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DOE United States
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EPA United States
Environmental Protection
Agency
Office of Energy, Minerals, and
Industry
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Integrated Assessment of Texas Lignite Development

Volume I. Technical Analyses

Interagency Energy/Environment R&D Program Report

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AN INTEGRATED ASSESSMENT OF TEXAS LIGNITE DEVELOPMENT

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FOREWORD

Recent years have witnessed increasing awareness of the declining availability of our most widely used energy sources - oil and natural gas - accompanied by sharp increases in price. Both direct government policy and the market price mechanism are now operating to stimulate a shift away from oil and natural gas to other fuels wherever possible. One area in which this shift is likely to be especially pronounced is the Gulf Coast. There, massive electric utility and industrial capacity is fueled by oil and natural gas which have historically been locally plentiful. Assuming this shift continues, other fuels will be required to power both new and existing sources. One promising candidate to fill much of the emerging energy gap in the Gulf Coast region over the near and medium term is lignite which exists in the same general region and appears to be very competitive economically. There are, however, significantly different and more serious environmental consequences associated with extraction, transportation, and utilization of large quantities of lignite than is the case for oil and natural gas.

Thus, this study was conceived as a timely first attempt at defining and analyzing the consequences and constraints associated with the potential extensive use of lignite in Texas (which comprises a major portion of the region in question), and the public policy options available for managing this development. A notable feature of this research effort has been its cooperative interagency character. It has been a valuable experience in federal/state research cooperation between the Department of Energy (DOE) and the Environmental Protection Agency (EPA), two federal agencies for which cooperation is essential in this sensitive policy area, and the Texas Energy Advisory Council, an agency of the State of Texas. In addition, active involvement of the DOE and EPA regional offices was incorporated into the design and management of the study. Efforts required to establish this complex structure were amply compensated for by the range of viewpoints and experience brought into the research design.

The study has been conducted under demanding constraints of both funds and time. The time constraint has been an especially difficult one. From the study's inception, it was agreed that major users to whom this study would be directed were state and local policy makers (although appropriate elements of the federal government, including regional offices, are considered to be major users as well). In that context it was considered essential that the study results be available to the 1979 session of the Texas State Legislature (which meets once every two years). Consequently, only eight months were available to complete this research, limiting the level of detail at which lignite development issues could be examined.

A significant decision made early in the study's planning was to emphasize the aggregate, regional impacts rather than the specific impacts associated with a single mine or power plant. This decision was based on two primary factors. First, because of its geologic and geographic distribution, lignite's development will occur over a broad region of Texas rather than be concentrated in a few limited areas. As such, it was felt that an analysis of the regional impacts of lignite development might yield valuable information not recognized at the level of an individual site. Second, the attempt to hypothetically site future plants at a more detailed geographic level was too complex a task to be completed in a credible manner within the constraints of the study.

Given this perspective, the study team has done an excellent job of analyzing a number of constraints to and consequences of lignite development at the regional level and has pointed out many potential problems which deserve examination at a finer level of detail. Many environmental problems do not become apparent in an analysis at the regional level of aggregation although their cumulative impacts may be substantial. This study should, therefore, be viewed as a "first cut" overview of the issues associated with Texas lignite development. A finer grained analysis is still required in future research studies as well as through the permitting process.

The reader should also be sensitive to the effect of assumptions on conclusions in a study such as this. It was necessary, of course, to make assumptions about a wide range of future social and economic conditions in order to assess the potential impacts of lignite development. Varying these assumptions could substantially alter the study's conclusions. One clear example relates to availability of water for lignite development. Assumptions were made concerning future municipal and agricultural water demand and future development of dams and other measures to augment water supply. Given these assumptions, water availability does not appear to pose a significant constraint to lignite development in most areas of the lignite belt. Other assumptions, however, could have resulted in quite different conclusions. It was not possible within the limits of the study to examine the sensitivity of conclusions to variations in many such assumptions. The reader should, therefore, be aware of the context of assumptions in which these conclusions were drawn and the resulting limits on their predictive validity.

The project team, put together by the Radian Corporation, is to be congratulated for producing a thought-provoking technical and policy analysis report. In addition, special thanks are due to all members of the review panel and to Bill Honker and Mike Gibson of EPA's Dallas Regional Office and Lila Williams of DOE's Dallas Regional Office for unselfish commitments of time and experience to the project.

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READER'S GUIDE

This Integrated Assessment of Texas Lignite Development was performed by the Radian Corporation of Austin, Texas, for the Texas Energy Advisory Council. Joint sponsors of the project, with TEAC, are the U.S. Environmental Protection Agency and the U.S. Department of Energy.

The report is divided into sections, as follows:

VOLUME I - Technical Analysis

Chapter I - Potential Use of Solid Fossil Fuels

Chapter II - Lignite Development Scenario

Chapter III - Siting Constraints

Chapter IV - Environmental and Socioeconomic Impacts

VOLUME II - Policy Analysis

Chapter V - Policy Analysis

VOLUME III - Technical Working Papers

The organization of the first two volumes of the report follows the sequence of tasks performed in the analysis. Thus, the material in the later chapters is developed from work presented in the earlier chapters. Recognizing however, that most readers will not be equally interested in all of the report's contents, it has been organized for "skipping".

Each of the first four chapters begins with an abstract, summarizing the topics to be discussed. The technical presentation that follows is subdivided into major subsections, each prefaced by a brief summary. The technical presentation is followed by a summary statement of key policy issues arising from the analysis, which will be discussed subsequently in Chapter V. Finally, major data gaps and recommendations for further research are listed, again in summary form. (Chapters III and IV are organized roughly by disciplinary area, with research recommendations at the end of each major section.) Each chapter is followed by its own list of references.

Chapter V contains an analysis of the eighteen policy issues identified in the first four chapters. Each discussion stands alone, and consists of a summary statement of the issue, a table comparing the attributes of alternative actions or policy options, and a short explanatory text. The "meat" of the analysis is in the tables. A final section of Chapter V discusses several underlying issues bearing on lignite development.

Volume III contains a number of technical working papers developed midway through the research project to provide background information on specific areas. The working papers have not been edited or extensively reviewed prior to printing and may contain typographical and informational errors. They do, however, provide summaries of the information which was readily available to the project at the time they were prepared on specific aspects of Texas lignite development. A limited number of these volumes have been printed and will be made available on request from David White, Texas Energy Advisory Council, 7703 North Lamar, Austin, Texas 78757.

A reader wishing to get an overview of the report before deciding which sections to read in detail is advised to begin with Volume I, by reading the abstracts for each chapter, and the summaries of each major section. Then, a brief glance at the summary statements of the issues presented in Chapter V will acquaint the reader with the scope of the policy analysis portion of the study.

ACKNOWLEDGEMENTS

In addition to the authors listed on the title page, a great many people gave assistance in the preparation, review, and production of this report. The heartiest thanks are due to these people from the authors, and it is with pleasure that we acknowledge the contributions of these individuals.

The conduct of the study was overseen by two groups: an Overview Committee representing the three funding agencies, and a Review Panel representing various parties of interest to lignite development, assembled to advise and comment on the technical aspects of the work.

The Overview Committee served to steer the overall direction of the study, and consisted of the following individuals:

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The Review Panel consisted of an invited group of technical experts, interest group representatives, industrial and acedemic personnel, and government agencies involved in lignite development in Texas. This group reviewed the draft reports produced by the Radian study team, and provided expert guidance and

suggestions. The present report strongly reflects the valuable contributions of this group, as interpreted by the Radian staff. Panel members are not, however, responsible for the contents of the final report nor does it always represent a consensus among the group.

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ACRONYMS AND ABBREVIATIONS

CAA	-	Clean Air Act of 1977
DoE	-	Department of Energy
EPA	-	Environmental Protection Agency
ERA	-	Economic Regulatory Administration (Department of Energy)
FUA	-	Fuel Use Act (Portion of National Energy Act of 1978)
HC	-	Hydrocarbons
LNG	-	Liquefied Natural Gas
MBFC	-	Mandatory Boiler-Fuel Conversion
NAA	-	Non-Attainment Area
NAAQS	-	National Ambient Air Quality Standards
NEA	-	National Energy Act of 1978
NO_x	-	Oxides of Nitrogen
NSPS	-	New Source Performance Standards
O&M	-	Operation and Maintenance
PAN	-	Peroxy Acyl Nitrate
PSD	-	Prevention of Significant Deterioration
PUC	-	Public Utility Commission (Texas)
RD&D	-	Research, Development & Demonstration
RRC	-	Railroad Commission (Texas)
SIP	-	State Implementation Plan
SO_2	-	Sulfur Dioxide
TACB	-	Texas Air Control Board
TDWR	-	Texas Department of Water Resources
208	-	Section 208 of the Water Pollution Control Act Amendments of 1977, mandating areawide wastewater management
316a	-	Section 316a of the Water Pollution Control Act Amendments of 1977, dealing with variance procedures for thermal discharges

CHAPTER IV: ENVIRONMENTAL AND SOCIOECONOMIC IMPACTS OF THE DEVELOPMENT SCENARIO

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CHAPTER I: POTENTIAL USE OF SOLID FOSSIL FUELS

Abstract

This chapter addresses the extent to which coal and lignite may contribute to the Texas fuel mix through the end of the century. Plausible growth rates in total energy demand by utilities and industry are developed, and upper and lower bounds discussed. The effects of nuclear policy and the Fuel Use Act on interfuel competition are estimated. Alternative fuels and technologies for industrial use are discussed in terms of economic and engineering feasibility. A series of working assumptions about future fuel choices are outlined based on implementation of the Fuel Use Act and plausible market penetration rates for new technologies. These are used to estimate total solid fossil fuel use. Sensitivity of this use level to changes in these assumptions is evaluated. Relevent policy issues related to overall energy growth and to fuel choices are summarized. Recommendations are also made for further RD&D and planning-related research.

1.0 OVERVIEW OF METHODS

The first step in evaluating the potential impact of lignite development in Texas' future is to obtain an idea of how rapid and extensive this development may be. The process by which a reference energy demand scenario was developed for use in this study is described below.

The process begins with a determination of plausible future demands for energy in sectors where lignite is a competitive fuel. The potential effects of conservation and the introduction of renewal energy resources were accounted for in developing these demand curves. The role of nuclear power was then evaluated, leaving that portion of demand likely to be met by fossil fuels. A plausible estimate of the amount of oil and gas use probable in the remainder of the century was derived from a critical examination of fuel choice economics and the probable effect of the recently enacted Fuel Use Act. The remaining demand represents the potential for coal and lignite use in Texas. The ratio of coal to lignite use as well as the geographic distribution of coal and lignite demand are investigated in the next chapter.

A quantitative evaluation of the complex relationships among the variables which help to determine the rate and extent to which demand for solid fossil fuel develops requires sophisticated modeling techniques. Even with such techniques, the influence of behavioral variables often limits the usefulness of the result. Accordingly, the study team chose not to attempt a modeling approach. Instead, this task was conducted as a series of "what if" questions, in which values of the key variables consistent with reasonably probable futures were used in making simple calculations. Variant cases were also examined to determine how much flexibility was inherent in the situation under study.

2.0 DEMAND FOR CONVENTIONAL ENERGY

Summary and Conclusions

- Utility demand growth in Texas has historically been higher than the national average. This reflects both substantial population growth and the major role on industry in the state.

- The Nominal Case scenario developed for use in this study assumes an annual growth rate of 5.3% to 1987, and 4.3% thereafter. This scenario reflects a modest level of voluntary conservation based largely on price increases, with little or no federal involvement.

- Industry uses more energy than utilities, but its energy use has grown more slowly in recent years. Economics already favor a substantial trend toward conservation, which has been steadily reducing the ratio of energy input to product output.

- The Nominal Case scenario assumes an annual growth rate of raw energy input (excluding feedstocks) of 3.8% to 1990, and 3.2% after 1990.

Lignite competes with other fuels chiefly in the generation of electricity and industrial process heat and steam. It does not contribute directly to either commercial/residential or transportation sectors. Thus, the following discussion centers on that portion of Texas' overall demand for energy in which lignite has a potential role to play. Demand for energy is evaluated separately for electric utilities (which includes indirect contributions to residential and commercial needs) and for industrial applications. Potential demand reductions from conservation are considered, along with the possibility that solar energy, biomass, and other renewable energy forms may reduce demand. What is left is the demand for "conventional" energy: fossil fuels and nuclear power.

2.1 Limiting Effects of Non-Attainment of Oxidant Standard

To a significant degree, energy demand growth in Texas will be driven by growth in the state's dominant economic sectors: petroleum, petrochemicals, and allied industry, Not only does growth in these sectors directly influence the amount of energy used by them, it has a strong bearing on employment and population in-migration. Population growth, in turn, increases the demand for electricity. Since lignite potentially provides energy to both industry and utilities, any factor which can affect growth in the petroleum and petrochemical sectors can affect the future of lignite.

A key air-quality issue currently under debate could prove to be such a factor; the decisions to be made in the near future regarding permitting of new sources in areas not in attainment of National Ambient Air Quality Standards (NAAQS) could have a large impact on the petroleum/petrochemicals industries.

Under the Federal Clean Air Act of 1970, the Nation's air quality was mandated to attain the national primary Ambient Air Quality Standards by 1975, or by 1977 in certain areas. Permits for new sources were not to be issued in areas not attaining the standards. By 1976, it had become apparent that large areas of the nation would be unable to meet the standards. To permit continued industrial growth and still provide progress toward the objectives of the Act, EPA adopted a policy of emission offsets.[1] This policy permits major new sources to locate in non-attainment areas (NAA's) if the emissions from the new source can be more than offset by a corresponding reduction in emissions from other sources in the vicinity.

Each state is required to show in its State Implementation Plan (SIP) that each NAA can be brought into attainment by December 31, 1982.* If EPA has not accepted a state's SIP by July 1, 1979, EPA will not approve permits for construction of new sources. Additional sanctions include a cutoff of federal highway funds and sewage treatment grant monies.

Texas is largely in compliance with standards for three of the five regulated pollutants. Several counties fail to comply with NAAQS for particulates and ozone, but the ozone problem is considered the more serious. Although only fifteen out of 254 Texas counties have been designated by EPA as out of attainment for ozone, these counties comprise 58 percent of the state's population and 71 percent of the state's economic activity.** Figure 2-1 shows their location.

On January 26, 1979, EPA announced the revision of both the primary and secondary ozone standard from 0.08 ppm to 0.12 ppm, to be exceeded for not more than a single one-hour period during the course of a full year. Under the new standard, most of the inland counties are below or very near compliance levels. Oxidant levels measured in the Gulf Coast industrialized zone, however, exceed even the new standard. In the Houston area, recent ozone statistics indicate 50 to 60 hours of noncompliance yearly. Monitoring data for adjacent inland areas are lacking. Because of the degree of noncompliance in the coastal industrial zones, however, and considering air parcel movements from that

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* Extensions to December 31, 1987 are available for carbon monoxide and oxidant NAA's if the state can show that compliance by 1983 is not possible.

**Based on 1974 Bureau of Census estimates and wage and salary income (excluding certain sectors such as self-employed).[2]

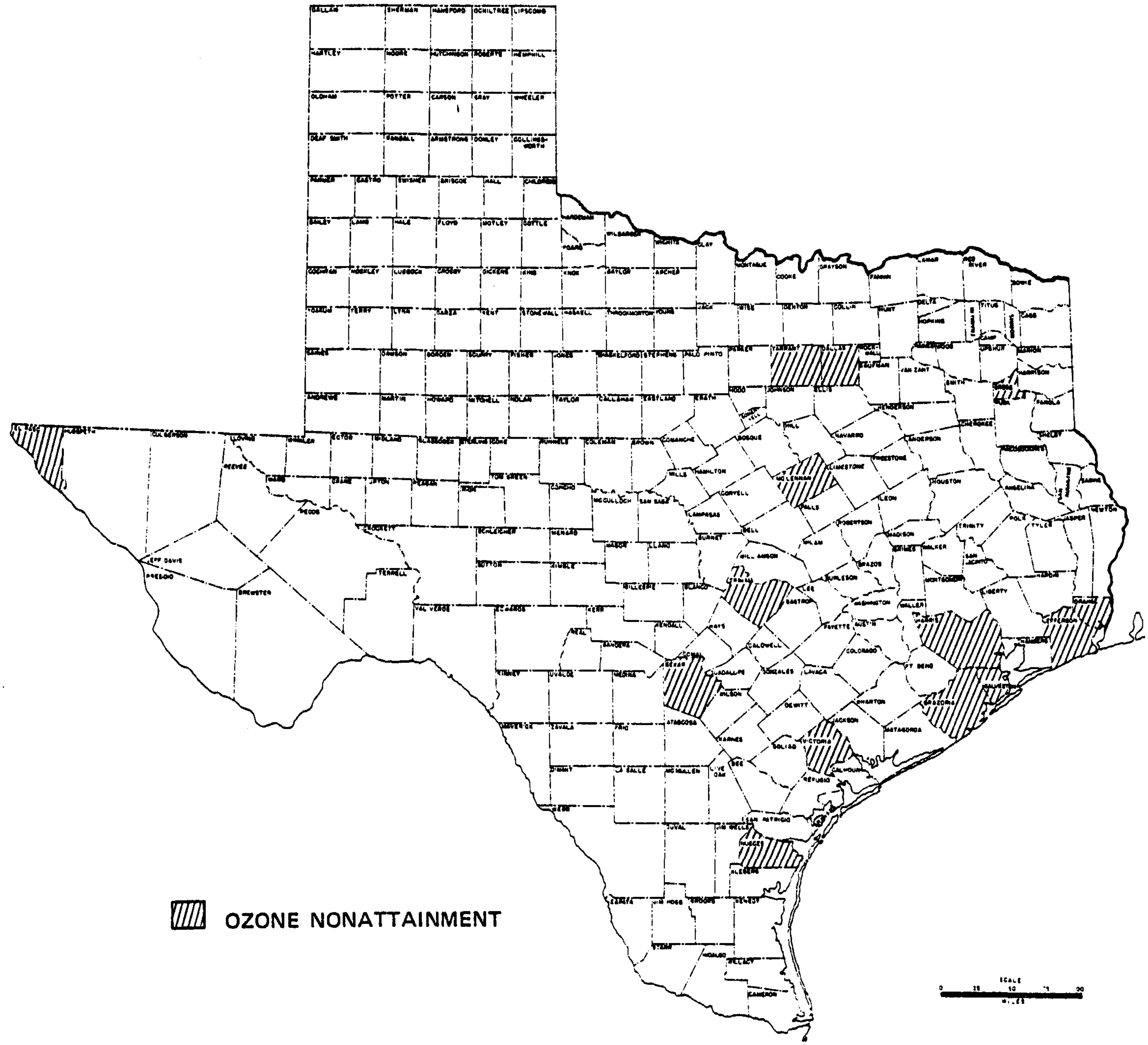

Figure 2-1. Areas Out of Compliance with National Ambient Air Quality Standards for Ozone as of January 1, 1979.

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region, it is reasonable to expect that noncompliance problems may be fairly widespread in eastern Texas.*

The extent and severity of Texas' ozone problem is of great concern to the petroleum refining and chemicals industries. These industries, together with mobile sources (i.e., autos) emit hydrocarbons which combine with nitrogen oxides in the presence of sunlight to form ozone and other oxidants. (According to TACB emissions data for the Houston-Galveston area, 53 percent of hydrocarbon emissions come from "major sources"--virtually all of which involve the petroleum and petrochemical industries.)

The Texas economy is currently based, to a large extent, on these industries. Although the state is moving toward a more diversified industrial base, petroleum refining and petrochemicals will continue to be a significant driving force in the economy. Given that large areas of the state adjacent to the existing refining and chemicals industrial complex are out of compliance with even the newly relaxed standards for ozone, the method of permitting new sources in non-attainment areas is crucial to the expansion of these industries.

The current offsets policy, if rigidly enforced, will almost certainly increase costs and introduce delays into the process of siting new chemicals-related industry and may force a shift to less economically desirable sites away from present

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* In a September 16, 1977 meeting of the Texas Air Control Board, a written status report on attainment/non-attainment of the then-applying National Ambient Air Quality Standards was presented which made the following observation regarding oxidants: "the oxidant standard has been exceeded at every location in the State monitoring zone. It is expected that the standard will continue to be exceeded at these locations and other violations could probably be found if monitors were located in other areas of the State."

industrial concentrations. There is considerable polarity of opinion as to the seriousness of this effect on the state economy. EPA has contended that, through expansion into neighboring counties in attainment of the ozone standard and simultaneous control of vehicle traffic, industrial expansion can take place without undue hindrance.[3] Texas officials point out that because of past efforts at the state level, hydrocarbon emissions are now well enough controlled that further offsets will come only at increasing expense, if they are possible at all.[4]

It is beyond the scope of this study to evaluate quantitatively the potential effects of the offsets policy on growth in Texas' demand for energy. It has been assumed here that a resolution to the problem will be found which does not significantly affect either the growth rate of Texas industry, or the mix of industries potentially developing.

2.2 Utility Energy Demand

Historically, electricity demand has grown rapidly in Texas. The annual growth rate was 9.7 percent between 1960 and 1975, as compared with 6.3 percent nationally.[5] This higher growth rate reflects the rapid growth of industry in the state, as well as recent rapid population growth.

Growth rates this high are not expected to continue, as is foreshadowed by the drop in Texas' annual growth rate to 7.2 percent between 1970 and 1975.[5] The expected down-trend includes four components: a reduction in population growth rate; a decline in the rate of increase of per capita energy use because of changing technology and industrial mixes; increased conservation; introduction of the so-called "soft" energy technologies to substitute for electricity. The growth curves used to define the demand scenario developed here take all four factors into account.

An average annual population growth rate of 1.7 percent has been used in this study and was derived in consultation with economists from the Texas Department of Water Resources. This figure contrasts with an annual rate of 1.8 percent between 1970 and 1974.[6] The presumption behind the declining growth rate is that the intensity of the "Sun Belt Phenomenon," which produced the high in-migration of the 1970's, will not remain at this level, although growth from in-migration could continue for a long time. Also, a nationwide trend of declining fertility is expected to be expressed in lower birth rates.

2.2.1 Conservation and Unconventional Sources

Rising prices and increasing public awareness suggest that some degree of conservation will act to reduce future growth in electricity consumption. Very high levels of conservation in residential and utility energy use have been considered technologically feasible, leading to predictions of annual demand growth rates for electric energy of as little as 0.7 percent.[7] However, without substantial government intervention to provide artificial economic incentives to change consumer attitudes, major gains may take place slowly. Slow turnover rates for housing and large equipment help hold back the trend. A further drawback is the low short-term economic return perceived by many consumers faced with large capital investments in energy-conserving equipment and structures.

Similar drawbacks are expected to prevent the so-called "soft" energy technologies--solar and related renewable forms such as wind and biomass--from contributing large amounts of energy in the near term. The technology needed to use these unconventional sources is available. Recent studies indicate that they could meet between eight and 25 percent of the nation's energy demand in 2000.[8,9] However, large capital requirements and uncertain economics suggest that without a substantial national program to promote them, these sources will not displace a significant portion of the demand placed upon utilities.

2.2.2 Development of Utility Fuel Use Scenario

Figure 2-2 shows the estimate of energy demand growth in utilities developed for use in this study. It represents a middle-ground view, assuming no major changes in federal policy affecting conservation and soft energy. The effects of voluntary conservation, a slowdown in population growth, and market saturation are reflected at levels which are felt to be a reasonable extrapolation from today's trends. The upper and lower bounds were developed to show what are believed to be plausible limits. Without major changes in the economy or styles of life, the use of energy in utilities is not expected to go beyond these limits. A tacit assumption in all three curves is that major changes in the efficiency of power production do not occur.

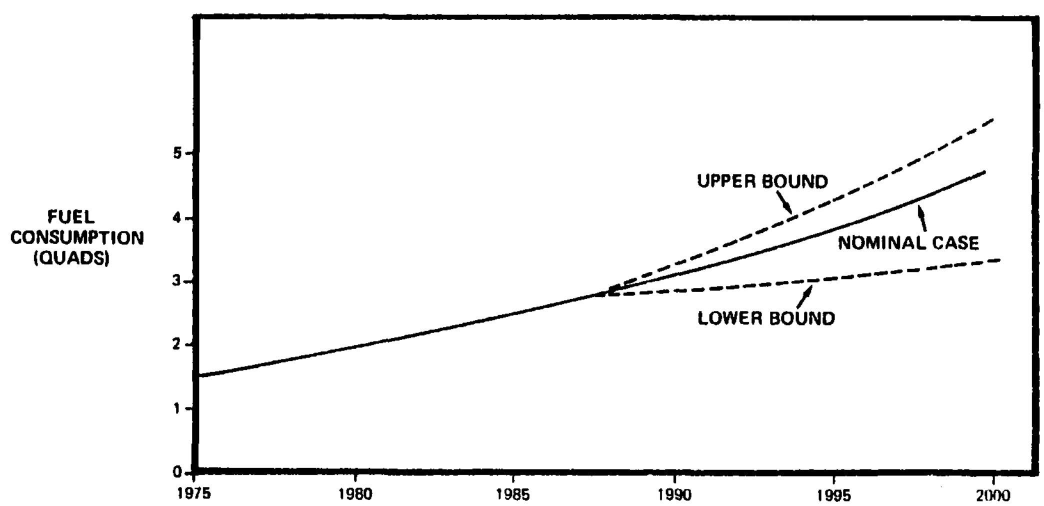

Figure 2-2. Growth Rate in Conventional Energy Demand for Electric Power Generation
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A number of estimates are available for annual utility growth applicable to Texas, ranging from between 2.6 and 3.1 percent[2] to between 6 and 7 percent.[10] The study team chose an intermediate set of forecasts, prepared by the Electric Reliability Council of Texas (ERCOT),[11] which shows growth to 1987 of 5.3 percent, and from 1987 to 1997 of 4.8 percent per year. For comparative purposes, electrical growth in Texas averaged 7.7 percent per year between 1975 and 1977[12], and is estimated to have grown 7.4 percent in 1978.[13] Presently, ERCOT represents roughly 80 percent of the electrical generation in Texas, and it was assumed that these projections are representative of the entire state. Using TEAC figures for 1975 fuel consumption, the solid curve was generated using the ERCOT growth rates, breaking at 1987. The ERCOT projections assume modest levels of voluntary conservation.

The curve for the upper bound was derived assuming a continuation of the 5.3 percent growth rate of 1975-1987 through the end of the century. A higher growth rate than this would involve a major change in baseline assumptions, such as increasing (rather than declining) population growth, or introduction of new electricity-intensive technologies, such as electric cars.

The lower bound was calculated by letting the per-capita growth in electricity consumption fall to zero by 1987. From this point on, population growth alone accounts for the rise in energy demand.

To test the reasonableness of the values so obtained, the year-2000 energy demand was calculated that results from a variety of projections of potential conservation and soft-energy futures.[5,7] The effects of conservation alone could reduce this demand from 4.8Q to between 4.6 and 3.4Q. Adding soft energy[9,14] brings it down to between 3.7 and 2.5Q. The lower bound projection for the year 2000 is 3.3Q. Thus it appears that something near a zero per-capita growth rate in demand for conventional energy sources to generate power may lie within the realm of technological feasibility. However, as is pointed out in the preceding section, numerous economic and institutional variables presently oppose such a trend.

2.3 Industrial Energy Demand

In 1975, Texas industry used more energy (excluding feedstocks) than did utilities: 2.2Q as compared with 1.56Q. Virtually all of this energy was in the form of oil and gas, with gas accounting for 1.5Q. Furthermore, most of this industrial fuel use was concentrated on the Gulf Coast. Seventy-five percent of the natural gas used in industrial boilers was burned there.[15] Petroleum refining and petrochemicals together account for two-thirds of the state's industrial fuel use.

Industrial fuel consumption grows more slowly than fuel demand for power generation. Largely, this is because economic incentives produce improvements in processes and operating procedures. Further advances in energy efficiency could be made by improving operating and maintenance practices, by capital expenditures in new processes and equipment, and by the introduction of cogeneration.*

2.3.1 Conservation and Unconventional Sources

Significant reductions in energy use by industry may be possible, both by improved operation and maintenance procedures and through the replacement of capital equipment. Estimates of

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*Cogeneration is here defined broadly as the use of "waste" heat from power generation to perform useful work.

total energy savings possible by the end of the century range from 10 percent to 40 percent.[5,11,16,17,18] There is considerable disagreement, however, about the relationship between conservation at these levels and the health of the nation's economy. The key uncertainty is the degree of elasticity of industrial energy demand in the face of rising prices. Cogeneration may be the most immediately attractive option, from an economic standpoint, and extensive opportunities may exist for its application in Texas.[19] Reluctance on the part of utilities to accept power generated by industry, and concern by industry over possible government regulation, remain to be overcome.[20] Nevertheless, at least one large-scale Texas cogeneration project is already in the planning stages.

Unconventional energy sources at present do not appear widely applicable in industry. The displacement possible by 2000 may be equivalent to only 0.05 to 0.10Q--less than five percent of energy consumption in 1975.[21]

2.3.1 Development of Industrial Fuel Use Scenario

Figure 2-3 presents the fuel use growth curve for industry developed for this study. It is bounded by what are

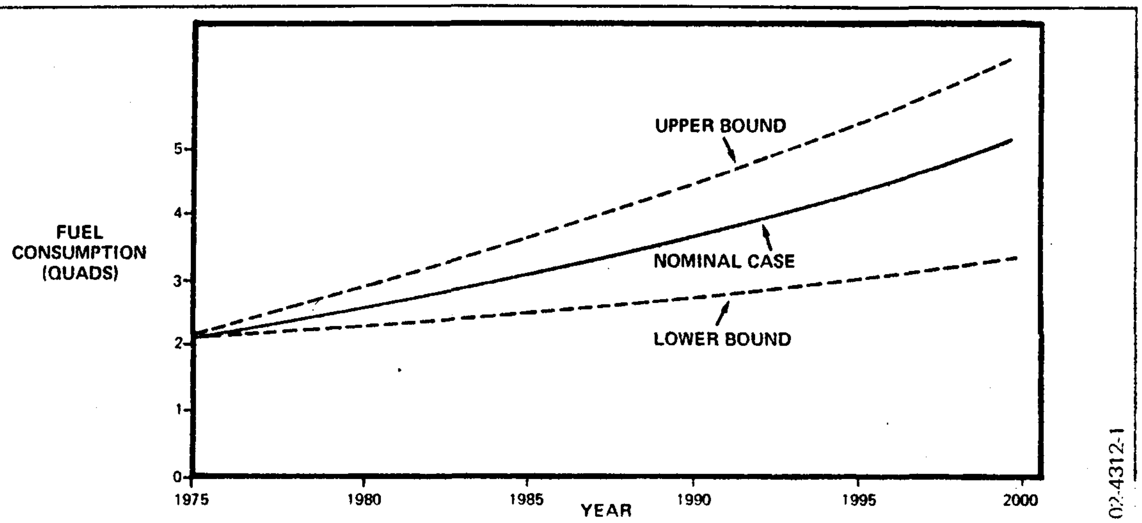


Figure 2-3. Demand Growth for Convential Energy In Industry (Excluding Feedstocks)

believed to be reasonable upper and lower limits to plausible growth in energy demand.

The beginning value of 1975 fuel consumption was derived from TEAC, Bureau of Mines, and Federal Power Commission data and represents process heat, process steam, and on-site electric power production. The solid curve is based on an annual growth rate of 3.8 percent from 1975 through 1990. This growth rate is consistent with studies done by TEAC and FPC,[5,22] and is based on both Chase Econometrics and Bureau of Economic Analysis projections of economic activity. After 1990, the growth rate is dropped to 3.2 percent to reflect what is believed to be a moderate degree of voluntary conservation (roughly 2 percent per year per unit output, as estimated by TEAC[5]) and a changing industrial mix in which services and non-energy-intensive industries become more important.

The upper bound corresponds to the rate at which earnings in industrial sectors are projected to grow by the Texas Water Resources Department. This effectively assumes that productivity per worker, energy intensity per worker, and the ratio of salaries to output do not change. The lower bound is calculated using population growth rate alone. This assumes that per-capita measures of productivity and energy intensiveness in industry, taken across the entire population, do not change.

The validity of the lower limit was checked by comparing it to the effect of widespread measures promoting conservation and soft energy.[5,7,9,14,17,23] Counting only the highest estimates of potential conservation, the year-2000 energy demand of 5.18Q shown on the solid curve is reduced to between 3.8 and 3.10Q. Adding the potential contribution of soft energies in direct industrial applications brings the total into the range of 3.75 to 3.0Q. Thus, it is concluded that the lower bound is a reasonable estimate of what might happen if a strong push toward conservation took place. However, as was discussed in the preceding section, such large amounts of conservation might be associated with other economic consequences which would have far-reaching negative effects.

3.0 EFFECTS OF REGULATORY POLICY ON CONVENTIONAL FUEL MIX

Summary and Conclusions

- For the remainder of the century, the bulk of Texas' energy supply is expected to come from "conventional" sources: oil, gas, coal, lignite, and nuclear energy.

- Nuclear power is presently constrained by uncertainty regarding costs and lead-times, which have recently forced cancellation of several large power projects in Texas. Given this trend, it was assumed that no new nuclear capacity would come on line in the 1990's. The Nominal Case scenario projects 0.3Q of nuclear power in 1985 and 0.4Q in 2000.

- The Fuel Use Act portion of the National Energy Act contains provisions for mandatory boiler fuel conversion (MBFC) that are more stringent than those already in force or under consideration at the state level (Railroad Commission Docket 600). For this reason, the federal policy is expected to take precedence over the state's.

- Depending upon its administration, the Fuel Use Act may substantially increase amounts of coal and lignite used under new industrial boilers, as well as existing utility boilers required to stop using gas and oil. Rising prices and uncertainty of supply over long plant life-times have already caused a shift to coal and lignite for new utility boilers.

At this point in the analysis, we have derived an estimate of input energy requirements for uses where lignite is a competitive fuel. The contributions of "soft" energy and co-generation have been shaved off, leaving that portion of the demand which must be met by oil, gas, coal, lignite, and nuclear energy (for utilities). The next step is to derive a reasonable estimate of nuclear power availability and divide the remaining demand among the other four "conventional" fuels. To do so requires consideration of policies and trends surrounding nuclear energy and mandatory boiler fuel conversion as they affect interfuel competition in Texas.

3.1 Nuclear Trends and Policy

Nuclear energy will compete with coal and lignite in the electricity sector over the next two decades. Although no nuclear power is currently produced in Texas, construction is underway on two plants and at least one other is in the planning stage.

Table 3-1 lists nuclear plants planned for Texas, along with out-of-state nuclear plants which might provide power to consumers in Texas. Year-2000 estimates of Texas nuclear capacity (without the breeder reactor) have ranged from a low of what is

TABLE 3-1. STATUS OF FUTURE NUCLEAR PLANTS TO SUPPLY TEXAS

Status	Plant (Unit)	Utility	MW(e) Net	On-Line
		IN-STATE		
U.C.	Comanche Peak (1)	Texas Utilities	1150	1981
U.C.	South Texas (1)	Houston Lighting & Power*	1250	1983
U.C	Comanche Peak (2)	Texas Utilities	1150	1982
U.C.	South Texas (2)	Houston Lighting & Power*	1250	1982
Planned	Allen's Creek	Houston Lighting & Power	1150	1985
		OUT-OF-STATE		
	Palo Verde (1)	El Paso Electric**	1240 (136)	1982
	Palo Verde (2)	El Paso Electric**	1240 (136)	1984
	Palo Verde (3)	El Paso Electric**	1240 (136)	1986
	River Bend (1)	Gulf States Utilities†	935 (468)	1985

*Also share of power to City of Austin, City of San Antonio, and Central Power and Light.

**El Paso Electric's share in Arizona's Palo Verde units. The figure in parentheses is the estimate available for Texas use.

†Half of this unit's capacity is expected to be generated to supply GSU's Texas demands.

Source: Provision of Electric Power in Texas: Key Issues and Uncertainties.[23] Modifications based on updated information from John Gordon of TEAC.

now planned (less than 7000 MWe) to a high of 20,000 to 25,000 MWe.[24] The high estimate is based on Texas' share of the nation's uranium reserves.

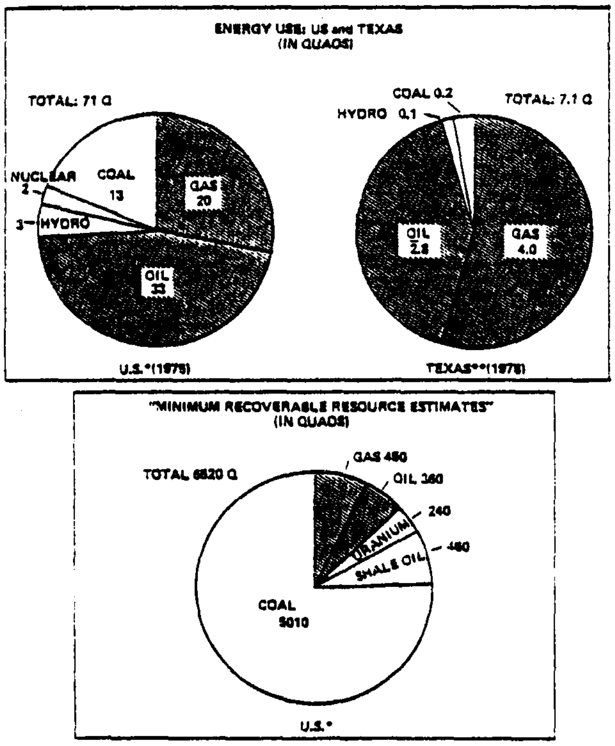
Given the ten-to-twelve-year lead time required for nuclear plant construction, any units which will be on line by 1990 must be in the planning stages now. Recent trends suggest that without substantial changes in the licensing process and in public attitudes, few new plants will be planned in the 1980's.

Thus, for purposes of determining Texas' coal and lignite demands, it will be assumed that no new nuclear plants are added during the 1990's. Therefore, the Texas nuclear supply is estimated to 0.3Q in 1985 and 0.4Q in 2000.

If, indeed, current trends in policy are reversed, several additional plants could be added in the 1990's raising the nuclear supply estimate for 2000 to between 0.7 and 1.0 Quads.

3.2 Mandatory Boiler Fuel Conversion Policies

The impetus to develop a public policy forcing utilities and industry to convert from oil and gas as a boiler fuel stems from two aspects of the U.S. energy situation. First, domestic oil and gas supplies are perceived as decreasing at a dangerous rate. Second, continued dependence on oil imports is seen as potentially disastrous both from an economic and a foreign policy viewpoint. Perhaps the most compelling evidence in support of mandatory boiler fuel conversion (MBFC) policies is a comparison of recent patterns of energy use with estimated domestic resource availability on a fuel-by-fuel basis. These data are graphically illustrated in Figures 3-1 and 3-2. Figure 3-1 shows the distribution of energy use by fuel in the



02-4334-1

Figure 3-1. Energy Use Versus Resource Size

*Source: Energy Perspectives, US DoI, June 1976 [25]

**Source: Texas Energy: A Twenty-Five Year History, GEAC, August 1977 [26]

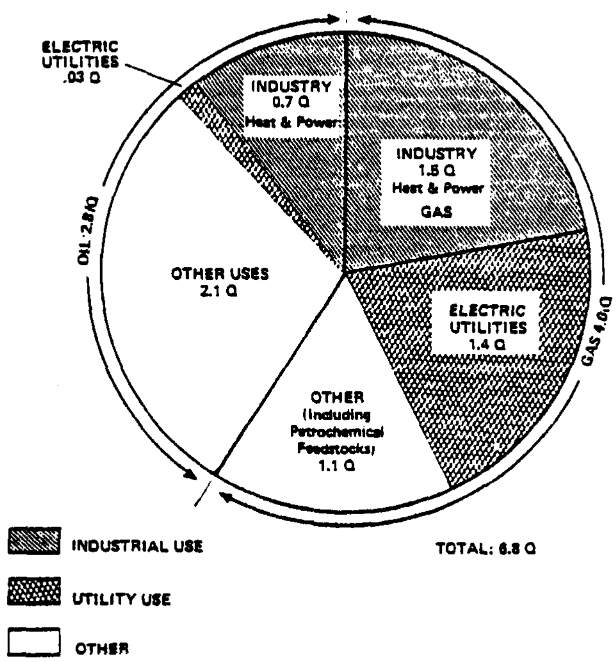


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Figure 3-2. 1975 Use of Oil and Gas in Texas (in Quads)
Source: Texas Energy: A Twenty-Five Year History [26]

U.S. and Texas, and compares this to the energy reserves in the U.S. by fuel. Figure 3-2 shows how oil and gas were used in Texas in 1975.

The conclusion which may be drawn from this presentation is that the shift should take place as quickly as possible from fuels with dwindling domestic supplies to the nation's more abundant energy sources. As indicated in Figure 3-1, the reliance on oil and gas in Texas (95 percent of all energy inputs in 1975) is even greater than that of the nation as a whole (80 percent of all energy inputs in 1975). And, as shown in Figure 3-2, over half of the oil and gas used in Texas in 1975 was used to generate electric power and industrial heat and steam. Many of these uses are technologically amenable to coal substitution. Consequently, a strong policy of fuel conversion can have a very great impact on Texas industries and utilities.

3.2.1 Federal MBFC Policies

The Fuel Use Act, recently enacted as part of the National Energy Act, mandates much more extensive conversion away from gas and oil by large boiler fuel users. Exemptions are provided for, but the burden of proof for securing them rests not with the government, as under previous legislation requiring boiler fuel conversion (ESECA), but with utilities and industries. This form of administration makes it much easier for the Department of Energy, as the agency charged with implementing the Act, to take and hold a tough regulatory stance. Draft regulations under the Act, issued in November, reflect just such a policy.[27]

The major thrust of President Carter's original energy plan involved controlling boiler fuel use through a system of disincentives and incentives (through oil and gas taxes and tax rebates). This approach was intended to promote conversion of oil and gas to coal for utility and industrial use. In its course through the legislative process, the taxing provisions have been stripped away. The original MBFC provisions have also been substantially altered through the creation of numerous exemptions and alternative compliance schemes. Nevertheless, since the Act vests considerable discretionary authority in the Department of Energy, the FUA is potentially a powerful instrument for forcing utility and industrial boiler fuel users to convert to coal.

Federal MBFC policy deals primarily with two classes of oil and gas users: utility power plants and industrial "major fuel-burning installations" (MFBI's). Neither power plants nor MFBI's which have a heat input rate of less than 100 million Btu's per hour are affected by the act. However, if there are several units at a single site and the total fuel-burning capability exceeds 250 million Btu's, all of the units fall under the provisions of the Act.

The major provisions of the Fuel Use Act are summarized in Table 3-2. The Act prohibits the use of oil or natural gas in new utility and industrial boilers coming under the Act's size criteria, and calls for a total phaseout of gas use in existing utility boilers by 1990. Existing MFBI's, however, are not specifically required to convert, although DOE is given authority to designate categories of MFBI's which must stop using oil and gas. Similar discretionary authority is given DOE to prohibit the use of oil and gas in designated categories of MFBI's for purposes other than boiler fuel.

The Act is set up to be administered through the granting of both temporary and permanent exemptions, and sets forth a variety of criteria under which they may be justified. The principal criteria are inability to meet environmental standards with alternative fuels and excessive costs of conversion.

TABLE 3-2. BASIC PROVISIONS OF THE FEDERAL FUEL USE ACT

	BASIC PROHIBITIONS	MAJOR EXEMPTIONS
NEW UTILITIES	. Oil or gas cannot be used as primary fuel . Must be constructed with alternate fuel capability	. All units less than 10 MWe unless total capacity on site exceeds 25 MWe (P) . Unreliable or high-cost coal supplies (T or P) . One or more site limitations (T or P) . Violation of environmental regulations (state or federal) (T or P) . Public interest (T) . Unavailability of capital (P) . Cogeneration (P) Emergency Use (P) . Impairment of reliability (T) . Use of synfuels or mixtures (T or P) . Peakload and certain intermediate loads (P)
EXISTING UTILITIES	. No gas use after 1990 . No gas use in a plant that did not use gas in 1977 . Case-by-case prohibitions for facilities with coal-burning capability . Utilities may apply for exemptions or exercise the system compliance option	. All units less than 10 MWe unless total capacity on site exceeds 25 MWe (P) . Unreliable or high-cost alternative fuels (T or P) . One or more site limitations (T or P) . Violation of environmental regulations (T or P) . Synfuels or innovative technology (T) . Public interest (T) . Reliability Cogeneration (P) . Peak load
		. SYSTEM COMPLIANCE OPTION (Existing Utilities) . Submit plan by 1980 . No new baseload oil or gas units . Reduce to 20 percent of 1976 gas consumption by 1990 . DoE approval of gas contracts . Complete elimination of gas use by 2000
NEW MFBI'S*	. Oil or gas cannot be used as primary fuel source . DoE may establish categorical prohibitions for non-boiler uses	Basically includes most of those listed under "new utilities" above.
EXISTING MFBI'S	. No phase out required . DoE may prohibit oil or gas on a categorical basis	

*Major Fuel Burning Installation (P) Permanent (T) Temporary

In principle, it would be possible to fine-tune such a scheme, so as to allow for adjustment to changing conditions of oil and gas supply. The Act itself is comparatively open, and leaves a great deal to the discretion of the Energy Secretary. However, the draft regulations for new boilers reflect an opposite interpretation. The draft regulations have been designed to make exemptions very difficult to obtain at the outset, leaving little room for increasing stringency as a response to changing oil and gas supplies. Thus the Act is being administered specifically as a means to reduce imports, rather than as a more generalized conservation tool.

DOE's regulations clearly evince a willingness to pay a significant economic price for the benefits of conversion. Requests for exemptions on the basis of unfavorable economics must show not simply that an alternative fuel costs more to use than oil and gas, but that the cost differential be "significant," perhaps in excess of 80 percent. The final regulations will specify a cost differential; the draft regulations use 50 percent. Alternatively, the applicant must show that the additional capital required to switch to an alternative fuel is more than 25 percent of the parent company's average annual capital budget over the last three years.

Alternative sites must be investigated, including sites outside the utility's service territory, before an exemption may be granted on the basis of unavailability of alternative fuels, or inability to comply with environmental regulations. In addition, the formal permit procedure must be exhausted before an exemption may be made on environmental grounds. A final determination from EPA or the state confirming the unacceptability of alternative fuels is required to support such an application.

A comprehensive "Fuels Decision Report," containing a detailed examination of alternative fuels, alternative sites, and environmental and other considerations, must be submitted with an application for exemption. Also, compliance with NEPA will be required for most permanent exemptions.

3.2.2 Texas MBFC Policy

In the early 1970's, prompted by concern over long-term prices and availability of natural gas, the Texas Railroad Commission instituted a formal plan to phase out the use of natural gas under boilers. The original order, Gas Utilities

Docket 600, was issued in December of 1975 and was amended in March 1976. Subsequent minor revisions have been based on administrative decisions and litigation.

Since the Commission regulates the transport and sale of natural gas, Docket 600 imposes boiler fuel restrictions by prohibiting deliveries of natural gas to boiler fuel users in excess of 3,000 Mcf per day.* This prevents new large boilers from using gas. Existing users are exempt from the prohibition. However, Docket 600 requires a ten-percent reduction in deliveries to all current boiler fuel users (exceeding 3,000 Mcf/d) by January 1, 1981, and a 25-percent reduction by January 1, 1985. The reduction is calculated on the basis of the customer's 1974 or 1975 boiler fuel use (whichever is greater).

Docket 600 reserves the right of the Commission to grant exemptions to its provisions. To date, economic cost-benefit criteria have been paramount in considering exemption requests.

With the passage of the Fuel Use Act, it is expected that Docket 600 will very soon be withdrawn. Unlike the federal Act, Docket 600 requires existing industrial firms to reduce their use of gas, a measure which might put Texas industries at a competitive disadvantage. The federal Act is also more stringent with regard to both the total extent of conversion and the granting of exemptions. Thus, its provisions effectively encompass and exceed the goals of the Texas measure.

*The 3,000 Mcf is calculated as a daily average over a year. This level was chosen because it exempts small users (hospitals, schools, laundries, etc.) but affects 95 percent of the gas burned in boilers.[28]

4.0 FOSSIL FUEL ALTERNATIVES FOR INDUSTRY

Summary and Conclusions

- Coal and lignite are not presently as attractive for industrial use, based on economic considerations alone, as are oil and gas, even at current prices.

- The regulatory approach proposed by ERA in its draft FUA regulations effectively alters the economics of interfuel competition to favor coal by placing an arbitrary economic penalty or "handicap" on oil and gas use.

- While conventional pulverized coal boilers will probably dominate in industrial applications, favorable economics suggest possible significant penetration of AFBC systems by the 1990's.

- The proposed DoE regulatory approach improves the chances for commercial-scale gasification as an environmentally acceptable alternative in cases where an alternative site is infeasible and poor air quality restricts direct coal combustion.

- Unless non-boiler fuel choices came to be widely regulated under FUA, with a similar "handicap" approach, synthetic fuels are not likely to achieve significant market penetration in process heat applications.

- In addition to fuel uses, gas made from coal or lignite has a large potential market as a chemical feedstock. Large solid-fuel-based integrated complexes combining steam, heat and power generation with chemical syntheses, may develop.

- Before gasification becomes widespread, two key uncertainties must be resolved:

  ✓ Environmental control requirements, especially NSPS, which can affect economics.

√ The potential for high ambient ozone levels to limit siting.

- The combined uncertainty felt by industry over both the future of clean air rules and the future of MBFC, may cause many firms to delay making large investments in expansions. The situation on the Gulf Coast is particularly constrained in this regard. Some firms may perceive incentives to consider long-term relocations.

Having considered potential regulatory influence on boiler-fuel choice, it now remains to consider in some detail how the general energy use patterns discussed in Section 2 may break down into a mix of fuels. This section deals with industry; Section 5 contains a similar discussion for electric utilities. Future industrial fuel choices will be made against a constantly changing backdrop of economics, environmental controls, and technology. Moreover, most of these decisions will be made within the rules set by mandatory boiler fuel conversion policy. The following sections present an overview of the principal driving forces behind the choice of fuels for generating process steam and heat.

Boiler fuel choice is under the jurisdiction of the Fuel Use Act, while the status of fuel choices for generating process heat alone is unclear. Although the FUA provides for extending its provisions over non-boiler applications, no determinations have yet been made. Depending on how non-boiler fuel uses are eventually regulated, choices in this area of applications could be made quite differently than those in the area of boiler fuels. For this reason, the two types of applications will be discussed separately.

Finally, although chemical feedstocks have been deliberately excluded from the potential energy demand curves for industry, they constitute a potential market for lignite. Therefore, feedstock choices will be briefly discussed, as a potential additional demand.

Background

As was pointed out in Section 2.3 above, petroleum refining and petrochemicals together account for two-thirds of the fuel used by Texas industries. These industries experience considerable economies of agglomeration, and tend to develop in clusters or strips. Between 75 percent and 90 percent of the state's large industrial boilers are located within 50 miles of the Gulf Coast between Corpus Christi and the Louisiana border.[29] The Houston area is the center of this development, and now comprises the largest petroleum refining-petrochemicals complex in the nation.

The high degree of interconnection between plants in the Gulf Coast industrial complex is an important characteristic with respect to fuel choices. A 1200-mile pipeline network, known as the Spaghetti Bowl, allows complex direction of product streams, which can be adjusted almost on a day-to-day basis to allow for economic optimization. Many streams can be either sold or used as fuel. Thus, the actual fuel mix in use at any time will consist of a variety of substances which varies both with the cost of raw fuels and with product prices.

Natural gas is now the dominant energy source in Texas petroleum and petrochemicals industries. The larger integrated refining and petrochemical facilities may own gas supplies sufficient for a large part of their needs. These supplies are exempt from the Fuel Use Act. Additional gas is supplied by utility-type vendors, or on long-term contract from producers. Thus, the delivered price of natural gas may vary from the recent intrastate prices of up to $3.00 per million Btu, to well under $1.00 on older, long-term contracts. This situation could result in considerable firm-to-firm variation in the economic cost of converting to coal or lignite, and hence on ability to pass the FUA cost test.

