig. 3-19) (Cowling 1986). The only forest decline unambiguously known to have been caused by an air pollution component occurred in the San Bernardino Mountain region of the Los Angeles air basin and in the southern Sierra Nevada area. In both cases, ponderosa pine, Jeffrey pine, and other species were shown to have been damaged by ozone, possibly acting with one or more associated oxidants. Definitive conclusions as to the relative importance of stresses for the other six cases cannot be determined with the current level of data and knowledge.

Sensitive genotypes of white pine growing in the eastern United States and southeastern Canada have also shown pollution related (ozone) injury (Kress and Skelly 1982). Red spruce and other species growing at high elevations in the northeastern United States and the southern Appalachian Mountains and pitch pine and shortleaf pine growing in the New Jersey Pine Barrens area have shown declines that are potentially pollution-related. Loblolly, shortleaf, and slash pine in the Southeast, red spruce at both low and high elevations in the Northeast, and sugar maple in the northeastern states and southeast Canada also have shown declines that may be related to pollution. Maple syrup production in an area of southern Quebec between the St. Lawrence River and the U.S. border, a region downwind of both the industrial Midwest and southern Ontario, decreased from 3 million gallons in 1981 to 1.6 million gallons in 1984 and continues to decline (Borie 1987).

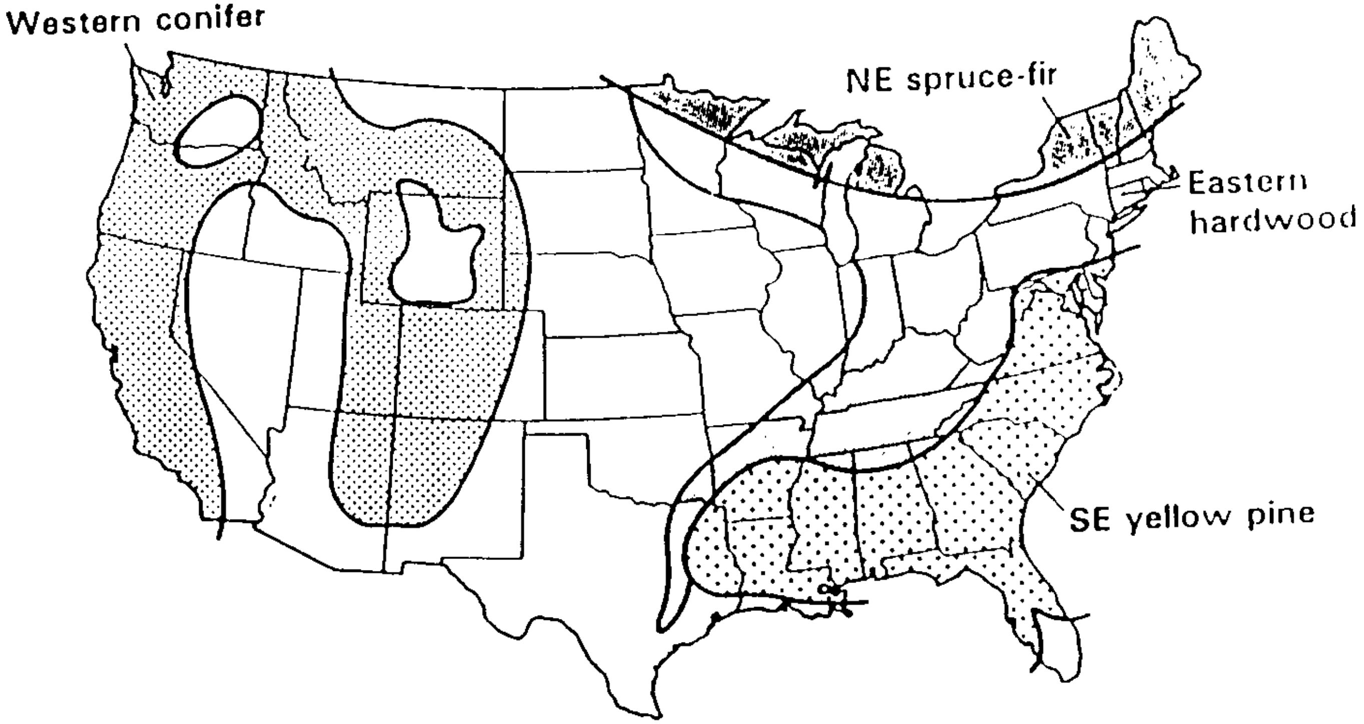

Fig. 3-19. General boundaries of major forest regions potentially impacted by acidic deposition. [Source: Forest Response Program. 1986. Response of forests to atmospheric deposition. National Research Plan for Forest Response Program. A. Carey, A. C. Janetos, and R. L. Blair, national program managers. National Acid Precipitation Assessment Program (USEPA, USDA Forest Service, National Council for Air and Stream Improvement)]

Hypotheses of the detrimental effects of acidic deposition on forests by soil-mediated mechanisms include reduction of the productivity of microorganisms that decompose litter, reduction of mycorrhizal efficiency, leaching of essential nutrients (i.e., potassium, calcium, and magnesium), release of monomeric aluminum into the soil solution, and mobilization of trace metals (NAPAP 1987b). Limited field studies have not conclusively demonstrated any of these effects in U.S. forests, even though such effects have been demonstrated in simulated exposures at greater than ambient concentrations or deposition amounts. Recent research by Shortle and Smith (1988) suggests that soil acidification may result in Al^{3+} competition for Ca^{2+} uptake, leading to growth loss, increased susceptibility to secondary stress factors, and accelerated decline in red spruce.

Effects of acidic deposition on agricultural plants may contribute to reduction in growth and yield and/or interference with reproduction. Direct foliar injury and alteration of physiological processes such as carbon allocation, leaching, and nutrient cycling are proposed mechanisms (Heck et al. 1986). Plant growth, yield, and reproduction are the most important individual plant responses. In a recent assessment, however, NAPAP (1987b) concluded that there are no consistent and measurable effects on crop yield from direct exposure of vegetation to acidity equivalent to ambient levels (pH 3.8 to 5.0) (Fig. 3-20). Highly acidified simulated rain or fog (pH 3.0) does cause some measurable damage to some crops. In contrast, yield reductions ranging from 1% or less for sorghum and corn to about 7% for cotton and soybean to greater than 30% for alfalfa have been attributed to ambient levels of ozone (Heck et al. 1984). Crops exposed to gaseous SO_2 have shown decreases in yield ranging from 8.1% for straw oats to 28.3% for flax grown for seed. On intensively managed soils, the sulfur and nitrogen input from acidic deposition could possibly supplement the required fertilizer amendments (Irving 1987a) and are not thought to represent major negative factors in crop growth through this soil pathway. Increases in plant growth and yield have been reported for low concentration NO_x exposures. This fertilizer effect has been noted for both nitrogen-deficient and nitrogen-sufficient soils (Irving 1987b).

Wetlands that could be most affected by acidic deposition include ecosystems having predominantly inorganic sediments and those that accumulate organic peat. These systems have substantial effects on the chemistry of the water that runs through them to streams and lakes. Wetlands are locally exploited for agricultural purposes (e.g., drained fens and cranberry bogs), forestry, and peat mining (Gorham et al. 1987a). Acidic deposition may enhance the invasion and spread of bog mosses (*Sphagnum* spp.) in areas with waters low in calcium and bicarbonate alkalinity. The accompanying nitrogen may be important as a nutrient. At low to moderate rates of acid deposition, nutrient effects may complicate or even offset the toxic effects expected from acidification. In bogs, this nitrogen probably increases the growth of bog mosses such as *Sphagnum fuscum* and of trees such as black spruce (*Picea mariana*) and tamarack (*Larix americana*) (Gorham et al. 1987b).

Recent data from a Canadian study of boreal wetlands suggest that sulfur emitted from marshes, bogs, and other wetlands may have originated as sulfur emissions from coal-fired power plants and other industrial sources, deposited in the bog by acid rain, and then reemitted considerably later in another form. The role of this recycling process in wetlands in the continuing acidification of the environment even after reduction of the quantity of anthropogenic sulfur emissions may be important (Nriagu et al. 1987), and more study is needed to determine the mechanisms and interactions of wetlands and atmospheric pollutants..

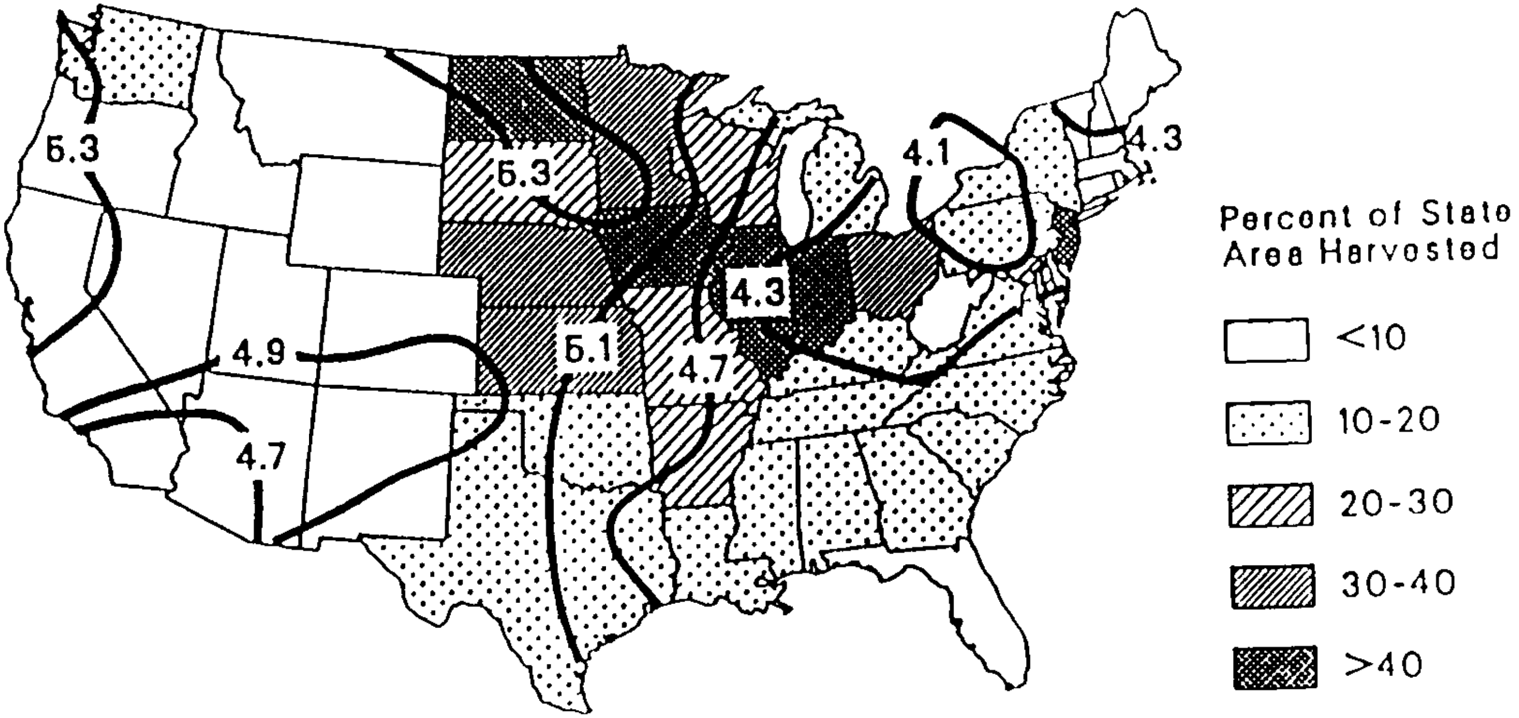

Fig. 3-20. Relationship of cropland area harvested to average pH rain acidity measurements during the growing season. (Source: NAPAP. 1987)

The reduction of food resources, habitat, and shelter and mobilization of toxic metals due to acidic deposition may also affect terrestrial wildlife. Decreased reproductive capability due to the loss of food sources and the accumulation of heavy metals is potentially a hazard for wildlife in an acid-stressed region. The decline of fish and aquatic invertebrates such as mollusks and crustaceans may eliminate potential food sources for many wildlife species including waterfowl and aquatic mammals. The effects of acidic deposition on fish (Sect. 3.2.4) may reduce the ability of lakes and streams to support breeding of some species of birds such as loons and mergansers. Nesting failures may result from the disappearance of fish and acid-sensitive invertebrates or from predator-prey relationship alterations. Changes in the food web structure have important implications for wildlife. For example, duck populations, which feed on aquatic insects, have not shown visible symptoms of decline in the short term; however, populations of insects believed to be acid tolerant show declines as the pH drops below 5.0 (Canadian Wildlife Service 1985). As these aquatic insects become less abundant, fewer food sources are available. Reproductive failure in acid-stressed systems may be linked to the availability of prey during the critical period when newly hatched young require an abundant supply of aquatic insects near the nest.

Potential contamination of wildlife by heavy metals mobilized by acidic deposition is another concern (Canadian Wildlife Service 1985). Wetland inhabitants such as loons, herons, otter, and mink are especially susceptible to the buildup of mercury from fish in their diets. Insect- and fish-feeding birds are also at risk from the accumulation of toxic metals. Insects also accumulate metals from the water and their prey, with the accumulation rates increasing under acid conditions. For birds such as swallows and flycatchers and their young, that feed primarily on emergent insects, metal intake via contaminated prey may be sufficient to cause reproductive damage or mortality of the young. Metal accumulations affecting population densities and species distributions in earthworms and phytophagous arthropods have been reported. Nutrient cycling of litter on the forest floor may be affected by reduced populations of decomposing animals. Loss of moss cover reduces habitats for spiders and insects. Because these organisms serve as prey, the populations of small mammals such as voles and mice may be affected (Klein and Perkins 1987).

Atmospheric pollutants are transported in both directions across the border between the United States and Canada. The Canadian government estimates that 84% of its "prime" agricultural land and 96% of the "prime" forest land in eastern Canada receive greater than 20 kg/ha/yr of wet sulfate deposition. These deposition levels are considered by the Canadian government to be detrimental to various ecosystem components (Lynch-Stewart et al. 1986).

Existing effects of acidic deposition vary regionally. A brief discussion of current regional effects known or potentially due in part to acidic deposition or other air pollutants analysis is provided below for each of the four quadrants.

3.2.4.2.1 Northeast quadrant

Decline in red spruce is occurring at high altitudes in the Adirondack Mountains in New York and the northern Appalachian Mountains of the northeastern states. Mortality is confined largely to middle and upper elevations. Death of twigs and needles occurs on the top of the crown and at the ends of the branches, while in the spring and late winter browning of needle tips is common. The affected trees generally have light green foliage. Examination of radial increment growth shows that an abrupt reduction in growth in all age classes occurred about 20 years ago.

The occurrence of sugar maple forest decline in Quebec was first reported in 1981. Affected trees, including sugar maple, beech, black ash, yellow birch, and several other deciduous species, die back from the tips of the upper branches. The leaves on these branches are dwarfed, pale and yellowish and often develop premature red autumn coloration in midsummer. The decline initially affects mature trees and those on uplands with nutrient-poor and particularly acidic soils. Eventually, younger trees are affected, as are trees growing on poorly drained sites. Estimates of about 15-20% of the land area in the eastern United States (primarily parts of New England, the Upper Midwest, and the South) have these nutrient-poor soils (OTA 1984). Foliar analyses show low concentrations of calcium and magnesium in the leaves of declining trees. The potential role of acidic deposition in sugar maple decline is highly uncertain at this time. Multiple stress factors including drought, insect defoliation, and root disease are known to have had major impacts on these stands during the past decade also.

Deciduous forest stands along portions of the upper Ohio River Valley show a decrease in species composition with increasing chronic exposure to chloride, sulfur, and fluoride. Species richness, evenness, and diversity were depressed in the overstory, subcanopy, and herb layers (McClenahen 1978). Other studies relating proximity of coal-fired power plants to SO_2- and O_3-injury symptoms in vegetation along the Ohio River from Pittsburgh, Pennsylvania, to Louisville, Kentucky, also indicate that the damage severity level decreases as the distance from point source increases (Patel 1987).

Much of the midwestern agricultural area is exposed to high concentrations of O_3. It has been estimated that if O_3 levels were reduced to their natural background levels, the corn yields would be 2% higher, wheat yields 5% higher, soybean yields 13% higher, and peanut yields 24% higher (Heck et al. 1984), assuming that the same cultivars continued to be used. Major agricultural areas of Ohio, Indiana, and Illinois also receive high levels of dry acidic deposition due to their proximity to point sources.

Simultaneous exposures of SO_2 and NO_x produce results that would not be predicted from the individual effects of these two gases. Grasses and cereals are able to recover from the initial, severe suppressions of growth, but in woody species the recovery is limited (Mansfield et al. 1987).

In the eastern United States, more than 60-90% of annual sulfate deposition to bogs is retained as reduced sulfur in these bogs, perhaps serving as a source of future atmospheric sulfur (Urban et al. 1987).

Populations of Bicknell's thrush in damaged high elevation coniferous forests of Camels Hump Mountain, Vermont, show decreases compared with populations in the less affected coniferous forests on Mt. Mansfield, Vermont. This species feeds on conifer buds and on insects indigenous to such forests (Klein and Perkins 1987).

3.2.4.2.2 Southeast quadrant

Ozone levels in the summer months in high altitude forests of the southeastern states are sufficient to cause detectable damage to the foliage of white pine (McBride and Miller 1987). Although a relationship to air pollution has not been proven, loblolly pine, slash pine, and shortleaf pine plantations in the southeast also have had reported growth decline (NAPAP 1987b). Seedling studies with loblolly pine have demonstrated growth effects due to ozone exposure at near ambient levels (McLaughlin et al. 1988). The endangered red cockaded woodpecker, which inhabits southern pine plantations, is further threatened by forest degradation.

Dieback of Fraser fir and red spruce in the Great Smoky Mountains National Park and at Mt. Mitchell, North Carolina, is evident. The damage to Fraser firs has not been linked directly to atmospheric pollutants, however, the dieback may be indirectly affected by pollutants (Hain 1987). About 7% of the red spruce on Mt. Mitchell are dead, with about 50% of the spruce forest at lower altitudes showing symptoms of decline (Conrad 1987). The northern flying squirrel, a unique and extremely rare species in the Southern Appalachians, is threatened by this decline (Kauffman 1987).

3.2.4.2.3 Southwest quadrant

In the Pacific Southwest, oxidants have had major impacts on forests. In zones exposed to 0.08 to 1.2 parts per million (ppm) O_3 as an hourly average, as many as 33% of the ponderosa pine trees died, while only 6.9% died in zones where the hourly average of ozone exposure was less than 0.08 ppm. Approximately 15% of ozone-sensitive trees in the region have been destroyed. Similar effects on Jeffrey pine and epiphytic lichens have also been reported. The ozone sensitivity of white fir and black oak species was moderate, with sugar pine and incense cedar being the most tolerant. The overall effect has been a change in species composition of the forest (McBride and Miller 1987). Elevated levels of SO_2 and sulfate acidic deposition are not significant in this area, and the role of NO_x and related compounds in this region is not clear. Approximately 30 and 35% of the annual SO_2 and NO_x emissions, respectively, in this quadrant come from fossil-fueled facilities (see Sect. 4.1)

Decline in coastal sage shrub (*Salvia*, *Eriogonum*, and *Encelia*) cover over its range from San Francisco to Baja California has been attributed to the increasing mean annual concentrations of oxidants (Westman 1979).

3.2.4.2.4 Northwest quadrant

The Douglas-fir region of Washington and Oregon has large areas of coniferous tree plantations. It is unlikely that significant detrimental effects of acidic deposition would affect the soils of these plantations because the plantations are situated on high-quality sites and are located in areas of low acidic deposition (Kulp 1987). The potential for increased acidic deposition in this region exists if any new coal-fired plants are built in the western states. Increases in NO_x emissions, a precursor to formation of O_3, would be the major concern because it is currently the major pollutant of concern. Approximately 40% of the 1985 annual SO_2 emissions and 33% of the NO_x emissions in this quadrant originated from fossil-fueled facilities (see Sect. 4.1).

3.2.5 Socioeconomics

3.2.5.1 Coal cleaning

The effects of coal cleaning operations on air and water quality—as well as the need for and effects of solid waste disposal—can affect land use and people in proximity to the plants, as well as some distance away. Currently, coal cleaning is undertaken mostly for Appalachian region coal. Coal may be cleaned at either the minehead or at the site of use. Currently, chemical cleaning processes are much more expensive and used much less frequently than mechanical cleaning processes. With regard to workforce, an average of 440 people are required to build a coal beneficiation plant that processes about 2.9 million tons/yr of coal. To operate and maintain such plants, personnel requirements average 82 workers. Such a plant requires about 240 acres of land and has an expected lifespan of 20 years. (DOE 1981a,b; Robeck et al. 1980; Systems Consultants, Inc. 1981).

3.2.5.2 Coal-fired power plants

Socioeconomic effects of coal-fired power plants occur both locally (e.g., through direct use of land for power plant complexes; see Sect. 3.2.2.2) and across local, regional, state, or natural boundaries (e.g., due to air emissions and water requirements). Socioeconomic impacts of coal-fired power plants are particularly apparent in the NE quadrant of the country, where existing fossil-fueled electric utility plants are concentrated (see Fig. 3-1). Many of the older plants that would be candidates for retrofitting or repowering are sited in urban areas. In contrast, newer utility plants are located in more rural areas (Robeck et al. 1980).

The workforce to operate and maintain 500-MW conventional steam electric power plants averages approximately 155 for western plants using subbituminous coal and 160 for eastern plants using eastern bituminous coal. These figures are based on the assumption that there is on-site waste disposal and water treatment. The life expectancy of coal-fired electric utility plants is approximately 30 years in the absence of life extension measures (DOE 1981b).

3.2.5.3 Coal-related waste disposal

Land requirements for disposal of wastes from coal cleaning and coal-fired power plants are discussed in Sect. 3.2.2. Surface runoff and potential groundwater contamination resulting from disposal sites may affect people and resources (e.g., land values, land uses, development potential, water quality) in close proximity to, as well as some distance from, disposal sites. The following is based on a recent EPA report (EPA 1988a).

The sizes of populations surrounding coal combustion waste disposal sites are given in Table 3-6. An average of about 360 people (ranging from 0 to about 3,700) live within a 1-km distance of these waste disposal sites. However, no one lives within 1 km at 71% of these waste disposal sites. Within 3 km, an average of about 3,700 reside (ranging from 0 to about 35,600) and within 5 km of waste disposal sites, an average of about 12,100 people reside (ranging from 0 to about 123,000). About 34% of the waste disposal sites have drinking water systems located within a 5-km radius in the downgradient plumes of these waste-water systems; about 44% of these systems serve more than 5,000 people, and about 56% serve fewer than 5,000 people.

Coal-fired power plant waste disposal occurs both on and off the plant site. Financial and operational responsibility for managing waste disposal sites may vary according to whether locations are on or off the site; utilities may contract with other companies to manage and dispose of wastes. Further, off-site disposal requires transportation of wastes. Because of the expense of transporting wastes, particularly wet slurries, it is expected that off-site disposal sites are located relatively close to generating facilities.

Costs for waste disposal varies significantly according to power plant size, its rate of operation, the type of coal used, the use of FGD equipment, and site preparation needs. Closure of waste facilities and postclosure activities also are costly.

Table 3-6. Populations surrounding coal combustion waste disposal sites

	Percentage of sites		
Population km	within 1 km	within 3 km	within 5
0	71	32	10
1-500	12	19	10
501-2,000	10	17	21
2,001-10,000	7	20	31
10,001-25,000	0	9	15
25,000+	0	3	14

Source: EPA 1988a.

4. ENVIRONMENTAL CONSEQUENCES

4.1 ENVIRONMENTAL CHARACTERISTICS OF CLEAN COAL TECHNOLOGIES

4.1.1 Introduction

The purpose of this section is to present a summary of the changes in national emissions relative to the no-action alternative for four environmental parameters of concern (SO_2, NO_x, CO_2 and solid waste) resulting from the maximum commercialization by the year 2010 of 22 generic clean coal technologies. The extent of future commercialization of each of the 22 technologies will depend on its economic competitiveness and technical suitability to retrofit or repower existing facilities or to its use in new facilities. This PEIS does not attempt to predict the economic competitiveness of each of the technologies considered. Further, no attempt has been made to develop scenarios of different mixes of clean coal technologies because it is not known what technologies will be selected for demonstration, and there is no basis for defining a mix of technologies to be commercialized. Rather, maximum commercialization within each applicable market is assumed in order that projected changes in the environmental parameters of interest will not be exceeded by actual changes.

The change in national emissions is based on the extent of the applicable market for the clean coal technology and the environmental performance characteristics of the technologies. The product of these two factors is then measured against a projected baseline of total 2010 national emissions for SO_2, NO_x, CO_2, and solid waste that does not include any clean coal technology (no-action alternative). The comparison, quantified as a percentage change from the projected emissions baseline, determines the impact of each of the 22 generic clean coal technologies.

The information presented in this section and Appendix B is used in Sects. 4.2 and 4.3 as a basis for evaluating the environmental consequences of the no-action and the proposed action alternatives. The information here is based to a large extent on estimates from a computer model, the Regional Emission Database and Evaluation System (REDES), designed by Argonne National Laboratory.

4.1.2 Methodology

The basic methodology for the quantitative portion of this analysis is summarized as follows:

1. Establish a baseline for the environmental parameters of concern (SO_2, NO_x, CO_2, and solid waste) assuming the use of conventional technologies in existing and new sources in the year 2010. (The resulting baseline values represent the no-action alternative.)

2. Calculate the total national emissions for the year 2010 resulting from the maximum commercialization in the applicable market for the generic version of each of the clean coal technologies separately. This calculation uses the environmental performance factors and the applicable market for each technology discussed in Sect. 2.2 and summarized in Appendix B.

3. Calculate the differentials between the emission baseline and the national emissions resulting from the maximum commercialization of the clean coal technology in the applicable market. The resultant change represents a maximum environmental impact of the technology. These national level changes are discussed for each of the 22 technologies in Sect. 4.1.5.

The environmental impacts of the clean coal technologies described later in this section are based on the change in the total amount of each pollutant projected to be emitted in the year 2010. This projection of emissions is based on the environmental analysis of the National Energy Policy Plan-V (NEPP-V) prepared for DOE (Placet et al. 1986). The economic assumptions and energy values used in developing these environmental projections are consistent with NEPP-V reference case projections (DOE 1985c). The emission factors and emission projections for three aggregate sectors for each state are contained in REDES (Sect. 1). The three aggregate sectors are:

- electric utilities;
- industrial boilers; and
- other (sum of residential, commercial, transportation, and industrial processes).

The environmental parameters contained in REDES are:

- sulfur dioxide (SO_2);
- nitrogen oxides (NO_x);
- total suspended particulates (TSP);
- collected fly and bottom ash;
- sulfur byproducts (S.B.P.);
- other nonhazardous wastes; and
- water consumption.

Collected fly and bottom ash, sulfur byproducts, and other nonhazardous wastes have been combined into a solid waste category. TSP was eliminated from the analysis because increased control of TSP to meet new source performance standards would result in little change from the baseline levels. Qualitative discussion of the impact on water resources is continued in Sect. 4.3.3.

A summary of the total emissions forecast for the year 2010 for the nation and the four quadrants is shown in Table 4-1. This emissions forecast includes all sources and is the emissions baseline against which the national and regional level changes in the environmental parameters of concern resulting from the commercialization of clean coal technologies are compared.

Table 4-1. **Baseline national and regional emissions forecast for the year 2010 (REDES)**

	(10^6 tons/yr)			
Quadrant	SO_2	NO_x	CO_2	Total solid waste
NE	12.6	10.0	3145	249
SE	6.2	5.4	1735	105
NW	3.4	3.9	407	17
SW	5.9	8.4	1813	166
US total	28.1	27.7	7100	537

4.1.3 Applicable Market

A critical aspect in projecting the environmental impacts of the clean coal technologies is the determination of the maximum market to which each technology can be implemented. This applicable market is characterized by a variety of engineering and other technical parameters that are combined with the REDES forecast of energy use and emissions to construct the emissions baseline for the technology. The REDES is a computer system that is utilized to define the applicable market and to compare the environmental characteristics of widespread commercialization of each of the clean coal technologies. The following is a brief summary of the methodology used in REDES to determine the applicable market.

The applicable market is defined using five broad descriptors that include: use sector (industrial, utility); boiler size; fuel type; sulfur content of fuels; and, as applicable, firing type. The descriptors for utility and industrial sectors are shown in Tables 4-2 and 4-3, respectively. Once the market is defined using the descriptors, the extent to which the technology is applied to the market is then defined. The description of the applicable markets for the clean coal technologies is summarized in Sect. 4.1.5 and in Appendix B.

4.1.4 Methodologies for Forecasting Emissions

REDES computes the cumulative effect of each technology introduced over a 15-year period, beginning in 1995 and ending in 2010. It quantifies the changes in emissions that will occur from the technology's introduction in 1995 until the target year 2010. The model produces results in 5-year increments. Plants falling in the intermediate years are allocated to the next higher terminal year (e.g., a plant coming online in 1998 is considered new in 2000). Since different technologies are applicable to different vintages of plants, REDES considers the ages of the plants over the

Table 4-2. Descriptor categories for utilities

Descriptor	Category	Definition
Boiler size	Small	<100 MW
	Medium	100-400 MW
	Large	>400 MW
Coal sulfur content	Low	<1.5%
	Medium	1.5-3.0%
	High	>3.0%
Firing types	Single wall	
	Opposed wall	
	Tangential	
	Spreader stoker	
	Cyclone	

Table 4-3. Descriptor categories for industry

Descriptor	Category	Definition
Boiler size	Small	<100 x 10^6 Btu/h
	Medium	100-250 x 10^6 Btu/h
	Large	>250 x 10^6 Btu/h
Coal sulfur content	Low	<1.5%
	Medium	1.5-3.0%
	High	>3.0%
Firing type	Not applicable	

1995-2010 time horizon. In 1995, all plants of the appropriate age for retrofit (5-35 years old) or repowering (30-35 years old) are candidates for clean coal technologies. In subsequent years (2000, 2005, and 2010), only plants that have just become the age for retrofit or repowering, 5 years and 30 years old exactly, are considered. By the year 2000, it is assumed that all candidate plants will have been modified.

In cases where the clean coal technology is used to repower existing plants, emissions are calculated from each of three sources of power generation (i.e., remaining old, repowered, and new units) and then added together. For generation from remaining old units that are not repowered, the emissions are based on the existing average emission rate in the baseline. For generation from repowered units, the emission rates are the baseline unregulated emission rates multiplied by the removal efficiencies of the clean coal technologies (or the assumed emission rates in the clean coal technology specification). In addition, emissions are adjusted to reflect any change in the efficiency of the technology. For generation from new units, two possibilities exist. If the clean coal technology is applicable to greenfield plants, REDES applies the same emission rates as those calculated for repowered units. If the technology is not applicable to new units, the emission rates are based on the average rate for new units in that region.

For greenfield plants and retrofit applications, only the emission characteristics of the technologies described in Sect. 2.2 are used (i.e., the emissions are not adjusted to reflect changes in efficiencies). For the new fuel form and coal preparation technologies, the emissions from both the fuel preparation facility and the fuel use facility are included. These emissions were adjusted to account for the thermal efficiency of the fuel production facility. REDES calculates 2010 emissions based on unregulated emissions multiplied by the removal efficiencies for each applied clean coal technology. REDES also assumes that the proposed technology will replace the current controls, if any, so that the emission rate is based on the new technology alone. For example, the emissions forecasted for the spray dryer with lime, which controls both SO_2 and NO_x, are based on this technology alone. On the other hand, the forecast for wet limestone FGD does not include NO_x control, so the existing NO_x control is applied.

The calculation of emissions from greenfield and retrofit plants follows one of two methodologies: (1) an unregulated emission rate is calculated and multiplied by the clean coal technology removal efficiency or (2) the clean coal technology emission rate specified is multiplied by the energy-use value (in Btus) found in the baseline. Where the technology is not applicable for controlling a certain type of emission (i.e., NO_x in an FGD unit), the 2010 emission is set to equal the 2010 baseline emission.

The percentage change in national emissions is then calculated based on the difference between the baseline emissions and the emissions from the clean coal technology as it is applied to the applicable market divided by the baseline national emissions forcast for the year 2010 as shown in Table 4-1.

4.1.5 Environmental Characteristics

4.1.5.1 Introduction

This section presents a summary of the percentage change in national emissions relative to the no-action alternative for the four pollutants of concern for each of the 22 generic clean coal technologies available for consideration in the CCTDP. This comparative summary is relative to the total national emissions, not the total emissions from the applicable market. The analysis demonstrates the potential change in national emissions as the technologies are applied to 100% of the applicable market.

The results depicted in this section are based on a number of factors which, if changed, could significantly alter the results. The long-range energy projections used in the PEIS are consistent with NEPP-V. Because projections cannot fully represent important qualitative factors such as political events, economic performance, market behavior, and policy changes that influence energy markets, the projections incorporate a considerable amount of judgment and are inherently uncertain. The projections consider a national mix of energy supply components including liquids, gas, nuclear, renewables, and others in addition to coal. Coal is the only energy alternative considered in the PEIS. The coal-use projections are used in the PEIS as a point of departure to understand possible environmental futures associated with the proposed action. Changes in the national energy mix or the efficiency in the use of energy in 2010 would change the 2010 emission levels of the environmental parameters of concern. While other projections of national energy mix could have been selected, the use of NEPP-V projections provides a consistent basis for this analysis. The widespread commercialization of clean coal technologies assumed in the PEIS enables the analysis of environmental futures that will not be exceeded by actual events. While clean coal technologies may achieve higher market shares in some future markets, the potential increase in the use of coal could be offset by the higher efficiencies of the technologies (i.e., more energy output per Btu of coal input). Other factors include:

- No change in environmental regulations between 1989 and 2010,
- Environmental characteristics of the clean coal technologies are based on public available estimates of generic technologies. (Project-specific technologies represented by the generic technologies may differ significantly in emission characteristics),
- Changes in calculation conventions could alter results, and
- Each technology was analyzed independently and is assumed to be the sole technology as applied to 100% of the applicable market.

The remainder of this section presents a discussion of the applicable market and the potential change in national emissions in 2010 relative to the no-action alternative for repowering and retrofit technologies.

4.1.5.2 Repowering technologies

The repowering technologies considered in this PEIS are the atmospheric circulating fluidized bed, pressurized fluidized bed, integrated gasifier combined cycle, and the gasifier fuel cell.

Repowering technologies are those which, by replacing a major portion of an existing facility, not only achieve a significant emissions reduction, but also may provide for the use of a new fuel form, increase facility capacity, extend facility life, and/or improve system efficiency. For the purpose of this analysis, the available applicable market for repowering technologies may be limited by the demand for new electric power generation (i.e., plants will not be repowered unless additional electricity is needed). When evaluating the impact of repowering technologies, REDES computes the increase in electricity available from the repowered units. This potential increase in electricity is compared with the new electricity demand on a region-by-region basis. If the potential increase from repowered units is greater than the new demand, only a portion of the old units is considered to be repowered, replacing the generation from all new units. If the potential increase in electricity output from repowered units is less than new demand, all candidate units in the applicable market are considered to be repowered. Only plants older than 30 years are assumed to be candidates for repowering.

The capacity increment (i.e., the percentage increase in generation capacity that can be achieved when repowering an existing power plant) has a significant impact on the applicable market for a repowering technology. The four technologies considered to be repowering technologies in this PEIS have the following capacity increments:

Circulating Atmospheric Fluidized-Bed (CAFB)	15% (DOE 1987a)
Pressurized Fluidized-Bed (PFB)	40% (DOE 1987a)
Integrated Gasifier Combined Cycle (IGCC)	130% (DOE 1987a)
Coal Gasification Fuel Cell (FC)	430% (DOE 1985d)

The structure of the applicable market for each of the four major repowering technologies is shown in Table 4-4. As can be seen, the technologies with higher capacity increment factors (IGCC and FC) actually repower less of the 1985 capacity that still exists in 2010, reflecting the fact that capacity cannot exceed demand based on a region-by-region analysis. Table 4-5 shows the environmental characteristics for the repowering technologies evaluated in this PEIS, using the emissions characteristics of the technologies and the applicable market defined in Table 4-4.