4.1 Alternative Boiler Fuel Choices

Table 4-1 summarizes what is thought to be a currently feasible range of choices for new industrial boilers. The table

TABLE 4-1. ALTERNATIVE CHOICES FOR FIRING NEW INDUSTRIAL BOILERS

	New Facilities and Site Requirements	Transport Requirements	Limiting Environmental Considerations	Technical Feasibility
New coal- or lignite-fired boiler with FGD	Boiler; scrubber; coal handling; solid waste disposal and handling; lime/limestone handling.	Rail or Barge Transport	PSD at boiler.	Commercial
New residual fuel oil-fired boiler with FGD	Boiler; scrubber; oil storage; solid waste disposal.	Pipeline or Barge Terminal	PSD at boiler.	Commercial
New distillate fuel oil-fired boiler	Boiler; oil storage	Pipeline or Barge Terminal	PSD at boiler.	Commercial
New natural gas-fired boiler	Boiler.	Pipeline	PSD at boiler.	Commercial
New coal or lignite AFBC boiler	Boiler; coal handling; solid waste disposal & handling; lime/limestone handling.	Rail or Barge Terminal	PSD at boiler.	Conceptual, might be available in 1990 for industrial applications.
New low-Btu gas-fired boiler	Gasifier; boiler; coal handling facilities; waste disposal at gasifier.	Rail or Barge Terminal	NAAQS at gasifier. PSD at gasifier. Gasifier solid and liquid wastes.	Commercially demonstrated in U.S. except for H_2S removal unit.
New medium-Btu gas-fired boiler	Boiler; availability of medium-Btu gas from off-site producer.	Pipeline	PSD at gasifier.	Commercially demonstrated overseas. No commercial U.S. installations.

indicates equipment, siting, and transportation requirements for each option, as well as pointing out potential siting limitations imposed by environmental restrictions. Table 4-2 gives rough cost comparisons, which should be considered approximate. Particularly for synthetic fuels and fluidized bed combustion, the exact figure depends on a number of assumptions which vary considerably between applications. Thus, these figures are useful principally as a means of comparing the various choices on the basis of the same assumptions.

4.1.1 Present Coal, Oil, and Gas Economics

Not surprisingly, it is less expensive to burn fossil fuels directly to generate steam than it is to burn gasified coal. However, the relative economics of coal versus oil or gas in new boilers vary with the size of the boiler and with its capacity utilization rate.

Coal-fired boilers are favored at large sizes and high capacity utilization rates. This is due to the fact that the annualized costs of coal-fired boilers are more capital-intensive than those of oil- or gas-fired boilers, as shown in Table 4-2. Thus, economics of scale have a more beneficial impact on coal-fired boilers (in dollars per thousand pounds of steam) than on oil- or gas-fired boilers. Also, higher capacity utilization rates for a given boiler size favor coal boilers more than oil or gas boilers. This is because the fixed capital-related charges can be spread over a higher steam production rate, giving a lower cost per thousand pounds of steam.

To examine for this effect, it is useful to plot combinations of size and capacity utilization rate at which the costs of using coal just balances those of using an alternative fuel. Such a set of "break-even" curves, developed by ICF, Inc. in a recent (June, 1978) report,[30] is shown in Figure 4-1. Boilers

TABLE 4-2. SUMMARY OF ANNUALIZED OPERATING COSTS FOR ALTERNATIVE ENERGY PATHWAYS FOR NEW INDUSTRIAL BOILERS[1,2,3]

			Annualized Operating Costs, $/10^3 lb stm			
	Heat Rate, Btu/lb 650 psig, 750°F stm	Capital Investment, $10^6	Annualized Capital Charges[4]	O + M Costs	Fuel[5] Costs	Total Annualized Costs
New coal- or lignite-fired boiler[6]						
Boiler		21.6	1.93	0.58	1.96	4.47
Pollution Control		8.9	0.80	0.55	-	1.35
Total	1400	30.5	2.73	1.13	1.96	5.82
New residual fuel oil-fired boiler						
Boiler		7.2	0.64	0.41	2.70	3.75
Pollution Control		7.0	0.63	0.45	-	1.08
Total	1350	14.2	1.27	0.86	2.70	4.83
New distillate fuel oil-fired boiler						
Boiler		7.2	0.64	0.41	3.64	4.69
Pollution Control		1.0	0.09	0.04	-	0.13
Total	1350	8.2	0.73	0.45	3.64	4.82
New natural gas-fired boiler						
Boiler	1380	6.1	0.55	0.35	3.45	4.35
New coal- or lignite-fired AFBC boiler						
Boiler	1400	23.2	2.08	1.14-2.29	1.96	5.18-6.33
New boiler fired with low-Btu gas from coal or lignite						
Boiler	1380[8]	6.1	0.55	0.35	-	0.90
Gasifier		29.6	2.65	1.40	2.62	6.67
Total	1850	35.7	3.20	1.75	2.62	7.57
New boiler fired with medium-Btu gas from coal or lignite	1380	6.1	0.55	0.35	6.90-9.66	7.80-10.56

[1]All costs are mid-1978 dollars.
[2]Pollution control includes both SO_2 and particulates for coal- and residual fuel oil-fired boilers. Only particulate control is included for distillate fuel oil fired-boiler and AFBC boiler.
[3]Based on steam demand of 300,000 lbs/hr.
[4]Annualized capital-related charges were calculated as 20 percent of capital investment.
[5]*Fuel costs used:* coal - $1.40/MM Btu; *Residual fuel oil* - $2.00/MM Btu; Distillate fuel oil - $2.70/MM Btu; Natural gas - $2.50/MM Btu; Medium-Btu gas - $5.00 to $7.00/MM Btu.
[6]Capital requirements are based on 2 equivalent units each rated at 200,000 lb stm/hr with an average annual operating factor of 64 percent, which equals a 300,000 lb stm/hr facility with an 85 percent annual operating factor.
[7]Low-Btu gasification facility includes two 275 x 10^6 Btu/hr trains with a 75 percent reliability factor and an average annual operating factor of 64 percent.
[8]Total heat rates for coal derived gas-fired boilers include gasification efficiency.
[9]Medium-Btu gasification facility is located off-site and supplies fuel gas via pipeline.

Source of Data: AFBC capital requirements and O + M costs developed from data presented in Reference 29.
Low-Btu gasification costs are Radian estimates for on-site Wellman-Galusha gasifiers with Stretford process used for H_2S removal.
Medium-Btu gas costs are Radian estimates for Lurgi gasification system.
All other cost information and boiler heat rate data were taken or developed from Reference 30.

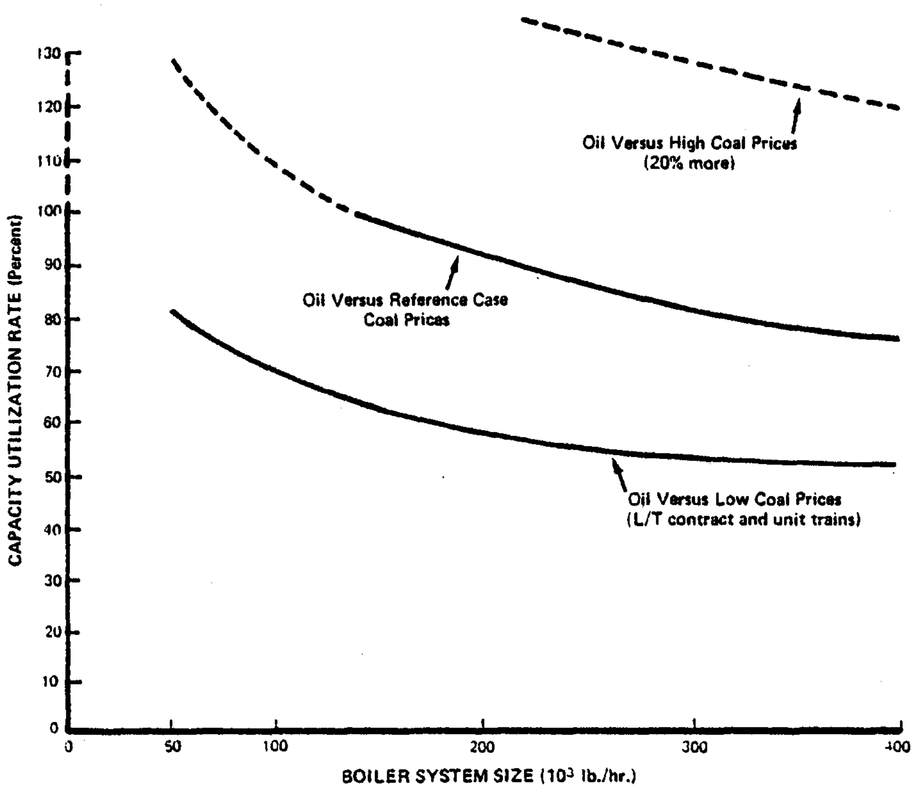

Figure 4-1. Breakeven Sensitivity to Coal Prices
(Midwest Location, 1980 Start up)
(Redrawn from ICF, Inc. 1978 [30]) 02-4328-1

with capacity factors and sizes falling above each curve favor the use of coal, while points below each curve represent design conditions better suited to the alternative fuel.

Because of low capital and operating costs, natural gas at current prices* is a far more economical boiler fuel than either coal or oil. Natural gas, however, is widely seen as a highly uncertain fuel, both in terms of price and of supply. Since gas prices account for 70 to 80 percent of the total cost of steam from a gas-fired industrial boiler,[30] price changes are highly significant. The Natural Gas Policy Act, enacted as part of the National Energy Act of 1978, allows for the deregulation of new gas by 1985. It also requires boiler fuel users and some other, yet-to-be-specified, industrial users to pay the incremental cost of higher priced gas supplies purchased by the pipeline companies serving them, up to the equivalent cost of fuel oil. These two provisions assure price increases for industries purchasing gas from pipelines. Added to rising prices is the threat of supply curtailments under conditions of shortfall. Thus, even without the Fuel Use Act, substantial incentives exist for industry to turn away from heavy dependence on natural gas.

The next major competitor with coal for industrial boiler-fuel markets would normally be fuel oil. Figure 4-2 shows breakeven curves for coal versus low- and high-sulfur oil. Under the existing NSPS, low-sulfur oil may be burned without a scrubber. The proposed new NSPS, however, would require a scrubber for many oil-fired boilers. The curve shown here for high-sulfur residual oil reflects the use of both flue-gas desulfurization (FGD) and baghouse filters for particulate control. Some distillate fuel oils may have sufficiently low sulfur contents to be burned without a scrubber even under the new NSPS. These oils can, therefore,

*Price used by ICF, Inc. in developing these curves was $2.85 per million Btu, based on delivery to a midwest location.

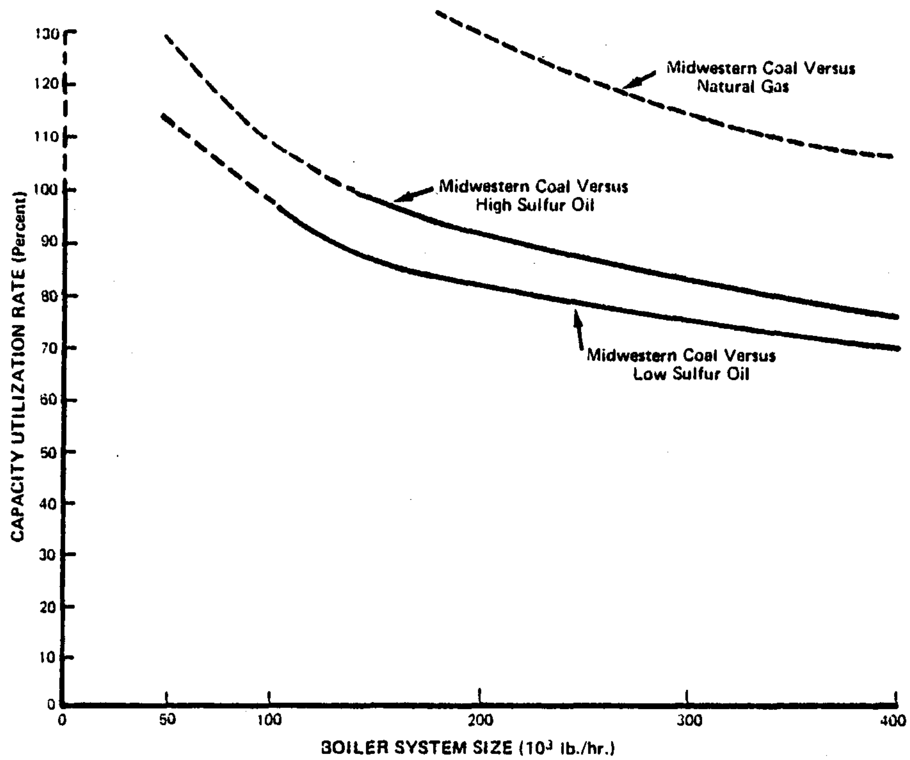

Figure 4-2. "Breakeven Curves"
(Midwestern Location, 1980 startup)

(Redrawn from ICF, Inc. 1978 [30]) 02-4329-1

command a higher market price. In consequence, coal competes more effectively with low-sulfur oil, as the figure shows. However, coal becomes the most economical fuel only at high capacity factors and large boiler sizes.

Given the uncertainties inherent in so generalized a set of curves, it is fair to say that a comparatively small drop in the cost of using coal relative to either high- or low-sulfur oil would allow coal to compete effectively over a wider range of boiler sizes and capacity utilization rates. Conversely, a small increase in the cost of coal use would tend to reduce even further the portion of the market in which coal is now competitive with oil. Since coal-fired plants require more capital than oil-fired plants, changes in capital costs and interest rates will affect coal use more than oil use, as shown in Figure 4-3.

Under the Fuel Use Act, most but not all affected boilers will probably have difficulty obtaining exemptions based on cost. The approach taken by the "cost test" in the FUA regulations has been to "handicap" oil. Requiring the cost of using coal to exceed that of using oil (or natural gas) by some percentage before an exemption can be granted effectively shifts the breakeven curves down and to the left, just as if the cost of using oil had been increased. These curves suggest that the higher the percentage handicap on the use of oil, the smaller must be both boiler size and capacity utilization factor before oil is again the preferred fuel. According to these curves, at the level of 50 percent proposed in the draft regulations, boilers running at the 85 percent capacity factor used in Table 4-2 would be unable to overcome the oil-use handicap at any size. Boilers running at a 55 percent capacity utilization rate (close to a recent national average among all industrial boilers)[31] would find oil the preferred fuel at sizes below 100,000 pounds of

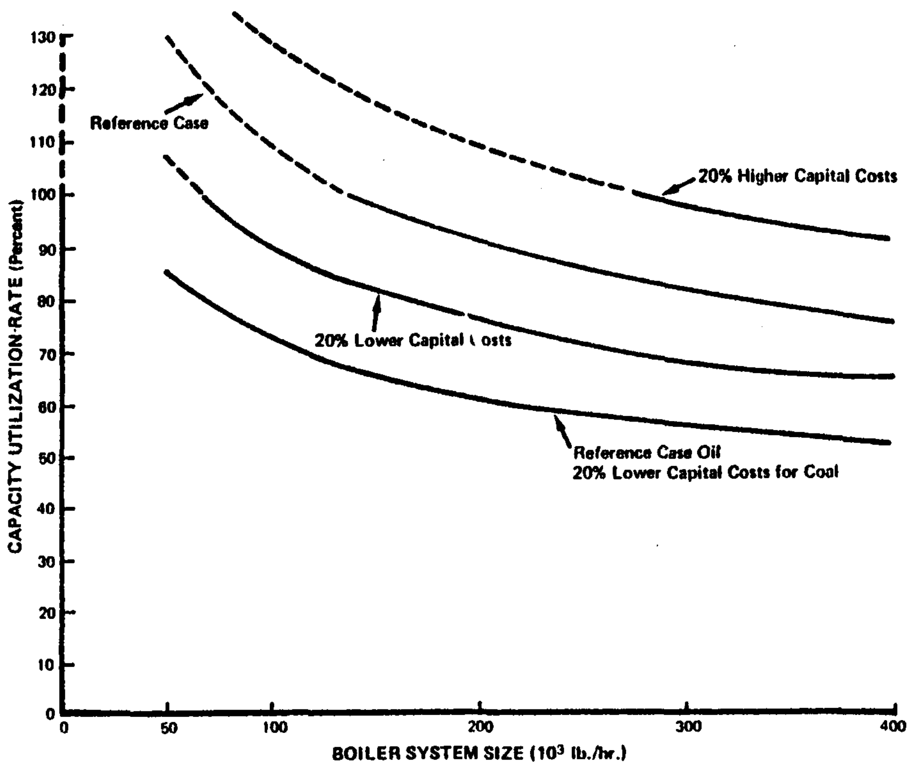

Figure 4-3. Breakeven Sensitivity to Capital Costs
(Midwest Location, 1980 Startup, Coal Versus Oil)

(Redrawn from ICF, Inc. 1978 [30]) 02-4327-1

steam per hour. For reference, the lower size limit of 100,000 Btu/hour on boilers affected by the FUA is roughly equal to 70,000 pounds per hour.

To summarize, the economic forces which help determine the extent of oil-firing that might be economically feasible in industrial boilers fall into two groups. Those favoring coal over oil include potential increases in the price of fuel oil and the imposition of a percentage handicap on oil use through the Fuel Use Act. Working in the opposite direction are rising capital costs and interest rates, which affect the economics of coal more than oil. Also, the price of coal use may be expected to rise, largely in response to implementation of the Federal Surface Mining Control and Reclamation Act, the Resources Conservation and Recovery Act, and increases in rail tariffs approved by the Interstate Commerce Commission. The balance among these forces at any given moment will determine the amount of oil which might be economically used in new industrial boilers.

Uncertainty regarding any or all of these factors, however, may tend to make decision makers shy away from oil, as they have recently done from gas. Applying for an economic exemption also promises to be a lengthy process, which industrial observers fear is likely to add one to three years to a project's schedule.

The foregoing discussion has compared oil and gas to conventional pulverized-coal-fired (PC) boilers. At present, atmospheric fluidized bed combustion (AFBC) appears to hold promise as an alternative mode of burning coal. Based on pilot-scale experience, AFBC appears competitive with PC (with scrubber) and has the added advantage of requiring no flue-gas SO_2 scrubber. The principal technical drawbacks keeping AFBC out of the present marketplace are problems in scale-up and untested operational reliability at commercial sizes. However, for some industrial applications, these problems may be overcome in the next ten years.* Other uncertainties regarding AFBC include its ability to meet the proposed New Source Performance Standards requiring 85 percent sulfur removal and the disadvantages arising from the very large amounts of solid waste generated.**

4.1.2 Possible Effects of MBFC on the Attractiveness of Gasification

For some industries, limited as to location, the combination of MBFC and clean air requirements might make gasification a feasible alternative. Given the high degree of interconnection in coastal refining-petrochemical complexes, and the associated economies of agglomeration, it may be considered very desirable to build a certain proportion of needed new boiler capacity on or near existing sites.*** Many such complexes, however, are located in areas where the PSD increment for SO_2 allowable under the Clean Air Act of 1977 has already been filled. In these areas, burning coal directly would require obtaining offsets and possibly operating at very low emission rates.

Environmental exemptions may be granted under the FUA to firms demonstrating that coal cannot be burned without violating environmental standards. However, the entire permitting process must be exhausted before such an application can be made, which could substantially delay a project. Applying for an

*Because utility applications require much larger sizes, it may take longer to commercialize AFBC in this area.

**The amount of solid waste produced goes up rapidly at higher levels of SO_2 removal, because the sulfur removal process requires a Ca/S ratio of between 2 and 2.5 to one, in practice.

***The FUA draft regulations define a site to include a company's facilities located within ten miles of each other.

environmental exemption also entails a risk, which cannot be evaluated without some experience with the new regulatory procedure, of being obligated to select one of the alternative sites or alternative fuels which must be evaluated in the report which accompanies application. In some instance, if the proposed boiler is not part of a highly integrated system, it may be preferable to choose a remote site where PSD is not a problem.

An alternative to the environmental-exemption route is to burn medium- or low-Btu gas from coal or lignite, from which the sulfur has been removed at the gasification plant. High-Btu gas costs more to produce than either low- or medium-Btu gas, and at current prices the higher heating value does not justify the added expense for industrial applications. Both economic and technological hurdles must be cleared before liquefaction processes can enter the industrial fuels market. Synthetic fuels from coal would be attractive in cases where the extra cost is outweighed by the potential costs either of obtaining emissions offsets to burn coal directly or of moving to another site. The key factor, however, will be the cost-test percentage fixed in the final FUA regulations. Set toward the low end of the 30 to 80 percent range, the cost test could allow exemptions to burn oil or gas where the only environmentally acceptable way to burn coal was to gasify it before combustion in the boiler. Set toward the high end, gasification, unable to pass the cost test in favor of oil or gas use, might be the selected technology.

The price of coal-derived gas is sensitive to essentially the same factors as is direct coal-firing. Because capital costs are high, the gas price is very sensitive both to plant size and changes in capital costs. Next in importance is the price of the feedstock coal itself, of which transportation cost is the most significant component.

The economics of gasification vary with the application. Because of the large capital costs involved, gasification is most economically applied to uses with a continuous, high-volume fuel demand. Thus, the gasification plant can run steadily at a more or less constant load. According to a recent study[32] of potential syngas market penetration in industrial applications, the two best-suited industries in this respect are petroleum refining and chemical production. Without taking into account the differential effects of the FUA on process heat and process steam generation, this study evaluated applications within refineries and chemical plants where syngas could replace other fuels. Based on cost alone, the study concluded that medium-Btu gas from coal or lignite could displace some volume of both natural gas and refinery liquids as in-plant fuels. The study pointed out that the size of large integrated refining-chemical complexes makes reliability of supply an extremely important concern. Thus, only a relatively small part of a complex's fuel requirements would typically come from any one source. This tendency, coupled with concerns over reliability in gasification processes not yet well proven on a commercial scale, was cited as potentially setting a limit on market penetration.

In general, low Btu is favored over medium Btu for smaller, on-site applications with short internal distribution distances. For larger applications with complex internal distribution, or where the gasifier cannot be located on site, medium-Btu may be the economical choice. Furthermore, where syngas replaces natural gas, medium-Btu gas can usually be burned without rebuilding the boiler, while low-Btu gas requires extensive retrofit. However,to fully realize potential economics of scale, medium Btu gasification plants must be very large - 150 billion Btu/day or more. This favors their development by joint ventures or very large firms.

A potential option for the user with fuel requirements of small or intermediate size is to build a large gasifier at a remote location serving several industrial customers. The gasifier might be built and run by the users themselves, as a joint venture, a form of business development common among petroleum and petrochemical firms along the Texas Coast. Gasifiers might also be built and operated by a separate firm functioning as a utility or supplier.

Large gasifiers may run into air-quality-related siting problems, however, even at remote locations. If violations of the National Ambient Air Quality Standard for ozone is as widespread in Texas as some suspect, then gasification plants might have to obtain offsets for their hydrocarbon emissions. Another potential problem with gasification is uncertainty regarding the future imposition of environmental standards and their costs, particularly New Source Performance Standards and standards for solid waste disposal.

4.1.3 Other Industrial Options

Two additional choices are available: major relocation away from the current center of activity, or delay. For highly integrated chemical operations, the combined constraints of finding offsets for both hydrocarbons and coal plant emissions might be seen as an incentive to consider long-range relocation plans. A less drastic and perhaps more likely response is to postpone expansions, waiting to see if the current set of air-quality and fuel-use constraints may not give way to economic pressure.

4.2 Alternative Fuel Choices for Process Heat

It is not possible to tell what regulatory stance DoE will take regarding fuels not used in boilers. For the present study, however, it should be assumed that non-boiler fuels are not brought under the FUA, or at least not extensively.

The direct firing of coal to supply process heat will likely be limited, in an unregulated situation, first by process suitability, and next by economic factors, including the cost of compliance with environmental rules. Applications requiring rapid turn-down, special flame characteristics, or special atmospheres are not well suited to coal as a substitute for natural gas. For those applications not so restricted, the difficulty of controlling emissions or obtaining offsets in PSD-limited industrial areas provide a strong disincentive to burn coal, even in the face of rising oil and gas prices. Also, coal-burning requires more capital equipment and higher fixed operating costs than either oil or gas, coupled with substantially larger site requirements and solid waste disposal costs. Thus, direct firing of coal for process heat does not seem as promising as its use for boiler fuel.

The high cost of synthetic gas relative to oil and natural gas is a major drawback to widespread process-heat applications. Recent prices for gas and fuel oils range from $2.50 to $3.00 per million Btu's[32], while most current estimates place the cost of medium-Btu gas from coal at $5.00 to $7.00 per million Btu's.[33]

The ability of synthetic fuels to compete with natural fuels is largely a matter of their price. Currently, that price is not sufficiently competitive with most natural fuels to provide the driving force for investments in commercial-scale plants. Various proposals have been made for the federal government to take action making investments in synfuels more attractive. The newly enacted Energy Tax Act, passed as part of the National Energy Act, allows a 10 percent tax credit to industry for equipment to produce, store, and handle alternative fuels, including synfuels. This tax credit is in addition to the existing 10 percent investment tax credit. Funds for direct financial assistance in syngas commercialization are presently limited.

However, uncertainty over the supply and price of gas and oil might tend to favor gasification as an alternative in applications where a solid fuel is unsuitable. SRI[32] estimated that independent of mandatory boiler fuel conversion, a total syngas market penetration in the Houston area of 0.15 quads was possible in 1985, and 0.33 quads might be used by 2000. For comparison, the nominal-case industrial demand for energy in 2000 is 5.2 quads.

Low-Btu gasification may lend itself cost-effectively to process heat applications. This is because low-Btu gasification is more cost-effective (versus medium-Btu) for small sizes; that is, they have relatively low capital and operating costs. Thus, some on-site low-Btu gasification could take place for such applications as drying and low-temperature heat.

4.3 Synthetic Feedstocks

In addition to its utility as a fuel, medium-Btu gas from coal or lignite can also be used as a feedstock in certain existing chemical synthesis processes requiring CO or H_2 as a base. Currently, natural gas is subjected to reforming or partial oxidation processes to produce a synthesis gas rich in H_2 and CO. Since coal or lignite gasification produces a product already rich in these substances, it could be cleaned and used directly as a feedstock, without further treatment. Because the H_2:CO ratio in gasified coal or lignite is lower than that in synthesis gas made from methane, CO-intensive syntheses such as methanol and acetic acid production might be favored economically over H_2-intensive processes such as ammonia synthesis. The H_2:CO ratio can be controlled, however, either through adjustments in reaction conditions in the gasifier, or by chemically reacting the CO with H_2O to form H_2 and CO_2. Additionally, technology exists for producing various chemicals from CO, rather than from hydrocarbons, but these processes would not be competitive at historic natural gas prices.

The production of ammonia and methanol together constituted 25 percent of the activity in Texas chemical manufacturers in 1975. Consequently, there is a large potential market for snythesis gas from coal or lignite. By-products such as phenols may also have commercial value. The convenience of large lignite deposits to the coastal chemical centers makes it likely for Texas to be the first state to introduce synthetic feedstocks.[32] At least one firm, Air Products and Chemicals, Inc., foresees large-scale integrated complexes combining gasification, cogeneration, and chemical synthesis.[34]

At present, shortages of natural gas severe enough to force curtailments for feedstock applications do not seem likely before the end of the century. Consequently, the introduction of synthetic feedstocks will depend largely on the comparison between the cost of producing synthesis gas from conventional hydrocarbons and the cost of gasification. The situation is further complicated by the complexity of overall chemical manufacturing economics and its sensitivity to a variety of product prices. However, one company is currently proceeding with plans to build a large gasification plant in East Texas to produce synthesis gas for piping to the coast. Whether or not economics eventually justify the completion of the project remains to be seen. System reliability will undoubtedly be a principal concern.

5.0 FOSSIL FUEL ALTERNATIVES FOR UTILITIES

Summary and Conclusions

- Conventional pulverized-coal combustion technologies, with flue-gas clean-up, are expected to dominate at least through 1985 and probably for the remainder of the century.

- AFBC technology offers promise by the end of the century as an alternative to flue-gas scrubbers. Commercial-scale demonstration, however, is needed.

- Coal or lignite gasification for use as boiler fuel is inefficient and costly, and is not expected to be used by utilities.

- Gasification and pressurized fluidized bed combustion can potentially be used more cost-effectively with combined cycles, but technological problems are likely to hold back combined cycles until late in the century or beyond.

- *In-situ* gasification still has many problems to overcome, both in the gasification process itself and in adapting potential uses to the special conditions of *in-situ* production. Although it can make available very large amounts of energy from the deep-basin lignites, widespread use of the technology is not expected in this century.

- Most utilities are expected to find the FUA's "System Compliance Option" attractive, whereby total gas phaseout is delayed until 2000 on condition that no new gas- and oil-fired boilers are built.

The situation regarding future fuel choices by utilities is considerably clearer at this time than that of industrial users as well as being visible over a longer time frame because of the forecasting and reporting requirements of government regulatory agencies. Also, unlike industrial boilers, both existing and new units come under the jurisdiction of the Fuel Use Act. However both the choices and the appropriate economic considerations open to existing utility boilers differ somewhat from those available for new units. For this reason, they will be discussed separately.

5.1 New Utility Boilers

Most new utility generating units planned in the state of Texas are large--at least 400 MWe--and will be part of multiple-unit plants at grass-roots sites. Both economics and environmental considerations favor remote locations for large new plants. A typical unit lifetime is 30 years.

Even without the impetus of the FUA, coal is clearly the fuel of choice for new, base-loaded units. Their large size and long operating lifetimes improve the economics of coal use. Also, the high premium placed on the reliability of fuel supply, combined with uncertainty over the long-term price of oil and gas and inability to obtain long-term supply contracts, favors coal over oil and gas. Accordingly, by far the bulk of the new capacity proposed for Texas before 1985 is to be fired with coal or lignite.

Given that solid fossil fuel appears to be the dominant new utility-boiler fuel for the remainder of the century, a variety of options exist for using it. Table 5-1 summarizes those currently thought of as having potential utility applications. Because of their proven reliability and economics, however, conventional combustion methods can be expected to dominate the scene at least until 1985, and most likely through the remainder of the century.

TABLE 5-1. SUMMARY OF ANNUALIZED OPERATING COSTS FOR ALTERNATIVE ENERGY PATHWAYS FOR NEW AND EXISTING UTILITY BOILERS

	Heat Rate, Btu/kwk	Capital Investment $/kw	Annualized Operating Costs, ¢/kwh: Annualized Capital Charges	O+M Costs	Fuel Costs	Total Annualized Costs
New coal- or lignite-fired unit						
Power Plant	9,000	475- 575	1.08-1.31		1.33	
FGD		145- 210	0.33-0.48		-	
Total	9,500	620- 785	1.41-1.79	0.3	1.33	3.04-3.42
New coal-or lignite AFBC Unit	9,500	580- 835	1.32-1.91	0.3	1.33	2.95-3.54
Convert existing gas-fired boiler to fire medium-Btu gas						
Power Plant	9,000	------see notes------				
Gasifier		1000	2.28		2.10	
Total	15,000	1000+	2.28+	0.3	2.10	4.68+
New facility fired with low-Btu gas from coal or lignite (Lurgi)						
Power Plant	9,000	310- 375	0.71-0.86		-	
Gasifier		665- 880	1.52-2.01		1.90	
Total	13,600	975-1255	2.23-2.87	0.3	1.90	4.43-5.07
New facility fired with medium-Btu gas from moving bed slagging gasifier						
Power Plant	9,000	310- 375	0.71-0.86		-	
Gasifier		435- 625	0.99-1.43		1.58	
Total	11,300	745-1000	1.60-2.29	0.3	1.58	3.48-4.17
Combined cycle using low-Btu Lurgi						
Power Plant	7,500	260- 345	0.59-0.79		-	
Gasifier		570- 760	1.30-1.74		1.33	
Total	9,500	830-1105	1.89-2.53	0.3	1.33	3.52-4.16
Combined cycle using medium-Btu slagging, moving bed process						
Power Plant	7,500	260- 345	0.59-0.79		-	
Gasifier		370- 530	0.84-1.21		1.27	
Total	9,100	630- 875	1.43-2.00	0.3	1.27	3.00-3.57

Notes: All costs are mid-1978 dollars.

Total heat rates for coal derived gas-fired boilers include gasification inefficiency.

Annualized capital-related charges were calculated as 14 percent of capital investment.

All facilities are assumed to have a 70 percent average annual operating factor.

Costs shown for medium-Btu gas retrofit case do not include any costs associated with the operation of the existing gas-fired boilers.

Source of Data: Capital investment for medium-Btu gasification facility for retrofit case is a Radian estimate, pro-rated from a 150 x 10^9 Btu/day facility using Lurgi technology. All other cost data and heat rate information were obtained from Reference 35 and escalated to 1978 dollars at 8 percent/year. O+M costs were reported in Reference 35 to vary between 2 and 4 mils/kwh. Since this is a small portion of the total annualized costs, 3 mils/kwh was used for all cases.

Of the developing technologies, AFBC appears at present to offer the greatest promise. Because sulfur is removed during the combustion process, it offers an alternative to the use of scrubbers. A recent DoE-funded study[36] compared three conceptual designs, prepared by boiler manufacturers, for AFBC units in the neighborhood of 550 MWe. Compared with these manufacturers' own designs for similarly sized PC boilers, the conceptual AFBC units were economically competitive.* AFBC economics are more sensitive to the cost of coal, however, than the conventional units.

Before AFBC can be shown ready to enter the market, however, its reliability must be demonstrated at a commercial scale, and several technical problems must be solved. In particular, scaling up the beds themselves will require further R&D, as regards bed placement, bed expansion, and particle circulation behavior. Another technological problem involves splitting the incoming feed stream so that coal can be introduced evenly into the beds. These problems may hold back commercialization until the 1990's or beyond.

The environmental acceptability of AFBC also remains to be demonstrated at a commercial scale. Although pilot-scale operations have shown that SO_2 emissions can be reduced to comply with current NSPS, it is not certain whether AFBC can comply with the more stringent NSPS recently proposed by EPA. Similarly, NO_x emissions at the pilot scale appear acceptable. However, although the low combustion temperatures used in AFBC retard formation of NO_x, the mechanism by which NO_x is produced

*Comparisons were made with PC boilers equipped with limestone scrubbers. When compared with PC boilers equipped with more expensive regenerable FGD systems, AFBC appears more favorable yet.

is not yet well known. The acceptability of NO_x emissions remains to be shown under the less rigidly controlled operating conditions of a large demonstration unit. Finally, AFCB generates large amounts of solid waste, especially at limestone/coal ratios appropriate to more stringent sulfur control standards. Disposal of these wastes, however, may not pose problems much different than those attending the disposal of ash and scrubber wastes from conventional boilers.

Gasification offers a way to burn coal cleanly in boilers of conventional design. However, the two energy conversion steps required to generate electricity in this way make gasification followed by combustion very inefficient compared with direct combustion, which requires only one step. This feature, combined with high capital and operating costs, make for an unfavorably high cost of power at the busbar. The newer slagging moving-bed gasifiers which are being developed potentially will offer some improvement in both efficiency and capital costs, but the improvement is not sufficient to provide an economic advantage over direct combustion.

Combined cycles offer a possibility of improved efficiencies, and producing electricity at competitive prices. A variety of gasification processes, as well as pressurized fluidized bed combustion (PFBC), can in principle be adapted to use in a combined cycle. Both are "clean" coal-conversion steps. However, combined cycle technology integrated with gasification or PFBC has not yet been demonstrated, and important technical problems still remain to be solved. Particularly with PFBC, turbine-blade corrosion and erosion is a major technical drawback. For these reasons, it is not expected that combined cycles will achieve market penetration before 2000. Because of its relatively high water content, lignite use may result in lower gas temperatures than coal. Pretreatment to lower its water content may be needed to adapt it to use in combined cycles.

An alternative to above-ground gasification is the process of gasifying lignite seams in place. In-situ gasification has strong proponents in Texas, and considerable monies are being invested in its development. It is still too early to tell, however, whether the technology can be successfully applied to Texas lignite. It is then another step to develop an economic method of using the product gases. If in-situ gasification can be commercialized, however, it may offer the only means of recovering the energy in Texas lignites too deeply buried for conventional mining. The size of this resource may be ten times that of the strip-mineable resource.

Recent efforts at Texas A&M University to gasify a five-foot lignite seam in place encountered serious problems in part resulting from the seam's close proximity to a highly permeable aquifer.[37] Although, in general, the lignite-bearing formation itself is not a major aquifer, it can and does transmit water under pressure, and is hydrologically connected with the overlying Carrizo and underlying Simsboro aquifers. Thus, it may be that, depending on local conditions, the kind of geologic circumstances hampering the TAMU test may be encountered elsewhere. Air injection problems also resulted in very low heating values in product gases.

Given the technological problems involved, it seems unlikely that in-situ gasification will become commercially available until after the turn of the century. The potential it affords to extend the recoverable lignite reserve, however, ensures continuing interest in this technology. Commercialization, however, may encounter legal questions surrounding the effect of in-situ gasification, and related subsidence, on subsequent land use and the recovery of other mineral values.

5.2 Existing Utility Boilers

Most of the utility boilers now in service in Texas are fired with natural gas. These boilers cannot be converted to burn coal without extensive rebuilding and/or derating.[38] Consequently, there has been some interest expressed in gasifying coal or lignite so that it can be burned in boilers. However, as Table 5-1 shows, the cost of electricity produced in this way is higher than that generated in a new grass-roots, coal-fired unit. In addition, no gasification technology has yet been operated at a current commercial scale in this country; and reliability factors are uncertain. Environmental uncertainties, discussed above under industrial applications, also argue against attempting to apply gasification to existing boilers, where unforeseen delays due to permitting could cause serious reliability problems.

In the face of these difficulties in converting existing gas-fired boilers, it is likely that many Texas utility companies will take advantage of the System Compliance Option written into the Fuel Use Act. This provision allows utility systems to put off conversion in the short term, provided that they build no new base-loaded units fired with oil or gas, reduce gas consumption by 80 percent by 1990, and end gas use entirely by 2000. Unless prohibited by the FUA regulations concerning existing utility boilers, much of the required reduction in gas use may come from substituting oil.

If oil substitution is not allowed, coal-oil or coal-methanol slurries might be viable options. Also, the Lower Colorado River Authority is making efforts to beneficiate lignite so that it can be used independently in a gas-fired boiler. If such methods of firing can be made feasible, they could save millions in short-term fuel costs and reduce the large capital expenditures required to replace gas-fired capacity with new units firing coal or lignite.

6.0 DERIVATION OF DEMAND FOR SOLID FOSSIL FUELS

Summary and Conclusions

- Under Nominal-Case assumptions, solid fossil fuel use in Texas would rise from present levels of 0.50 in utilities and 0.05Q in industry to 1985 levels of 1.0Q in utilities and 0.2Q in industry.

- By the year 2000, 3.1Q would be used in new utilities and 1.4Q in new industry, under the Nominal Case. Utility use might be reduced by 2.0Q if nuclear power is developed rapidly. Extensive replacement of existing oil and gas use with solid fuel could raise the year-2000 total to 4.4 as much as 4.4Q (utilities) and 1.6Q (industry).

The amount of coal and lignite likely to be used in 1985 and 2000 was estimated as a proportion of total utility and industrial "conventional" energy growth. A Nominal Case was selected to be used in subsequent analysis, which represents a plausible, slightly conservative outlook for growth in solid fossil fuel use. Variations of the Nominal Case were investigated to show the sensitivity of solid fossil demand to overall conventional energy growth, and to alternative assumptions regarding the availability of nuclear power and the extent to which boiler fuel conversion is enforced. Figure 6-1 shows the "conventional" fuel mix corresponding to the Nominal Case. Tables 6-1 and 6-2 present the results of the sensitivity tests.

The Nominal Case was based on the solid curves of conventional energy demand graphed in Figures 2-2 and 2-3, and considered utilities and industry separately. Simplifying assumptions were made regarding fuel choices under the Fuel Use Act. These assumptions reflect the foregoing discussion of alternatives available to both utilities and industry, but do not reflect any quantitative attempt at technological forecasting.

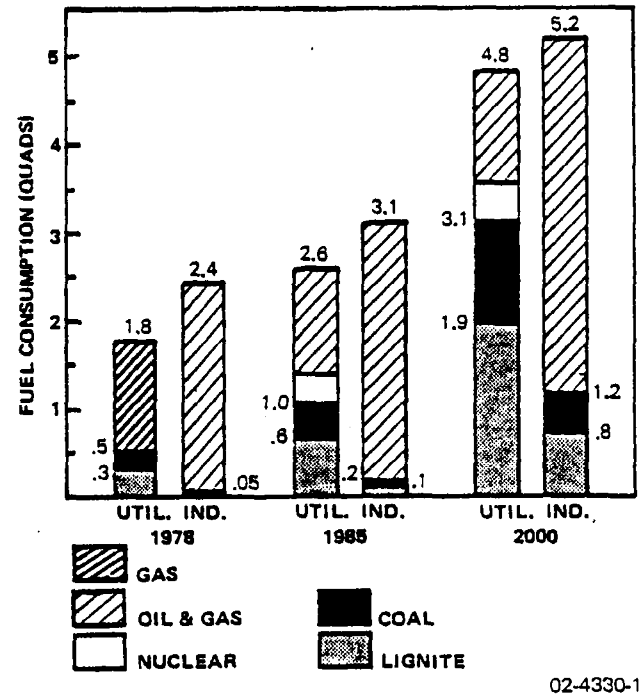

Figure 6-1. Fuel Mixes for Texas - Nominal Case

Assumptions regarding utilities included:

. New utility power plants will rely primarily on lignite, coal and nuclear fuels. Some use of oil will be allowed in new poer plants in order to maintain system reliability.

. Some existing utility power plants will shift from gas to oil, some will receive conversion exemptions based on environmental or economic grounds, and some will continue to use gas for peaking purposes. None will convert directly to coal or lignite.

. Present use of solid fossil fuel amounts to 0.5Q.

TABLE 6-1. DERIVATION OF SOLID FOSSIL FUEL REQUIREMENTS

	1978	1985	2000 High	2000 Nominal	2000 Low
Total Conventional Energy Requirement					
Utilities	1.76Q	2.6	5.4	4.8	3.3
Industry	2.42Q	3.1	6.5	5.2	3.3
Exempted Oil and Gas Use					
Utilities	1.26Q	1.3	1.3	1.3	1.3
Industry	2.37Q	2.9	4.6	4.0	3.0
Prospective Nuclear Supply					
Utilities	0.0Q	0.3	0.4	0.4	0.4
Solid Fossil Fuel Requirement					
Utilities	0.50Q	1.0	3.7	3.1	1.6
Industry	0.05Q	0.2	1.9	1.2	0.3

TABLE 6-2. SENSITIVITY OF SOLID FOSSIL FUEL REQUIREMENTS IN THE YEAR 2000 TO ALTERNATIVE ASSUMPTIONS

	Utilities	Industry
Nominal Case	3.1Q	1.2Q
High Nuclear Case (1.5Q in 2000)	2.0Q	1.2Q
Constrained Oil & Gas Supply • Utilities replace existing gas use with solids by 2000 • Industries replace 25% existing gas use with solids by 2000	4.4Q	1.8Q
Moderately Constrained Oil & Gas Supply • Utilities replace existing gas use with solids by 2000	4.4Q	1.2Q
3% Annual Retirement Rate • Utilities replace oil & gas retirements with solids • Industries replace 50% of oil & gas retirements with solids	3.7Q	1.8Q

- Nuclear power will supply 0.3Q in 1985 and 0.4Q in 2000. No new nuclear plants will be built other than those announced.

- All new capacity after 1978, other than nuclear, will be fired with solid fossil fuel.

Assumptions used to calculate industrial demand were:

- Feedstocks are excluded from calculation.

- Process heat represents half of industrial fuel use; process steam is the other half.

- Existing industrial boilers are currently exempt by law from conversion requirements and assumed to remain exempt.

- New industrial process heat demands will continue to be met by either oil or gas.

- New industrial boilers built between 1978 and 1982 will be fired with oil (change-over to solids involves four-year lag time).

- New industrial boilers after 1982 will be fired with solid fossil fuel or gasified solid fossil fuel.

The basic picture behind the Nominal Case is one in which conventional energy sources still constitute the bulk of the energy used, and conservation takes place slowly. Lignite and coal use grows rapidly in utilities, because uncertainties of oil and gas supply and price, together with considerable freedom of siting, make solid fossil fuels the least risky choice. Exemptions from MBFC are obtained for existing gas- and oil-fired utility boilers through a combination of the environmental, site, and cost provisions described above. In addition, new gas and/or oil-fired peaking, and perhaps combined-cycle, units are built in order to assure system reliability such that total oil and gas use remains the same. (Given the present DoE perception of natural gas oversupply, and the emphasis placed on reducing oil imports, this assumption may become increasingly plausible.) Industry experiences a cutback in gas use arising jointly from increasing prices and the threat of curtailment, and from MBFC.

Table 6-1 shows how the fuel mix would differ if the lower and upper bounding curves had been used for total conventional energy demand for utilities and industry (see Figures 2-2 and 2-3). None of the other assumptions are varied.

Table 6-2 shows four sensitivity cases, compared with the Nominal Case, in which key assumptions were varied, using the Nominal Case curves for total energy requirements.

In the high-nuclear case, it was assumed that nuclear power was available in Texas in proportion to the state's share of the nation's uranium reserves. This translates to a total "share" of 25,000 MWe of power generation.[24] Assuming a 0.7 capacity factor and a heat rate of 10^4 Btu/kwh, this is the equivalent of 1.5Q.

A more stringent case for MBFC was derived by requiring the use of natural gas and oil to be phased out completely in 2000. It was further assumed for this case that this amount would be entirely replaced by coal. In addition, it was assumed that 25 percent of current industrial gas use will be replaced by the year 2000 with solids or solid-based synthetic fuel. The rationale for this more stringent scenario would be scarcity or uncertainty of supplies of gas, coupled with high prices or supply curtailment of oil. Major OPEC price increases or oil and gas shortfalls, for example, could conceivably bring about such a scenario.

A sub-case was defined in which utilities phased out oil and gas completely, but industry did so only to the extent of the Nominal Case. Such a situation might arise if oil were available, but long-term contracts, such as utilities require, were difficult to obtain. This oil-supply situation might provide a more serious constraint to utilities than to industry, causing a divergence in utility and industrial behavior. If the Department of Energy takes a strong stand on total phase-out of existing boilers by 2000, this subcase may become more plausible than the Nominal Case.

In the Nominal Case, retirements of existing oil- and gas-fired boilers have been neglected. This choice was made originally to provide conservatism in the ultimate requirements for lignite. However, a fourth sensitivity case was run to evaluate the potential significance of this assumption. An annual retirement rate of three percent was assumed. For utilities, the total amount of gas use thus retired was assumed to be replaced by solids, probably in large new base-loaded units. For industry, half the retired gas use was assumed to be replaced by new gas- or oil-fired installations and half converted to solids. The gas- and oil-fired portion could be made up principally of process heat, which is not covered by MBFC. As pointed out above, process heat accounts for roughly half the fuel now used by industry. Thus, the allocation is consistent with other assumptions in the Nominal Case.

As can be seen from Table 6-2, the "sensitivity" assumptions cause more variation in utility requirements for solid fossil fuels than in industry. This reflects the view that utilities may generally prefer to convert to coal rather than oil, that most of the generating capacity in 2000 will be new capacity, and that utility companies are basically free to avoid sites at which coal cannot be burned without violating air quality rules. The range of variation in utility use of solid fossil fuel among the sensitivity cases is as great as that between the high and low energy growth cases. The range among the industry figures, however, is much less between the sensitivity cases than between the different growth cases.

> Ozone: Even as revised, National Ambient Air Quality Standards for ozone may restrict the growth of the petrochemicals and refining industries in areas of present concentration. These industries affect lignite demand both directly, as potential consumers for fuel and feedstocks, and indirectly as driving forces behind statewide economic and population growth.

For purposes of this analysis, it was assumed that Texas industry continues to grow at a fairly steady rate throughout the remainder of the century. However, more than half of the state's current economic activity is located in areas now designated as out of compliance with the National Ambient Air Quality Standards for ozone. As additional measurements are taken over the state, the area found to be in non-attainment may become much larger. Even as revised, the current ozone standard of 0.12 ppm is low enough that many non-attainment areas in the industrialized Gulf Coast will be unable to comply by 1982. New sources cannot be permitted in non-attainment areas without a simultaneous greater offsetting reduction in emissions from another source or sources.

Industries mainly affected by this requirement are those which emit large amounts of hydrocarbons, which are oxidant precursors. NO_x emissions also play a part in ozone formation. Future control strategies may involve both pollutants. Petroleum and petrochemicals, and potentially power production, would be the major industrial targets of control.

It is feared that non-attainment areas will soon run out of offsets, and be unable to obtain permits for new sources. If large parts of the state are found to be out of compliance, it may be difficult to find other sites for these sources.

A reduction or stoppage of industrial growth in Texas affects lignite in two ways. First, it reduces demand for lignite as an industrial fuel. Second, through its effects on population inmigration, it affects demand for electric power, much of which is generated with lignite.

> Implementation of MBFC: Recent major oil and gas discoveries in Mexico and Canada have greatly increased world reserves. Under these conditions the need for a stringent fuel-choice policy to conserve gas and oil is open to question. A fuel-choice policy may, however, be used to reduce imports. Such a policy involves widespread secondary economic costs and potential environmental problems. How can these secondary impacts be reduced?

Under the Fuel Use Act, MBFC affects primarily new industry and existing utilities. Concerns over the FUA and its implementation focus both on the total economic impact of the required conversion and on the way the impact is spread. The total impact is reduced when limited allowable gas and oil use is distributed in ways that give the largest economic return, including jobs and value of products. If oil and gas use are cut back across the board, the result may be reallocation of gas and oil away from economically efficient industrial uses in the industralized Gulf Coast, and into less efficient non-industrial uses in other parts of the country. The recent ERA draft regulations for the FUA do not explicity consider the economic efficiency of gas use in the exemption procedure.

Increased coal and lignite use under MBFC will increase the pressure on the available PSD increments, primarily for SO_2. ERA's proposed draft regulations for the FUA require alternative sites to be considered before granting exemptions from coal or lignite use. If this provision results in more new industrial sources locating away from the Gulf Coast, conflicts over the use of the air resource could develop between utilities and industry. In addition, NO_x emissions from coal and lignite burning may add to existing oxidant problems by contributing to ozone formation. Potentially more serious conflicts could arise if sulfates and ozone forming downwind of large sources are carried into adjacent states.

8.0 RECOMMENDED FUTURE RESEARCH

The foregoing analysis and scenario development is based on existing quantitative studies and readily available data. A more sophisticated and, therefore, more sensitive analysis would require additional basic research and information-gathering. Below are listed major areas where further technological research and development appears most likely to extend and improve potential applications of lignite besides direct combustion. Also listed are subjects in which more detailed information and analysis is needed to support energy planning and forecasting.

8.1 Technological RD&D in Lignite-Related Technologies

Extraction Technology

- Economic recovery techniques for deeper seams
- Economic recovery techniques for thinner seams
- Technological improvements to lower conventional mining costs

Atmospheric Fluidized Bed Combustion

- Demonstrate technological feasibility of scaled-up operations
- Measure emissions of scaled-up installation, with respect to further control needs for SO_2, NO_x, hydrocarbons
- Compare economics with conventional PC boiler with scrubber, for application in industrialized areas with dirty or marginal air

- Characterize amounts and composition of solid wastes, disposal options, and potential impacts of federal rulemaking under RCRA

Coal-Oil and Coal-Methanol Slurry Firing

- Adaptability to retrofit on existing utility and industrial boilers

- Economic feasibility

- Pollution control requirements, solid waste characteristics and disposal options under RCRA

- Identify and assess effectiveness of state options for encouraging coal-oil and coal-methanol slurry firing

Co-Generation and Energy/Industrial Parks

- Evaluate technological, economic, and environmental feasibility of developing lignite-based industrial parks including co-generation and/or gasification for fuel and feedstock use

- Identify potential siting constraints and conflicts, especially over air resources and water requirements

- Identify and assess effectiveness of federal, state, and local options for encouraging such development, through taxation, utility rate-setting, and assistance with front-end financing

Above-Ground Gasification

- Evaluate potential effects of Fuel Use Act "cost test" on economic feasibility of gasification in various applications and environments

- Potential future demand for gasification

- Design improvements that lower capital costs

- Advantages/disadvantages of lignite vs coal as a feedstock; process and design alternatives to reduce disadvantages

- Pollution control requirements, especially for hydrocarbons with respect to ozone formation and possible violation of standards

- Identify and assess effectiveness of federal, state, and local options for encouraging gasification

In-Situ Gasification

- Improvements in ignition and burn control, well link-up, product quality, energy recovery efficiency

- Control of gas leakage, subsidence, groundwater penetration

- Adapt products of <u>in-situ</u> gasification potential uses; develop means of product transport to point of use

- Identify areas particularly suitable or unsuitable for in-situ gasification by reason of:

  - Seam thickness and depth

  - Overburden character with respect to well integrity, subsidence problems

  - Proximity to aquifers with respect to groundwater intrusion and process control, as well as potential pollution.

- Evaluate potential quantities of energy recoverable by <u>in-situ</u> technologies

<u>Combined Cycle Power Generation, Using PFBC or Gasification</u>

- Adaptability of lignite as a fuel, with respect to:

  - Turbine blade erosion from particulate carry-over

  - Turbine blade corrosion from alkali metals, sulfur species

- Lowered gas temperatures because of high lignite moisture content

8.2 Information Needed for Better Energy Planning and Forecasting

Future Texas Industrial Mix

- Identify existing trends, the economic and policy factors driving them, and key uncertainties about the future

- What role do state policies and actions have influencing the ultimate energy mix?

- How is the industry mix reflected in overall energy demand growth and desirable fuel mix?

Future Industrial Siting Patterns

- Evaluate the role of economics of agglomeration in site selection for petroleum and petrochemical facilities. Using economic criteria, evaluate flexibility of siting choices and alternatives to Gulf Coast siting

- Inventory status of PSD increments and the availability of offsets for future growth in and near existing industrialized areas

- Identify existing trends and their causes and key uncertainities in future siting patterns

- What role do state policies and actions have in influencing industrial siting choices

Industrial Use of Lignite

- Evaluate the engineering cost and environmental feasibility of lignite use or substitution in selected new and existing processes and installations

- Identify and quantify advantages and disadvantages of lignite versus coal in industrial applications; identify R&D needs to improve lignite's position

- What factors appear to drive the ratio of lignite to coal use?

Mexican Oil and Gas

- What is the potential demand for Mexican oil and gas in Texas?

- What options exist for international cooperation/investment in developing the Mexican refining and petrochemicals industry?

- What potential effects could Mexican fuels have on the overall Texas energy mix, and the demand for lignite?

- Evaluate key policy issues:

- Import limitations

- Import prices

- Allocation of imported fuels

- Evaluate the consequences for the Texas economy of using vs not using Mexican fuels:

  - Domestic energy production

  - Energy costs

  - Product prices and competitiveness

- Assess the potential impact of Mexican oil and gas on national MBFC policy

<u>Conservation</u>

- Develop measures of conservation technically and economically feasible in the short, medium, and long term, for representative uses in Texas

- Evaluate/estimate demand elasticities for these uses in Texas

- Evaluate financial incentives, price levels, required to achieve given levels of conservation, identify most readily achievable energy use reductions

- Identify and evaluate effectiveness of state options for encouraging conservation, including assistance in front-end financing

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CHAPTER II: LIGNITE DEVELOPMENT SCENARIO

Abstract

In this chapter, a working scenario of plausible levels of lignite development is derived. The present study did not attempt a modeling exercise that would show how coal and lignite price and supply are driven by economic and policy variables. These variables are discussed qualitatively, along with certain distinctive aspects of the developing Texas market for solid fossil fuels. The development scenario is developed in a "what-if" manner, based on a series of simplifying assumptions. The sensitivity of the result is tested by varying the assumptions. It is concluded that the demand for lignite will be high enough to result in the commitment by 2000 of most or all of the currently economically strippable reserve above 150 feet.

1.0 FACTORS AFFECTING THE SUPPLY OF SOLID FOSSIL FUELS IN TEXAS

Summary and Conclusions

- Coal supply shortages are not foreseen under current policy. Wyoming and Illinois are expected to be Texas' main suppliers.
- It is assumed that federal coal leasing policy will not constrain the supply to Texas of coal from the western states. The potential for supply problems to arise over leasing policy or controversies is noted, however.
- Texas lignite is almost entirely under private control.
- Low heating value versus high ash and water content place economic limitations on the distance lignite can be shipped. Combined with high in-state demand, this makes export to other states unlikely.
- Texas lignite lies in sloping beds; thus the economics of recovery tend to determine reserve size. Consequently, lignite reserve size responds to price, within geological limits.
- It is estimated that 6.7 billion tons of lignite can be economically stripped to depths of 150 feet. The reserve estimate is increased to 8.9 billion tons when mining to 200 feet is assumed.

The competition between coal and lignite for the Texas market is driven partly by the relative supply of the two fuels, and partly by their price. This section discusses supply; factors influencing price are discussed in the following section.

1.1 Factors Affecting the Supply of Coal in Texas

As a national resource, coal is extremely plentiful. Supplies entering the market in the remainder of this century will be determined by demand, rather than limited by resource availability.[1,2] The National Energy Act, passed without proposed taxes on the use of oil and gas, and without the crude oil equalization tax, does not appear likely to create a sudden short-term upswing in coal demand. Thus, over the entire study time frame, coal supply shortages are not foreseen under current policy.

Currently, almost all of Texas' coal imports come from the western states, where much of the resource is under federal control. Thus, the development of federal coal leasing policy is of potential concern in the state. Some 70 percent of the nation's unleased coal is federally owned, and the proportion is higher in the western states most likely to supply Texas: Wyoming, Montana, and New Mexico. In a recent report, the Department of Energy's Coal Leasing Policy Development Office expresses the belief that more reliance on diligence requirements for existing leases and emphasis on non-federal reserves will reduce the need for new leasing.[3] New leasing would still be required, however, particularly in the heavily federal western states.

For purposes of the development scenario used in this study, it has been assumed that no shortages of coal occur. This reflects the view that any difficulties surrounding leasing or production will be resolved in the short term, and will not have a significant effect as far in the future as 2000. Given that lead times for opening large mines are now five years or more, a serious impasse over leasing, coupled with a high nationwide demand for coal, could result in inadequate supplies.

However, since future leasing decisions cannot be predicted at this time, it has been assumed for purposes of this study that coal supplies in Texas will be adequate through 1985.

Of those areas capable of supplying coal to Texas, eastern Wyoming has the most reliable proven supply, with some excess production capacity in existing mines. The Illinois Basin is also producing at a high rate from numerous mines, but with little excess capacity. These two areas are likely to be the main suppliers to Texas.

1.2 Factors Affecting the Supply of Texas Lignite

The Texas lignite resource differs from coal in two important ways, with respect to supply response. First, the federal government has no control over leasing the bulk of the state's lignite, which is privately owned. Thus, leasing and mine development is free to respond to demand. Second, lignite's low heating value and high ash and water content limit the distances it can be economically shipped. Combined with high demand in-state, this makes it unlikely that Texas lignite will be used outside the state. Competition from other states will therefore not affect supplies available for use in Texas.

In addition, the lignite found in Texas lies in beds that dip downward toward the coast, so that the bulk of the resource is buried too deeply for economic recovery by strip mining techniques.* The boundary between strippable and deep-basin resources is set by economics; if prices rise, more lignite can be mined profitably than if prices are low. Thus, the amount of lignite actually "available" for use is somewhat indeterminate.

*The looseness of the overburden also precludes conventional underground mining, except at great cost.

Practical limits to surface mining, however, are set by technology. Within these limits, the resource is quite small, compared to the amounts of coal mineable from the basins supplying Texas imports.

Figure 1-1 illustrates the effect of resource size on price. Although data for drawing a lignite supply curve are not yet available, its qualitative relation to a typical coal supply curve from one of the basins supplying Texas would be as shown. Thus, it can be seen that for both fuels, the most economically recoverable resources are mined first, leading to higher prices for later increments of supply. Because there is less lignite, however, the lignite curve rises faster, and at a given cumulative level of resource consumption crosses the curve for coal. When this quantity of lignite has been consumed, it becomes the more expensive of the two fuels and demand can be expected to fall off. Although rising prices can shift the crossover point to the right, the size of the resource limits this flexibility.

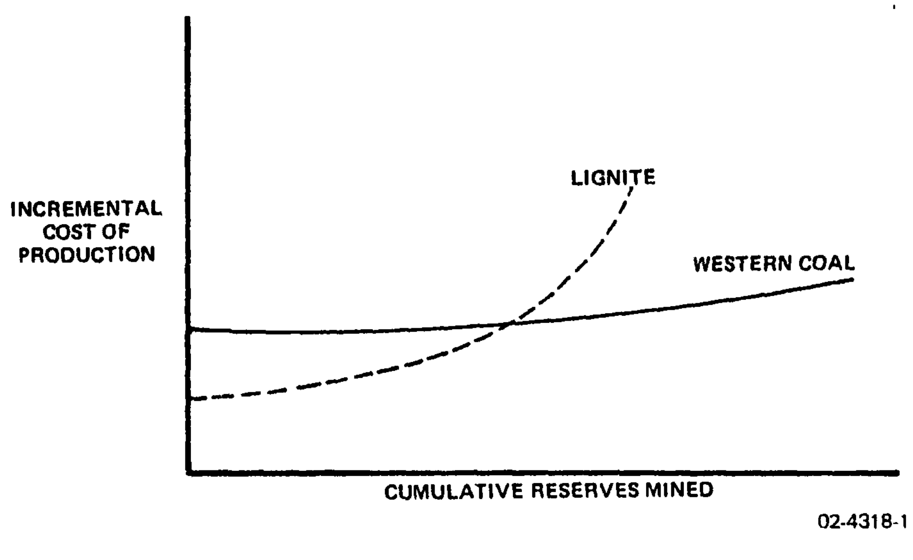

Figure 1-1. Effect of Reserve Size on Rate of Increase in Cost of Production

Geologically, a "resource" is considered the amount of a mineral which is actually present, as opposed to the concept of the "reserves," which is the proportion of the resource that can be recovered economically. At present, exploration of the Texas resource is not sufficiently advanced to support detailed estimates of reserves, although drilling is proceeding at an accelerated rate. The size of the resource, however, has been estimated, first by Perkins and Lonsdale for the Bureau of Mines[4] and later by Kaiser, of the Texas Bureau of Economic Geology.[5] The earlier study (1955), estimating 3.3 billion tons of strippable lignite, has been adopted by the Bureau of Mines and is still widely quoted in national assessments. Kaiser's work (1974, updated in 1978[6]) is based on more extensive drilling information and uses a detailed consideration of the depositional environments to attempt to develop accurate resource estimates. Kaiser's current estimate of strippable lignite--in seams three feet thick or more under less than 200 feet of overburden--is 12.2 billion tons. Figure 1-2 shows its distribution across the state. Assuming mining to 150 feet, and an excluded fraction of 10 percent for roads, lakes, and similar obstructions, two-thirds of this resource is economically recoverable with present methods. Of this, only 85 percent may actually be recovered using conventional mining technology. The economically recoverable reserve is estimated statewide as 6.7 billion tons.

This estimate is one of the most important figures used in this study. It is based on geological and technological considerations not directly coupled to price. Although tests of Kaiser's predictions against subsequent drilling data have shown his method to be remarkably accurate, price increases taking place in the future could result in recovery of a larger fraction of the resource. The 6.7 billion ton estimate assumes mining to only 150 feet in depth. However, several mines have been

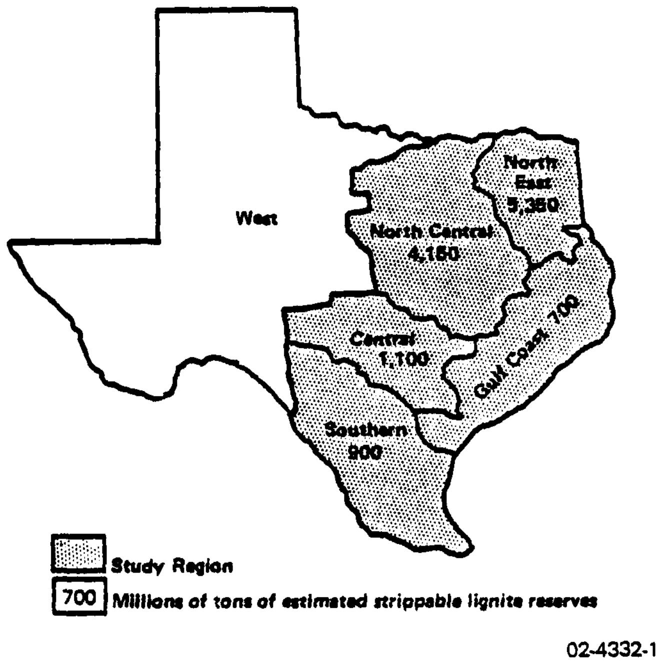

Figure 1-2. Strippable Lignite Reserves by Subregion

planned with the potential for recovery up to 250 feet below the surface. Also, some lignite promoters are reporting much larger reserve estimates than Kaiser's estimates would appear to support. Typically, as a mineral deposit is explored, reserve estimates tend to rise.

Thus, while Kaiser's estimates are considered to be the most rigorously derived statewide figures now available, the actual tonnage ultimately recovered could prove to be considerably different. Even assuming recovery to a depth of 200 feet raises the reserve estimate from 6.7 to 8.9 billion tons.[7] Over the time frame of the present study, then, the amount of lignite mined is likely to be driven primarily by the cost at which mining can be justified. Price competition with coal will thus prove to be a major determining factor.

2.0 FACTORS AFFECTING THE PRICES OF COAL AND LIGNITE

Summary and Conclusions

- Recent federal legislation, coupled with rising costs and the demands of organized labor, are expected to drive up the price of both coal and lignite. Their effects are expected to be stronger on coal, however, so that lignite prices will not rise as fast.

- The imposition of uniform scrubbing standards in the Clean Air Act and in pending EPA regulations removes a major advantage of low-sulfur western coal over higher-sulfur Texas lignite.

- It is expected that a favorable regulatory climate will allow continued escalation of interstate rail freight rates for coal. Within Texas, lignite shipment costs are not expected to rise as rapidly, since the rail rates are state regulated and much lignite is moved by truck or on short private rail lines.

- Much of Texas' lignite is leased by the firms intending to use it. The lignite recovered from these "captive leases" can be valued by these firms at anything between the cost of mining and the cost of replacement with coal. Because of this uncertainty regarding lignite's price, lignite and coal will not compete in a normal market situation.

Table 2-1 presents a summary of current prices for coal from Wyoming (Powder River Basin), Illinois (Illinois Basin) and lignite from eastern Texas. All of these prices are given as of mid-1978. The coal prices are based on representative costs for typical mines. Transportation costs reflect recent ICC approvals of substantial rail tariff increases.

TABLE 2.1 ALTERNATIVE FUEL COSTS[8]

	Illinois No.6	Powder River Basin Subbituminous	Texas Lignite
Ash, wt%	11.0	6.0	13.9
Moisture, wt%	11.0	29.0	33.0
Sulfur, wt%	3.5	0.5	1.2
Heat Content, Btu/lb	11,000	8,500	6,700
Minemouth Cost			
$/ton	22.00	8.00	13.40
$\$/10^6$ Btu	1.00	0.47	1.00
Transportation Cost			
(to the Gulf Coast)			
Methods	Barge	Rail	Rail
$/ton	9.00	17.00	4.50
$\$/10^6$ Btu	0.41	1.00	0.34
Delivered Cost			
$/ton	31.00	25.00	17.90
$\$/10^6$ Btu	1.41	1.47	1.34

2.1 Policy Factors Affecting the Cost of Coal and Lignite

Several new pieces of federal legislation are likely to cause the costs of mining to rise over the next twenty years. Among these are:

- The Surface Mining Control and Reclamation Act
- Mine Health and Safety Act Amendments
- Black Lung Legislation

Likewise, the recent negotiated settlement with the United Mine Workers will cause labor costs to rise substantially for eastern and midwestern coals, at least in the near term.

These pieces of legislation, along with increasing costs and the continued demands of labor, will cause the prices of coal and lignite to escalate over the remainder of the century. It is reasonable to suspect, however, that their effect may not be as strong in Texas as in the west and midwest. Midwestern coals may receive the higher increase due to labor-oriented costs, not only because of union strength but because much of the coal is mined underground. Mine health and safety costs will thus be higher than in the west and in Texas, where surface mining prevails.

Another potentially important factor is the imposition of severance taxes on coal sold outside the state of origin to help defray environmental and socioeconomic costs. Recently imposed severance taxes amounting to 30 percent of the value of Montana coal indicate how important a factor this can be.

Uncertainties regarding reclamation costs in semiarid climates could introduce some additional cost to Western coal, while prime farmlands requiring special topsoil handling and replacement could do the same to Illinois coal. Since seams are thick, however, high per-acre costs can often be spread over large tonnages. Here again, Texas is fortunate in having a climate which favors reclamation, thus holding down costs. Recent disputes over the definition and treatment of prime farmlands in Texas have been resolved in favor of allowing mixed overburden strata to be used as the planting medium, when suitable, rather than requiring topsoil to be saved and respread in all cases. With the thinner seams characteristic of Texas lignite, holding down per-acre reclamation cost is particularly important to maintaining a competitive price.

Thus, until the physical limits of mining technology are reached, it is reasonable at this time to expect that the price of coal relative to lignite may tend to rise. It seems unlikely, given the factors just mentioned, to fall.

2.2 Effect of SO_2 Emission Standards

The development of new New Source Performance Standards for coal burning may affect the relative economics of using coal and lignite. Under the old standards, many utilities contracted for long-term supplies of low-sulfur western coal rather than installing scrubbers as would have been required with lignite.

Although uniform scrubbing standards have been proposed by EPA, alternative proposals are being pushed which would allow partial scrubbing of coals with low sulfur contents. Ebasco Services, Inc., calculated for Phillips Coal Company the difference made by scrubber requirements in total cost of electricity at the busbar.[10] These results, for a 1300-MWe power plant with a 70 percent capacity factor, showed the cost per-KW of lignite generation as 30 percent higher than the cost of using coal under the old NSPS. When both fuels require scrubbing of 100 percent of the flue gas, the difference becomes only 5 percent.*

2.3 Transportation Costs

Transportation costs add greatly to the cost of fuels away from the mine mouth. Particularly in the case of the western railroads, recent large tariff hikes for unit coal trains have brought this factor to national attention. The Interstate

*Assumptions used in the calculation: lignite is 6100 Btu/lb, 0.64% sulfur; 65% of the flue gas is scrubbed under the old NSPS, with a heat rate of 10,170 Btu/Kwh. For western coal, heating value is 8250 Btu/lb, sulfur content is 0.48%, unscrubbed under the old NSPS; the heat rate is 9600 Btu/Kwh. Heat rates under 100% scrubbing are 10,220 Btu/Kwh and 9700 Btu/Kwh.

Commerce Commission has recently granted rate increases of more than 20 percent to individual lines, including an increase that will raise the cost of Wyoming coal delivered to San Antonio 30 percent.[11,12,13] With ICC's backing, this trend of large tariff increases seems very likely to continue, at least in the short term.

Over the longer term, the likelihood of continued rapid increases in interstate rail freight rates is difficult to assess. However, it seems at this point that the pressures toward very rapid escalation in the next few years are strong. To summarize a discussion of this question contained in an internal EPA memorandum,[14] several circumstances conspire to push higher tariffs. These include:

- New regulatory approach of the Railroad Revitalization and Regulatory Reform Act of 1976
- Large capital requirements to improve existing facilities and build new trackage and rolling stock
- The increased maintenance and shortened life span of unit trains and trackage
- A favorable attitude of ICC

In Texas, however, conditions do not suggest similar increases in the cost of shipping lignite within the state. Within Texas, railroads are regulated not by the ICC but by the Texas Railroad Commission. The Commission is currently very concerned over the economic costs to the state of the National Energy Act's plan to regulate intrastate gas and to encourage the use of coal. It therefore seems unlikely that it would approve rate increases that might decrease lignite's attractiveness compared with coal, and thus drive dollars out of the state that could be invested in energy production here. In addition, the Texas Lignite Belt is served by a number of railroads that must compete with one another. Over short distances, it may also be more economical for the firm using the lignite to build and operate its own railway. Finally, the much shorter hauls within Texas, compared to the distances travelled by unit trains from out of state, require fewer cars, less trackage, and afford longer lifetimes for both. All of these factors together suggest that rail tariffs for lignite shipment in Texas will rise much more slowly than interstate freight rates.

Although utilities will most probably exploit the much lower costs of lignite at the mine mouth by siting on or near the Lignite Belt, industries may not be as free to do so. Thus, the relative escalation rates of coal and lignite transport cost may have an impact on the competition between these fuels for use by industries on the Gulf Coast.*

Midwestern coal could be moved by barge as well as rail. However, uncertainties as to the capacity of existing waterways to carry large volumes of coal place calculation of an appropriate escalation factor beyond the scope of this study.

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*Much higher interstate freight rates could raise the cost of using coal on the Gulf Coast to the point where even with the cost of shipping, lignite would be cheaper. At the same time, however, the value of lignite to utilities would also rise, driving up the cost of new supplies. This would act to dampen the advantage conferred by transport costs on coastal lignite use.

2.3 Market Characteristics

The picture emerging at this point is one where lignite, already economically attractive at the mine mouth, may become even more so, to the point of eventually becoming competitive on the Gulf Coast (with respect to delivered price). However, the situation is further complicated in that coal and lignite in Texas do not compete equally in a mature market, owing to the fact that much of the lignite is owned by potential users.

Texas lignite lessors can be divided into three groups. The first, which holds 32 percent of the acreage now under lease, consists of utilities planning to develop the lignite themselves for use in mine-mouth power plants. The second group is made up of industrial firms also likely to develop and use lignite themselves. They hold 19 percent of the lignite acreage currently leased. The remaining 49 percent is leased by firms classed as "vendors." These will either open mines and sell lignite in the same market as coal, or they will sell or sublease their holdings to utilities, industries, or other vendors.

Under ordinary conditions, the price of lignite in a developed market would be expected to rise eventually until the cost of using it met that of using coal from outside the state. However, 51 percent of the coal already leased is held by firms that will not necessarily pay that price. At the very least, owners of "captive" leases can obtain lignite for the cost of producing it, regardless of the price of replacing it with another fuel. Depending upon the financial posture of the individual firm, however, it may be desirable to value the lignite at something above the cost of production. A firm with a mining subsidiary, for example, may include a return on investment in the value of the lignite it produces. Utilities and industry may differ in their behavior, since the prices charged by utilities for their product are regulated by government, while those charged by industry are controlled by competition in the open market.

Thus, a substantial proportion of the lignite under lease in Texas may be valued below the price of replacing it on the open market. A portion of that controlled by vendors may also enter this category if it is transferred into the hands of utilities or industrial users. This situation places even greater potential pressure on lignite, as an economically desirable alternative to oil, gas, and--it appears likely--to coal.

3.0 DERIVATION OF LIGNITE DEVELOPMENT SCENARIO

Summary and Conclusions

- Even using the conservative assumption that the coal/lignite ratio through 2000 will be the same as that in announced plans through 1987, it appears that by the end of the century, virtually all of the reserves currently estimated to be economically recoverable by strip mining are likely to have been committed (although it will be close to 2030 before all are mined).

- Current reserve estimates are based on recovery to 150 feet. If mining recovered lignite to 200 feet, the resulting reserves would be extended from 6.7 to 8.9 billion tons. This amount would cover even the highest estimates of commitments required by 2000. The price increase needed to bring about this increase in production is not known.

- Industry has so far been cautious in converting to solid fossil fuels. If, as may be the case, most of the strippable lignite is committed to the coming decade, this slowness could reduce the proportion of lignite used by industry, under the mandate of the Fuel Use Act.

- If the economics of gasification and liquefaction do not become favorable until after 2000, there may not be enough uncommitted strippable lignite available for them to support widespread development. *In-situ* gasification of deep-basin reserves would then appear to be the most promising of the new technologies in the long term.

Given the difficulty of estimating a future "price" for lignite to compare with competing coal prices, the lignite development scenario presented here was not developed by balancing supply and demand in a competitive situation. Instead, the scenario represents a what-if situation, based on historical trends. Several alternative cases were also evaluated, to test the sensitivity of lignite development rates to plausible future situations. The results are expressed in terms of subregional divisions of Texas, illustrated in Figure 1-2. Since transportation costs make lignite non-competitive in west Texas, only the eastern part of the state is involved in the scenario. Table 3-1 summarizes the steps taken in the analysis.

TABLE 3-1. STEPS TAKEN TO DERIVE SUBREGIONAL LIGNITE DEVELOPMENT SCENARIO

Step 1	Based on known acreage under lease, estimate recoverable tonnages of lignite now held by utilities, industry, and vendors. Assume this ratio holds for future disposition of lignite yet to be leased.
Step 2	Calculate the number of facilities, equivalent to a 500 MWe steam-electric unit with a 30-year lifetime, which could be fired with the amounts of recoverable lignite under lease (resource unit). Table 3-9)
Step 3	Based on solid fossil fuel demands calculated for the Nominal Case, assume that 60% will be satisfied by lignite and 40% by coal, through 2000. Express the required amounts of each as resource units. (Table 3-13)
Step 4	Within each subregion, allocate vendor holdings to utilities and industry so as to satisfy both groups' needs. (Table 3-15)
Step 5	Allocate remaining coal demand, for utilities and industry, to subregions, based on announced plans through 1985 extrapolated to 2000, and projected industrial growth through 2000. (Table 3-15)

3.1 Leaseholding Patterns

The best information currently available on actual leaseholdings is that supplied by Steele and Associates, of Huntsville. Based on a 1978 search of courthouse records, the total acreage under lease in each county was identified, by holder. Using these data, holdings were aggregated into the five subregions and the three holder groups. Then, to translate acreage into tonnages, the resource endowment in each region (see Figure 1-2) was divided by the total leased acreage. This amounts to assuming first that all acreage underlain by strippable lignite is leased, and second that the ratio of recoverable lignite reserve to acreage is the same for each lease.

A comparison of 1978 leaseholdings with 1977 holdings data (also furnished by Steele and Associates) indicates that little change occurred in that twelve-month period. Thus, short-term evidence does not belie the first assumption. The second is likely in practice not to be true. Many new entries into the leasing arena are companies with little experience in coal, and there is reason to suspect that they are leasing larger amounts of "scenery" than firms with more experience.[15] However, since it would be mere guesswork to estimate what effect this pattern might have on actual tonnages held, the second assumption was made as a matter of convenience.

The acreage totals thus obtained were converted to resource units equivalent to that tonnage required to fire a 500-MWe steam-electric station for thirty years. Assuming a 0.7 capacity factor, a 10,000 Btu/kwh heat rate, and a heating value for lignite of 6500 Btu/lb, such a facility requires approximately 77 MMT. Results were rounded to the nearest tenth, and leaseholders with fewer than 36 MMT under lease were neglected. Table 3-2 presents the results of these calculations.

TABLE 3-2. LIGNITE "RESOURCE UNITS" HELD BY LESSOR GROUPS
(Assumes uniform ratio of tonnage to acres leased)

	Northeast	North Central	South	Central	Gulf Coast	Total
Utilities	13.6	9.2	3.5	1.9	0	28.2
Industries	5.8	8.9	0.5	1.3	0	16.5
Vendors	22.5	12.6	4.3	2.4	1.8	43.6
Total Holdings	41.9	30.7	8.3	5.6	1.8	88.3

Note: A "resource unit" is equivalent to the amount of lignite required to fire a 500-MWe steam-electric unit for 30 years.

The table shows that the amount calculated as "vendor-held" is the largest of the three classes. This might be an overestimate, since at least some of the vendors may be speculators whose strategy is to lease relatively large acreages, without extensive prior exploration. These leases may therefore have a lower ratio of tonnage to acres leased than those held by potential users.

3.2 Ratios of Lignite to Coal Use

The third step in the analysis refers to the total demand for solid fossil fuels. Announced plans through the year 1988 show that if all plants are built as planned, the split between coal and lignite for existing and new capacity will be 42 percent to 58 percent. Table 3-3 summarizes these announcements, and Figure 3-1 shows their locations. Table 3-4 summarizes forecast consumption of coal and lignite by utilities through 1987. The split for the year 2000 was calculated assuming a continuation of this 60/40 ratio.

TABLE 3-3 TEXAS COAL AND LIGNITE POWER PLANTS

	COAL			LIGNITE			
Year of Start-Up	Plant	Mw(e)	Utility Code	Plant	Mw(e)	Utility Code	Composite Total Coal/ Lignite
1978 and earlier	Harrington #1	333	SPS	Sandow (1-3)	360	TU/AL	
	Deely #1	418	CPSB	Big Brown #1	575	TU	
	Deely #2	418	CPSB	Big Brown #2	575	TU	
	Welsh #1	528	SWEP	Monticello #1	575	TU	
	Harrington #2	338	SPS	Monticello #2	575	TU	
	Parish #5	660	HL&P	Monticello #3	750	TU	
				Martin Lake #1	750	TU	
				Martin Lake #2	750	TU	
Total Exist.	6 Units	2695		10 Units	4910		7605 Mw
1979	Coleto Cr #1	550	CP&L	Martin Lake #3	750	TU	
	Parish #6	660	HL&P	San Miguel #1	400	ST/B	
	Fayette #1	550	LC/A				
Total 1979	3 Units	1760		2 Units	1150		2910 Mw
1980	Fayette #2	550	LC/A				
	Welsh #2	528	SWEP				
	Harrington #3	317	SPS				
	Parish #7	570	HL&P				
Total 1980	4 Units	1965					1965 Mw

TABLE 3-3 (CONTD.)

Year of Start-Up	COAL Plant	COAL Mw(e)	COAL Utility Code	LIGNITE Plant	LIGNITE Mw(e)	LIGNITE Utility Code	Composite Total Coal/ Lignite
1981				Sandow #4	545	TU	
Total 1981				1 Unit	545		545 Mw
1982	Welsh #3	528	SWEP	Gibbon's Creek #1	400	TMPA	
	Tolk #1	508	SPS				
Total 1982	2 Units	1036		1 Unit	400		1436 Mw
1983	Morgan Creek #6	460	TU				
	Parish #8	550	HL&P				
1983	2 Units	1010					1010 Mw
1984	TMPA Undeter-mined	200	TMPA	Pirkey #1	640	SWEP	
				San Miguel #2	400	ST/B	
				Forest Grove #1	750	TU	
Total 1984	1 Unit	200		5 Units	1790		1990 Mw

TABLE 3-3 (CONTD.)

	COAL			LIGNITE			
Year of Start-Up	Plant	Mw(e)	Utility Code	Plant	Mw(e)	Utility Code	Composite Total Coal/ Lignite
1985	Tolk #2	508	SPS	Martin Lake #4	750	TU	
	DeCordova	713	TU	HL&P #1	750	HL&P	
Total 1985	2 Units	1221		2 Units	1500		2721 Mw
1986	TMPA Undetermined	200	TMPA	Twin Oak #1	563	TU	
				Karnack #1	640	C&SW	
				HL&P #2	750	HL&P	
				Fayette #3	400	LCRA	
				Mill Creek #1	750	TU	
Total 1986	1 Unit	200		5 Units	3103		3303 Mw
1987	Lake Kemp #1	640	C&SW	Twin Oak #2	563	TU	
				Oak Knoll #1	750	TU	
				Mill Creek #2	750	TU	
Total 1987	1 Unit	640		3 Units	2063		2703 Mw
1988	Coleto Creek #2	640	CP&L				
Total 1988	1 Unit	640	CP&L				

TABLE 3-3 (CONTD.)

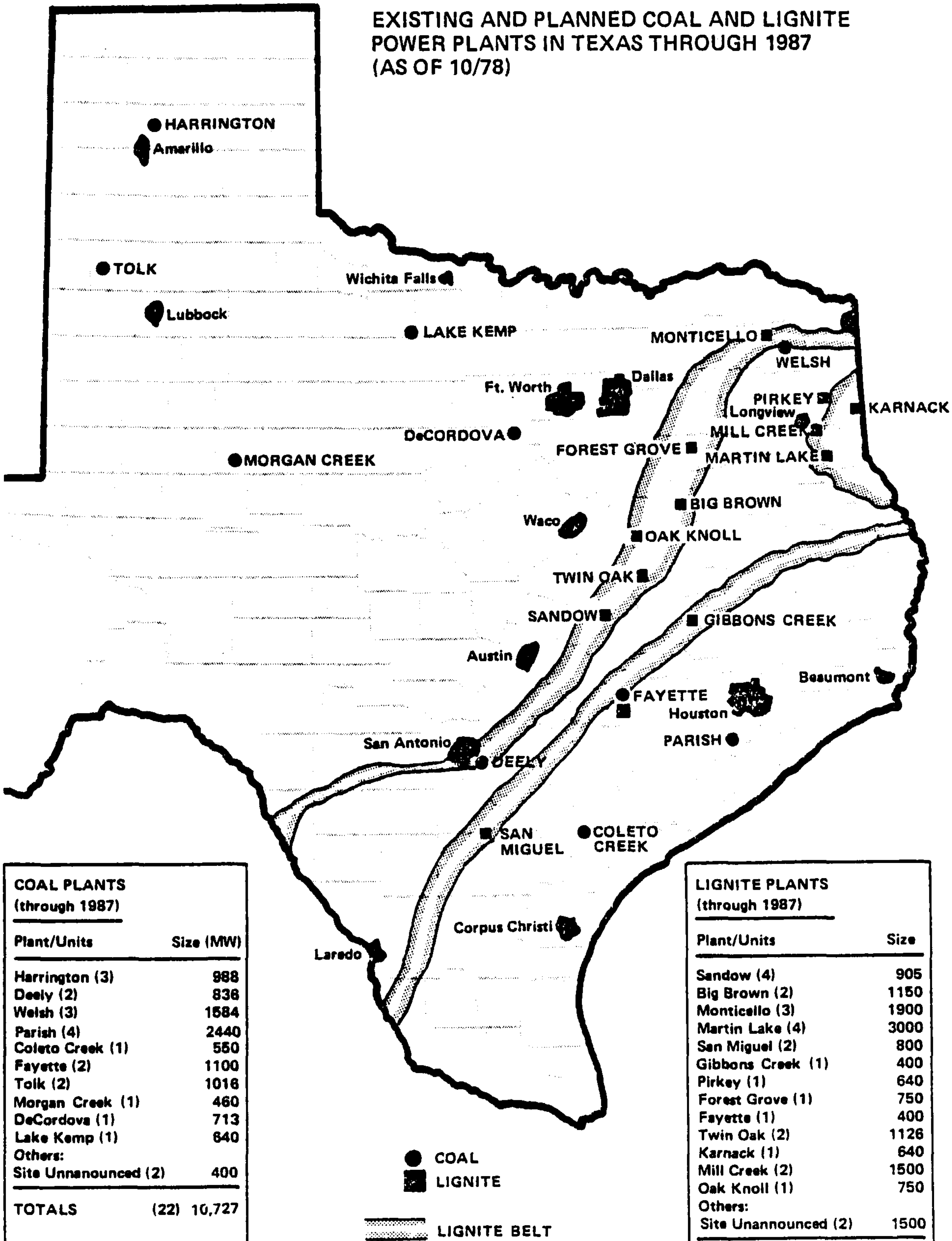
	COAL			LIGNITE			
Year of Start-Up	Plant	Mw(e)	Utility Code	Plant	Mw(e)	Utility Code	Composite Total Coal/ Lignite
TOTAL EXISTING	6 Units	2695		10 Units	4910		7605 Mw
TOTAL 79-87	15 Units	8032		19 Units	10,551		17,773 Mw
TOTAL EXISTING AND PLANNED	21 Units	10,727		29 Units	15,461		26,188 Mw

TABLE 3-3 (CONTD.)

Information Sources:

1. Status of Coal Supply Contracts for New Electric Generating Units, 1977-1986, U.S. DOE, FERC, Office of Electric Power Regulation, May 1978.
2. Electric Reliability Council of Texas (ERCOT), "Report to DOE on Coordinated Bulk Power Supply Programs," August 1, 1978.
3. Personal communication with utility officials:
   - Southwestern Public Service Company, Amarillo (Pete Smith).
   - Central & Southwest Corporation (SWEPCO, WTU, CP&L) (Jim Bruggeman, Dallas).
   - Texas Utility System Inc. (TUSI) (Ken Herman, Dallas).
4. Texas Air Control Board, Permit Records
5. Newspaper Article Press Release
6. Texas Department of Water Resources planning data

Utility Code	Utility Name(s)
TU	Texas Utilities System (Texas Power & Light, Texas Electric Service, Dallas Power & Light)
TU/AL	Joint Project, TU and ALCOA
CPSB	City Public Service Board of San Antonio
SWEP	Southwestern Electric Power
SPS	Southwestern Public Service
HL&P	Houston Lighting & Power Co.
CP&L	Central Power & Light
LCRA	Lower Colorado River Authority
LC/A	LCRA/City of Austin Joint Project
TMPA	Texas Municipal Power Agency
ST/B	Joint Project, South Texas Electric Cooperative & Brazos Electric Co.
C&SW	Central & South West Corporation, Holding Company for SWEP, CP&L, West Texas Utilities, and Public Service of Oklahoma



COAL PLANTS (through 1987)

Plant/Units	Size (MW)
Harrington (3)	988
Deely (2)	836
Welsh (3)	1584
Parish (4)	2440
Coleto Creek (1)	550
Fayette (2)	1100
Tolk (2)	1016
Morgan Creek (1)	460
DeCordova (1)	713
Lake Kemp (1)	640
Others:	
Site Unnanounced (2)	400
TOTALS (22)	10,727

LIGNITE PLANTS (through 1987)

Plant/Units	Size
Sandow (4)	905
Big Brown (2)	1150
Monticello (3)	1900
Martin Lake (4)	3000
San Miguel (2)	800
Gibbons Creek (1)	400
Pirkey (1)	640
Forest Grove (1)	750
Fayette (1)	400
Twin Oak (2)	1126
Karnack (1)	640
Mill Creek (2)	1500
Oak Knoll (1)	750
Others:	
Site Unannounced (2)	1500
TOTALS (27)	15,461

Figure 3-1. Existing and Planned Coal and Lignite Power Plants in Texas

TABLE 3-4. COAL AND LIGNITE CONSUMPTION BY TEXAS ELECTRIC UTILITIES

	Coal		Lignite		Total Quads
Year	Quads	Tons x 10^6	Quads	Tons x 10^6	Coal and Lignite
1977	0.10	6.0	0.23*	17.6*	0.33
1980	.37	21.8	.43	32.7	0.80
1985	.54	31.7	.74	56.9	1.28
1987	.63	37.2	1.09	84.2	1.72

*Actual lignite production reported by the DoE. All other figures are year-end rates of consumption based on assumptions stated below.

Assumptions

- Current announced plans (Table 3-3) are carried out on schedule.
- Each unit reaches full output by the end of the year it is scheduled to start up.
- Heating values of 6,500 Btu/lb for lignite; 8,500 Btu/lb for coal.
- No retirements take place.
- Each coal plant requires 3,400 tons per year per MW of installed capacity; each lignite plant requires 5,400 tons per year per MW of installed capacity.

The tonnage figures were calculated based on the amount of coal and lignite required to support the plants announced by Texas electric utilities in DoE's Status of Coal Supply Contracts of New Electric Generating Units 1977-1985.

Existing and planned industrial coal and lignite use is summarized in Table 3-5. Although the potential for use of coal and lignite in the industrial sector in Texas is large, the pace of industrial conversion appears to fall far short of utility plans. A comparison of Tables 3-4 and 3-5 indicates that announced industrial coal use through 1982 amounts to less than half the current utility coal/lignite use. Among the reasons for this are the following:

- Utilities are required to make known their intentions at an earlier point in the planning stage. Thus, while utility plans may be announced 10 years in advance, a major industrial expansion may not be revealed more than

TABLE 3-5. EXISTING & PLANNED TEXAS INDUSTRIAL COAL/LIGNITE USE[1]

Start-Up Date	Industry	Location	Facility	Coal Type
1979	Celanese Corp.	Pampa	Cogeneration 2 Boilers 116,000 lb/hr steam capacity each	Western Coal (540,000 t/y)
1980	Texas Eastman	Longview	3 Boilers 70,000 lb/hr capacity each	Undecided (300,000 t/y)
1944	ICI, Americas	Darco (near Marshall)	Mine-mouth activated carbon production	Lignite (300,000 t/y)
1983	Union Carbide AMOCO Monsanto (CAM)	Texas City	Process steam/ electric power cogeneration facility	Undecided (3,000,000 t/y)
1982	Shell	Houston	3 Boilers total capacity 218,000 lb/hr	Undecided (1,500,000 t/y)
1974-1981	Brick, Cement & Lime Kilns	Scattered: North Central, South Central, & Southeast Texas	23 Facilities 43 kilns	Texas bituminous, Texas lignite, & Western coal (1,800,000 t/y)

Total Coal & Lignite Tonnage: 7,440,000 tpy
Estimated Energy Content*: 116×10^{12} Btu or 0.12 Quads

[1]Primary source for most of these data is the permit application file at the Texas Air Control Board (data as of 10/78). ALCOA lignite production is used jointly by Texas utilities & ALCOA & is tabulated under utilities in Table 3-2.

*Assume half lignite, half bituminous with average Btu content of 7,500 per pound.

two or three years in advance. Therefore, Table 3-5 represents a shorter time horizon than does Table 3-2 (announced utility plans).

- Utility boilers are generally several times larger than industrial boilers and therefore more economical for coal burning.

- As indicated in Chapter I, existing industrial boilers are not required to convert under the new federal mandatory boiler fuel conversion legislation.

- The major industrial energy consumers in Texas, the petrochemical and refining sectors, are more site-constrained than electric utilities. New utility power plants can locate along the Lignite Belt (or otherwise outside the industrial coastal zone or other urban areas) and supply their customers through the power grid.

- Utilities are less subject to economic uncertainties regarding the major investment decisions involving coal/lignite conversion. A favorable regulatory climate in Texas has enabled Texas electric utilities to attract the needed capital for coal conversion.

Thus, for a variety of reasons, Texas industry has taken a wait-and-see attitude with respect to coal conversion relative to the firm commitment to conversion exhibited by the utility sector. Under these circumstances, it is not possible to detect trends that can be extended as far as 2000.

3.3 Sensitivity of Lignite Development to Alternative Assumptions

Because of these reasons and the price uncertainties discussed earlier, the actual coal-lignite ratio in industry cannot be predicted. Therefore, it was assumed for purposes of this study that the same 60/40 ratio would apply to industry as does to utilities.

The results of this assumption, given in Table 3-6, indicate that by 2000, 6.0 billion tons of lignite will have been committed for all uses. Given the uncertainty in the method used, this can be considered very close to the total 6.7 billion tons of economically recoverable strippable reserves estimated by Kaiser. It should be understood that this tonnage does not reflect the amount burned or produced in that year. It represents the amount that must have been committed, by 2000, to support all of the lignite use that has taken place up to that time, plus future use, assuming a 30-year plant lifetime for all installations.

TABLE 3-6. POTENTIAL REQUIREMENTS FOR LIGNITE COMMITMENT

		1978	1985	2000
Total Energy Required (Quads)	Utilities	1.76	2.60	4.80
	Industry	2.42	3.14	5.18
Solid Fuel Demand (Quads)	Utilities	.50	1.28	3.14
	Industry	.05	.15	1.16
Lignite Demand (Quads)	Utilities	.30	.74	1.90
	Industry	.05	.09	.70
Lignite Reserve Commitment Required (Billions of Tons @ 6500 Btu/lb)	Utilities	.70	1.72	4.38
	Industry	.10	.17	1.62
	Total	.80	1.89	6.00
Resource Equivalents	Utilities	10.0	25.0	62.0
	Industry	2.0	3.0	23.0

To test the sensitivity of this measure of development rate, a series of cases were considered that reflect the assumptions used earlier in examining the sensitivity of overall solid fossil fuel demand. The results of these cases, calculated for the year 2000, are shown in Table 3-7. As can readily be seen, the only two cases which produced a lignite commitment

TABLE 3-7. SENSITIVITY TO ALTERNATIVE ASSUMPTIONS OF LIGNITE COMMITMENT BY THE YEAR 2000

	Utilities (billion tons)	Industry (billion tons)	Total (billion tons)
Nominal Case	4.4	1.6	6.0
High Growth	5.2	2.6	7.8
Low Growth	2.2	0.4	2.6
High Nuclear; Moderate Growth	2.8	1.6	4.4
Constrained Gas & Oil; Moderate Growth	6.1	2.5	8.6
Moderately Constrained Gas & Oil; Moderate Growth	6.1	1.6	7.7
High Lignite Demand for Utilities; Moderate Growth	5.1	1.6	6.7
3% Annual boiler retirement	5.1	2.5	7.6
Estimated Economical Reserves to 150 ft			6.7
Estimated Economical Reserves to 200 ft			8.9

level lower than the Nominal Case were the low-growth and high-nuclear cases. The first assumes that per-capita consumption of electricity stabilizes in 1985, and that per-capita consumption of energy in industry remains at 1975 levels. Thus, demand grows only in proportion to population. The high-nuclear case is based on the moderate conventional energy growth used for the Nominal Case, but assumes 25,000-MWe of nuclear power generation. Both of these cases appear extremely unlikely.

It is interesting to note that the highest total results, not from the high growth case, but from the cases in which boiler fuel conversion is assumed to be most stringently applied. Although strong economic, social, and political forces would oppose such a trend, the initial moves by DoE in administering the Fuel Use Act point in that direction.

If the current reserve estimate of 6.7 billion tons is correct, then the cases totalling to commitments greater than this number imply the possibility of running out of uncommitted lignite some time in the 1990's. The residual demand would then be met with coal. However, it will be recalled that, since the lignite-bearing strata dip toward the coast, more lignite might be strip-mined if economics warranted digging deeper. The price of coal, the logical replacement for lignite, may rise faster than that of lignite over the next 22 years, as discussed above. Thus, economics may justify the more expensive mining methods required to recover larger amounts of lignite. As indicated in the table, mining to 200 feet could produce enough lignite to cover all the cases. The price increases necessary to support this increment cannot, however, be estimated without a more detailed analysis than the scope of this study will support.

In interpreting the figures in Table 3-7, it should be borne in mind that leasing typically takes place in advance of the demand, as firms attempt to secure themselves against uncertain future needs. Thus, the time frame over which the tabulated commitments are actually to be made may be considerably shorter than the 22 years between now and the year 2000.

The significance of this accelerated rate could be great for industry if large amounts of lignite are needed. As has been pointed out, industries have so far been cautious and held back on committing themselves to solid fossil fuels. Marketplace competition adds an element of risk to such a move, as seen by individual firms, which regulated utilities do not experience.

Utilities already recognize the value of using lignite. If industry is slower in responding, it may find itself competing with utilities for vendor-controlled lignite. Lignite could be obtained from vendors by direct purchase and transfer of lease, by sub-leasing for "captive" development, or by purchase of lignite mined by the vendor. The first two modes are likely to prevail in the short term, with each round of trading raising the per-ton cost of leasing and thus the value or price of the lignite. Operating a "captive" mine may be economically preferable, in many cases, to purchasing lignite directly from a supplier. However, as time passes, it may become more and more difficult to obtain the necessary leases. Also, the cost differential between "captive" and purchased lignite may decrease with time, as more lease trading takes place.

It may also be possible that utilities will tie down the most economically recoverable lignite fast enough to leave fewer, or more expensive reserves for industry use. In order to satisfy utility demands, the consolidation of lease blocks into mining units of at least 75 million tons will be important. Thus, there may be a danger of fragmenting remaining holdings, which may hamper industry if it enters the picture late.

Adding to the strength of the concern over utility-industry competition for lignite is the current debate over interconnecting the present Texas Interconnect System with surrounding interstate grids. Some TIS members, through corporate linkages with interstate, non-TIS utilities, favor interconnection, to reduce costs and increase reliability. The Carter Administration also favors interconnection for the same reasons. The result of interconnecting the TIS network might be to increase the overall demand for lignite for power generation.

Thus, the longer industry waits to enter the game, the higher the price it may have to pay for the lignite it uses. The result of paying higher fuel costs may be expected to show up in product prices. To evaluate whether this effect is large or small, relative to competing industry outside the state, is beyond the scope of this study.

In all but the low-growth and high-nuclear cases, then, it appears that there is a good chance that all of the currently estimated economic reserves of lignite could be committed for specific uses by the end of the century. It also appears, to judge by current behavior, that industry may enter the picture late, with an attendant penalty in the cost of the lignite it eventually obtains. Both conclusions are significant with respect to developing new technologies for use with lignite.

As has been discussed in the preceding chapter, the economics of gasification and liquefaction, and of certain applications of fluidized bed combustion, do not appear favorable at present compared with conventional combustion. Widespread application of these technologies is likely therefore to occur late in the century or into the next. If the economically recoverable strippable lignite reserves are committed by then, these technologies will be forced to use coal. If, on the other hand, relatively lower-cost lignite were still available by then, it might reduce product costs and conceivably add to incentives to bring these technologies on line slightly sooner.* Otherwise, *in-situ* gasification is likely to be the only one of the new technologies with a long-term future using lignite.

3.4 Subregional Breakdown of Lignite Development

Step 4 takes the statewide requirement for lignite and distributes it among the regions. This is accomplished in the following manner:

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*It should be pointed out that capital costs at present contribute more than feedstock costs to product price in gasification. Therefore, this effect would not be decisive across the board, though it might be in individual cases.

1. The difference is calculated, at the state level, between utility and industrial holdings and their projected needs (Nominal Case) expressed as resource units.

2. All utility use is assumed to be within the same subregion as the associated lignite production (mine mouth or near it).

3. The proportion of vendor holdings is calculated which must be transferred to utilities to meet the entire requirement.

4. It is assumed that vendor-utility transfers involve that same portion in each of the five regions.

5. The subregional transfers are calculated by multiplying the proportional factor from (3) by the vendor holdings in each subregion.

All of these steps are performed only for the year 2000. Results for utilities are truncated to the nearest whole number of resource units. This method permits generation of power outside the subregion consuming it, and produces results which reflect the distribution of lignite. This pattern squares well with announced plans through 1987.

Industrial demand was derived in a similar fashion, by first assuming that vendor holdings would be distributed to industry so as to satisfy industry's requirements in the year 2000 for the Nominal Case. The proportion of vendor holdings was then applied as an allocation factor to vendor holdings in each region to obtain a measure of resources available to industry in each subregion.

At this point, the two methods diverged. Industrial use was assumed to be possible at any point--not only at the mine mouth. It was also decided to enter two medium-Btu lignite gasification plants into the scenario, sized at 300 MMBtu per day. These were arbitrarily sited in the northeast and north central regions. The commitments required for these plants were counted as coming from the lignite available to the Gulf Coast region, reflecting a probable pattern of mine-mouth gasification and pipelining to coastal industrial centers. The remaining lignite use was divided among the regions based on their projected growth in industrial sectors of the economy. Projections made by the Texas Department of Water Resources of the chemical and allied industries--the main energy consumers among Texas industries--were used as an index.

The final step of the analysis allocates the remaining solid fossil fuel requirement to coal. For utilities, this is accomplished by using as an index projections made by the Texas Department of Water Resources of manufacturing growth. This index, disaggregated to a subregional level, was thought to reflect both economic growth and population growth. For industry, the growth of chemical and allied industry was used as the allocation index, as was done in allocating lignite use.

Table 3-8 presents, in terms of resource units, the resulting lignite and coal commitments by subregion. The parenthetical number entered for utilities translates these resource units into 1500-MWe station equivalents.

A comparison of Tables 3-2 and 3-8 shows that industrial demand for lignite matches supplies held more closely

TABLE 3-8. COAL AND LIGNITE COMMITMENTS IN THE YEAR 2000, BY SUBREGION

		W	NE	NC	S	C	GC	Total
Coal Utilities	1985	4(1)*	2(1)	2(1)	0	2(1)	4(1)	14(5)
	2000	12(4)	6(2)	4(1)	0	7(2)	12(4)	41(13)
Lignite Utilities	1985	0	10(3)	7(2)	3(1)	1(1)	0	21(7)
	2000	0	32(11)	20(7)	6(2)	3(1)	1(1)	62(21)
Coal Industrial	1985	.2	.1	.2	0	0	1.5	2
	2000	1.4	.7	1.3	.2	.2	11.2	15
Lignite Industrial	1985	0	.5	2	0	0	.5	3
	2000	2.1	5.3	6.2	.3	.4	8.7	23

*Entries are in resource units, equivalent to a 30-year commitment of fuel for a 500-WMe steam-electric unit.