Table 4-4. Structure of the applicable market for repowering technologies

Existing/new generation mix in 2010 (GWh x 10^3)	CAFB	PFB	IGCC	FC
1985 generation repowered	1,064	973	676	426
1985 generation not repowered but still on-line in 2010	21	112	409	659
New 2010 generation satisfied by repowered plants	150	345	666	1,042
New greenfield generation	1,270	1,075	754	378
Total	2,505	2,505	2,505	2,505

Table 4-5. Environmental characteristics for the repowering technologies

	Applicable market	Change in national emissions (%)			
	(quads)	SO_2	NO_x	CO_2	Solid waste
CAFB	27.4	-44	-17	-5	+8
PFB	27.4	-48	-17	-8	-4
IGCC	27.4	-37	-17	-6	-5
Fuel cell	27.4	-29	-14	-12	-16

The CAFB affects the largest market share and results in a significant change in 2010 national SO_2 emissions of the repowering technologies. The PFB has slightly better environmental performance and a reduced heat rate as compared to the CAFB, thus the reduction expected in SO_2 is slightly more even though the PFB does not repower 91,000 GWh of generation that is repowered by CAFB. The reduction in CO_2 and solid waste is directly attributable to the improved PFB heat rate.

Of the repowering technologies, the IGCC and fuel cells have the best environmental performance; however, their impact on 2010 national emissions is somewhat diminished because of the large capacity increment associated with these technologies. Even with the penalty of smaller market shares associated with the capacity increment, the analysis shows that IGCC and fuel cell technologies do lead to significant changes in national emissions relative to the no-action alternative.

The larger percentage change in 2010 national emissions of CO_2 and solid waste associated with the gasifier-fuel cell technology is directly related to the higher efficiency of this clean coal technology. The capacity increment used in the PEIS analysis effectively bounds the minimum market share for each of the technologies. It should be recognized that the IGCC and fuel cell technologies could be deployed in smaller modules and thus, may capture more of the 1985 capacity that still exists in 2010 than is shown in the analysis. However, there is no basis to analyze the 2010 demand for electricity on a plant-by-plant basis that would be necessary to determine the deployment of modular IGCC and fuel cell plants. The fuel cell and gas turbine could be fueled by the new fuel forms, such as methanol, produced from an indirect liquefaction process. While all possible combinations of fuel and electric power generation technologies could not be analyzed, it is felt that the IGCC and gasifier-fuel cell are representative of these technologies.

The emissions effect of less than 100% availability of the applicable market to repowering technologies depends on the extent to which the demand for new power production already limits the penetration of these technologies. For the fluidized bed technologies, the capacity increment is relatively small; hence, these technologies are not limited by the demand for new power production. Any reduction in the availability of the applicable market, below 75% of the total market, will result in roughly linear reduction in the size of the emissions reductions. For the gasifier technologies, significant expansion of capacity occurs when the technologies are applied.

The low demand for new electric generating capacity, particularly in the initial years, naturally limits the application of these technologies. Lower availability of plants in the applicable market for repowering does not appreciably change the size of the emissions effect until the utilization falls below 50% for IGCC and 25% for the fuel cell. Of course, the efficiency gains from all of these repowering technologies benefits new plants as well. The emissions reductions of these efficiency improvements are also roughly linear when the application of these technologies is limited in greenfield applications. This impact is small relative to the impact of the direct removal of SO_2 from older, unregulated, repowerable plants.

4.1.5.3 Retrofit technologies

Retrofit technologies are those which reduce emissions of SO_2 and/or NO_x by modifying existing facilities or their present feedstock or by utilizing new fuel forms.

The retrofit technologies are divided into three classes: (1) those technologies that, when applied singly, meet both SO_2 and NO_x NSPS and thus can be retrofitted on existing plants and used for new plants; (2) those technologies that, when applied singly, will control emissions of either SO_2 or NO_x to NSPS levels and thus could be retrofitted on existing plants where SO_2 or NO_x controls are required. However, the technologies could not be applied singly to new plants to meet full NSPS requirements; and (3) those technologies which chemically or physicially alter the state of coal to produce a new fuel form with the objective of mitigating emissions of SO_2 and/or NO_x. It should be understood that many of the technologies (e.g., NO_x controls) could be applied with FGD technologies to greenfield plants. However, this PEIS does not consider combinations of technologies,because there is no basis for defining a manageable list of such combinations. The remainder of this section provides a discussion of the environmental characteristics of the three classes of retrofit technologies.

Retrofit—NSPS capable

The clean coal technologies in this class which have been analyzed include: advanced slagging combustor, copper oxide flue gas cleanup, and dual-alkali scrubber. The applicable market for all of these technologies is very large and includes the slate of existing unregulated plants still in service in 2010 and all new plants. A maximum market of almost 30 quads has been defined for most of the technologies, the exceptions being the dual-alkali that is not applied to plants burning low sulfur coals and the advanced FGD with salable byproduct that is not applied to small boilers. Table 4-6 summarizes the emissions changes as measured relative to the total national emissions of the no-action alternative in 2010.

Table 4-6. **Environmental characteristics for retrofit—NSPS capable technologies**

	Applicable market (quads)	Change in national emissions (%)			
		SO_2	NO_x	CO_2	Solid waste
Advanced slagging combustor	29.5	-45	-18	<-1	+17
Copper oxide process	29.5	-45	-33	0	-22
Dual-alkali scrubber	18.5	-30	-11	0	-5

As can be seen, these technologies can provide comparable environmental performance and reduce SO_2 emissions 30-45%, depending on the applicable market share. All combine SO_2 and NO_x emissions control to some extent. The advanced slagging combustor increases the amount of solid waste generated as a result of controlling SO_2. It should be noted that these wastes for the most part are dry and do not present the sludge disposal problems associated with the no-action alternative. The results presented above represent the applications of the technology to 100% of the market. Application to any other market share would result in a reduction in emissions directly proportional to that market share.

Retrofit—partial NSPS capable

The clean coal technologies in this class that have been analyzed include: advanced FGD with salable byproduct, spray dryer with lime, limestone injection multistage burner (LIMB), sorbent injection, selective catalytic reduction, low NO_x burner and reburning. Each technology is applied to essentially the same market consisting of 1985 unregulated sources that exist in 2010. This amounts to approximately 12.9 quads of energy use. Table 4-7 shows the results of the analysis.

Table 4-7. **Environmental characteristics of retrofit—partial NSPS capable technologies**

	Applicable market	Change in national emissions (%)			
	(quads)	SO_2	NO_x	CO_2	Solid waste
Advanced FGD with salable byproduct	12.5	-48	0	0	+9
Spray dryer with lime	12.9	-45	-5	<1	+8
LIMB	12.9	-30	-11	0	+8
Sorbent injection	12.9	-38	0	0	+8
Gas reburning	12.9	-10	-11	-2	-2
Selective catalytic reduction	12.2	0	-15	0	0
Low NO_x burner	12.6	0	-11	0	0

The advanced FGD with salable byproduct and spray dryer with lime have the largest impact on the reduction of SO_2 (48% and 45%, respectively); however, solid waste is increased approximately 8-9% for both technologies. The LIMB and sorbent injection can be used to reduce SO_2 emissions in 2010 approximately 30-38%. LIMB can reduce NO_x emissions approximately 11% with respect to the national emissions in the no-action alternative; however, solid waste is expected to increase by approximately 8%. Reburning, selective catalytic reduction, and low NO_x burners are used primarily to reduce NO_x. As can be seen above, an 11-15% reduction in NO_x emissions can be achieved if 100% of the unregulated plants in 1985 are retrofitted with these technologies. As discussed in the previous section, if these technologies were applied to any other market share, the reduction would be proportional to that share.

Retrofit-new fuel forms

The clean coal technologies in this class consist of those that chemically or physically alter the form of coal before its use as a fuel. These include advanced physical and chemical coal cleaning, mild gasification, direct liquefaction, indirect liquefaction, coal/oil coprocessing, and coal/water mixtures. Each of these technologies produces a product which, for the purpose of this PEIS, is used in a narrowly defined market. The analysis considered the emissions produced from the new fuel form production facility and its combustion in a boiler. Coal switching was not considered as an option for analysis in this PEIS. Therefore, for the coal cleaning technologies, two cases were considered: cleaning high sulfur coals and using the cleaned high sulfur coal only in the high sulfur coal market and cleaning medium sulfur coals and using the cleaned medium sulfur coals only in the medium sulfur coal market. Since ultrafine and advanced physical technologies reduce sulfur content by less than 50%, it is assumed to be used only in existing utility and industrial boilers. Chemical cleaning can reduce sulfur content by 90% or more; therefore, it can be used in greenfield boilers that would use high sulfur coal. Table 4-8 presents a summary of the emissions changes as measured relative to the total national emissions of the no-action alternative in 2010 for high sulfur coal cleaning.

Table 4-8. Changes in national emissions for coal cleaning technologies using high sulfur coal

	Applicable market	Change in National Emissions (%)			
	(quads)	SO_2	NO_x	CO_2	Solid waste
Ultrafine	0.4	<-1	0	0	+1
Advanced physical	0.4	<-1	0	0	<1
Advanced chemical	8.0	-4	0	0	0

The rationale for defining the market for cleaned medium sulfur coal is the same as that used for defining the market for cleaned high sulfur coal. The changes in national emissions with these technologies are shown in Table 4-9.

Table 4-9. Changes in national emissions for coal cleaning technologies using medium sulfur coal

	Applicable market	Change in National Emissions (%)			
	(quads)	SO_2	NO_x	CO_2	Solid waste
Ultrafine	4.5	-16	0	0	+12
Advanced physical	4.5	-3	0	0	+10
Advanced chemical	9.9	-26	0	0	+23

Mild gasification, direct and indirect liquefaction, and coal/oil coprocessing produce a fuel which, at a minimum, could be used to displace residual oil in utility and industrial boilers. For the PEIS analysis, the products from these technologies were assumed to replace only high, medium, and low sulfur residual oil. Table 4-10 presents a summary of the emissions changes as measured relative to the total national emissions of the no-action alternative in 2010.

Table 4-10. Changes in national emissions for new fuel form technologies that could displace residual oil in utility and industrial boilers

	Applicable market	Change in National Emissions (%)			
	(quads)	SO_2	NO_x	CO_2	Solid waste
Mild gasification	4.6	-5	-2	+1	+14
Direct liquefaction	4.6	-9	-3	+1	+9
Indirect liquefaction	4.6	-5	+4	+1	+4
Coal/oil coprocessing	4.6	-4	<+1	<+1	+3
Coal/water mixtures	1.1	-2	0	0	+4

Products from these technologies could replace coal in boilers, fuel gas turbines, direct engines, other heat engines, and fuel cells used as refining and chemical feedstocks and other uses. An exhaustive analysis of all possible uses of the products from these technologies would not be possible for there is no firm basis to define the market. As expected, SO_2 decreased and solid waste increased. The slight increase in CO_2 is based on the fact that residual oil combustion produces less CO_2 than combustion of coal-derived fuels.

The coal/water mixture technology assumes the use of ultrafine coal preparation technology. The coal/water mixture fuel is used to replace medium and high sulfur residual oil in utility and industrial boilers. SO_2 emissions would increase if coal/water mixtures were used in boilers fired with low sulfur residual oil. The applicable market for coal/water mixtures was calculated to be 1.1 quads. National emissions changes as measured relative to total national emissions of the no-action alternative in 2010 are -2% for SO_2 and +4% for solid waste.

Appendix B contains a more detailed description of environmental emissions for each of the 22 technologies analyzed in this PEIS. This appendix includes information on the identification of the applicable market, the applicable market characteristics, applicable market baseline emissions, applicable market emissions with clean coal technologies, percentage change in applicable market emissions, percentage change in total national emissions, and percentage change in the emissions in the four quadrants. The environmental impacts associated with clean coal technologies are discussed in Sect. 4.3.

4.2 ENVIRONMENTAL IMPACTS OF THE NO-ACTION ALTERNATIVE

The no-action alternative assumes that existing regulations would continue to be in effect in 2010. The alternative assumes that many of the presently existing coal-fired plants would be retired or refurbished and all new plants that come into operation would be equipped with FGD systems to meet NSPS.

4.2.1 Impacts on Air Resources

4.2.1.1 Air quality

This section summarizes potential air quality impacts of energy development under no action in the year 2010, based on regional summaries of key data obtained from the REED (Boyd et al. 1988b). Beyond the year 2010, the uncertainties involving retirement of pre-NSPS plants and their replacement by regulated new facilities make projections of "no action" after 2010 highly speculative. Projected emissions in the year 2010 are compared to 1985 baseline emissions for both the sum of all market sectors (utility, industrial, commercial/residential, and transportation) and fossil-fueled utilities alone. Comparisons are presented for the United States as a whole and each of the four regional quadrants. Emissions from the REED data (Boyd et al. 1988b) are used since they are the basis for discussing impacts to air resources from commercialization of clean coal technologies in Sect. 4.3.1. Assumptions by REED include a doubling of coal use by utilities between 1980 and 2010, a plant retirement age of 50 years, a continuation of current capacity factors for the older plants, and no change in air pollution regulations (i.e., NSPS are met by new power plants).

Future energy development in the United States without the CCTDP would have impacts on air resources. For the three criteria air pollutants of principal interest for coal combustion [sulfur dioxide (SO_2), nitrogen oxides (NO_x), and total suspended particulates (TSP)], total emissions (the sum of all market sectors) under the no-action alternative are projected to increase between 1985 and 2010. Table 4-11 compares total emissions for these pollutants in the United States under the no-action alternative in 2010 with 1985 baseline emissions. Total national emissions of SO_2 and NO_x are projected to increase by about 20 and 60%, respectively, between 1985 and 2010. Table 4-12 shows similar comparisons for coal-fired utility boilers and industrial boilers. For this latter case, national emissions are anticipated to change very little for SO_2 and increase by about 30% for NO_x. Coal-fired electric utility generating facilities are the principal sources for SO_2 emissions. Industrial boilers, process heaters, nonferrous smelters, and other industrial processes are other significant sources of SO_2, for which emissions are expected to rise (Fig. 4-1).

Table 4-11 includes a comparison by quadrant of projected emissions in 2010 with 1985 baseline emissions. The comparison reveals that percentage increases in SO_2 emissions are expected to be largest in the NW quadrant and second largest in the SW quadrant. The projected changes in the NE and SE quadrants are relatively small. Table 4-12 depicts similar comparisons by quadrant for coal-fired utility boilers and industrial boilers. SO_2 emissions are projected to drop slightly in the NE quadrant, change very little in the SE quadrant, and increase moderately in the NS and SW quadrants.

Table 4-11. Baseline and projected annual air pollutant emissions for all market sectors by quadrants

Pollutant	Quadrant	*1985 baseline* emissions (10^6 tons/yr)	*2010 no-action* emissions (10^6 tons/yr)	Change in *emissions,* 1985-2010 (%)
SO_2	Northeast	13.7	12.6	-8
	Southeast	5.7	6.2	9
	Southwest	3.5	5.9	69
	Northwest	1.0	3.4	240
	National[a]	23.9	28.1	18
NO_x	Northeast	8.2	10.0	22
	Southeast	3.4	5.4	59
	Southwest	4.2	8.4	100
	Northwest	1.2	3.9	225
	National[a]	17.0	27.7	63

[a] These values differ slightly from those shown in Fig. 4-1 and 4-2 because of differences in projecting emissions for 2010.

Source: Staff computations based on unpublished information from the REDES.

Table 4-12. Baseline and projected annual air pollutant emissions for coal-fired utilities by quadrants

Pollutant	Quadrant	1985 Baseline emissions (10^6 tons/yr)	2010 No-action emissions (10^6 tons/yr)	Change in emissions, 1985-2010 (%)
SO_2	Northeast	10.5	9.6	-9
	Southeast	4.1	4.1	0
	Southwest	1.9	2.5	32
	Northwest	0.4	0.5	25
	National	16.9	16.7	-1
NO_x	Northeast	3.6	3.9	8
	Southeast	1.5	2.0	33
	Southwest	1.0	1.9	90
	Northwest	0.4	0.6	50
	National	6.5	8.4	29

Source: Staff computations based on unpublished information from the REED database.

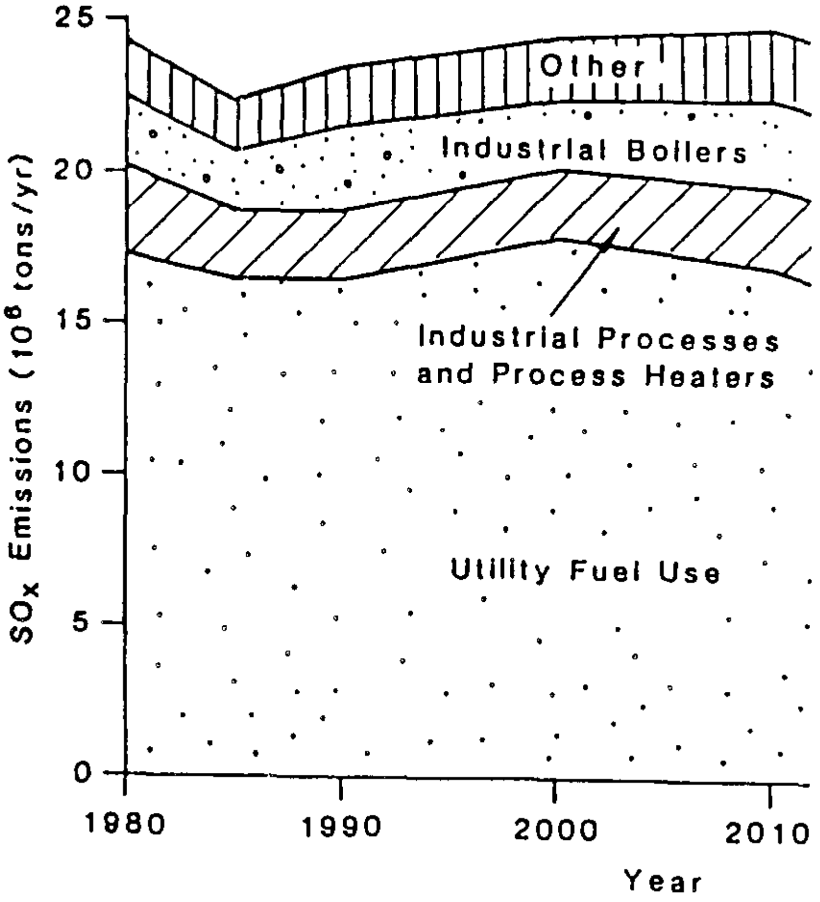

Fig. 4-1. Projected SO$_x$ emissions by source. (Source: Placet et al. 1986)

Electric utilities and transportation are the two principal sources of NO_x emissions, and each is expected to grow from 1985 to 2010. Emissions of NO_x from coal-fired power plants are projected to rise due to increased demand for electric power. Retirement of existing facilities has a lesser effect on the amount of NO_x emissions than on SO_2; therefore, the quantity of NO_x emissions tends to follow growth in utility fuel use. Transportation-related NO_x emissions are projected to increase, largely as a result of increased transportation demand. NO_x emissions from coal-fired facilities are expected to increase from 7 million tons/yr in 1985 to 8 million tons/yr in 2010, and total NO_x emissions are estimated to increase from 17 million tons/yr to 28 million tons/yr in the same time period. Figure 4-2 illustrates the projected trends in NO_x emissions by market sector.

Table 4-11 indicates a large variability in the percentage change in NO_x emissions by quadrant. The percentage change for the NE quadrant is relatively small, because 1985 baseline emissions are large compared with the other quadrants. Conversely, the percentage change for the NW quadrant is relatively large due to relatively small 1985 baseline emissions. Table 4-12 shows a narrower range of percentage increases of NO_x by quadrant for emissions by coal-fired utility boilers. The increases range from about 10 to 90%, with the NE quadrant showing the smallest increase.

Figure 4-3 shows projected trends in TSP emissions by market sector. This figure indicates that no major increases in TSP from the utility sector are anticipated by the year 2010.

Projected increases in emissions of the above pollutants potentially could result in continued degradation of air quality in areas currently not in attainment of the standards (Sect. 3.2) or could lead to new nonattainment areas. The projected increase in NO_x emissions, together with expected increases in volatile organic compound emissions (which are the other principal ozone precursor and which are not appreciably affected by coal combustion), potentially could lead to future ozone nonattainment areas. It should be emphasized, however, that the existing Clean Air Act, as amended, contains provisions in Prevention of Significant Deterioration (PSD) regulations to limit the degradation of air quality and provisions in National Ambient Air Quality Standards (NAAQS) regulations to prevent new nonattainment areas from occurring. Therefore, the projected increases in emissions presumedly would occur in locations that would not actually result in violations of these regulations. Lastly, given a projected slight increase in SO_2 emissions and a projected increase in NO_x emissions, it is unlikely that acidic deposition (acid precipitation and dry deposition) would be improved over 1985 levels, and it could become worse given the assumption of no new emission regulations.

4.2.1.2 Carbon dioxide and other greenhouse gases

Both the concentration of CO_2 in the atmosphere and the mass of CO_2 emissions from fossil-fuel burning have been increasing since at least 1958, when systematic monitoring began and probably since the middle of the 19th century. Although the annual emissions rate has varied with global economic conditions and actually decreased during the early 1980's, growth has resumed and is expected to continue. The observed increase in atmospheric CO_2 concentrations suggest that slightly over half of the anthropogenic CO_2 emissions have remained in the atmosphere (Fig. 4-4). It would require a major change in global economic conditions or fossil-fuel usage patterns to

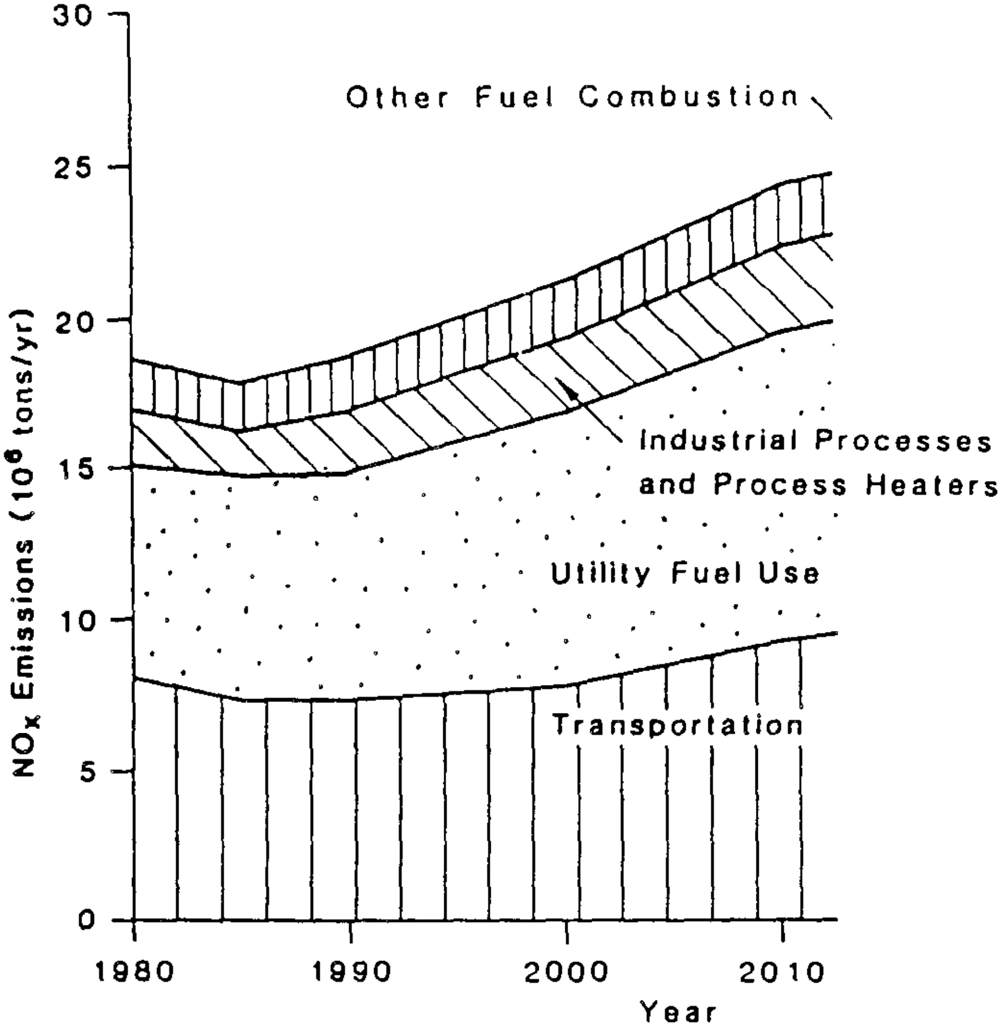

Fig. 4-2. Projected NO_x emissions by source. (Source: Placet et al. 1986.)

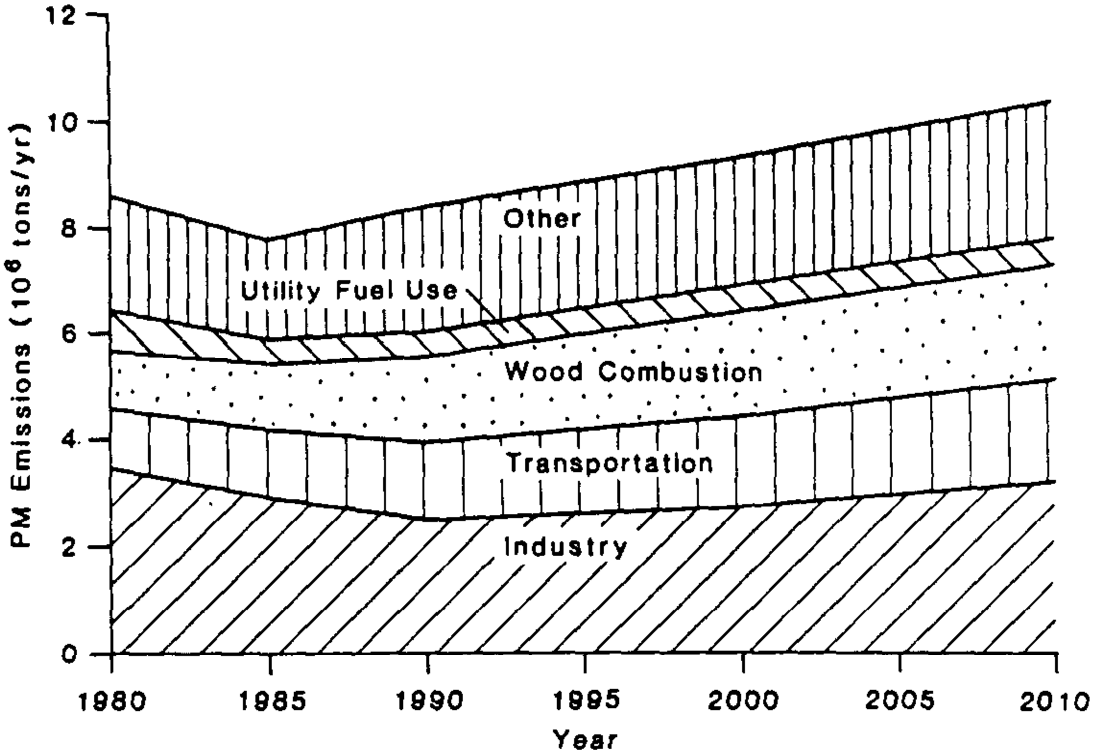

Fig. 4-3. Projected TSP emissions by source. (Source: Placet et al. 1986).

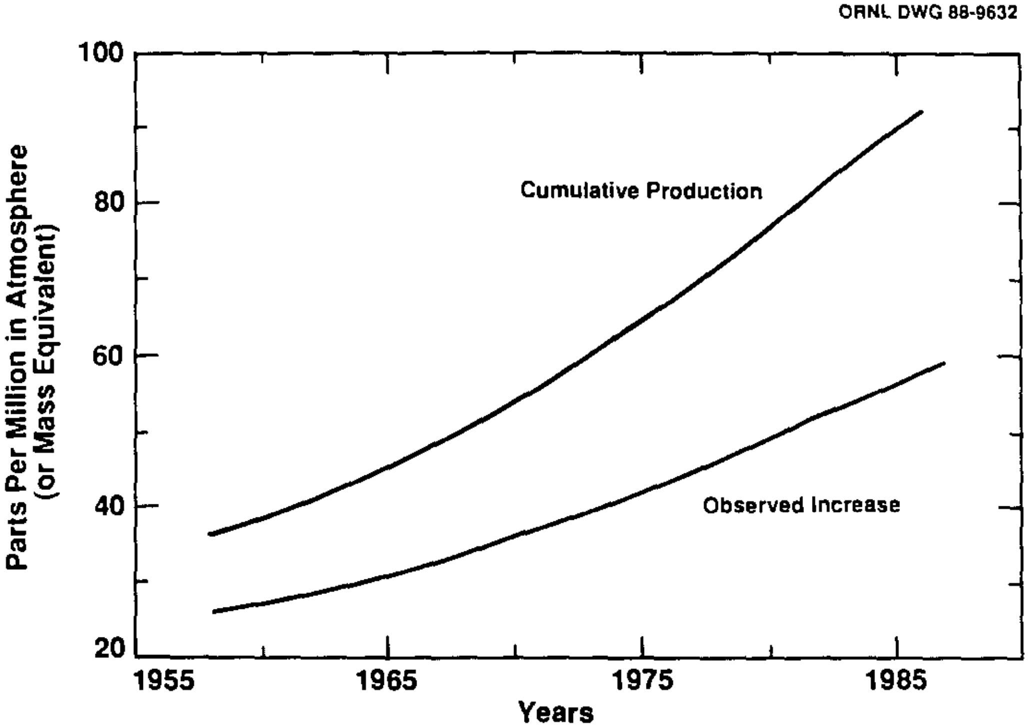

Fig. 4-4. Cumulative fossil-fuel emissions of carbon dioxide.

significantly alter the trend shown in Fig. 4-4. With continued economic growth in the United States and the rest of the world, the atmospheric CO_2 concentration can be expected to continue to increase unless there is a major decrease in fossil fuel usage or an increase in efficiency of CO_2 sinks.

Various studies (e.g., EPA 1989) have now shown that a policy to reduce CO_2 emissions could be successful if it incorporated a combination of measures that included improving the efficiency of energy conversion and use, switching to energy systems that do not discharge CO_2 (e.g., solar or nuclear power), protecting and/or replanting global forests, etc. All of these studies emphasize that (1) there is no single measure that will "solve" the greenhouse problem, (2) there are many less dramatic measures that could collectively make a significant difference, and (3) CO_2 is a global problem that will require global solutions.

Because of the many linkages between greenhouse gas emissions and other human activities and because of the magnitude of the commitment that would be required to significantly reduce global CO_2 emissions, it is important to consider climate issues in the context of other societal and environmental objectives. Although coal burning in the United States is one of the largest single targets for reducing global CO_2 emissions, it comprises only 8% of current global total CO_2 emissions from energy systems. Actions that have only small effects on the rate of consumption of coal in the United States will, in turn, have little effect on global CO_2 emissions. Whether or not a U.S. CCTDP program is implemented is expected to have little effect on global CO_2 emissions.

4.2.2 Impacts on Land Use

4.2.2.1 Power plant land use

The expected doubling in coal-fired electricity generation capacity by 2010 could lead to a doubling in direct land use by coal-fired power plants compared to direct land use in 1986 (Sect. 3.2.2.2). Thus, a maximum of 300,000 acres of land could be committed to coal-fired power plant sites by 2010 (Table 4-13). Of this acreage, about one-half could be located in the NE quadrant, about one-fourth would be in the SE quadrant, and nearly one-fourth would be in the SW quadrant.

4.2.2.2 Solid waste disposal

The expected distribution of land needed for disposal of ash and FGD sludge for the no-action alternative is shown in Table 4-14. Estimates in this table indicate that on a national basis, about 60% more land would be needed for disposal of sludge than for disposal of ash. This situation is the result of assumed nearly universal use of FGD scrubbers. A greater need of land for disposal of FGD sludge than for disposal of ash is characteristic of those regions where a large proportion of the power plants must meet NSPS while burning medium- or high-sulfur coal. Federal Region 6 and much of the NE quadrant fit this pattern because most plants were built after NSPS went into effect. The SE quadrant (Federal Region 4) would have a lower proportion of FGD sludge to ash generated because this region would have a relatively high proportion of pre-NSPS power

Table 4-13. Estimated direct land use by coal-fired power plants in 2010 for the no-action alternative

Quadrant/ Federal Region	Generating capacity (GW)	Area[a] (acres)
Northeast		
1	9	4,500
2	33	16,500
3	73	36,500
5	131	65,500
7	33	16,500
Subtotal	279	139,500
Southeast		
4	164	82,000
Southwest		
6	117	58,500
9	25	12,500
Subtotal	142	71,000
Northwest		
8	30	15,000
10	11	5,500
Subtotal	41	20,500
National total	626	313,000

[a] Based on 50 acres/100 MW (Systems Consultants, Inc. 1981).

Table 4-14. Estimated annual landfill requirements for ash and flue gas desulfurization (FGD) sludge disposal of coal-fired electric utility power plants in 2010 for the no-action alternative.

	Ash		FGD Sludge	
Quadrant and Federal Region	Quantity (10^6 tons/yr)	requirements (acres/yr)	Quantity (10^6 tons/yr)	requirements (acres/yr)
Northeast				
1	1.4	30	0.8	30
2	6.8	130	6.7	250
3	11.4	220	18.8	710
5	35.5	670	27.2	1,030
7	8.8	170	5.1	190
Subtotal	63.9	1,220	58.6	2,210
Southeast				
4	33.9	610	18.4	700
Southwest				
6	32.9	590	34.8	1,320
9	4.8	90	0.9	30
Subtotal	37.7	680	35.7	1,350
Northwest				
8	7.3	130	1.0	40
10	1.9	30	0.5	20
Subtotal	9.2	170	1.5	60
National total	144.7	2,680	114.2	4,320

Source: Table 3-3 and landfill requirement estimates of 19 acres/10^6 tons for ash and 38 acres/10^6 tons for FGD sludge.

plants in 2010. The NW quadrant and part of the SW quadrant (Federal Region 9) would have a low proportion of FGD sludge to ash because these regions use predominately low-sulfur coals.

4.2.2.3 Limestone mining

Under the no-action alternative, the amount of limestone mined for use in FGD systems is expected to increase substantially by 2010. One projection shows FGD-related limestone production at over 20 million tons/yr by the year 2000 (BuMines 1985). By 2010, limestone mining for FGD purposes should be between 20 and 30 million tons/yr. If overall limestone production grows only enough to accommodate this use, only about 4% of the nation's limestone production would go to FGD uses.

Limestone is a plentiful, widely distributed mineral that is usually mined close to its point of use. The regional distribution of the increased mining of limestone would closely follow the pattern of FGD sludge generation presented in Table 4-14. Impacts of limestone use are expected to be of a local nature and minimal.

4.2.2.4 Other land use issues

Under the no-action alternative the volumes of solid waste generated would increase with the use of FGD systems. Because many new and existing power plants and industrial facilities would be or are currently located close to waterbodies, they are likely to be within the 100-yr floodplain. For older plants that are refurbished, the capacity of existing solid waste disposal areas may be limited, and alternative disposal areas off the existing plant site may be needed. Because locating new disposal areas close to existing plant sites will be advantageous economically to reduce transportation costs, proposals to locate within floodplains are likely to occur.

Losses of prime farmlands and wetlands and construction in floodplains (Sect 3.2.2.2) would continue to occur under this alternative where new sites for power plants, solid waste disposal areas, and other ancillary facilities (e.g., coal cleaning facilities) are developed. The amount of this loss is uncertain because the location and number of new facilities is unknown. As noted in Sect. 3.2.2.2, loss of wetlands and construction in floodplains may be less than in the past because of the environmental review requirements associated with these resources.

The possible loss of significant archeological, historical, cultural, and paleontological resources could also occur under the no-action alternative. This loss would be directly related to the siting of new facilities, but impacts cannot be evaluated at this time because of the lack of information on the location of specific sites and types of facilities.

Careful siting and consultation with appropriate regulatory authorities can minimize or avoid impacts on these important resources.

4.2.3 Impacts on Water Resources

Under the no-action alternative, water resources would be affected by continued consumptive use of water for steam-electric generation (including boiler water makeup, boiler blowdown, and cooling), coal cleaning, and wet scrubbing of flue gas (Sect. 3.2.3.1). All new conventional coal-fired power plants are expected to consume approximately 690 acre-feet (1.1×10^9 liters) per 10^{12} Btu of energy produced, or 82 cubic feet (2300 liters) per MWh for steam-electric generation, excluding cooling. Cooling is expected to consume about another 55 cubic feet (1500 liters) of water per MWh.

The no-action alternative assumes that about half of new plants will include coal cleaning (Sect. 2.2.1); this technology is expected to use about 3.7 acre-feet (4.5×10^6 liters) per 10^{12} Btu of cleaned coal produced or about 1.5 cubic feet (42 liters) per MWh. This alternative also includes wet limestone scrubbing, which is expected to consume about 8-10 cubic feet (230-280 liters) per MWh, depending on the quality of the coal and the process used (EPRI 1980).

For the no-action alternative, the impacts on water resources from atmospheric deposition of sulfur and nitrogen compounds would depend on regional increases in energy demand, the rates of power plant replacement, the degree to which older plants are equipped with SO_2 controls (generally FGD, a process that does not control NO_x), and any changes in emission regulations.