Numbers in parentheses are nearest equivalent to a 1500 MWe generating station.

than is the case for utilities. Thus, it seems plausible that, over the short term, "vendors" may transfer proportionately more lignite to utilities than to industries. If utility demand is high, equilibrium prices for lignite (and/or the values of leases directly transferred) will rise. This may hurt lignite in competition with coal in areas like the Gulf Coast where lignite transportation is a cost factor. The effect on industry depends on the speed with which industrial firms enter the market. Another potentially significant factor is the high proportion of lignite in the hands of a few firms, as shown in Table 3-9.

TABLE 3-9. CONCENTRATION OF LEASE OWNERSHIP*

TOP TWO:	%	TOP FOUR:	%	TOP SIX	%
Utilities	28	Utilities	30	Utilities	31
Industries	15	Industries	19	Industries	20
Vendors	23	Vendors	30	Vendors	37

*Percentage of total acreage under lease.

SOURCE: Steele & Associates, July 1, 1978

4.0 POLICY ISSUES

> Utility Interconnection. Federal policy supports interconnection of the Texas Interconnect System with surrounding interstate grids. Certain utilities within TIS are planning lignite-fired plants and interties with the interstate grid. This trend could increase the demand for the limited supply of Texas lignite, at the expense of Texas utilities and ratepayers.

Interconnection potentially offers increased reliability to participating utilities and reduces inequalities in generating costs. While these advantages apply over the interconnected system as a whole, the effects of interconnection may vary among different components. If transportation economics continue to preclude using Texas lignite outside the state, then the cost advantages of lignite-fired generation would be limited to utilities in the Texas Interconnect System. Interconnection would allow these benefits to be spread over a larger area, but at the cost of reducing the relative advantage to Texas consumers. In some ways, this parallels the historical regulation of natural gas production and distribution, which causes some concern in Texas over potential unfair exploitation of indigenous lignite reserves.

The extent of any such potential inequity depends both on the extent of interconnection and the relative cost advantage of lignite versus other fuels for power generation. In new capacity, the comparison will be chiefly with coal. Presently, the costs of generation differ little between coal and lignite. However, current trends suggest that the price of coal may rise faster than that of lignite, so that any inequities arising from interconnection might become more pronounced with time.

Also, since the economically recoverable lignite reserve is limited, any significant increase in demand arising from interconnection would shorten the time frame of resource development and depletion. This, in turn, would tend to intensify environmental impacts. As well, it would contribute to the problem of resource depletion before the next generation of utilization technologies becomes commercialized.

> <u>Rapid Lignite Commitment</u>. It appears that a substantial portion of the state's strippable lignite reserve may be committed by 2000, largely to combustion uses. Should large-scale synthetic fuel production become desirable after this time, the least costly potential feedstock--lignite--would no longer be available. A tradeoff therefore exists between the short-term benefits of using lignite as a boiler fuel and having it available in the future as a feedstock.

Left unhampered, the market system will tend to allocate lignite, as a relatively cheap fuel, to boiler use in the short term. Since the resource is limited, it can very quickly be committed to this use. A few decades from now, however, it may be possible and desirable to commercialize synthetic gas and liquids technologies, not only for fuels but as chemical feedstocks as well. The demand for synthetic feedstocks in Texas could be quite high, if the petrochemicals industry continues to expand.

If lignite is not available, or only the most expensive reserves remain uncommitted, imported coal will necessarily provide most of the feedstock. But coal prices are expected to increase steadily, and perhaps markedly, due to a host of factors affecting the cost of production and transportation.

Thus, it appears that if coal were to provide a greater part of the fuel mix now, it might be possible to spread the economic advantages of lignite over a longer time frame. If the cost savings realized by using lignite as a feedstock for synthetics were greater than the added expense of using coal now, the result would be greater economic efficiency in the use of the lignite reserve.

This argument applies to the reserve as a whole, looked at from the point of view of the whole state's economy. However, different firms would probably use lignite for synthetic production than those which would realize short-term benefits from using it as boiler fuel now. Therefore, this issue involves a question of inter-firm equity versus economic efficiency at a larger scale.

> <u>Lignite RD&D Priorities</u>. Given the Nominal Case projections of demand, most of the state's currently economically strippable lignite may be committed to specific projects by the end of this century. If such is the case, RD&D efforts with regard to technologies which will not be commercialized within the next two decades do not appear justified. Key assumptions in the Nominal Case which affect this conclusion are the economical depth of surface mining and the utilization of lignite by the industrial sector.

Because of the finite size of the state's lignite resource, lignite RD&D should focus on expansion of the reserve base and on facilitating the fuel conversion requirements of the Fuel Use Act. Efforts to expand the reserve base should include improvements in the efficiency and depth of near surface lignite recovery and development of technologies that would make the deep-basin resource available. The greatest uncertainty with regard to the state's ability to satisfy the state's economic, environmental and fuel use objectives concurrently is over the future use of coal and lignite in the major industrial centers located on the Gulf Coast. Efforts to identify and clarify regulatory conflicts and to develop economically and environmentally acceptable technologies for industrial lignite use in the next two decades are needed.

RD&D efforts to develop utilization technologies which will not be commercially available in the next two decades do not currently appear cost-effective. Examples of such technologies include liquefaction and chemical processes using lignite-derived feedstocks. These technologies are currently held back by both the need for further RD&D and unfavorable economics as compared to oil and natural gas.

5.0 RECOMMENDED FUTURE RESEARCH

The lignite development scenario derived in this chapter relies of necessity upon a number of assumptions in key places. The most critical of these are the assumptions of total available lignite, of a continued 60/40 ratio of lignite to coal use in all applications throughout the century and the rigid enforcement of the Fuel Use Act. Additional research is needed to make a more refined estimate and to identify those factors to which these assumptions are most sensitive. Research in the following topic areas would be particularly useful in providing needed insights.

Quantitative Analysis of the Relationship of Recoverable Resource to Price

- Geological factors
- Equipment and operating costs
- Economies of scale
- Labor costs and trends
- Reclamation costs

Utility Demand for Lignite

- Effects of interconnection on the demand for lignite
- Effects of proposed New Source Performance Standards for sulfur on relative economics of coal and lignite: percentage removal versus sliding scale

Industry Demand for Lignite

- Specific industrial applications appropriate for lignite

- Applications where lignite is superior or inferior to coal

- Potential use of lignite as a chemical feedstock

- Factors constraining the use of coal and lignite in the industrialized Gulf Coast region

Industry/Utility Competition

- Improved characterization of "vendor" category of leaseholders

- Estimates of proportion of lignite held by utilities and industries that has already been committed to future uses

- Industry and utility perceptions of the future desirability and availability of lignite

- Estimate elasticity of lignite/coal demand with price for utilities versus industry

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CHAPTER III: SITING CONSTRAINTS

Abstract

This chapter considers factors which may affect siting the energy facilities called for in the development scenario, and specifically considers the availability of an adequate number of power plant sites. Six potentially constraining factors, reflected in the cost and difficulty of permitting a new 1500-MWe station, are evaluated. A series of maps is developed, showing how these factors vary across the study area. A composite site-suitability map, based on these factors, weighted according to perceived importance is generated. This map indicates that future siting may be most difficult and costly along the Gulf Coast, and least constrained near the Lignite Belt. It is not expected that any or all of these constraints would preclude developing all the facilities called for by the scenario in each subregion, although they may tend to "herd" them somewhat. Because industrial uses of coal and lignite are varied both in size and locational constraints, it was not feasible to perform a similar evaluation for them. An overview of factors affecting industrial siting in the study area is given. In the light of the power plant siting exercise, it is not expected that industrial growth will be hampered by siting constraints. Some conflict with utilities, however, especially over emissions permitting, may be inevitable.

1.0 INTRODUCTION AND OVERVIEW

The scenario developed in the preceding chapter allocates a certain number of lignite- and coal-fired power plants to each of five subregions in the eastern half of the state (see Figure 1-1). Lignite production for industrial consumption is also included. The principal questions raised by this scenario are whether all the required facilities could actually be sited in the appropriate subregions, given certain constraints, and what factors can be anticipated to constrain siting the projected number of facilities.

In practice, site selection includes a large number of factors specific to the project, including the firm's economic position, availability and cost of land, proximity to markets, transportation links, labor supply, other natural resources, the personal preferences of the decision makers, and the political/legal context of the jurisdiction. Certain factors, however, must be considered in all siting decisions, and can be studied to gain insights into potential siting constraints on a regional basis. In the analysis which follows, siting factors are evaluated which have a direct impact on the cost of construction and operation, on the availability of sites, and on the likelihood of delay or difficulty in the permitting process. These include:

- water availability,
- ambient air quality with respect to allowable deterioration,
- flood prone areas,
- extraterritorial jurisdictions of communities,

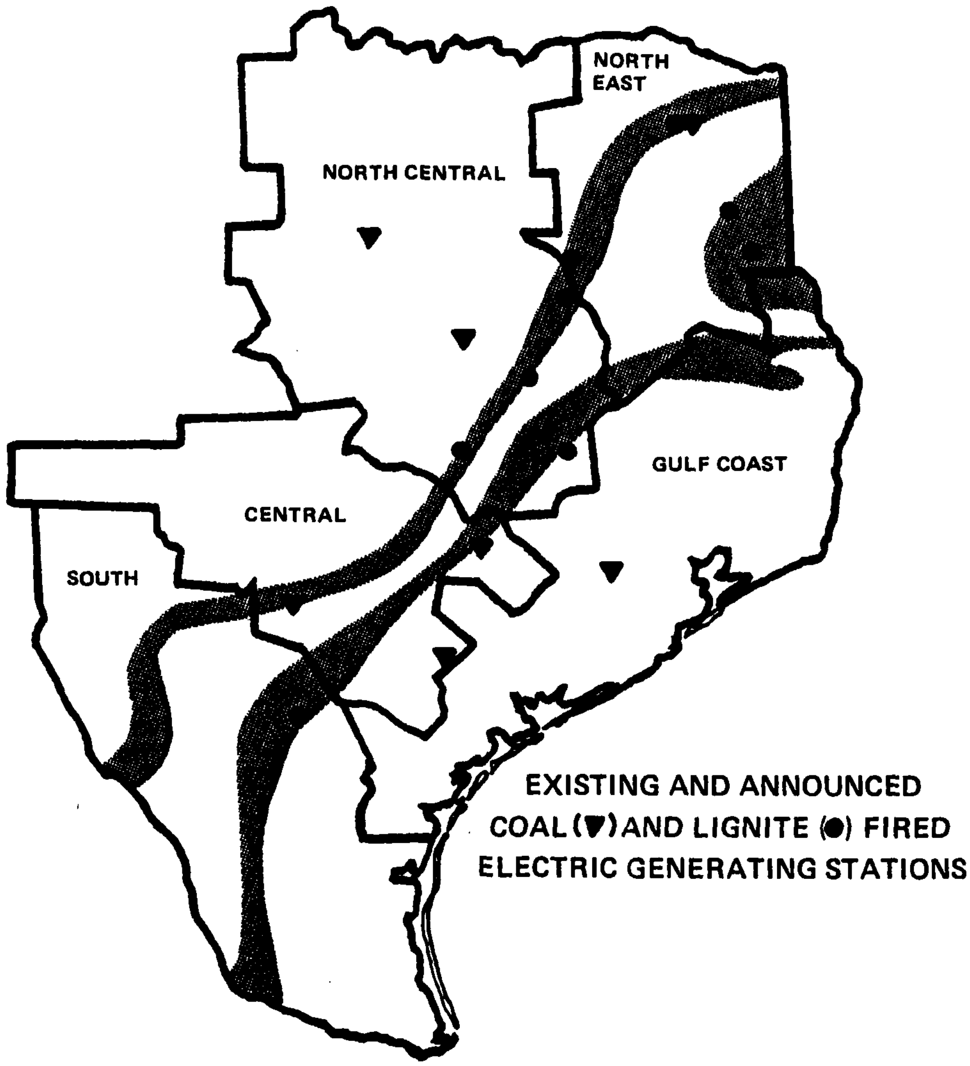

Figure 1-1. Study Area Subregions Showing Existing and Planned Power Plants.

- foundation suitability, and

- distance from lignite deposits.

Other factors, such as aesthetic considerations and public willingness to accept a large project, are also important concerns. However, their costs are not yet formally internalized, and the importance given them will vary considerably from case to case. Since the purpose of the present exercise is to evaluate the factors which will influence siting choices, not those which possibly should, only those factors universally affecting costs, site availability and permittability were included.

The siting analysis which forms the bulk of this Chapter focuses primarily on power plants, and to a lesser degree on surface mines, but does not attempt to deal specifically with industrial uses of lignite. Utility boilers will in general tend to be much larger than industrial boilers, and thus more subject to certain constraints such as air quality and water availability. Also, they can be postulated to be of a uniform size for purposes of analysis, so that the total number of facilities to be sited can be derived. Industrial boilers may vary greatly in size, and this, along with the complexity of the industries potentially using coal, makes it difficult to identify a realistic "standard" size, or to estimate the total number of lignite-fired industrial plants in individual regions.

Even greater uncertainty attaches to the nature and strength of the forces which drive industrial siting patterns. These forces, and their relationships, could easily be the subject of an entire study in themselves. A summary of current attitudes and thinking about industrial growth in the Lignite Belt is presented as the first section of the Chapter.

The following sections present the study team's evaluation of the geographical distribution, and significance to power plant development, of the six types of constraints listed above. A map accompanies each section.

To arrive at a composite evaluation of the cumulative effects of all the constraints examined, a computer program was used which divided the study area into a grid of 20-kilometer squares. Each constraining factor was given a weight, according to the comparative degree of constraint it presented, and the maps converted to digital form. The sum of the weighted values for all factors was determined for each grid square and the results plotted on a map (Figure 4-1).

2.0 POTENTIAL PATTERNS OF INDUSTRIAL SITING IN THE LIGNITE BELT

Summary and Conclusions

- Current trends indicate that new growth may be attracted to smaller metropolitan areas, rather than large existing centers.

- Industrial or energy parks would probably be favored by cogeneration.

- Although lignite is relatively cheap at the mine mouth, this advantage may be outweighed, at least for the petrochemicals industry, by the economic benefits of siting near existing industrial complexes.

- Increased pressures from mandatory boiler-fuel conversion, clean-air policies, and difficulties of obtaining water supplies may drive some new industrial growth away from the Gulf Coast.

- Lignite-generated electricity, if cheap and plentiful, might attract heavy energy-consuming industry, but siting would be dispersed throughout the appropriate service territories, not concentrated on the Lignite Belt proper.

- Gasification plants, which emit hydrocarbons, might encounter siting difficulties because of high ambient ozone levels.

- Currently, there is too little concrete industrial siting activity in the Lignite Belt to identify a trend.

- It is assumed for purposes of this study that the Lignite Belt will not become an area of concentrated industrial growth.

Figure 2-1 shows the position of major industrial growth centers of the next two decades, relative to the Lignite Belt. Also shown are announced new coal- and lignite-fired power plants. While economics clearly favor mine-mouth siting for utilities using lignite, the siting priorities for industries are not nearly as clearcut. The amount of industrial lignite use taking place on the Lignite Belt itself is significant both in terms of its immediate impact, as well as on competition with utilities for sites in favorable areas. A wide variety of opinions have been expressed concerning possible lignite-related industrial expansion along the Lignite Belt. Fred Benson, Vice President of Engineering at Texas A&M and head of its Civil Engineering Department, has projected that lignite development will make parts of Texas resemble Germany's Ruhr Valley or England's industrial midlands. Other observers suggest that it is too early to discern a significant trend in industrial locations.[1] The following discussion sets forth the principal factors that militate both for and against a concentration of industrial growth localized along the Lignite Belt, as the study team perceives them.

2.1 Socioeconomic Background of the Lignite Belt

At present, the Lignite Belt and its surrounding region is comparatively sparse in population, without major metropolitan centers. Employment in manufacturing (SIC categories 19-39) is low, and excess labor migrated out of the area in the 1950's and 1960's.[2] The Tyler-Longview-Marshall district, however, stands out as a rising metropolitan area with a more diversified industrial base and higher manufacturing employment than the rest of the region.

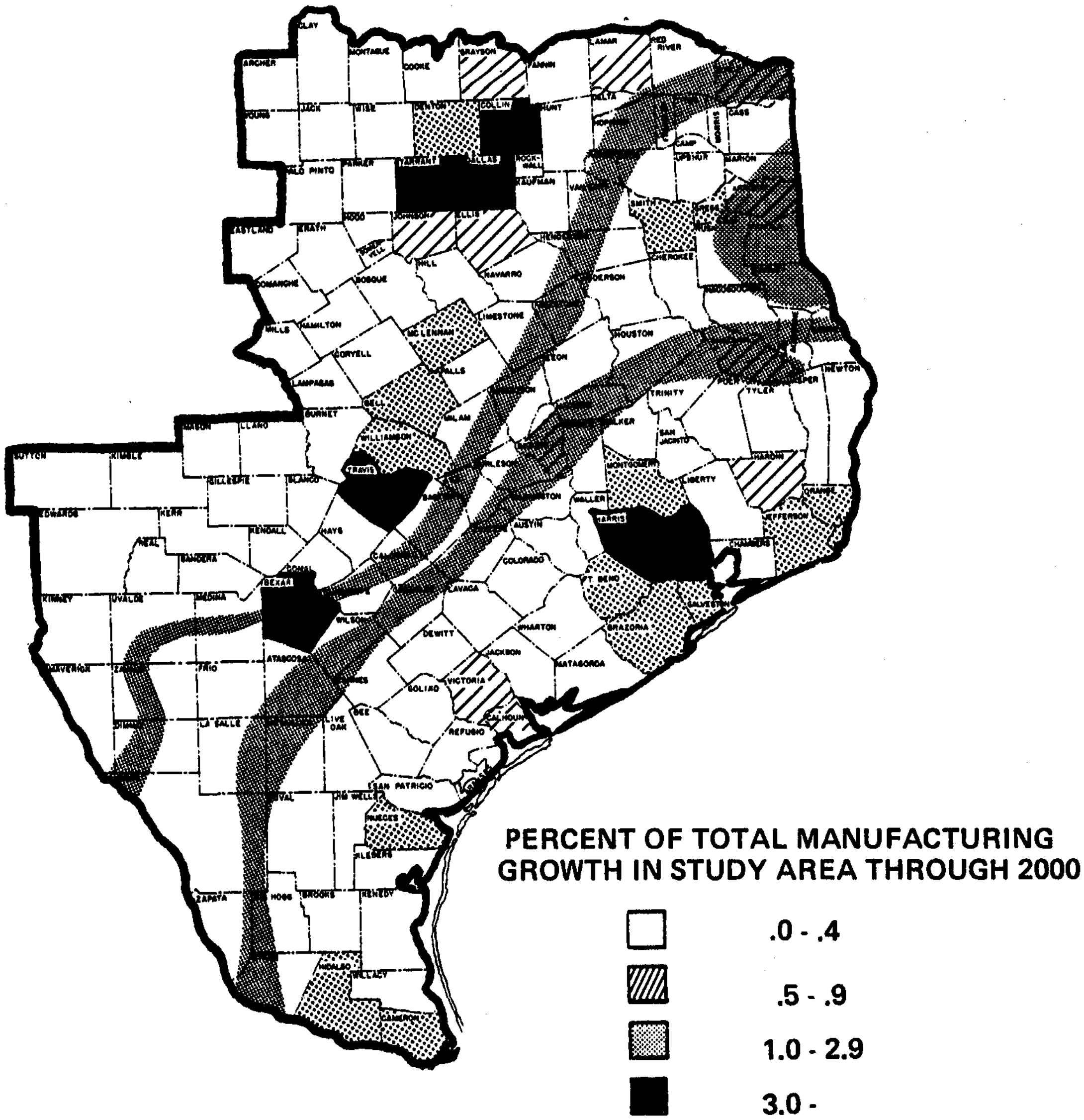

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Figure 2-1. Growth Centers in Relation to Lignite Deposits

Without lignite, it would be expected that growth would occur first in those counties which are immediately adjacent to existing metropolitan counties.[3] Current trends indicate that smaller metropolitan areas, rather than large existing centers, may be the growth areas of the future.[2]

Transportation is a key factor in industrial location. The Lignite Belt is not well connected with the rest of the state by major highways. This area is well served by railroads, however. The Missouri-Pacific's main line runs roughly parallel with the entire lignite trend, and is crossed by numerous other main or secondary lines. Not only are there several available rail shipment routes crossing the Lignite Belt, these routes are owned by different railroad companies, encouraging competition in freight rate and services. A drawback to rail service, however, is the separation of the Lignite Belt from the Gulf industrial centers by a broad band, just inland from the coast, in which there are few rail lines. Thus, the Lignite Belt is better connected to the north and east than to the south.

2.2 Regional Factors Affecting Industrial Siting on the Lignite Belt

Table 2-1 summarizes the major pro's and con's regarding industrialization along the Lignite Belt. The table, and the following discussion, are based on telephone and personal interviews with personnel of the Texas Industrial Commission and local Chambers of Commerce, along with insights developed at Radian in the process of conducting specific studies for its industrial clients.

TABLE 2-1. INDUSTRIALIZATION OF THE LIGNITE BELT: PRO'S AND CON'S

Pro	Con
• Availability of reliable electric power, greater certainty of price. • Air quality constraints on coastal siting, coupled with gas cutback and increasing difficulty of obtaining water supplies. • Lignite's main economic advantage is at the mine mouth. • Economies of scale might make siting secondary chemical plants near large gasification plants desirable.	• Economics of agglomeration along the Gulf Coast vs limited skilled labor, infrastructural gaps on Lignite Belt. • Rail shipment of lignite to Gulf Coast may be increasingly cost-effective; this would tend to reduce economic drawbacks of coastal siting. • Community desires for clean industry. • Possible PSD limitations and siting conflicts. • Difficulty obtaining offsets along Lignite Belt, if monitoring shows widespread "baseline" violation of ozone standard. • Industry uncertainty over regulatory postures, leading to hesitation over new ventures.

2.2.1 Cogeneration

Considering all these factors, it appears that concentrated development, involving several heavy industrial installations within a few miles of one another, would be favored by cogeneration. Cogeneration would help to make industrial parks more feasible under PSD, as well as adding to the economic advantage of mine-mouth location. Thus, it is possible to envision combined power plants and electricity-intensive industries, such as steel plants, using cogeneration. Similarly, it is possible to imagine large gasification plants with associated chemical plants, provided that their hydrocarbon emissions do not interfere with ozone standards. However, although complexes such as these might conceivably be built and operated within environmental limitations, very complex economic considerations unique to individual firms are also involved. It is beyond the scope of this study to examine any of these economic variables.

2.2.2 Fuel Cost

The most obvious advantage of the Lignite Belt for industrial siting is the much lower cost of lignite at the mine mouth. Currently, lignite shipped by rail to the Gulf Coast from East Texas would be worth almost exactly as much per million Btu's delivered as western coal and Illinois coal.[4] Using lignite at the mine mouth would reduce this cost by about a quarter. This advantage, as shown in Chapter II, is a major factor in expected heavy use of lignite by utilities at the mine mouth. While industrial facilities could do the same, it seems to be generally felt that lignite's real economic drawing card is the perceived reliability and cheapness of electric power generated by utilities with a long-term supply firmly committed. Dr. Benson[5] sees plentiful electricity as having the power to attract big power consumers such as carbon-arc steel manufacturing, aluminum refining, and other heavy industry. This view is shared by many Chambers of Commerce. Such a trend, however, would be more likely to be spread throughout the service territories of utilities with long-term lignite supplies than concentrated near the lignite itself.

2.2.3 Coastal Environmental and Resource Constraints

Currently, stringent air quality requirements, coupled with mandatory boiler-fuel conversion, are seen by many as a potentially serious constraint on future industrial growth.* Not only are many areas currently out of compliance with ozone standards, but recent efforts to obtain permits have revealed that the PSD increment for SO_2 in many places is partially or completely consumed. Thus, future siting will require offsets. The situation is complicated by the requirement contained in the National Energy Act for new facilities to shift from oil and gas toward coal.**

The extent of these limitations is imperfectly known to date because of limited monitoring. As PSD permits are sought for new sources, required background monitoring will reveal how widespread these problems are.

The potential power of this situation to induce new industrial facilities to locate away from the industrialized coastal zone depends on several factors which cannot yet be evaluated:

- Geographic extent of nonattainment of ozone standards and unavailability of PSD increment;

*See Chapter I, Section 2.1 for a discussion of this view, and Chapter V, Section 2.2, for an analysis of policies surrounding the issue.

**For a complete discussion of the mandatory boiler-fuel conversion provisions of this Act, and Texas' own regulations, see Chapter I, and Chapter V. This chapter assumes the reader is familiar with these policies.

- Long-term availability of offsets in industrial zones; and

- Administration of exemptions from mandatory boiler-fuel conversion.

It should also be pointed out that industries locating away from existing centers would not necessarily move inland as far as the Lignite Belt. Particularly for refineries dependent on access to ocean shipping, Mexico might prove an attractive alternative, especially if large quantities of Mexican natural gas become available.[6]

In addition to air-quality constraints, water supply may place increasing difficulties on siting new industrial facilities in the coastal basins. As is discussed at greater length in Section 3.1, below, these basins are among the most strained in the state.

2.2.4 Prevention of Significant Deterioration (PSD)

Prevention of Significant Deterioration (PSD) regulations can also be cited as a possible constraint to siting industrial facilities on the Lignite Belt proper. PSD limits the number of sites along the Lignite Belt that may be occupied by sources meeting proposed New Source Performance Standards. In Section 3.2 below, it will be shown that several new plants, not subject to these standards, as well as existing facilities not subject to PSD, will consume all or part of the increment for SO_2 over large sections of the North Central and Northeast Subregions--the richest in lignite reserves. These areas are also projected to experience the largest growth in both coal and mine mouth lignite power generation. Thus, by the turn of the century, offsets might be needed to site industrial facilities at the mine mouth or near it.

Potentially significant over a broader area than the Lignite Belt proper would be a need to obtain offsets for hydrocarbons. If, as some believe, oxidant standards are already widely violated in East Texas, refineries, petrochemical plants, or gasification plants might require offsets. It might be easier to obtain offsets in the industrialized coastal zone than in the relatively undeveloped areas near the Lignite Belt. Such a constraint would considerably reduce the attractiveness of siting new facilities inland from the coast. The choice of location, other factors being equal, would involve a tradeoff between the cost of offsets on the coast and strict emission control inland.

2.2:5 Gasification

If natural gas supplies continue to be restricted, and mandatory boiler-fuel conversion is strictly enforced, gasification could gain attractiveness as a means of burning coal or lignite cleanly in existing industrialized areas. Economies of scale favor large installations of 300 billion Btu/day or more for medium-Btu gas. Based on the comparative cost of shipping lignite versus medium-Btu gas, these plants may be most economically sited at the mine mouth, all other factors being equal. Plants this size might also justify co-location of certain chemical industries as well. For example, methanol and ammonia can be synthesized directly from low- or medium-Btu gas made from lignite. These two chemicals made up 25 percent of the output of Texas' chemical industry in 1975.[3]

Gasification plants might also prove difficult to site near the coast because of their air quality impacts. Large gasification plants could emit substantial amounts of fugitive hydrocarbons under normal operating conditions. Upset and start-up conditions might also result in significant short-term emissions. Currently, EPA favors hydrocarbon control as a major strategy to control the formation of ozone, of which many hydrocarbons are precursors.[7] The availability of offsets for a large new gasification plant might also become more of a problem as time passes. Long lead times for planning and financing would therefore increase the difficulty of finding coastal sites.

2.2.6 Infrastructure

One major drawback to industrial location along the Lignite Belt is its current lack of the kind of infrastructure found on the coast: large labor pools, a good rail network, and supporting industries and facilities. The affinity for areas with a well developed infrastructure is especially high in the chemical industry, which forms a highly interdependent complex. Labor supply is low in the Lignite Belt. A strong demand for additional workers would soon bring a response of in-migration, and large new industrial developments near communities already experiencing growth from utility exploitation of lignite could seriously overtax local government services and facilities.

A possible alternative to industrial siting on the Lignite Belt proper would be a trend toward siting at intermediate locations, closer to the industrially developed areas of the Gulf. However, as mentioned above, rail service in the area between the coast and the Lignite Belt is poor. At the same time, continued rapid rises in interstate rail tariffs on coal may make shipment of lignite to the coast more economically attractive.*

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*For a more complete discussion of rail tariffs, see Chapter II, Section 2.2.

2.2.7 Community Attitudes

Another possibly influential factor is the desire of some--but not all--communities to attract only "clean" industry. As lignite development impacts begin to be widely experienced, it is possible that this feeling may grow in intensity. As one Chamber of Commerce representative put it, "We're selling life-style here."

2.2.8 Availability of Oil and Gas

Finally, uncertainty over future availability of natural gas and oil can be expected to discourage any major siting trend in response to lignite. The current oversupply of natural gas is apparently widely perceived as a sign of things to come, at least in the short term. With large supplies of both domestic and foreign gas recently discovered, there is no widespread impetus to consider looking away from existing industrial centers. Such a move would be very risky in the face of potential new gas supplies becoming available.

2.3 Current Activity

At the present time, although many firms and more promoters are talking about future industrial growth along the Lignite Belt, there is too little concrete activity to identify a definite trend. Pulp and paper companies could use lignite, and one firm owns substantial acreage underlain by lignite. Most of the major chemical firms are investigating lignite, although few have made specific plans to use it at or near the mine. Texas Utilities has a Soviet *in-situ* gasification process under study. One Chamber of Commerce executive indicated that an industrial firm had expressed an interest in using lignite at the mine mouth as a boiler fuel. To our knowledge, however, no major mine-mouth industrial user has yet entered the permit-application stage.

2.4 Conclusion

For purposes of subsequent impact analysis, it has been assumed that lignite development does not include a major shift of industrial growth into areas near the Lignite Belt itself.

3.0 ANALYSIS OF CONSTRAINTS ON POWER PLANT SITING

The following sections present detailed discussions of the constraints placed upon power plant siting by water supply, air quality, flood-prone areas, the extra-territorial jurisdictions of cities and towns, geological factors, and distance from lignite deposits.

These factors impose costs directly, by constraining design and operation, the cost of sites, and the cost of raw materials. Delays induced by controversies over permits or water rights also add to the cost of siting. These factors may thus be said to have been internalized into the cost of building and operating a power plant, and affect the costs incurred by all potential developers.

The siting analysis conducted here is not an attempt to predict where plants will be sited. Rather, it is intended to show geographic variation in the degree of difficulty--measured in terms of costs and delays in permitting--likely to be encountered by a utility attempting to site a large, new generating station. Though developed specifically with lignite-fired plants in mind, essentially the same pattern of constraints applies to coal-fired plants. Removing the distance-from-lignite factor from the analysis does not materially alter the final pattern.

3.1 Water Availability as a Constraining Factor

Summary of Conclusions

- Calculations were made of aggregate water supply and demand by study-area subregion, based on planning data published by the Texas Department of Water Resources. Supply data included both existing and projected surface water development, as well as maximum potential use of groundwater. Demand figures used by TDWR were adjusted by substituting figures for energy-related demand appropriate to the development scenario of Chapter II.

- Based on these data, it appears that, considering supply and demand in the aggregate at the subregional level, more than enough water can be developed to supply the needs of the scenario along with other demands.

- New surface developments are critical to future adequacy of supply. Without them, supply deficits could develop by the year 2000 over most of the basins in the Southern and Central Subregions, as well as in the Trinity and the Brazos basins.*

- The process of increasing water consumption for energy development is likely to result in heavier demands on groundwater, both from direct use by energy and from displacement of surface water demand.

- Two potentially important demands on the study area's developable water supplies are not presently quantifiable. These are: freshwater inflows for bays and estuaries, as required by law; and future supplements to the dwindling groundwater supplies of the irrigated High Plains.

*Although apparent surpluses would remain in the Brazos basin, commitments by existing contract or water rights to coastal users would exceed these surpluses if all projected water projects are not built in a timely manner.

3.1.1 Selection of Data Base

In studies such as this, where the range and scope of various issues can become quite extensive, the data base used in the analysis should meet certain criteria in order to be acceptable. The criteria are completeness, consistency, accuracy, objectivity, and applicability. For the purposes of this technology assessment, water resources data compiled by the Texas Department of Water Resources met these criteria. In Section 3.1.6, below, comparisons are made with other published studies of water and energy.

As part of an ongoing process to update and revise the Texas Water Plan, the Department published a comprehensive two-volume report presenting an analysis of current water development and use in Texas along with projections of future water needs. The report, entitled Continuing Water Resources and Development for Texas,[8] "...identifies major water and water-related problems... actions currently underway to provide for part of Texas' present and future water needs, and presents a preliminary draft plan of development ... for meeting water supply and water-related needs in parts of the State through the year 2000."

3.1.1.1 Water Supply Data

The supply figures developed by the TDWR represent total amounts from three components: surface water, groundwater, and return flows. The surface-water component consists of the safe yield from existing and proposed reservoirs. The groundwater component consists of an amount equal to an aquifer's recharge rate plus an annual depletion rate based on that aquifer's recoverable storage volume (safe yield). Return flow represents that volume of water which is returned to surface waters after use.

One portion of the supply component, that amount from proposed reservoirs, is critical to subsequent sections of this analysis. If these reservoirs are not built, or if the construction of key reservoirs is delayed, then the water surpluses in certain basins would be greatly diminished or eliminated completely. The lead time for the construction of some of these reservoirs can easily take 10 to 15 years, depending on funding and possible opposition. The importance of this issue is addressed in more detail in Section 3.1.7 below.

In the following analysis, no constraints have been placed on water use relative to the quality of available water supplies. It is assumed that if the water is physically available, the water will be of sufficient quality to meet all needs. While this assumption may not be valid on a site-specific basis, it is generally valid given the existing quality of Texas' waters and the existing regulatory framework.

3.1.1.2 Water Demand Data

The primary components of water demand used by TDWR are municipal, manufacturing, steam-electric power generation, and irrigation. Municipal demand consists of the total amount of water distributed to a municipality, less any water sold to industries for use, and is based on population projections. Figures for manufacturing use are projected based on 1974 base-year demands by industry and include corrections for employment, labor productivity, recirculation practices, and technology changes.

TDWR steam-electric power generation figures for water demand are based on "actual plant design data" assuming that future additions to the system consist of equal proportions of nuclear and coal/lignite generation. Since 1974, a series of nuclear power plant cancellations has taken place, which makes this assumption appear too favorable to nuclear power. The TDWR steam-electric stations have accordingly been replaced by figures developed to match the assumptions of the lignite demand scenario.

Irrigation demands represent water drawn off for non-project irrigation. Thus, demand is a measure of required throughput, rather than consumptive use alone.

3.1.1.3 Typical Basin Figures

An example of the type of information used in the following analysis is given in Table 3-1, a supply/demand analysis for the Neches River Basin.

For the lignite development analysis, basin figures were recompiled according to the five subregions shown in

TABLE 3-1. WATER SUPPLY AND DEMAND SUMMARY ANALYSIS, IN THOUSANDS OF ACRE-FEET, NECHES RIVER BASIN*

Supply and Projected Demand	2000 Groundwater	2000 Surface Water	2000 Total	2030 Groundwater	2030 Surface Water	2030 Total
BASIN SUMMARY						
Firm Supply	78.3	1227.1	1355.4	92.5	1921.2 3/	2013.8
Import	-0-	5.7	5.7	-0-	11.2	11.2
Return Flows	-0-	146.3	146.3	-0-	418.9	418.9
TOTAL SUPPLY	78.3	1429.1	1507.4	92.6	2351.3	2443.9
In-Basin Demand	78.3	357.6 1/	435.9	92.6	816.7 1/	909.3
Export	-0-	430.3	430.3	-0-	517.6	517.6
SUBTOTAL DEMAND	78.3	787.9	866.2	92.6	1334.3	1426.9
Surplus/Shortage 2/	-0-	641.2	641.2	-0-	1017.0	1017.0
Project Irrigation Demand	-0-	-0-	-0-	-0-	-0-	-0-
Surplus/Shortage 2/	-0-	641.2	641.2	-0-	1017.0	1017.0

1/ - Requirements exclude mining and livestock needs, which can be met from local, unregulated supplies.

2/ - Shortages are indicated by parentheses.

3/ - Firm supply includes incremental yield of authorized Rockland Reservoir.

*From Continuing Water Resources Planning and Developments for Texas.[8]

Figure 1-1. This recompilation tends to average out some of the local variations in water supply and demand.

3.1.2 Analysis by Region (Recompilation of TDWR Estimates by Study Region)

3.1.2.1 Regional Supply and Demand

Based on the recompilation of TDWR estimates of water supply and demand by subregion, each subregion of the study area is projected to have a surplus of water in the year 2000, even after water for power production is accounted for. This analysis is shown in Table 3-2. The subregion with the greatest surplus based on this analysis is the Northeast, with 1,270

TABLE 3-2. TDWR SUPPLY-DEMAND FOR THE YEAR 2000, SHOWING NON-FIRM SUPPLY
(Units are thousands of acre-feet per year)

Subregion	Supply	Demand	Surplus	"Non-Firm Supply"*	Ratio of NF Supply To Surplus
Northeast	2,264	993	1,270	398	.31
North Central	2,582	1,931	651**	335	.51
Central	1,950	1,698	252	246	.98
Southern	858	694	164	477	2.91
Gulf Coast	7,732	6,965	350†	103	.29
Totals	15,386	12,281	2,687	1,559	.58

*"Non-firm supply" consists of water from reservoirs that have been proposed, but not yet built. Any delay or cancellation of such plans would affect this analysis.

**Approximately 586 thousand acre-feet per year of this surplus must be passed through to the Gulf Coast Subregion to satisfy existing water rights and contracts.

†Surplus may be greater than figure shown due to municipal return flows, and water passed through from the North Central Subregion.

thousand acre-feet per year surplus water remaining from a supply of 2,264 and demand of 993 thousand acre-feet per year. The smallest surplus projected occurs in the Southern Subregion and is 164 thousand acre-feet per year. The surplus for the Gulf Coast Subregion may be greater than the 350 thousand acre-feet per year indicated, because of municipal return flows not included in the TDWR analysis, and because of contracted surplus water from the North Central Subregion.

The distribution of water supplies is only considered, in this analysis, on a subregional basis. In the Gulf Coast Subregion, most of the supply comes from the eastern coastal basins. In order to distribute this supply throughout the subregion, some means of conveyance would be necessary. A major east-to-west distribution system has been proposed, but no firm plans have been made.

3.1.2.2 "Non-Firm" Supply

Also shown in Table 3-2 is that portion of water supply projected for each area which is comprised of water from reservoirs that have been proposed but not yet built. This "non-firm" supply can be quite significant, as illustrated by an examination of the supply/demand figures for the Southern Subregion. Of the 858 thousand acre-feet per year (TAF/y) in projected water supply, 477 TAF/y are from reservoirs not yet built. Obviously, any cancellation, interruption, or delay in the construction of these reservoirs would significantly alter the long-term supply/demand picture for the subregion. Even in the subregion least dependent on this non-firm supply, the Gulf Coast, 29 percent of the surplus of 350 TAF/y, or 103 TAF/y, consists of non-firm sources of supply.

3.1.3 Revised Steam-Electric Water Demand Figures

The water demand estimates in Table 3-3 show consumptive water demand figures for the various energy facilities considered in the development scenario. These figures do not include water that is taken in, used, and released again. Throughput varies with plant design. In general, the need to clean up waste streams has led to a trend toward recycling them for in-plant use. Thus total water withdrawals for new plants are tending to go down, with consumptive use a greater portion of the whole. While there are significant regional and technological variables which ultimately determine the amount of water consumed by any given power plant or mine/plant complex, these figures are reasonable estimates for the purposes of this analysis.

TABLE 3-3. TYPICAL PLANT WATER REQUIREMENTS

Technology	Size	Water Demand AF/y*
Lignite Mine & Power Plant	500 MWe (unit) 1,500 MWe (plant)	7,815 23,450
Coal-Fired Power Plant	500 MWe 1,500 MWe	7,567 22,700
Nuclear Power Plant	500 MWe 2,000 MWe	9,625 38,500
Medium-Btu Gasification	0.2 Quads	18,400

*Acre-feet per year, estimates by Radian staff.

The consumptive water demand figures for the lignite mine and power plant configuration include mine-related demands, cooling, and make-up water at the power plant. The coal and nuclear demand figures include cooling and make-up estimates, while the medium-Btu gasification figures include all uses. In the case of a mine-mouth, lignite-fired power plant, more than 80 percent of the water consumed is required for power plant cooling.

These technology-based water demand estimates were matched with projected steam-electric demand figures for each study region to produce a new subregional analysis of water demand as indicated in Table 3-4. These new demand figures replace those developed by TDWR.

TABLE 3-4. YEAR-2000 STEAM-ELECTRIC WATER DEMAND ESTIMATES BY SUBREGION

	Number of 500 MWe Units			Medium-Btu Gasification	Water Demand
Subregion	Coal	Lignite	Nuclear	Quads	TAF/y*
Northeast	6	32	0	.2	314
North Central	4	20	0	.2	205
Central	7	3	4.6	0	121
Southern	0	6	0	0	47
Gulf Coast	12	1	6.9	0	165
Totals	29	62	11.5	.4	852

*Thousand acre-feet per year.

The Northeast Subregion has the greatest projected need for water to satisfy future energy demands, with a 314 TAF/y consumptive water demand. Next greatest in terms of water demand is the North Central Subregion, with a projected water demand of 205 TAF/y, followed by the Gulf Coast, Central, and lastly the Southern Subregion.

3.1.4 Updated Water Supply/Demand Analysis

The new estimates of steam-electric water demand, when substituted for the 1974 TDWR figures, yield the analysis shown in Table 3-5. On a state-wide basis, the two estimates of year-2000 steam-electric water demand are quite close. In 1974, the TDWR, then the Texas Water Development Board, projected a year-2000 steam-electric water demand of 909 TAF/y statewide. This is in substantial agreement with the 852 TAF/y estimate generated by the revised analysis. On a subregional basis, however, some differences do occur. The siting analysis figures indicate a shift in steam-electric water demand from the Central and Gulf Coast Subregions to the Northeast. This is illustrated by the significant decrease in water demand in these two subregions and the increase in water demand from 159 to 314 TAF/y in the Northeast Subregion. The projected water surplus figures do not differ significantly in the two analyses, with the largest differences occurring in the subregions with the largest surpluses.

TABLE 3-5. YEAR-2000 STEAM-ELECTRIC WATER SUPPLY/DEMAND ESTIMATES BY SUBREGION, TAF/y*

Subregion	TDWR Surplus	TDWR Steam-Electric Demand	Revised Surplus	Revised Steam-Electric Demand
Northeast	1,270	159	1,115	314
North Central	651**	281	727**	205
Central	252	214	345	121
Southern	164	41	158	47
Gulf Coast	350	214	399	165
Totals	2,687	909	2,744	852

*Thousand acre-feet per year.

**Existing contracts and water rights require that 586 TAF/y of this surplus be passed through to the Gulf Coast Subregion.

The conclusion to be drawn from this analysis is, therefore, that surface and ground water supplies more than sufficient to meet the year-2000 consumptive water demand of the development scenario can be made available at the subregional level. This means that if planned and proposed water projects are implemented in a timely manner, the aggregated supply in each subregion should be enough to meet all projected aggregated needs, including consumptive water use for energy.

The word, "aggregated" is important, however. Considering water supply and demand at the level of the subregion necessarily assumes that there is no insurmountable problem of distribution within the subregion; in other words, that water is either fairly equally available everywhere within it, or can be made so without undue expense or difficulty. This assumption, although needed to simplify the analysis, is not equally valid for all subregions. In particular, the Gulf Coast Subregion's surplus is mainly in the northeastern portion of the subregion; extensive diversion works would be needed to distribute this surplus through the entire subregion. In order to obtain a better focus upon such geographical discontinuities, supply was reconsidered at the level of river basins and subbasins.

3.1.5 Water Supply and Siting

In the case of an actual proposed power plant, detailed engineering studies would be made concerning the availability of a suitable water supply. These studies would examine the amounts of water available, the "timing" of this availability, the question of water rights, and engineering options for optimizing the water system selected. Such detailed studies are beyond the scope of this present study, but an effort was made to look at water as a constraint on a subbasin basis. The following method was used in this analysis:

- Using TDWR data base values for the year-2000, compute the following by subbasin:

Total Supply = Supply - (Demand + Steam-Electric Demand)

Area of the Subbasin

$$\text{Water Supply Density} = \frac{\text{Total Supply (TAF/y)}}{\text{Area (100 sq. miles)}}$$

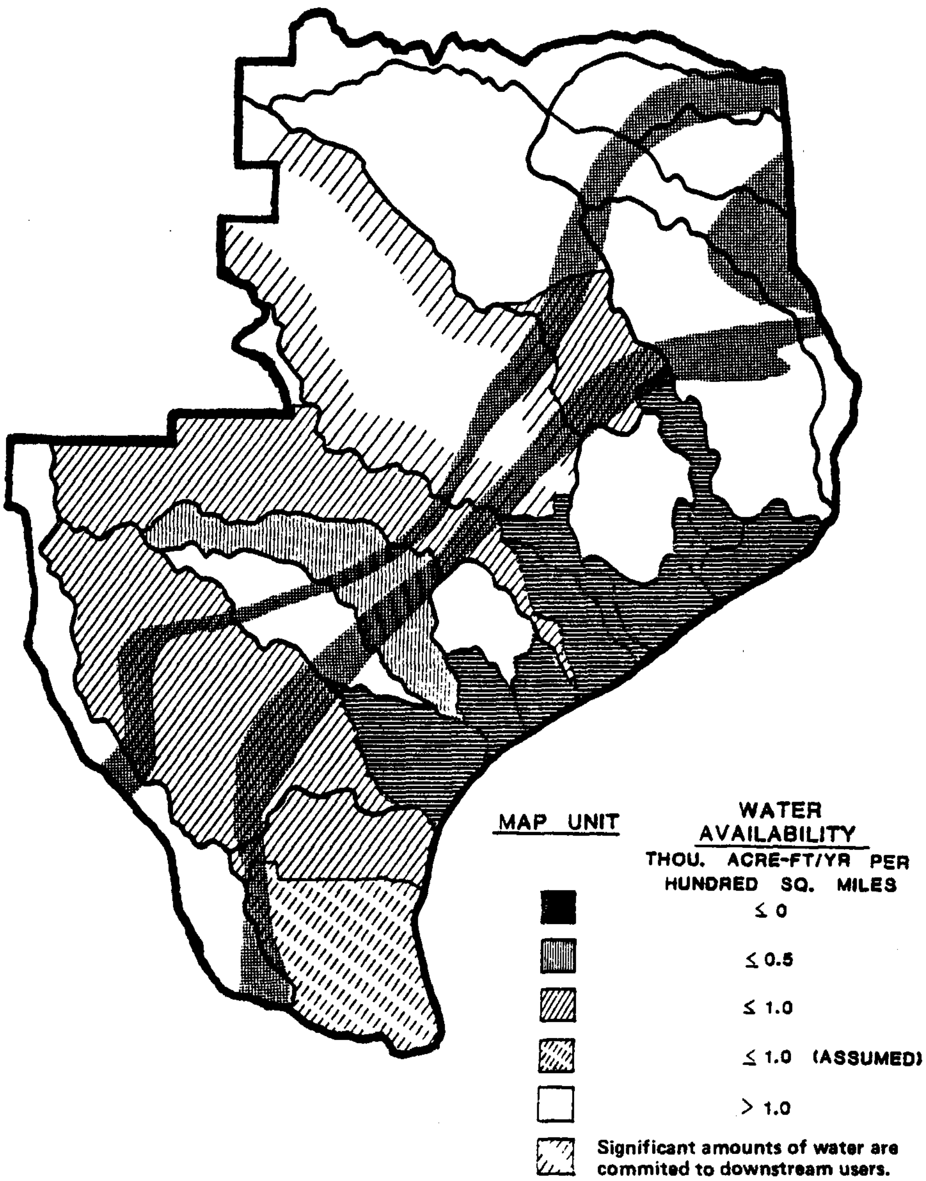
- Map the values by subbasin and water supply density based on the following arbitrary criteria:

≤ 0, ≤ 0.5, ≤ 1.0, and ≤ 1.0

The results of this analysis are shown in Figure 3-1. The selection of the mapping units is somewhat arbitrary and meaningful to the extent that it allows a comparison of water supply amounts on a subregional basis.

3.1.6 Comparison with Other Studies

Several recent studies at the national level have focused attention on the potential conflict of energy development with water supply. The National Academy of Sciences' Committee on Nuclear and Alternative Energy Strategies has recently completed studies which conclude that "there is a high probability that freshwater supplies will significantly constrain the



WATER AVAILABILITY AS A CONSTRAINING FACTOR IN SITING
Fig. 3-1 02-4305-1

growth of energy in the U.S."[9] Oak Ridge National Laboratory reached a similar conclusion in an evaluation of the effects of the proposed National Energy Plan.[10] Figure 3-2 shows where this study projects water supply problems in 1985, considering demands from all sectors. Over most of Texas, this study shows that potentially all or nearly all of the "Critical Surface Supply" could be consumed even at this early date. The situation in the year 2000 would be even more serious. Yet another nationwide survey of surface water supply and demand, conducted for the Utility Water Act Group (UWAG) by Espey, Huston and Associates, Inc.[11], reached the conclusion that demand for water currently exceeds "dependable" surface water supply over most of Texas.

At first glance, these studies appear to contradict the conclusions drawn here, on the basis of planning information developed by the Texas Department of Water Resources. These studies, however, used very different methods of calculating "supply," which resulted in substantially lower estimates than those in the basin-by-basin studies reported by TDWR. Also, none of them attempted to account for new surface water supply development or transfers within and between basins, a very substantial consideration in TDWR's figures.

CONAES, Oak Ridge, and Espey, Huston all calculated supply as some proportion of low flow, averaged over large areas. CONAES based their estimates on 7-day, 10-year low flow and evaluated potential water consumption from energy development as a fraction of this value. Use of flow statistics creates unavoidable problems, although it is the only method of obtaining a nationwide supply estimate on a consistent basis. First, not all records span the same period. Rivers with short periods of record may show unrealistic values for statistical measures of low flow. Second, new on-stream impoundments are continually being built for flood control and water supply.