The region of the United States that would be most affected by trends in continuing production of acidic emissions by current technologies (no action) would be the NE quadrant. The acid-sensitive zones in the Adirondack Mountains of New York State, the upper Great Lakes drainage basin (upper Midwest), and the whole of New England could continue to be affected (Fig. 3-12). Nearly all of southeastern Canada is highly vulnerable, especially southwestern Ontario, the Laurentian Shield of Ontario and Quebec, and the small lake region of Nova Scotia (Fig. 3-13). If acidic emissions were to continue to rise, the less acid sensitive zones might be expected to show detrimental effects. Poorly buffered coastal plain streams of the NE and SE quadrants might experience more acidic runoff with consequent effects on water quality and ecological resources, especially spawning anadromous fishes.

Emissions of SO_2 and NO_x from all sources are estimated to increase nationally by 18 and 63%, respectively, between 1985 and 2010 (Table 4-11). These increases follow a decline from historical highs that were reached about 1975. In the NE quadrant where sensitive aquatic resources are present (Sect. 3.2.3), total SO_2 is estimated to decrease while total NO_x would increase by about 22%. Thus, the trend is different whether one emphasizes the impacts to susceptible regions or to the country as a whole. The SW quadrant, which is generally least susceptible to acidification (Sect. 3.2.3), has the second highest projected percentage increase in SO_2 emissions (Table 4-11).

The impacts on water resources would continue to differ from location to location even within a region, depending on the local processes controlling water acidity and the degree to which anthropogenic acid deposition contributes to the resulting local chemical equilibrium (Sect. 3.2.3). If water quality responds quickly to atmospheric deposition (a matter still debated), then the NEPP-V projections of total SO_2 and NO_x emissions nationally would suggest that only a slow return to less acidified water conditions would occur, following a continued increase in acidification to about the year 2000 (Sect. 4.2.1.1). The smallest rise in SO_2 emissions would occur in the NE quadrant (Table 4-11).

Recent trends and model estimates of future changes due to continuing SO_2 and NO_x emissions suggest disparate scenarios of the future without controls (e.g., Cook 1988; Malanchuk and Turner 1987). For example, empirical regional models that have been used to estimate the expected changes in surface water chemistry in lakes of eastern Canada that would result from steady-state 1980 levels of acidic deposition (Marmorek et al. 1988) indicate that substantial damage could occur. Once the lakes reach steady state with these deposition levels, 10,000 to 36,000 lakes in the Province of Ontario are predicted to have a pH <5 and more than twice this number would have values <5.5 (indicating that they are becoming acidified), using one set of parameter combinations. The models suggest that increases in deposition from the 1980 levels can cause progressively larger increases in the number of acidified lakes because the upward trend is nonlinear.

The results of another modeling study (Minns and Kelso 1986) are summarized in Fig. 4-5. The figure illustrates possible changes in the number of acid lakes in eastern Canada (pH < 5.5) that could be associated with changes in sulfate deposition (the model does not include NO_x emissions) from the current level (vertical dashed line = 100% on the scale showing percentage of current rate). The high degree of uncertainty in making such estimates is illustrated by the wide spread between the upper and lower bounds of the predicted number of acid lakes at each rate of sulfate deposition. Although the Minns and Kelso model is not a particularly good basis for predicting change, it is the only comprehensive attempt to project the status of Canadian lakes (Marmorek et al. 1988). On the basis of mean values of this model, an estimated 16% increase in SO_2 emissions nationally by the year 2010 could increase the number of acidified lakes by nearly 25%.

All of these estimates are tentative and subject to considerable debate. Questions of whether the aquatic systems are in steady state and whether the direct or delayed mechanisms apply (and where, if they both have site-specific validity) make confident prediction of impacts of SO_2 and NO_x releases on water quality impossible (Sect. 3.2.3). Even the characterization of trends is not universally accepted due to uncertainties as to how extrapolation from measured data can be done.

The NAPAP Interim Assessment (Malanchuk and Turner 1987) concluded that surface water chemistry in the NE quadrant (glaciated Northeast and upper Midwest) is at or near steady state with respect to sulfur deposition. There was no indication that a significant number of lakes would change their acidity rapidly if deposition loading were to continue at present levels. Research in the Southern Blue Ridge Province suggested that the surface waters of most watersheds were not in steady state with respect to sulfur deposition. Even though waters were above pH 6.0, surface water acidity could gradually increase at current deposition loading levels. The very dilute lakes of the West were expected to respond rapidly to any change in watershed input, but little change in lake chemistry was expected if deposition levels remained constant.

Measures other than reduction of air emissions have been proposed for mitigation of acid deposition effects. The technique receiving most consideration is liming [addition of lime (CaO) or limestone ($CaCO_3$)] of lakes and/or watersheds (Huckabee et al. 1989). Liming raises the pH

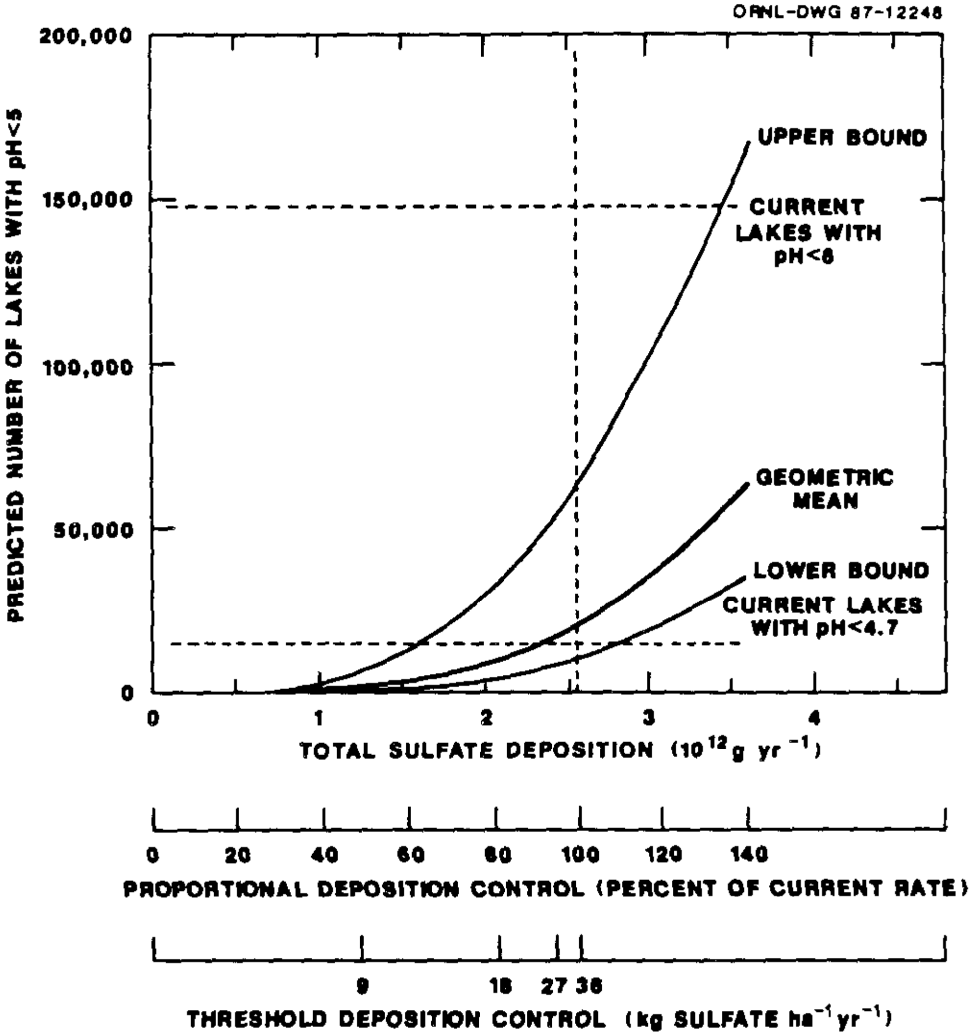

Fig. 4-5. Model predictions of the relationship between the number of lakes of pH 5 and total sulfate deposition in eastern Canada, south of 52° N. The lower and upper bounds represent the minimum and maximum damage, respectively. The vertical line of dashes indicates the level of deposition that is currently observed and is reflected in the proportional deposition control axis as 100%. Proportional deposition control assumes proportional changes in deposition in watersheds. (Source: Minns and Kelso 1986 as adapted by Cook et al. 1988)

of acidified waters and provides buffering capacity. Liming of watersheds neutralizes acid deposition before it enters surface waters. However, there are significant drawbacks to liming, including the costs, the temporary nature of the results, and the potential for sharp changes in pH over time and distance resulting from entry of acidic waters into the lake. Liming lakes and watersheds may provide short-term mitigation but does not appear appropriate to permanently prevent acidification.

Quantification of increases in nutrients in water due to increased NO_x emissions is not currently possible. The relationships between nitrogen emissions and nutrients in waterways is still poorly known, especially in relation to generalizing upon site-specific watershed processing (Sect. 3.2.3).

Leaching of pollutants from solid waste handling and their effects on water resources would continue to require regulatory attention and careful management at specific sites. Because use of FGD controls produces a great deal more solid waste than a plant without SO_2 controls (Sect. 3.2.2.3), the likelihood is increased that waters would become affected by leachates through implementation of FGD control technology.

4.2.4 Impacts on Ecological Resources

4.2.4.1 Aquatic ecosystems

Because causal linkages between acidic deposition, the acidification of surface waters, and the loss of biological resources are poorly quantified on a national or continental scale, projections of impacts to biota from any emission scenario are necessarily tentative. Experimental studies have helped show the biological effects of long-term acid stress on lake ecosystems (e.g., Schindler et al. 1985). Attempts have been made to relate these changes to emission levels. In Ontario, for example, the changes in water chemistry estimated to result from a steady-state equilibrium at 1980 emission levels (Sect. 4.2.3) are estimated to decrease the species richness by about 4%, the probability of presence of a species by about 6 to 9%, and biological production by about 2% for all Ontario fisheries (Marmorek et al. 1988). In the 10,000 to 36,000 Ontario lakes projected to have pH values <5.0 after equilibration to 1980 deposition rates, there is estimated to be little fish life.

In the NE quadrant SO_2 emissions are projected to decrease by about 8% from all sources under the no-action alternative (Sect. 4.2.1). Emissions of NO_x are projected to increase by about 22% in the same quadrant. It is not clear what the combined effect of these two pollutants would have on the level of acidic deposition or whether any changes would translate into improved conditions.

Under the no-action alternative, NO_x emissions would continue to rise (Fig. 4-2, Table 4-11), and the incremental change of algae-stimulating nitrate in atmospheric deposition could increase in the manner seen in the recent past (Sect. 3.2.3). The problems of eutrophication in inland and coastal waters could, therefore, be aggravated (e.g., Coutant and Benson in press). Eutrophication has been recognized for many years, and the biotic responses (e.g., nuisance growths of algae, hypoxia and anoxia of bottom waters that eliminate habitat for bottom organisms and many fish) are well known. However, the linkage of biotic changes with atmospheric deposition of combustion-derived nitrates has received little attention (Sect. 3.2.3).

Regulatory controls and management practices are assumed capable of keeping pace with the existing rate of increase in potential volume of leachates to surface waters from power plant-derived ash and solid wastes. Thus, coal waste leachates should produce no major nationwide impacts on fish and aquatic life.

4.2.4.2 Terrestrial ecosystems

4.2.4.2.1 Impacts from acidic deposition

Pollution sources are unevenly distributed across the United States, with major concentrations of coal-fired plants in the Northeast, Texas, and the Ohio River Valley (Fig. 3-2). The relative impact of emissions from local, midrange, and distant sources varies by region. For example, according to one modeling study (OTA 1984), sulfur deposition in the Midwest (a region with very high emissions) is dominated by emissions from sources within 300 km. Sulfur compounds that reach New England and eastern Canada have been transported much farther; the average distance from both local and distant sources is about 500 to 1000 km (OTA 1984). The NE and SE quadrants emitted 75% of the total 1985 annual SO_2 and 57% of the 1985 total annual NO_x generated in the United States (Table 4-11). Approximately 83 and 69% of the total SO_2 and NO_x emissions, respectively, from coal-fired utilities in 1985 were generated in the NE and SE quadrants (Table 4-12).

Potential impacts on terrestrial ecological resources from the no-action alternative are primarily related to the continued exposure and possible long- term effects from acidic deposition and O_3. The following discussion provides a regional evaluation of these possible impacts.

Under the no-action alternative, a small reduction (about 10%) in SO_2 and an increase (about 10%) in NO_x emissions (Table 4-12) would occur in the NE quadrant by the year 2010. The region could be at risk from continuing damage from these emissions. The increase of NO_x emissions and subsequent O_3 formation could possibly accelerate the rate of damage to ecosystems. The increase in NO_x emissions could impact growth and yields of sensitive agricultural species and enhance the formation of ozone. A combined exposure to NO_x and O_3 of tree species has resulted in growth suppression in Virginia pine and loblolly pine, suppressed root accumulation in sweet gum, and decreases in the dry weight of white ash (Kress and Skelly 1982). Increases of emissions to the area in which damage has already occurred and impacts to additional species are possible results of continued emissions under the no-action alternative.

In the SE quadrant, emissions of SO_2 from coal-fired facilities (Table 4-12) are predicted to remain about the same, while emissions of NO_x, are predicted to increase (about 33%). The increase in NO_x emissions and, consequently, increased O_3 concentrations would have detrimental effects. Under the no-action alternative, damage would be expected to continue in this quadrant at least at the current rate. Sensitive species, especially those sensitive to O_3, would continue to be at high risk.

In the SW quadrant, changes in emissions of SO_2 and NO_x from coal-fired facilities (Table 4-12) are predicted to increase by 2010. The total air pollutant emissions in this quadrant are low compared to the total emissions in the NE quadrant (Table 4-11). In California, damage from ozone has been observed for ponderosa pine, Jeffrey pine, and some species of coastal shrubs. With increased emissions of SO_2, NO_x, and associated O_3 formation from all sources, the risk of damage to terrestrial ecosystems would be increased. The emissions from power plants in Texas could possibly affect pine plantations in the SE quadrant, via long-distance transport and deposition of pollutants, and could extend into the NE quadrant as well.

In the NW quadrant, emissions from coal-fired facilities of SO_2 and NO_x are predicted by 2010 to increase by about 0.1 and 0.2 million tons/yr (25% and 50%, respectively) (Sect. 3.2.4.2). When compared to the NE and SE quadrants, however, the total air pollutant emissions for this quadrant are low (Table 4-11). No documented evidence of continuing ecosystem damage has been attributed to these pollutants from fossil-fueled facilities. Increases in SO_2 and NO_x emissions and associated increases in O_3 could somewhat increase the risk to Douglas fir and pine plantations. Natural stands, especially at high elevations, would be at increased risk. Plantation stands would probably not be significantly impacted by the SO_2 and NO_x emissions as a source of nutrient inputs because these stands are intensively managed. However, O_3 might adversely affect the health of forest stands.

4.2.4.2.2 Impacts from disposal of solid waste

Under the no-action alternative the amount of solid waste produced would increase as additional FGD systems are added to existing and new facilities (Sect. 4.2.2). Because additional land area would be needed for disposal of these wastes, loss of terrestrial habitat would occur. Encroachment on important ecosystems such as wetlands (including wetlands located on floodplains) for waste disposal could occur (Sect. 4.2.2).

4.2.4.3 Impacts on endangered and threatened species

Under the no-action alternative, the impacts of acidic deposition and the related stress on habitat for certain endangered and threatened species would occur with increased emissions of SO_2 and NO_x, although FGD systems would be installed at all new facilities. The loss of habitat from constructing new power plants and other facilities such as solid waste disposal areas would also occur. In an EPA-sponsored study of 100 coal combustion waste sites (EPA 1988a), the Nature Conservancy Heritage Program database was used to obtain information on endangered and threatened species occurring within a 5-km radius of the sites. Of the 85 sites where information was available, 12% had federally designated plants or animals within the 5-km radius. Species of priority state concern were identified at 29% of the sites, and 32% of the sites had species of concern to state environmental offices. No data were available for 12% of the sites. Such data indicate the high potential for endangered and threatened species to be exposed to coal combustion constituents. The impacts on endangered and threatened species from the construction and operation of new facilities will be addressed on a site-specific basis in consultation with appropriate state and federal fish and wildlife agencies before individual facilities are approved for construction.

4.2.5 Impacts on Socioeconomic Resources

With the no-action alternative, many existing coal-fired electric utility generating facilities could undergo life extension. In addition, over 600 new 500-MW coal-fired power plants could be constructed to provide about 320 GW new capacity for increased energy demands (Sect. 2). Coal cleaning, primarily through physical cleaning processes, is expected to continue for about one-half the domestic coal produced. It is likely that new waste disposal facilities also will be necessary.

The greatest socioeconomic impacts of the no-action alternative may arise from the construction of new coal-fired power plants. The peak construction workforce of conventional two-unit power plants averages nearly 2,100, and construction may take more than 6 years (Budwani 1985). The influx of new workers and their families, either directly for the coal plant or indirectly for other businesses and services, could create significant impacts on local areas. Community services (e.g., utilities), schools, transportation systems, housing, and the economic base are likely to be affected. Often, there is a financial strain on communities that are put in the position of providing services and resources before revenues from the new facility are available (Schweitzer et al. 1983). Impacts from the construction of coal preparation or waste disposal facilities, as well as from the refurbishing of existing facilities, are likely to be less substantial because fewer workers are required. For instance, coal beneficiation plants require an average of 440 workers and approximately one year to build (DOE 1983).

Life extension of older plants probably would occur in urban areas, where such plants are frequently located. The trend in recent years is for new facilities to be sited in rural rather than urban areas. The impacts of building new facilities are likely to be more significant in rural communities because people either would have to commute longer distances or increases in local housing and services would have to occur to support the work force population.

If new facilities are located in rural areas, changes in land use are likely to occur. These changes may not always be significant on a case-by-case basis, but they have greater importance when considered for the entire country. For example, if new power plants and associated waste disposal facilities are sited on prime farmland (Sect. 4.2.2), (1) that land would be lost from agricultural use; (2) farmers and their families may have to relocate and find other work; (3) surrounding farmland may be affected by power plant or waste disposal air emissions, leachate, and surface runoff as well as by the effects of increased traffic to and from the facilities and, possibly, further growth-related encroachment on prime farmland; (4) water needed by power plants may have to be diverted from other uses, such as irrigation; and (5) changes in water quality may affect surrounding farmland.

Another set of potential localized socioeconomic impacts may arise from attempts to site new facilities. Whether or not such impacts occur depends on such case-specific factors as the economic health of a community; projected growth-related impacts of the facility; changes in actual or potential land uses; the lifestyles and quality of life in the community; past experiences with similar technologies or sponsors of similar technologies; and potential physical harm from the facilities. Potential adverse consequences of facility siting, which may be felt for several years, include increased social conflict and expenditures of time and money by members of the public, municipalities, other governmental bodies, social organizations, and industries (e.g., O'Hare et al. 1983; Rayner and Cantor 1987; Sorensen et al. 1984).

4.2.6 Impacts on Health and Safety

Health and safety issues associated with the direct production of electricity in coal-fired power plants can be analyzed by considering each stage of the fuel cycle including mining, transportation, coal preparation, and power generation. Gehrs et al. (1981) assessed the occupational and public health and safety impacts of direct power generation by conventional coal combustion and compared it to those from low-Btu gasification/combined cycle electric power generation, high-Btu gasification, and coal liquefaction. Because the impacts are calculated on the basis of units of useful energy, the lower efficiency of conventional power generation leads it to have slightly higher impacts than high-Btu gasification and liquefaction in the mining, coal transportation, and coal preparation phases of the fuel cycle. Occupational safety and health issues dominate in the mining phase of the cycle for all the technologies. The estimates of impacts from mining depend on the assumptions regarding the continued extent of underground mining with which most of the safety and health impacts are associated. It should be noted that the estimates of coal workers' pneumoconiosis (CWP), particularly projections for the future, reflect considerable uncertainty. Other mining-induced lung diseases are not included as they are not caused exclusively by exposure to coal dust as is CWP.

Occupational deaths and injuries are projected to be slightly higher for the gasification technologies than conventional combustion or liquefaction in the generation or conversion phase of the fuel cycle, but public health and safety impacts are estimated to be far higher for conventional coal combustion than for other technologies that reduce sulfur oxide emissions. While considerable uncertainty also underlies these calculations, the overall impacts from conventional coal combustion are estimated to be an order of magnitude higher than for the clean coal technologies in the generation part of the fuel cycle. Sulfur oxides emissions are used as a surrogate for the health impacts from all pollutant emissions (Table 4-15). Overall, the production of electricity by conventional coal combustion processes is estimated to have greater health and safety impacts both on workers and the public from the fuel cycle as a whole than do the clean coal technologies, even those such as gasification and liquefaction.

Table 4-15. Health Impacts from Coal Unit Systems (number of cases per unit of useful energy to consumer) During the Five Stages of the Fuel Cycle[a]

Health Effect	Electric	Low-Btu Gasification-Combined Cycle Electric	High-Btu Gasification	Liquefaction
		Mining		
Occupational				
CWP deaths	2.4–10.9	2.4–10.6	1.8–8.0	1.9–8.6
CWP disease	95–290	93–280	70–210	76–230
Accidental deaths	1.0–1.8	1.0–1.7	0.7–1.3	0.8–1.4
Accidental injuries	46–82	43–76	34–57	35–62
		Transportation		
Occupational				
Accidental deaths	0.2–0.6	0.2–0.6	0.1–0.4	0.2–0.5
Accidental injuries	20–60	20–60	10–40	20–50
General Public				
Accidental death	1.9–5.8	1.8–5.4	1.3–4.0	1.5–4.4
Accidental injuries	5–16	5–15	4–11	4–12
		Coal Preparation		
Occupational				
Accidental deaths	0.08	0.08	0.06	0.06
Accidental injuries	8.7	8.1	6.1	6.6
		Generation or Conversion plus Utilization		
Occupational				
Accidental deaths	0.1	0.6	0.5	0.2
Accidental injuries	3	20	15	3
General public				
Disease deaths	0–58	0–5.5	04.1	0–11
Asthma	860–86,000	82–8200	61–6100	160–16,000
		Distribution of Fuels		
General public				
Accidental deaths	–	–	0.004	0.007
Accidental injuries	–	–	1.3	0.4

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[a] Source: Gehrs, C. W., D. S. Shriner, S. E. Herbes, E. J. Salmon, and H. Perry. 1981. Environmental, Health, and Safety Implications of Increased Coal Utilization. pp. 2159-2223 IN M. A. Elliott (ed.), Chemistry of Coal Utilization, Second Supplementary Volume. John Wiley & Sons. Copyright© 1981. Reprinted by permission of John Wiley & Sons, New York.

4.3 ENVIRONMENTAL IMPACTS OF THE PROPOSED ACTION

The analysis provided in this section is based to a large extent on information developed using the Regional Emission Database and Evaluation System (REDES) (Sect. 4.1). The model considers each of the clean coal technologies individually without any mix or summation of impacts from technologies. The results are presented in the form of comparisons to baseline predictions, which are for the no-action alternative in the year 2010. The model assumes full commercialization of the technology in the applicable market, and thus the results represent an upper bound of possible change from the no-action alternative. Documentation of the ANL model and descriptions of the underlying assumptions and information on the clean coal technologies are provided in three Argonne National Laboratory technical reports (Boyd et al. 1988a,b; Poch et al. 1988).

In the evaluation of environmental impacts of commercialization of proposed clean coal technologies, the data from model runs have been used to identify differences among the technologies in terms of their atmospheric emissions and solid waste. In addition, the model has provided a general indication of geographic locations where major reductions or increases in emissions, effluents, or solid wastes would occur. For the analysis, other sources of information on the clean coal technologies and their environmental impacts have been used to supplement the output from the model, either in cases where information was not available from the model or where other assumptions needed to be considered.

4.3.1 Impacts on Air Resources

4.3.1.1 Impacts on air quality

From a national perspective, commercialization of clean coal technologies would have a beneficial effect on air quality in the United States by the year 2010 as compared to the no-action alternative. Implementation of these technologies would result in decreases in atmospheric emissions of some criteria pollutants: primarily SO_2, and to a somewhat lesser extent, NO_x. These emission reductions would translate into improved ambient air quality. Depending on the specific distribution of the reductions, the number of SO_2 nonattainment areas in the United States should be reduced. The number of nonattainment areas for O_3 could also potentially drop from reduced emissions of NO_x, which are precursors of O_3 formation. This latter conclusion is not certain, however, because for some areas in which the ratio of NO_x to hydrocarbon emissions is high, reductions in NO_x emissions can exacerbate O_3 levels. The emission reductions would also reduce acidic deposition (acid precipitation and dry deposition), although impacts are very difficult to quantify. Acidic deposition occurs in the United States due largely to the addition of SO_2 and NO_x from pollution by industrial processes, combustion, and mobile sources and any strategy to reduce these types of emissions would favorably impact acidic deposition. Substantial SO_2 and NO_x emission reductions would occur as compared to the no-action alternative projected for 2010.

Impacts resulting from commercialization of clean coal technologies would be greatest in the NE quadrant, regardless of which individual technology, technology grouping, or mix of technologies is implemented. Conversely, the NW quadrant would be practically unaffected by commercialization. The extensive use of coal in the NE quadrant greatly affects the existing (1985) air quality and projected air quality in 2010 under the no-action alternative. Correspondingly, all clean coal technologies would tend to focus on this quadrant because they involve repowering or retrofitting of existing plants. Reductions in atmospheric emissions would, therefore, result in the greatest improvement in ambient air quality within this quadrant. The most noticeable reduction in acid rain formation should also occur within this quadrant and in southeastern Canada. Because large distances are involved between sources of acid rain precursors and occurrence of acid rain, emissions reductions in the NE quadrant should alleviate acid rain formation in southeastern Canada, which is generally downwind (at levels of pollutant transport) from major areas of emissions in the NE quadrant (see Sect. 3.2.1 for a more detailed discussion).

Emissions of total suspended particulates (TSP) would be minimally affected by the technologies. All technologies would at least meet NSPS, in many cases using conventional pollution control equipment, so that changes from national baseline emissions would not be significant. Therefore, further discussion regarding TSP will be limited to general descriptions of TSP control for the individual technologies.

Table 4-16 summarizes, in qualitative terms by technology groupings, the expected national reductions in air emissions from the assumed full commercialization of the individual technologies. Emission reductions are qualitatively described as high (greater than 50% reduction), medium (10-50%), or low (less than 10% reduction). Examination of Table 4-16 indicates that, on a national scale, the technologies generally tend to exhibit greater emission reductions for SO_2 than for NO_x

In general terms, the reductions in emissions summarized above should result in improvements in future air quality. Section 3.2.1 characterized the air quality in each of the four quadrants in 1985. Under the assumptions given in Sect. 2, some improvements to 1985 SO_2 emissions are likely to occur under the no-action alternative as older, more-polluting sources are replaced by newer ones that meet emission standards. For the purposes of this section, it is assumed that the spatial distribution of air quality problems in 2010 under no action is as described for 1985. Given this assumption, the NE quadrant is likely to receive the greatest potential benefits from commercialization of the clean coal technologies, principally in three areas:

- reductions in SO_2 emissions would reduce ambient SO_2 levels and should reduce the frequency and magnitude of NAAQS violations;
- reductions in SO_2 and NO_x emissions should reduce acidic deposition (acid precipitation and dry deposition) in the northeastern United States and in southeastern Canada; and
- reductions in NO_x emissions could help reduce the frequency and magnitude of O_3 levels violating the NAAQS.

The other three quadrants would experience some air quality benefits, but the potential for improvement is much less than that in the NE quadrant. Reductions in SO_2 and NO_x emissions in the Southeast may reduce the magnitude and frequency of violations of the SO_2 and O_3 NAAQS, respectively. The SW and NW quadrants are not likely to experience much improvement in air

Table 4-16. Summary of national reductions in air emissions postulated to result from commercialization of clean coal technologies

Clean coal technology groupings	National reductions in air emissions from full commercialization of innovative clean coal technologies[a]	
	SO_2	NO_x
Repowering	M-H	M
Retrofit—NSPS capable	M-H	M
Retrofit—partial NSPS capable	NA-H	NA-M
Retrofit - new fuel form	L-M	I-L

[a] Percentages (L = 0.1-10%, M = 10-40%, H = >40%) are based on reductions in total (i.e., all market sectors) national emissions from those that would have occurred in the year 2010 without the CCTDP. NA means not affected. I means an increase is expected.

quality due to the presence of fewer coal-burning sources of air pollution and to fewer air quality problems related to coal combustion in these quadrants.

In addition to qualitative estimates, reductions in ambient SO_2 concentrations resulting from reductions in SO_2 emissions can be quantified fairly well by examining historical changes in emissions and corresponding changes in ambient air quality. Nationally, SO_2 emissions decreased 21% from 1977 to 1986, reflecting the installation of FGD controls at coal-fired power plants and a reduction in the average sulfur content of fuels used (EPA 1988b). During this period, a steady downward trend in ambient levels of SO_2 occurred. Nationally, the annual mean SO_2 concentration decreased at a rate of about 4%/yr, for an overall change of approximately 37% (EPA 1988b).

The disparity in the amount of decrease between SO_2 emissions and ambient SO_2 concentrations can be attributed to several factors. For example, SO_2 monitors tend to be located in urban areas and therefore do not monitor many of the major sources of SO_2 that tend to be situated in more rural areas. In urban areas, decreases in ambient SO_2 concentrations comparable to reductions in SO_2 emissions have been measured. Another factor that accounts for some of the discrepancy is the stack height of air emissions. The average height at which SO_2 is released increased during the period of the study as a consequence of new plants with very tall stacks; therefore, ground-level concentrations can decrease with no change in emissions because of increased stack height.

In spite of the disparity, it is clear that reductions in SO_2 emissions would result in reductions in ambient SO_2 concentrations. Therefore, commercialization would result in improvement of ambient air quality for SO_2. Specifically, the potential for 30-45% reduction in national SO_2 emissions due to commercialization of certain clean coal technologies should result in comparable decreases in ambient national SO_2 concentrations, with the greatest impact occurring in the NE quadrant.

Corresponding reductions in NO_x emissions from commercialization of clean coal technologies would reduce ambient NO_x concentrations. Emissions of NO_x from coal combustion, however, are currently less than levels that trigger nonattainment in the ambient air. A key concern is whether reductions in NO_x emissions would alleviate nonattainment of NAAQS for O_3. This question is difficult to answer because of the complex reactions involving hydrocarbons and NO_x in the presence of sunlight which produce O_3. Although different species of hydrocarbons have differences in reactivity that should be considered for specific locations, one general yardstick in assessing impacts on O_3 formation resulting from changes in NO_x levels is the ratio of NO_x to hydrocarbons. If the ratio is very high, then reductions in NO_x emissions can actually increase O_3 formation. If the ratio is moderate or low, however, reductions in NO_x emissions would decrease O_3 formation. While the ratio varies for different metropolitan areas and emissions sources, full commercialization should somewhat improve O_3 air quality for the quadrants as a whole because of reductions in NO_x emissions, particularly in the NE quadrant and to a lesser extent in the SE quadrant.

Changes in acidic deposition (acid precipitation and dry deposition) in the year 2010 resulting from commercialization of clean coal technologies are difficult to quantify. The complex chemical reactions which transform SO_2 and NO_x emissions into acidic compounds that contribute to acid rain are not fully understood, and the source-receptor relationships between power plant emissions and acidic deposition have not been fully quantified. There has been much debate on the amount of reduction in SO_2 and NO_x emissions necessary to mitigate acidic deposition. It is clear, however, that a large percentage of acidic deposition is associated with anthropogenic emissions of SO_2 and NO_x, and any strategy to reduce these emissions should mitigate acid rain formation and dry deposition.

The following discussion provides information on reductions in SO_2 and NO_x emissions for technology groupings as a consequence of the commercialization of individual technologies. Ranges in emission reductions within each technology grouping represent the spectrum of individual technologies. The discussion is based primarily on data developed from the REDES model that gives changes in levels of SO_2 and NO_x emissions from baseline (i.e., emissions in 2010 without commercialization) in units of millions of tons per year and also indicates percentage change from the national baseline emissions, including all market sectors (i.e., utility, industrial, commercial/ residential, and transportation). It should be noted that technologies with greater pollutant removal efficiencies will not necessarily also have greater reductions in national emissions, because the latter also depends on the size of the applicable market for each of the technologies.

The repowering technologies included in this PEIS are the CAFB, PFB, IGCC, and fuel cells. The circulating atmospheric fluidized-bed combustion (CAFB) and pressurized fluidized-bed (PFB) combustion technologies both provide SO_2 and NO_x emission control. The operating temperature of the combustion process is well below the point of NO_x formation. An alkali sorbent is injected into the bed of the combustor to capture SO_2 released during the combustion process. Both technologies employ a conventional electrostatic precipitator or baghouse to trap TSP. The REDES model assumes an SO_2 removal efficiency of 90% for CAFB and 95% for PFB and an NO_x removal efficiency of 60% for CAFB and 70% for PFB. The coal gasification technologies [fuel cells and integrated coal gasification combined cycle (IGCC)] produce relatively small quantities of emissions, since sulfur, nitrogen, and ash in the coal are removed during production of the fuel (E&ER et al. 1986). Acid gas removal systems eliminate a very high percentage of sulfur compounds in the crude gas produced during gasification. Only small amounts of NO_x are formed because most of the nitrogen is converted to ammonia, which is subsequently stripped and recovered. Fuel cells by themselves have no effect on NO_x, SO_2, and TSP, while gas turbines by themselves (used in IGCC) have no impact on SO_2 and TSP emissions but emit small amounts of NO_x during combustion. The REDES model assumes an SO_2 removal efficiency of 97% for both technologies and an NO_x removal efficiency of 92% for fuel cells and 97% for IGCC. Thus, the potential exists for very large reductions in both SO_2 and NO_x emissions with full commercialization of the technologies. For the repowering technologies, results indicate reductions from national baseline emissions ranging from 30-50% for SO_2 and about 15% for NO_x. Reductions would occur primarily in the NE and SE quadrants, with smaller declines in the SW quadrant. Very little reduction is expected to occur in the NW quadrant.

Those retrofit technologies that meet NSPS (as discussed in this PEIS) include the ASC, CuO process, and dual-alkali scrubber. The ASC controls SO_2 emissions by limestone injection into the combustor, and NO_x emissions are limited by staged combustion. Cyclonic action in the combustor removes much of the coal's ash content as a liquid slag. Both SO_2 and NO_x can also be removed by the copper oxide and dual-alkali technologies. The REDES model assumes 90% SO_2 removal efficiency for all three technologies, with 50% NO_x removal efficiency for the advanced slagging combustor (ASC) and dual-alkali scrubber and 90% NO_x removal efficiency for the CuO process. Results of the REDES model show that national SO_2 emissions would decrease by about 30-45% from baseline emissions, and NO_x emissions are lowered about 10-35% for all technologies. The NE and SE quadrants would experience the largest reductions, with substantially smaller decreases in the SW and NW quadrants.

The retrofit technologies that singly achieve reduction levels necessary to partially meet NSPS (i.e., meet NSPS for either SO_2 or NO_x) considered in this PEIS include LIMB, low-NO_x burner, SCR, sorbent injection, gas reburning, spray dryer with lime, and the advanced flue gas cleanup with salable byproduct. LIMB and the low-NO_x burner are advanced combustor technologies. While SO_2 and NO_x can be removed by LIMB, the entire function of the low NO_x burner is to reduce NO_x emissions by allowing a more gradual mixing of fuel and air to decrease flame temperature and by using a richer fuel-air mixture to reduce oxidation of nitrogen in the fuel. SO_2 and TSP emissions are unaffected by the low NO_x burner. It is possible, however, for the low NO_x burner to be used in conjunction with other technologies to control both SO_2 and NO_x emissions. The REDES model assumes 60% SO_2 removal efficiency and 60% NO_x removal efficiency for LIMB and 60% NO_x removal efficiency for the low NO_x burner. Advanced flue gas cleanup technologies are varied in their capabilities of removing SO_2 and NO_x. SCR removes only NO_x, while sorbent injection and the salable byproduct technology remove only SO_2. The primary purpose of the reburning process is to reduce NO_x emissions, but SO_2 emissions can also be reduced, depending on the fuel used for reburning. Both SO_2 and NO_x also can be removed by the spray dryer with lime process. The REDES model assumes an NO_x removal efficiency of 90% for SCR and an SO_2 removal efficiency of 60% and 99% for sorbent injection and the salable byproduct technology, respectively. An SO_2 removal efficiency of about 20% and an NO_x removal efficiency of 60% are assumed for gas reburning. The REDES model assumes an SO_2 removal efficiency of 90% and an NO_x removal efficiency of 30% for the spray dryer with lime process. Results of the model runs show the potential for reductions from baseline emissions varying considerably, depending on the individual technology. Maximum reductions of 48 and 15% are indicated for SO_2 and NO_x, respectively, in the technology grouping. The NE and SE quadrants would experience the largest decreases, with lesser reductions in the SW and NW quadrants.