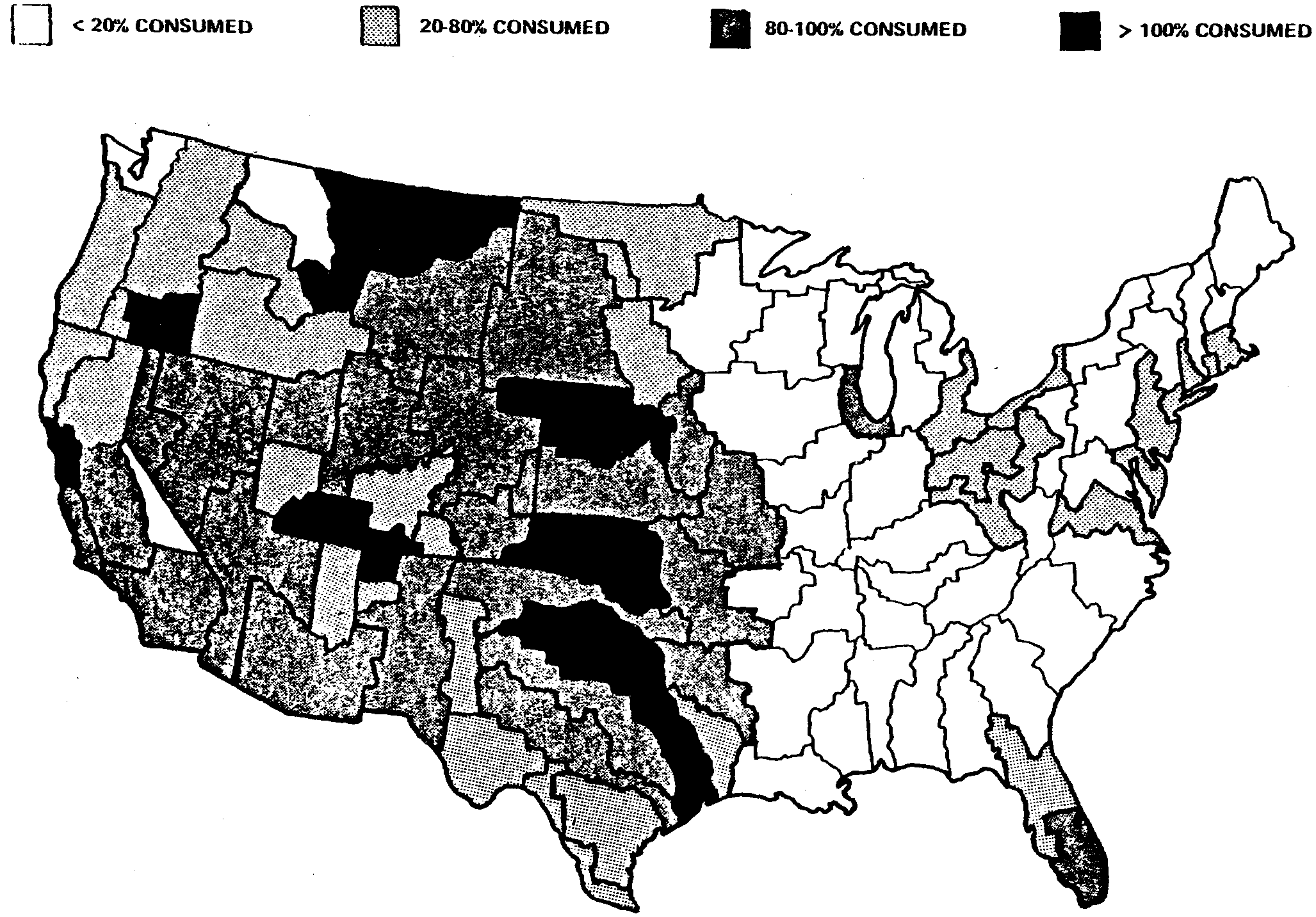


Figure 3-2. Critical Surface Supply.
Source: Oak Ridge National Laboratory

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Their operation can greatly alter flow regimes, and tend to increase low flows. Old records do not account for these changes, and low-flow statistics may be obsolete. Future impoundments thus not only increase supply by storage, but affect flow-derived estimates by stabilizing discharge regimes.

The CONAES study also assumed that substantial amounts of synfuels made from coal might be needed to replace dwindling supplies of oil and natural gas, and linked water supply problems to the added water demand of these industries over and above that of mining and conventional combustion. It did not count groundwater as part of the total water supply. Although few large energy facilities would actually use groundwater directly, surface water can be displaced from other users and made available to energy industries if groundwater is substituted. Thus, omission of this source of supply has a considerable influence on the results.

The Oak Ridge study computed surface supply on the basis of Water Resources Council Aggregated Sub-Areas (ASA's). Two measures were used. On a national level, each ASA's supply was considered as the surface outflow with a 95 percent chance of being exceeded in critical supply months. This "Critical Surface Supply" was corrected for current storage and management practices. A second measure, used in a more detailed look at federal Region VI, estimated water supply available to energy as 10 percent of the 7-day, 10-year low flow. Groundwater was included in supply calculations, but in basins with existing depletion problems, use was frozen at 1975 levels. This was the case in most Texas basins.

Despite their conservatism, however, these studies point to the importance of developing new supplies in Texas. They may be taken as evidence that the time frame for such development is not long. If existing supplies appear incapable of supporting anticipated consumptive use, at low-flow periods, as soon as 1985, then small delays in implementing supply projects are obviously significant. These projections of supply problems also serve as a signal for potential heavy increases in groundwater demand, which would be intensified by failures to develop surface supplies. Figure 3-2 can thus be construed broadly as a map of potential future groundwater demand, and possibly of depletion problems, for the next decade.

3.1.7 Sensitivity of Key Water Supply Policies

The conclusions that a water supply adequate for the entire development scenario may be made available depends upon the maintenance of a delicate and sensitive equilibrium. For sufficient supplies of water to be available for energy development at any particular time, three sources must contribute simultaneously:

- New surface water development,
- Groundwater pumping (mainly replacing surface water for other uses), and
- Water rights conversion, from other beneficial uses to steam-electric power generation.

If energy's total demand is thought of as growing at a given rate, corresponding to growth in consumptive demand, then it is clear that if the contribution from one source is restricted, the other sources must supply still more.

In practice, as demand grows, the balance between sources will not always be the same. The nature and extent of the problems that accompany the process of supplying energy's needs will be determined by the degree to which the three sources balance one another. Should any one of them be unduly constrained, then pressures on the others may result in both economic and environmental stress.

That these needs will be met is assumed, since in Texas law the only beneficial use with priority over industry (including steam-electric power production) is municipal water supply. Growth in municipal demand as projected by the Texas Department of Water Resources is not large enough to compete seriously with industrial requirements.

3.1.7.1 Policy Constraints on Timely Development of Surface Water Supplies

Table 3-2 illustrates the significance of new surface water development in the five subregions of the study area, by the year 2000. As seen in the table, new supplies (planned or recommended by TDWR) account for a significant percentage of projected surpluses in the North Central and Central Subregion, while in the Southern Subregion there would be a considerable short-fall without new development.

Looking at a finer scale, Table 3-6 shows those individual basins in which projected surplus in the year 2000 is less than new development, or in which a deficit is forecast. The accompanying map (Figure 3-3) shows their locations.

Many of the new reservoirs included in TDWR's supply projection are not yet authorized or funded. Construction delays or cancellations could considerably strain water supplies in several basins.

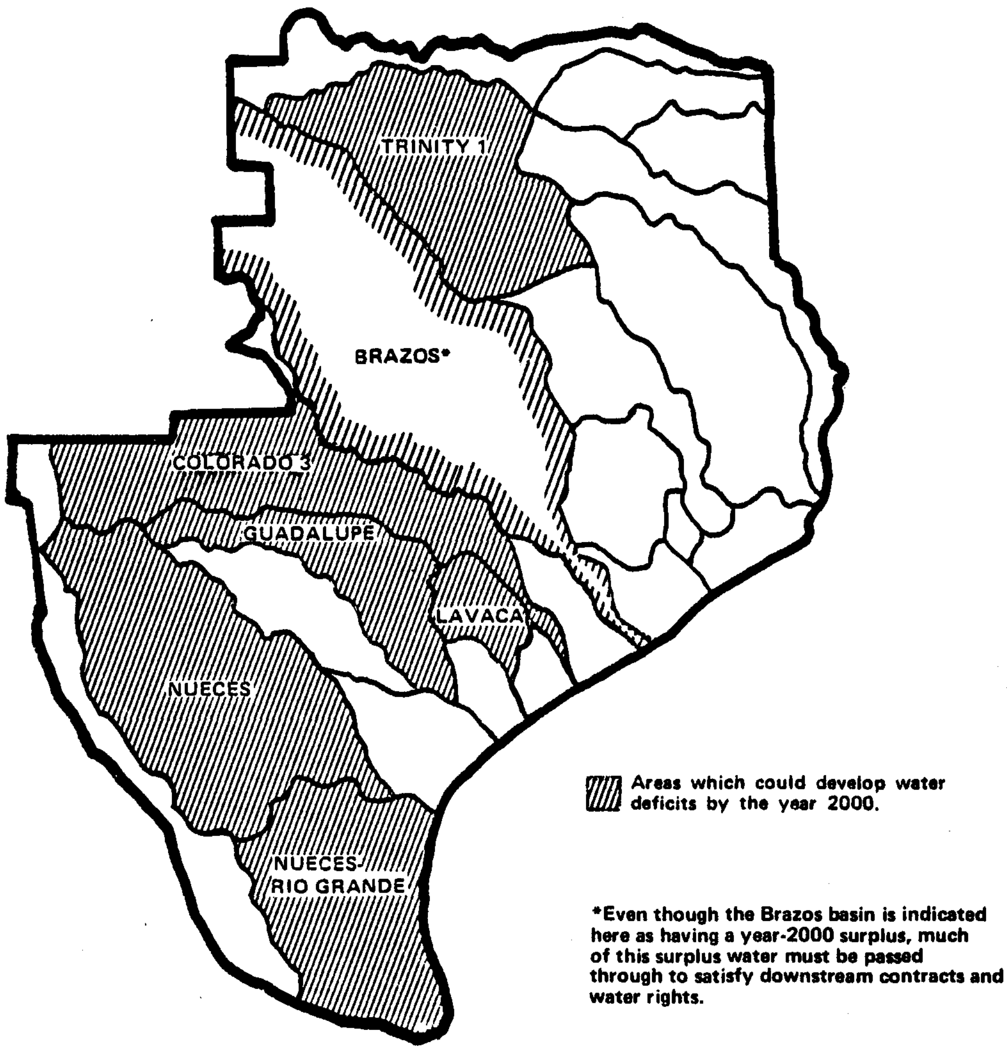

Figure 3-3. Year 2000 Critical Basin Segments.

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TABLE 3-6. CRITICAL BASINS

Basin and Segment	Surplus (Shortage)	New Development
Trinity 1	64	191 (Richland Creek*)
Colorado 3	86	151 (Columbus Bend*)
Guadalupe	(6)	58 (Ingram*, Cloptin Crossing**, Lockhart*)
Nueces	75	252 (Choke Canyon**)
Nueces-Rio Grande 1	89	225 (Choke Canyon**)
Lavaca	36	75 (Palmetto Bend**)

*Needed but not authorized.

**Authorized federal project.

Funding and participation from federal agencies, as well as the Texas Department of Water Resources, will be necessary to bring all of the needed projects on line. Recently, however, the federal water agencies have been requiring more state and local participation in funding, increasing the price of water to users, and looking harder at non-structural alternatives to flood control. Recent presidential vetoes of reservoir appropriations and attempts by the Executive Branch to develop a more restrictive national water policy also suggest a trend toward a reduced federal role. At the same time, the TDWR lost its last bid to increase bonding authority from $400 million to $800 million, and "Proposition 13 fever" will certainly result in generally greater scrutiny for publicly funded projects. Opposition to specific reservoirs on environmental grounds, or because of land use conflicts, can also slow surface water development.

These issues, and potential alternatives for assuring adequate water supply, are discussed at greater length in Chapter V.

3.1.7.2 Water Rights and Surface Water Distribution

Most of the water needed to support lignite mining is expected to come from local surface and groundwater sources.[12] Utility and industrial boilers, and gasification plants, however, require substantially more water to meet their cooling requirements. Typically, cooling will be provided by wet towers or by ponds. An off-stream cooling pond sized appropriately for cooling a large installation may not be able to impound enough water through runoff to supply consumptive needs. The remainder must be made up by water brought in from a main-stem reservoir,

3.1.7.3 Water Rights Doctrine

Texas currently recognizes both riparian and appropriative water rights. Riparian rights are limited to a "reasonable use" of the base flow of streams. The use of riparian rights is generally limited to domestic use, livestock watering, and irrigation.[13] Appropriative rights apply to flood flows, and base flow not under riparian rights. Statutory priorities were established by the Wagstaff Act of 1931, giving the order in which needs for different beneficial uses are to be met in appropriating these supplies. These are, in order:

1) Municipal supply,

2) Industry and manufacturing, including non-hydroelectric power generation,

*San Miguel Station, in Atascosa County, is designed to use groundwater for cooling tower makeup.

3) Irrigation,

4) Mining, oil and gas extraction,

5) Hydroelectric power,

6) Navigation, and

7) Recreation and pleasure.

These priorities are to be applied in cases of dispute and during water shortages. They do not affect the granting of permits which are not contested. The key concept behind these priorities, and reflected throughout the body of case law, appears to be that water should be allocated to the most economically efficient uses, after basic domestic needs have been met.

Water impounded by reservoirs is appropriated to the operator of the reservoir in the same manner as direct withdrawals. Authorizations are made of proportions of the usable supply for various beneficial uses. Viewed in the aggregate, authorizations for municipal uses comprise the largest proportion in existing reservoirs, followed by industry, irrigation, and mining.[12] The operator of the reservoir is free to contract with individuals to supply needs within the authorized beneficial use categories, at a price mutually agreed upon.

Except for municipalities, appropriations may not be made in excess of need, anticipating future use.[13]

3.1.7.4 Water Rights Adjudication

The pressure of a dual water-rights system in Texas creates administrative confusion, which grows more significant as pressures on water supplies increase. To correlate the two doctrines, the Legislature passed the Water Rights Adjudication Act of 1967. Its purpose is the clarification of the very uncertain water rights held under the riparian doctrine, and the eventual merger of the two doctrines into a single permit system. Claims on any basis are collected for each basin, and evaluated case by case by the Texas Water Commission. Those judged valid are granted a certificate which states the quantity of water which may be used. The adjudication process is expected to be complete by the mid 1980's. As it proceeds, the Commission is attempting to cancel unused appropriation permits.*

After adjudication, however, some streams may still be over-appropriated, since the new certifications will be based on maximum use in a given period. All users will not have actually made these maximal withdrawals at the same time. A second round of cancellations may follow adjudication. All told, it is estimated that water freed up in this way could total upwards of 25 percent of the available supply, in some basins.[12]

3.1.7.5 Current Uses of Surface Water

Figure 3-4 indicates the relative amounts of surface-water resources now used for different types of demands within the various basins. Generally, a much higher percentage of total demand goes for irrigation in the more southerly basins. Towards the north, where the bulk of the highest quality lignite is found, manufacturing and municipal uses predominate. In the central portion, municipal and agricultural uses generally dominate the total demand. Mining uses very little of the total water supply. Power generation uses large quantities in the Trinity and Guadalupe basins. In the Guadalupe basin,

*A 1971 Supreme Court Decision, Texas Water Rights Commission vs. Wright, establishes the right of administrative cancellation of permits after 10 years of continuous non-use.

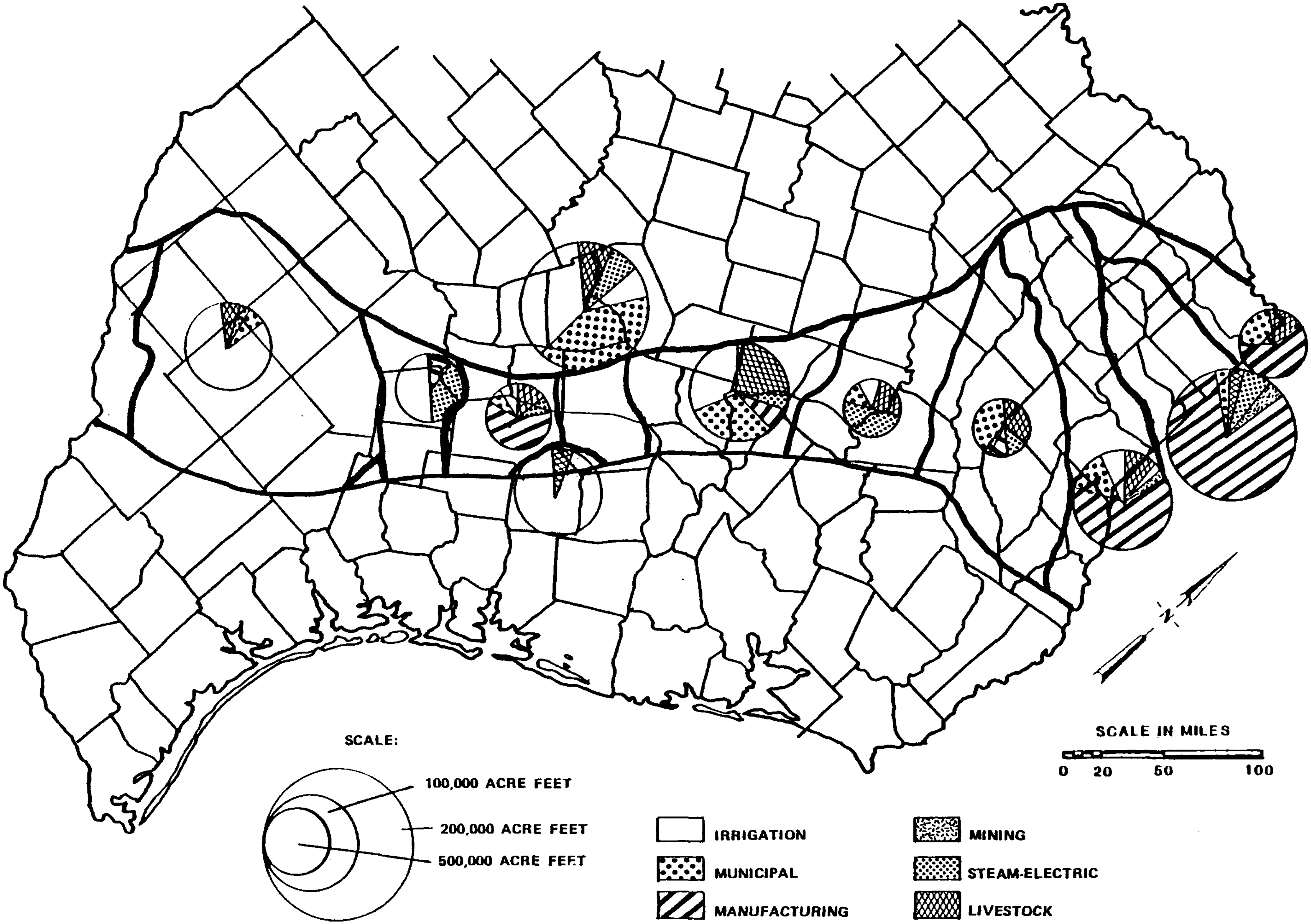

Figure 3-4. Surface Water Use

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most of this water is used to generate hydroelectric power. In the Trinity basin, however, the entire amount goes to cooling.

In comparison to streams of the eastern United States and to even the main streams of the western United States, the numerous rivers that drain the Texas coastal plain are relatively small. This means that an incremental increase in demand, such as could result from lignite development, can have a large impact on flow patterns. It also means that rising overall demand potentially affects all the users in the basin.

Where the surface water resource is almost completely allocated, particularly on those streams in the southwestern extension of the Lignite Belt, continued growth in surface-water use will require additional conservation measures and wider application of water re-use. Water re-use has already begun to expand in industry, under economic pressure. Especially for individual large users, recycling and re-use can produce significant economic benefits. Consequently, those basins where manufacturing is a dominant water use may be in a better position to adjust to lignite-related increases in water demand than other basins. Use patterns in the agricultural sector, especially in irrigation, are harder to shift than industrial ones, in part because of the large capital expenditures required for equipment. Individual farmers and ranchers may have more difficulty financing newer, water-saving technologies than industrial operations. Municipal demand is very difficult to curtail, largely because there are few opportunities to conserve enough water to have basinwide significance. Also, many individual household decisions are needed to produce a measurable demand reduction. Figure 3-4, therefore, suggests that the greatest potential flexibility in water use patterns probably exists in the northern part of the Lignite Belt. Fortunately this coincides with the greatest expected development of the resource.

3.1.7.6 Transfer of Water Rights

Given that little if any surface water remains to be appropriated in Texas, new energy industries will have to obtain most of their surface water needs either by contract from large reservoirs or by purchase and conversion of water rights.* It appears likely that the net result of this trend will be the transfer of water out of agricultural use and into the higher-priority industrial use.

Both riparian and appropriative rights may, with administrative approval, be severed from the lands on which the water was originally used, and sold to other persons for use on other lands.[13] Riparian rights, however, remain limited to domestic, livestock, and irrigation use. Appropriative rights may be converted to a new beneficial use, if approved by the Water Commission. Thus, the division of beneficial uses in the current body of appropriative rights appears the more likely to experience significant changes as a result of energy development.

The economic return from the use of a unit of water for agriculture is as much as an order of magnitude less than that from its use in power generation or other energy activities. This means that if demand for water grows faster than supply, agriculture will be less able to keep up with increases in its value. Industries capable of more economically efficient use of the water supply will be able to pay high prices in competition for contract water, and to purchase water rights from less efficient agricultural users. Unless efforts are made to interfere, the economic system, which by itself tends to allocate

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*Construction of an off-stream cooling impoundment requires a permit to appropriate and impound runoff, but quantities supplied by runoff will typically be only part of the total make-up required.

resources most efficiently, will allow the gradual shift of water away from the agricultural sectors.

Publicly owned power companies may occupy a unique position with regard to competition for water supply. Municipalities are granted by statute the right to make appropriations from streams other than the Rio Grande "which will supersede appropriations already made...for other purposes."[13] State agencies generally can condemn water if a fair price is paid, and this right might extend to water supplies for power production.[14]

3.1.7.7 Uncertain Future Demand Factors

In addition to existing and projected demands for surface water, two potentially large additional demands could further stress water availability: freshwater inflows to bays and estuaries, and transfers of water to the High Plains irrigated agricultural region.

Some quantity of freshwater inflow is required to sustain ecosystem productivity in bays and estuaries. Regulatory agencies are now required to evaluate water withdrawals and reservoir regulation with respect to ecological effects on the estuaries. The data base for this evaluation, however, is only in the formative stages. The Texas Department of Water Resources has been charged by the Legislature to prepare a detailed report on estuarine freshwater inflow requirements by December of 1979. Once these inflows are quantified, they must be reserved from other uses. The Legislature will determine what priorities these inflows will have relative to other uses. In order to assure these inflows, the state may have to condemn and purchase existing rights, or condition their use on maintenance of required instream flows.

The rapid depletion of the Ogallala Aquifer, source of irrigation water for the highly productive High Plains area, is a growing concern to water planners. Attempts to plan an interstate diversion of water from the Mississippi have already been made and discarded because of the extremely high cost and potential inequities of cost distribution. Potential imports from Arkansas are currently being discussed,[8] but plans are far from consummation. Thus, it is not unreasonable to consider the possibility that planners might turn to East Texas as a possible source of water for the High Plains.

The economic stakes may be very high. The High Plains supplies 20 percent of the nation's cotton, 25 percent of its grain sorghum and 5 percent of its wheat. Demand for these commodities is relatively inelastic, such that a decrease in supply is met with a more than proportional increase in price. Without imports of water, TDWR calculates that irrigated acreage will have declined by more than 40 percent in the year 2000.[8] The economic impacts of such a reduction in productivity could be felt nationwide. The amounts of water needed to avert it total to millions of acre-feet annually.

The High Plains situation potentially affects lignite in two ways. First, about three-fourths of the runoff in Texas originates in the eastern quarter of the state,[15] making it a prime potential candidate for intrastate transfers. Second, very large amounts of electric power would be needed to raise the needed millions of acre-feet of water several thousand feet in elevation between East Texas and West Texas. This need would also apply to water from outside the state. The result would not only be potentially larger demands on lignite to generate the power, but significant increases in cooling water demand as well.

3.1.7.8 Indirect Pressures on Groundwater

The consumptive use of groundwater from all of the aquifers in the lignite trend is shown in Figure 3-5, according to the various surface drainage sectors. Generally, where surface supplies and usage are relatively large (Figure 3-4), groundwater use is small, and vice versa. Irrigation use is concentrated in the southwestern part of the trend, and virtually no groundwater is now used for steam-electric power generation. With institutional and economic constraints on surface-water development increasing and with potential additional pressure on surface water from freshwater inflow allocations, the relative proportion of the total water demand that is met by groundwater is likely to increase.

Groundwater is considered a property right, and can be taken without limit from under the land on which it is found. It can likewise be freely sold or transported for any beneficial purpose. Currently, the only means of controlling pumpage rates is by the formation of a Groundwater Conservation District. This process is complex and must be approved by a regional election. Consequently, only a few have been formed in the High Plains and in areas near Houston affected by subsidence and saltwater intrusion.

The result of this lack of regulation has been the development of widespread depletion problems. In the Lignite Belt, the Carrizo and the Trinity Group Aquifers have already been affected. Increased drawdown increases pumping costs, and may also result in quality problems.[12] Over the long run, uncontrolled pumpage depletes long-term storage and reduces future availability to the amount that is recharged each year.

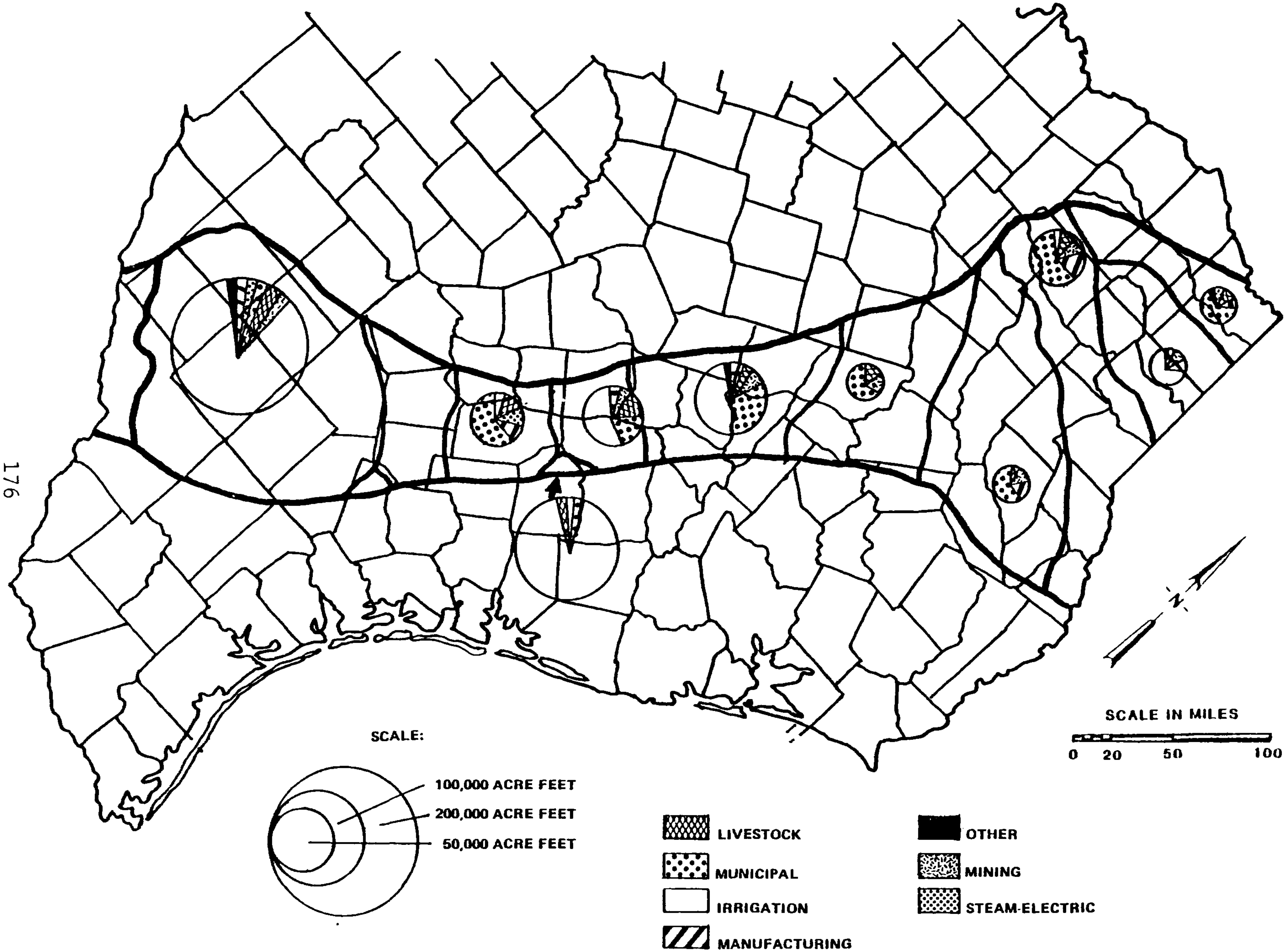

Figure 3-5. Groundwater Use

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Given its essentially unregulated status, groundwater offers a limited "cushion" in the event that surface water supplies are constrained. Those users which would suffer most would be those whose groundwater supply is completely depleted, or whose pumping costs were increased by drawdown beyond the point where economic returns justify the cost. For the reasons cited in the previous section, agriculture is again likely to be the most strongly affected.

3.2 Air Quality as a Constraining Factor

Summary and Conclusions

- The minimum allowable distance between new emission sources is jointly determined by New Source Performance Standards (NSPS) and the available PSD increments.
- The analysis presented here used SO_2 as an indicator pollutant to estimate minimum new-source spacing.
- If the SO_2 increment is fully available, it is estimated that under proposed NSPS, new 1500 MWe lignite-fired power plants could be sited as close as 20 km apart.
- In many areas along the coast, and in the eastern portion of the Gulf Coast Subregion, existing sources may impose moderate to severe siting constraints. Further constraints might develop from efforts to preserve high standards of air quality in and around the Big Thicket and the East Texas National Forests.
- In spite of these constraints, more than an adequate number of sites, separated by a minimum distance of 20 km, can be found in each subregion to accommodate all scenario power plant activity.
- Pending decisions on strategies for allocating the PSD increments could have an impact on "packing" of new sources. In general, economics-based methods improve packing.

3.2.1 Air Quality Regulations That Constrain Plant Spacing

Current policy for the prevention of significant air-quality deterioration (PSD) approaches the problem from two directions, with standards both for areawide increments of allowable deterioration and for emissions from new sources. The PSD increments in effect refer to emission densities. An acceptable density--one which does not allow the increments to be exceeded--can be achieved both by emission control and by source spacing. Emissions must meet New Source Performance Standards set by EPA. Given these emission levels, minimum source spacing is effectively set by the requirements of PSD.

The following discussion relates proposed NSPS to lignite- and coal-fired power plants, and sets forth the methods by which compliance of a new source with PSD is assessed. Then, in the following section, these methods are used in a hypothetical example to estimate a minimum distance by which the new plant called for in the scenario must be separated. The availability of the full PSD increment is evaluated over the study area, and the extent to which siting might be constrained is evaluated. Finally, in the last section, current uncertainties in policy are evaluated as they affect new-source spacing.

3.2.1.1 New Source Performance Standards

Emissions from a new power plant must meet applicable New Source Performance Standards (NSPS). EPA has not yet completed promulgation of revised New Source Performance Standards (NSPS) for fossil-fired steam electric plants, which are required by the Clean Air Act Amendments of August, 1977.

The Amendments dictate that NSPS require a maximum allowable emission rate and a percent reduction of a particular pollutant from an uncontrolled emission. At this time EPA is proposing that the maximum allowable emission rate for SO_2 would be 1.2 lb/MM Btu (same as the current standard) and an 85 percent removal efficiency. The removal efficiency requirement would be waived if emissions of 0.2 lb/MM Btu or less could be achieved with a lower removal. EPA's current interpretation suggests that the removal efficiency is to be based on emissions without controls versus emissions with the proposed control device; therefore "credit" cannot be taken, for example, for sulfur retention in the ash.

To determine the effect of these proposed standards on lignite-fired generating stations, a "typical" quality of lignite was derived from data presented in Radian's earlier Environmental Overview of Future Texas Lignite Development.[3] Five grades of lignite were identified in that report, based on ranges of heating value, sulfur content and ash content. For this application only sulfur content and heating value were used. A single heating value and sulfur content was selected to represent each grade of lignite conservatively. This conservatism entailed using a heating value lower than the average of the range and a sulfur content higher than the average of the range.

Given the assumed plant conditions (three 500 MWe units and heat rate = 10,000 Btu/kwhr), the typical fuel quality, using EPA emission factors for SO_2,[16] and assuming 85-percent scrubber efficiency, the SO_2 emission rate for each grade of fuel could be calculated.[17] The ranges of heating value and sulfur content, assumed coal characteristics and calculated SO_2 emission rate for each of the five grades of lignite are presented in Table 3-7.

TABLE 3-7. ESTIMATED SO_2 EMISSION RATE FOR 1500 MWe ELECTRIC GENERATING STATIONS, FIRING LIGNITE OF VARIOUS GRADES

Grade[1]	Heating Value[1] Range (Btu/lb)	Sulfur Content[1] Range (%)	Assumed Heating Value (Btu/lb)	Assumed Sulfur Content (%)	Calculated SO_2[2,3] Emission Rate (lb/hr)
1	7000-7500	<1.0	7200	0.8	3750
2	7500-8000	1.0-1.5	7700	1.3	5698
3	6500-7000	1.0-1.5	6700	1.3	6549
4	<7000	1.5-2.0	6900	1.8	8804
5	<6500	1.5-2.0	6200	1.8	9798

[1]From An Environmental Overview of Future Texas Lignite Development.[3]

[2]Plant conditions assumed: 1500 MWe (three 500-MWe units)
Heat rate = 10,000 Btu/kwhr
Total Heat Input = 15,000 x 10 Btu/hr

[3]Assumes EPA AP-42 factors.

The calculated emissions in Table 3-7 are less than 18,000 lb/hr (1.2 lb/MM Btu) and more than 3000 lb/hr (0.2 lb/MM Btu). Thus it appears that the proposed requirement for 85 percent removal efficiency is the more restrictive of the two standards.

3.2.1.2 PSD Increments

The Clean Air Act Amendments of 1977 establish allowable increases (or "increments") in ambient air pollutant levels above "baseline concentrations" for each of three area classifications (Class I, II, or III). These classifications are generally based on the increase in pollutant-emitting industries considered acceptable. The floor for each class is the baseline concentration level and the ceiling is the NAAQS.

At the present time, increments exist for two pollutants - total suspended particulates (TSP) and sulfur dioxide

(SO_2). Table 3-8 gives these allowable increments and a brief description of the area classifications. With the exception of two areas in west Texas (which are Class I areas), the entire state of Texas has been designated Class II.

TABLE 3-8. PSD CLASSIFICATIONS

Class	Type of Area	Industrial Potential	Allowable Increments Averaging Period	SO_2	TSP
I	International parks; national parks; monuments; wilderness areas; etc., and other areas designated by each state.	Little or no growth of pollutant-emitting industries	Annual[1] 24-hr max 3-hr max	2 5* 25*	5 10* none
II	All areas not classified I or III.	Moderate growth of pollutant-emitting industries	Annual[1] 24-hr max 3-hr max	20 91* 512*	19 37* none
III	Areas with heavy industrial concentrations, or where such concentrations are planned.	Restricted growth of industries emitting pollutants for which NAAQS are threatened. Large but controlled growth where few industries exist.	Annual[1] 24-hr max 3-hr max	40 182* 700*	37 75* none

[1]SO_2 annual standard is arithmetic mean but TSP annual standard is geometric mean.

*The 24-hr or 3-hr increments may be exceeded once per year.

Regulations[18] implementing the amendments to the Clean Air Act require that all new sources undergo a PSD review (a few exceptions have been made). Most sources of pollutants addressed in this study would be considered "major" sources and therefore must undergo a detailed review. The general requirements of the review consist of the following:

- <u>Description of the Proposed Facility</u>
  Location, operating characteristics, design specifications, control equipment, fuels, process description.

- <u>Description of Emissions</u>
  Sources of emissions, calculated emissions (controlled and uncontrolled), removal efficiencies.

- <u>Best Available Control Technology (BACT) Assessment</u>
  Includes a discussion of justification of control equipment proposed based on energy, environment, economics, and ability to meet NSPS.

- <u>Air Quality Analysis</u>
  Includes assessment of impacts of the proposed facility on PSD increments, NAAQS, regional visibility, soil and vegetation, industrial, residential and commercial growth. This evaluation must consider the effects of the proposed source in combination with those other "applicable sources."

Of greatest concern here is the Air Quality Analysis. The general approach used in a PSD Air Quality Analysis consists of four steps:

Step 1:	Define the source's "Area of Impact."
Step 2:	Identify other "Applicable Sources."
Step 3:	Identify meteorological data to be used.
Step 4:	Model combined impacts of new source and "Applicable Sources" and identify areas where PSD increment is exceeded.

Step 1. Define the "Area of Impact"

In the regulations implementing the PSD requirements of the Clean Air Act,[18] the Administrator indicates that EPA did not intend to analyze impacts of a proposed facility beyond 50 km, due to model inaccuracy and decreasing concentrations with distance. Alternatively, no analysis would be required for distances beyond which concentrations due to the proposed facility fall below certain "significant" values. "Significant" is defined in the regulation. These values are presented in Table 3-9.

TABLE 3-9. SIGNIFICANCE LEVEL FOR PSD ANALYSIS

Pollutant	Averaging Time Annual	24-Hour	8-Hour	3-Hour	1-Hour
TSP	1 $\mu g/m^3$	5 $\mu g/m^3$	N/A	N/A	N/A
SO_2	1 $\mu g/m^3$	5 $\mu g/m^3$	N/A	25 $\mu g/m^3$	N/A
NO_2	1 $\mu g/m^3$	N/A	N/A	N/A	N/A
CO	N/A	N/A	0.5 $\mu g/m^3$	N/A	2 $\mu g/m^3$

N/A = Not applicable.

The "area of impact" of a facility is defined as that area surrounding a proposed facility within which that facility would be expected to have a "significant" impact (either where concentrations fall below "significant" values, or within a 50-km radius, whichever area is smaller).

Two methods of determining the area of impact can be used: the radius approach and the isopleth method. The radius approach involves determination of the greatest distance in any direction at which the facility's impact is considered significant. A circle is centered on the facility, with a radius equal to that distance, which defines the area of impact. The isopleth approach involves determination of the maximum distance in each direction where the facility would be expected to have a significant impact. The area of influence defined in this way is thus an irregular shape, with the facility centrally located.

The difference in the size and shape of the area of impact calculated by these two methods can be seen in Figure 3-6. Region VI of EPA requires the use of the radius method in PSD air quality analyses.

The area of impact is used to define the area in which impacts of the proposed facility are to be assessed, as well as serving as a guide to which sources should be included in the analysis.

Step 2. Identify Other "Applicable Sources"

As mentioned earlier, the proposed source or modification in combination with other "applicable sources" must demonstrate compliance with the NAAQS and PSD increments. "Applicable sources" are at least those within the area of impact. In addition, Region VI requires inclusion of sources outside the area of impact, if including them may significantly affect the results of the analysis.

For the PSD increment analysis "applicable sources" are those which consume increment within the area of impact (and significant sources outside). For the analysis of compliance with NAAQS, "applicable sources" are all sources of the pollutant of concern within the area of impact and significant sources outside the area of impact.

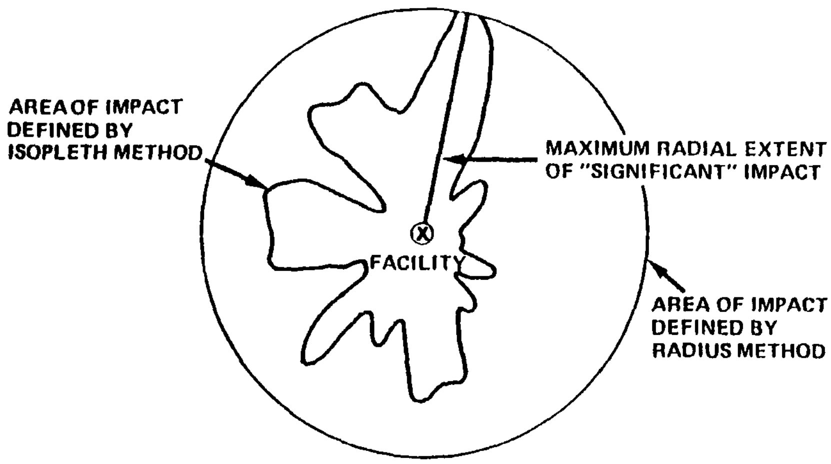

Figure 3-6. Area of Impact
(Radius and Isopleth Method)

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Step 3. Identify Meteorological Data To Be Used

Two basic types of models are used in an air-quality analysis: climatological models and sequential models.

The climatological models are used to assess compliance with the annual standards. Meteorological data used in the models consist of joint frequency distributions of wind speed, stability, and wind direction, averaged over an extended period of time (five years or more). Such data are available from the National Climatic Center for many weather stations throughout Texas. The primary concern with respect to modeling compliance with annual standards is assuring that the data selected are representative of the area of impact.

The sequential models are used for assessing compliance with the short-term standards (24 hours and less). These models calculate a concentration for each data period (usually an hour) and average these concentrations appropriately to produce the desired short-term average. EPA suggests that five years of data "yield an adequate meteorological data base."[16] At present, hourly data covering five years can seldom be obtained. Even if such data were available, the cost of modeling multiple sources (if applicable) would be prohibitive. The usual approach is to identify a worst-case meteorological sequence by use of screening techniques (aided by professional) judgment. This worst case is then used as the basis of the modeling exercise. The screening techniques themselves vary considerably, depending upon the particular situation, but generally involve the use of simplified dispersion models. Representativeness of the meteorological data is extremely important for modeling short-term impacts as well as long-term impacts.

Step 4. Model Combined Impacts and Evaluate Compliance

This is fairly self-explanatory and involves application of the models selected to the sources identified for the meteorological conditions chosen. Another important part of this portion of the analysis is selection of the receptor locations used in the model.

Analysis of modeling results involves identification of the areas of noncompliance (if any) and an assessment of the potential impacts (soils, vegetation, visibility, etc.).

3.2.2 Effect of Air Quality Constraints on Siting New Sources in the Study Area

A three-step approach was used in this portion of the analysis. In the first step, assuming the full Class II increment was available, the closest spacing of power plants which would allow compliance with the increment was determined. The second step involved an assessment of existing air quality to identify areas in which siting may be limited and to evaluate the extent of the constraint. The third step involved assessment of relative suitability of various areas and determination of site availability.

3.2.2.1 Minimum Spacing for Fully Available Class II Increments

The question to be answered in this part of the analysis is, "If the total Class II SO_2 increment were available, how close together could the proposed 1500 MWe electric generating facilities be placed?" Essentially this amounts to a determination of the maximum number of facilities which could be accommodated given the "best" practical conditions.

SO_2 was selected for this portion of the analysis for three primary reasons. These were:

- The nature and scope of this study dictated a generic approach to the assessment of air quality. Since it was not possible to examine impacts of all pollutants associated with the development scenario, the use of some "indicator" pollutant was desirable.

- For a major portion of the study area the Class II increments appeared more restrictive than other factors such as NAAQS. Since increments currently exist for Total Suspended Particulates (TSP) and SO_2, the choice was narrowed to two.

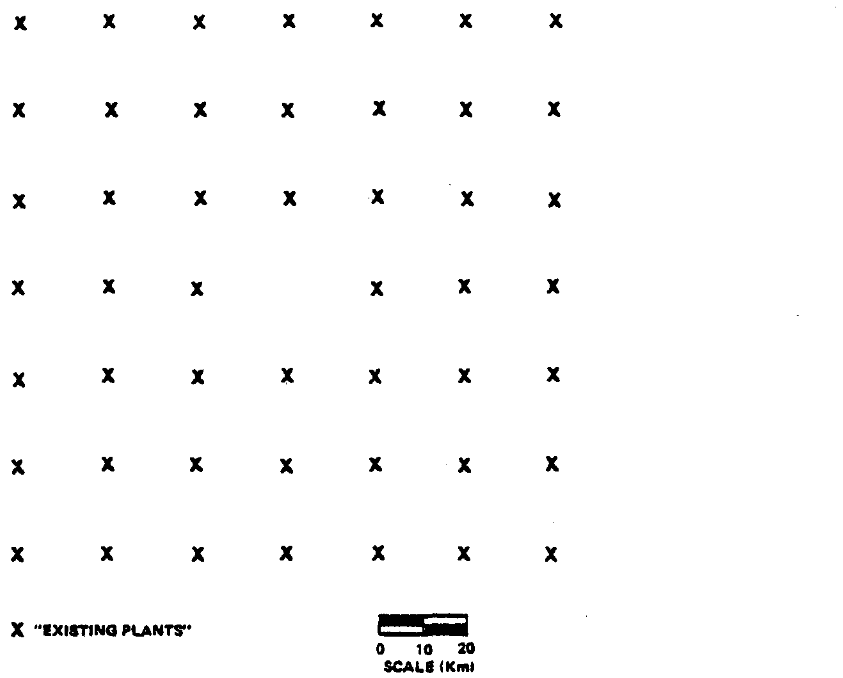

Figure 3-7. Hypothetical "existing facilities" within an area (equally spaced).

- SO_2 is a major component of emissions from lignite combustion. TSP also results, but the situation is complicated in that atmospheric reactions result in the formation of additional TSP downwind from the plant. SO_2 is more amenable to modeling.*

It should be realized that on a localized basis, the estimated impact of SO_2 emissions on air quality may not indicate the impact of other pollutants, but should provide a reasonable assessment of overall air quality.

*The potential importance of TSP and other products of downwind atmospheric transformations is discussed in Chapter IV, Section 2.0.

A modeling approach was taken to estimate the minimum spacing possible between hypothetical 1500-MWe stations. The approach used assumed that a series of identical, equally spaced electric generating facilities exists within a grid area, and that a permit is being sought for one facility. Such a hypothetical grid of existing sources is shown in Figure 3-7. The proposed facility is to be located in the unfilled space in the center. The model calculates the space between the sources in this arrangement.

According to the guidelines for an air quality analysis described earlier, the first step is to determine the area of impact of the proposed facility. In this case, however, it was necessary to establish some design parameters for the facilities. The design parameters assumed are provided in Table 3-10. As stated, the "proposed facility" exhibits the same parameters as the "existing facilities."

TABLE 3-10. DESIGN PARAMETERS FOR 1500 MWe ELECTRICAL GENERATING STATIONS USED IN AIR QUALITY MODELLING

Size:	1500 MWe (3 Units @ 500 MWe)
Heat Rate:	10,000 Btu/kwh
SO_2 Emission Rate:	6000 lbs/hr (0.4 lbs/10^6 Btu)
Stack Height:	500 Feet
Stack Diameter:	24.2 Feet
Stack Gas Temperature:	160°F
Stack Gas Volumetric Flow:	1,442,200 ACFM
Stack Gas Velocity:	52.5 ft/sec
Capacity Factor:	100%

Given these parameters, the area of impact can be determined. For this facility size, the area of impact was found to have the maximum modelable radius of 50 km. The "proposed source" and its area of impact together with the "existing sources" are shown in Figure 3-8.

The sources included in the analysis consisted of the "proposed" source, those "existing sources" within the area of impact, and other "existing sources" within 10 km of the area of impact. This approach effectively defines the area of impact at a 60 km radius which is somewhat conservative. The "applicable sources," in the sense of PSD permitting procedures, are shown in Figure 3-9.

The assessment considered the 24-hour and annual averaging periods. A plot of predicted worst-case 24-hour concentrations versus distance from the proposed facility is shown in Figure 3-10. This plot can be considered highly conservative, since the highest 24-hour concentrations at each receptor distance have been used. In reality, the same type of meteorological conditions producing a peak 24-hour average would not cause the high concentrations shown at greater distances.

Assuming alignment of the sources in any particular wind direction (a maximum of seven "applicable sources" could be so aligned in the patterns evaluated here), calculating minimum plant spacing for the 24-hour average involved determining coincident peak concentrations at various distances. Figure 3-10 cannot be an accurate guide to maximum possible 24-hour concentrations, but is provided to give "feel" for downwind concentrations from a facility.

The annual averaging period provided to be the most restrictive with the assumptions used. Determination of the

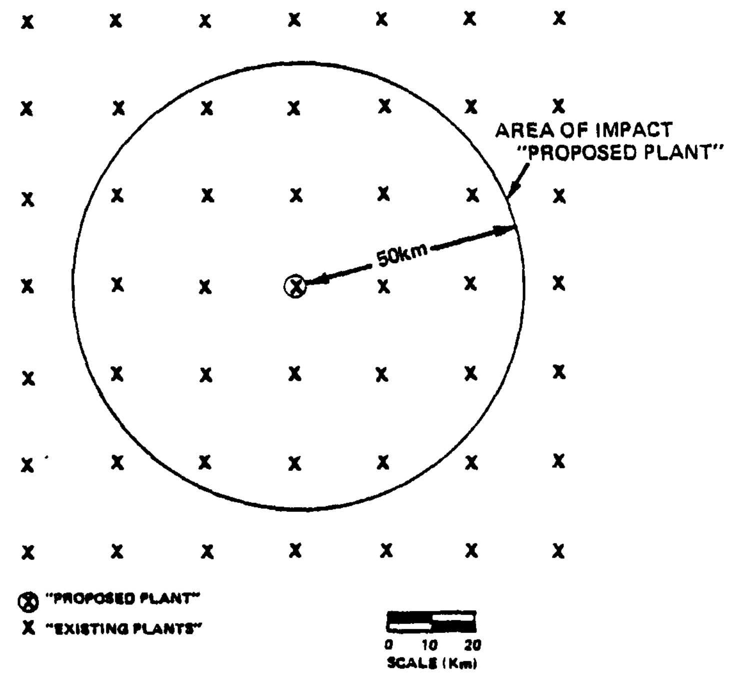

Figure 3-8. "Proposed facility" and area of impact

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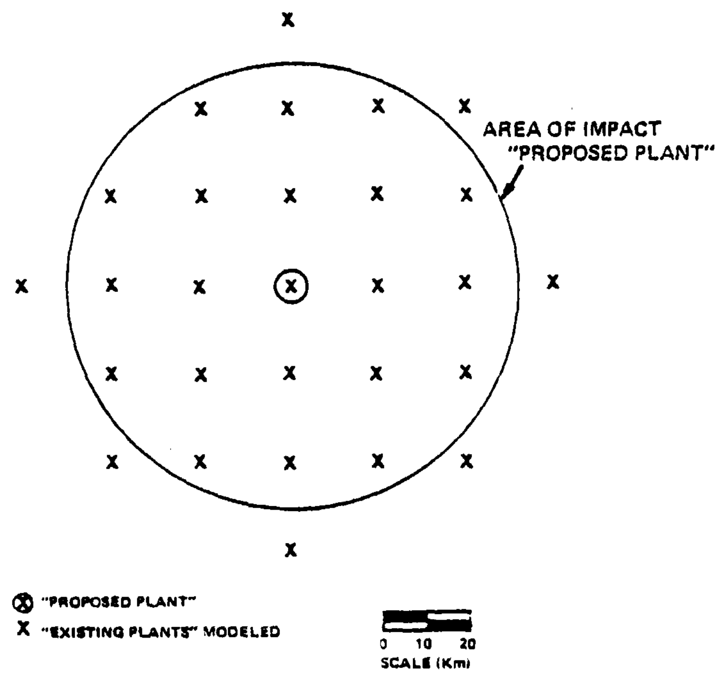

Figure 3-9. Facilities included in modeling.

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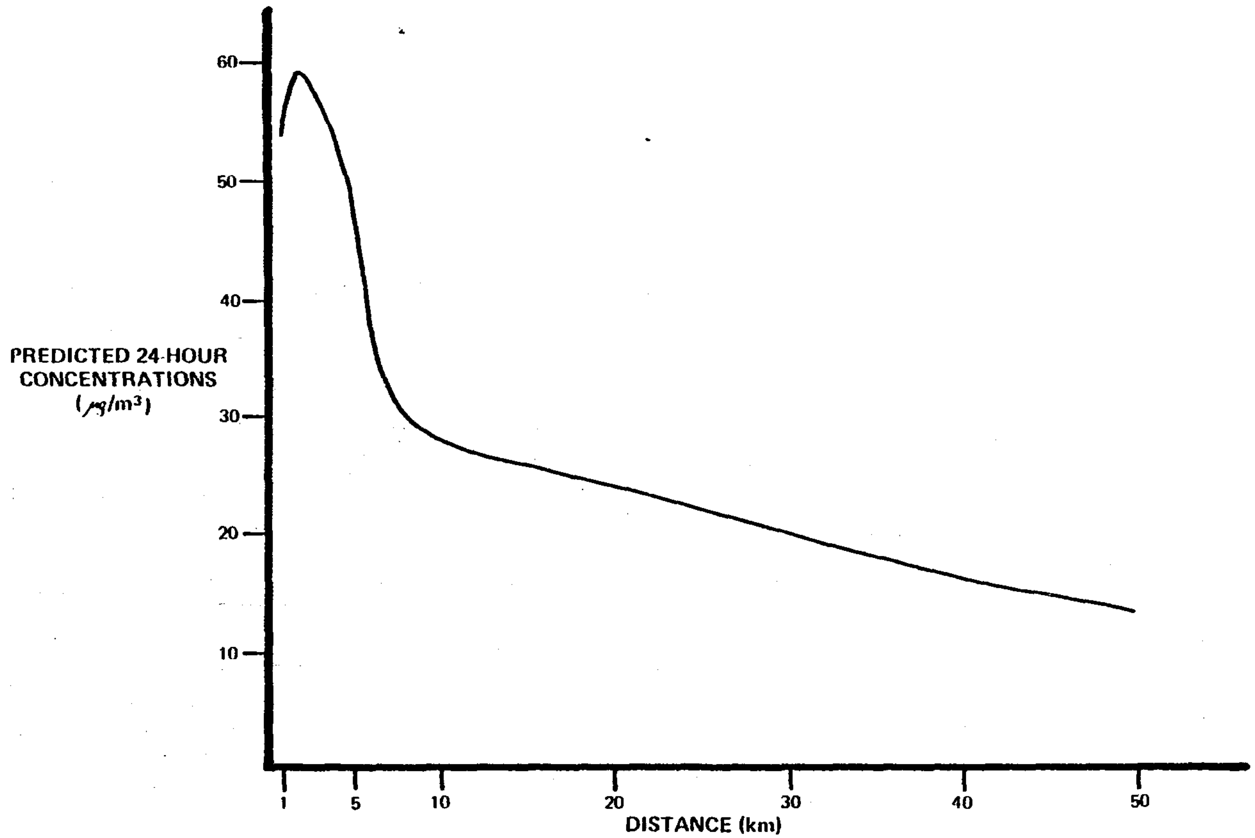

Figure 3-10. Worst-case predicted 24-hour SO_2 concentrations versus distance for hypothetical 1500-MWe power plant.