The clean coal technologies in the "new fuel forms grouping" of retrofit technologies consist of those that chemically or physically alter the form of coal before its use as a fuel. These include advanced physical and chemical coal cleaning, mild gasification, direct liquefaction, indirect liquefaction, coal-oil coprocessing, and coal/water mixtures. Three types of coal liquefaction technologies considered here are direct, indirect, and coal/oil coprocessing. The REDES model assumes SO_2 removal efficiencies ranging from 90 to 99% and NO_x removal efficiencies from 60 to 80% for the three types, and results indicate reductions in national SO_2 emissions of about 5-10%. Potential NO_x changes from national baseline emissions are minimal. Most of the SO_2 and NO_x reductions would occur in the NE quadrant.

Air pollutants would also be emitted from the coal conversion processes used in liquefaction. Using emission factors for direct and indirect coal liquefaction (DOE 1981a) and the assumed energy content of converted coal to be burned in 2010 (from the REED), emissions from direct liquefaction (assuming the SRC II process) as a percentage of "existing" regional emissions in 2010 ranged from 0.75% for particulate matter to 10% for NO_x, each in the NE quadrant. Emissions from indirect coal liquefaction (assuming Lurgi Fischer-Tropsch), as a percentage of existing regional emissions in 2010, were found to range from 2% for particulate matter in all quadrants to about 30% for NO_x in all quadrants. These emissions would partially "offset" the emission reductions achieved from burning the converted coal in lieu of burning conventional coal. Quantifying the offset is subject to uncertainty because the assumptions used to derive the emission factors in DOE (1981a) may not be entirely consistent with the assumptions used in REDES.

The advanced coal cleaning technologies can be characterized by physical and chemical removal processes. Sulfur removal by physical coal cleaning methods is limited to removal of the pyritic sulfur content of any given coal, which can vary substantially from one seam to another (E&ER et al. 1986). Generally, 40 to 70% of the total sulfur can be removed by advanced physical cleaning. Chemical cleaning processes are able to remove over 90% of the total sulfur and 90% of the ash from certain coals. Neither physical nor chemical cleaning affects nitrogen contained in the coal, and, therefore, neither process alters NO_x emissions. The REDES model assumes sulfur removal efficiencies ranging from 10-50% for physical coal cleaning and 90% for chemical coal cleaning. Results indicate larger national reductions of SO_2 emissions are possible for medium sulfur coal than high sulfur coal because of the larger applicable market for the former. Declines from national baseline SO_2 emissions range from less than 1 to 5% for high sulfur coal and from 3-25% for medium sulfur coal with physical or chemical cleaning. Almost all of the SO_2 reductions would occur in the NE quadrant, with minor reductions occurring in the SE quadrant for medium sulfur coal. NO_x emissions, as mentioned above, remain unchanged.

Air pollutants would also be emitted from the coal cleaning process itself. Using air emission factors for coal cleaning (DOE 1981a) and the assumed energy content of cleaned coal to be burned in 2010 (from the REED), emissions from coal cleaning as a percentage of "existing" regional emissions in the year 2010 were found to range from less than 0.1% for SO_2 in all quadrants to about 2% for NO_x in the NE quadrant. These emissions partially "offset" the emission reductions achieved from burning the cleaned coal instead of conventional coal. Again, quantifying the offset is subject to uncertainty because the assumptions used to derive the emission factors in DOE (1981a) may not be entirely consistent with the assumptions used in REDES.

The products from mild gasification of coal, specifically a mixture of char and coal-derived liquid, are assumed to replace all residual oil in utility and industrial boilers. Results of the REDES model for mild gasification indicate very little reduction in national SO_2 or NO_x emissions from baseline emissions, specifically less than 10% decrease for either pollutant. Reductions would occur slightly more in the NE and SE quadrants than in the SW and NW quadrants.

The coal/water mixture technology assumes the use of the ultrafine coal preparation technology. The coal/water mixture fuel is used to replace medium- and high-sulfur residual oil in utility and industrial boilers. The impact on national baseline emissions by implementing this technology would be extremely small, with less than a 5% reduction in SO_2 emissions according to the REDES model results. The decreases would occur slightly more in the SE quadrant and slightly less in the NW quadrant than in the other two quadrants. NO_x emissions would not be affected by this technology.

Generally for new fuel forms, the REDES model indicates that reductions would be greatest in the NE or SE quadrants.

4.3.1.2 Carbon dioxide and other greenhouse gases

The main source of anthropogenic carbon dioxide (CO_2) emission is the combustion of fossil fuels, much of it electrical generation (Sect. 3.2.1.2). Any additional CO_2 generated by burning more coal, in an attempt to develop otherwise cleaner systems for burning coal would aggravate the CO_2 buildup and contribute to possible climate changes. Similarly, any reduction in CO_2 emissions accompanying clean coal programs would ameliorate the CO_2 buildup.

For coal-burning boilers, the amount of CO_2 generated would depend principally on the amount of coal burned to produce a given energy output. Consequently, the net plant heat rate provides an indication of the amount of CO_2 generated. To the extent that one power plant has a lower heat rate than another, it will discharge less CO_2. The individual technology tables in Sect. 2 indicate heat rates that suggest some clean coal technologies would generate more CO_2 and some less than the baseline. If, for example, PFB systems can be constructed with a heat rate of 8510 Btu/kWh, a significant decrease in CO_2 emissions could occur. Clean coal technologies that employ additional processing stages (e.g., coal cleaning technologies) can be expected to entail some additional energy expenditure, which would be made up by burning more coal or other energy resources, and, therefore, more CO_2 emissions would occur.

Adoption of clean coal technologies can actually impact CO_2 emissions in two fundamental ways. First, many of the clean coal technologies would result in changes in the efficiency of conversion of coal into useful energy; that is, changes in the amount of coal needed to provide the same energy, which would, therefore, change the total CO_2 emissions. However, the repowering technologies (e.g., PFB, IGCC, and fuel cells) could increase efficiency significantly, thus lowering the amount of CO_2 emitted. Second, many clean coal technologies involve lime or limestone and essentially rely on a stoichiometric exchange of CO_2 for SO_2 in the discharge gas. This latter factor is far less important than the former. Using limestone to remove all of the sulfur in a 3% sulfur coal would result in an increase in CO_2 emissions of less than 2%.

Because CO_2 is a product of combustion and because there is currently no realistic way of reducing or eliminating rates of CO_2 emissions for a given technology, CO_2 emissions would be a direct function of the quantity of coal burned. Thus, if commercialization of clean coal technologies results in a changed use of coal resources, the technologies would contribute to a change in CO_2 emissions.

With only about 8% of global fossil-fuel-related CO_2 emissions linked to coal burning in the United States, the potential for commercialization of the clean coal technologies to impact global atmospheric concentrations of CO_2 is very limited. A choice between the proposed alternative and the no-action alternative would, therefore, have little effect on global total CO_2 emissions; whether CO_2 emissions are increased or decreased marginally would depend on the mix of technologies ultimately adopted and commercialized. Impact of the clean coal technologies on N_2O is uncertain. Until recently, it was assumed that reductions of NO_x would result in proportionate reductions of

N_2O, but recent questions (Sect. 3.2.1.2) cast doubt on the absolute level of N_2O emissions from coal combustion. It still appears, however, that any measure taken to reduce NO_x emissions would also maintain very low N_2O emission rates.

4.3.2 Impacts on Land Use

4.3.2.1 Power plant land use

Direct power plant land use would not be affected by commercialization of the clean coal technologies except to the extent that repowering takes place with IGCC, fuel cells, and to a lesser extent with PFB and CAFB. These repowering technologies increase generating capacity of existing power plant sites (by a factor of 2.3 for IGCC, 4.3 for fuel cells, 1.4 for PFB, and 1.2 for CAFB). Increasing generating capacities of current sites would lead to fewer new power plants being built and, therefore, to less direct land use by power plants.

4.3.2.2 Disposal of solid wastes

One of the major environmental trade-offs associated with reducing atmospheric emissions by retrofitting or repowering coal-fired boilers with clean coal technologies is the generation of solid wastes (ash, sludge, and other solid wastes), which require disposal in landfills and ponds or which, in some cases, are suitable for recycling. Currently, many coal-fired boiler operations dispose of their solid wastes in ponds and landfills located on the actual plant site. Many of these existing disposal sites are reaching the end of their operational lifetimes and cannot be expanded to accommodate additional wastes.

Currently, solid wastes from coal-burning utilities and industries are exempted from regulation under the Sect. 3001 of the Resource Conservation and Recovery Act (RCRA). Section 8002 of RCRA required the EPA to study alternatives for disposal of coal combustion wastes and present to Congress the results of the study. The study report (EPA 1988a) was presented to Congress in February 1988. The study found that fly ash, bottom ash, boiler slag, and FGD wastes generally do not exhibit hazardous characteristics under current RCRA regulations. EPA reported that it intended to regulate these wastes under Subtitle D of RCRA (for nonhazardous wastes). EPA found that some maintenance and water purification wastes do occasionally exhibit RCRA hazardous characteristics (EPA 1988a). EPA is considering removing the Sect. 3001 exemption for these wastes and making them subject to the requirements of RCRA Subtitle C.

The chemical and physical properties of the solid wastes from most clean coal technologies are not well known at present. One of the purposes of the CCTDP is to learn about the physical, chemical, and toxicological properties of solid wastes generated by the clean coal technologies. In general, the analysis in this PEIS assumes there is some uncertainty about the chemical and toxicological properties of these wastes. Detailed information on waste properties, where known, is noted in the discussion of individual technologies that follow.

Operators of utility and industrial coal-fired boilers who adopt clean coal repowering technologies that would extend the lifetime of their plants would frequently need to find new disposal sites for their solid wastes. Location of new landfills for disposal of wastes would be especially difficult in areas in the NE quadrant, where suitable landfill sites are scarce, particularly in urban areas. Similar problems would exist in urban areas in the other quadrants.

While use of most of these clean coal technologies leads to increased solid waste generation, several technologies produce byproducts that might be usable if a market for them exists. Some technologies produce elemental sulfur or some industrial sulfur compound (e.g., liquid SO_2). Some technologies produce solids that are expected to be useful for construction or road building. The hurdles these byproducts must overcome to be put to beneficial use include: purity requirements, transportation costs, and competition from current suppliers of the materials. Most of the technologies are expected to produce wastes that are easier to handle and dispose of than FGD sludges.

Data on the availability of landfill sites in different regions of the country are not consistently available or directly applicable to the current assessment. The issue of waste disposal would need to be examined carefully, however, in any site-specific environmental reviews done by state and federal agencies in granting project approvals during commercialization.

Information on the amount of solid waste that would be generated by the different clean coal technologies is limited because many of the technologies have not yet been operated on a commercial scale. The following discussion summarizes the information available on solid waste impacts of the technologies.

In the following discussions of individual technologies, all changes are with respect to the base case (i.e., the no-action alternative). This base case used in the REDES model assumes that all plants built after 1985 use wet-limestone FGD systems to meet EPA's NSPS and that no retrofits for SO_2 or NO_x controls are applied to existing power plants.

Repowering technologies. Repowering technologies are those which require replacing a major portion of an existing facility. In addition, to reducing atmospheric emissions, repowering technologies may increase a facility's generating capacity and energy efficiency. Increasing power plant efficiency reduces solid waste generation by reducing the amount of coal burned to produce a given amount of electricity.

Fluidized-bed combustion (CAFB and PFB) use more limestone to remove SO_2 than the conventional FGD systems. CAFB would produce more solid waste than conventional systems, but PFB would produce less because it is substantially more energy efficient than conventional power plants (Tables 2-2 and 2-7).

IGCC and fuel cells do not use limestone or lime to remove SO_2, so they produce less waste than either conventional power plants or fluidized-bed systems. The high energy efficiency of fuel cells combines with their waste generating characteristics to result in sizeable solid waste reductions. The large capacity increments of these technologies are an impediment to even larger reductions in solid waste generation by coal-fired power plants.

All of these technologies would have smaller land-use impacts than the no-action alternative. Even the CAFB, which produces more solid waste than the no-action alternative, would require less land area for disposal because the waste would not be in the form of a sludge.

Retrofit–NSPS capable technologies. Retrofit–NSPS capable technologies (Table 4-6) use various processes to remove SO_2 and NO_x. All except the copper oxide process use lime or limestone to remove the SO_2. The lime or limestone end up as calcium sulfate/sulfite waste. The copper oxide process uses hydrogen from natural gas to regenerate the CuO that removes SO_2 from combustion gases. The principal residue of the copper oxide process is elemental sulfur or some other sulfur compound, depending on the available markets. The dual-alkali scrubber uses sodium hydroxide as well as limestone to remove SO_2 from combustion gases.

The technologies in this group are mixed in their solid waste characteristics. Use of the advanced slagging combustor would result in a substantial increase in solid waste, but the waste would be a dry solid instead of a sludge, as is produced by conventional FGD systems.

The NSPS-capable retrofit technologies would have land use effects that range from substantially negative for the spray dryer to quite positive for the copper oxide and salable byproduct FGD if their byproducts can be put to use.

Retrofit–partial NSPS capable. Partial NSPS capable retrofit technologies are mixed in their effects on solid waste. Gas reburning, low NO_x burner and selective catalytic reduction are strictly NO_x-control technologies, and they also produce no solid waste (Table 4-7). Gas reburning results in slightly reduced solid waste generation, because the natural gas burned in the process displaces some coal that would otherwise be burned.

Sorbent injection and LIMB produce sizable quantities of solid waste while reducing national emissions of SO_2 by 30%. Both these technologies produce dry solid wastes which are easier to dispose of than sludges. For either technology, about 700 acres/yr would be needed to dispose of the waste. The spray dryer would generate about the same increase in solid waste but it would be a sludge much like that produced by conventional FGD systems. Most of the increases for this technology is the result of applying it to plants that do not presently meet NSPS SO_2 and NO_x emission limits. The advanced FGD with salable byproduct technology also uses limestone to remove SO_2 but produces gypsum, which is widely used in certain building materials. If this technology were used, the small increase in solid waste projected (Table 4-7) could turn into a decrease as the gypsum it produces is made into useful products.

Retrofit–new fuel forms. New fuel forms include advanced chemical and physical cleaned coal, and liquid fuels made from coal. Chemical coal cleaning can remove over 90% of the sulfur from the coal. This level of cleaning allows the cleaned coal to be burned without any sulfur emissions controls while meeting NSPS. The solid wastes from chemical coal cleaning would require about 2000 acres/yr for disposal.

The two physical coal cleaning technologies evaluated here are advanced physical and ultrafine (Tables 4-8 and 4-9). Neither technology would allow the coal to be burned in new power plants without additional sulfur controls. Maximal use of either technology would require about 1000 additional acres per year for landfilling the wastes. Ultrafine coal could be mixed with water to form a coal/water mixture that could be burned in some utility and industrial boilers. Three to four hundred acres per year would be needed to dispose of the solid wastes from this use of ultrafine coal.

Five other technologies (Table 4-10) produce liquid or gaseous fuels that could be used in both new and old residual oil-fired boilers. The technologies producing liquid fuels would produce 15 to 50 million additional tons of waste per year. These wastes would require 300 to 1000 additional acres per year for solid waste disposal. Mild gasification would produce somewhat more solid waste, about 70 million tons per year. These wastes would require about 1300 acres per year for disposal.

4.3.2.3 Limestone mining

Under the proposed action, the amount of limestone mining would vary, depending on which clean coal technology is considered. Nitrogen oxide control technologies (low-NO_x burner, gas reburning, and SCR) would have virtually no effect on limestone mining. Liquefaction technologies would lead to reduced limestone mining, because sulfur emissions are controlled by other means. Similarly, coal cleaning technologies would lead to unchanged or reduced limestone use, because sulfur is removed from the fuel instead of the combustion products. Other technologies (e.g., fluidized-bed combustion, LIMB, and FGD systems) would lead to increased limestone use to the extent that they are less limestone efficient than conventional FGD systems and to the extent that they are applied to pre-NSPS power plants.

In any case, the increase or decrease in limestone use is probably not too significant, because under the no-action alternative, the FGD limestone use would be about 4% of all limestone uses nationally. Under the most extreme case, coal-related limestone use would be very unlikely to more than double.

4.3.2.4 Other land-use issues

In the past, floodplains have been sought as sites for industrial, residential, or agricultural development. As a result, many of the coal-fired utilities and industrial plants that would be retrofitted or repowered are located on sites that are entirely or partially within the 100-yr floodplain. Increased attention currently is being given to both limiting development on floodplains (because of the risk of flooding) and protecting them for their natural values such as wetland habitat. Nevertheless, disposal of solid wastes on floodplains is a possibility for both retrofitted or repowered existing plants and for new (i.e., greenfield) facilities. In the former case, existing plants may have remaining capacity to store solid wastes in on-site ponds or landfills. However, if the facility has been in existence for some time, the remaining capacity may be very limited compared to the extended lifetime of the retrofitted or repowered plant. Although many states' regulations for coal plant wastes include site restrictions, these restrictions do not always include prohibition of locating on floodplains. Thus, new plants and disposal facilities subject to state regulations may still be permitted in floodplains. Facilities subject to federal regulations (e.g., loan guaranty projects for new clean coal technologies) must demonstrate that such disposal is the only practicable alternative under Executive Order 11988, "Floodplain Protection." In many cases, the cost of transportation to an upland site may be used by an agency to justify a judgment of the "only practicable alternative."

Impacts from waste disposal in floodplains are likely to be encountered in all areas of the country, but they may be particularly prevalent in the SE quadrant where floodplain systems are common. As previously noted, some of the clean coal technologies would produce more solid waste on a dry basis than would be expected under the no-action alternative, and problems with floodplain encroachment may increase. Transporting the solid waste to disposal sites located outside the 100-yr floodplain may be necessary to avoid adverse impacts.

Frequently, the most desirable sites for locating a new facility are also prime farmlands because they are relatively flat, have well-developed soil, and are frequently close to streams, rivers, or other water bodies (Sect. 3.2.2). In addition, sites on floodplains are often classified as prime farmlands. There is a national concern about the irretrievable loss of prime farmlands to urban and industrial development. This concern has been incorporated into a national policy by the Farmland Protection Policy Act (Subtitle I of Title XV of the Agriculture and Food Act of 1981, P. L. 97-98). Many states and local governments have land-use plans that restrict development on areas classified as prime farmland. Projects involving federal incentives or approvals are required to consider impacts on the prime farmland resource.

Siting a new clean coal project is likely to involve consideration of impacts on prime farmland. In addition, many existing plants that are retrofitted or repowered may need to locate new waste disposal or coal preparation facilities on sites that include prime farmland. Such projects would be required to ensure that projects conform with state, local, and regional land-use plans. If the project involves federal incentives or approvals, the proponents would be required to obtain information from the Soil Conservation Service on the presence of prime farmlands on their site. It is not possible to determine the amount of prime farmland that could be affected by commercialization of the clean coal technologies, because information on the number and location of sites is not available. Such impacts would need to be considered on a case-by-case basis during project review and approval. In comparison to the no-action alternative, the impacts of the proposed action on prime farmland are likely to be similar because new sites would be needed under both scenarios.

Any siting of new or ancillary facilities associated with clean coal plants would require careful consideration of impacts to archeological, cultural, and paleontological resources that may be present on the selected site. An analysis of impacts to these resources from commercialization cannot be made, because specific information on numbers and locations of new sites is not available. However, consultation with state offices responsible for preservation of these resources (e.g., state historic preservation officers), Native Americans, and specialists on resources (e.g., paleontologists) at universities would frequently be required to ensure that these resources are adequately protected. Impacts on these resources from the proposed action are expected to be similar to those of the no-action alternative, because both alternatives involve development of new sites.

4.3.3 Impacts on Water Resources

Many of the clean coal technologies would consume different amounts of water than the conventional technologies assumed in the no-action alternative. The no-action alternative assumes that water would be consumed for (1) processing coal prior to combustion, at about half of new plants; (2) steam electric generation, including boiler makeup water and cooling water; and (3) wet flue gas scrubbing (Sect. 4.2.3). Some clean coal technologies do not require coal cleaning because other processes are used to remove nitrogen, sulfur, and particulates. The only clean coal technologies that do not require water for steam-electric generation are fuel cells and liquifaction technologies that produce fuel used in gas turbines. Many clean coal technologies also do not include wet scrubbers, so scrubber water would not be required. Requirements of the clean coal technologies for coal processing, steam generation, and wet scrubbing are shown in Table 4-17.

Table 4-17 shows that gasification and liquifaction technologies require water for fuel processing; water is used in these processes to generate hydrogen gas. Most coal cleaning technologies also require water for fuel processing. Advanced combustors do not require water except for steam generation; however, their application may require wet scrubbers to remove SO_2. Information available from DOE (1983) on water consumption by specific clean coal technologies includes:

- Atmospheric fluidized bed: An electric power plant using atmospheric fluidized bed combustion with bituminous coal is expected to consume about 180 acre-feet (220 x 10^6 liters) of water per 10^{12} Btu, including water for power generation. An electric power plant using atmospheric fluidized bed combustion with western subbituminous coal is expected to consume about 580 acre-feet (700 x 10^6 liters) of water per 10^{12} Btu, including water for power generation.

- Gasification: A Lurgi high-Btu coal gasification plant is expected to use about 10 acre-feet (12 x 10^6 liters) of water per 10^{12} Btu of gas produced.

- Indirect liquifaction: An electric power plant using the Lurgi Fischer-Tropsch indirect liquefaction process is expected to consume about 110 acre-feet (130 x 10^6 liters) of water per 10^{12} Btu, including power generation.

- SRC-II: This process is expected to consume about 91 acre-feet (110 x 10^6 liters) of water per 10^{12} Btu of refined coal produced.

- H-coal: An electric power plant using the H-coal process is expected to use about 148 acre-feet (180 x 10^6 liters) of water per 10^{12} Btu, including power generation.

The major impact on water resources from commercialization of clean coal technologies could be an improvement in the quality of surface waters that may result from reduced emissions of SO_2 and to a lesser extent NO_x (Sect. 4.3.1). These emissions can affect surface water chemistry through acidic deposition and can consequently affect freshwater biota (Sects. 3.2.3 and 3.2.4), although the quantitative relationships are uncertain.

Table 4-17. Water consuming processes used in clean coal technologies

	Water Consuming Processes Used		
Technology	Coal washing/ preprocessing	*Steam generation*	*Wet scrubber*[1]
	Repowering technologies		
CAFB	No	Yes	No
PFBC	No	Yes	No
Gasification:			
Fuel Cells	Yes	No	No
IGCC	Yes	Yes	No
	Retrofit—NSPS capable		
ASC	No	Yes	No
Copper oxide	No	Yes	No
Dual-alkali scrubbing	No	Yes	Yes
	Retrofit—partial NSPS capable		
Advanced FGD w/salable byproducts	No	Yes	Yes
Spray dryer	No	Yes	Yes
LIMB	No	Yes	No
Sorbent injection	No	Yes	Yes
Gas reburning	No	Yes	No
SCR	No	Yes	No
Low NOx burner	No	Yes	No
	Retrofit—new fuel forms		
Ultrafine cleaning	No	Yes	No
Advanced physical cleaning	Yes	Yes	No
Advanced chemical cleaning	Yes	Yes	No
Mild Gasification	Yes	Yes	No
Direct liquifaction	Yes	Yes	No
Indirect liquifaction	Yes	Yes	No
Coal-oil coprocessing	Yes	Yes	No
Coal-water mixtures	Yes	Yes	No
	Industrial processes		
Integrated iron production	No	No	No

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[1] Some technologies do not necessarily provide thorough removal of SO_2 or NO_x, so additional water use for flue gas removal may be required. Only the water requirements inherent to the specific technology are included.

Most scientific and public concern over the environmental effects of coal combustion has been centered on the effects of SO_2 and NO_x emissions on acidification of water bodies and loss of associated biota (NAS 1981, NRC 1986, NAPAP 1987b, Mohnen 1988; Sects. 3.2.3 and 3.2.4). It is hoped that reductions in emissions will reduce acidity. Recovery of water quality as emissions decline can result from both natural and human introduction of substances that neutralize acidity or increase the rate of production of acid neutralizing capacity (ANC). Because acidity reflects the balance between a watershed's production of natural ANC through weathering of rocks and soils and the input of acid-producing materials, a reduction in atmospheric deposition could alter the balance toward less acid conditions in many waters. The response of watersheds to changes in acid deposition has been predicted with watershed models. Such studies have shown that the pH of some lakes would increase with reductions in SO_2 and NO_x deposition resulting from nationwide implementation of clean coal technologies, while other lakes would remain relatively unresponsive to decreases in deposition rates (e.g., Chen et al. 1988, Garrison et al. 1987).

In view of the uncertainties in directly relating changes in emissions of SO_2 and NO_x to changes in chemistry of surface waters, it is premature to make confident predictions about expected changes in water quality from clean coal technologies. It can reasonably be assumed, however, that the regional changes in water quality impacts generally will parallel the changes in SO_2 and NO_x emissions (described in Sect. 4.3.1.1).

Improvements to the acid-base status of water resources from implementing clean coal technologies would be greatest in the NE quadrant of the United States and in southeastern Canada, regardless of which individual technology or mix of technologies is implemented. This is due to the concentration of both acid-sensitive waters in the area and the long-range dispersion of acid-forming emissions from the large number of coal-fired generating stations in the quadrant (Sect. 4.3.1).

The most effective clean coal technologies for potentially remediating the acidification problems in the NE quadrant and eastern Canada are those technologies estimated to decrease the amount of acid-producing SO_2 and NO_x (Sect. 4.3.1.1 and Appendix B).

Reductions in NO_x are important for controlling both water acidity and nutrients (Sect. 3.2.3.2). Lower NO_x emissions could mean a reduction in eutrophying nitrogen compounds, principally nitrates, as well as lowered acidity. Reductions in NO_x production are estimated to be as much as 33% nationally, up to 45% in the NE quadrant, and up to 40% in the SE quadrant (Table 4-6; Appendix B). It is uncertain whether this reduction in NO_x alone would markedly affect surface water acidification; NO_x from coal burning is quantitatively less important for water acidification than is SO_2. For the problem of nutrient enrichment and eutrophication, reductions of 40% in all nutrients are called for by some analysts to stem damaging eutrophication of coastal waters (Fisher et al. 1988). A reduction of 40% is also, for example, the goal for reduction of all nutrient input to the Chesapeake Bay (Chesapeake Bay Agreement 1987). The most effective of the clean coal technologies are in this range whereas the others fall short. No quantitative analysis is possible without better understanding of the relationships between NO_x emissions and surface water nutrients.

The combined effect of reducing SO_2 and NO_x is postulated to be most protective of aquatic resources (OTA 1984, Cook 1988). Some technologies are effective in controlling only SO_2 or NO_x. Control of SO_2 alone (as with sorbent injection, wet limestone desulfurization, and all of the advanced coal cleaning technologies) or NO_x alone (as with low NO_x burner and SCR) (Appendix B) may be less effective than technologies that are effective in controlling both emissions.

Reduced quantities of solid wastes could also generate an improvement in water quality at some sites due to local reductions in point source discharges and leachates from landfill disposal (Sect. 4.3.2.2). Some technologies may increase solid wastes above conventional technologies, and, therefore, the potential for hazardous runoff and leachates from these technologies could be increased. Changes in the risk from leachates may parallel the changes in volume of solid wastes, although there is not a one-to-one relationship due to differing chemical composition of wastes. Some wastes would be similar to normal coal combustion ash while others would be gypsum, sulfur, and complex mixtures related to the composition of the source coals. The prospect for leaching and the chemical changes in groundwater and discharges to streams would differ greatly.

The solid wastes generated and the leachates that they might introduce to water resources would differ markedly by technology (Sect. 4.3.2.2; Appendix B). Sixteen technologies considered are estimated to increase solid wastes on a dry basis nationally. Two of these would show an increase of 1% or less. The advanced chemical treatment of medium sulfur coal would increase the wastes by more than 20%. The two technologies particularly effective for reducting SO_2 and NO_x, spray dryer with lime and advanced slagging combustor, are estimated to produce solid waste increments of about 8 and 17%, respectively. A breakdown of this waste by chemical composition and potential hazard is not available. Careful attention to landfill engineering tailored to the chemical composition of the wastes and to site monitoring should provide adequate mitigation for leaching of toxic materials to aquatic systems in most cases.

4.3.4 Impacts on Ecological Resources

4.3.4.1 Impacts on aquatic ecosystems

Reduction in emissions of acid-producing sulfates and nitrogen oxides by coal-fired utility and industrial boilers equipped with clean coal technologies may be reflected in improved aquatic life at some time following improved water quality (Sect. 4.3.3). The degree and timing of such improvement is uncertain.

That aquatic systems could recover from the effects of acidic deposition after emissions of SO_2 and NO_x have been reduced is clear. The uncertainties, however, are the rate and extent of recovery and whether recovery would result in the same biological community that existed prior to acidification. Evidence for recovery of water chemistry is becoming available from a number of studies; recovery of biotic communities is noticeably slower, however (Schindler 1986; Marmorek et al. 1988). Nevertheless, preliminary evidence shows improved fish recruitment for a few previously low-pH lakes that are recovering naturally in the Sudbury, Ontario area (Keller et al. 1986; Beggs and Gunn 1986). Chemical restoration improves the rate of recovery (Yan and Dillon 1984; Booth et al. 1986).

In addition to allowing recovery, clean coal technologies could prevent additional waters from being acidified. In principle, continued emissions at high rates could add newly acidified and biologically depauperate waters to the current inventory. With clean coal technologies, these resources will remain productive and would not, therefore, lose valuable living resources.

Because the impacts of acidic atmospheric deposition on water quality tend to be regional, the improvements in aquatic ecological resources by reduction in emissions from coal-fired utility and industrial boilers would also be regional. The region expected to show the most notable improvement would be the NE quadrant of the United States and the southeastern part of Canada, for reasons of susceptibility and the conditions already exhibited.

Improvements in biotic resources associated with lessened eutrophication as NO_x emissions are reduced are uncertain but would likely be small, in accord with small changes in input relative to other atmospheric nitrogen and nutrient sources (Sects. 3.2.3 and 4.2.1). Reversal of eutrophication can occur if nutrient input is controlled, based on experiences in Lake Washington, Lake Mead, and elsewhere (Ciecka et al. 1980, Schnoor and O'Connor 1980). However, for ecosystems heavily affected by nutrients in the sediments and a long flushing time, the period of recovery could be prolonged by internal recycling.

Changes in aquatic biota caused by changes in the amount and kind of ash and solid wastes generated and the runoff or leachates from their disposal sites (Sect. 4.3.3) would depend on the local disposal situations. Such changes are likely to be minor.

4.3.4.2 Impacts on terrestrial ecosystems

4.3.4.2.1 Impacts from acidic deposition

Estimates of reduction in emissions required for the adequate protection of terrestrial resources have not been determined. However, the OTA (1984) estimates that a reduction of emissions below the 1980 levels would be needed to "protect all but the most sensitive aquatic resources" in many areas receiving high levels of acidic deposition. Degradation of terrestrial resources could be slowed and the status of damaged ecosystems could possibly be improved by reductions similar to those recommended for aquatic resources. The northeastern states, which now receive the highest levels of deposition (Tables 4-11 and 4-12), would benefit most from reductions in SO_2 and NO_x emissions.

The repowering and retrofitting (NSPS capable) of existing coal-fired power plants using clean coal technologies have the potential for reducing SO_2 and NO_x (along with formation of O_3) emissions significantly in some regions (Table 4-1; Appendix B). Any reduction in emissions would reduce the potential exposure and possible damage to terrestrial ecosystems from acidic deposition. The development of those technologies producing the greatest reduction of acidic deposition components (Table 4-1) would provide the best opportunity to protect these resources from additional stress. For systems (especially forests) that have not already been greatly impacted, reductions could allow some natural recovery. The time between exposure and observable system response is not well established for the variety of mechanisms thought to be operating across the range of terrestrial ecosystems of concern. Thus, even with significant reductions, it is possible that atmospheric pollution-related injury, mortality, and recovery would continue in some areas for several to many years after the implementation of the technologies.

The risks of damage to terrestrial resources would be lessened by implementing the most efficient technologies that reduce SO_2 and NO_x emissions by the greatest amount. The state-of-the-science in determining "acceptable" levels of deposition to terrestrial ecosystems is dominated by many unknowns (i.e., length of exposure, topographic features, physiology and genetic susceptibility of the species, climatic factors, seasonality of exposure, and effects of pollutant mixtures). Consequently, the uncertainties in reduction levels necessary to protect terrestrial resources are also very large. The more sensitive species (e.g., red spruce) probably require significantly larger reductions in order to adequately protect the resource. For other species (e.g., maples, pines, and firs), the level of reduction required to protect the resource is unknown. In all quadrants, a reduction in SO_2 and NO_x emissions (and subsequent formation of O_3) would be beneficial by reducing the potential for damage and possibly reducing the areal extent and levels of damage in forests and plantations that now show symptoms of decline that have, in part, been attributed to air pollutants. Adverse impacts on wildlife inhabiting or utilizing the acid-stressed areas would also be lessened. Using the information provided in Sect. 4.3.1, a brief discussion of the expected impacts from reductions in SO_2 and NO_x emissions from commercialization of the clean coal technologies is given for each of the quadrants.

In the NE quadrant, sensitive species identified in Sect. 3.2.4.1 would be most protected from further damage with the commercialization of the repowering and retrofitting (NSPS capable) technologies (PFB, IGCC, ASC, Advanced FGD-CuO, Advanced FGD-dual alkali) having the greatest reductions in SO_2 emissions (Appendix B). The spray dryer with lime technology (retrofit—partial NSPS capable) also has significant reduction in SO_2 emissions. The risk of damage to both conifer and deciduous species in this quadrant would still exist, however. Reduction of NO_x emissions, using these technologies, is about one-half the reduction of SO_2 emissions. Reduction of NO_x emissions could also contribute to the reduction of O_3 levels and decrease the impacts on forest species and crops that are especially sensitive to O_3.

In the SE quadrant, the clean coal technologies that would provide the greatest emission reductions are much the same as those for the NE quadrant. The SE quadrant has not suffered the damage observed in the NE quadrant; however, damage to various pine species and red spruce that may be attributable to acidic deposition in the central portion of the region is significant in extent and magnitude. Similar reductions of NO_x and O_3 as in the NE quadrant would minimize damage and allow some recovery.

In the SW quadrant, ozone is the major atmospheric pollutant. Damage to ponderosa pine and Jeffrey pine and reductions in agricultural crop productivity have been observed in California. Most of this damage has been attributed to NO_x emissions and O_3 from motor vehicles. It does, however, demonstrate the sensitivity of these species to air pollutants. The heaviest concentration of coal-fired power plants in this quadrant is in Texas. Application of any individual clean coal technology in this quadrant would result in small (<10%) reductions in SO_2 and NO_x

Implementation of these technologies could not offset the expected large increases in SO_2 and NO_x emissions from fossil-fueled facilities and the possible continued or increased damage from these emissions (and subsequent formation of O_3) on areas surrounding and downwind of these facilities.

Oozone is also the major atmospheric pollutant of concern in the NW quadrant. Emissions of SO_2 and NO_x are low compared to those of the NE and SE quadrants because of the relatively small number of coal-fired plants operating in the region and because damage from SO_2 and NO_x emissions that can be attributed to coal-fired plants has not been observed. Applications of the repowering technologies (PFB, IGCC, and fuel cells) in this region would result in significant reductions of SO_2 (about 35%) and NO_x (about 20%) and would somewhat offset the expected emissions increases for this quadrant in 2010 under the no-action alternative (Sect. 4.2.1). Implementation of other technologies would result in small reductions of SO_2 and NO_x emissions.

4.3.4.2.2 Impacts from solid waste disposal

Some of the area required for disposal of solid waste would probably lie in floodplains (Sect. 4.3.2) or other sensitive wetland ecosystems. In the past, wetlands have been particularly attractive sites for disposal of combustion wastes (Dvorak et al. 1978). Low wetlands are preferred because little excavation is required and drainage is less. However, Executive Order 11990 requires that wetlands be protected from increased degradation, and a number of federal and state laws, regulations, and policies confer or would confer increased protection. If it is assumed that any remaining use of wetlands (including riparian wetlands on floodplains) would be proportional to the total area required for solid waste disposal, then estimates of that area provide an index of relative impacts to these terrestrial ecosystems.

In general, on the basis of the discussion in Sect. 4.3.2, the NE quadrant of the country would require the largest increase in waste disposal area for most alternatives, followed by the SE. However, because the NE quadrant is already heavily populated and industrialized, the greatest potential pressure on floodplain and wetland sites is likely to arise in the SE quadrant, which also has the greatest occurrence of wetland systems (e.g., bottomland hardwood forests and freshwater swamps and marshes; see Sect. 3.2.4). On the other hand, conflicts with floodplains and wetlands may be more serious ecologically when they occur in the SW quadrant because of the scarcity and consequent ecological importance of these systems. Whether this quadrant would experience an increase or a decrease in area needed for waste disposal would depend on the mix of technologies actually implemented during commercialization.

4.3.4.3 Impacts on endangered and threatened species

The impact of the commercialization of the clean coal technologies on endangered and threatened species is likely to have both positive and negative aspects. As noted above, there are likely to be beneficial effects of the program in the reduction of acidic deposition. Species dependent on habitats that are currently affected by acidification would benefit from the reduced deposition of acidic materials in both aquatic and terrestrial habitats.

Conversely, increased requirements for disposal of solid wastes on a dry basis from clean coal facilities is likely to contribute to the problem of loss of habitat upon which endangered and threatened species are dependent. In cases where such critical habitat is protected under state and federal laws and regulations, this additional threat would be minimal because disturbance to species or their critical habitat would not be permitted under these regulations. An evaluation of the impacts on specific endangered and threatened species is beyond the scope of this programmatic analysis because detailed information on the location and type of facilities that would be built during commercialization is unknown at this time. A detailed analysis to comply with Section 7 of the Endangered Species Act and state laws and regulations will be conducted during the environmental review of each project selected for funding.

4.3.5 Impacts on Socioeconomic Resources

Implementation and commercialization of clean coal technologies could affect all phases of the coal industry. Effects from these technologies may vary within and among quadrants according to which phase of the coal industry is the focus of discussion. The quadrants of possible impact are multiple and will vary according to the clean coal technologies, associated technologies, and factors under discussion. For example, retrofitted or repowered coal utility plants may benefit people located in downwind areas because of reduced air pollution. However, people located close to those plants and/or close to coal cleaning facilities could be affected by increased on-site waste disposal. Therefore, the regions of possible impact may cross community, state, regional, and national boundaries.

A detailed analysis of the socioeconomic impacts resulting from commercialization of the clean coal technologies, particularly in comparison with the no-action alternative, is not possible because specific information is not available concerning the location and number of new and existing plants that would be affected by commercialization. Nevertheless, a general discussion of the socioeconomic impacts is provided to identify issues that should be considered in evaluating the possible effects of commercialization. The overall effects of commercialization involve tradeoffs between benefits in some locations (e.g., reductions in polluting air emissions) and adverse impacts in other areas (e.g., hosting a waste disposal facility). Many of these impacts may not be deemed significant when viewed in a national context. However, such impacts could be highly significant at a local level for specific plants. Such impacts will be addressed in site-specific NEPA documents.

The socioeconomic impacts of commercialization of the clean coal technologies would most likely be very similar to those of the no-action alternative, differing mainly in the degree to which they are apparent. For instance, the greatest impacts, as in the no-action alternative, likely center on the construction of new facilities. The types of facilities constructed in both scenarios are coal-fired power plants, retrofitted or repowered power plants, industrial coal-fired boilers, coal preparation facilities, and waste disposal facilities. The impacts probably will be felt locally. Of these, the most labor-intensive is the construction of a complete coal-fired power plant. Because of the additions of different technologies, constructing new power plants equipped with clean coal technologies may require more workers and time than retrofitting or refurbishing old plants.

One difference between the proposed action and the no-action alternative is that some of the proposed technologies may have greater potential to generate social conflict during the siting process than conventional technologies. Siting facilities deemed socially and environmentally beneficial regionally, nationally, or internationally may, at the same time, affect much more directly the local communities in which such facilities are to be housed. Thus, there are tradeoffs between positive and negative impacts at the local level as well as between local, regional, national, and/or international levels.

Other distinctions may arise between the proposed action and the no-action alternatives. For clean coal technologies that generate more solid waste than is generated by wet-limestone FGD on a dry basis, more waste disposal facilities may be needed than for the no-action alternative. In addition, more coal preparation facilities may be envisioned with the proposed action than with the no-action alternative. For both alternatives, waste disposal requirements can be reduced by implementing and increasing recovery and recycling strategies (Sect. 4.2.2). For instance, the American Coal Ash Association (1987) reports that approximately 22% of the 66.8 million tons of fly ash, bottom ash, and boiler slag produced by utilities were used in the following ways: cement and concrete products; structural fills; road bases; filler in asphalt mixes; snow and ice control; blasting grit and roofing granules; and grouting.

4.3.6 Impacts on Health and Safety

Clean coal technologies represent efforts to reduce emissions associated with fuel production and use. The technologies included in this PEIS emphasize reduction of airborne sulfur and nitrogen oxidation products derived from coal combustion. This reduction of airborne waste may result in increased solid waste production at the plant sites, and the magnitude of that impact may increase as coal consumption increases. Estimation of the potential health impacts due to increased organic emissions from increased coal consumption requires additional information (Singh et al. 1986). The evaluation of human health impacts from organic wastes must consider both increased waste from increased consumption and the different compositions of organic wastes produced by the several technologies.

A detailed analysis of health effects cannot be prepared for this programmatic analysis because specific information on plant sites including coal composition and population densities surrounding specific waste storage sites is unavailable. Detailed evaluation of the potential health effects and description of the health and safety issues for each technology will be done as necessary when such information becomes available. Coal-derived solid, liquid and airborne emissions that are potentially hazardous to humans will probably be produced by the clean coal technologies (DOE 1985e). A comparison of solid wastes derived from these technologies relative to conventional coal combustion technology over the next two decades illustrates the magnitude of solid waste increases. Examples of toxic substance categories are documented for purposes of illustrating the potential human hazard (Munro et al. 1983).

Table 4-18 lists the range of issues to be addressed when evaluating the health impact of each specific clean coal project proposed for construction (DHHS 1989). The need for analysis of each plant site arises from considerable differences in plant construction, coal quality, coal transportation,

Table 4-18. Potential health and safety issues

General Issue	Potential Health and Safety
Air Quality	Dust control measures during construction Open burning Indoor air quality Compliance with air quality standards
Water Quality	Potable water (chemical, microbiological, and radiological quality) Body contact recreation Compliance with waste water treatment standards
Non-Hazardous Solid Waste	Any unusual or suspected health effects associated with solid waste disposal Effects of littering and provisions for cleanup, particularly conditions which might lead to vector harborage
Noise	Ambient noise levels during construction, implementation, etc. Effectiveness of any proposed noise reduction measures following construction, implementation, etc.
Radiation	Exposures to ionizing and non-ionizing radiation which may adversely affect human health
Hazardous Wastes	Solid, liquid, or gaseous wastes which because of their physical, chemical, or infectious characteristics pose a substantial threat to human health
Wetlands and Floodplains	Contamination of the food chain Construction in floodplain which may endanger human health
Occupational Health and Safety	Evaluation of the occupational and public health hazards associated with the construction and operation of the proposed project Evaluation of any occupational and public health hazards associated with the operation of a proposed program (e.g., pesticide application, disposal of toxic chemicals, etc.)
Land Use and Housing	The provision of adequate ventilation, heating, insulation and lighting Vector control provisions Impacts of a project upon the displacement and/or relocation of persons

Source: DHHS letter, Appendix A

and waste disposal, as well as differences in the particular clean coal technology used. The categories cover issues that pertain to both conventional technology and clean coal technologies. While each issue for each technology cannot be evaluated with available information, issues can be identified that may be impacted by reduction in airborne SO_2 and NO_x. Because of the potential for increased solid waste production, water quality, hazardous wastes, wetlands- and floodplains-associated food chain contamination, and occupational health and safety may require special attention.

When considering potential mortality associated with the various coal technologies, the estimated principal contributor to public mortality from proposed coal liquefaction facilities is rail and truck transportation of coal (Munro et al. 1983; Watson and O'Donnell 1985). Estimates of public and worker mortality from chemical toxicity, from that same model, show polynuclear hydrocarbons and chromium as significant sources of health risk (Munro et al. 1983, Dudney et al. 1983). Current efforts to reduce organic and toxic metal ion waste from the several clean coal technologies are expected to be continued.

A broad range of toxic responses has been observed when mammals and humans are exposed to a variety of chemicals associated with clean coal technologies. Table 4-19 lists some of those chemicals and chemical classes that may be part of the solid, liquid, and airborne wastes from the several technologies, and known toxic responses to those chemicals in test systems and in humans. The assessment of potential health hazards for each clean coal technology will depend on the extent of fugitive emissions and water quality for each clean coal plant.

Among the advanced coal cleaning technologies, the coal conversion processes (liquefaction and gasification) pose probably more issues affecting worker health and safety than the rest. The liquefaction step involves treating coal under fairly severe conditions of high temperature and pressure to achieve the conversion into liquids or gas. These conditions give rise to potential safety problems of fire and explosion and the attendant possibility of process stream releases. The process streams pose acute and chronic health hazards including cancer and mutation. The process streams may also be more abrasive than equivalent petroleum streams and have a considerable ability to degrade seals and valves, leading to enhanced possibilities of leaks and spills and consequent worker exposure. Maintenance workers, in particular, may face hazards from working on contaminated equipment; elevated levels of benzene-soluble compounds in the air were seen in the vicinity of shop welding on contaminated parts in the Ft. Lewis solvent refined coal pilot plant (DOE 1980). The gasification process produces a number of asphyxiant and acutely toxic gases so that leaks or accidents may expose workers to potentially injurious or even fatal concentrations of these substances. The liquefaction step of the indirect liquefaction processes involves the use of catalysts, some of which are toxic or give rise to toxic compounds. The Mobil Methanol-to-Gasoline Process involves potential exposure to methanol; here the major concern is probably more for the exposure of the public because industrial practices for worker protection are fairly well established. With proper worker protection measures, noise is not expected to be a significant occupational health issue in coal conversion plants.

Table 4-19. Health effects of compounds potentially present in clean coal technologies.[a]

Chemical	Health effects
Aliphatic hydrocarbons	This group is generally thought to be unlikely to present a significant hazard. One exception is dodecane, a possible potentiator of skin tumorigenesis by benzo[a]pyrene (BaP) and uv radiation. It has been shown to be cocarcinogenic with BaP in mice (Horton et al., 1957) and a potentiator in mice of skin carcinogenesis by a broad spectrum of uv radiation (Bingham and Nord, 1977). Dodecane is also a suspected but unproven inhalation hazard as a carcinogen. It is a known product of low-temperature coal conversion. Two other aliphatics, *n*-decane and *n*-tetradecane, have also shown potentiating effects on uv radiation carcinogenesis.
Ammonia	Intense acute irritation upon inhalation. No evidence of chronic effects from prolonged exposure to tolerable concentrations.
Aromatic amines	Aniline and its analogs are highly toxic, causing methemoglobinemia, central nervous system (CNS) effects, liver damage, skin sensitization, and, with some, human bladder cancer.
	B-naphthylamine and benzidine are potent carcinogens; 4-biphenylamine also causes human bladder cancer. Biphenylamines have been found in coal-derived SRC-1 materials (Paudler and Cheplen, 1979).
Benzene	Toxic to the blood-forming components of the bone marrow. Also a carcinogen that may cause leukemia in exposed workers.
Carbon disulfide	Acute CNS effects at 300 ppm and life threatening at 3000 ppm. Chronic CNS effects; increased incidences of coronary heart disease and hypertension at 10 to 40 ppm.
Carbon monoxide	A chemical asphyxiant causing rapid acute symptoms at 1000 ppm. Some indication of cardiovascular effects at chronic low-levels of exposure. Known to be fetotoxic in humans (Longo, 1977)
and	fetotoxic and teratogenic in animals (Kurzel and Cetrulo, 1981).
Carbonyl sulfide	A slight irritant, exerting its principal effects on the CNS. Toxicologically similar to but probably less hazardous than CS_2 and H_2S.
Coal tar products	Cancer, primarily lung, bladder, and skin, but also of other organs (see polycyclic aromatic hydrocarbons).
Cyanates, thiocyanates	Acute poisoning in animals induces rapid respiration, tremors, convulsions, etc. No evidence of chronic poisoning or lasting harm.

Table 4-19. Continued

Chemical	Health effects
Cresols	Highly toxic; similar to phenols but generally less severe (see Phenols below).
Dodecane	See aliphatic hydrocarbons.
Heterocyclic aromatics	*N*-heterocyclics: Pyridine and its derivatives are irritant and narcotic, and hepatorenal injury has been reported. Acridine and analogs are agents of proven irritancy and photosensitization and should be considered carcinogenic potentiators.
Hydrogen chloride	An intense acute irritant; no evidence of harm at chronic low-level exposure.
Hydrogen cyanide	An acute chemical asphyxiant with immediate death occurring at 270 ppm. Exposure of 18-36 ppm causes slight symptoms. Chronic effects include hypoxia, vertigo, rapid pulse, and nausea.
Hydrogen sulfide	A dangerous acute CNS and respiratory system poison at 400 ppm. A strong irritant of the eye and respiratory tract at 100 ppm; a slight irritant at 10 ppm. Chronic exposure to low levels may produce conjunctivitis or occasionally pulmonary edema (Doull, Klaassen, and Amdur, 1980).
Iron pentacarbonyl	Highly toxic, although less so than nickel carbonyl (see the latter). Can cause death.
Isopropyl ether	Anesthesia, but only at concentration above irritant threshold. More serious as a fire and explosion hazard.
Mercaptans	Can cause nausea and headache; exposure to high concentrations can produce unconsciousness with cyanosis, cold extremeties and rapid pulse.
Methanol	Highly toxic via ingestion and moderately toxic via inhalation and skin absorption. Poisoning results in systemic acidosis and CNS effects and can cause blindness or death (Casarett and Doull, 1975). Effects associated with inhalation and percutaneous absorption include: headache, dizziness, nausea, vomiting, vertigo, dermatitis, numbness, visual effects, and others. Available data indicate that chronic exposure to air concentrations of 1200 to 8300 ppm can lead to impaired vision; concentrations in excess of 200 ppm may lead to persistent, recurring headaches; occupational exposures at 25 ppm for an 8-h day appear to produce no harmful effects (NIOSH, 1976).
Naphthalene	Moderate-to-high acute toxicity; causes nausea, headache, fever, anemia, intravascular hemorrhage, liver and kidney damage, convulsions, and coma. It is an experimental carcinogen.

Table 4-19. Continued

Chemical	Health effects
Nickel carbonyl	Regarded as the most hazardous of the metal carbonyls. Inhalation of the vapor affects the CNS and may induce acute chemical pneumonitis. Brief exposure at 0.15 ppm reported to induce transient headache. Chronic exposure to nickel carbonyl has been implicated epidemiologically in the occurrence of human nasal sinus cancer and lung cancer (Casarett and Doull, 1975).
Nitrogen dioxide	Delayed lung irritation and edema; probably increases susceptibility to pulmonary infectious diseases (Doull, Klaassen, and Amdur, 1980).
Nitrosamines	It is hypothesized that nitrogen oxides from combustion processes might react with amines to produce these potent carcinogens.
Phenols	Most monohydric phenols are highly toxic via inhalation, skin absorption, and ingestion. Acute poisoning affects the CNS. Chronic exposure to vapors results in digestive disturbances, nervous disorders, and skin eruptions; dermatitis is common among exposed workers. There is evidence to indicate an enhancement of carcinogenicity of tars and oils in the presence of phenols.
Polycyclic aromatic hydrocarbons	Active members of this class are well-established skin carcinogens, as well as respiratory carcinogens and, in some cases, other types. BaP is widely used as an example and proxy for the group, because it is strongly carcinogenic and common where high-boiling polycyclic aromatic hydrocarbons are found.
Sulfur dioxide	Upper respiratory tract irritant; possible cocarcinogen. May induce asthmatic attacks.
Toluene	A CNS depressant causing narcosis at relatively high (>0.1% by vol) concentrations; no evidence of chronic effects below narcotic threshold.
Trace elements	Arsenic: anemia, gastric disturbance, renal symptoms, ulceration; skin and lung carcinogen in humans; a suspected teratogen.
	Beryllium: respiratory disease and lymphatic, liver, spleen, kidney effects; an animal and probable human carcinogen.
	Cadmium: emphysema and fibrosis of the lung, renal injury, possible cardiovascular effects; an animal and possible human carcinogen; testicular toxicity in mice and rats; teratogenic in rodents.
	Lead: anemia, cardiovascular, neurological, growth retarding, and gastrointestinal effects; some compounds are animal and possible human carcinogens; fetotoxic and probably teratogenic to humans.

Table 4-19. Continued

Chemical	Health effects
	Manganese: respiratory and other effects.
	Mercury: neural and renal damage, cardiovascular disease; methyl mercury is teratogenic in humans.
	Nickel: dermatitis, intestinal disorders; nickel and nickel oxide dusts are carcinogenic to guinea pigs and rats; nickel refining is associated causally with cancer in humans.
	Selenium: gastrointestinal disturbance, liver and spleen damage, anemia; a possible carcinogen, a suspected teratogen.
	Vanadium: acute and chronic respirator dysfunction.
Xylene	A CNS depressant and respiratory irritant.

[a]Source: Munro et al. 1983.

Any of the clean coal processes that produce very finely pulverized coal or coal dust may pose hazards from explosive mixtures of coal dust and air.

4.4 UNAVOIDABLE ADVERSE IMPACTS

A major goal of the CCTDP and subsequent commercialization by the private sector is to reduce atmospheric emissions of SO_2 and/or NO_x from coal-fired utilities and industries. Such reductions would alleviate the effects of acidic deposition on sensitive natural ecosystems (e.g., poorly buffered lakes) and other important resources (e.g., croplands and structures). These beneficial impacts of lowering emissions must be weighed against possible adverse impacts.

For the clean coal technologies, some new atmospheric emissions would occur. For example, new facilities utilizing technologies such as coal liquefaction, coal processing, and coal preparation would become new sources of atmospheric emissions. More vehicle emissions would be generated from transporting and disposing of additional solid waste. It is not possible to quantify these impacts because specific locations and technologies that will be developed during commercialization are not known. Although these impacts on air resources can be minimized through compliance with regulations by using available technology, some unavoidable impacts would occur. Nevertheless, the overall impacts from commercialization of clean coal technologies are expected to be beneficial.

The use of coal in either the proposed or no-action alternative would result in some unavoidable additions of CO_2 to the atmosphere, with possible negative effects on climate (e.g., global warming). Because carbon dioxide is a major product of any fossil fuel combustion, any action that increases the quantity of coal burned would unavoidably increase the amount of CO_2 released to the atmosphere. Increased efficiency associated with many of the clean coal technologies could reduce the amount of coal burned and, thereby, reduce CO_2 proportionately. The two alternatives would be roughly equivalent, however, in terms of their effects on the overall level of CO_2 emissions.

Clean coal technologies may generate more solid waste on a dry basis than conventional technologies under the no-action alternative. The impact of this additional waste is unknown because the mix of technologies that would be commercialized and the locations of the facilities is not known. However, additional waste disposal capacity would be needed in the form of new or expanded landfills and ponds. Although the impacts of siting new waste disposal sites or expanding existing facilities cannot be avoided entirely, with careful planning such impacts probably can be minimized. Proper siting will avoid or minimize disrupting important natural resources such as floodplains, wetlands, and prime farmlands. Moreover, the benefits of reducing acidic deposition are likely to outweigh any adverse impacts on land use.

Commercialization of clean coal technologies would contribute to improved water quality and positive effects on aquatic biota in the NE quadrant and southeastern Canada. However, localized, unavoidable impacts on water quality and aquatic life could still result from leachates released from solid waste disposal areas. Such impacts could be minimized by proper on-site control and mitigation. Reduced atmospheric emissions of SO_2 and NO_x could contribute to reduction in damage to forests, crops, wetlands, and wildlife from acidic deposition. Loss of terrestrial habitat from construction of new sites for disposal of solid waste and other types of facilities (e.g., new liquefaction plants) would also be unavoidable but is unlikely to differ substantially from the loss associated with the no-action alternative. Proper siting of these facilities can minimize such losses. Again, the benefits of reducing acidic deposition probably outweigh these adverse impacts.

Unavoidable socioeconomic impacts would be similar for both commercialization of clean coal technologies and the no-action alternative. The proposed action could involve a greater number of sites for new power plants, ancillary or supporting facilities (e.g., coal cleaning or liquefaction facilities), and a consequent increase in siting disputes with their social ramifications would be expected. In rural areas, the large construction work force necessary for building new power plants would unavoidably affect local infrastructures but would be compensated to a large degree by benefits from new taxes and jobs. Additional storage areas for coal piles and wastes from coal preparation and coal combustion would take land away from other potential uses and users either directly (land commitments for facilities, etc.) or indirectly (through potential contamination of water supplies or land).

4.5 IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES

Although commercialization of clean coal technologies would result in a reduction of SO_2 and NO_x emissions and, therefore, a reduction in acidic deposition, there would continue to be some release of these and other pollutants into the atmosphere from coal cleaning and transportation of additional waste.

The proposed action would create the need for more solid waste disposal on a dry basis than the no-action alternative, which in turn would involve the irretrievable commitment of land. Waste disposal sites would contain contaminants that, over time, could leach into ground and surface water bodies. On the short term, however, the potential impacts of leachates on water quality and aquatic life would be largely minimized by proper site design and monitoring. In the long term (i.e., 100s and 1,000s of years), some movement of these materials into ground and surface waters is inevitable. The contribution to this long-term problem from commercialization of clean coal technologies is small compared to the contribution from all coal waste disposal sites, and the magnitude and type of impact is highly uncertain.

Resources used to fabricate equipment and construct new facilities would be irretrievably lost under both alternatives. Commercialization of the clean coal technologies would be likely to involve more new equipment and, therefore, the use of more resources.

4.6 RELATIONSHIP BETWEEN SHORT-TERM USES OF THE ENVIRONMENT AND THE MAINTENANCE AND ENHANCEMENT OF LONG-TERM PRODUCTIVITY

Decreases in atmospheric emissions of SO_2 and NO_x from commercialization of clean coal technologies would enhance the long-term productivity of resources presently experiencing adverse impacts from acidic deposition. The reduction in atmospheric emissions would contribute toward maintaining and improving long-term productivity of water resources, including the biological productivity of regional lakes and streams, particularly in the acid-sensitive NE quadrant of the United States and southeastern Canada. As a technological solution to a long-term and regional problem, there are only minor tradeoffs involved, especially in the short term.

The clean coal technologies have both economic and environmental short-term costs. Short-term environmental costs would include increased land use for solid waste disposal above that for the no-action alternative. In addition, more land for such facilities as coal preparation and liquefaction facilities would be needed. These uses are likely to reduce the long-term productivity of the affected land, even with reclamation.

Because CO_2 emissions resulting from the CCTDP and subsequent commercialization by the private sector are a small fraction of global CO_2 emissions, the long-term global impact of such commercialization is similar to that of the no-action alternative. Under the proposed action, however, the amount of CO_2 released could decrease if repowering technologies (Table 4-4) such as pressurized fluidized-bed, integrated gasifier combined cycle, and fuel cells were commercialized.

4.7 MITIGATION

In the most general sense, the CCTDP and subsequent commercialization of the successfully demonstrated technologies is itself a mitigation measure designed to avoid or minimize emissions of SO_2 and NO_x, thereby reducing the impacts of acidic deposition both in the United States and Canada. Commercialization of these technologies should have a major, beneficial effect by improving air quality and reducing the impacts of acidic deposition. While no net adverse impacts to air quality are expected from commercialization of clean coal technologies, commercialization that maximizes reductions in SO_2 and NO_x emissions would consequently optimize improvement in ambient air quality and acid precipitation. Air pollution control technology would mitigate adverse impacts such as additional dust from coal cleaning and ash handling, and atmospheric emissions that occur during fuel production in accordance with regulations applicable in 2010.

The best available mitigation to avoid or minimize adverse impacts on land use is the selection of those clean coal technologies that provide the smallest quantities of solid waste. Technologies that generate usable byproducts generally have minimal undesirable land-use side effects. Most clean coal technologies produce some solid wastes. Disposing of these wastes at the site from which the coal was mined, where possible, would substantially reduce land-use impacts. The area needed for solid waste disposal may be reduced if increased uses and markets can be found for fly ash, bottom ash, and slag. The American Coal Ash Association (1987) reports that approximately 22% of the 66.8 million tons of fly ash, bottom ash, and boiler slag produced by utilities in 1986 was used in the following ways: cement and concrete products, structural fills and road bases, filler in asphalt mixes, snow and ice control, blasting grit and roofing granules, and grouting.

On-site actions at waste disposal sites will be taken to control leaching of contaminants from the new solid waste disposal sites into local streams and lakes. Such control will minimize impacts of leachates on water quality and aquatic life. Wherever additional materials are mined for the new technologies (e.g., limestone for the FGD process), local controls that are already common practice would be necessary to prevent runoff of silt and other materials that could be detrimental to aquatic organisms and local water resources.

5. RELATIONSHIP TO FEDERAL ENVIRONMENTAL REQUIREMENTS

The purpose of this section is to identify major federal environmental laws and regulations that are generally applicable to activities under the CCTDP. State and local laws also may be applicable but are not discussed here because the primary federal regulatory programs establish the basic framework within which the states must act.

As discussed previously, the CCTDP is directed toward the Special Envoy's recommendations on demonstrating technologies that can significantly reduce emissions of SO_2 and NO_x from existing coal-burning facilities. To obtain near-term reductions in emissions that can help reduce acid precipitation affecting ecosystems in the United States and Canada, many of the projects proposed will involve retrofit technologies for pollution control or technologies for repowering existing facilities or for use in new facilities to generate electricity from coal more cleanly and efficiently. Thus, emphasis is given here to requirements that affect electric power generation.

5.1 CLEAN AIR ACT

Standards and regulations promulgated under the Clean Air Act (CAA, Pub. L. 95-95, as amended) and related legislation are the most critical to the commercialization of innovative clean coal technologies. This Act, administered jointly by the EPA and the states, is intended to ensure that air quality is maintained or improved. National Ambient Air Quality Standards (NAAQS) set by EPA (40 CFR Part 50) are the foundation of the air quality program. New Source Performance Standards (NSPS) emissions limitations (40 CFR Part 60) applicable to specific categories of stationary facilities having the potential to emit more than a specified amount of pollutants per year are instrumental in achieving NAAQS. Regulatory approaches differ in areas where air quality is better than ambient standards for regulated pollutants and in areas where standards have not yet been met. Where ambient air quality is better than national standards, Prevention of Significant Deterioration (PSD) permitting requirements (40 CFR 51.24) apply. Where air quality measured for one or more regulated pollutants does not meet national standards, Nonattainment Areas New Source Review requirements must be met.

5.1.1 National Ambient Air Quality Standards

Since 1970, air pollution abatement efforts have focused on limiting emissions of SO_2, NO_x, CO, particulates, and organic compounds that promote ozone formation in the lower atmosphere. Lead was added to the list in 1978. For these substances, EPA has established NAAQS which set maximum allowable concentrations in the atmosphere according to type of effects they pose. Under NAAQS, both primary and secondary standards must be met. Primary standards set emissions levels above which concentrations of regulated pollutants are believed to threaten public health. Secondary standards set emissions levels for these pollutants above which public welfare is believed to be negatively affected (Table 5-1).

Effective July 31, 1987, the concentration limit and basis for measurement for particulate matter were changed. Previously based on the total suspended particulates (TSP), attainment of primary

Table 5-1. National Ambient Air Quality Standards for air pollutants

Pollutant/averaging period	Primary standard		Secondary standard	
	(ug/m^3)	(ppm)	(ug/m^3)	(ppm)
Sulfur dioxide				
Annual arithmetic mean	80	0.03		
24-hour	365	0.14		
3-hour			1,300	0.5
Particulate matter (as PM_{10})[a]				
Annual arithmetic mean	50		Same	
24-hour	150		Same	
Carbon monoxide				
8-hour	10,000	9	Same	
1-hour	40,000	35	Same	
Ozone				
1-hour	235	0.12	Same	
Nitrogen dioxide				
Annual arithmetic mean	100	0.05	Same	
Lead				
Maximum quarterly average	1.5		Same	

[a] PM_{10} = particulate matter with an aerodynamic diameter ≤ 10 μm.

and secondary NAAQS for particulate matter now must be determined by measuring particles termed "PM_{10}" (those with an aerodynamic diameter ≤ 10 μm). The major reason for this change was to account for the greater potential health and welfare effects of smaller respirable particles.

5.1.2 New Source Performance Standards

Stationary sources, including electric generating plants and certain types of industrial equipment, must meet federal NSPS emissions limits. During the 1970s and 1980s, EPA promulgated several different "sets" of NSPS applicable to fossil-fuel steam generators. Generally, the date when construction, reconstruction, or modification begins and the boiler capacity determine which NSPS a steam generating unit must meet. States may (and some have) set ambient and emission standards more stringent than federal standards.

5.1.3 Regulatory Approaches Under the Clean Air Act Programs

Under the CAA, areas of the country are designated as "Attainment" or "Nonattainment" for regulated pollutants. Attainment areas are those in which ambient air quality is better than national standards for an NSPS pollutant. Nonattainment areas are those in which air quality standards are exceeded for a regulated pollutant. One area may be attainment for some pollutants and nonattainment for others. Regulatory approaches applicable to attainment and nonattainment areas differ and may affect permitting and performance requirements of clean coal technologies.

In Attainment areas, the regulatory goal is to preserve or improve the existing air quality. New sources must demonstrate that their development will not increase ambient concentrations of contaminants beyond established acceptable increments above assumed baselines. The increments must serve all new sources, and total increments generally will not be available to a single facility. In such areas, new sources in any of 28 categories established by EPA (including fossil-fueled electric generating facilities with a heat input capacity of more than 73 MW) with the potential to emit 100 tons/yr or more of an NAAQS pollutant must undergo PSD New Source Review. For new sources not listed as one of the 28, the emission rate "trigger" for PSD review is 250 tons/yr. These requirements also apply to major modifications to existing facilities which may result in a "significant" increase in any pollutant for which the area is in attainment. The definition of a significant increase differs among criteria pollutants.

In nonattainment areas, the regulatory goal is to improve air quality to meet NAAQS. A major stationary source for these areas is one with potential to emit 100 tons/yr or more without regard to source category. For nonattainment areas, EPA has instituted an "offset policy" that requires new sources to meet:

- lowest achievable emission rate,
- compliance of applicant's existing sources,
- emissions offsets, and
- net positive air quality benefit.

Emission offsets (reductions) must be obtained from existing sources in an amount at least equal to the proposed new emissions. Emission offsets may be from facilities controlled by the applicant or from other outside sources. Only intra-pollutant emission tradeoffs are acceptable. For example, particulate matter reductions may not be used to offset new or increased SO_2 emissions. For net positive air quality benefit, it must be shown that emission offsets will provide a positive net air quality benefit in the nonattainment area to ensure reasonable further progress toward attainment of the NAAQS.

5.2 CLEAN WATER ACT

The Clean Water Act (CWA; Pub. L. 92-500, as amended) is intended to ensure that the overall quality of navigable waters of the United States is either improved or maintained at levels that will support their highest use. (As with the CAA, this statute is based on federal-state cooperation.) Standards act as a "floor" below which water quality should not drop, and effluent discharge limits "at the end of the pipe" are intended to ensure that these standards are met. Title III of the CWA directs EPA to set these discharge standards and gives the agency enforcement powers. Title IV establishes a permit program system, the National Pollution Discharge Elimination System (40 CFR Part 122), that regulates discharges to surface waters. No person may discharge any regulated pollutant into any surface water without a permit from either EPA or the state.

EPA has not published specific effluent limitations for many source categories that may discharge to surface waters. For certain types of facilities listed in the CWA, such as steam electric power plants, however, EPA has established effluent limitations for existing and new sources (40 CFR Part 423). Table 5-2 shows New Source Performance Standards for these plants, which are representative of what might be expected from clean coal technology projects.

5.3 RESOURCE CONSERVATION AND RECOVERY ACT AND AMENDMENTS

The Resource Conservation and Recovery Act (RCRA; Pub. L. 94-580, as amended) and a major amendment to it known as the 1984 Hazardous and Solid Waste Amendments (HSWA; Pub. L. 98-616) are intended to ensure that all solid waste, including suspensions, other liquids, and especially hazardous waste, is handled so as to minimize risks to the environment and the public. RCRA provides for "cradle to grave" tracking by requiring waste generators, transporters, and treatment/storage/disposal facilities to use a manifest system keyed to a generator identification number (40 CFR Part 260). Treatment/storage/disposal facilities must obtain permits which set facility-specific requirements for waste-handling methods (40 CFR Parts 262, 263, and 264). HSWA limits land disposal of many wastes and sets strict requirements for construction and operation of land disposal facilities.

Currently, solid wastes from coal-burning utilities and industries are exempted from regulation under Sect. 3001 of the Resource Conservation and Recovery Act (RCRA). Section 8002 of RCRA required the EPA to study alternatives for disposal of coal combustion wastes and present the results to Congress. The study (EPA 1988a) found that fly ash, bottom ash, boiler slag, and flue gas desulfurization wastes generally do not exhibit hazardous characteristics under current

Table 5-2. New source performance standards for steam electric power generation[a]

Source	Pollutant/ property	Concentration One-day maximum (mg/L)	Concentration Thirty-day average (mg/L)
Low volume wastes	Total suspended solids	100.0	30.0
	Oil/grease	20.0	15.0
Metal cleaning wastes	Total suspended solids	100.0	30.0
	Oil/grease	20.0	15.0
	Copper	1.0	1.0
	Iron	1.0	1.0
Bottom ash transport water	TSS	100.0	30.0
	Oil/grease	20.0	15.0
Cooling water (once through) >25 MW	Chlorine (residual)	0.20[b]	
Cooling water (once through) <25 MW	Chlorine	0.5[b]	0.2[c]
Cooling tower (blowdown)	Chlorine (free available)	0.5[b]	0.2[c]
	126 priority pollutants	not detectable	not detectable
	Chromium (total)	0.2	0.2
	Zinc (total)	1.0	1.0
All sources	Polychorinated biphenyls	0	0
All sources except once-through cooling water	pH	6.0-9.0	6.0-9.0

[a] The quantity of pollutants discharged from the following sources shall notexceed the quantity determined by multiplying the flow of the waste source times the concentration listed.

[b] Maximum concentration.

[c] Average concentration.

RCRA regulations. EPA reported that it intended to regulate these wastes under Subtitle D of RCRA (for nonhazardous wastes). EPA found that some maintenance and water purification wastes do occasionally exhibit RCRA hazardous characteristics (EPA 1988a). EPA is considering removing the Sect. 3001 exemption for these wastes and making them subject to the requirements of RCRA Subtitle C. If catalysts, filter cakes, slag, ash, or byproducts contain sufficient amounts of heavy metals or extractable/leachable organics and are disposed of off site or without mixing with other solid wastes, they could be classified as hazardous.

5.4 FISH AND WILDLIFE COORDINATION ACT AND ENDANGERED SPECIES ACT

The Fish and Wildlife Coordination Act (Pub. L. 85-624, as amended) requires federal agencies to (1) consult with the U.S. Fish and Wildlife Service (USFWS) and appropriate state fish and wildlife agencies, and (2) modify project plans by "justifiable means and measures" in order to prevent the loss of or damage to fish and wildlife resources, as well as to provide concurrently for the development and improvement of such resources.

Under Section 7 of the Endangered Species Act of 1973 (Pub. L. 93-205, as amended), federal agencies are required to consult with the USFWS and the National Marine Fisheries Service (NMFS) to ensure that proposed actions are "not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of the critical habitat of such species . . ."

DOE has initiated contact with the USFWS by providing them with a copy of the PEIA. In response to comments provided to DOE by the USFWS (Appendix A), DOE contacted the USFWS. Because the present PEIS is a programmatic analysis and information is not currently available on the specific location of projects, it was agreed that further consultation is unnecessary until site-specific NEPA review for individual projects is initiated. DOE intends to fully meet its obligations under the FWCA and the Endangered Species Act during the site-specific NEPA reviews.

5.5 FLOODPLAINS AND WETLANDS REQUIREMENTS

Federal agencies must consider the effects of their proposed actions on floodplains and wetlands under Executive Orders (EOs) 11988 ("Floodplain Management") and 11990 ("Protection of Wetlands"). These EOs require federal agencies to avoid to "the extent practicable" adverse impacts associated with the occupancy and modification of floodplains and the destruction and modification of wetlands. Agencies are also directed to avoid direct or indirect support of development in floodplain and wetlands wherever there is a practicable alternative. Agencies must determine whether a floodplain or wetland is present that may be affected by an action, assess the impacts on such floodplains and wetlands, and consider alternatives to the action. Early public review is required, and measures for minimizing harm must be included in any plans for actions that might occur in a floodplain or wetland.