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minimum plant spacing permitting PSD levels to be maintained over the annual period required trial and error, since no "guide" (such as Figure 3-10) is provided by the model. The results from the short-term analysis were useful in determining a starting point for the analysis of the annual period, however.

The theoretical minimum spacing between the power plants was determined to be 20 km on the basis of the modeling performed. The models used were the CDM (Climatological Dispersion Model) for modeling annual periods and the Single Source CRSTER Model for the modeling short-term conditions. Both models are EPA-developed and approved.

Meteorological data from Hobby Airport were used, covering the period from 1959 to 1968 for the annual modeling. 1976 data were used for the short-term modeling. These data are probably not representative of meteorological data in the Lignite Belt; however, the differences in the maximum predicted concentrations would probably not be substantial.

The modeling described above is intended to be a guide to evaluating the maximum number of power plants that could be located in a region, taking into account only the PSD increment The results are extremely sensitive to the assumptions made and the assumptions implicit in the models. Of particular importance are the following:

- Stack Parameters
  The diameter, velocity, temperature and height of the stack ultimately influence effective plume height, which can affect predicted concentrations (thus spacing) significantly.

- Emission Rate

  Concentrations are directly proportional to the emission rate for a particular source.

- Pollutant Considered

  Increments for other pollutants (when promulgated) could be more restrictive than SO_2, which would affect spacing. For example, the proposed NSPS for NO_x is 0.6 lb/MM Btu; the proposed maximum allowable NSPS for SO_2 is 1.2 lb/MM Btu. Thus, if the NO_2 increment were based on the same ratio to NSPS as characterizes the SO_2 increment, the annual Class II increment would be 10 $\mu g/m^3$, which would require a wider plant spacing than suggested here.

- Location

  The spacing derived assumed the total Class II SO_2 increment was available. In areas where this is not true, spacing would be affected.

- Terrain

  The model assumed level terrain. In areas exhibiting extreme relief, plume impaction could cause significantly higher concentration, thus requiring greater spacing.

- Meteorological Data

  Although not thought to be significant in this determination of spacing requirements, it is possible that different joint frequency distributions could require different plant spacing.

- If long-distance transport and transformation of pollutants is shown to be a significant contributor to background TSP levels downwind of plants or groups of plants, wider spacing might be required to control areawide emission density. The meterological conditions that favor such additive effects are not the same as worst-case conditions for SO_2 alone (see Chapter IV, Section 2.0).

Thus it is concluded that the modeling results should be interpreted only as a useful guide to estimating the number of power plants that can be accommodated in a given region. The spacing derived involves a complex relationship of meteorological conditions, source strengths, number of sources and source relationships. For example, a decrease in spacing increases concentrations at receptors where plume interaction is prevalent (assuming other factors remain constant). This is magnified by the possibility of increasing the number of sources which are within the area of influence. Therefore a change in any of these factors could significantly alter the results.

3.2.2.2 Assess Limitations of Increment Availability

The major assumption in the previous analysis was that the Class II SO_2 increment was totally available. It is intuitively obvious, however, that this is not the case throughout the study area. The next step of the analysis involved evaluating the availability of the PSD increment for SO_2 throughout the study area.

A great deal of judgment was required in this step. There are two possible ways of evaluating the availability of the increment: modeling and monitoring. Neither method, however, can be applied to the study area at this time.

Monitoring cannot accurately assess the status of the increment because an extensive monitoring network does not exist. Although Texas has a large network of monitors, the data are not sufficient to support conclusions in many portions of the state. There is also a lack of accurate emissions data. Ambient monitoring data can be extremely misleading if all sources are not emitting at their permitted rates. Finally, it is not possible to differentiate between the contributions of different sources. If monitoring is to be used to show compliance, there must be a mechanism for differentiating the contributions of non-baseline sources from those of baseline sources. This is not possible in areas where a large number of sources currently exist.

Modeling would appear to be the most precise method of "tracking" the progressive use of the increment. This would entail modeling the entire state of Texas, however, including every source for the pollutant being modeled. This would be a massive undertaking. The Texas Air Control Board (TACB) is currently performing such modeling for certain portions of the state; however, results are not yet available.

Although the availability of the SO_2 increment was of primary concern, areas of potentially high concentrations of other pollutants were identified when they appeared more restrictive. Of particular importance in this regard were non-attainment areas for TSP and photochemical oxidants (PCO).

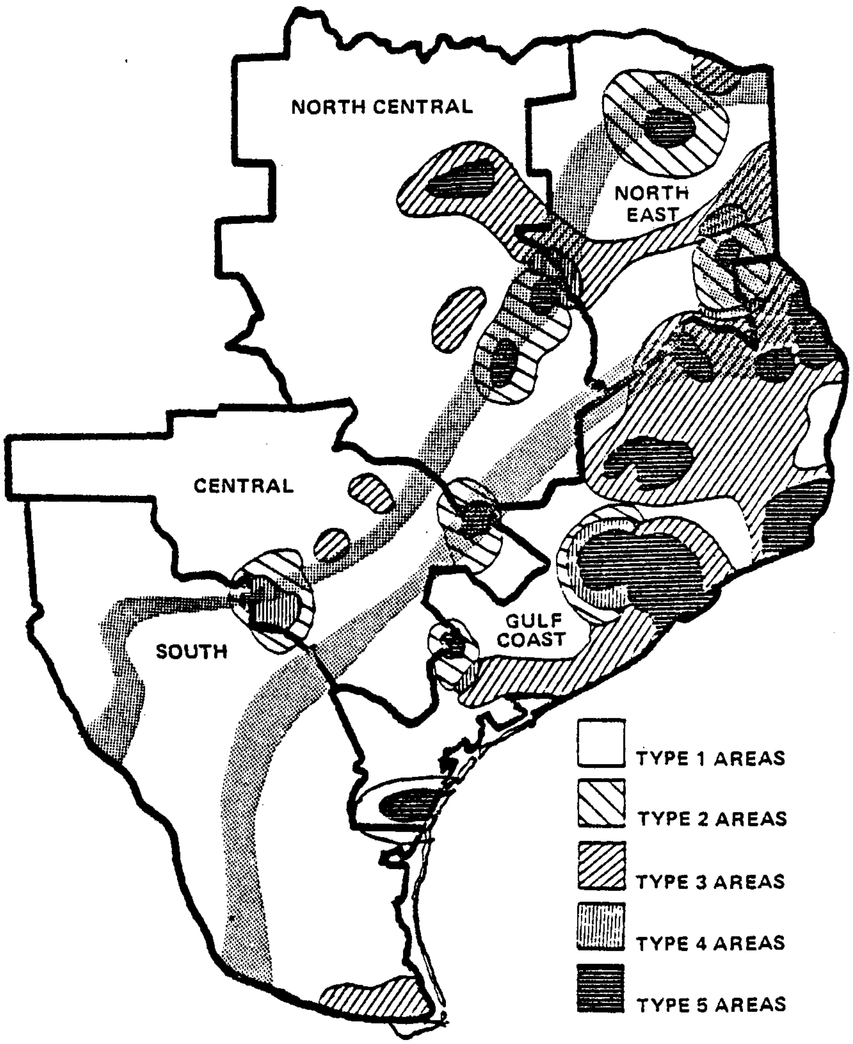
Five degrees of air quality constraints on power plant siting were identified and mapped (see Figure 3-11). These were defined as follows:

- <u>Type 1 - No Constraints</u>
  Areas where few or no pollutant-emitting sources are located or are proposed according to announced plans. Most or all of the Class II SO_2 increment should be available.

- <u>Type 2 - Single Constraint</u>
  Area in which a single large source (existing or proposed) is thought to produce levels of SO_2 approaching the Class II increment. Siting can generally be accomplished in these areas; however, interaction with the large source should be considered.

- <u>Type 3 - Moderate Constraint</u>
  The Class II SO_2 increment may not be fully available in portions of these areas for one or more reasons. Siting can be accomplished in these areas as well, although special consideration should be given to possible air quality limitations.

  These areas include:



AIR QUALITY AREAS
Figure 3-11

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- Potentially sensitive areas - an example of this is the Big Thicket area in portions of Liberty, Hardin, Polk and possibly Tyler Counties,

- Buffer zones around Class I areas and potentially sensitive areas,

- Buffer zones around Type 5 Areas, and

- Areas where a moderate number of pollutant sources exist.

• <u>Type 4 - Strong Constraint</u>
A higher probability of Class II increment being partially consumed. Areas included are those areas where Type 2 and Type 3 Areas overlap.

• <u>Type 5 Areas - Severe Constraint</u>
Location of a fossil-fueled electric-generating facility in these areas would incur large economic penalties due to tighter SO_2 control required; emission trade-offs would be necessary, and possible delays in permitting could occur.

Type 5 Areas include:

- Designated Class I areas,

- Areas in which up to several hundred sources exist and the Class II increment and/or NAAQS is judged to be exceeded, and

- National forests. Although not Class I Areas, the national forests are considered undesirable for power plant siting in this exercise. Areas which have been designated non-attainment for particulates and/or photochemical oxidants are included in Type 5 Areas as well.

3.2.2.3 Analysis of Site Availability

This portion of the analysis used data derived in the first two steps. The number of sites that could be accommodated in each region could be determined using only air quality constraints. The maximum number of sites available was assessed by a "site" ranking system of desirability. The Type 1 Areas (Figure 3-11) were most desirable whereas Type 5 Areas were least desirable. For purposes of this exercise, Type 5 Areas were considered unavailable for siting. A grid was laid over Figure 3-11 such that each grid unit would accommodate a hypothetical 1500-MWe power plant under conditions of full increment availability (each grid square was 20 km on a side). Each grid unit was rated on a scale of 1 to 5, with 1 being most desirable and 5 being least desirable. These ratings correspond to the area types described earlier; thus a grid unit totally within a Type 5 Area was rated 5, a grid unit totally within a Type 1 Area was rated 1, and so on. Interpolation was used for grid units partially covered by a particular area type.

Given the number of sites estimated to be needed in each subregion, the first approach was to count the number of grid units rated 1 in each region. If the number of grid units was greater than the number of sites required, it could be concluded that sufficient sites could be accommodated on the basis of air quality alone. If there were not enough Type 1 "sites", then Type 2 Areas were assessed, but with two (an arbitrarily assigned value) grid squares required for each power plant rather than one.

The total number of 1500-MWe complexes (three 500-Mwe units) to be sited in the study area by the year 2000 is 34. Taking into account only air quality, an assessment of the study area (assuming a plant could be located every 20 km) looking only at Type 1 Areas determined that far more than the required 34 plants could be sited in the total study area.

These plants are not anticipated to be equally distributed throughout the study area, as reflected by the regional scenario breakdown. The greatest number are expected to be in the Northeast Subregion (13 plants) followed by the North Central Subregion with 9, the West and the Gulf Coast Subregion with 4 each, the Central Subregion with 3 plants, and the Southern with 2 plants. Even the most restrictive region had sufficient Type 1 Areas to accommodate the required number of facilities.

The conservatism in the modeling exercise would tend to make the allowable spacing greater than could otherwise be allowed if less conservatism were used. Also, the Type 2, 3, 4, and 5 Areas in the air quality exercise are felt to be conservatively approximated. If less conservatism were used in these two analyses, the decreased spacing requirement and the increased extent of Type 1 areas would allow many more facilities.

3.2.3 The Influence of Developing Air Quality Policy on Siting Density

Current policy for the prevention of air quality deterioration approaches the problem from two directions, setting standards both for areawide increments of allowable deterioration and for emissions from new sources. Both aspects of air quality policy, however, require further definition. EPA must soon promulgate final New Source Performance Standards for SO_2 from power plants. Also, states must submit plans for implementing PSD by March 19, 1979,* and are encouraged to choose from a wide range of strategies with varying potential impacts on siting patterns.[18]

Depending on how the issues surrounding these decisions are resolved, the minimum siting distance could be extended. A rough calculation was made, for each subregion, of the theoretical spacing between plants which would just allow all the plants required by the development scenario to be sited. If larger distances were mandated, for example, as part of a strategy to control regional sulfate formation,** it would begin to be difficult to site all the needed plants. This "threshold spacing" was least in the Northwest, at 65 km. In all other subregions, minimum spacings of 100 km or more would be needed before air quality alone could hamper the siting of the required number of both coal- and lignite-fired plants. Thus, the primary effects of PSD strategies and NSPS will probably be felt to the Northeast Subregion, in which the largest number of plants must be sited within the smallest area.

3.2.3.1 Alternative PSD Strategies and Their Impact on Clustered Development

When permits are granted to new sources under PSD requirements, clean air is effectively treated as an allocable

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*Although this date is indicated in the final regulations of June 19, 1978, staff of EPA's Office of Air Quality Planning and Standards indicate that no sanctions will be applied to states not submitting a plan by this date.

**See Chapter IV, Section 2.0.

resource, limited in supply. Thus, the assimilative capacity of the air is a resource as necessary for the operation of a new power plant as the water it uses for cooling. In allocating its use among competing applicants, a balance must be struck between promoting economic efficiency and assuring equity of distribution. Similar considerations apply to water rights, and the two situations are analogous in many ways. In each case, the state's economy benefits most by allocating limited resources to users which generate the most employment, personal income, value added, and other measures of economic efficiency. At the same time, the rights of prior users have a claim to protection, and unfair interference with normal competition among firms should be avoided if possible.

Besides the currently practiced first-come, first-served method of allocating the increment, EPA has suggested that states consider methods based on economics. Table 3-11 compares three such mechanisms with first-come, first-served, and summarizes their relative effectiveness with respect to efficiency and equity criteria. The table also shows their potential effects on siting density, or packing of new sources, under a given PSD ceiling.

Economics-based systems which internalize the cost of air pollution tend to provide incentives to reduce emissions. This in turn makes it possible to fit more users into a set increment of allowable air-quality deterioration. These effects will be most pronounced in areas where the increment is all or partly consumed. Thus, these strategies could increase packing in the Gulf Coast Subregion and parts of the Northeast Subregion. Eventually, under the first-come, first-served system, offsets would be required to add new sources. In the interim, however, emissions themselves have value of future offsets. This produces a worst-case situation for siting density until the increment is consumed.

TABLE 3-11. COMPARISON OF PSD IMPLEMENTATION STRATEGIES

	FIRST COME, FIRST SERVED	EMISSION FEES	MARKETABLE PERMITS	EMISSION DENSITY ZONING
Implementation	. Permittees required to meet NSPS, PSD increment limitations only.	. Permittees must meet NSPS, PSD, and pay fee proportional to emissions.	. Permits subject to NSPS, PSD, but may be sold for use by entities other than original permittee. (Analogous to appropriative water rights.)	. Permits subject to NSPS, PSD, and maximum emission density per acre. "Air rights" may be traded. (Analogous to riparian water rights.)
Spacing	. Early permittees have a disincentive to reduce emissions. Provides low initial siting density for large facilities.	. Reduction of emissions has economic value. Packing is improved for large facilities.	. Permits have economic value, providing incentive to reduce emissions. Packing is improved for large facilities.	. "Air rights" have economic value, providing incentive to reduce emissions. Packing is improved for large facilities.
Efficiency	. Economic efficiency not a direct factor in obtaining permits.	. Fees set high to promote clean-up may favor most efficient uses.	. Market system allocates permits to most efficient users as they become scarce relative to demand.	. Tends to favor efficient users in the long run. In the short run, "early birds" favored as with first-come, first-served.
Equity	. "Senior" permit holders favored over newcomers.	. No major inequities between utilities.	. No major inequities between utilities.	. Speculation in "air rights" possible, favoring early permittees, unless a diligence provision is included.

3.2.3.2 NSPS and Its Impact on Clustered Development

EPA has proposed an across-the-board requirement for power plants to remove 85% of the sulfur content of flue gases (daily average). An alternative option has been suggested by DOE and by the utility industry which would allow partial scrubbing for lower-sulfur coals. The effect of this option on emissions from individual plants--and thus on spacing--would depend on the fuel used and the amount of scrubbing required. If low-sulfur coal could be burned without scrubbing or with little enough scrubbing to give it an economic advantage over lignite, then widespread use of low-sulfur coal might result. The emissions from these plants could be lower than those from lignite-fired plants with scrubbers, allowing closer packing. Plant siting density might be reduced if a sliding scale of sulfur-removal requirements allowed many coal or lignite-fired plants to emit significantly more SO_2 than 85% scrubbing would allow. Calculations of the sensitivity of spacing between plants to allowable sulfur emissions were beyond the scope of the present study.

3.3 Flood-Prone Areas as a Constraining Factor

Summary and Conclusions
• Between five and ten percent of the land area of the Texas Lignite Belt may lie in 100-year floodplains.
• Floodplain regulations are significant local constraints on siting mines and energy facilities; in many cases, however, engineering solutions can be applied which allow siting in floodplains.
• Scenario activities may be ranked as follows in order of constraint by floodplain regulations: Surface Mines > Mine-Mouth Plants > Other Utilities and Industry
• Provisions of federal and state surface mining legislation could preclude recovery of some lignite underlying major floodplains, subject to interpretation. At present, such restrictions are not thought likely to have a significant impact on the overall development scenario.

3.3.1 Constraints on Energy Development Activities

Table 3-12 summarizes the major provisions of state, federal, and local floodplain regulations affecting scenario activities.

3.3.1.1 Lignite Surface Mines

Floodplains intersect the Lignite Belt in many places, and mining is confined to areas with economically favorable mining conditions. Thus, lignite surface mining is likely to be

TABLE 3-12. SITING CONSTRAINTS IN FLOOD PRONE AREAS

Activity	Description of Regulation					
	Federal and State Surface Mining Acts		National Flood Insurance Program		Wetlands Protection	
	Provision	Constraint	Provision	Constraint	Provision	Constraint
Surface Mining	. Federal: Reclamation plan review Designation of areas unsuitable for mining . State: Reclamation plan review Designation of areas unsuitable for mining	 . Cost . Prohibition . Cost . Prohibition	. Participating counties only: Construction permit according to county floodplain ordinance	. Prohibition or Cost (depends on flood level) reroute stream levee	. Federal Corps of Engineers 404 permit review . State Certification of Corps 404 permit Comment by wildlife agency	. Prohibition or Cost (Mitigation) . Same
Mine-Mouth Power Plants	Not Applicable		Same as above	Same types floodproofing elevation	Same as above	Same as above
Industrial Plants	Not Applicable		Same as above	Same types floodproofing elevation	Same as above	Same as above

the most constrained by floodplain regulations of all scenario activities. Mining within a 100-year floodplain will be subject to special review requirements and encounter special site design standards regarding maintenance of drainage patterns. It is possible that actual prohibitions may arise on a case-by-case basis, based on interpretation of the "lands unsuitable" provision in the federal and state mining laws. Mining anywhere within the 100-year floodplain could possibly be prohibited because it may not be possible to properly mine and reclaim the area. Operations proposed for the floodway will almost certainly be considered as areas unsuitable for mining. Engineering solutions may, however, be available in each instance, which would allow mining of the resource. The cost will increase, and feasibility of engineering solution (such as rerouting the stream around the mine site or constructing protective levees) is likely to decline as the flood frequency factor increases.

3.3.1.2 Power Plants

Mine-mouth generating facilities would have somewhat greater flexibility in siting than surface mines and so would have less difficulty avoiding floodplain problems. Although presently constrained to be sited relatively near the lignite source by transportation costs, a power plant would have comparatively more alternatives than a mine within a particular locale in terms of being sited outside floodprone areas.

3.3.1.3 Industries

Industrial facilities using lignite are not necessarily confined to the lignite region and therefore will not encounter floodplain constraints different than at present. Conversion to lignite will not necessarily increase their existing problems with floodplain restrictions.

3.3.1.4 Secondary Development

Secondary development such as housing, schools, hospitals, commercial services, etc. would be required to either locate outside floodprone areas or elevate and floodproof structures. The constraint posed on secondary development would not affect the scale of lignite development, but could influence community land use patterns on a local level.

3.3.2. Authority for Floodplain Regulations

Floodplain restrictions exist at the federal, state, and local level. Federal controls include:

- Surface mining requirements under the Federal Surface Mining and Reclamation Act,[20]

- Wetland protection measures pursuant to Section 404 of the Federal Clean Water Act,[21]

- Floodplain management provisions of the National Flood Insurance Program.[22]

State controls include:

- Review of facilities located in water courses under the Texas Water Code,

- Certification of Section 404 permits issued by the Corps of Engineers, and

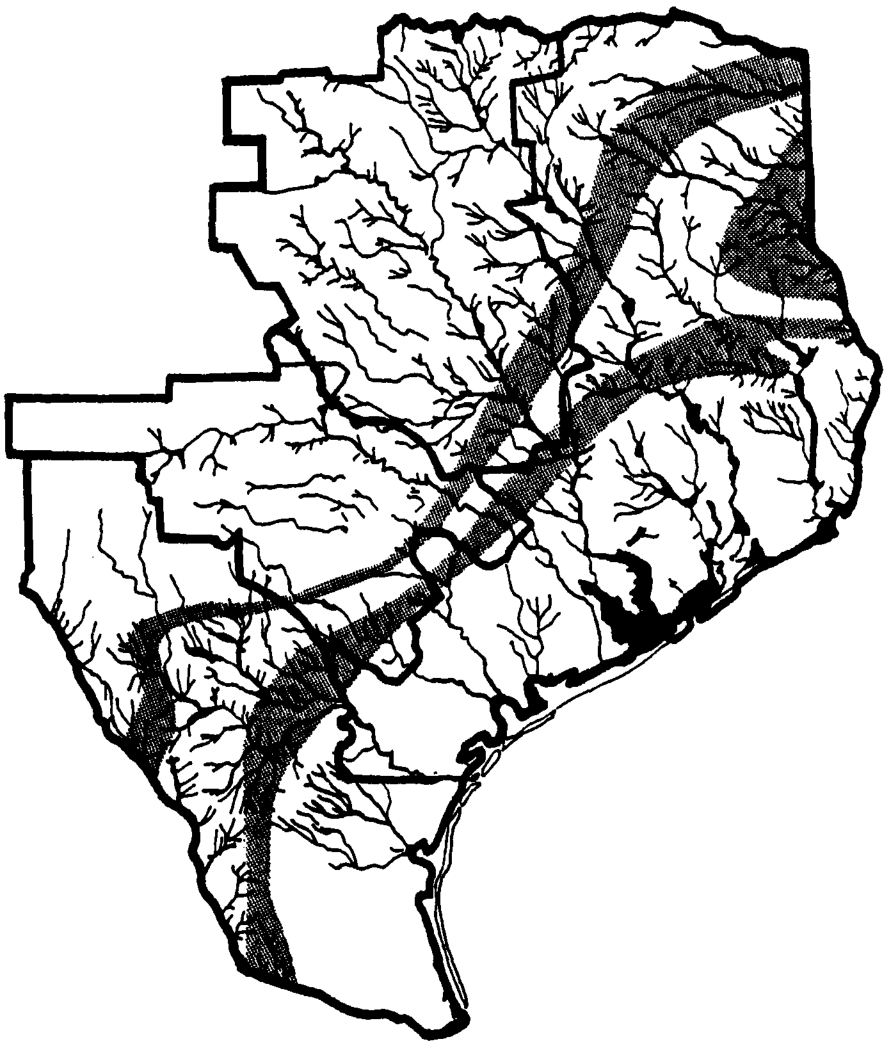
- Surface mining requirements under the Texas Surface Mining and Reclamation Act.

Local control outside municipal boundaries is exercised by county floodplain management ordinances adopted pursuant to National Flood Insurance Program requirements, which restrict development in flood hazard areas. Of 61 counties underlain by lignite, 18 now have such ordinances and many, if not most, of the remainder can be expected to enact similar ordinances so as to participate in the Flood Insurance Program.

3.3.3 Geographic Scope of Floodplains

Twelve major river basins intersect Texas' Lignite Belt, flowing roughly perpendicular to the direction of the lignite trend. Approximately five to ten percent of the total area of the Lignite Belt may lie within a 100-year floodplain. This percentage is higher for certain areas, especially those in the Northeast and Central Subregions, where lignite deposits with the best potential are found. Figure 3-12 shows floodplains intersecting lignite deposits.

Figure 3-12 shows that the Central, North Central, and Northeast Subregions are intersected by numerous floodplains of varying geographic extent. The development of lignite resources could be significantly restricted in or near major water courses and the siting of lignite facilities could be affected by floodplain controls in as much as 10 percent of the entire study area.



FLOOD PRONE AREAS
Figure 3-12

02-4308-1

3.4 ETJ's (and Incorporated Areas) as a Constraining Factor

Summary and Conclusions

- Extraterritorial jurisdictions (ETJ's) are not expected to impose a serious constraint on the overall development scenario, although it is assumed that siting within an ETJ will be difficult or impossible in the future.
- For the most part, ETJ's of significant size do not overlie the actual lignite trend.

According to Article 970A, TEX. REV. CIV. STAT., an incorporated town or city in Texas has certain authority (subdivision controls, for instance) over land beyond the city limits. This authority is referred to as extra-territorial jurisdiction (ETJ). The geographic extent of ETJ varies directly with population size, according to the schedule in Table 3-13.

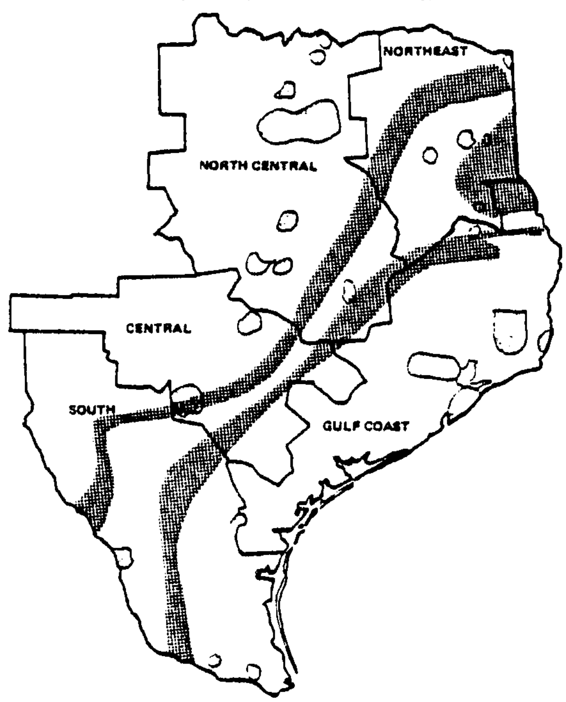
TABLE 3-13. EXTENT OF ETJ IN TEXAS

Population	ETJ
Less than 5,000	½ mile
5,000 to 25,000	1 mile
25,000 to 50,000	2 miles
50,000 to 100,000	3½ miles
Over 100,000	5 miles

An assumption used in this siting analysis is that decision makers will choose not to locate a power plant within the ETJ of a city because of potential controls the city might exercise and because of probable opposition from within the city. Hence, areas within the ETJ of a city are generally not considered available for power plant or surface mine siting. In actual practice, plants are sometimes located within ETJ's; thus, this assumption reflects an expected future trend.

Only those cities with populations greater than 25,000 are included in the siting analysis. The reason for excluding cities less than 25,000 is that their areas, even with a one-mile ETJ, are not sufficiently large to affect the overall availability of sites within the entire study area.

The results of the exercise are presented in Figure 3-13.



AREAS CONSTRAINED
BY ETJ CONSIDERATIONS
Figure 3-13

02-4310-1

3.5 Substrate Capability as a Constraining Factor

Summary and Conclusions

- Suitability of physical land features was evaluated, at the county level, on the basis of suitability for heavy construction and surface-water impoundment.
- No counties were classed as good according to these criteria.
- Relatively speaking, counties in the Gulf Coast Subregion, and in parts of the Southern, Central, and Northeastern Subregions, exhibited the greatest constraint.

Substrate capability, or the suitability of a particular location for the construction of a power plant in terms of physical land features, was examined according to the following method. The source of information for this analysis was work done by the Bureau of Economic Geology at the University of Texas at Austin.[24] This very useful study classified different areas of Texas according to natural suitability for particular land uses. One such category of analysis was construction suitability. The following descriptions define physical properties and features in terms of construction suitability:

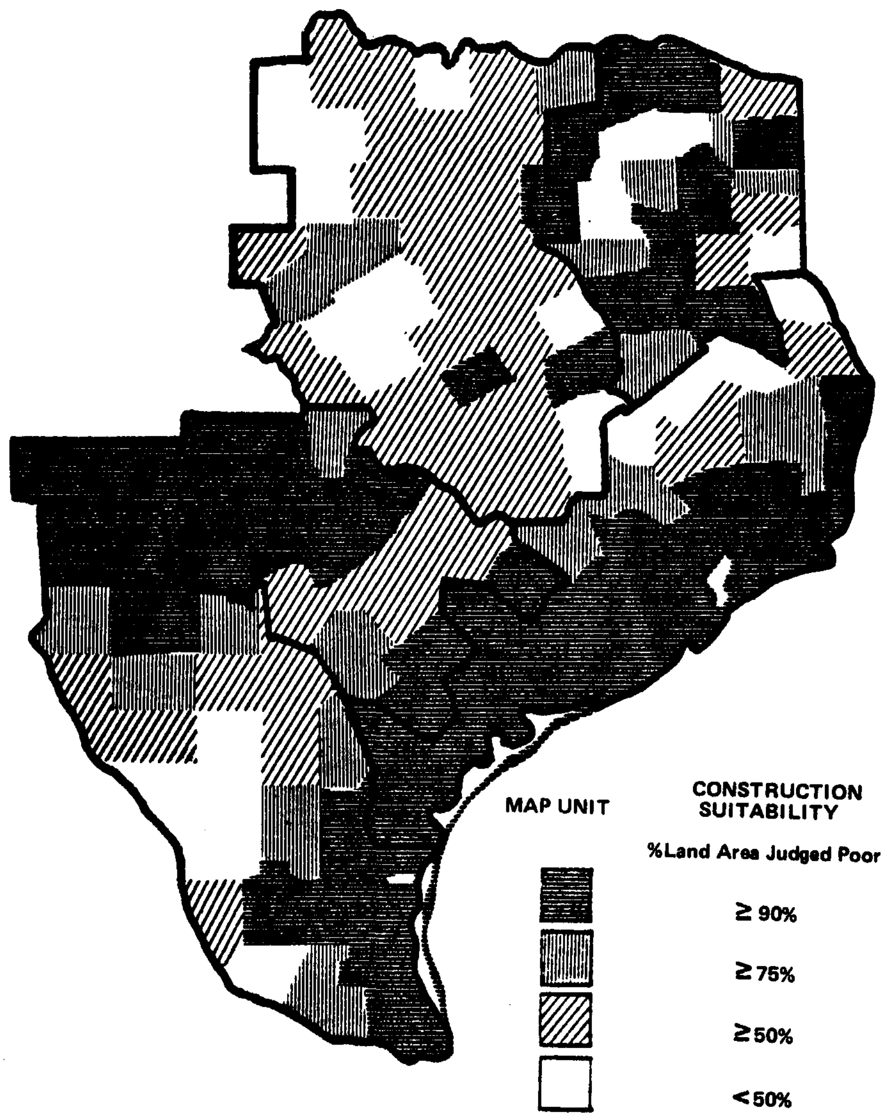
Construction Suitability	Properties and Features
Good	Generally suitable for light and heavy construction, high foundation strength, low flood potential.
Moderate	Structural designs may require modification because of moderate to high shrink-swell potential, low foundation strength, moderate to steep slopes.
Poor	Includes areas with high flood potential, unstable slopes, high potential for storm drainage, high biological productivity.

These construction-suitability categories were further refined by including permeability as a factor. Low permeability was defined as optimum and high permeability as a negative factor, due to the difficulties of impounding necessary water for power-plant cooling and make-up in permeable soils. The two factors, construction suitability and permeability, were joined according to Table 3-14.

TABLE 3-14. OVERALL SUBSTRATE CAPABILITY AS A SITING FACTOR, DEFINED BY CONSTRUCTION SUITABILITY AND PERMEABILITY

Construction Suitability Rating	Permeability	Overall Substrate Capability
Good	Low	Good
Good	Moderate	Moderate
Good	High	Poor
Moderate	Low	Moderate
Moderate	Moderate	Moderate
Moderate	High	Poor
Low	Any Rating	Poor

This analysis resulted in all areas being defined as moderate or poor in terms of substrate capability. There were no areas where construction suitability was judged to be good and where permeability was low. Therefore, using the percent of land area in each county classified as poor in terms of substrate capability, the map shown in Figure 3-14 was made. The darkest areas show those counties which had 90 percent or more of their land area classified as poor in terms of substrate capability. These regions include the entire Gulf Coast and portions of South, Central, and Northeast Subregions.



CONSTRUCTION SUITABILITY AS A
CONSTRAINING FACTOR IN SITING

Figure 3-14 02-4306-1

3.6 Distance from Lignite as a Constraining Factor

Summary and Conclusions
• Presently, lignite shipments covering more than 50 miles are not considered economical.
• Rail access and condition of lines is not expected to constrain lignite shipment.

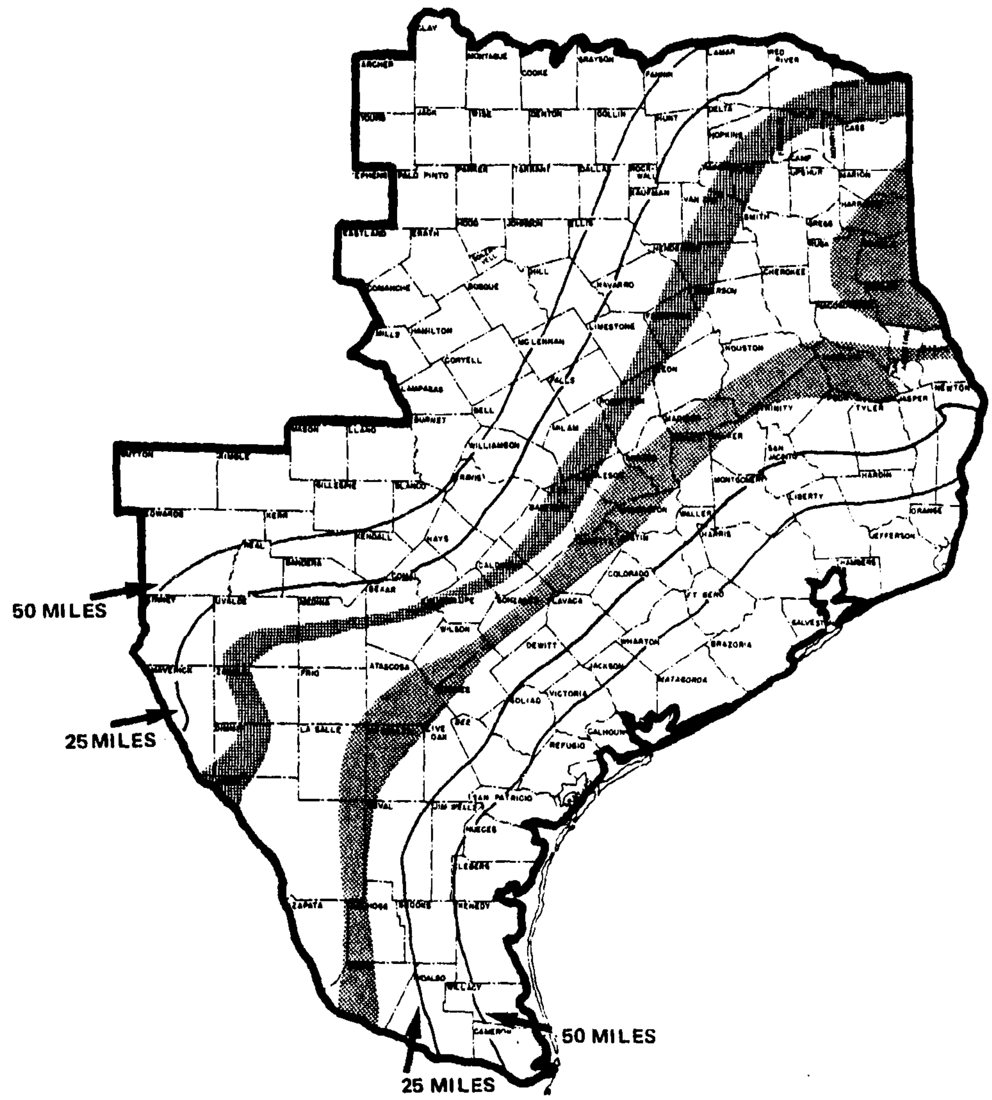
At this time, almost all lignite is used at or near the mine mouth, and haul distances of more than a few miles are generally considered uneconomical. The primary reason for this is the high ash and water content of lignite, relative to its heating value. Based on current shipping costs, the per-million-Btu-mile cost of moving lignite by rail is higher than that for either western or midwestern coal. Short hauls made by truck are even more expensive, per million-Btu-mile. Another drawback to long-distance transport of lignite is its tendency to spontaneous combustion. Overcoming this problem during shipment requires special precautions that add to the overall cost.

Presently, most lignite is hauled less than five miles by truck from the mine to the point of use. Only three instances of regular rail shipment of lignite are known at present. Two of these are in North Dakota, at distances of 20 and 28 miles. The third is in Texas, and covers a total distance of 45 miles from the mine to Texas Utilities' Monticello Generating Station.

As pointed out in Chapter II, however, the economical transport distance for lignite is really set by the delivered cost of coal. As this cost rises, due to increasing production costs, rail tariffs, severance taxes, etc., it may become economical to ship lignite longer distances by rail. This factor is more likely to affect industrial uses, which may have a strong affinity for existing industrial centers, than power plants which can be more easily sited near lignite supply sources.

Rail access is good throughout the Lignite Belt. Although some lines might have to be upgraded to carry unit lignite trains, availability of rail transport was not considered a constraint in and of itself.

Figure 3-15 presents the base map used to illustrate lignite shipping distance as a constraint on siting. Distances of less than 25 miles, and 25 to 50 miles are shown.



DISTANCE FROM LIGNITE

Figure 3-15 02-4323-1

4.0 DEVELOPMENT OF COMPOSITE SITE-SUITABILITY MAP

The evaluations given in the preceding section of potential siting constraints imposed by six physical and environmental factors were combined to yield a composite evaluation of all the constraints acting together. To do this, a grid of squares 20 km on a side was laid over each of the constraint maps. This size was chosen to correspond with the minimum spacing acceptable between 1500-MWe power plants, when the full PSD increment for SO_2 is available. Each grid unit was then given a rating from one to five for each of the constraining factors, reflecting the relative degree of constraint appropriate for that square. (A rating of one indicated least constraint, and five, most.) Then, each factor's score was weighted by a factor selected by the study team as a whole to reflect the strength of that factor relative to the others. Out of a possible range of one to five, the following weights were chosen:

Factor	Weight
Air Quality	4
Fresh Water Availability	3
Flood-Prone Areas	3
Extra-Territorial Jurisdiction	4
Construction Suitability	2
Distance to Lignite	2

Figure 4-1 depicts the composite grid array and identifies various ranges of calculated values. The original array of undifferentiated composite numerical values was first separated into ten classes by dividing the interval between the highest and lowest scores into ten equal parts. Then these groups were condensed into the four groups shown in Figure 4-1, on the basis

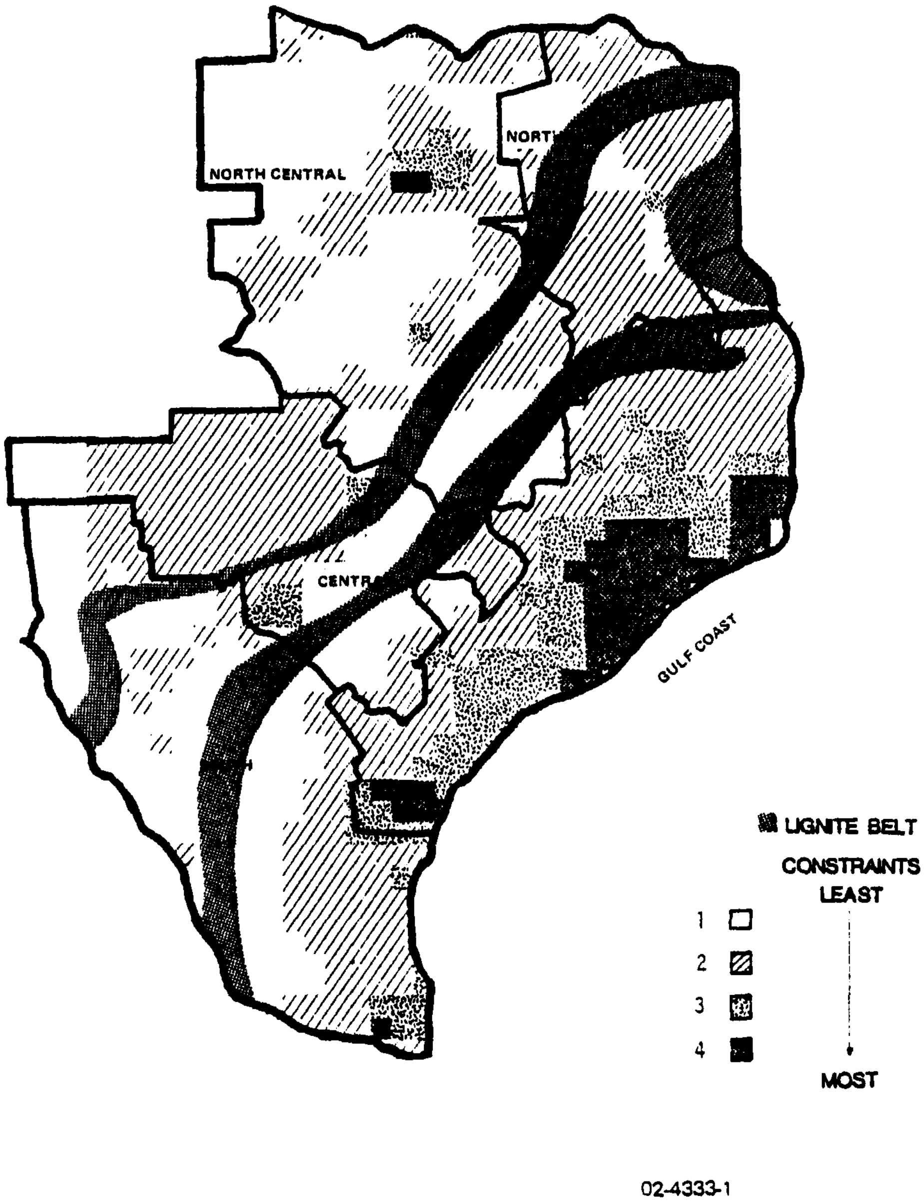


Figure 4-1. Composite Site Suitability Map Showing Study Area Subregions

of the major breaks between groups in the original series of ten. For example, the numbers of squares differentiating the three highest-scoring groups was small, compared to the number of squares added when the fourth-highest is added. Thus, the first three were combined, while the fourth was considered as belonging to a new group.

The composite map primarily depicts zones of increasing cost and decreasing permittability. While there may be small areas within each square where a power plant could not be sited, it is doubtful that in even the highest-scoring squares there would be no possible sites at all. However, the differences in the cost of constructing and operating a plant, as well as the difficulty of obtaining the necessary permits, may differ considerably between high- and low-scoring squares.

As an aid to identifying potential future siting patterns, the two lowest-scoring zones--the zones of lowest presumed cost and highest permittability--may be considered likely to experience siting activity sooner, and perhaps more intensively, than the others. Of eight new or planned coal- and lignite-fired power plants within the five study subregions, six are located in areas mapped in the lowest-scoring zone in Figure 4-1. Eleven are in the following zone, but this number may be slightly misleading, since potential air quality effects of these plants were included as a factor in evaluating air-quality constraints. Only one plant falls in the highest-scoring category, and none in the second-highest.

The circumstances which may induce a utility to locate a plant in an area with high attendant costs and risks vary from firm to firm and cannot be predicted. Thus, it would not be reasonable to conclude that future siting patterns will conform exactly to the zones in Figure 4-1. However, the map suggests that an overall trend toward siting new plants away from the Gulf Coast may be looked for, not only for lignite-fired plants but for coal-fired plants as well.

Because industrial uses of lignite and coal will vary greatly in size, no such standardized analysis may be applied to them. Also, different industries experience varying degrees of economic affinity for already-developed areas. However, it appears from the preceding analysis that sufficiently large areas exist which are relatively free of serious constraint to accommodate both industrial and utility growth. Some conflicts are likely to arise, especially over air emissions, especially in areas which are favorably located with respect to both major market centers and available lignite.

5.0 POLICY ISSUES

Most of the policy issues related to siting arise over the impacts of individual projects, considered one by one. These issues concern provision of adequate protection for the environment and adequacy of governmental resources to plan for and cope with change. Issues of this kind are identified at the end of Chapter IV, which deals with impacts, rather than here. Two distinctive issues emerge from the discussion of water as a constraining factor, however, which relate to problems of allocation, rather than impact.

> <u>Water Supply</u>. How can adequate supplies of water be made available for energy growth, at reasonable cost and without undue conflict between water users?

As was discussed at length in Section 3.1, increasing pressure on the state's water supplies, arising partially from energy growth, appears likely to result in a redistribution of use patterns. Both changes in the relative amounts of water used by different sectors are probable as prices rise under increasing competition. At the same time, increased demands will be placed on ground water. Higher pumpage rates will draw down aquifers and pumping costs per unit of water will rise as water is withdrawn from greater and greater depths.

These trends potentially pose problems of equity and efficiency. On the one hand, some present users - particularly in agriculture - may find themselves progressively disadvantaged relative to other users with greater economic returns. On the other hand, these other users may return more to the economy through their use of water. The considerations of equity - protection of existing users - must be balanced against those of economic efficiency - getting the most for everybody from the use of a limited resource.

Of particular concern is the lack of control over ground water use and pumping rates. Considerable debate also centers around pricing new water supplies. It has been proposed that increased water prices will promote conservation, but not all users are in a position to make the necessary investments in new equipment and technologies.

> Consumptive Water Use. How can increasing power-plant cooling water consumption be kept from placing an undue burden on water supply management.

Evaporative cooling consumes very large amounts of water, which accounts for the bulk of the consumptive water use by power plants. Current federal and state policies, however, conflict over the best way to balance consumptive use with control of thermal discharge. Aside from dry cooling, which entails very large efficiency penalties, the available options consist of once-through cooling in natural or constructed water bodies, or wet cooling towers. Once-through cooling on a large water body, such as the ocean or a large, multi-purpose reservoir, consumes relatively smaller amounts of water than the others. The Texas Department of Water Resources advocates such designs. But EPA, administering the Clean Water Act of 1977, which generally prohibits thermal discharge, requires a complex and costly study program in support of a variance to permit once-through cooling.

The amounts of water consumed by cooling towers or special-purpose cooling lakes vary with the climate where they are located. There is thus an optimal distribution for the two options across the state resulting in the lowest combined water consumption. However, a distinction is made in the federal law between specially constructed cooling lakes and cooling ponds, the former requiring the same variance procedure needed for discharge into rivers, lakes, and the ocean. As interpreted by EPA, nearly all cooling impoundments are classified as cooling lakes.

A key pending decision is EPA's promulgation of new source performance standards for thermal discharges from steam-electric power plants. The original standards were overturned by a federal court in 1976.

6.0 FUTURE RESEARCH AND INFORMATION NEEDS

- Specific information regarding the perceived importance of various siting factors in recent or pending siting decisions by utilities and industry.

- More specific breakdown of potential industrial lignite use, followed by a detailed analysis of factors which may constrain siting for various types of industrial facilities in the study area. Particular attention should be given to potential conflicts with utilities and their consequences for overall management of the PSD increment.

- Revision of the current supply-demand forecasts of the Department of Water Resources to include the effects of existing contracts and water rights.

- Following publication of the results of the Bays and Estuaries Study, evaluate alternative mechanisms--both legal and engineering--of managing current and future water supply to provide needed fresh water inflows.

- Evaluation of potential extent to which rising prices displace surface-water demand onto groundwater resources, as well as the hydrological and economic consequences of such a shift.

- Evaluate the possibility of conflicts between demands for eastern Texas water for energy use and to maintain and support potential economic growth in more arid western Texas.

- Collect existing data and establish new monitoring stations to evaluate precisely the geographic extent to which PSD increments for both TSP and SO_2 are completely available.

- Perform an evaluation of the sensitivity of minimum source-spacing to site-specific meteorological conditions characteristic of the Lignite Belt.

- Evaluate quantitatively the effects of alternative strategies for allocating the PSD increment on area-wide emission densities.

- Evaluate the additive effects of potential new combustion sources in the Lignite Belt, with special attention to downwind formation of suspended particulates, to determine if the availability of PSD increments for TSP are threatened at a greater distance than that to which new source compliance is normally calculated. Analyze the impact of spacing and emission control on such effects.

- Quantitatively estimate the tonnage of lignite potentially in questionable status due to location under 100-year floodplains.

- Perform sensitivity analyses of the CLASS method of evaluating the joint effects of several constraining factors by varying the weights assigned to them.

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20. Surface Mining Control and Reclamation Act, Pub. L. 95-87, 91 Stat. 445, 30 U.S.C. 1201 et seq. (1977).

21. Clean Water Act of 1977, Pub. L. 95-217, 91 Stat. 1566, 33 U.S.C. 1251 et seq. (1977).

22. Flood Disaster Protection Act, Pub. L. 93-234, 42 U.S.C. 4001, as amended.

23. Texas Surface Mining and Reclamation Act, art. 5920-10, TEX. REV. CIV. STAT.

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CHAPTER IV: ENVIRONMENTAL AND SOCIOECONOMIC IMPACTS OF THE DEVELOPMENT SCENARIO

Abstract

In this chapter, the development scenario derived in Chapters I and II is used as a basis for evaluating the potential impacts of energy development in the study area. Impacts are considered in the areas of air quality, solid waste, water quality, water supply, aquatic and terrestrial ecosystems, and socioeconomic factors. The discussion of each area is preceded by a summary of conclusions, and followed by suggestions for further research which would improve impact evaluation and prediction. Emphasis has been placed on discovering impacts operating at a cumulative, regional level, which might not become evident from studying local impacts only. Local, site-specific impacts are also discussed, but from a generic perspective. The concluding section of this chapter sets forth policy issues arising from the findings of this environmental review.

1.0 INTRODUCTION AND STATEMENT OF PURPOSE

The following sections present the results of an environmental and socioeconomic review of the development scenario derived in Chapters I and II. The scope of this review was limited to existing information. Thus, the results illustrate not only what can be said at this time about the impacts of energy development, but also where more research is needed. In addition to literature review, emphasis has been placed on expert opinion among individuals involved in dealing with these impacts. Many of the ideas presented here are derived from discussions with utility representatives, environmentalists, regulatory agency personnel, and other researchers in academic and private institutions.

In conducting this review of impacts, emphasis has been placed on identifying impacts occurring on a cumulative, regional scale, which are not immediately apparent from a study of individual projects. This decision was based on the fact that the current system of permits required for large energy facilities requires extensive local data-gathering, and evaluation of site-specific impacts. There is also a large and growing body of academic literature on site-specific impacts and case studies. Comparatively little effort has yet been made to integrate these local perspectives into a regional picture. Yet, it is with long-term regional-level phenomena that resource planners must deal.