5.6 OTHER FEDERAL REGULATORY REQUIREMENTS

The federal regulatory requirements discussed above are those that are most likely to be encountered for CCTDP projects. In addition, particularly for projects involving new sites, the need for compliance with the National Historic Preservation Act (Pub. L. 89-665, as amended) and the American Indian Religious Freedom Act (Pub. L. 95-341) will be assessed and appropriate steps taken to ensure compliance.

In some instances, regulations under the Safe Drinking Water Act (Pub. L. 93-523, as amended) could apply to a CCTDP project where contamination of public drinking water supplies or protection of groundwater becomes an issue. DOE will comply with requirements under this statute as appropriate.

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7. LIST OF PREPARERS

Oak Ridge National Laboratory

Name	Degrees and dates	Position
Boston, Charles R.	Ph.D. Chemistry, 1953	Group Leader
Coutant, Charles C.	Ph.D., Fisheries Biology, 1965	Senior Research Ecologist
Hinkle, Norman E.	B.S., Mechanical Engineering, 1952	Research Staff Member
Hunsaker, Donald B., Jr.	D.Env., Environmental Science and Engineering, 1980	Research Staff Member
Marland, Gregg	Ph.D., Geology, 1972	Research Staff Member
McCold, Lance N.	M.S., Mechanical Engineering, 1977	Research Associate
Miller, Robert L.	M.S., Meteorology, 1977	Research Staff Member
Munro, Nancy B.	Ph.D., Mammalian Physiology	Research Associate
Railsback, Steven F.	M.S., Environmental Engineering, 1981	Research Associate
Reed, Robert M.	Ph.D., Botany/ Plant Ecology, 1969	Group Leader
Roop, R. D.	M.S., Biology	Research Associate

Rickert, L. W.	B.S., Chemistry, 1948	Research Associate
Salk, Martha S.	Ph.D., Plant Ecology, 1975	Research Staff Member
Uziel, Mayo	Ph.D. Biology, 1955	Research Staff Member
Watts, Julie A.	M.S., Mathematics, 1968; graduate work in ecology	Research Staff Member
Webb, J. Warren	Ph.D., Insect Ecology, 1974	Research Staff Member
Wolfe, Amy K.	Ph.D., Anthropology, 1986; MRP, Regional Planning, 1980	Research Associate

Technology & Management Services, Inc.

Name	Degrees and dates	Position
Andrews, Michael	B.S., Biological Sciences, 1980	Senior Analyst
Monsour, Regina M.	Ph.D. coursework, 1982; M.A. Political Science, 1978; B.A. Political Science, 1973	Senior Analyst
Soni, Jesse	M.S., Environmental Control, 1976; B.S. Chemical Engineering, 1970	Senior Environmental Engineer
Stone, John T.	M.B.A., Quantitative Methods, 1964; B. Aeronautical Engineering, 1958	Principal Vice President, Technical Services
Zukor, Stephen	M.S., Engineering Administration, 1975, B.S. Chemical Engineering, 1969	Senior Engineer

8. LIST OF RECIPIENTS

Administration and Congress

The Honorable James H. Baker
The Honorable Max Baucus
The Honorable Quentin N. Burdick
The Honorable Robert C. Byrd
The Honorable John H. Chafee
The Honorable Silvio O. Conte
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Economic Development Administration
Environmental Protection Agency
Federal Emergency Management Agency
Federal Energy Regulatory Commission
General Accounting Office
Interstate Commerce Commission
National Aeronautics and Space Administration
National Bureau of Standards
National Oceanic and Atmospheric Administration
National Science Foundation
Office of Management and Budget
Public Health Service
Solar Energy Research Institute
Tennessee Valley Authority
U.S. Mission to OECD

State and Local Agencies and Indian Tribes

City of New Bedford, Massachusetts
Council of Energy, Resources Tribes
Illinois Department of Natural Resources
Indiana Department of Commerce
Massachusetts Executive Office of Energy Resources
Michigan Legislative Service Bureau
Missouri Department of Natural Resources
Ohio Coal Development Office
Ohio Office of the Consumers Council
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Southern States Energy Board
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Western Interstate Energy Board
Wisconsin Department of Natural Resources
Wisconsin Department of Administration

Media

Acid Precipitation Digest
Advance Fuel Technology
Cleveland Plain Dealer
Commerce Clearing House

Florida Power Line
Global Climate Change Digest
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Knoxville Journal
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Washington Service
Waste Technology News

Environmental and Other Public Interest Groups

Alliance for Acid Rain Control
Clean Coal Technology Coalition
The Conservation Foundation
Environmental Policy Institute
Greenpeace
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Industry, Universities, and Other Organizations

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Anderson, Passarelli and Associates
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Florida Institute of Phosphate Research
Foster Wheeler Development Corp.
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Gamma-Metrics
Gas Desulfurization Corporation
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Hazen Research
Independent Power Corporation
Ingram Coal Company
Institute for Gas Technology
Inter-Power of New York
Interstate Natural Gas Association of America
Iowa-Illinois Gas and Electric
Iowa State University
Katzen Associates
Kerr McGee Coal Corporation
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Liquid Air Corporation
Lummus Crest, Inc.
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M-C Power Corporation
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Metropolitan Energy Systems, Inc.
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Oak Ridge Associated Universities
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Ohio Edison Company
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Pennsylvania Coal Association
Pennsylvania State University
Pyropower Development Corporation
Radian Corporation
Rivers, Trainor, Doyle, and Light
Sheladia Associates
Shell Development
Shell Mining Company
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Slurry Tech Corporation
Solite Corporation
Southern Illinois University at Carbondale
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Tampa Electric Company
Technical Insights, Inc.
Technology and Management Services, Inc.
Texaco, Inc.
Texas Gas Transmission Corporation
Turn Point Engineering
University of Illinois at Chicago
University of New Hampshire
University of North Dakota
University of Pittsburgh

University of San Diego
University of Tennessee Space Institute
University of Washington
Veritas Petroleum Services
Virginia Center for Coal and Energy Research
Western Kentucky University
Western Organization of Resource Councils
West Virginia University
WORC
ZURN Industries, Inc.

International

Alberta Office of Coal Research and Technology
Applied Research Laboratories S.A.
Associacion Gestora para la Investigacion
  y Desarrollo Technologico del Carbon Ocicarbon
Consumer Gas
Ontario Department of Energy
Embassy of Belgium
Embassy of Canada
Embassy of South Africa
Embassy of Sweden
Hydro-Quebec
Indian Institute of Chemical Technology, Hyderabad
Institute of Isotopic and Molecular Technology,
  Romania
Institute of Minerals, Energy and Construction,
  Australia
International Energy Agency
IEA Coal Research
Manchester Polytechnic, Great Britain
Norges Geologiske Undersokelse, Norway
Ontario Hydro
Saskatchewan Energy & Mines
University of Regina, Saskatchewan

Individuals

Mary Alford
Bob Arguero
Dan Augenstene
Charles Barnwell
Christian Bolta

Edith Chase
Padma Datta
George Ellis
Wanna Freeman
Leon Green, Jr.
Charles W. Hoskins
Harry B. Keck
James Kelly Kindig
Stephen Lien
Stephen Maheris
David R. Maneval
Wayne Martin
Jim McCarthy
John Memmi
Paul Merrion
Sophia A. Mortillaro
Donald E. Olsen
Shaik Qaber
William B. Retallick
Gordon Rogers
Robert Shannon
J. R. Spraul
Grant Thompson
Walter R. White

9. GLOSSARY

Acidification. A process in which a water body or substrate becomes increasingly acidic because of additions of pollutants or naturally occurring chemical compounds.

Anthropogenic. Referring to the impact of man on nature.

Ash. All mineral matter left after the complete combustion of fuel.

Attainment area. Under the Clean Air Act, areas of the United States that are designated by EPA as having air quality that is cleaner than the air quality standards.

Baseline. 2010 emissions expressed in millions of tons/yr.

Capacity factor. The actual output of a facility per unit time (usually a year) divided by the output while operating continuously at design rate.

Capacity increment. Percentage increase in output resulting from the application of a clean coal technology.

Criteria pollutants. Under the Clean Air Act, pollutants that could endanger public health include sulfur dioxide, nitrogen dioxide, ozone, carbon monoxide, total suspended particulates, and lead.

Dry deposition. A component of acidic deposition that refers to the contribution of salts and pollutants (e.g., sulfurous and nitrous compounds) in the atmosphere that are deposited directly on vegetation and other surfaces during periods when no rainfall is occurring.

Eutrophication. The process by which a body of water becomes either naturally or by pollution rich in dissolved nutrients. The body of water is frequently shallow and has seasonal oxygen deficiency in the stagnant bottom waters.

Federal regions. The ten standard regions used by many agencies of the U.S. government; Fig. 1-2 of the PEIS shows the boundaries of these regions.

Fen. A type of wetland that is in contact with mineral-rich water.

Ferruginous. Containing iron.

Greenfield plants. New plants.

Greenhouse gases. Gases such as carbon dioxide, nitrous oxide, methane, and chlorofluorocarbons whose elevated levels in the atmosphere may be contributing to the warming of the atmosphere.

Heat rate. A measure of the overall efficiency of the system expressed in Btu's of energy supplied by the fuel to produce one kilowatt-hour of electricity. An ideal system, one with no loss, would require 3,413 Btu/kwh. Conventional power plants have efficiencies about 1/3 of ideal, so they require about 3 times the Btu's per kwh.

HHV (higher heating value). Water vapor is one of the products of combustion for all fuels which contain hydrogen. The heat content of a fuel depends on whether this water vapor is allowed to remain in the vapor state or is condensed to liquid. In the bomb calorimeter the products of combustion are cooled to the initial temperature and all of the water vapor formed during combustion is condensed to liquid. This gives the high, or gross, heat content of the fuel with the heat of vaporization included in the reported value. Units of HHV are expressed as Btu's/lb.

Mycorrhizal. A symbiotic relationship between a fungus and the roots of a higher plant that is often important in plant nutrition.

Nameplate capacity. The full-load continuous rating of a generator, prime mover, or other electrical equipment under specified conditions as designated by the manufacturer. It is usually indicated on a nameplate attached physically to the equipment.

National Ambient Air Quality Standards. Under the Clean Air Act, standards which define maximum allowable ambient concentrations for the criteria pollutants.

National Pollutant Discharge Elimination System. Under the Clean Water Act, a permitting process used by EPA and authorized states to control point source discharges into navigable waters.

Nonattainment areas. Under the Clean Air Act, areas of the United States designated by EPA in which violation of one or more air quality standards for criteria pollutants is occurring.

Nitrogen oxides (NO_x). Product of combustion of fossil fuels whose production increases with the temperature of the process. It can become an air pollutant if concentrations are excessive.

Ozone (O_3). An allotropic (pertaining to a substance which exists in two or more forms) form of oxygen. An unstable blue gas with a pungent odor and powerful bleaching action.

PM_{10}. Particulate matter with an aerodynamic diameter less than or equal to 10 micrometers.

Prime farmland. Those lands having the best combination of physical and chemical characteristics for producing food, feed, fiber, forage, oilseed, and other agricultural crops with minimum inputs of fuel, fertilizer, pesticides, and labor, and without intolerable soil erosion.

Quadrants. The areas in which the United States is divided for the PEIS. These areas were chosen to follow the format of CCT-1 established in 1986 and are shown in Fig. 1-2 of the PEIS.

Quad. Quadrillion. Expressed as 10^{15} Btu.

REDES (Regional Emission Database and Evaluation System). Computer model developed by Argonne National Laboratory. The model incorporates a baseline against which changes in emissions are compared. Database contains information on energy use and corresponding environmental source terms for five sectors (electric utilities, industrial boilers, residential/commercial energy use, transportation and industrial processes) for each federal region. The base year is 1985 and 2010 is the forecast year. Most of the data for the five sectors comes from models and databases used in the environmental assessment for NEPP-V.

REED (Regional Emissions Evaluation Database). Spreadsheet comprised of data used for REDES.

Refurbish. The process of making improvements at an existing coal-fired facility to extend the lifetime of the facility without making major changes to the type of equipment already in place; this process is discussed in the PEIS primarily for pre-1971 power plants which are not required to meet NSPS.

Repowering. The process of installing major new equipment at an existing power plant site or industrial facility; repowering often involves installing an entirely different technology and will increase the electricity output of a plant.

Retrofitting. The process of installing new equipment at an existing power plant or industrial facility to improve efficiency or pollution control without replacing the basic unit.

Sulfur dioxide (SO_2). Compound composed of sulfur and oxygen produced by the burning of sulfur and its compounds in coal, oil, and gas. It is harmful to the health of man, plants, and animals, and may cause damage to materials.

Wet deposition. Precipitation that is more acidic than normal as a result of exposure to acid-forming pollutants in the atmosphere. Commonly referred to as acid rain.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
EXTERNAL AFFAIRS

MAR 6 1989

Dr. Jerry Pell
Senior Environmental Scientist
Clean Coal Technology Program
Office of Fossil Energy, FE-22
U.S. Department of Energy
Washington, DC 20585

Dear Dr. Pell:

In accordance with its responsibilities under the National Environmental Policy Act (NEPA) and Section 309 of the Clean Air Act, the U.S. Environmental Protection Agency (EPA) is furnishing comments on the scope of the Environmental Impact Statement (EIS) for the Clean Coal Technology Program and on the Programmatic Environmental Impact Analysis (PEIA), which will serve as the basis for the preparation of the EIS. The technology for the clean combustion of coal is of great interest to EPA because of the potential for reduced emissions of pollutants.

In general, the PEIA is a well written and comprehensive document. The selection of a projection year can change the attractiveness of the alternatives, and the basis for selecting 2010 as a base case should be presented in the EIS. If 2020 were used as the projection year, many existing utility plants with high emissions could be replaced by new plants meeting EPA's New Source Performance Standards, and the no action alternative would be more attractive.

There are also many environmental and economic tradeoffs between different technologies. These include air, water, solid waste, and land use considerations, as well as economic and engineering considerations. These tradeoffs should be presented and discussed in the EIS; in addition, it would be helpful if these considerations were presented in tabular form in the summary of the EIS.

I am enclosing comments on the PEIA which should be considered in preparation of the EIS. I would also appreciate it if two copies of the EIS were sent to each of EPA's regional offices at the same time it is transmitted to my office for filing. If you have any questions or need further assistance, please contact Dr. W. Alexander Williams (382-5909) of my staff.

Sincerely,

Richard E. Sanderson
Director
Office of Federal Activities

cc: Ms. Carol Borgstrom

Enclosure

Comments of the Environmental Protection Agency
on the Department of Energy's
Programmatic Environmental Impact Analysis
and the scope of the
Environmental Impact Statement for the
Clean Coal Technology Program

Page 2-1: The No Action Alternative should be based on many of the same assumptions as will be used in the National Acid Precipitation Assessment Program (NAPAP) Analysis Reference Case, e.g., power plant lifetime, rate of life extension/refurbishment, electricity demand growth, etc.

Page 2-5: Plants may also use adipic acid to lower plant maintenance costs and increase emission reductions; was this included in the No Action Alternative?

Page 2-7: Add "potentially" between "these" and "more" in line 6 of the second paragraph.

Page 2-13: Add the same solid waste discussion for PFBC as for AFBC.

Page 2-23: The appropriateness of advanced slagging combustors for retrofit use is not clear cut because of potential space restrictions/considerations.

Page 2-38, 4-52: The potential for ammonia slip as an environmental problem needs to be addressed for the use of selective catalytic reduction.

Page 3-6 and CO_2 discussions: How is coal use projected to change due to the Clean Coal Program? A table similar to Table 3.1-1 is needed for 2010 for the No Action and maximum coal use Proposed Action Alternatives. Also another table is needed to show national percent change from base in CO_2 emissions due to each technology, assuming each is fully commercialized without regard to economic competitiveness.

Page 5-6, Second paragraph and in other sections: This should be revised to say: "Continued degradation of air quality would only be to the limited extent allowed by Prevention of Significant Degradation (PSD) regulation. National Ambient Air Quality Standards (NAAQS) maintenance provisions in the current regulations and in the Clean Air Act are designed to prevent new nonattainment areas from occurring and would presumably prevent them from occurring in both the Action and No Action Alternatives."

Page 5-6, Third paragraph: The number of SO_2 and ozone nonattainment areas would also presumably be reduced by 2010 even under the No Action Alternative, without new regulations. Therefore, the last two sentences in the paragraph may be misleading.

Page 5-13, immediately prior to Section 5.4.5: Might not the Proposed Action increase coal usage by 2010? If technologies that are less efficient than flue gas desulfurization (e.g., coal cleaning technologies) were the ones mostly commercialized, wouldn't CO_2 emissions increase over the No Action Alternative? The assertion in the second sentence, "should not increase," is incorrect.

Page 6-2, 6-5: It should be noted here, and earlier in the individual discussions of the technologies, that some of the systems do not meet new source performance standards (NSPS), best available control technology (BACT), and/or lowest achievable emissions rate (LAER) criteria. This is particularly true for the limestone injection multistage burner, reburning, sorbent injection, and advance coal cleaning with no flue gas desulfurization when considering sulfur dioxide reductions. This fact may impact on the emissions reductions assumed for the national impacts of the proposed action cases.

TENNESSEE VALLEY AUTHORITY
KNOXVILLE, TENNESSEE 37902

FEB 24 1989

Dr. Jerry Pell
Senior Environmental Scientist
Clean Coal Technology Program
Office of Fossil Energy, FE-22
U.S. Department of Energy
Washington, D.C. 20585

Dear Dr. Pell:

REFERENCE: LETTER, C. LOWELL MILLER TO SIR/MADAM, FEBRUARY 7, 1989

This responds to the referenced request for comments on the Clean Coal Technology Programmatic Environmental Impact Analysis (EIA). Although the limited review time did not allow for detailed review of the entire document and all its conclusions, we do have a few comments as follows.

The EIA does not appear to assess the impacts of solid waste disposal in detail. These technologies could create special and potentially expensive permitting problems in this regard. However, the Tennessee Valley Authority (TVA) doubts that additional costs such as making disposal area liners thicker for one technology versus another would significantly impact the findings of the assessments.

Section 4.3.1.1 addresses the impacts of NO_x reduction on ozone levels (specifically on pages 4-30, 4-31, and 4-33) in a very simplistic manner that is not representative of the situation in general. Basing the discussion on the ratio of NO_x to hydrocarbon emissions ignores the significant differences in the reactivity of the different species of hydrocarbons in the atmosphere which is a very important factor in most areas of the country. The atmospheric chemistry involved in the formation of ozone and the transport of ozone precursor pollutants is too complex to address so simplistically as with a NO_x to hydrocarbon ratio. The discussion of the NO_x reduction impact on ozone needs to be significantly revised to reflect the complexity of the situation and what the more generally representative impacts would be.

Pages 4-34 and 4-35 contain a big jump in logic from percent control efficiency to percent reduction in national baseline emissions. The assumed penetration and replacement rate for existing combustion should be specified. Is this to occur by 2010 or over some other time period? More explanation of the REDES model is needed to explain these factors.

Contrary to the statement on page 4-36, an emissions decrease for coal ash is not necessarily a decrease in total suspended particulates. We suggest that the parenthetical expression be removed.

The statement on page 4-37 that removal of sulfur (S) in a three percent S coal would result in an increase of CO_2 of less than two percent is misleading. A three percent S coal will result in about 6 lbs SO_2/million Btu's, whereas a two percent increase in CO_2 would increase emissions about 50 lbs CO_2/million Btu's. The actual increase in total CO_2 emissions based on stoichiometric replacement of SO_2 with CO_2 would be about 0.2 percent.

We appreciated the opportunity to comment on the PEIA and look forward to receiving the Draft Environmental Impact Statement (DEIS). When the DEIS is available, please provide TVA with eight copies to allow for a thorough and complete review.

If there are any questions on the preceding comments, please have your staff call Dale V. Wilhelm of my staff at (615) 632-6693 in Knoxville, Tennessee.

Sincerely,

M. Paul Schmierbach, Manager
Environmental Quality

United States Department of the Interior
FISH AND WILDLIFE SERVICE

MAILING ADDRESS:
Post Office Box 25486
Denver Federal Center
Denver, Colorado 80225

STREET LOCATION:
134 Union Blvd.
Lakewood, Colorado 80228

IN REPLY REFER TO:

FWE
Mail Stop 60120

FEB 27 1989

Dr. Jerry Pell
Senior Environmental Scientist
Clean Coal Technology Program
Office of Fossil Energy FE-22
U.S. Department of Energy
Washington, D.C. 20585

Dear Dr. Pell:

This letter is in response to the request from the Department of Energy (Energy) for comments on a Federal Register Notice (Notice) concerning the intent to prepare a Clean Coal Technology Program Environmental Impact Statement (Statement). The request was transmitted to the Fish and Wildlife Service (Service) by memorandum dated February 10, 1989, from the Office of Environmental Project Review as ER 89/120.

A copy of a previous Programmatic Environmental Impact Analysis (Analysis) was included with the memorandum as an example of the scope of the proposed Statement. Comments on the adequacy of the Analysis were also requested.

The Notice and Analysis have been reviewed and although we have no comments on the Notice we do offer the following comments on the Analysis. The Analysis contains the sections and chapters which would be necessary for a Statement. However, the treatment of fish and wildlife aspects are not detailed enough to provide decision makers and the public sufficient information to determine impacts. Since the application of the technology has the potential for impacting large areas we suggest Energy contact the Service as well as appropriate State Wildlife Agencies to develop a more detailed scope of work. Service Regional offices would be the point of contact for developing this cooperation.

It is particularly important to adequately address the impacts on threatened and endangered species. The Analysis does not adequately address compliance with the Endangered Species Act.

In any case, sufficient copies of the proposed Statement should be sent to Service Regional Offices so reviews can be made for impacts on threatened and endangered species, wetlands, waterfowl, migratory birds, and refuges by the staffs from the Divisions of Fish and Wildlife Enhancement and Refuges.

Sincerely,

Robert D. Jacobsen
Assistant Regional Director
Fish and Wildlife Enhancement

cc: Office of Environmental
Project Review
Washington, D.C.
Assistant Director, FWS,
FWE, Washington, D.C.
Attention: Don Peterson
Fish and Wildlife Service (FWE)
Region 2, Albuquerque, New Mexico
Refuges and Wildlife, FWS
Region 6, Denver, Colorado

DEPARTMENT OF HEALTH & HUMAN SERVICES

Public Health Service

Centers for Disease Control
Atlanta GA 30333

March 3, 1989

Ms. Carol M. Borgstrom
Director, Office of NEPA Project Assistance
EH-25
U.S. Dept. of Energy
Washington, District of Columbia 20585

Dear Ms. Borgstrom:

We have learned that your office is developing documentation under the National Environmental Protection Act (NEPA) entitled "Clean Coal Technology Program." While we have no specific comments to offer on your project at this time we are writing to urge your consideration of any perceived safety and health impacts posed by this project. As a guide, we have enclosed a list of potential health impacts for your review. We hope these suggestions may be helpful in developing a comprehensive analysis of potential environmental impacts associated with your proposed project.

Please insure that we are included on your mailing list for further documents which are developed under the National Environmental Policy Act (NEPA).

Sincerely yours,

David E. Clapp, Ph.D., P.E.
Environmental Health Scientist
Special Programs Group
Center for Environmental Health
and Injury Control

Enclosure

RECEIVED
3/15/89

I. AIR QUALITY:

   A. Dust control measures during construction.

   B. Open burning.

   C. Indoor Air Quality.

   D. Compliance with air quality standards.

II. WATER QUALITY:

   A. Potable water (chemical, microbiological, and radiological quality).

   B. Body contact recreation.

   C. Compliance with waste water treatment standards.

III. NON-HAZARDOUS SOLID WASTE:

   A. Any unusual or suspected health effects associated with solid waste disposal.

   B. Effects of littering and provisions for cleanup, particularly conditions which might lead to vector harborage.

IV. NOISE:

   A. Ambient noise levels during construction, implementation, etc.

   B. Effectiveness of any proposed noise reduction measures following construction, implementation, etc.

V. RADIATION:

   A. Exposures to ionizing and non-ionizing radiation which may adversely affect human health.

VI. HAZARDOUS WASTES:

   A. Solid, liquid, or gaseous wastes which because of their physical, chemical or infectious characteristics pose a substantial threat to human health.

VII. WETLANDS AND FLOODPLAINS:

   A. Contamination of the food chain.

   B. Construction in floodplain which may endanger human health.

VIII. OCCUPATIONAL HEALTH AND SAFETY:

A. Evaluation of the occupational and public health hazards associated with the construction and operation of the proposed project.

B. Evaluation of any occupational and public health hazards associated with the operation of a proposed program (e.g., pesticide application, disposal of toxic chemicals, etc.).

C. General worker safety/injury control provisions.

VIIII. LAND USE AND HOUSING:

A. The provision of adequate ventilation, heating, insulation and lighting.

B. Vector control provisions.

C. Impacts of a project upon the displacement and/or relocation of persons.

APPENDIX B

GENERIC ENVIRONMENTAL CHARACTERISTICS

Environmental Characteristics of Wet Limestone Flue Gas Desulfurization Technology

Applicable Market Description

The wet limestone flue gas desulfurization technology is retrofitted on all 1985 unscrubbed utility and industrial power plants existing in 2010 and is applied to all new utility and industrial power plants built between 1985 and 2010.

Applicable Market Characteristics

Sector	– Utility – Industrial
Sulfur Content	– Low – Medium – High
Boiler Size	– Small – Medium – Large

Applicable Market Size (10^{15} Btu) – 29.5

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	18.9	10	3025	271
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	6.1	10	3055	372
% Change in Applicable Market Emissions	-68%	0	+1%	+37%
% Change in Total National Emissions	-45%	0	0	+19%
NE - Clean Coal Technologies % Change in Total Emissions	-65%	0	0	+22%
SE - Clean Coal Technologies % Change in Total Emissions	-52%	0	0	+26%
NW - Clean Coal Technologies % Change in Total Emissions	-10%	0	0	+11%
SW - Clean Coal Technologies % Change in Total Emissions	-15%	0	0	+11%

Environmental Characteristics of Circulating Atmospheric Fluidized-Bed Technology

Applicable Market Description

The circulating atmospheric fluidized-bed (CAFB) technology is assumed to repower approximately 1060 x 10^3 GWh of 1985 electric power generation which would exist in 2010. Approximately 150 x 10^3 GWh gained through the capacity increment would be used to satisfy the new demand during the 1985-2010 period. New power generation of approximately 1270 x 10^3 GWh would be satisfied by new CAFB plants.

Applicable Market Characteristics

Sector	– Utility
Sulfur Content	– Low – Medium – High
Boiler Size	– Small – Medium – Large

Applicable Market Size (10^{15} Btu) – 27.4

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	17.5	9.5	2890	251
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	5.1	4.8	2505	296
% Change in Applicable Market Emissions	-71%	-49%	-13%	+18%
% Change in Total National Emissions	-44%	-17%	-5%	+8%
NE - Clean Coal Technologies % Change in Total Emissions	-61%	-23%	-4%	+8%
SE - Clean Coal Technologies % Change in Total Emissions	-51%	-22%	-2%	+28%
NW - Clean Coal Technologies % Change in Total Emissions	-7%	-5%	-3%	+47%
SW - Clean Coal Technologies % Change in Total Emissions	-21%	-12%	-8%	-8%

Environmental Characteristics of Pressurized Fluidized Bed Technology

Applicable Market Description

The pressurized fluidized bed (PFB) technology is assumed to repower approximately 970 x 10^3 GWh of 1985 electric utility capacity which would exist in 2010. Approximately 110 x 10^3 GWh gained through the capacity imcrement would be used to satisfy new demand during the 1985 to 2010 period. New capacity of approximately 1075 x 10^3 GWh would be satisfied by new PFB plants.

Applicable Market Characteristics

Sector – Utility

Sulfur Content – Low
– Medium
– High

Boiler Size – Medium
– Large

Applicable Market Size (10^{15} Btu) – 27.4

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	17.5	9.5	2890	251
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	3.9	4.7	2290	231
% Change in Applicable Market Emissions	-78%	-51%	-20%	-7%
% Change in Total National Emissions	-48%	-17%	-8%	-4%
NE - Clean Coal Technologies % Change in Total Emissions	-60%	-22%	-6%	-5%
SE - Clean Coal Technologies % Change in Total Emissions	-60%	-24%	-6%	-12%
NW - Clean Coal Technologies % Change in Total Emissions	-9%	-6%	-5%	+31%
SW - Clean Coal Technologies % Change in Total Emissions	-32%	-13%	-10%	-15%

Environmental Characteristics of Integrated Gasification Combined Cycle Technology

Applicable Market Description

The integrated gasification combined cycle (IGCC) technology is assumed to re-power approximately 675 x 10^3 GWh of 1985 electric utility generation which would exist in 2010. Approximately 660 x 10^3 GWh gained through the capacity increment would be used to satisfy new demand during the 1985 to 2010 period. New capacity of approximately 750 x 10^3 GWh would be satisfied by new IGCC plants.

Applicable Market Characteristics

Sector – Utility

Sulfur Content – Low
– Medium
– High

Boiler Size – Small
– Medium
– Large

Applicable Market Size (10^{15} Btu) – 27.4

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	17.5	9.5	2890	251
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	7.2	4.8	2445	225
% Change in Applicable Market Emissions	-59%	-49%	-15%	-10%
% Change in Total National Emissions	-37%	-17%	-6%	-5%
NE - Clean Coal Technologies % Change in Total Emissions	-40%	-19%	-4%	-7%
SE - Clean Coal Technologies % Change in Total Emissions	-46%	-25%	-4%	+10%
NW - Clean Coal Technologies % Change in Total Emissions	-7%	-6%	-3%	+34%
SW - Clean Coal Technologies % Change in Total Emissions	-36%	-14%	-10%	-16%

Environmental Characteristics of Gasifier-Fuel Cell Technology

Applicable Market Description

The integrated gasifier-fuel cell technology is assumed to repower approximately 425 x 10^3 GWh of 1985 electric utility generation which would exist in 2010. Approximately 1040 x 10^3 GWh gained as a result of the capacity increment would be used to satisfy new demand during the 1985 to 2010 period. New capacity of approximately 380 x 10^3 GWh would be satisfied by new integrated gasifier-fuel cell plants.

Applicable Market Characteristics

Sector – Utility

Sulfur Content – Low
– Medium
– High

Boiler Size – Small
– Medium
– Large

Applicable Market Size (10^{15} Btu) – 27.4

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	**Solid Waste**
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	17.5	9.5	2890	251
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	9.5	5.6	2040	165
% Change in Applicable Market Emissions	-46%	-41%	-30%	-34%
% Change in Total National Emissions	-29%	-14%	-12%	-16%
NE - Clean Coal Technologies % Change in Total Emissions	-31%	-26%	-9%	-18%
SE - Clean Coal Technologies % Change in Total Emissions	-32%	-20%	-11%	-8%
NW - Clean Coal Technologies % Change in Total Emissions	-5%	-4%	-8%	+4%
SW - Clean Coal Technologies % Change in Total Emissions	-34%	-13%	-14%	-23%

Environmental Characteristics of Advanced Slagging Combustor Technology

Applicable Market Description

The advanced slagging combustor technology is assumed to be applied to all 1985 coal-fired electric utility and industrial plants that exist in 2010 and to all new electric utility and industrial plants put into service between 1985 and 2010 and would require scrubbing to meet NSPS.

Applicable Market Characteristics

Sector – Utility
– Industrial

Sulfur Content – Low
– Medium
– High

Boiler Size – Small
– Medium
– Large

Applicable Market Size (10^{15} Btu) – 29.5

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	18.9	10	3025	271
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	6.1	5	2970	361
% Change in Applicable Market Emissions	-68%	-50%	-2%	+37%
% Change in Total National Emissions	-45%	-18%	<-1%	+17%
NE - Clean Coal Technologies % Change in Total Emissions	-65%	-25%	<-1%	+19%
SE - Clean Coal Technologies % Change in Total Emissions	-52%	-24%	<-1%	+22%
NW - Clean Coal Technologies % Change in Total Emissions	-10%	-1%	0%	+10%
SW - Clean Coal Technologies % Change in Total Emissions	-15%	-12%	<-1%	+14%

Environmental Characteristics of LIMB Technology

Applicable Market Description

The LIMB technology is assumed to be retrofitted to all uncontrolled 1985 utility and industrial power plants existing in 2010.

Applicable Market Characteristics

Sector
- Utility
- Industrial

Sulfur Content
- Low
- Medium
- High

Boiler Size
- Small
- Medium
- Large

Applicable Market Size (10^{15} Btu) – 12.9

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	14.2	5.0	1330	52
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	5.7	2.0	1320	93
% Change in Applicable Market Emissions	-60%	-60%	-0.7%	+79%
% Change in Total National Emissions	-30%	-11%	0	+8%
NE - Clean Coal Technologies % Change in Total Emissions	-39%	-17%	0	+10%
SE - Clean Coal Technologies % Change in Total Emissions	-34%	-14%	0	+9%
NW - Clean Coal Technologies % Change in Total Emissions	-6%	-4%	0	+7%
SW - Clean Coal Technologies % Change in Total Emissions	-16%	-5%	0	+2%

Environmental Characteristics of Spray Dryer with Lime Technology

Applicable Market Description

The spray dryer with lime flue gas desulfurization technology is retrofitted on all 1985 unscrubbed utility and industrial power plants existing in 2010.

Applicable Market Characteristics

Sector	– Utility – Industrial
Sulfur Content	– Low – Medium – High
Boiler Size	– Small – Medium – Large

Applicable Market Size (10^{15} Btu) – 12.9

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	14.2	5.0	1320	52
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	1.4	3.5	1315	97
% Change in Applicable Market Emissions	-90%	-30%	-0.5%	+86%
% Change in Total National Emissions	-45%	-5%	0	+8%
NE - Clean Coal Technologies % Change in Total Emissions	-62%	-9%	0	+11%
SE - Clean Coal Technologies % Change in Total Emissions	-51%	-7%	0	+8%
NW - Clean Coal Technologies % Change in Total Emissions	-10%	-2%	0	+6%
SW - Clean Coal Technologies % Change in Total Emissions	-20%	-2%	0	+2%

Environmental Characteristics of Copper Oxide Advanced Flue Gas Desulfurization

Applicable Market Description

The copper oxide flue gas desulfurization technology is retrofitted on all 1985 unscrubbed utility and industrial power plants existing in 2010 and is applied to all new utility and industrial power plants built between 1985 and 2010.

Applicable Market Characteristics

Sector	– Utility – Industrial
Sulfur Content	– Low – Medium – High
Boiler Size	– Small – Medium – Large

Applicable Market Size (10^{15} Btu) – 29.5

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	18.9	10	3040	271
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	6.1	1.1	3025	152
% Change in Applicable Market Emissions	-68%	-89%	-0.5%	-44%
% Change in Total National Emissions	-45%	-33%	0	-22%
NE - Clean Coal Technologies % Change in Total Emissions	-65%	-45%	0	-23%
SE - Clean Coal Technologies % Change in Total Emissions	-52%	-40%	0	-22%
NW - Clean Coal Technologies % Change in Total Emissions	-10%	-10%	0	-3%
SW - Clean Coal Technologies % Change in Total Emissions	-15%	-22%	0	-24%

Environmental Characteristics of Dual-Alkali Flue Gas Desulfurization

Applicable Market Description

The dual-alkali flue gas desulfurization technology is retrofitted on all 1985 unscrubbed utility and industrial power plants existing in 2010 and using high and medium sulfur coals. The technology is applied to all new utility and industrial power plants between 1985 and 2010 which use high and medium sulfur coals.

Applicable Market Characteristics

Sector	–	Utility
	–	Industrial
Sulfur Content	–	Medium
	–	High
Boiler Size	–	Small
	–	Medium
	–	Large

Applicable Market Size (10^{15} Btu) – 18.5

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	13.9	6.2	1905	226
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	5.4	3.1	1895	199
% Change in Applicable Market Emissions	-61%	-50%	-0.5%	-12%
% Change in Total National Emissions	-30%	-11%	0	-5%
NE - Clean Coal Technologies % Change in Total Emissions	-55%	-17%	0	-3%
SE - Clean Coal Technologies % Change in Total Emissions	-33%	-14%	0	-2%
NW - Clean Coal Technologies % Change in Total Emissions	N/A	N/A	N/A	N/A
SW - Clean Coal Technologies % Change in Total Emissions	-3%	-7%	0	-8%

Environmental Characteristics of Advanced Flue Gas Desulfurization Technology (Salable Byproduct)

Applicable Market Description

The advanced flue gas desulfurization technology is retrofitted on all large and medium size 1985 utility and industrial power plants existing in 2010.