In some cases, this effort has revealed significant new perspectives, as in the case of the additive air quality impacts of regionwide lignite combustion and dispersion of employment impacts over time. In other cases, what appeared to be a potential regional problem was shown, on further investigation, to be of less concern than was first thought. Thus, the impacts of consumptive water use on streamflow and assimilative capacity, at the basin level, are shown to be measurable, but small. Both negative and positive results are of value, for they point out to planners where the most pressing problems may lie.

The progressive interlocking of regulatory policies governing various environmental resources is tending more and more to place long-term planning responsibilities on agencies which in the past have been chiefly concerned with granting permits. It is hoped, therefore, that what follows will provide both useful perspectives for the evolution of this kind of planning capability, and point the way to further research efforts needed to provide it support.

2.0 AIR QUALITY IMPACTS OF LIGNITE DEVELOPMENT

Summary and Conclusions

- The overview of potential air quality impacts presented here considers the joint effects of both coal- and lignite-fired facilities built in the East Texas study area. Modeling was not attempted, either of single sources or areawide patterns of sources.

- New Source Performance Standards will result in power-plant emissions an order of magnitude or more below uncontrolled sources. New plants will be cleaner than most existing ones.

- Gasification plants emit criteria pollutants, but levels are held down when product gas is used to supply the plant's fuel needs. Fugitive hydrocarbon emissions arise from a variety of in-plant sources.

- Lignite appears to contain less arsenic than average values for western coals, but may contain very large levels of uranium at seam boundaries or near partings.

- Based on combined emissions from all coal and lignite sources operating in 2000, the lignite development scenario would raise particulate emissions 5 percent, SO_2 emissions 70 percent, and NO_x emissions 60 percent over 1973 state-wide totals.

- Gaps in air quality and meteorological data and possibly inadequacies in theory, prevent definitive evaluation of the risk of long-distance transport and transformation of pollutants. The potential for downwind violation of TSP and ozone standards because of atmospheric transformation and transport processes remains an open question.

2.1 Emissions from Lignite Development

The increased development and use of lignite in Texas will directly contribute to the state's air pollutant loading through mining, combustion, gasification, and indirectly through urban growth induced by economic growth along the lignite belt.

2.1.1 Emissions from Mining

Although the heavy equipment used in mining produces some sulfur dioxide (SO_2), nitrogen oxide (NO_x),particulates. carbon monoxide, and hydrocarbon emissions, the principal air-quality impact of mining is on particulate levels close to the mine.

In most circumstances, lignite mining operations will generate considerable particulate matter--coal dust and soil particles. Except for the fine particulates, it appears that most of this matter settles to earth within the mined area itself.

In the southwestern portion of the lignite belt, which generally contains lower-quality lignite and also has lower annual rainfall, there is greater potential for fugitive dust emissions from mines. Wetting mine haul roads will minimize the formation of fugitive dust, and dust-suppression systems can control emissions from lignite handling. The handling of lignite for mine-mouth steam electric stations typically does not include processes that heat, wash, or blow air upon the lignite or involve discrete air emission sources. Handling facilities such as hoppers, silos, stackers, and crushers include dust-suppression systems which dampen the lignite for dust control. Dust collection systems are generally used at transfer points to minimize dust release from lignite handling.

Current federal air quality regulations exempt fugitive dust, defined as native soils uncontaminated by industrial activity, from consuming the PSD increment, and the state of Texas similarly does not regulate fugitive dust from mining. A potential problem may exist in that NAAQS for particulates make no distinction as to their source. Thus, in cases where mining may contribute to NAAQS violations, the regulatory situation is ambiguous, and could lead to litigation.

2.1.2 Emissions from Combustion

Particulates, sulfur dioxide, and nitrogen oxides emissions are the three major criteria pollutants emitted from lignite- and coal-combustion, and have received most of the attention that has been directed toward control of atmospheric emissions from power plants.

2.1.2.1 Potential Emissions of Criteria Pollutants from Single Sources

Fuel type and quality play an important role in determining the quantities of particulates, sulfur dioxide, and nitrogen oxides which are emitted from uncontrolled conventional combustion operations. Particulate emissions are greater for coal-fired units than for oil- or gas-fired units, due to the greater ash content of the fuel. Sulfur dioxide emissions depend upon the amount of sulfur in the fuel, which may vary considerably depending upon fuel source. Boiler design and operating conditions will affect the particulate and nitrogen oxide emissions from a power plant. In general, Texas lignite has a higher ash and sulfur content than the subbituminous western coals which will compete with it as a boiler fuel in Texas.

Lignite (on an as-received basis) ranges in grade from 10 to 40 percent ash and 0.6 to 2.3 percent sulfur (by weight).[1] A 1,500-MWe power plant (three 500-MWe units) will produce the emissions shown in Table 2-1.* These figures reflect the use of lignite from the Wilcox Group, which accounts for about 70 percent of the total lignite resource, and is the best in quality of the Texas lignites.

TABLE 2-1. EMISSIONS FROM A HYPOTHETICAL 1500-MWe STATION FIRING A TYPICAL TEXAS LIGNITE FROM THE WILCOX GROUP

	No Emission Controls	With Controls Required for Proposed NSPS†
Sulfur Dioxide	141,500 tpy	21,200 tpy
Particualtes	849,000 tpy	1,380 tpy
Nitrogen Oxides	106,000 tpy	27,600 tpy

†New Source Performance Standards as proposed by EPA on September 19, 1978.

2.1.2.2 Control Technology for Criteria Pollutants

The application of emission control at the level required by EPA-proposed new standards vastly reduces the potential emissions. Various options for controlling to these levels are now available.

*Assumes 70 percent capacity factor, and lignite with 6500 Btu/lb, 12 percent ash and 1 percent sulfur, 10,000 Btu/kwh heat rate.

Particulates

Particulates emitted from both coal and lignite combustion consist primarily of carbon, silica, alumina, and iron oxide in the fly ash. The quantity of particulate emissions depends upon the design of the boiler, the ash content of the coal, and the type of control equipment used.

Until recently the primary means of controlling particulate emissions from stationary combustion sources has been electrostatic precipitation. With the increasing emphasis on reducing SO_2 emissions, wet scrubbers and baghouses have become alternatives for the control of particulates.

Sulfur Oxides

Coal-burning electric generating stations are the major source of sulfur dioxide emissions in the United States. Other than the use of relatively scarce clean fuels, flue gas desulfurization (FGD) is the viable SO_2 control alternative currently available for lignite. AFBC technologies, currently in the developmental stages, offer an alternative to FGD toward the end of the study period.

Flue gas desulfurization systems may be classified into two general categories: throwaway processes (systems in which the sulfur product is disposed of as a waste); and recovery processes (systems in which the sulfur product, such as sulfur or sulfuric acid, may be sold). A number of FGD systems are in various stages of development. At the present time, six processes are generally considered to be the most advanced for control of SO_2 emissions from fossil-fuel burning electric generating stations. Three of these--lime scrubbing, limestone scrubbing, and double alkali scrubbing--are throwaway processes.

These processes convert the SO_2 from the flue gas to calcium sulfite and calcium sulfate solids which must be disposed of as a waste sludge or solid by-product. Three recovery processes are considered to be well advanced: magnesia or magnesium oxide scrubbing; sodium-based scrubbing (Wellman-Lord); and catalytic oxidation. These processes recover SO_2 in the flue gas for conversion to sulfuric acid, liquid SO_2, or elemental sulfur.

In AFBC systems, sulfur oxides are captured by sorbents (usually calcined limestone) which are mixed with the coal/lignite in the fluidized bed itself. The residue, which contains both ash and calcium-sulfur-oxygen compounds, is dry. AFBC pilots have been successfully tested at current NSPS of 1.2 lb per million Btu's, but performance under proposed NSPS has not yet been evaluated.

Nitrogen Oxides

Nitrogen oxides may be formed during combustion of fossil fuels either by thermal fixation of atmospheric nitrogen from combustion air (thermal NO_x) or by conversion of fuel bound nitrogen to NO_x (fuel NO_x). By modifying the conditions at which fuel combustion occurs, it is possible to minimize the formation of both fuel and thermal NO_x. In simple terms, the most significant combustion parameters are the combustion temperature, the amount of oxygen available to combine with nitrogen, the length of time which N_2 and O_2 remain in high concentrations in high temperature regions, and the rate of combustion-gas cooling.

Methods for controlling NO_x emissions from fossil fuel-fired electric generating stations are 1) low excess air firing (LEA), 2) staged combustion (SC), 3) flue gas recirculation (FGR), and combinations of these.

2.1.3 Emissions from Gasification Processes

The sulfur contained in feed coal or lignite is removed from the product gas stream in a gasification plant, so that the gas will burn cleanly. Sulfur is ultimately removed in the solid, elemental form, so the plant has no major SO_2-containing waste gas stream. Process vent gases, which contain hydrocarbons and carbon monoxide are typically incinerated so that only CO_2 and water are released. Small amounts of sulfur in these vent gases are oxidized to SO_2.

Facilities ancillary to the gasifier train itself may produce larger emissions. If coal is combusted to supply in-plant heat, steam and power needs, its emissions will be similar to those from a power plant boiler, although lower in total quantity.

Product and by-product storage and transfer may result in fugitive emissions of hydrocarbons. Hydrocarbon emissions arise from a very large number of sources such as pump seals, joints, valves, flanges, and storage tanks. Use of mechanical seals on pumps, vapor recovery systems on tanks, and other protective design and equipment features, properly maintained, can reduce these emissions considerably.

Table 2-2 summarizes all of these various emissions expected from a well-operated Lurgi-process gasification plant of a size similar to that postulated for the development scenario under analysis.

2.1.4 Trace Elements and Radioactive Emissions

Trace elements contained in coal may be captured in bottom ash or may volatilize and go out the stack. Portions of

TABLE 2-2. AIR EMISSIONS OF CRITERIA POLLUTANTS FROM A 250 MMscfd LURGI PLANT*

Source	Air Emissions (lb/hr) Particulate	SO_2	NO_x	CO	HC	Stack Parameters Stream Rate(lb/hr)	Volumetric Flow(ACFM)	Velocity (fps)	Hgt (ft)	Temp (°F)
Boilers & Turbines	negligible	248	418	--	--	5.7×10^6	1.8×10^6	60	300	300
Steam Superheater	negligible	34	57	--	--	0.31×10^6	0.10×10^6	60	300	300
Fuel Gas Heater	negligible	8	13	--	--	68.0×10^3	22.0×10^3	60	300	300
Incinerator	negligible	226	161	--	--	1.6×10^6	0.5×10^6	60	300	300
Storage	--	--	--	--	7	7	--	--	50	--
Fugitive Losses	--	--	--	--	40	40	--	--		
TOTAL	negligible	516	649	--	47					

Source: Radian Corporation. Characterization of Waste Effluents from a Lurgi Gasification Plant.[2]
*Producing High-Btu gas.

the volatilized emissions of this latter group of elements typically recondense on small fly ash particles as the flue gas cools. Three of these elements are particularly relevant to the use of Texas lignite.

Arsenic from coal combustion, carried mainly on particles, is one of the major components of man-made arsenic contributions to the atmosphere. Because arsenic pollution from man-made sources is about five times the size of natural contributions in the Northern Hemisphere, EPA is considering emission standards for arsenic.[3] Arsenic has been measured in a limited number of samples from the Wilcox lignite in Freestone County.[4] The values found ranged from 1.0 to 5.5 ppm, as compared with an average value of 101 western coals of 15 ppm.[5] Thus, at least in some cases, Texas lignite may result in arsenic emissions considerably lower than those of some competing western coals.

In the same set of Texas lignite samples, selenium concentrations varied from 3.9 to 22.9 ppm, and exhibited strong fluctuations within the same seam. The upper values are considerably higher than average concentrations of 2 ppm for 101 western coal. The highest value among the western coals were only 8 ppm.[5] Thus, depending on whether the average selenium concentrations of the large volumes of coal used in a commercial facility lie toward the upper or lower end of this range, selenium emissions from lignite could be higher than those of most competing western coals. Unlike arsenic, however, selenium is not one of the unregulated pollutants which EPA is required by the Clean Air Act Amendments of 1977 to give immediate regulatory consideration.

Uranium is found in Texas lignite in quantities that vary considerably throughout seams. Highest uranium levels are found at the contacts of lignite seams with sandstones or shales, and sometimes adjacent to shale partings. In the Wilcox lignite, concentration at these contacts may be by a factor of as much as 20, resulting in maximum concentrations of 20 ppm. In the Yegua-Jackson lignite, similar concentration factors lead to high values of 70 ppm, while in the Upper Jackson, a noncommercial lignite strata, concentrations are reported of up to 7800 ppm.[6]

The maximum values are very high, compared both to seam averages and to comparable values in western coals. Fort Union Coal from Wyoming, for example, typically contains less than 1 ppm.[5] Thus, those portions of seams with the highest uranium values will probably need to be segregated from fuel supplies delivered to commercial users.

Under the Clean Air Act Amendments of 1977, EPA is required to determine whether radioactive emissions require regulation to protect human health. Any such regulation, applied to Texas lignite, would have to take account of the occurrence of localized uranium concentrations.

2.1.5 Secondary Impacts

Although the major air quality impacts associated with lignite development relate to the mining and combustion of the resource, the activities associated with increased population and secondary developments will generate air pollutants. These are primarily in the form of hydrocarbons, carbon monoxide and nitrogen oxide emissions from automobiles.

2.2 Projected Emissions of Criteria Pollutants

Currently, there are no areas designated as non-attainment for SO_2 or NO_x in Texas. Only small portions of several counties have been designated as non-attainment for particulates.* None are near lignite producing areas. In general, the air quality for the entire study area is good. Table 2-3 shows representative cities.

TABLE 2-3. THE 1976 AMBIENT AIR QUALITY CONCENTRATIONS IN THE URBAN AREAS AROUND THE LIGNITE BELT (micrograms per cubic meter)

	Total Suspended Particulates			Sulfur Dioxide (SO_2)			Nitrogen Dioxide (NO_2)
Site Location	Maximum 24-Hour Average	2nd Maximum 24-Hour Average	Geometric Mean	Maximum 24-Hour Average	2nd Maximum 24-Hour Average	Arithmetic Mean	Arithmetic Mean
Austin	193	163	60	9	2	2	28
Bryan	169	110	74	2	2	2	4
Dallas	175	161	69	19	8	2	54
Houston (Cypress)	166	148	62	8	2	2	23
San Antonio	202	96	53	2	2	2	24
Mt. Pleasant	146	103	56	96	67	6	23
Texarkana	194	180	99	18	14	3	25
Tyler	151	111	55	15	2	2	30
National Ambient Air Quality Standard	260	260	75	365	365	80	100

Source: Texas Air Control Board[6]

*As noted in the Federal Register, March 3, 1978 (p. 9037), parts of the following counties were designated as non-attainment for particulates: El Paso, Cameron, Hidalgo, Nueces, Dallas, Harris, Galveston, Maverick and Bexar.

within the study area and recent ambient air quality data. Also listed in the table as a point of reference is the applicable primary national ambient air quality standard (NAAQS). The table indicates that, in general, the air quality of the region is below NAAQS. In particular, the levels of SO_2 are well below NAAQS.

It would be useful to compare the ambient air quality data in Table 2-3 with levels estimated based on the siting exercise described in Chapter III. However, estimates of future air quality cannot be made without extensive dispersion modeling. Therefore, it must be presumed that unless the NAAQS are changed, the ambient levels of SO_2, NO_x and particulates will fall below NAAQS. The future levels of these pollutants are, however, anticipated to be higher than present levels.

Although future estimates of ambient air quality cannot be made with confidence, estimates of emissions can be made based on assumptions regarding fuel characteristics, plant capacity factors, coal and lignite consumption rates, and emission control levels.

Tables 2-4, 2-5, and 2-6 indicate estimated regional and total SO_2, NO_x, and particulate emissions for 1985 and 2000 based on the proposed NSPS, current NSPS, and controls on existing sources. The emission level estimates are based on the number of coal and lignite plants forecast in Chapters I and II and sited in Chapter III.

To put these emission estimates in better perspective, actual emission data based on Texas Air Control Board's 1973 emission inventory for the entire state are also presented.

TABLE 2-4. COAL AND LIGNITE COMBUSTION IN THE STUDY AREA: ESTIMATED 1985 AND 2000 SO_2 EMISSIONS (tons per year)

Assumed Emission Rates	1973	1985	2000
Total Number of Coal Facilities[1]	--	16	56
Total Number of Lignite Facilities	2	24	85
@ .4 $lb/10^6$ Btu[2]	--	245,300	864,600
@ 1.2 $lb/10^6$ Btu[3]	--	735,800	2,594,000
@ 3.0 $lb/10^6$ Btu[4]		1,840,000	6,486,000
Actual 1973[5]	134,800		

[1]Utilities and industrial facilities equivalent to 500 MWe units

[2]Proposed NSPS levels (85% scrubbing)

[3]Current NSPS levels

[4]Current control levels for existing sources

[5]TACB actual historical data for coal- and lignite-burning sources only

TABLE 2-5. COAL AND LIGNITE COMBUSTION IN THE STUDY AREA: ESTIMATED 1985 AND 2000 NO_x EMISSIONS (tons per year)

Assumed Emission Rates	1973	1985	2000
Total Number of Coal Facilities[1]	--	16	56
Total Number of Lignite Facilities	2	24	85
@ .6 $lb/10^6$ Btu[2]		367,900	1,296,900
@ .7 $lb/10^6$ Btu[3]		429,200	1,513,000
Actual 1973[4]	32,800		

[1]Utilities and industrial facilities equivalent to 500 MWe units

[2]Proposed NSPS levels

[3]Current NSPS levels

[4]TACB actual historical data for coal- and lignite burning sources only

TABLE 2-6. COAL AND LIGNITE COMBUSTION IN THE STUDY AREA: ESTIMATED 1985 AND 2000 PARTICULATE EMISSIONS (tons per year)

Assumed Emission Rates	1973	1985	2000
Total Number of Coal Facilities[1]	--	16	56
Total Number of Lignite Facilities	2	24	85
@ .03 $lb/10^6$ Btu[2]		18,400	74,800
@ .1 $lb/10^6$ Btu[3]		61,300	216,200
@ .3 $lb/10^6$ Btu[4]		184,000	648,500
Actual 1973[5]	29,500		

[1]Utilities and industrial facilities equivalent to 500 MWe units

[2]Proposed NSPS levels

[3]Current NSPS levels

[4]Current control levels for existing sources

[5]TACB actual historical data for coal- and lignite-burning sources only

From Table 2-4, it is evident that even under the strict proposed NSPS (requiring 85 percent sulfur removal), SO_2 emissions from coal- and lignite-fired utility and industrial facilities are projected to increase approximately six-fold between 1973 and 2000. While this appears to be a significant increase, it should be noted that total statewide SO_2 emissions (from all sources) were approximately 1,215,000 tons per year in 1973.[7] If the total emissions (from all sources) were to remain unchanged through year 2000, the incremental increase caused by the new coal and lignite facilities would be about 70 percent (assuming application of the proposed NSPS). In addition, it should be kept in mind that there is no simple and direct relationship by which air quality can be predicted on the basis of emissions only.

Table 2-5 shows that NO_x emissions from coal- and lignite-fired facilities will increase to about 1.3 million tons per year by 2000. This compares to the 1973 total of 2.1 million tons of NO_x emissions from all point sources in the state.[7]

Table 2-6 shows that particulate emissions under the proposed NSPS will result in more than doubling 1973 levels from coal and lignite combustion. The approximately 75,000 tons per year projected for year 2000 is small, however, compared to the approximately 1.4 million tons per year of total particulate emissions for all point sources in the state in 1973.

2.3 Potential Long-Term Impacts of Increased Coal and Lignite Burning

2.3.1 Downwind Fate of Power Plant Emissions

By law, all new power plants permitted in Texas will be required to avoid violating either NAAQS or PSD for regulated pollutants. Models used to assess compliance are considered accurate out to 50 km,* although accuracy becomes very uncertain at greater distances. Thus, standards may be presumed met at least this close to each plant. Assuming that these standards are adequately set, then substantially adverse affects on human health, vegetation, and animals will be avoided within this 50-km radius.

Recent research, however, has shown that the impacts of large power plants potentially extend well beyond this range, especially where plants are aligned with respect to wind direction. Of particular importance is the formation of particulate sulfate compounds through the oxidation of SO_2 in the atmosphere downwind of the original source.[8] Since water participates in

*Reference is made to the EPA CRSTER model.

these reactions, they are favored by high humidity. The presence in the atmosphere of ozone, a strong oxidizing agent, also promotes sulfate formation. Other airborne particulates may also form in a similar manner downwind from the source.[8] These particles contribute to acid rainfall, and are frequently a significant component of total suspended particulates (TSP). Sulfate is through to be directly related to visibility.[9]

Conditions in East Texas combine both humidity and, perhaps, high ozone levels.* In addition to the ozone already in the ambient air, recent observations suggest that under some conditions ozone may form downwind from power plants by light-mediated atmospheric reactions of NO_x.[10,11] A downwind ozone "bulge" is not always observed, however. The reactions responsible for it have been shown in laboratory experiments to depend strongly on the presence of a high ratio of ambient non-methane hydrocarbons to NO_x. Also, meteorological conditions must allow the plume to remain stable for several hours so that the rather slow reactions have time to build up significant amounts of ozone. Warm temperatures and bright sunlight are also needed. The best conditions for the formation of a downwind ozone bulge are thought to occur in rural areas with naturally high nonmethane hydrocarbon levels and naturally low NO_x.[10]

Where more than one source is involved, these impacts may be additive if they are aligned with persistent winds. Figure 2-1 illustrates schematically that these additive effects are more pronounced for the secondary pollutant, sulfate, than for the original pollutant, SO_2. The figure also gives an idea

*Although ozone has not been extensively monitored in East Texas, recorded levels in adjacent coastal areas are high enough to suggest that elevated levels may characterize inland regions, as well.

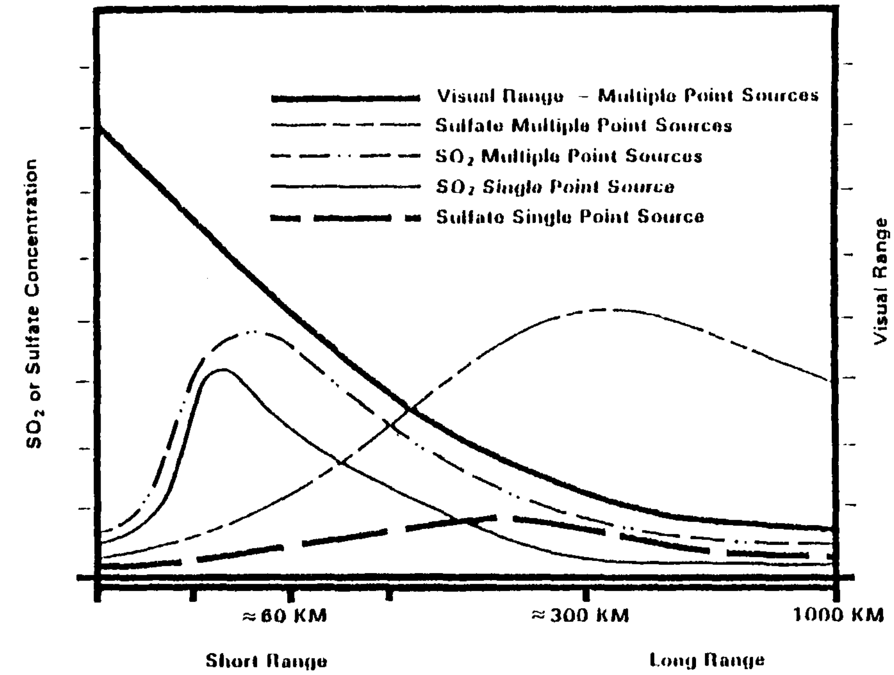

Figure 2-1. Schematic Diagram of Short-Range and Long-Range Air Quality Impacts from Single and Multiple Point Sources
(Courtesy of Teknakron, Inc.)
02-4304-1

of the distances at which these downwind effects occur. It should also be noted that worst-case conditions used in modeling to determine the effects of single sources are not necessarily those which produce the worst cases for additive impacts.

To determine whether these effects could cause violations of air quality standards becuase of the relatively clustered development of lignite- and coal-fired power plants in East Texas would require sophisticated computerized modeling beyond the scope of this study. Appropriate modeling techniques are being developed,* but their application is hampered by the

*Considerable in-depth investigation of this problem is now being funded by EPA's Office of Energy, Minerals, and Industry.

absence of meteorological and ambient air quality data at a sufficient level of detail.*

In the present state of uncertainty, several concerns have been raised which cannot yet be quantitatively assessed. There is concern that emissions originating on the industrialized Gulf Coast may be carried inland and added to emissions from lignite-belt development. At the TEAC-sponsored Third Annual Texas Energy Policies Conference held at Austin in May of 1978, Dr. Louis R. Roberts, Director of the Texas Air Control Board Permits and Source Evaluation Division pointed out that SO_2 emissions in highly industrialized coastal areas may already be high enough to approach ambient standards. At the same meeting, Mr. Joe Moore, Head of the Graduate Program in Environmental Sciences at the University of Texas at Dallas, suggested that the combined effect of effluents from the 12 to 15 new power plants sited and upwind of Dallas-Fort Worth may keep this area from attaining NAAQS. The national secondary particulate standard is also thought likely to be threatened by power plant development, such that siting new facilities will become progressively more difficult.[13] Additions to TSP because of sulfate formation would worsen this situation.

In addition to these effects, which would take place within Texas, concern has also been expressed over transport of pollutants over longer distances. Data analyzed by Teknekron, Inc., under contract to EPA, suggest that measured levels of TSP in Arkansas, high enough to violate the secondary standard, may be related to long-distance transport both from the Ohio River Valley and from the areas along the Gulf Coast.[14] In a number of cases examined by Teknekron, air parcel paths suggested that

*Brand Niemann, Teknekron, Inc., personal communication, February 9, 1979.

sulfate levels in the Ohio River Valley may have been elevated by long-distance transport from parts of the Gulf Coast. Insufficient data on the prevailing directions of persistent winds near the surface and at plume levels make it impossible to say with certainty whether developing an array of new sources in East Texas would contribute to these problems.

It appears, however, that both plant spacing and emission levels would together contribute to the extent of whatever long-distance transport problems might develop. Although strict controls might mitigate relatively short-range additive impact problems, continued growth in a relatively confined area could offset strict controls at the mid-range level of interstate distances. At very long distances, such as those separating Texas from the Ohio Valley, local siting arrangements and emission controls might have little effect, even though mid-range problems were eased.[14]

Thus, regulation of the additive, downwind impacts of an array of power plants, should it prove necessary, might involve very fundamental control of regional development, so as to acquire the necessary leverage on total emissions over large areas.

2.3.2 Potential Ecological and Health Impacts of Power Plant Emissions

A major concern expressed about sulfate buildup is the potential for acid rainfall.[9] The mechanisms by which rainfall is acidified are only beginning to be understood. However, it is thought that sulfate, nitrate, and chloride are the major chemical species involved.[15] Acid rainfall problems can occur quite locally, around individual plants or small clusters of them, or regionally as a result of heavy concentrations of sources. Although techniques to predict rainfall pH from SO_2 emission rates have not yet been developed, the relationship of sources in the Ohio Valley to acid rain in the eastern United States is generally well accepted.[9] Emission levels there, however, average more than 20 tons/km^2,[16] much higher than what seems likely to result from the growth of power production in East Texas. Thus, acid rainfall problems on a parallel scale appear unlikely to result, although impacts at lower levels cannot be ruled out without further research. Evidence has also been presented implicating atmospheric sulfates in health damage.[17] Recent research, however, has led to a general lessening of concern over health effects.[18]

Recent modelling and epidemiological work[17,19,20,21] also suggests that even with extensive development of coal and lignite, East Texas populations are unlikely to experience significant changes in mortality rate or life span due to emissions of presently regulated pollutants. Although long-term increases in respiratory disease or dysfunction cannot be entirely ruled out, the SO_2 and particulate levels accompanying regional lignite and coal development will be unlikely to cause noticeable effects of this kind. National Ambient Air Quality Standards for SO_2, NO_2, and particulates should, if met, provide adequate protection from short-term adverse health effects.

2.4 Research Needs

- Further characterization of trace-element concentrations in lignites from various parts of Texas.

- Measurement of radioactive emissions from existing lignite-fired power plants, and evaluation of potential desirability of lignite segregation as a means of control.

- Realistic, sophisticated modeling of the additive impacts of multiple sources in East Texas. Effect on PSD increments for SO_2 and particulates should be particularly emphasized.

- Improved assessment of reaction rates for key atmospheric pollutant-transformation processes, and identification of principal sources of geographic and temporal variation in these rates.

- Observations of conditions producing "ozone bulges" downwind of existing coal- and lignite-fired power plants, and assessment of the potential importance of this phenomenon to meeting NAAQS for ozone.

- Extensive collection and assembly of meteorological tower data and ambient air quality data for use in relating air parcel trajectories originating in Texas to potential problems in other states.

- Improved modeling of pollutant transformation, transportation and dispersion at regional and sub-national scales.

- Improved understanding and assessment of the potential for acid rain in East Texas due to lignite demand.

- Analysis of potential interstate policy conflicts concerning long-distance pollutant transport, and alternative modes of resolution.

- Assessment of the potential for visibility deterioration in East Texas as a result of increased formation of sulfates and other particulates.

3.0 IMPACTS OF LIGNITE-RELATED SOLID WASTES

Summary and Conclusions

- Solid wastes associated with the development scenario consist chiefly of ash and residues from sulfur removal. Ash and scrubber sludges are usually disposed of in slurry form. Wastes from fluidized bed combustion are dry, and contain both ash and sulfur salts.
- All these wastes are alkaline, and contain most of the trace elements originally present in the coal. When leached with water, many of these materials go into solution at concentrations higher than those permitted in drinking water.
- According to criteria proposed by EPA under the Resource Conservation and Recovery Act, many of these wastes would be considered "hazardous" and require special handling.
- A 500-MWe generating unit with a lime/limestone scrubber and ESP would produce, over its lifetime, about 9,000 to 21,000 acre-feet of solid wastes if it burned Texas lignite of various grades, 7,600 if it burned western coal, and 11,000 with midwestern coal. Use of regenerable scrubber systems, which produce no solid wastes requiring disposal, would cut these amounts by one half to two thirds.
- Cumulative volumes produced depend on the choice of fuel and SO_2- removal method. Assuming as a worst case that lime/limestone scrubbing is used on all plants projected by the development scenario, a total of about 1.3 million acre-feet of sludge and ash would ultimately be produced. A grand total of 66 square miles would be needed for disposal, assuming surface impoundments 30 feet in depth.
- Because aquifer recharge is a complex phenomenon over the Lignite Belt, disposal sites must be carefully chosen. Simultaneous growth in both ground water use and solid waste production will probably result in increasing difficulty in siting disposal facilities.

3.1 Sources of Solid Waste

Federal and state air pollution requirements to remove particulates and sulfur dioxide from flue gases are resulting in a large and growing solid waste disposal problem. By far the largest amounts of solid wastes generated from increased coal and lignite use will be ash and sludge from sulfur removal.

3.1.1 Ash

Coal and lignite combustion produces two kinds of solid residue: bottom ash and fly ash. Bottom ash is a coarse material somewhat like gravel. Fly ash is the very fine particulate matter that is carried in the flue gas. When collected, it has a fine texture similar to cement.

A requirement for near-total removal of fly ash from flue gas is now standard. EPA's performance standard for particulate removal for fossil-fuel fired electric generating units is 0.1 lb/million Btu heat input, with an opacity rating of no more than 20 percent (visually measured smoke density), for units permitted after 1971.[23]

Collection methods and the estimated percentage of power plants using each is as follows:[24]

Method	Percent
Dry Electrostatic Precipitators (ESP)	61
Mechanical (Baghouse, etc.)	13
Wet ESP	6
Particulate Scrubber	3
Other	17

ESP's are capable of removing more than 99 percent of the particulates if properly designed. Mechanical collection methods usually achieve a somewhat higher efficiency and are sometimes used in parallel with ESP's.

Since operators are required to achieve about a 99 percent removal efficiency, the volume of ash residues produced does not significantly affect the choice of removal technologies. The ability of the method to meet air quality requirements, and its cost and its reliability are considerably more important factors.

3.1.2 Sulfur Removal Residues

Current proposals call for removal of 85 percent of the sulfur dioxide in flue gas from all coals.[25] SO_2 in flue gas can be controlled both by techniques which remove sulfur from the flue gas itself (Flue Gas Desulfurization or FGD) and by capturing sulfur in the combustion zone (Fluidized Bed Combustion, or FBC). A number of FGD systems, usually called scrubbers, are available now. FBC is not expected to become commercial until late in the study period.*

The removal of SO_2 by means of scrubbers is a choice between two general types of processes--regenerable and nonregenerable. Regenerable scrubbers produce elemental sulfur as a marketable by-product, and can reuse the sorbent. Non-regenerable or "throwaway" processes produce an unusable solid waste stream which requires disposal. The most widely used of the throwaway processes is lime or limestone scrubbing. This is the only FGD technology currently planned for uses in Texas.

*See Chapter I, Sections 4 and 5, for a discussion of FBC as applied to industrial and utility boilers.

with respect to groundwater contamination. Trace elements not extracted with the fly ash and bottom ash will generally be deposited in sludge. For both separate and mixed disposal, several trace elements potentially toxic to humans may leach out of the wastes. The degree and rate of leaching primarily depends on the stability of the wastes and the permeability of the material used to line the disposal site. Mixing ash and sludge wastes from lignite usually results in a more stable material due to chemical reactions which take place when they are combined.

Solid residues from FBC operation also contain various sulfur-based salts of silicon, iron, potassium, sodium, magnesium, aluminum and titanium, and oxides and salts of various trace heavy metals.

3.2.2 Definition of "Hazardous Waste" under RCRA

The Resource Conservation and Recovery Act (RCRA) requires EPA to develop criteria for identifying "hazardous" wastes. Hazardous wastes are defined in the Act as:

> "waste, which because of its quantity, concentration, or physical, chemical, or infectious characteristics may - (A) cause, or significantly contribute to an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness; or (B) pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of, or otherwise managed." [Subtitle C, Section 1004(5)]

Criteria for identifying the characteristics of hazardous waste were proposed under Sec. 3001, on December 18, 1978 (43 FR 58946), and include:

- toxicity
- flammability
- corrosiveness
- ignitability
- reactivity
- radioactivity
- infectiousness
- toxicity to plants
- mutagenicity
- teratogenicity

Of these criteria, toxicity is most pertinent to solid wastes from coal and lignite. EPA has proposed to classify utility waste as "special waste" along with certain other high-volume/low-risk wastes. Treatment, storage and disposal requirements are being deferred until further studies are completed.

EPA's approach to establishing criteria for contaminant levels is twofold:

1) Determine the risk of toxic wastes becoming available to the environment (i.e., the ability of toxic species to migrate out of wastes); and
2) Set concentration levels based on the National Interim Primary Drinking Water Standards (NIPDWS) which take into account an appropriate dilution factor, providing an adequate margin of safety.

In assessing the potential for utility wastes to contaminate the environment, EPA calls for testing ash and sludge leachate. An extraction procedure is used, which attempts to simulate real leaching conditions, and assesses the composition of the leachate, rather than the wastes themselves.

Threshold concentration levels are established for leachate on the basis of uncontrolled conditions. They are based only on the chronic toxicity to humans (rather than genetic activity, bioaccumulation in tissue, and toxicity to plants and animals) as defined by the drinking water standards promulgated pursuant to the Safe Drinking Water Act of 1974. The proposed level is ten times the NIPDWS. The ten-fold dilution factor is based on the amount of purification that can reasonably be expected from the point at which the contaminants enter an aquifer to the point of a water well (assuming a 500-foot minimum distance).[27]

TABLE 3-2. MAXIMUM CONCENTRATIONS OF CONTAMINANTS ALLOWED UNDER NIPDWS AND RCRA

	NIPDWS mg/liter	RCRA mg/liter
Arsenic	.05	.5
Barium	1.0	10.
Cadmium	.010	.1
Chromium	.05	.5
Lead	.05	.5
Mercury	.002	.02
Nickel	10.	100.
Selenium	.01	.1
Silver	.05	.5

Several of the trace elements in scrubber sludge leachate may occur in concentrations of more than the national drinking water standard. These elements include: arsenic, barium, boron, cadmium, chromium, lead, mercury, and selenium. Depending on the results of an individual test, the elements selenium, mercury, barium, boron, and chromium may exist in concentrations of more than ten times the drinking water standard.[28] Waste containing concentrations at these levels would be classified as hazardous by EPA under Subtitle C of the Resource Conservation and Recovery Act. Any contaminant concentration of more than ten times drinking water standards must be viewed as exceeding the safe contaminant threshold for groundwater quality protection resulting from lignite solid waste disposal.

According to these criteria, EPA Region VI officials believe that much, if not most, of the sludge and ash generated by coal- and lignite-fired power plants in Texas may be defined as hazardous.

3.3 Potential Volumes of Solid Waste Produced in Texas

3.3.1 Waste Production from Individual Sources

For systems using throwaway FGD technology, total solid waste production rates depend on the following factors:

- Btu content of coal or lignite,
- Sulfur and ash content of coal or lignite,
- Boiler size and type,
- Type of ash and SO_2 control equipment, and
- Separation or blending of ash and scrubber sludge.

Since the first two of these factors depend on fuel type, the choice of fuel affects the total volume of waste produced. Table 3-3 shows how these volumes differ between coals from the west and midwest, and between lignites from various parts of Texas. Emission control is assumed to be by a cold-side ESP and a throwaway limestone scrubber.

A comparison of the volumes of ash and sludge wastes resulting from the use of lignite and coal, assuming other non-fuel factors to be the same in each case, shows that for a typical 500-MWe power plant, use of lignite will produce considerably more ash residue than eastern coal and somewhat more than

TABLE 3-3. COMPARATIVE VOLUMES OF SOLID WASTE PRODUCED BY COAL AND LIGNITE COMBUSTION

	Texas Lignites			Coal	
	Northeast	North Central	Central & South	West	East
Fuel Assumptions	.7% SO_2 14% Ash 7000 Btu/lb	1.1% SO_2 8% Ash 7500 Btu/lb	2.0% SO_2 20% Ash 6500 Btu/lb	.8% SO_2 10% Ash 8500 Btu/lb	3.5% SO_2 10% Ash 12,500 Btu/lb
Coal Rates					
tons/hr	406	379	437	334	227
tons/year	2,845,000	2,650,000	3,060,000	2,340,000	1,600,000
Waste Quantities					
tons/yr dry sludge	98,000	132,500	275,400	88,920	256,000
tons/yr ash	398,300	212,000	612,000	234,000	160,000
Waste Volumes					
acre-ft/yr sludge	117	159	330	107	307
acre-ft/yr fly ash	157	86	249	96	65
acre-ft/yr bottom ash	39	21	62	24	16
total acre-ft	313	266	641	227	388
Total acre-ft per 30-yr plant life	9390	7980	19,230	6810	11,640
Total acres assuming 30-ft average disposal depth	313	266	641	227	388

Assumptions:				
	Unit rating	500 MWe	SO_4/SO_3 ratio	80/20
	Load factor	80%	Ash dry density	90 lb/ft^3
	Efficiency	30%	Sludge percent dry solids	45%
	Scrubber efficiency	90%	Average disposal depth	30 ft
	Fly ash/bottom ash ratio	80/20	Average plant life	30 years

western coal, except for lignites from the central and southern study regions, which are characterized by higher ash contents. For sludge residues, lignite results in greater volumes than western coal, but less than eastern coal, except once again in the central and southern regions of the Lignite Belt.

The higher amounts of both ash and sulfur sludge from lignite occur largely because it simply takes more lignite to generate 1 MWe of electricity than in the case of either western or eastern coal. Any comparative advantage lignite may have for the ash and SO_2 content factors tends to be offset or lost entirely by its considerably lower heating value.

This comparison shows that western coal would be somewhat preferable to lignite in terms of the quantities of solid wastes in need of disposal. The difference, however, is probably not great enough to be a factor in choosing to use coal rather than lignite, except possibly in the case of poorer grade lignite desposits containing high ash and sulfur contents and having comparatively low heat value. For better lignite deposits, the difference in volume is in the range of from only 7 to 15 percent, whereas for the poorer quality lignite deposits, the difference is as much as 275 percent.

It has been demonstrated in pilot FBC systems that solid waste is produced at a rate of about 0.5 acre-feet/MWe-year when the unit operates under present NSPS. For a 500-MWe unit, this would result in an annual production of 250 acre-feet, or 7500 acre-feet over a 30-year lifetime.[29] This volume would increase if new NSPS were met.

3.3.2 Cumulative Waste Production Levels

Table 3-4 shows the cumulative volumes of ash and sludge which would result from the lignite development scenario.

TABLE 3-4. INDUSTRIAL AND UTILITY SOLID WASTE VOLUMES BY STUDY AREA SUBREGION (acre-feet per year)*

	Western	Northeast	North Central	Southern	Central	Gulf Coast	Total
Coal Utilities 1985**	908	454	454	0	454	908	3178
Coal Utilities 2000	2724	1362	908	0	1583	2724	9301
Lignite Utilities 1985	0	3130	1862	1923	641	0	7556
Lignite Utilities 2000	0	10,016	5320	3846	1923	266	21,371
Coal Industrial 1985	45	23	45	0	0	340	453
Coal Industrial 2000	318	158	295	45	45	2542	3403
Lignite Industrial 1985	0	156	532	0	0	133	821
Lignite Industrial 2000	657	1658	1643	192	256	2314	6720

*Radian staff estimates, assuming 99 percent ash removal and 90 percent sulfur dioxide removal.

**Coal is assumed to be all western coal.

These figures are a worst-case estimate, since they assume throw-away scrubbing on all plants. In reality, some might use re-generable scrubbing systems, reducing the total wastes generated. In addition, these figures include all industrial facilities, some of which may not use scrubbers. They also assume state-of-the-art removal efficiencies.

If all these wastes were disposed of in impoundments above ground, the total land required would be what is shown in Table 3-5. This total volume, however, will be divided among numerous disposal sites. The amount of land needed to dispose of the solid wastes from a single coal- or lignite-fired power plant is sizable, but still only a small percentage of the total area required for the generating station. Sludge handling and disposal may use from 100 to 200 acres of land, compared with an average of 2000 acres for the plant site, coal pile storage and drainage areas, cooling reservoir, and haul roads. If one includes a surface mining area adjacent to a lignite-fired plant, the proportional land requirements of waste disposal grows even smaller.

TABLE 3-5. CUMULATIVE LAND COMMITMENTS FOR SOLID WASTE DISPOSAL BY STUDY AREA SUBREGION* (ACRES)

	Western	Northeast	North Central	Southern	Central	Gulf Coast	Total
1985	953	3763	2893	1923	1095	1381	12,008
2000	3699	13,194	8166	4083	3807	7846	40,795

*Calculated for 30-year operating lifetime, with wastes piled to an average depth of 30 feet.

Of the totals shown in Table 3-5, approximately 12,700 acres will be required by 2000 to dispose of the wastes from plants projected to use low-sulfur western coal in Texas. This figure could vary considerably if less western coal were used because of the proposed NSPS requirement for full scrubbing for virtually all coals and lignites.

The total cumulative land area required for disposal of sludge and ash will be an estimated 40,800 acres.* Although a significant percentage of lignite use will be from the Northeast and North Central Subregions of the Lignite Belt, which are characterized by comparatively low waste volumes, enough will use lignite from the Central and Southern Subregions to justify a total figure above 40,000 acres.

Disposal sites for lignite wastes will generally be concentrated along the Lignite Belt near the generating stations themselves. The total land area required for lignite waste disposal represents only about 4 percent of the area estimated to be overlain by lignite by the Bureau of Economic Geology (1 million acres), but represents 16 percent of the area estimated by the Bureau of Mines (251,000 acres). This may not be considered a serious obstacle to the siting of the projected number of lignite facilities on a regional basis, but the land requirement is the equivalent of approximately 50 square miles, assuming an average depth of 30 feet.

Added to the combined estimates for coal and lignite wastes from power plants is the amount of land required to dispose of coal and lignite wastes from industrial processes. Since the requirements for SO_2 removal are less stringent than for power plants, quantitative estimates are less certain. Table 3-4 provides estimates describing "worst-case conditions" which assume full scrubbing for all industrial boilers. Generating sources for these wastes will tend to be located near

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*Assuming storage to an average depth of 30 feet over a 30-year plant lifetime.

the Gulf Coast, away from the Lignite Belt. Disposal options may, however, include disposal in places at some distance from the coast due to the environmental and economic difficulties of siting large numbers of surface disposal facilities in the coastal region itself.

3.4 Alternative Disposal Methods and Practices

Current industrial sludge disposal methods include ocean dumping, incineration, ponding or landfilling, land spreading as a soil fertilizer and conditioner, and recycling for commercial utilization. Only ponding, landfilling and recycling are presently used for disposal of ash and sludges resulting from the combustion of coal and lignite. In Texas, an estimated 25 percent is reused.[30]

3.4.1 Waste Collection and Transport

While fly ash may be collected dry, as with an electrostatic precipitator or a baghouse, wet sluicing may then be employed to convey the ash to a disposal pond. Where wet sluicing and ponding are not employed, the material is usually hauled by truck for landfill disposal or recycling. If the ash is collected with a wet system, as with a wet venturi, disposal is usually accomplished by subsequent pumping to a pond in slurry form. The choice of pumping a water mixture of the ash or transporting it dry is often site-specific and highly dependent upon the method of collection.

In addition to direct disposal of fly ash, it is often advantageous to mix fly ash and scrubber sludge together to take advantage of the increased stabilization and fixation resulting from the mixture.

3.4.2 Disposal Options

The options for disposal of scrubber sludge involve direct ponding or dewatering. In either case, the sludge can be mixed with fly ash or a mixture of fly ash and lime. A number of other materials are also mixed with sludge in commercial fixation processes. If not dewatered, sludges are commonly pumped at 10 to 15 percent solids. Sludges can undergo partial dewatering and be pumped to ponds at 20 to 35 percent solids. The sludges also can be vacuum filtered to 50 to 60 percent solids and trucked or otherwise hauled to the landfill. A predominantly gypsum scrubber sludge can be produced by some processes which can be sold as a marketable by-product. Predominantly sulfite sludges can also be fully oxidized to gypsum.

The options for disposal of combined fly ash and scrubber sludge, such as that generated from a combined particulate and SO_2 scrubber, are basically the same as those for sludge alone. The combined sludge can be pumped directly to a pond, either fully oxidized to gypsum or as a sulfite sludge. The sludge can be dewatered and fixed and, depending on the extent of dewatering, either ponded or landfilled.

Landfill sites for dry ash disposal are rarely lined. In the case of ponding of wet sluiced fly ash or combined fly ash and scrubber sludge, the ponds can be lined or unlined. Common liners include clay and synthetic liners. A stabilized mixture of fly ash and scrubber sludge can also serve as an effective pond liner.

In every case where ponding is used, either for dewatered sludges or the slurry pumped directly to ponds, the solids can be removed and landfilled after settling. The economics of alternative disposal techniques depend upon:

- Whether the sludge is treated or untreated,
- The design and operating characteristics of a pond or landfill, and
- Which sludge treatment method is used.

Untreated sludge generally becomes cheaper over time when compared with treated disposal techniques. Although the capital costs for untreated waste may exceed certain treated processes, the total lifetime revenue requirement of the untreated alternative is less than any other treated alternative. The principal cost for untreated waste is in the acquisition, construction, and operation of the pond or landfill. Also, the use of synthetic linings rather than natural liners such as clay greatly increases the capital costs of ponds or landfills. Another cost factor is the distance from the disposal site of generation source. If trucks are used for transportation, the difference is not major. If pipelines are used, the incremental cost of longer disposal distances will be important because of the expense of laying additional pipe.[31]

Mine disposal is an attractive option for mine-mouth lignite-fired facilities. However, the combined provisions of RCRA regarding hazardous wastes and of the Surface Mining Control and Reclamation Act regarding groundwater protection are likely to make mine disposal less attractive. Final programs have not yet been developed under both acts to cover solid waste disposal in mines. When fully implemented, however, they are likely to both raise the cost and increase the difficulty of permitting mine-site disposal.

3.5 Potential Environmental Impacts of Solid Waste Disposal

The greatest potential concern over solid waste disposal is over possible contamination of groundwater through leaching from disposal sites. Leachate from solid wastes is high in pH (alkaline) and contains a variety of trace elements which may be present in quantities as much as ten times those allowable in drinking water. The likelihood of groundwater becoming contaminated by waste leachate varies from site to site, and with the nature of the wastes and the treatment given them before disposal.

3.5.1 Leaching Conditions

The "leachability" of solid wastes depends on a number of factors including:

- Solids content of the wastes;
- Reactivity between the ash and sludge if mixed;
- Status of the disposal site (active or inactive);
- Disposal site climate (rainfall, humidity, etc.);
- Subsurface soils and geology; and
- Type of disposal facility (pond or landfill).

When seepage occurs, contaminants form a plume downgradient from the disposal site. The shape, extent, and flow rate of the plume will be determined by local geology, groundwater flow, characteristics of the contaminants, and the continuity of waste disposal. Nearby groundwater pumping may speed the flow rate and elongate the plume.[32]

The leachability of ash and sludge wastes may be altered by various chemical treatment processes. Chemical treatment or "fixes" serve to stabilize the wastes, reduce solubility, and ultimately reduce concentrations of trace elements in leachate.

3.5.2 Groundwater Contamination

The Environmental Protection Agency has established primary and has proposed secondary standards for drinking water. Primary standards indicate the maximum contaminant levels above which human health would be endangered, whereas the secondary standards are based upon aesthetic considerations such as smell, taste, and color of water.

Primary drinking water standards (mg/liter) have been promulgated for arsenic, barium, cadmium, chromium, nickel, lead, mercury, selenium and silver. Secondary drinking water standards have been promulgated for copper, iron, manganese, fluorine, and zinc. EPA has also promulgated standards applicable to the use of water for irrigation purposes. These standards set levels for beryllium, boron, cadmium, chromium, cobalt, copper, fluorine, iron, lead, manganese, molybdenum, nickel, and selenium.

Contaminants will, to some extent, be attenuated by the soils beneath the disposal site. Sulfite/sulfate crystals may serve to clog natural soil pores and impede the flow of water containing dissolved elements. Soils will also selectively absorb various contaminants, including many heavy metals, leaving only certain ones to migrate into groundwater supplies. It is possible that certain sandy soils will be able to remove up to 95 percent of the elemental contaminants over ten years of flow. This ability of soils below disposal sites to attenuate contaminants which are passing through them is the basis of the

500-foot "margin-of-safety" assumption in the proposed RCRA criteria.

As noted above, the maximum tolerable level of contaminants in solid waste leachate has been set by EPA at ten times the primary or secondary drinking standard. These levels allow for the natural processes of purification and cleansing that take place as the leachate percolates through various substrata. It is assumed that a distance of 500 feet between disposal site and groundwater withdrawal point will reduce contaminants by a factor of ten.

One important implication of this threshold of contamination is that the siting of disposal facilities in close proximity to wells which are used for drinking water purposes would possibly result in trace element levels above the national primary drinking water standard. Another implication is that identifying suitable sites at sufficient distances from existing wells may become more difficult as both waste volumes and dependence on groundwater increase.

3.5.3 Groundwater Usage

The Wilcox-Carrizo aquifer is the major water-bearing formation of East Texas. Wells in the Wilcox-Carrizo aquifer supply water for most municipal and industrial uses in East Texas. Although figures for individual localities within the Wilcox-Carrizo vary, the pattern of numerous small communities which depend upon groundwater sources for their drinking water supplies is noteworthy. Throughout the region, there is a high dependence on groundwater supplies for drinking water when compared to other areas of the state, especially the large metropolitan regions, which rely more heavily on developed surface water supplies. There is a strong likelihood that groundwater pumpage rates will increase and as a result the potential for drinking water contamination may increase as the number of sludge disposal sites in the area of the Carrizo-Wilcox aquifer grows.