Applicable Market Characteristics

Sector – Utility
– Industrial

Sulfur Content – Low
– Medium
– High

Boiler Size – Medium
– Large

Applicable Market Size (10^{15} Btu) – 12.5

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	13.7	4.9	1280	50
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	0.2	4.9	1280	97
% Change in Applicable Market Emissions	-99%	0	0	+94%
% Change in Total National Emissions	-48%	0	0	+9%
NE - Clean Coal Technologies % Change in Total Emissions	-71%	0	0	+13%
SE - Clean Coal Technologies % Change in Total Emissions	-54%	0	0	+11%
NW - Clean Coal Technologies % Change in Total Emissions	-9%	0	0	+6%
SW - Clean Coal Technologies % Change in Total Emissions	-16%	0	0	+2%

Environmental Characteristics of Low NO_x Burner Technology

Applicable Market Description

The low NO_x burner technology is assumed to be retrofitted on all uncontrolled 1985 industrial and utility power plants existing in 2010. This technology is not applied to cyclone burner boilers. It should be noted that this technology could be applied for NO_x control on greenfield plants put into service between 1985 and 2010. However, for this PEIS, the case of mixing SO_2 control technology and Low NO_x burner technology was not analyzed.

Applicable Market Characteristics

Sector	– Utility – Industrial
Sulfur Content	– Low – Medium – High
Boiler Size	– Small – Medium – Large

Applicable Market Size (10^{15} Btu) – 12.6

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	13.9	5.0	1290	51
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	13.9	3.0	1290	51
% Change in Applicable Market Emissions	0	-60%	0	0
% Change in Total National Emissions	0	-11%	0	0
NE - Clean Coal Technologies % Change in Total Emissions	0	-17%	0	0
SE - Clean Coal Technologies % Change in Total Emissions	0	-14%	0	0
NW - Clean Coal Technologies % Change in Total Emissions	0	-4%	0	0
SW - Clean Coal Technologies % Change in Total Emissions	0	-5%	0	0

Environmental Characteristics of Sorbent Injection Technology

Applicable Market Description

The sorbent injection with lime technology is assumed to be retrofitted to 1985 utility and industrial power plants without FGD that are in service in 2010.

Applicable Market Characteristics

Sector	– Utility – Industrial
Sulfur Content	– Low – Medium – High
Boiler Size	– Small – Medium – Large

Applicable Market Size (10^{15} Btu) – 12.9

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	14.2	5.0	1320	52
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	3.6	5.0	1320	93
% Change in Applicable Market Emissions	-75%	0	0	+79%
% Change in Total National Emissions	-38%	0	0	+8%
NE - Clean Coal Technologies % Change in Total Emissions	-56%	0	0	+10%
SE - Clean Coal Technologies % Change in Total Emissions	-41%	0	0	+9%
NW - Clean Coal Technologies % Change in Total Emissions	-8%	0	0	+6%
SW - Clean Coal Technologies % Change in Total Emissions	-12%	0	0	+2%

Environmental Characteristics of Selective Catalytic Reduction (SCR) Technology

Applicable Market Description

The selective catalytic reduction (SCR) technology is assumed to be retrofitted to all uncontrolled 1985 utility and industrial power plants existing in 2010. This technology can not be applied to plants using high sulfur coals. It should be noted that this technology could be applied for NO_x control on greenfield plants put into service between 1985 and 2010. However, for this PEIS, the case of mixing SO_2 control technology and SCR technology was not analyzed.

Applicable Market Characteristics

Sector – Utility
– Industrial

Sulfur Content – Low
– Medium

Boiler Size – Small
– Medium
– Large

Applicable Market Size (10^{15} Btu) – 12.2

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	12.7	4.5	1250	49
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	12.7	0.5	1250	49
% Change in Applicable Market Emissions	0	-90%	0	0
% Change in Total National Emissions	0	-15%	0	0
NE - Clean Coal Technologies % Change in Total Emissions	0	-22%	0	0
SE - Clean Coal Technologies % Change in Total Emissions	0	-20%	0	0
NW - Clean Coal Technologies % Change in Total Emissions	0	-6%	0	0
SW - Clean Coal Technologies % Change in Total Emissions	0	-7%	0	0

Environmental Characteristics of Reburning Technology

Applicable Market Description

The reburning technology is assumed to be retrofitted to the 1985 utility and industrial power plants that are in service in 2010. It should be noted that this technology *could be applied for NO_x control on all greenfield plants put into service between* 1985 and 2010. However, for this PEIS, the case of mixing SO_2 control and reburning was not analyzed.

Applicable Market Characteristics

Sector	– Utility – Industrial
Sulfur Content	– Low – Medium – High
Boiler Size	– Small – Medium – Large

Applicable Market Size (10^{15} Btu) – 12.9

Environmental Characteristics – 2010

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	14.3	5.1	1320	52
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	11.4	2.0	1215	42
% Change in Applicable Market Emissions	-20%	-60%	-8%	-20%
% Change in Total National Emissions	-10%	-11%	-2%	-2%
NE - Clean Coal Technologies % Change in Total Emissions	-15%	-17%	-2%	-3%
SE - Clean Coal Technologies % Change in Total Emissions	-11%	-14%	-2%	-2%
NW - Clean Coal Technologies % Change in Total Emissions	-2%	-4%	-1%	<1%
SW - Clean Coal Technologies % Change in Total Emissions	-4%	-5%	<-1%	-3%

Environmental Characteristics of Ultrafine Coal Preparation Technology: High Sulfur

Applicable Market Description

The ultrafine coal preparation technology is assumed to be applied to high sulfur coal (greater than 3% sulfur) and is utilized in 1985 industrial and utility boilers without FGD that are in service in 2010.

Applicable Market Characteristics

Sector – Utility
– Industrial

Sulfur Content – High

Boiler Size – Small
– Medium
– Large

Applicable Market Size (10^{15} Btu) – .35

Environmental Characteristics – 2010 (Includes emissions from coal preparation plant)

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	1.2	0.2	35	2
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	0.8	0.2	35	5
% Change in Applicable Market Emissions	-33%	0	0	150%
% Change in Total National Emissions	-1%	0	0	+1%
NE - Clean Coal Technologies % Change in Total Emissions	-3%	0	0	+1%
SE - Clean Coal Technologies % Change in Total Emissions		Negligible	0	
NW - Clean Coal Technologies % Change in Total Emissions		N/A	0	
SW - Clean Coal Technologies % Change in Total Emissions		Negligible	0	

Environmental Characteristics of Ultrafine Coal Technology: Medium Sulfur

Applicable Market Description

The medium sulfur coal (1.5% - 3% sulfur) cleaned using the ultrafine advanced physical process is used in all 1985 industrial and utility boilers without FGD in service in 2010. This technology is not used in the Northwest sector.

Applicable Market Characteristics

Sector	– Utility – Industrial
Sulfur Content	– Medium
Boiler Size	– Small – Medium – Large

Applicable Market Size (10^{15} Btu) – 4.5

Environmental Characteristics – 2010 (Includes emissions from coal preparation plant)

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	8.3	1.9	460	20
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	3.8	1.9	460	86
% Change in Applicable Market Emissions	-54%	0	0	+335%
% Change in Total National Emissions	-16%	0	0	+12%
NE - Clean Coal Technologies % Change in Total Emissions	-22%	0	0	+19%
SE - Clean Coal Technologies % Change in Total Emissions	-15%	0	0	+16%
NW - Clean Coal Technologies % Change in Total Emissions		N/A	0	
SW - Clean Coal Technologies % Change in Total Emissions	-1%	0	0	+0.5%

Environmental Characteristics of Advanced Physical Coal Preparation Technology: High Sulfur

Applicable Market Description

The advanced flotation coal preparation technology is applied to high sulfur coal (greater than 3% sulfur) and is utilized in 1985 utility and industrial boilers without FGD that are in service in 2010.

Applicable Market Characteristics

Sector	– Utility – Industrial
Sulfur Content	– High
Boiler Size	– Small – Medium – Large

Applicable Market Size (10^{15} Btu) – .35

Environmental Characteristics – 2010 (Includes emissions from coal preparation plant)

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	1.2	0.2	36	2
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	1.0	0.2	36	4
% Change in Applicable Market Emissions	-16%	0	0	+100%
% Change in Total National Emissions	-0.7%	0	0	+0.4%
NE - Clean Coal Technologies % Change in Total Emissions	-1%	0	0	+0.7%
SE - Clean Coal Technologies % Change in Total Emissions		Negligible	0	
NW - Clean Coal Technologies % Change in Total Emissions		N/A	0	
SW - Clean Coal Technologies % Change in Total Emissions		Negligible	0	

Environmental Characteristics of Advanced Physical Coal Preparation Technology: Medium Sulfur

Applicable Market Description

The advanced physical coal preparation technology is assumed to be applied to medium sulfur coal (1.5% - 3% sulfur) and is utilized in 1985 industrial and utility boilers without FGD that are in service in 2010.

Applicable Market Characteristics

Sector – Utility
– Industrial

Sulfur Content – Medium

Boiler Size – Small
– Medium
– Large

Applicable Market Size (10^{15} Btu) – 4.5

Environmental Characteristics – 2010 (Includes emissions from coal preparation plant)

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	8.3	1.9	460	20
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	7.4	1.9	460	74
% Change in Applicable Market Emissions	-11%	0	0	+270%
% Change in Total National Emissions	-3%	0	0	+10%
NE - Clean Coal Technologies % Change in Total Emissions	-5%	0	0	+16%
SE - Clean Coal Technologies % Change in Total Emissions	-4%	0	0	-13%
NW - Clean Coal Technologies % Change in Total Emissions	N/A	N/A	N/A	N/A
SW - Clean Coal Technologies % Change in Total Emissions	-0.2%	0	0	+0.4%

Environmental Characteristics of Advanced Chemical Coal Preparation Technology: High Sulfur

Applicable Market Description

The product from advanced chemical coal preparation technology is retrofitted onto all 1985 unscrubbed utility and industrial power plants existing in 2010 and is applied to all new utility and industrial power plants built between 1985 and 2010.

Applicable Market Characteristics

Sector	– Utility – Industrial
Sulfur Content	– High
Boiler Size	– Small – Medium – Large

Applicable Market Size (10^{15} Btu) – 8.0

Environmental Characteristics – 2010 (Includes emissions from coal preparation plant)

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	4.4	2.5	820	141
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	3.4	2.5	820	141
% Change in Applicable Market Emissions	-23%	0	0	-3%
% Change in Total National Emissions	-4%	0	0	0
NE - Clean Coal Technologies % Change in Total Emissions	-8%	0	0	0
SE - Clean Coal Technologies % Change in Total Emissions		Negligible		
NW - Clean Coal Technologies % Change in Total Emissions		N/A		
SW - Clean Coal Technologies % Change in Total Emissions	-1%	0	0	0

Environmental Characteristics of Advanced Chemical Coal Preparation Technology: Medium Sulfur

Applicable Market Description

The advanced chemical coal preparation technology is retrofitted on all 1985 unscrubbed utility and industrial power plants existing in 2010 and is applied to all new utility and industrial power plants built between 1985 and 2010. All power plants use medium sulfur coal (1.5%-3% sulfur).

Applicable Market Characteristics

Sector – Utility
– Industrial

Sulfur Content – Medium

Boiler Size – Small
– Medium
– Large

Applicable Market Size (10^{15} Btu) – 9.9

Environmental Characteristics – 2010 (Includes emissions from coal preparation plant)

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	8.9	3.6	1020	82
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	1.8	3.6	1020	207
% Change in Applicable Market Emissions	-80%	0	0	+152%
% Change in Total National Emissions	-26%	0	0	+23%
NE - Clean Coal Technologies % Change in Total Emissions	-42%	0		+26%
SE - Clean Coal Technologies % Change in Total Emissions	-11%	0		+57%
NW - Clean Coal Technologies % Change in Total Emissions		N/A		
SW - Clean Coal Technologies % Change in Total Emissions		N/A		

Environmental Characteristics of Mild Gasification

Applicable Market Description

The products of the mild gasification of coal, namely a mixture of char and coal derived liquid, are assumed to replace all residual oil in utility and industrial boilers.

Applicable Market Characteristics

Sector – Utility
– Industrial

Sulfur Content – High - residual oil
– Medium - residual oil
– Low - residual oil

Boiler Size – Small
– Medium
– Large

Applicable Market Size (10^{15} Btu) – 4.6

Environmental Characteristics – 2010 (Includes emissions from mild gasification plant)

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	2.7	0.8	400	0
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	1.2	0.1	470	78
% Change in Applicable Market Emissions	-55%	-84%	+18%	
% Change in Total National Emissions	-5%	-2%	+1%	+14%
NE - Clean Coal Technologies % Change in Total Emissions	-7%	-4%	+1%	+17%
SE - Clean Coal Technologies % Change in Total Emissions	-9%	-2%	+1%	+16%
NW - Clean Coal Technologies % Change in Total Emissions	-2%	-2%	0	+8%
SW - Clean Coal Technologies % Change in Total Emissions	<-1%	<-1%	0	+19%

Environmental Characteristics of Direct Liquefaction

Applicable Market Description

The products from the direct liquefaction technology are assumed to replace residual oil in all utility and industrial oil fired boilers.

Applicable Market Characteristics

Sector	– *Utility* – Industrial
Sulfur Content	– Low - residual oil – Medium - residual oil – High - residual oil
Boiler Size	– Small – *Medium* – Large

Applicable Market Size (10^{15} Btu) – 4.6

Environmental Characteristics – 2010 (Includes emissions from direct liquefaction plant)

	SO_2	NO_x	CO_2	*Solid Waste*
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	2.7	0.8	400	0
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	0.2	0.07	470	46
% Change in Applicable Market Emissions	-93%	-91%	+18%	
% Change in Total National Emissions	-9%	-3%	+1%	+9%
NE - Clean Coal Technologies % Change in Total Emissions	-10%	-4%	+1%	+10%
SE - Clean Coal Technologies % Change in Total Emissions	-12%	-3%	+1%	+10%
NW - Clean Coal Technologies % Change in Total Emissions	-2%	<-1%	0	+12%
SW - Clean Coal Technologies % Change in Total Emissions	-5%	-1%	0	+6%

Environmental Characteristics of Indirect Liquefaction

Applicable Market Description

The products from the indirect liquefaction technology are assumed to replace residual oil in all utility and industrial oil fired boilers.

Applicable Market Characteristics

Sector – Utility
– Industrial

Sulfur Content – Low - residual oil
– Medium - residual oil
– High - residual oil

Boiler Size – Small
– Medium
– Large

Applicable Market Size (10^{15} Btu) – 4.6

Environmental Characteristics – 2010 (Includes emissions from indirect liquefaction plant)

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	2.7	0.8	400	0
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	1.2	1.8	470	20.0
% Change in Applicable Market Emissions	-56%	+130%	+18%	
% Change in Total National Emissions	-5%	+4%	+1%	+4%
NE - Clean Coal Technologies % Change in Total Emissions	-7%	+6%	+1%	+13%
SE - Clean Coal Technologies % Change in Total Emissions	-8%	+5%	+1%	+13%
NW - Clean Coal Technologies % Change in Total Emissions	-1%	+1%	0	+15%
SW - Clean Coal Technologies % Change in Total Emissions	-2%	+3%	0	+6%

Environmental Characteristics of Coal-Oil Coprocessing

Applicable Market Description

The products from the coal-oil coprocessing technology are assumed to replace residual oil in all utility and industrial oil fired boilers.

Applicable Market Characteristics

Sector – Utility
– Industrial

Sulfur Content – Low - residual oil
– Medium - residual oil
– High - residual oil

Boiler Size – Small
– Medium
– Large

Applicable Market Size (10^{15} Btu) – 4.6

Environmental Characteristics – 2010 (Includes emissions from coal oil coprocessing plant)

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	2.7	0.8	400	0
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	1.6	0.9	470	18
% Change in Applicable Market Emissions	-41%	+22%	+18%	
% Change in Total National Emissions	-4%	<+1%	+1%	+3%
NE - Clean Coal Technologies % Change in Total Emissions	-5%	0	+1%	+4%
SE - Clean Coal Technologies % Change in Total Emissions	-7%	0	+1%	+4%
NW - Clean Coal Technologies % Change in Total Emissions	0	0	0	+4%
SW - Clean Coal Technologies % Change in Total Emissions	-1%	0	0	+2%

Environmental Characteristics of Coal-Water Mixture

Applicable Market Description

The coal-water mixture technology assumes the use of the ultrafine coal preparation technology. The coal-water mixture fuel is used to replace medium and high sulfur residual oil in utility and industrial boilers.

Applicable Market Characteristics

Sector	– Utility – Industrial
Sulfur Content	– Medium - residual oil – High - residual oil
Boiler Size	– Small – Medium – Large

Applicable Market Size (10^{15} Btu) – 1.1

Environmental Characteristics – 2010 (Includes emissions from coal-water mixture plant)

	SO_2	NO_x	CO_2	Solid Waste
National Applicable Market Baseline Emissions (Tons X 10^6/yr)	1.1	0.2	95	0
National Applicable Market Emissions with Clean Coal Technologies (Tons X 10^6/yr)	0.6	0.2	115	20
% Change in Applicable Market Emissions	-44%	0	+21%	
% Change in Total National Emissions	-2%	0	0	+4%
NE - Clean Coal Technologies % Change in Total Emissions	-2%	0	0	+4%
SE - Clean Coal Technologies % Change in Total Emissions	-4%	0	0	+6%
NW - Clean Coal Technologies % Change in Total Emissions	-0.5%	0	0	+5%
SW - Clean Coal Technologies % Change in Total Emissions	-2%	0	0	+3%

APPENDIX C

LETTERS OF COMMENT ON THE DRAFT PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT AND STAFF RESPONSES

The Notice of Availability for the draft Programmatic Environmental Impact Statement (PEIS) was published in the *Federal Register* on July 14, 1989. The draft PEIS was mailed to Federal, state, and local agencies and individuals for comments on July 7, 1989. Section 9 of the final PEIS provides a list of agencies, groups, and individuals that were sent copies of the draft PEIS.

All timely letters of comment on the draft PEIS were reviewed in developing the final PEIS. Suggestions for correcting text or data and requests for further discussion of a subject have been considered. Revisions to the text where appropriate.

Sections or pages of the final PEIS that have been modified as a result of comments received are identified in the staff responses to the right of the letters of comments. Other responses are self explanatory.

The respondents and the pages on which their letters occur are as follows:

Robert H. Shannon C-1
Fuels Management, Inc. C-4
Electric Power Research Institute C-5
U.S. Environmental Protection Agency C-8
Department of Health and Human Services C-15
Public Citizen C-16
Tennessee Valley Authority C-18
U.S. Department of the Interior C-19
Ohio Ontario Clean Fuels, Inc. C-21

ROBERT H. SHANNON
CONSULTING ENGINEER
P O BOX 2264
ROCKVILLE, MARYLAND 20852

301-984-9254

July 24, 1989

Mr. Allyn Hemenway, FE-222
Office of Clean Coal Technology
U.S. Dept. of Energy
Washington, D. C. 20585

Subject: Draft Programmatic Environmental Impact Statement - Clean Coal Technology Demonstration Program

Dear Mr. Hemenway:

The following summarizes comments based on a review of the subject report:

- A key factor concerns selection of the year 2010 vs. 2000 in view of the Administration's proposed Clean Air Act Amendment legislation directed to Acid Deposition Control -- based on the Bill's proposed implementation schedule, Retrofit Technologies will need to meet a commercial date by the year 2000. 1
- The report also needs to address the matter of Hazardous Air Pollutants -- Title III of the Administration Clean Air Act proposed legislation. For example: the potential chlorine and ammonia emission problems based on Title III yearly stack emission limits. 2
- Attachment A includes additional comments/questions directed to the report.

The report is broad based and generally covers key environmental matters involved in DOE's Clean Coal Technology Program. 3

Very truly yours,

Robert H. Shannon
Robert H. Shannon

RHS:scs

1. The long-range energy projections used in the PEIS are consistent with NEPP-V. The baseline emission levels forecasted for 2010 are based on the environmental analysis of NEPP-V prepared for DOE (Placet et al. 1986). It is this baseline which is used in REDES to analyze the environmental impacts of the widespread commercialization of clean coal technologies. In the methodology, all candidate plants for retrofit technologies are, in fact, modified by the year 2000 (pg. 4-3 - 4-5). The staff recognizes that the Administration's proposed legislation calls for the completion of the second phase reduction by December 31, 2000, however, this is a legislative proposal and the implementation dates will be debated. Therefore, the year 2010 represents a reasonable date for the comparative analysis of the environmental impact of the widespread commercialization of clean coal technologies contained in the PEIS.

2. Hazardous air pollutants normally associated with clean coal technologies are identified in Table 4-19, however, estimates of emission levels and the environmental effects requires additional information which is unavailable at this time. Text in Sect. 3.2.1.1 has been modified in response to this comment.

3. Comment noted.

Attachment A

July 24, 1989

ROBERT H. SHANNON
CONSULTING ENGINEER
P O BOX 2264
ROCKVILLE, MARYLAND 20852

301-984-9254

CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM
DRAFT PROGRAMMATIC
Environmental Impact Statement
- Comments -

Executive Summary

- Page xxi - second paragraph

Based on the Administration's proposed Bill covering Clean Air Act Amendments to be of real value -- Retrofit Clean Coal Technologies will need to be commercially feasible by 1995, and fully implemented by the year 2000 -- not by the year 2010. 4

- Page xxii - first paragraph

Statement, "......it is not known what tachnologies will be selected for demonstration, and there is no basis for defining a mix of technologies to be commercialized." 5

This does not agree with the current status of the DOE Clean Coal Technology Demonstration Program on-going commitments (CCT-I and CCT-II).

- Page xxiii

Repowering technologies -- AFBs(Fixed Bed Atmospheric Fluidized Bed Boilers)should be included -- in some cases, technical and/or economic reasons may dictate use of Fixed Bed over Circulating AFBs. 6

- Page xxiii - Retrofit NSPS Technologies - Table E-3

The copper oxide process -- what is the basis for including this process as a potential for coal-fired power plants. Is there any experience other than bench scale tests (?) -- technical and economic factors are unknown. 7

- Page xxvi - Retrofit Non-NSPS technologies

The Non-NSPS only classification for technologies listed in Table E-4 is misleading. These technologies have the potential for application to some plants burning low-sulfur and medium-sulfur coals, making it possible in some cases that the technology retrofit could result in the units (or plants) meeting NSPS SO_2 and NO_x stack emission limits -- specifically for older plants (pre-1971) coal-fired plants retrofitted under a Life-Extension basis. Also, the Slagging Combustor can be used on Cyclone type coal-fired boilers (some cyclone type boilers may still be operating in the year 2000). 8

4. See response to Comment 1.

5. The PEIS is intended to be an EIS for the entire Clean Coal Technology Demonstration Program which consists of multiple solicitations. Several projects selected in CCT-I are still in negotiation and all the projects in CCT-II are still in negotiation. CCT-III projects will not be selected until December 28, 1989, and future solicitations remain to be structured. Further, there is no assurance that the technologies being demonstrated under negotiated CCT-I cooperative agreements will be commercialized. The PEIS, however, does cover the major generic technologies considered likely to be candidates for eventual demonstration.

6. Fixed-bed or bubbling atmospheric fluidized bed (AFB) technology may, in fact, be used instead of circulating fluidized bed technology (CAFB). However, the environmental characteristics of the two technologies are essentially the same and, thus, the CAFB is considered representative of both technologies. The text in Sect. 2.3.2.1 has been modified to include both bubbling-bed and CAFB.

7. The copper oxide (CuO) process was considered, for the purposes of the PEIS, a generic advanced combined SO_2 and NO_x removal technology. A 2,500 standard cubic foot per minute proof-of-concept unit is currently being constructed and will be tested at a utility. The design goal is 90% reduction in both SO_2 and NO_x. The design is based on a 750 scf pilot unit which is larger than earlier bench scale tests conducted at the Pittsburgh Energy Technology Center. The design goals are the same as the environmental characteristics for the CuO process contained in the PEIS. While detailed economics of the process remain to be resolved, economics was not a consideration in the PEIS analysis.

8. Non-NSPS capable technologies have been redefined as partial NSPS capable technologies, which include those technologies that do not achieve reduction levels necessary to meet both SO_2 and NO_x NSPS levels and, thus, could not be applied singly to greenfield plants (see response to Comment 24). There is no reasonable basis for defining those technologies which will, in fact, be commercialized. To determine if the application of a technology in the partial NSPS capable category would enable an older plant to meet NSPS requirements would require a plant-by-plant analysis which is beyond the scope of this programmatic environmental impact statement.

Clean Coal Tech. Demo Program
Comments - RHS

Attachment A-pg. 2

-Page 1-16 - First paragraph

Third bullet, ".....will be available to be repowered with ....." some of the 30-35 year old capacity will be possible candidates for Life-Extension/Retrofit Technologies -- not all just repowering. 9

- Page 2-3 - First paragraph

Comment, the assumption "..... that there will be no changes in environmental regulations pertaining to coal-fired facilities before 2010" is unrealistic as the basis for the evaluation -- what was the basis for this type of an assumption? 10

- Page 2-9 - Table 2-4

Footnote "a" -- "..... multiple technologies are not applied to the same plant". What is the basis for this? Multiple technologies can be utilized on the same plant. The evaluation should be based on the best possible combined mix where feasible. 11

Figure 4-1 -- needs to be corrected 12

-Page 4-37 -- third paragraph

States some retrofit technologies will not singly meet NSPS -- as previously noted, in some cases these retrofit technologies can result in pre-1971 coal-fired plants meeting 1971 NSPS requirements (page xxvi comment). 13

Appendix B

Pages B-1, B-6, B-7, B-8, B-9, B-10, B-12, B-14

Applicable Market Description

states the specific retrofit technology in each case is retrofitted ".....on all 1985 unscrubbed utility and industrial power plants existing in 2010" -- if SO_2 and NO_x emissions are within the required 1971 NSPS (or State) emission limits. What is the basis (or reason) for retrofit of any specific system -- i.e., FGD, sorbent injection etc.
Note: also in many cases site and/or plant physical space constraints will prevent installing retrofit FGD systems/or repowering with CAFB, PFB, IGCC systems. 14

9. Text has been modified in Sect. 1.7.1 to include retrofitting with clean coal technologies.

10. This assumption was made on the basis that it is not possible to define the specific requirements of future unknown regulations. The text on page 2-3 discusses the uncertainties associated with attempting to assess different approaches that might be taken to impose stricter requirements and describes qualitatively how the analysis of impacts might be affected by such requirements.

11. DOE agrees that multiple technologies can be utilized at the same plant. However, there is no basis for defining the full potential mix of technologies capable of being commercialized at each individual plant. This will be analyzed in the site-specific NEPA documents prepared later by DOE. The draft PEIS did not make an attempt to predict the economic competitiveness of each of the technologies considered and, thus, feasible mixes cannot be defined on a programmatic basis.

12. Figure 4-1 has been corrected to show SO_2 emissions rather than NO_x emissions.

13. See response to Comments 8 and 24.

14. The PEIS analyzes the environmental parameters of concern resulting from the maximum commercialization of the technology; thus, the impacts from the technologies could never be exceeded. It is recognized that space limitations may significantly affect repowering and retrofit applications of many of the technologies. However, space constraints is only one factor which could reduce the applicable market below the maximum and there is no reasonable basis for quantitatively defining that reduction.

FUELS MANAGEMENT, INC.

DONALD D DUNLOP

7027 S. W. 148TH TERRACE
MIAMI, FLORIDA 33158

TELEPHONE (305) 253 4560
TELEX 887979 FMISI WSH

July 28, 1989

Mr. Allyn Hemenway
FE-222
Office of Clean Coal Technology
U.S. Department of Energy
Washington, D.C. 20585

Reference: Draft Programmatic Environmental Impact Statement (PEIS), Clean Coal Technology Demonstration Program

Dear Mr. Hemenway:

In the above referenced document, it was stated in the chart on page 2 - 74 that coal water slurry (CWS) had no impact on NO_x reduction. Actually it does. 15

CWS reduces NO_x formation by about 50%. This comes about from the lower flame temperature which is caused by the water content of CWS.

CWS can reduce SO_x emissions to a greater degree that stated in your chart on page 2 - 74. With new coal cleaning technologies, sulfur levels of CWS can be in the 0.5% range depending on the organic sulfur in the parent coal. Since many utilities burn oil containing 2.5 to 3.5% sulfur, the SO_x reduction is by a factor of 5 to 7. I believe these impacts are most significant and I request that this information be made public. 16

Sincerely,

Donald D Dunlop / dw
Donald D. Dunlop

DDD:dw

15. DOE's Pittsburgh Energy Technology Center (PETC) reviewed the combustion tests of coal-water mixture and determined that NO_x emissions were not reduced. Other research results under different conditions could show changes in NO_x levels. One of the purposes of the CCTDP is to develop extensive environmental information to establish overall performance of the technology.

16. The analysis of coal-water mixture shown on page B-26 of the draft PEIS showed a 44% reduction in SO_2 when coal-water mixture fuel is used to replace medium and high sulfur residual oil in utility and industrial boilers.

EPRI
Electric Power
Research Institute

August 21, 1989

Mr. C. Lowell Miller
Associate Deputy Assistant Secretary
Office of Clean Coal Technology
Department of Energy
Washington, D.C. 20585

Dear Mr. Miller:

Thank you for providing a copy of DOE's draft Programmatic Environmental Impact Statement for the Clean Coal Technology Demonstration Program (DOE/EIS-0146D). EPRI has reviewed the document and forwards the comments provided below for your consideration.

As you know, EPRI has endorsed DOE's earlier Phase I and II CCT demonstration program; the Department's continued efforts in this area are appreciated. The EPRI membership, represented by over six hundred electric utilities nationwide, has firmly stated its support for new generation technology demonstrations, including those directed at more clean and efficient ways to utilize coal. The industry participates directly in this effort by funding a number of clean coal demonstration projects of its own.

EPRI believes it is important to view all such programs in the light of current scientific and technological knowledge. In this regard, we would like to bring to your attention observations regarding Sections 3.0, "Affected Environment", and 4.0, "Environmental Consequences" of the draft EIS.

Section 3.2.3.2 discusses acidification of surface waters. Over the past ten years EPRI has, on behalf of its member utilities, invested more than $85 million towards researching source-receptor relationships related to the acid deposition issue. This effort has resulted in an enhanced understanding of watershed processes as reflected by such projects as the Integrated Lakes Watershed Acidifidcation Study (ILWAS), the Lake Acidification & Fisheries (LAF) project, the Regional Integrated Lakes Acidification Study (RILWAS) and offspring such as the Paleoecological Investigation of Recent Lake Acidification (PIRLA) project. Not only has this work resulted in new ecological concepts coming to light, but management methodologies and tools have also been derived | 17

17. Text in Sect. 3.2.3.2 has been expanded to discuss recent paleoecological studies done to determine past pH changes in lakes, as well as recent modeling results of watershed responses to acid deposition.

Headquarters 3412 Hillview Avenue Post Office Box 10412, Palo Alto, CA 94303 USA • (415) 855-2000 • Telex 82977 EPRI UF • Telecopy (415) 855-2954
Washington Office 1019 Nineteenth Street, NW, Suite 1000, Washington, DC 20036, USA • (202) 872-9222 • Telecopy (202) 296-5436

which enhance scientific understanding of watershed processes. We believe this knowledge should be incorporated in the PEIS as part of the modern baseline for scientific understanding of watershed ecology. This information has been summarized in the attached document, "Acid Rain Research Results".

The work referenced above provides an improved foundation from which to evaluate source-receptor relationships as well. Thus we observe that Section 4.3.4.1 of the draft EIS might be amended to incorporate this new understanding. For example, the relationship between reduced SO2 and NOx emissions and recovery of ecosystems has long been understood. What remains uncertain, however, is the important relationship between amount of reduction and degree of recovery, based on the new understanding of watershed processes provided by ILWAS, LAF, etc. Today's literature is comprehensive in addressing this issue, and we recommend the authors reexamine the question of long term recovery with current results in mind. 18

18. Text in Sect. 4.3.3 has been modified to discuss predictive modeling results of watershed response to acid deposition and the uncertainties associated with these modeling efforts; also, see response to Comment 17.

With respect to short term recovery options, we suggest some mention of currently available mitigation strategies available to watershed managers. The EPRI Lake Acidification Mitigation Program (LAMP), in concert with international investigations such as those performed in Scandinavia over the past ten years, has sufficiently established the viability of lake liming, for example, to warrant some discussion in this PEIS. Mitigation strategies are cost effective solutions to acidification problems while knowledge is expanded on the relationship between emissions and deposition. 19

19. Text in Sect. 4.2.3 has been modified to reflect that mitigative strategies other than the reduction of air pollutants have been proposed and are being studied.

Section 4.3.2.2 discusses the disposal of solid wastes from CCT combustion processes. It may be useful to discuss the chemical characteristics of various CCT solid waste byproducts in this section. Some processes, such as FBC, produce highly alkaline materials which may present as yet undiscovered disposal problems. Again, EPRI staff would be able to provide the authors with current research results on this topic. 20

20. One of the purposes of the CCTDP is to develop data on the physical, chemical and toxicological properties of solid wastes generated by clean coal technologies. Further, DOE conducts a waste management R&D program which addresses critical waste characterization and waste disposal/utilization issues associated with advanced coal technologies. Where such information was available on a specific technology it was included in the discussion of that technology. We agree that a broader discussion of the properties of CCT solid wastes would have been helpful. However, a review of the literature showed that there is little available information about the chemical and physical properties of many of the new solid wastes.

Section 4.2.1.2 discusses carbon dioxide and other greenhouse gases. We appreciate the authors' conclusions that "CO2 emissions would be a direct function of the quantity of coal burned", and that a "changed use of coal resources" would "contribute to a change in CO2 emissions" (4-40). The authors do not say whether such a change would be an increase or a decrease. Because it is possible that a national commitment to CCT could result in increasing CO2 emissions, it seems appropriate for the document to reflect such conclusions on a scale appropriate to the proposed action. 21

21. Text in Sects. 4.2.1.2 and 4.3.1.2 has been modified to discuss the role fossil fuels have in the observed increase in CO_2 concentrations and other measures that are used to reduce CO^2 levels. The mix of CCTDP technologies that is eventually commercialized would determine whether CO_2 concentrations would increase or decrease as a result of implementation.

In a similar vein, the document may wish to reflect the many scientific unknowns associated with global warming issues, and/or to discuss the policy implications of ignoring fossil-fuel alternatives in the context of an evolving national energy strategy. 22

Lastly, *figures* and other visuals presented throughout the document are generally informative and well-organized. One graphic, however, Figure 3-1, showing the location of coal-fired power plants in the lower 48 states, may need to be reviewed for accuracy. For example, in Arkansas two large coal-fired plants are currently operating, the White Bluff plant (shown) and the Independence plant, located in the north-central portion of the state. Perhaps the original ORNL reference did not validate its original plant listings. 23

Thank you for the opportunity to share these views. Please contact me if EPRI's Environment Division can provide any additional information.

Sincerely,

George Hidy
Vice President

GH/wgc
Attachment

22. Text in Sect. 3.2.1.2 has been modified to reflect the scientific uncertainty associated with the global warming issue.

23. A new figure (Fig. 3-1) has been used in the final PEIS.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

AUG 25 1989

OFFICE OF
EXTERNAL AFFAIRS

Mr. Allyn Hemenway
Office of Clean Coal Technology (FE-222)
U.S. Department of Energy
Washington, DC 20585

Dear Mr. Hemenway:

In accordance with our responsibilities under Section 309 of the Clean Air Act, the U.S. Environmental Protection Agency (EPA) has reviewed the U.S. Department of Energy's (DOE) Draft Environmental Impact Statement (DEIS) for the Clean Coal Technology Demonstration Program. The purpose of the DEIS is to address the potential environmental impacts of the widespread commercialization of successfully demonstrated clean coal technologies by the private sector in the year 2010. The potential impacts of individual demonstration projects will be addressed in site-specific environmental documents.

24 One of the major goals in the Clean Coal Technology program is to identify and demonstrate coal combustion methods that meet applicable environmental requirements. In the case of air pollution, these requirements include the New Source Performance Standards (NSPS). Some of the retrofit technologies in the DEIS have a demonstrated capability of complying with these standards. Others have shown a possibility or promise of compliance based on laboratory studies or pilot scale demonstrations. Still others have not shown a capability of meeting the NSPS despite extensive developmental and pilot scale testing. In the DEIS, some of the retrofit technologies that have shown promise of meeting the NSPS are identified in the same group as technologies that have demonstrated this capability. We recommend that the technologies be grouped according to their demonstrated performance. Further, throughout the document the NSPS references are to the emissions of SO_2 and the SO_2 NSPS. The selective catalytic reduction technology can meet the NO_x NSPS emission rate, although it is shown in the group of technologies that are not capable of meeting NSPS.

25 EPA presented a report to Congress in 1988 entitled "Wastes from the Combustion of Coal by Electric Utility Power Plants." It appears that DOE considered this report in the preparation of the DEIS. However, some of the conclusions in the DEIS go beyond

24. The PEIS was prepared to evaluate programmatic environmental issues associated with alternatives related to selecting one or more clean coal projects proposed by the private sector in response to the CCTDP solicitations. The 22 generic clean coal technologies selected for analysis were determined to be representative of the technologies and are placed into two general categories (i.e., repowering and retrofit), with the retrofit having three classes (i.e., retrofit–NSPS capable, retrofit–partial NSPS capable, and retrofit–new fuel forms). The classes were established to reflect the potential commercial application of the technologies and were not based on the stage of development and extent of testing. The existing classification appears to be reasonable as the PEIS examines the environmental implications of the widespread commercial applications of each technology separately. The comment, however, prompted a reexamination of the retrofit classes and the associated definitions. Based on that reexamination, the following changes were made in the definitions and are reflected in the revised text of the final PEIS: (1) Retrofit–NSPS capable technologies are those that, when applied singly, will control emissions of SO_2 and NO_x to NSPS levels for high and low sulfur coals and thus can be retrofitted on existing plants and used on new plants; (2) Retrofit–partial NSPS capable technologies are those that, when applied singly, will control emissions of either SO_2 or NO_x to NSPS levels for high or low sulfur coals and thus could be retrofitted on existing plants where SO_2 or NO_x controls are required. However, these technologies could not be applied singly to new plants to meet full NSPS requirements. Two technologies, spray dryer with lime and advanced flue gas cleanup with salable byproduct, were moved from the retrofit–NSPS capable class to the retrofit–partial NSPS capable class as a result of this reexamination. The analyses of these technologies in the PEIS has been modified to reflect the changes in the applicable markets.

25. Text in Sects. 4.3.2.2 and 5.3 has been modified in response to this comment.

those in EPA's report. First, EPA indicated that certain high volume utility wastes (fly ash, bottom ash, boiler slag, and flue gas desulfurization wastes) did not generally exhibit hazardous characteristics under current regulations. Accordingly, EPA stated that it did not intend to regulate these wastes as hazardous waste under Subtitle C of the Resource Conservation and Recovery Act (RCRA). EPA prefers that these wastes remain under Subtitle D of RCRA. Second, EPA expressed concern that some wastes (such as metal and boiler cleaning waste, wastes from other maintenance activities, and water purification wastes) may exhibit hazardous characteristics of corrosivity or EP toxicity. EPA has not determined whether to promulgate regulations under Subtitle C of RCRA or continue the management of these wastes under RCRA Subtitle D. Therefore, coal fired utility wastes are currently subject to the solid waste management provisions of RCRA Subtitle D, but some of these wastes may be regulated under RCRA Subtitle C in the future.

In general, the DEIS is well written and comprehensive. In accordance with our policies, we have rated this DEIS as EC-2; this means that we have environmental concerns and that additional information is requested for the Final EIS. I am enclosing detailed comments that address EPA's concerns more fully. If you have any questions concerning our comments, please contact Dr. W. Alexander Williams (382-5909) of my staff.

Sincerely,

Richard E. Sanderson
Director
Office of Federal Activities

Detailed Comments of the U.S.
Environmental Protection Agency
on the U.S.
Department of Energy's
Draft Environmental Impact Statement for the
Clean Coal Technology Demonstration Program

1. Page xxiv: Page 4-10 of the earlier Programmatic Environmental Impact Analysis (PEIA) indicated that the solid waste generated by PFBC was +18%. Why is there such a large change to -4% on page xxiv of the DEIS? Why are the 2010 national SO_2 and NO_x emission reductions so much greater now for CAFB: -44% and -17% respectively? They were -26% for SO_2 and -7% for NO_x in the PEIA.	26	26. A number of refinements and modifications were made during the preparation of the PEIS which account for changes between the earlier PEIA and the PEIS. These refinements and modifications included: • Refinement in the REDES methodology to more accurately and precisely calculate changes in the environmental parameters of concern; • Refined environmental characterization data for the 22 generic technologies • Addition of a number of new technologies including copper oxide, advanced FGD with salable byproduct, dual alkali, mild gasification and coal/water mixtures.
2. Page xxx: The DEIS should state that the potential market for saleable byproducts produced by CCT, e.g., gypsum wallboard, may quickly be saturated by the gypsum produced from just a few power plants. The ability to profitably sell byproducts such as gypsum is greatly dependent on distance to the market because of transportation costs.	27	27. The comment is true and has merit for inclusion in the PEIS, however, the PEIS does not attempt to address the economics of solid waste disposal or saleable byproducts such as gypsum or elemental sulfur, of which distance to the market is but one factor.
3. Pages 1-2, 1-4: Atmospheric fluidized bed combustion (AFBC), including circulating fluidized bed combustion (CFBC), is an established and demonstrated technology for industrial scale boilers. However, it has not been demonstrated in the larger utility size boilers.	28	28. The draft PEIS states that CFBC is proposed for demonstration under both CCT-I and CCT-II. Three CAFB utility projects have been selected. These projects are the Nuclu CFB in Colorado (110 MWe), the City of Tallahassee, Florida (250 MWe), and the Southwest Public Service Company in Texas (250 MWe).
4. Page 2-6: The analysis uses a capacity factor of 65% for both the no-action and proposed action alternatives, but Table 2-9 provides a 91% fuel cell capacity factor. Why?	29	29. Table 2-9 has been corrected to show a fuel cell capacity factor of 65%.
5. Page 2-12: When discussing the calcium-to-sulfur (Ca/S) ratio, it should be noted that there is a tradeoff between SO removal and cost. A higher level of SO_2 removal can be achieved with a higher Ca/S but at increased cost.	30	30. Footnotes in Table 2-6 and 2-7 have has been modified to reflect the fact that higher levels of SO_2 removal can be achieved with higher Ca/S ratios.
6. As noted in the text on page 2-12, EPA agrees that CFBC units are capable of 90% to 95% SO_2 removal. The 85% to 90% shown in Table 2-6 is in error.	31	31. Table 2-6 has been modified to reflect that CFBC units are capable of 90 to 95% removal.
7. Page 2-21 states that NO_x formation is nonexistent for fuel cells, yet Table 2-9 indicates a 1.3 lbs/MMBtu emission rate.	32	32. Table 2-9 has been modified to reflect an NO_x reduction of 92%.
8. Page 2-28 and following: The identification of the three classes of retrofit technologies is an improvement over the discussion in the earlier programmatic environmental impact analysis. However, by placing a technology in a category in the DEIS, it could be inferred that the technology has demonstrated the attributes of the category under full-scale operation, rather than just being expected to fulfill the attributes of the category based on laboratory or pilot tests. For example, the advanced slagging combustor (ASC) and copper oxide process have	33	33. See response to Comment 24. The demonstration undertaken within the CCTDP will be on a scale large enough to generate technical, environmental, performance, and economic data that is necessary for the private sector to judge the commercial potential and to make informed decisions on commercial readiness.

been placed in the "Retrofit-NSPS capable" category. We are uncertain whether either of these processes has been utilized beyond pilot scale operations. Thus, while achievement of the NSPS is theoretically possible, it is the purpose of the program to determine the actual ability of the various technologies. We recommend three NSPS categories: (a) Retrofit-NSPS demonstrated; (b) Retrofit-NSPS possible; and (c) Retrofit-non-NSPS capable. The NSPS demonstrated category would include the spray dryer with lime, the advanced flue gas cleanup with saleable byproduct, and the dual-alkali process. These processes are currently in use in industry. The NSPS-possible category would include ASC and the copper oxide process.		
9. Page 2-29: The appropriateness of the ASC for retrofit use needs to be modified somewhat due to potential space restrictions and considerations. It may not be "... appropriate for any utility or industrial boiler in new and retrofit uses." (Emphasis added.)	34	34. See response to Comment 14. Space restrictions and considerations are *factors that will* reduce the maximum commercialization of ASC. However, there is no reasonable basis for quantifying this reduction at a programmatic level with information currently *available.*
10. Pages 2-42 to 2-44: The current version of EPA's limestone injection multistage burner (LIMB) does not involve co-injection of limestone and coal as shown in Figure 2-28. Rather, the limestone is injected into the boiler downstream of the burners. Duct humidification has also been included to enhance SO_2 removal and to make the dust more amenable to removal by an electrostatic precipitator. In fact, SO_2 removals approaching 60% were only achieved by utilizing duct humidification.	35	35. Text and Fig. 2-28 in the draft PEIS (Fig. 2-9 in the final PEIS) *have been modified* to reflect the LIMB technology more accurately.
11. Pages 2-45, 2-47: Sorbent injection has been used in a few cases to meet the NSPS level of 70% SO_2 reduction for low sulfur coals, and, thus, it may be in the wrong category. This reduction is consistent with the text statement that 55% to 75% SO_2 removal is possible. However, Table 2-18 indicates that only 50% to 60% SO_2 removal is achievable, an inconsistency.	36	36. Text and Table 2-18 have been modified to reflect the ability to meet the NSPS level of 70% SO_2 reduction for low sulfur coals.
12. Page 2-50: Selective catalytic reduction (SCR) should be in the NSPS-possible category.	37	37. See response to Comment 24.
13. Page 2-50: Low NO_x burners have not been demonstrated on small industrial boilers, because, in part, of flame impingement problems. Thus, they may not be "...appropriate for any size utility or industrial coal-fired boiler...." (Emphasis added.)	38	38. See reply to Comment 14 and 34.
14. Page 4-8: Why are the applicable markets the same (27.4 quads each) in Table 4-5 for all four repowering technologies when Taole 4-4 seems to indicate differing market shares between the repowering technologies?	39	39. For repowering technologies, those that increase the output of electricity, REDES may not replace the entire Applicable Market. *Additional discussion* of the model operations may be found in the REDES model documentation. In Table 4.5, the Applicable Market for all repowering technologies is *defined to be 27.4 quads of energy* input. This refers to the "potential" or "engineering feasible" market. For repowering, this is the sum of the energy input into all old (1985 online) plants that could be repowered between *1995 and 2010* as well as all new plants that would be built in that same timeframe. Table 4.4 presents the generation mix that occurs under the REDES assumptions about *repowering. These* assumptions are different than those used for the analysis of non-repowering technologies. In non-repowering technologies the entire Applicable Market is *replaced with the new* technology. For repowering, plants are only replaced with the new technology if there is demand for the additional energy they produce. The *additional generation produced by repowered* units displaces the corresponding generation (and emissions) from new plants.
15. Page 4-17, 4-20: Section 4.2.1.2 seems to minimize the need to consider the effects of CO_2 emissions in the atmosphere, since "only about 8% of the current global total CO_2 emissions" come from U.S. sources. We believe that the effects need to be considered. A similar statement appears also on page 4-39 and 4-40 for the proposed alternative, and the effects of these	40	

from U.S. sources. We believe that the effects need to be considered. A similar statement appears also on page 4-39 and 4-40 for the proposed alternative, and the effects of these emissions also need consideration.

16. Page 5-4: The second paragraph in section 5.3 should be revised to more clearly reflect the first and second conclusions of EPA's 1988 Report to Congress entitled "Wastes from the Combustion of Coal by Electric Utility Power Plants." It is EPA's intention not to regulate ash, slag, and flue gas desulfurization wastes as hazardous waste under Subtitle C of the Resource Conservation and Recovery Act (RCRA). EPA remains concerned about the management of certain other wastes from power plants; EPA is considering whether to regulate these wastes under RCRA Subtitle C. We recommend that all of the second paragraph be deleted except for the first sentence. The paragraph should then repeat or paraphrase the two conclusions from the 1988 EPA report and note that EPA has not yet decided to regulate the wastes under RCRA Subtitle C or to not regulate the wastes under RCRA Subtitle C. Until this decision is made, coal-fired electric utility wastes are subject to the solid waste management provisions of RCRA Subtitle D. Copies of pages ES-6 and ES-7 of the 1988 report are enclosed for your convenience. 41

If there is insufficient demand in a region for the incremental energy, fewer plants are replaced with the new technology. Technologies with high capacity increments, like IGCC and FC, tend to repower fewer plants, since they more easily displace the new incremental demand.

It is this difference that is the source of the apparent discrepancy between Tables 4.4 and 4.5. While this is a somewhat dichotomus treatment of retrofit vs repowering, the critical difference is that the repowering technologies produce additional energy, which must have a market if the technology is to be used.

40. See response to Comment 22 above and text changes in Sect. 4.2.1.2.

41. See response to Comment 25 above.

the incremental cost of new waste disposal practices, excluding corrective action costs or higher recycling costs, could range up to $70 per ton, or $3.7 billion annually if all wastes were listed as hazardous. While substantial on a total cost basis, these increases would be unlikely to significantly affect the rate at which existing power plants consume coal. Due to the competitiveness of alternative fuels for electricity generation at future power plants, however, any increase in disposal costs could potentially slow the growth in electric utility coal consumption in future years. Moreover, if new disposal standards require corrective action measures as set forth in 40 CFR 264.100, the costs to utilities could be extremely high and could have a substantial effect on the utility industry.

Based on the findings from this Report to Congress, the Agency presents three preliminary recommendations for those wastes included in the scope of this study. The recommendations are subject to change based on continuing consultations with other government agencies and new information submitted through the public hearings and comments on this report. Pursuant to the process outlined in RCRA 3001(b)(3)(C), EPA will announce its regulatory determination within six months after submitting this report to Congress.

First, EPA has concluded that coal combustion waste streams generally do not exhibit hazardous characteristics under current RCRA regulations. EPA does not intend to regulate under Subtitle C fly ash, bottom ash, boiler slag, and flue gas desulfurization wastes. EPA's tentative conclusion is that current waste management practices appear to be adequate for protecting human health and the environment. The Agency prefers that these wastes remain under Subtitle D authority. EPA will use section 7003 of RCRA and sections 104 and 106 of CERCLA to seek relief in any cases where wastes from coal combustion waste disposal sites pose substantial threats or imminent hazards to human health and the environment. Coal combustion waste problems can also be addressed under RCRA Section 7002, which authorizes citizen lawsuits for violations of Subtitle D requirements in 40 CFR Part 257.

Second, EPA is concerned that several other wastes from coal-fired utilities may exhibit the hazardous characteristics of corrosivity or EP toxicity and merit regulation under Subtitle C. EPA intends to consider whether these waste streams should be regulated under Subtitle C of RCRA based on further study and information obtained during the public comment period. The waste streams of most concern appear to be those produced during equipment maintenance and water purification, such as metal and boiler cleaning wastes. The information available to the Agency at this time does not allow EPA to determine the exact quantity of coal combustion wastes that may exhibit RCRA Subtitle C characteristics. However, sufficient information does exist to indicate that some equipment maintenance and water purification wastes do occasionally exhibit RCRA hazardous characteristics, and therefore, may pose a danger to human health and the environment. These wastes are similar to wastes produced by other industries that are subject to Subtitle C regulation, and waste management practices for coal combustion wastes are often similar to waste management practices employed by other industries. EPA is considering removing the exemption for all coal-fired utility wastes other than those identified in the first recommendation. The effect would be to apply Subtitle C regulation to any of those wastes that are hazardous by the RCRA characteristic tests. EPA

DEPARTMENT OF HEALTH & HUMAN SERVICES

[illegible]

Centers for Disease Control
Atlanta GA 30333

August 25, 1989

C. Lowell Miller
Associate Deputy
  Assistant Secretary
  Office of Clean Coal Technology
Department of Energy
Washington, DC 20585

Dear Mr. Miller:

We have reviewed the Oraft Programmatic Environmental Impact Statement (PEIS) for "Clean Coal Technology Demonstration Program." We are responding on behalf of the U.S. Public Health Service. Clearly, this important project is in the best interest of every American who wishes cleaner air as well as an initiative which will utltimately result in the reduction of diseases resulting from poor air quality

42 We were pleased to find that the PEIS contains a specific section dedicated to "Impacts on Human Health." While this section is necessarily brief at this early stage of program development, it reflects the dedication of your planning staff to the minimization of potential impacts on the health and safety of workers as well as the general public which may arise from this program. We noted that a list of public health and safety concerns, which we reported to you in an earlier letter, are included in the PEIS as Table 4-18. The specific inclusion of our concerns is convincing evidence that it is the intent of DOE to fully assess potential impacts to human health and safety.

Thank you for sending this document for our review. Please insure that we are included on your mailing list for future, process-specific documents which are developed for this project as well as other documents describing other projects with potential public health impacts which are developed under the National Environmental Policy Act (NEPA).

Sincerely yours,

David E. Clapp, PH.D.,P.E.,CIH
Environmental Health Scientist
Center for Environmental Health
  and Injury Control

42. *Comment noted.*

PUBLIC CITIZEN

Buyers Up ☐ Congress Watch ☐ Critical Mass ☐ Health Research Group ☐ Litigation Group

August 28, 1989

Secretary James Watkins
U.S. Department of Energy
Washington, D.C. 20588

Dear Secretary Watkins:

43

We would like to express Public Citizen's opposition to the Clean Coal Technologies Demonstration Program (CCTDP), as proposed by the Department of Energy (DOE). The CCTDP is not based upon least-cost energy planning (i.e. investing in those energy options with the lowest overall economic, environmental, and social costs) and will bias the market against better energy alternatives. The limited federal energy dollars should be spent on energy conservation and renewable energy supplies which are less expensive, more quickly adopted, and less environmentally damaging.

Energy conservation and many renewable energy technologies are less expensive than coal technologies. The cost of new coal generated electricity is approximately 6 cents per kilowatt hour (kWh), and clean coal is expected to be even more expensive. By comparison, many energy conservation measures cost less than 3 cents per kWh. Many renewable energy technologies are already cost-competitive with coal, at a cost of between 3 and 6 cents per kWh, and are likely to become even less expensive by the mid-1990's.

Energy efficiency and renewables can be implemented in less time than coal technologies. Substantial gains in energy efficiency can begin to be realized in just months, and most renewable energy technologies have lead times of less than 2 years. However, a coal-fired power plant takes from 3 to 5 years, or more, to begin providing electricity.

Coal technologies are more hazardous to the environment than are renewables and energy conservation. Even "clean" coal technologies emit unacceptable levels of sulfur dioxide and nitrous oxides (components of acid rain). Carbon dioxide emissions, a primary contributor to global warming, are essentially unimproved by "clean" coal technologies. Energy conservation measures reduce all of these emissions by decreasing fossil fuel consumption. Renewables release little or no sulfur dioxide, nitrous oxides, or carbon dioxide. By displacing fossil fuels, renewables can reduce total carbon dioxide levels by 8 to 15 percent by the year 2000, depending on total energy use.

43. DOE acknowledges the existence of a wide range of additional options available to our nation to reduce the emissions of acid rain precursors and greenhouse gases, that could be considered as alternative actions to be undertaken in place of, or as a supplement to, the Clean Coal Technology Demonstration Program. These available options include, for example, nuclear energy, natural gas, hydropower, and conservation, each of which has its supporters. DOE has demonstrated leadership in developing and encouraging the use of alternative fuels, renewable forms of energy, and energy-saving improvements to reduce dependence on new energy production. Therefore, DOE has substantial quantities of information available regarding these, and other, alternatives. For the purposes of this programmatic document, however, DOE decided to limit the scope of the alternatives being considered to the potential efficiencies and environmental benefits that can reasonably be expected through improved techniques in coal combustion and use.

Congress has given DOE specific direction and funding authorization to proceed with the Clean Coal Technology Demonstration Program (CCTDP). Most recently, Congress authorized funds and directed DOE to proceed with a third solicitation of clean coal technology demonstration projects, with selection of projects to be made no later than January 1, 1990 (Pub. L. 101-45).

Unfortunately, given these realities, the DOE is not demonstrating an adequate commitment to energy efficiency and renewables. In fiscal year (FY) 1989, DOE will spend less than 5 percent ($166 million) of its annual energy research and development (R&D) budget on energy efficiency, and only $112 million on renewable energy R&D. DOE is spending $190 million in FY 1989 on "clean" coal technology R&D, and a total of over $5 billion by the year 2010.

In summary, the focus of DOE planning should be determined by least-cost criteria. The energy resources that best fit these criteria are energy conservation and renewables: these alternatives are quicker to implement, cheaper, and less environmentally damaging. Therefore, CCTDP should not be a DOE priority. "Clean" coal is not a least-cost energy alternative, and the CCTDP will skew the market away from better alternatives.

Thank you for the opportunity to comment on the Clean Coal Technology Demonstration Program.

Sincerely,

Geoffrey A. Davis
Energy Policy Analyst
Critical Mass Energy Project
of Public Citizen

P.S. Public Citizen is a non-profit, tax exempt research and advocacy organization founded by Ralph Nader in 1971 to address a broad range of consumer and environmental issues. The Critical Mass Energy Project is the energy policy arm of Public Citizen.

TENNESSEE VALLEY AUTHORITY

AUG 29 1989

Mr. Allyn Hemenway
Office of Clean Coal Technology
Office of Fossil Energy
FE-222
United States Department
of Energy
Washington, D.C. 20585

Dear Mr. Hemenway:

TENNESSEE VALLEY AUTHORITY (TVA) COMMENTS ON DRAFT PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT - DEPARTMENT OF ENERGY - CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

REFERENCES: 1. LETTER, C. LOWELL MILLER TO M. PAUL SCHMIERBACH, JULY 7, 1989

2. LETTER, C. LOWELL MILLER TO RALPH H. BROOKS, JULY 7, 1989

We have reviewed the material included with the referenced letters and have the following comments.

The alternatives to the proposed action need extensive updating and elaboration. Broad statements are made about technologies which are no longer true. 44
For example, on page 2-31, the statements under "Environmental characteristics" are not correct. Our spray electrostatic precipitator work indicates baghouses are not required to get high SO_2 removal, but Cl^- or $CaCl_2$ addition is required to recycle the process stream.

As another example, the section on fluidized combustors (FBC) does not mention TVA's bubbling bed atmospheric FBC (AFBC). Page 2-10 lists FBC removal of SO_2 as 92-95 percent; the correct upper limit is 98 percent. Page 2-12 45
fails to note that a circulating AFBC will not fit into the existing plant area. In addition, the hot cyclones will cause problems and there are unaddressed issues of scale with units above 200 MW.

As now written, the alternatives section is more a justification for the proposed action than a serious review of alternatives. 46

If there are any questions, please have your staff call Dale V. Wilhelm at (615) 632-6693 in Knoxville, Tennessee.

Sincerely,

for M. Paul Schmierbach, Manager
Environmental Quality

44. DOE has reviewed the alternatives section in response to the TVA comment and does not agree with the comment. The draft PEIS was based on an analysis of 22 generic clean coal technologies which are representative of the technologies that are anticipated to be demonstrated under the CCTDP. The environmental characteristics described in the DEIS are those which could reasonably be expected to be achieved under normal operations. DOE recognizes that many of these technologies are under development, demonstration and testing and that significant advances continue to be made in environmental performance as exemplified in TVA's experience.

45. *See response to Comments 6 and 14.*

46. DOE has reviewed the alternatives section in response to the TVA comment and does not agree with the comment. The proposed action assumes one or more clean coal technology projects are selected for cost shared federal funding and that successfully demonstrated technologies undergo wide spread commercialization by 2010. The 22 generic technologies analyzed in the DEIS are representative of those which are anticipated to be proposed by the private sector and selected for cost-shared demonstration under the proposed action.

United States Department of the Interior
OFFICE OF ENVIRONMENTAL PROJECT REVIEW
WASHINGTON, D.C. 20240

ER 89/570

SEP 1 3 1989

C. Lowell Miller, Associate Deputy
Assistant Secretary
Office of Clean Coal Technology
Department of Energy
Washington, D.C. 20585

Dear Mr. Miller:

The Department of the Interior has reviewed the Draft Programmatic Environmental Impact Statement for the Clean Coal Technology Program and has the following comments.

Demonstration Program

We understand that the U.S. Department of Energy (DOE) may fund demonstration projects using clean coal technology to replace natural gas-fired generators. We understand utilities may be interested in the conversion because of long-term relatively cheap, fixed price coal since long-term fixed price natural gas contracts are not available. On the other hand, the clean coal technology still emits a number of air pollutants several orders of magnitude greater than natural gas-fired powerplants. 47

The air emissions from coal-fired powerplants using the clean coal technology will be within the Federal air emission standards. However, we recommend the conversion of a natural gas-fired powerplant to a coal-fired powerplant which will increase the air emissions by as much as 1000 percent should not be funded. Rather, federally funded demonstrations should be limited to coal-fired plants that may already exceed existing air quality standards. 48

The Navajo Generating Station (NGS), a facility of the Central Arizona Project (CAP), is a coal-fired generating plant. The Environmental Protection Agency has just made an Attribution Decision regarding visibility impairment in the Grand Canyon and attributes visibility impairment to the NGS. A Best Available Retrofit Technology Assessment (BART) will be performed to determine if pollution control equipment should be installed at the NGS. That assessment should be completed by February 1990. If, at some point, pollution control equipment is required, we believe the NGS to be a good candidate for a demonstration program. 49

Research Alternatives

The many possible research options addressed under Alternative 2 are not dealt with in an entirely consistent manner. While some of the technology options are discussed in precise terms and their potential environmental impacts examined in some detail, others are hardly explained at all. Examples of the latter are the sections dealing with coal preparation techniques that, while of similar length to the sections dealing with boiler technologies, contain far less substantive information. 50

47. The purpose of the CCTDP is to demonstrate clean coal technologies through cost-shared projects with industry. The demonstration of improved coal burning repowering technologies at an existing oil- or gas-fired unit would be acceptable if the requirements of the applicable solicitation instrument are met. DOE makes no claim that clean coal technologies are cleaner than non-coal fuels.

48. The comment appears to refer to a specific project selected during the CCT-II solicitation. The environmental impacts of these individual projects are being evaluated in site-specific NEPA documents. It is DOE's position in evaluating individual projects that the long-term benefits of demonstrating improved clean coal technologies are weighed against the environmental impacts associated with that specific project at the site of demonstration.

49. DOE is not aware of any proposal to use clean coal technology at the Navajo Generating Station. If such a proposal were to be made in response to a CCTDP soliticitation and should the proposal be selected, a site-specific NEPA document would be prepared to evaluate environmental impacts.

50. DOE has reviewed the coal preparation technical descriptions and prepared a more substantive discussion of the ultrafine and chemical coal cleaning processes (Sects. 2.3.3.3.1, 2.3.3.3.2, and 2.3.3.3.3).

We do not agree that the cleaning of a *solid coal* by *chemical* or physical means to produce a solid coal product creates new fuel forms. However, the size reduction of the coal necessary to *affect significant reduction* in sulfur and ash does require some refitting of the combustors and boilers. We recommend these technologies be discussed in a separate context from technologies *such as coal/oil* and *coal/water* mixtures, which are considered to be new fuel forms. 51

Fish and Wildlife

Acidic depositions from SO_2 and NO_2 emissions have an adverse effect on habitat and the food chain for fish and wildlife. It is unclear whether *Clean Coal Technology would* prevent emissions of heavy metals and metaloids such as selenium, arsenic, mercury, lead and cadmium either as vapor or particulates. *These elements* have been demonstrated to impact the health of fish and wildlife resources. Transport of these metals can occur via vapor, fly ash or bottom ash (solid waste). For example, *aerial deposition* appears to be the primary source of increased concentrations of *metals* in the Great Lakes. The final statement should address this issue. 52

We hope these comments will be helpful to you in the preparation of a *final statement*.

Sincerely,

Jonathan P. Deason
Director

51. The classification of the chemical and *physical coal preparation* technologies as retrofit—new fuel forms is consistent with the Clean Coal Technology-III (CCT-III) Program Opportunity Notice (PON). The PEIS will be used by *the source selection official* in the selection of projects for cost-shared funding resulting from the CCT-III PON solicitation.

52. The *possible effects of heavy metals* on *ecosystems* are addressed in Sects. 3.2.3.4, 3.2.4.2, 4.2.4.3 and 4.3.1.1. Potential phytotoxicity and lake sediment accumulation of heavy metals released by combustion of coal are related to emission rates, soil characteristics, bioaccumulation rates, and toxicity. Factors controlling the chemical and biological availability and biological effects on both terrestrial and aquatic ecosystems are complex and not well understood. Acidic precipitation may possibly enhance the *movement of heavy metals* (Cd, Pb, Zn, Fe, Cu, Hg, etc.) and soluble salts (Ca, K, P, B, Mg) through poorly buffered soils because the hydrogen ions in acidic water ties up ion exchange sites (*on soil particles*) *which* would otherwise be available for metals. The CCTDP is not expected to have any significant changes, in general, of *heavy metal emissions from the no-action alternative* since clean coal technologies are not expected to change emission rates of metals substantially. Concentrations *of Fe from the IGCC may increase very slightly*, but the emissions would still remain very low. The SCR technology could cause very slight increases in Ni concentrations. Again, any increase is expected to be *extremely small*. *The applications of the more efficient* technologies, such as the IGCC, FC, and other higher efficiency technologies, would decrease *the concentrations* of heavy metals, both as atmospheric emissions and ash constituents by reducing fuel use. Implementation of those technologies that lower plant efficiency could *slightly increase* emissions of metals by requiring combustion of more coal per unit of power generated. Application of those technologies that reduce the quantity of ash produced or produce ash that can be re-used could lower the potential for leaching of heavy metals into the waterways and soils. The technologies that reduce SO_2 and NO_x emissions could *possibly* reduce the concentrations of heavy metals moving through and accumulating in the ecosystems by potentially reducing the *acidic precipitation*.

Ohio Ontario Clean Fuels, Inc.

PO Box 1820 • Warren • Ohio • 44482 • Phone (216) 369-2568 • FAX (216) 369-2568

September 15, 1989

Allyn Hemenway FE-222
Office of Clean Coal Technology
U.S. Department of Energy
Washington, DC 20585

Re: Comments on June 1989
Draft Programmatic Environmental Impact Statement (PEIS)
Clean Coal Technology Demonstration Program

Dear Mr. Hemenway:

Ohio Clean Fuels, Inc., formerly Ohio Ontario Clean Fuels, Inc., appreciates the opportunity to submit comments on the draft PEIS. The company was a clean coal technology CCT-1 awardee in 1987. Since the award, the company and its subcontractors have developed additional technical and marketing information that is relevant to the PEIS. The following items are submitted for DOE's review:

1. Table 2-28, End-use oil-fired utility boiler. The SO_2 emission rate could be changed from 0.5 lb./MMBtu to 0.4 lb./MMBtu.^{2} See company fuel spec, Attachment No. 1. 53

2. The implementation of a coal/oil co-processing clean coal technology fuel at an "affected unit" would be considered a "repowering" technology according to Section 502(J) of the proposed Bush Bill (H.R. 3030). An "affected unit" includes a coal-fired unit repowered with co-processing fuel or a coal-fired unit retrofitted with combustion turbines using co-processing fuel. See Stone & Webster Engineering Corporation letter, Attachment No. 2. 54

Any further information concerning the above can be obtained by calling M. Douglas Rider at 216/933-7434 or Stanley C. Gustas, Jr. at 713/492-3905.

Sincerely,

M. Douglas Rider

M. Douglas Rider
Director, Environmental Affairs

cc: S. C. Gustas, Jr., Program Director
M. Eastman, DOE-PETC

Synergy in Energy

53. Table 2-28 has been modified to reflect the later fuels specification. The environmental consequences analysis was also redone and appropriate tables modified.

54. The classification of coal/oil co-processing on retrofit--new fuel forms is consistent with the Clean Coal Technology-III (CCT-III) Program Opportunity Notice (PON). The PEIS will be used by the Source Selection Official in the selection of projects for cost-shared funding resulting from the CCT-III PON solicitiation. At the present time H.R. 3030 is a legislative proposal and definitions are subject to change.

ATTACHMENT NO. 1

OHIO PROTOTYPE COAL-OIL CO-PROCESSING PLANT TYPICAL UTILITY FUEL ANALYSIS

Fuel Analysis	Typical OCF C5/975°F Fuel Oil (with naphtha)	Typical OCF 350°F/975°F Fuel Oil (without naphtha)
Carbon % (W)	86.78	87.98
Hydrogen % (W)	12.76	11.50
Sulphur % (W)	0.29	0.30
Nitrogen % (W)	0.17	0.22
Water % (W)	Nil	Nil
Ash % (W)	Nil	Nil
Higher Heating Value (BTU/LB)	19,680	19,080
Lower Heating Value (BTU/LB)	18,460	17,960
API Gravity	37.7	23.8
Specific Gravity	0.8363	0.9113
Viscosity, CP @ 122°F	2.4	3.7
Nickel, Wppm	0.1	0.1
Vanadium, Wppm	0.1	0.1
Flash Point, °F	54	164

STONE & WEBSTER ENGINEERING CORPORATION

330 BARKER CYPRESS ROAD HOUSTON, TEXAS 77094

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September 14, 1989

J.O. No. 17798.01
SW-91

Mr. S. C. Gustas, Jr.
Ohio Clean Fuel, Inc.
330 Barker Cypress Road
Houston, Texas 77094

Dear Mr. Gustas:

As per your request, Stone & Webster Engineering Corporation has reviewed the following documents:

- The Clean Air Act Amendments (CAA) of 1989 - 279 pp.
- CAA of 1989, Section-by-Section Analysis, EPA, - 68 pp.

  CAA of 1989, Highlights, The White House, Washington, D.C., - 6 pp.
- FACTSHEET: President Bush's Clean Air Plan, The White House, Washington, D.C. - 14 pp.
- Preliminary Analysis of the Clean Coal Technology provision included in President Bush's proposed CAA, Clean Coal Technology Coalition - 5 pps.

Regarding OCF's concern as to whether fuel switching to Co-Process produced fuel in currently coal fired utility power plants would qualify as "repowering" and whether the physical location of the Co-Processing plant is germane to qualification as "repowering"; we offer the following:

- The Clean Air Act Amendments of 1989 provide guidance to the Environmental Protection Agency (EPA), Department of Energy (DOE), and the States for attainment and maintenance of the national air quality standards; control of toxic air pollutants; prevention of acid deposition and other improvements in the quality of the nation's air. In short, the principal objective is to modify conventional pulverized coal combustion in utility boilers by installing pollution control equipment; environmentally acceptable combustion technologies; or by burning "cleaner" fuels.

- The Clean Air Act Amendments of 1989 is a law, not regulations. The regulations which implement the "Act" will be developed by the EPA, DOE, and the individual states. Utilities are cognizant of the law and will use it for intermediate and long range planning; but, they will react to regulations and implement changes required to satisfy those regulations in the short term.

- The Clean Air Act Amendments of 1989 is composed of seven (7) titles, six of which related directly or indirectly to implementation of clean coal technology as a major element in President Bush's clean air program. However, Title V - Acid Deposition Control, applies most directly to existing coal fired utility boiler and their relationship to the clean coal technologies. Section 502, "definitions", contains numerous terms which apply to existing utility units in the State of Ohio and the Co-Process based clean coal technology. Section 502 (b) discusses "affected units" in general and further clarification provided by Section 504 (a) (1) and associated Table A to show approximately 145 utility units in Ohio which are specific EOA targets for a two phased compliance effort for SO_2 and NO_x reduction/limitation. Phase I SO_2 compliance is required by December 31, 1995; and Phase II SO_2 compliance, Section 505 (b), by December 31, 2000. Similar reduction mandates for NO_x are discussed in Section 506.

- The implementation of a Co-Process Based Clean Coal Technology at an "affected unit: would be, in our opinion, considered a "repowering"; according to Section 502 (J) and further discussed in Section 508. Concurrence in this interpretation could be required from the EPA Regional administration and Secretary of Energy. As OCF is a DOE funded clean coal project this should pose no problem.

The utilization of Co-Processed produced fuel in lieu of direct coal combustion in a utility boiler should also qualify as a "repowering", as previously discussed, regardless of the physical location of the Co-Processing plant. Concurrence in this interpretation would be required from the EPA regional Administrator and the Secretary of Energy, as previously discussed.

Advantages of "repowering" to a utility by burning a Co-Process Based Clean Coal Technology Fuel are several; including, but not limited, to the following:

(1) Extension for "affected unit" compliance for Phase II from Dec. 31, 2000 to Dec. 31, 2003.

(2) Provision of Bankable Emission Allowances for use at other facilities based on differential "potentials to

emit".

(3) Provision of financial/regulatory incentives to utilities employing Clean Coal technology, as discussed in Section 515.

(4) Exemption of "repowered" unit from CAA Section 11 (NSPS), Part C (PSD), and/or Part D (non-attainment) requirements.

(5) Provides intertradable allowances between SO_2 and NO_x at a ratio of 1.5 pounds NO_x per 1.0 pound SO_2.

Lastly, with reference to the air emission comparison between pulverized coal boilers and coprocess-based clean coal technology presented in Section 5 of your last report, the coprocess based technology would provide utilities in Ohio and adjacent states (which have multiple affected units) with a source of banked emission allowances; which would provide flexibility for entire utility system compliance with provisions and requirements of CAA-1989 as well as provide for future capacity expansions.

Sincerely,

Karayel Rusen
Project Engineer

KR/sck

cc: F. Hassid
R. Delgado

☆U.S.GOVERNMENT PRINTING OFFICE:1989-251-303:00897