Another factor which should be considered when examining current and future groundwater usage patterns, is that as groundwater withdrawal rates increase, and the level of the water table is drawn down, there could be two changes:

- The distance between a surface disposal site and the water table will increase, thus allowing for a greater degree of purification before contaminant plumes reach groundwater supplies; but

- The flow rate of the aquifer could increase, thus speeding up the rate at which contaminants would be transmitted through water-bearing formations to the location of water supply wells nearby.

3.6 Environmental Limitations on Suitable Waste-Disposal Sites

To guard against aquifer contamination, disposal sites over possible recharge zones should be avoided or very carefully managed. Groundwater recharge is a complex phenomenon over most of the Lignite Belt. The several geological strata outcropping in the vicinity of potential mine and plant sites are hydraulically interconnected. Within each of these strata, moreover, permeability varies substantially. Thus, selection of a disposal site without due attention to local groundwater hydrology would risk possible seepage problems from waste leachate.

Most of the groundwater in the Lignite Belt is found in sandy strata which act as aquifers. The most important of these aquifers are the relatively continuous Carrizo and Simsboro sands, which lie stratigraphically immediately above and below the Calvert Bluff Formation, in which the lignite is found. The Carrizo aquifer is a major regional freshwater source for municipal, industrial, and agricultural use, especially on and near its outcrop. Other dominantly sand formations occur in a coastward direction and are also widely used as minor aquifers. These sands are generally isolated stratigraphically, and no significant lignite occurs within their recharge areas. However, these minor aquifers (especially the Queen City and Sparta sands) are locally important sources of water near the Yegua lignite trend.

The principal aquifers potentially affected by lignite mining are the Carrizo and Simsboro. The aquifers actually consist of a complex, hydrologically interconnected system of sand bodies which function as a single water-bearing unit. The manner of water movement into and through these aquifers is essentially the same in both. The Calvert Bluff Formation which lies between them is a mixed mud and sand formation. Although generally less permeable than the two sand strata, the Calvert Bluff can transmit water under pressure. Thus, the two aquifers are connected through the Calvert Bluff.

The Simsboro and Carrizo aquifers are recharged primarily by rainfall and streamflow infiltrating the sandy strata where they crop out at the surface. In these areas, water is found at quite shallow depths. In a similar manner, a much smaller amount of water infiltrates the Calvert Bluff Formation.

All of the sediments in these three geologic units have some degree of permeability. Disposal sites located over any part of their outcrop have the potential for infiltrating and entering the groundwater system to some extent. However, the more permeable sand elements will transmit contaminants into the groundwater at a much faster rate than other components. Permeability values for some of these sands in East Texas range from 17 to 338 gpd/ft^3, and average 88 gpd/ft^3. The permeability of the sandy clays is around .01 gpd/ft^3, or only about one-fourth the rate of the sands.[33] Because of their extensiveness at the surface, the Carrizo and Simsboro sands have the potential for a significant amount of groundwater contamination in the event scrubber and ash sludges are disposed of without proper safeguards.

3.7 Other Wastes

In addition to the ash and sulfur-removal wastes arising from power generation, two other solid waste types require consideration: gasification plant wastes, and potentially dangerous high-radioactive strata disturbed in mining.

Low- and medium-Btu gasification produce an ash similar to that resulting from combustion. This ash is mixed with a fraction of unburned coal and may contain a variety of organic substances. For a lignite-based plant in the size range economically attractive for Texas, this waste stream might be produced at a rate of 2500 to 3500 tons per day. Gasification also produces tars which may contain highly carcinogenic organic compounds. These tars, however, may be burned as fuel within the plant. This process destroys the hazardous organic compounds they contain.

Sulfur is recovered from product gas in solid form. If this material cannot be sold, it must be either stored or disposed of as solid waste.

It was pointed out in Section 2 above that very high uranium concentrations occur where lignite seams come in contact with sandstones and shales. High concentrations also sometimes appear next to shale partings.[6] In some instances, concentrations are high enough to suggest possibilities of commercial recovery.

Uranium in lignite is oxidized on contact with air, and becomes soluble. Thus, mixture of this material with overburden for backfill in strip mines might result in leaching and potential groundwater contamination. No data exist to show whether such problems have developed at existing lignite mines. An alternative to disposal, however, might be to segregate these uranium-bearing materials for processing to recover the uranium. Tests of the feasibility of uranium recovery from lignite are now being conducted at Texas A&M University's Center for Energy and Mineral Resources.[6]

3.8 Research Needs

- Investigation of the potential for groundwater contamination with uranium leached from waste lignite left in mines. Observation of existing mines for evidence of uranium solution and migration.

- Testing scrubber sludge and ash from lignite-based processes (combustion and gasification) for potential hazardous classification.

- Investigation of the fate of solid-waste contaminants following disposal, utilizing both laboratory tests and detailed field sampling to provide a basis of estimating risk of exposure.

- Evaluation of potential effects of solid waste disposal on future uses of the disposal site.

- Identification and mapping of conditions related to the suitability of sites for sludge and ash disposal.

- Evaluation of various ash and sludge treatment processes for stabilizing wastes and reducing trace metal migration into groundwater.

- Evaluation of techniques for reuse or recycling of solid waste products in terms of environmental effects.

- Investigation of possible regulatory barriers to recycling solid waste.

4.0 IMPACTS ON SURFACE AND GROUNDWATER QUANTITIES

Summary and Conclusions

- Over the entire study area, consumptive use by the mining and power-production aspects of the development scenario would total to about 4.6 percent of developed supply in the year 2000. By subregion, the proportion of consumption to supply varies from 13 percent (Northeast) to 1.3 percent (Gulf Coast).

- The cost of developing new surface water impoundments increases as a basin is developed. Thus, new supplies will cost more to the user than existing ones.

- As the value of water rises, there may be a tendency for the percentage used by agriculture to go down as energy's share goes up.

- Groundwater is likely to be developed as a substitute for high-priced surface supplies. As more is pumped, existing drawdown problems are likely to become more widespread. As this happens, the cost of using groundwater will go up. Agriculture may have little flexibility to cope with these rising costs.

- Although consumptive use is likely to cause general flow reductions, this effect is not expected to be serious on a subregional level. Impacts at specific locations could be significant.

- As flow is reduced, a stream's capacity to assimilate certain wastes also goes down, but much more slowly. Using the Brazos River as an example, a 20-percent reduction in flow results in only a 2-percent decrease in ability to assimilate biologically oxygen demanding waste (B.O.D.).

- Mining in some areas will disturb aquifer systems and replace them with new, artifically mixed material. In some instances, this may cause localized "aquifer damming," or sealing of a recharge area. The result could be a permanent loss of local well yields.

- Dewatering working mines can lower well levels within an area surrounding the mine. This impact is temporary.

4.1 Consumptive Water Use by the Development Scenario

The greatest consumptive use of water from the development scenario arises from power plant cooling. Added to this is the amount of water consumed in industrial coal and lignite use, especially gasification, and the increased demands of growing populations for municipal and domestic use.

Much of the water withdrawn by plants and communities is returned to the basin after use. Although the patterns of these withdrawals and return flows are of importance at the local scale to water planners, they are too complex, and too site-specific, to consider directly in this study. The major potential impact of the scenario on water management at the subregional level will arise through increased consumptive use, water which is withdrawn but not returned.

Table 4-1 summarizes the level of consumptive use associated with the power production part of the scenario, broken down by subregion. Industrial development will also consume water, but amounts vary depending on plant size and process. Without specifying all such uses, it would not be possible to estimate industrial water consumption, for the scenario. In general, however, it may be considerably lower for industrial uses not involving the production of power. A Lurgi gasification plant of 300 billion Btu-per-day capacity uses almost six times the lignite consumed by a 1500-MWe power plant over identical 30-year lifetimes, but consumes slightly less water. Consumptive losses from municipal and domestic uses are very small in comparison with both industrial and utility uses. For this reason, they can be safely neglected in the evaluation.

TABLE 4-1. SUBREGIONAL WATER CONSUMPTION BY LIGNITE- AND COAL-FIRED POWER PLANT DEVELOPMENT IN YEAR 2000 (in thousand acre-feet year - TAF/y)

	Lignite Plants: Number of 500 MWe Units	Coal Plants: Number of 500 MWe Units	Water Consumption TAF/y	Water Supply TAF/y*	Consumption as Percent of Supply
Northeast	32	6	295	2264	13.0
North Central	20	4	186	2582	7.2
Central	3	7	76	1950	3.9
Southern	6	0	47	858	5.5
Gulf Coast	1	12	99	7732	1.3
Total	62	29	703	15,386	4.6

Assumed Water Consumption:

- Lignite-Fired Plant

  Cooling: 6700 acre-feet/yr
  Mine: 250 acre-feet/yr
  Other 900 acre-feet/yr

- Coal-Fired Plant

  Cooling: 6700 acre-feet/yr
  Other: 900 acre-feet/yr

*Based on Texas Department of Water Resources future supply projections by river basin.

Note, from the table, that water consumption related to the development scenario ranges from 13.0 to 1.0 percent of the supply for the Gulf Coast and Northeast regions, respectively. For all regions, a total of about 4.6 percent of the supply will be consumed.

4.2 Impacts of Water Development

Energy's added water demand must be compensated for by further development of water supplies. As was discussed in Chapter III, the amounts of water needed for the growth of coal- and lignite-based industry and power generation can be made available in three basic ways. First, new surface water may be developed, either by the user or by a water development agency. Much of this development would involve new impoundments. Second, existing water rights can be converted from their present uses to energy-related uses. Third, some potential surface water demands can be satisfied by groundwater supplies, freeing surface supplies for new uses. Since the large quantities of water needed by utilities generally make surface water most desirable as a source, energy users would benefit indirectly from a general shift to groundwater supplies in other sectors. The following discussion highlights some of the consequences of these three modes of supplying water for energy.

4.2.1 Impacts of Surface Water Development

The first major impoundments in a river basin are generally developed high in the basin. Subsequent downstream reservoirs have less runoff available for capture, since upstream impoundments cut off large parts of the watershed. For a given yield of water, a larger conservation pool must be developed, and the reservoir must be larger. Downstream sites are likely to be shallower, resulting in higher evaporative losses per unit of water stored. Larger land areas must be inundated, as well.

Thus, surface water development proceeds, those impacts which relate to the size of impoundments increase relative to the yield of usable water. The investment required per unit yield also rises. When water prices are based on cost recovery, the price to the user goes up.

On-site cooling ponds have been a popular mode of development in the past, and may continue to be preferred. Although these ponds are not usually big enough to impound all of the water needed, they sometimes retain runoff from substantial acreage. In a basin with many such impoundments, design of mainstem reservoirs must compensate for this reduction in watershed area. Thus, the problems of larger size and higher cost may be made even worse.

4.2.2 Impacts of Water Rights Transfer

As the price of surface water from reservoirs increases, it may become prohibitively high for some users. In some older reservoirs, water may sell for about $15.00 an acre-foot. Water prices for new reservoirs, based on cost recovery, may be as high as $75.00 an acre foot.* These high prices reflect not only the higher conservation-to-yield ratio, but higher interest rates and construction costs as well.

Under these circumstances, agricultural users are likely to find it difficult to obtain affordable new supplies. Meanwhile, the potential value of old supplies to new users who can pay more for them will continue to rise. The result is likely to be a shift of water supplies away from agriculture. There are presently no particular institutional safeguards to protect agricultural uses from the impacts of rising water prices.**

4.2.3 Impacts of Increased Use of Groundwater

An alternative to high-priced surface water is the development of groundwater wells. Texas law regards groundwater as a property right, which may be developed at the landowner's discretion. For the most part, no regulatory control is exercised over either the manner or extent of development.*** In most cases, the Right of Capture principle allows pumping from a new well to draw down levels of adjacent existing wells.

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*Water Resources Department personnel, personal communication, January 12, 1979.

**Water Resources Department personnel, personal communication, October 17, 1978.

***In some areas, local Groundwater Conservation Districts have been formed to regulate pumping rates and new well development. See Chapter III for further information.

As pressure on groundwater grows, the current drawdown problems that plague most of the aquifers in the Lignite Belt may be expected to grow. As well levels fall, pumping costs increase. Also, in some cases, water quality degradation may accompany increased drawdown, leading to higher treatment costs.

Municipal, domestic, and agricultural uses account for a large share of the groundwater used in the Lignite Belt especially in the drier, southern parts. Rising pumping and/or treatment costs will disadvantage these users. Again, agriculture seems likely to have the least flexibility to cope with these trends.

4.3 Impacts of Consumptive Water Use

Translating water consumption into estimates of reduced flow requires estimates of the amount of water supply that will be developed by lignite users to support their own needs. Recognizing that this development will occur, it may be concluded that flow reduction will be less than the total amount of water consumed. Consequently, for this study, it was assumed that flow reduction in a subregion will be about 70 percent of the total water consumed by the mines and power plants located in it. This supposes that the entire complex will develop 30 percent of the needed additional water supplies. (It is realized that any given complex may develop from zero to 100 percent of its needs, depending on local topography and hydrology; the assumption is for illustrative purposes only.)

Results of regional flow reduction based on the 70 percent assumption are shown in Table 4-2. The projections show that a low of 0.9 percent reduction may be expected in the

Gulf Coast region and a high of 9.1 percent will occur in the Northeast region.

TABLE 4-2. SUBREGIONAL FLOW REDUCTION DUE TO NEW POWER PRODUCTION, YEAR 2000 (In thousand acre-feet per year - TAF/y)

	Total Water Supply TAF/yr	Percent Reduction In Flow In Region
Northeast	2,264	9.1
North Central	2,582	5.0
Central	1,950	2.7
Southern	858	3.8
Gulf Coast	7,732	0.9

These flow reduction estimates would change somewhat if the water demands of industry were known. However, considering that these demands will probably be overshadowed by utility requirements, including them would not be likely to change Table 4-2's estimates greatly.

4.3.1 Navigation

The effect of reduced flows on navigation primarily deals with inland waterways. Coastal waters used for navigation depend on the depth to channel-bottom below mean sea level. This level must be sufficient to provide the depth of water necessary to float boat or barge traffic. While dredging is frequently necessary to maintain this depth, it is important to realize that freshwater inflow is not a significant factor in maintaining the navigability of a channel.

Such is not the case in inland waters. These waters rely on the volume of water flowing in their channels to provide a sufficient depth. The depth is dependent on flow in a fairly predictable fashion for any given waterway. One expression commonly used is:

$$\text{Depth} = a \cdot \text{Flow}^{b}$$

The expression states that the depth of a flowing channel is predicted to vary with changes in flow, with the flow raised to some exponential power. The value of this exponent is 0.6 in the case of rectangular channels under steady flow, and varies from 0.3 to 0.8 under normal river conditions.

The Texas river most frequently considered as a potential inland waterway is the Trinity River. This river flows through east central Texas from Fort Worth to the coast east of Houston. Considerable work would be required to make this waterway conductive to heavy barge traffic. However, it is instructive for the purposes of this study to use it as an example for the analysis that follows.

Assume that depth varies according to the flow raised to the 0.6 power, and a reduction in average flow in the Trinity River is 5.0 percent (North Central Subregion). The average depth in the Trinity River will be reduced according to the following formula:

$$\begin{aligned} \text{Depth} &= a \cdot \text{Flow}^{b} \\ &= a \cdot (1.00 - 0.050)^{0.6} \\ &= a \cdot (0.950)^{0.6} \\ &= a \cdot (0.970) \end{aligned}$$

The new depth at reduced flow will be 0.970 or 97 percent of the old depth, a reduction of 3 percent. Assuming a 12-foot depth (adequate to float small barges), this reduction amounts to 0.36 feet or 4.3 inches. For actual existing conditions in the Trinity River, the average depth is closer to 3.0 feet, which under the reduced flow used in this example would be reduced to 2.9 feet (3.00 - .03 x 3.00).

To predict the actual effects of reduced flow (and depth) on the navigability of Texas rivers, of course, requires a much more specific and rigorous analysis than that given here. It does, however, illustrate that flow reduction may have a significant effect on the average depths of affected rivers. This effect will be more pronounced as flows are increasingly reduced. It may be possible in such cases to control withdrawals so that while average flows and depths are reduced, a certain level of low flow would be maintained in order to insure sufficient flow and depth for navigation purposes. This same argument of scheduling withdrawals to protect a given water use can be applied to each of the problem areas addressed below.

4.3.2 Groundwater Recharge

A certain amount of groundwater recharge comes from water flowing in existing river channels. A reduction in flow affects recharge because of three factors: (1) reduced stream width and contact area, (2) reduced pressure at the streambed due to reduced depths, and (3) reduced amounts of water available for infiltration.

A crude quantification of the recharge process is possible on a similar basis as that presented for navigation. However, the net result would be restricted to stating that flow reductions will reduce ground-water inflow to some essentially unknown degree.

That degree, on a percertage basis, will be roughly comparable to the amount of flow reduction. This reduction refers only to that portion of recharge attributed to streambed infiltration. Other sources of recharge will not be affected by the reduced flow. In and along rivers where no groundwater infiltration is occurring or where rivers are gaining flow from groundwater sources, the reduced flow will have no effect.

4.3.3 Stream Ecology

During years of normal stream flow, the changes in flow specific to lignite development will cause only minimal changes in the overall freshwater ecosystem. The most severe impacts probably will occur under low flow conditions, during which time some of the aquatic biota will suffer. This impact can be mitigated to a considerable degree by limiting water withdrawals during these periods as much as possible.

4.3.4 Freshwater Inflow to Bays and Estuaries

The estimates of Table 4-1 indicate the range of flow reduction to be from 0.9 to 9.1 percent of supply. The Northeast Subregion does not drain to the Texas Gulf Coast. This feature reduces the range of flow reduction in those areas draining to the coast from 0.9 to 5.0 percent. A considerable effort is now underway by the Texas Department of Water Resources and U.S. Fish and Wildlife Service to determine the effects of freshwater inflow on the ecological environment of Texas bays and estuaries. They include the development of methods of providing and maintaining the ecological environment in a manner suitable for living marine resources. The productivity of the bays is being studied relative to the amount of freshwater inflow and other inputs. The analysis of this production/

inflow relationship requires investment of considerable effort in both time and money.

The regional effects of flow reduction due to lignite development on freshwater inflows and on this production/inflow relationship are impossible to calculate without having the relationship defined.

4.3.5 Waste Assimilative Capacity

The waste assimilative capacity of a river or stream refers to the capacity of that water body to accept, neutralize, and render unobjectionable a given pollutant. A variety of processes are involved, which are usually grouped under the term "natural purification." Numerous variables enter the calculation, and assessment of assimilative capacity. Assimilative capacity for a particular pollutant under specific conditions allows some degree of water quality degradation to take place during the assimilation and purification process.

Waste assimilative capacity most often refers to the capacity of a stream to assimilate pollutants which exert an oxygen demand upon decay. The assimilative process results in some amount of depletion of the oxygen resource of the water body. The assimilative capacity of a flowing water body for oxygen-demanding substances is a function of steam flow, decay rate of the waste in the receiving stream, rate of oxygen addition to the system, and the degree of oxygen depletion allowed during the assimilating process. The rate of oxygen addition is predominantly that of atmospheric reaeration under normal conditions. Reduced stream flow changes stream depths and velocities, which in turn change the atmospheric reaeration rate. Flow reduction also affects assimilative capacity by reducing the amount of water available.

These effects may be illustrated using the assimilative capacity of the Brazos River as an example. The assimilative capacity, expressed as an allowable discharge of a certain amount of biochemically oxygen demanding substances, is graphed as a function of stream flow in Figure 4-1. Similar curves may be developed for most Texas streams given sufficient information on decay rates and stream hydraulics. However, the given example is representative of the process.

The key feature of the figure is that the assimilative capacity of the river decreases as flow decreases, but more slowly. Note that a flow reduction from 400 to 320 cfs (20 percent) causes a corresponding reduction in assimilative capacity

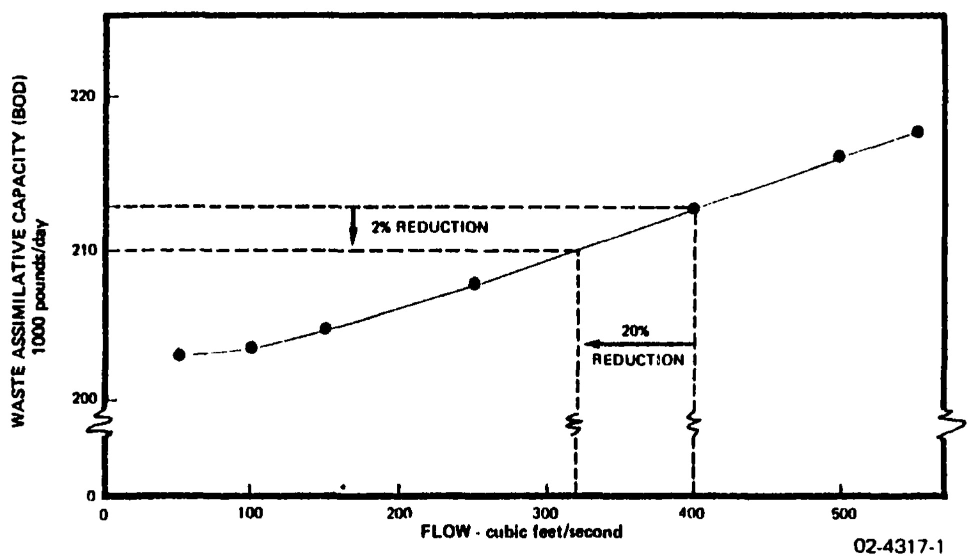

Figure 4-1. Waste Assimilative Capacity of the Brazos River as a Function of Flow

of from 213,000 to 210,000 pounds per day (a reduction of less than 2 percent). The ratio between flow reduction and assimilative capacity reduction varies from one river to another, but always indicates a proportionately smaller reduction in assimilative capacity compared to the flow reduction when expressed as a percentage.

The assimilative capacity of a flowing water body, as a function of flow, is more critical under low flow situations. In Texas, the critical flow, with respect to water quality standards, is the seven-day, two-year low flow. That is, the average seven-day low flow that may be expected to recur once every two years. Examples of this critical, seven-day, two-year low flow are given for some Texas rivers in Table 4-3. The range in these flows is considerable, varying from less than one cubic foot per second to over 300 cfs for the examples shown.

TABLE 4-3. CRITICAL LOW FLOWS FOR SELECTED TEXAS RIVERS

River	Location	Seven-Day, Two-Year Low Flow (cfs)
Trinity	Rosser	194
San Antonio	Below San Antonio	80
Brazos	Bryan	357
Nueces	Three Rivers	0.25
Sabine*	Longview	54
Sabine**	Longview	35.7

*Based on flow records since 1938.

**Based on flow records since 1960.

Source: Personal Communication with Texas Department of Water Resources staff, November, 1978.

The question of flow reduction and its effect on assimilative capacities, while somewhat involved technically, becomes in the end one of maintaining the critical low flow. Through proper management of water withdrawals, it is possible to maintain this low flow within certain limits, at previous levels. Waste assimilative capacity is reduced as flow is reduced, as shown in the previous example. But as with flow-recuction effects on navigation, the assimilative-capacity reduction is significantly less (on a percentage basis) than the flow reduction itself. Also like the navigation issue is the conclusion that through proper management practices which regulate the timing of water withdrawals, the impacts of flow reduction can be greatly reduced or eliminated.

The previous discussions on flow reduction related impacts should not be interpreted as proposing that for any given site there will be no more significant impact from water consumption by ehergy development. On the contrary, a careful examination of all water-related impacts is a vital part of any environmental assessment. In some areas, and for given types and sizes of developments, water-related impacts, including flow reduction, may be of critical importance. The foregoing discussion suggests only that flow reduction attributable to lignite development will probably not have any great impact on the state as a whole. As water becomes more scarce, through increased use by agricultural and industrial and municipal users, proper water resources management practices will be required to mitigate the potential detrimental impacts.

It should also be reiterated that the supply figures used in this analysis reflect timely development of new water supply projects, as set forth by the Water Resources Department's Continuing Water Resources Planning and Development for Texas.[34] To the extent that such developments are delayed or not built, the impacts of flow reduction would be to a degree increased.

4.4 Impacts on Groundwater

In Texas, steam electric generating plants use both surface and subsurface sources of water for cooling and process make-up purposes. Surface supplies are the preferred source where possible because of costs, difficulties of developing a well field, and the sometimes high cost of pumping the water to the surface. Some plants, of course, do use groundwater for these purposes because of the lack of available surface water supplies.

4.4.1 Groundwater Consumption

The discussion that follows addresses groundwater consumption and effects on water quantity and quality as related to lignite development. A compilation of steam-electric power plants within the lignite and coastal areas which use groundwater for cooling is given in Table 4-4. The installed capacity

TABLE 4-4. EAST, CENTRAL, AND SOUTHERN EXISTING AND PLANNED STEAM ELECTRIC POWER PLANTS IN TEXAS USING GROUNDWATER AS THE PRIME COOLING SOURCE*

Plant Name	County	Aquifer	Installed Capacity MWe 1978	1987	Fuel Type
Bryan	Brazos	C-Wilcox	140	140	Gas
Champion	Harris	Coastal	22	20	Gas
Clark-Hiram	Harris	Coastal	336	336	Gas
Collin	Collin	Trinity G.	153	0	Gas
Dallas	Dallas	Trinity G.	145	0	Gas
Gable Street	Harris	Coastal	62	62	Gas
Greens Bayou	Harris	Coastal	1141	1141	Gas
Leon Creek	Bexar	Edwards	197	145	Gas
Mission Road	Bexar	Edwards	120	80	Gas
Newman	Dallas	Trinity G.	94	94	Gas
Pearsall	Frio	C-Wilcox	75	75	Gas
San Miguel	Atascosa	C-Wilcox	0	800	Lignite
Texas A&M	Brazos	C-Wilcox	24	24	Gas
Tuttle	Bexar	Edwards	364	364	Gas
Wharton	Harris	Coastal	1221	1221	Gas
TOTAL			4094	4502	

*Source: Draft Planning Document, Texas Department of Water Resources, 1978.

of these plants in 1978 is 4094 MWe, and all of the existing plants are gas-fired. Existing installed capacity using groundwater as a cooling supply is expected to decrease between now and 1987. The increase shown in the total installed capacity is attributable to the San Miguel lignite-fired plant in Atascosa County, coming on line before 1987.

The aquifers being used as sources are the Carrizo-Wilcox, the Trinity Group, the Edwards, and the Coastal Group. According to information gathered by the Texas Department of Water Resources, all of these aquifers are experiencing either local or area-wide problems due to excessive pumping.[34] Problems include excessive drawdown, infiltration of bad water into clean water aquifers, and land-surface subsidence.

Most Texas aquifers are already in a stressed condition. Therefore, it seems likely that the developers of lignite mines and power plants will look first to surface supplies to provide cooling and process waters. Where a new lignite development uses ground-water resources considerable effort should be spent to insure that this water resource is not taxed at an unacceptable rate.

Finally, the increasing demand for water in all sectors is expected to place growing pressure on most of the state's aquifers. Thus, the problems discussed below must be viewed in context of increasing stress.

4.4.2 Groundwater Recharge Impacts

Lignite development may have an impact on groundwater recharge near mines and power plants. Recharge may increase in recently mined areas, at least temporarily, due to the "expansion" of the replaced overburden. In such eases, the expanded overburden will have an increased permeability because of increased pore space. This will not occur at all mines, and may be only temporary. Under its own weight the overburden may settle and compact to undisturbed levels. In some areas of the state it appears that the overburden disturbance caused by surface mining will decrease recharge due to the formation of relatively impermeable clay layers or crusts on the surface. The question is a very complicated one, requiring extensive studies at each mine site.

Considerable concern has been expressed over the possibility of "aquifer damming" where mining affects a recharge zone.[35,36] Permeable sandy strata are often interspersed with less permeable clayey layers near lignite seams. Sometimes, these sandy strata are part of an aquifer system, which is recharged where they outcrop on the surface. If a mining operation excavates an area in which both sand and clay layers are found, the two materials will be mixed when returned to the pit. The mixed material, less permeable than the sandy strata, now replaces them in what was once a recharge zone. If the mixed material is sufficiently impermeable, recharge may be so much reduced that wells drilled into the aquifer system, within a few miles of the mine may stop producing. While this effect is necessarily a local one, it is essentially irreversible.

A second groundwater problem associated with mining results from the need to pump groundwater out of a working pit, when mining intercepts an overlying aquifer. The resulting cone of depression may extend one or two miles from the mine site, and can, depending on the circumstances, reduce well yields or even cause wells to go dry. Where mining occurs near municipal well fields, or other intensive groundwater development, this problem can be locally serious, and requires the development of a substitute water supply. Unlike the "aquifer damming" problem, however, this effect is temporary.

As previously discussed, reduced stream flows downstream from the power plant may alter stream bed recharge due to reductions in contact areas, water depth, and water availability. None of these effects are likely to be significant on a regional basis and some offset each other to some extent. Site-specific problems may occur and should be studied as part of any complete environmental assessment. The quantitative groundwater effects, even in the most severe cases due to changes in recharge, will be a local, not a regional, phenomenon.

4.5 Research Needs

- Individual basin studies and forecasts of the impacts of consumptive use on low flows and on reservoir operation.
- Investigate potential impacts on aquatic impacts of altered flow regimes, especially of lowered or more frequent low flows.
- Well monitoring at existing mines to detect and measure permeability changes over time, resulting from mixing and subsequent compaction of overburden materials after replacement.
- Monitoring existing mines to observe water-table recovery time after cessation of pit dewatering.
- Additional study of the hydrodynamics of aquifers, particularly in the Northeast and North Central Subregions, in the immediate vicinity of developable lignite resources.
- Investigate the adequacy of existing institutions to protect against excessive aquifer drawdown and permanent or temporary reduction in productivity that may result directly or indirectly from energy development. Review policy options available for providing such protection, including those used by other states.

5.0 IMPACTS ON SURFACE AND GROUNDWATER QUALITY

Summary and Conclusions

- Power plant effluents potentially contain substances listed by EPA as "priority pollutants" of concern as toxins. Control technologies are available for each of these. Toxic-control strategies will vary between plants.

- Coal pile and mine runoff constitute major non-plant pollution sources. Their main threat to water quality is through silt and suspended solid loadings. Runoff can be caught in settling basins to allow the water to clear before it is released.

- Liquid wastes from gasification plants may contain relatively high levels of hazardous contaminants, particularly heavy hydrocarbons that may be cancer-causing. These waste streams would most probably be handled by forced evaporation. The solid residue remaining would require care in disposal.

- The need to dilute high-TDS waste streams from power plant cooling increases net plant throughput of water, and places greater demands on upstream reservoirs.

- Solid waste disposal will probably be the greatest threat to groundwater quality posed by the development scenario.

- Mining may affect groundwater quality because of overburden leaching. The potential extent and seriousness of this impact is highly site-specific and requires further study.

- Where well fields are developed for power plant cooling, excessive pumping may cause intrusion of poor-quality water into the aquifer.

5.1 Surface-Water Quality

Water quality of streams and reservoirs will be affected by the nature, quantity, and type of wastewater effluents associated with lignite mining and power plant operation. These effluents will be generated by a number of diverse processes but may be designated as "point" and "non-point" sources of pollution.

The development scenario does not extend in detail to the level of specifying generating technologies and their assoicated water uses. Therefore, an estimate of wastewater volumes was not attempted. The information that follows is a general discussion of potential wastewater problems.

5.1.1 Point Source Effluents

Power-plant effluents are generally associated with various aspects of operation. These sources typically are:

- Cooling water systems,
- Water conditioning,
- Fuel pile runoff,
- General plant drainage,
- Process spills and leaks,
- Ash handling,
- Equipment cleaning, and
- Boiler blowdown

The last three sources are typically operated as closed systems, and do not result in waste discharges.

Under the Toxic Substances Control Act, the Environmental Protection Agency has developed a list of toxic pollutants of concern to that agency. The 126 compounds of concern, or priority pollutants, are listed in Table 5-1. Based on current preliminary findings, those substances most likely to be found in utility effluents are indicated by an asterisk.

Based on a Radian study for the assessment of control technologies for toxic effluents from the electric utility industry,[37] a number of control technologies have been identified. These control technologies and the toxic pollutants removed by them are summarized in Table 5-2. The effectiveness of many of these controls is dependent on concentrations of toxic materials, and waste stream characteristics. As such, Table 5-2 serves only to indicate that for the proper circumstances, the technologies will control the indicated toxics to some appreciable degree. Table 5-2 also indicates that some control technology can be applied to each of the identified toxics. The selection of a specific control method at any particular generating station will depend on data specific to that station concerning fuel characteristics, plant design, and other controls used. Because the operations and effluents of power plants are so site-specific, required strategies to control toxics will vary from plant to plant.

The quantity and quality of industrial waste streams depends on the processes involved, plant design, and operating characteristics. The development scenario used here does not specify such detail. Special mention should be made, however, of the wastes produced by gasification.

A large coal- or lignite-gasification plant produces a number of liquid effluents, including:

- Oily and tarry gas liquors
- Process condensates

TABLE 5-1. PRIORITY LIST OF TOXIC SUBSTANCES

	Substance
	Acenaphthene
*	Acrolein
	Acrylonitrile
*	Benzene
	Benzidine
*	Carbon tetrachloride (tetrachloromethane)
*	Chlorobenzene
*	1,2,4-Trichlorobenzene
*	Hexachlorobenzene
*	1,2-Dichloroethane
*	1,1,1-Trichloroethane
*	Hexachloroethane
*	1,1-Dichlorethane
*	1,1,2-Trichloroethane
*	1,1,2-Tetrachloroethane
*	Chloroethane
*	Bis(Chloromethyl) ether
*	Bis(2-chloroethyl) ether
*	2-Chloroethyl vinyl ether (mixed)
	2-Chlorohaphthalene
*	2,4,6-Trichlorophenol
	4-Chloro-m-cresol
*	Chloroform (trichloromethane)
*	2-Chlorophenol
*	1,2-Dichlorobenzene
*	1,3-Dichlorobenzene
*	1,4-Dichlorobenzene
	3,3-Dichlorobenzidine
	1,1-Dichloroethylene
	1,1-Trans-dichloroethylene
*	2,4-Dichlorophenol
	1,2-Dichloropropane
	1,3-Dichloropropylene (1,3-Dichloropropene
	2,4-Dimethylphenol
	2,4-Dinitrotoluene
	2,6-Dinitrotoluene
	1,2-Diphenylhydrazine
	Ethylbenzene
	Fluoranthene
	4-Chlorophenylphenyl ether
	4-Bromophenylphenyl ether
	Bis-(2-chloroisopropyl) ether
	Bis(2-chloroethoxy) methane
	Methylene chloride (dichloromethane)
	Methyl chloride (chloromethane)
	Methly bromide (bromomethane)
	Bromoform (tribromomethane)
	Dichlorobromomethane
	Trichlorofluoromethane
	Dichlorodifluoromethane
	Chlorodibromomethane
	Hexachlorobutadiene
	Hexachlorocyclopentadiene
	Isophorene
*	Naphthalene
	Nitrobenzene
	2-Nitrophenol
	4-Nitrophenol
	2,4-Dinitrophenol
	4,6-Dinitro-o-cresol
*	N-nitrosodimethylamine
*	N-nitrosodiphenylamine
*	N-nitrosodi-n-propylamine
*	Pentachlorophenol
*	Phenol
	Bis(2-ethylhexyl) phthalate
	Butylbenzyl phthalate
	Di-n-butyl phthalate
	Diethyl phthalate
	Dimethyl phthalate
	1,2-Benzanthracene
	3,4-Benzopyrene
	3,4-Benzofluoranthene
	11,12-Benzofluoranthene
	Chrysene
	Acenaphthylene
*	Anthracene
	1,12-Benzoperylene
	Fluorene
*	Phenanthrene
	1,2,5,6-Dibenznathracene
	Indeno(1,2,3-c,d) pyrene
	Pyrene
	2,3,7,8-Tetrachlorodibenzo-p-dioxin (TCDD)
	Tetrachloroethylene
*	Toluene
	Trichloroethylene
	Vinyl chloride (chloroethylene)
	Aldrin
	Dieldrin
	Chlordane (technical mixture and metalbolites)
	4,4´-DDT
	4,4´-DDE (p,p´-DDX)
	4,4´-DDD (p,p´-TDE)
	α-Endosulfan
	β-Endosulfan
	Endosulfan sulfate
	Endrin
	Endrin aldehyde
	Endrin ketone
	Heptachlor
	Heptachlor epoxide
	α-Hexachlorocyclohexane
	β-Hexachlorocyclohexane
	γ-Hexachlorocyclohexane (lindane)
	δ-Hexachlorocyclohexane
*	Polychlorinated biphenyl (Arochlor 1242)
*	Polychlorinated biphenyl (Arochlor 1254)
	Toxaphene
*	Antimony (total)
*	Arsenic (total)
*	Asbestos (fibro)
*	Beryllium (total)
*	Cadmium (total)
*	Chromium (total)
*	Copper (total)
*	Cyanide (total)
*	Lead (total)
*	Mercury (total)
*	Nickel (total)
*	Selenium
*	Silver (total)
*	Thallium (total)
*	Zinc (total)
*	Vanadium (total)
*	Ethylenediaminetetraacetate (EDTA)

*Substances most likely to be present in utility effluents based on preliminary data and literature survey.

SOURCE: Rice, J. & S. Strauss, 1977. "Water Pollution Control in Steam Plants."[38]

TABLE 5-2. COMPARISON OF TOXIC CONTROL BY SELECTED TECHNOLOGIES

Process	Toxic Pollutants																												
	Acrolein	Antimony & Compounds	Arsenic & Compounds	Benzene	Beryllium & Compounds	Cadmium & Compounds	Carbon Tetrachloride	Chlorinated Benzenes	Chlorinated Ethanes	Chloroalkyl Ethers	Chlorinated Phenols	Chloroform	Chromium & Compounds	Copper & Compounds	Cyanides	2,4-Dichlorophenol	Lead & Compounds	Mercury & Compounds	Napthalene	Nickel & Compounds	Nitrosamines	Pentachlorophenol	Polychlorinated Biphenyls	Polynuclear Aromatic Hydrocarbons	Selenium & Compounds	Silver & Compounds	Thallium & Compounds	Toluene	Zinc & Compounds
ACTIVATED CARBON	✓		*	✓	*		✓	✓	✓	✓	✓	✓	*		*	✓			✓			✓	✓	✓	*				*
PRECIPITATION		✓	✓			✓											✓	✓		✓						✓	✓		✓
REVERSE OSMOSIS	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
BRINE CONCENTRATION	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
EVAPORATION PONDS	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

* Highly site-specific

SOURCE: Rice, J. & S. Strauss, 1977. "Water Pollution Control in Steam Plants."[38]

- Boiler blowdown
- Cooling tower blowdown
- Demineralizer and zeolite softener regeneration
- Wastes
- Lime softener sludge
- Sewage treatment wastes
- Ash quenching overflow.

When the raw gas is cooled, a portion of the gas stream's water content is condensed. This oily and tarry liquor contains a variety of heavy hydrocarbons, phenols, and trace inorganic compounds which may be toxic, carcinogenic or mutagenic. Phenols have market value and are likely to be removed for sale. This waste stream may also be partially cleaned to permit reuse in the plant. Eventually, however, this water must be discarded. Because of their hydrocarbon and trace inorganic contents, it is usual to design plants for on-site evaporation of these wastes. In Texas' humid climate, forced evaporation would be a likely method, resulting in a solid residue. This residue would probably require special handling for disposal.

The remaining waste streams can all be recycled within the plant and/or used to quench and slurry gasifier ash.

Gasification plants can thus be operated without any liquid discharge to the environment. The result is the transfer of potentially hazardous waste components to a solid waste stream. With proper handling and disposal, these components may be more effectively contained in the solid form.

5.1.2 Non-Point Sources

Non-point sources are generally associated with waste streams from the mine area and lignite pile at the power plant. The principal effluents derive from runoff associated with rainfall events, mine dewatering, and beneficiation processes, if used. The greatest threat to water quality from this area runoff will be from silt and assorted suspended solids carried into area streams. It is standard practice to construct temporary impoundments to catch turbid runoff waters, allowing sedimentation to remove most of the solids before release.

The location and design of these basins is a part of all mining plans required under current surface mining regulations. Runoff from lignite storage piles creates a more difficult problem with respect to the chemical character of the waste stream. Table 5-3 presents plant data relating to water quality parameters for coal pile runoff. While the chemical characters of lignite and coal differ in many ways, the table is useful in showing the types of contaminants in runoff from a fossil-fuel storage pile. The range shown for some of the contaminant concentrations is also significant, indicating the variability of concentrations due to different fuel characteristics and storage methods.

A common wastewater management option is to store and use captured runoff as a water supply for processes which do not need clean water. Such processes include some ash handling systems and other miscellaneous processes. Runoff from non-process areas within the generating plant property are generally not a problem from a pollutant standpoint. Where this discharge is contained in a wastewater system, effluent limitations are usually specified only for oil and grease content and suspended solids.

TABLE 5-3. PLANT DATA RELATING TO WATER QUALITY PARAMETERS FOR COAL PILE RUNOFF

Plant Code	3402	3401	3936	1825	1726	1729	3626	-0107	5305	5305	5305
Alkalinity (mg/l)	6	0	0	-	82	-	-	0	21.36	14.32	36.41
BOD (mg/l)	0	0	10	-	3	-	-	-	-	-	-
COD (mg/l)	1080	1080	806	85	1099	-	-	-	-	-	-
TS	1330	1330	9999	6000	3549	-	-	45000	-	-	-
TDS	720	720	7743	5800	247	-	28970	44050	-	-	-
TSS	610	610	22	200	3302	-	100	950	-	-	-
Ammonia	0	0	1.77	1.35	0.35	-	-	-	-	-	-
Nitrate	0.3	0.3	1.9	1.8	2,25	-	-	-	-	-	-
Phosphorous	-	-	1.2	-	0.23	-	-	-	-	-	-
Turbidity	505	505	-	-	-	-	-	-	8.37	2.77	6.13
Acidity	-	-	-	-	-	-	21700	27810	8.68	10.25	8.84
Total Hardness	130	130	1109	1850	-	-	-	-	-	-	-
Sulfate	525	525	5731	861	133	6837	19000	21920	-	-	-
Chloride	3.6	3.6	481	-	23	-	-	-	-	-	-
Aluminim	-	-	-	-	-	-	1200	825	-	-	-
Chromium	0	0	0.37	0.05	-	-	15.7	0.3	-	-	-
Copper (mg/l)	1.6	1.6	-	-	-	-	1.5	3.4	-	-	-
Iron (mg/l)	0.168	0.168	-	0.06	-	0.368	4700	93000	1.0	1.05	0.9
Magnesium (mg/l)	-		89	174	-	-	-	-	-	-	-
Zinc (mg/l)	1.6	1.6	2.43	0.0006	0.08	-	12.5	23	-	-	-
Sodium (mg/l)	1260	1260	160	-	-	-	-		-	-	-
pH	2.8	2.8	3	4.4	7.8	2.7	2.1	2.8	6.7	6.6	6.6

Source: EPA, 1974[39]

5.1.3 Effects on Assimilative Capacity

Wastewater discharges from surface mines and steam-electric generating plants will not directly affect the waste assimilative capacity of area streams. This is due to the absence of oxygen-demanding substances in typical wastewaters from these sources. As discussed above, assimilative capacity may be affected by flow reductions in area streams, but wastewater discharges from mines and power plants are not a major factor in determining the oxygen resources of a water body.

5.1.4 Effect of TDS Control on Water Requirements

The evaporative cycle of a power plant, whether it involves a cooling reservoir or cooling towers, builds up dissolved solids. The total dissolved solids level (TDS) must be controlled to avoid equipment corrosion and scaling. In a cooling reservoir, solids control may also be required to protect fisheries. To keep TDS levels at an equilibrium, a portion of the water in the system is continually bled off and discharged, while fresh water is constantly added. This blowdown stream, if discharged into a body of water, must not cause that water body to exceed the quality standards set for it. Consequently, the solids content of the blowdown stream must be controlled.

The amount of extra water required to control TDS may be a significant part of the plant's water budget. Blowdown from a cooling tower designed for a 500 MWe lignite-fired plant with 35 percent efficiency might range from 4,000 to 17,000 gpm, with salt concentration proportional to the size of the stream. Halving its TDS concentration would require an equal amount of dilution. Texas water planners have expressed concern over the magnitude of this demand, and its effects on water delivery.[40]

The requirement for dilution water does not change consumptive requirements, but increases the plant's net throughput of water. This in turn increases the demands on upstream, existing reservoirs. Because it is continuous, the incremental demand may reduce the flexibility available in managing reservoir discharge. Also this kind of demand moves water through the reservoir system more rapidly, limiting the intensity of use possible.

The potential significance of the extra demand for TDS dilution is greatest in drainages of streams which are already salty, such as the Brazos and some of its tributaries, and in dry areas where streamflow is periodically much reduced. The problem is least troublesome in moist regions, with relatively high flows even during dry periods or times of extensive withdrawal.

5.2 Groundwater Quality

Surface mining and steam electric power generation may affect the quality of local groundwaters by several different mechanisms. These are:

- Intrusion of poor-quality water into the aquifer, caused by excessive pumping where groundwater is used for power plant cooling;
- Groundwater contamination due to subsurface disposal of wastewaters;
- Groundwater contamination associated with leaching in disturbed overburden; and
- Groundwater contamination associated with solid waste disposal.

Of these processes, the greatest threat to local groundwater quality comes from the disposal of solid wastes. This problem is discussed in Section 3.0, above.

Where groundwater supplies are used for power plant cooling and where poor-quality water is already entering freshwater aquifers, the power plant withdrawals will only increase this problem. The encroachment of poorer-quality water is now a problem in many aquifers, including the Carrizo, the Trinity Group, and the Gulf Coast aquifer. The question of decreasing water quality as pumping continues will be an important factor in deciding on a groundwater or surface water supply. This issue is one of the driving forces behind efforts to develop additional surface water supplies within the state.

With the major exception of the oil production industry, subsurface disposal of wastewater is not a general practice in Texas at this time. Most wastewaters from steam electric generation plants are treatable by conventional methods and either discharged to surface waters or used within the plant where a cleaner water is not needed. It is unlikely that this situation will change as a result of lignite development.

Excluding solid waste disposal questions, the most serious threat to groundwater quality from lignite-related activities concerns groundwater contamination from the disturbed overburden. Water may enter the replaced overburden by two routes: surface-water infiltration and underground seepage. In either case, salts and trace elements may be dissolved. This is an area of ongoing research, but the following generalizations may be made:

- Groundwaters within the area of disturbed overburden will probably have somewhat higher levels of dissolved solids than those same waters before mining;

- The elevated dissolved solids will consist primarily of salts, organic compounds, and trace elements;

- This phenomenon is site-specific in terms of occurrence, dissolved solids type and concentration, and significance; and

- More research concerning this question is needed.

5.3 Research Needs

- Monitor surface streams around existing mines to evaluate water quality impacts of runoff, altered subsurface hydrology.

- Monitor groundwater quality around existing mines to detect evidence of contamination from overburden leaching; measure rates of resaturation of overburden after mining.

- Leaching tests of overburden from existing mines, of various ages and states of weathering, to determine changes in the solubility and mobility of contaminants with time.

- Column leach studies to determine the contaminant-immobilization capacity of Lignite Belt soils and strata potentially disturbed by mining.

- Investigate the adequacy of present institutional mechanisms to protect against groundwater contamination from mining and waste disposal. Identify available mechanisms for providing such protection, including those used in other states.

6.0 IMPACTS ON FISH AND WILDLIFE

Summary and Conclusions

- Mining and plant siting will account for most of the direct destruction of terrestrial habitat accompanying the development scenario. Total acreage is very small compared to habitat available. However, currently, wildlife habitat is in poor condition over much of the Lignite Belt. Thus, impacts will often occur in a context of heavy present stress.

- Reclamation has been successful on existing lignite mines. Most landowners appear to prefer restoration for "tame grass" pastures to reclaiming wildlife habitat values. This kind of monoculture is of low value to most native wildlife. Planting tame grass pasture may therefore result in a net habitat loss, even after successful reclamation.

- Cooling pond and reservoir construction destroys riparian and bottomland habitat. These are the least abundant terrestrial habitat types in the Lignite Belt, and have uniquely high value to wildlife of many kinds.

- Continued deterioration of surrounding habitat through poor land-use practices could outweigh the benefits of successful reclamation of mined lands for wildlife values. In the long run, poor agricultural and grazing practices may do far more damage to terrestrial ecosystems than mining.

- Construction of new impoundments fragments river habitats and replaces them with greatly different aquatic systems.

- Experience to date does not indicate that acid mine drainage is likely to be a widespread problem.

- Water development and use alters flow regimes in affected basins. Unless reservoirs are operated so as to compensate for the effects of consumptive use, low-flow conditions will occur more frequently. The degree of stress this places on aquatic ecosystems will vary between and within basins.

6.1 Terrestrial Ecosystems

The major impacts on terrestrial communities resulting from lignite development fall into two groups: direct destruction of habitat and indirect reduction of habitat quality resulting from overall population growth. Both kinds of impacts have already occurred over most of the Lignite Belt. These impacts arise from activities other than mining, and have drastically altered the character of both vegetation and animal populations over the course of the last century. The potential ecological impact of mining and plant siting must therefore be evaluted both in terms of the extent of disturbance expected and of the present condition and trend of affected habitat.

6.1.1 Extent of Habitat Disturbance

Accompanying the direct effects of lignite development will be indirect effects caused by the creation of thousands of new jobs and significant numbers of new people moving into the lignite area. People may commute 50 miles or more to work in semi-rural areas. The distribution of these new families and the land-use impacts of developing housing for them is therefore difficult to predict. As will be discussed in Section 7, below, most of the increased population is expected to settle in the existing small communities throughout the Lignite Belt, thereby causing little direct disturbance to the more remote wildlife habitats.

The major direct impact on habitat resulting from lignite development will be land clearing for mining and for plant siting. Assuming an average seam thickness of six feet, the process of mining sufficient lignite to support a single 500 MWe generating unit for a lifetime of 30 years would ultimately disturb approximately 5,700 acres of land. A 1500-MWe station would disturb over 17,000 acres. However, only about 570 acres would be disturbed each year. Assuming that three years pass before revegetation is complete, a total of about 1,700 acres would be in a disturbed condition during any given year after mine start-up. Considered on a regional basis, the forecast levels of lignite development projected in Chapter II will entail the ultimate disturbance of: 187,000 acres in the Northeast Subregion; 119,000 acres in the North Central Subregion; 34,000 acres in the Southern Subregion; and 17,000 acres each in the Gulf Coast and Central Subregions by 2000.

These acreages, large as they may seem, constitute only a small fraction of the total available habitat. Three major vegetation types characterize the bulk of the Lignite Belt: the Pineywoods, the Post Oak Savannah, and the South Texas Plains vegetation associations. These community types extend over 15 million acres, 8.5 million acres, and 20 million acres, respectively. Thus, the total land disturbance associated with lignite mining is equivalent to only about one percent of the total habitat available. Even if all this activity were concentrated in the least abundant habitat type--the Post Oak Savannah--only six percent of the total habitat area--would be affected. Considering the revegetation can be accomplished within three years in most areas, the percentage totally devoid of habitat value at any given time would be smaller yet.

Another major cause of habitat destruction will be the construction of off-steam cooling reservoirs. In addition, new mainstem reservoirs must also be built to provide sufficient surface water supplies to accommodate lignite growth along with other expected increases in water demand. The construction of such impoundments is important not only because of the relatively large acreages involved in any one of them, but also because of the type of habitat most frequently inundated. Over much of East Texas, bottom lands, rivers, and stream courses provide continuous ribbons of good cover and abundant food for many terrestrial wildlife species, and provide habitat for aquatic and semiaquatic forms as well. These habitats in some places are in better condition than upland habitats, long subject to grazing and the plow. In generally disturbed areas such as the eastern half of the state, riparian habitats may often serve as corridors permitting wildlife to move between scattered patches of appropriate upland habitat. Reservoir construction not only destroys the intrinsic value of the habitat inundated, but also cuts off these routes of movement.

6.1.2 Reclamation in Perspective

Even though reclamation can ultimately restore a vegetation cover to the mined areas, the ultimate impact on wildlife will depend on the use for which the reclamation is designed. Currently, there seems to be a strong preference among landowners for restoration to "tame grass" pastures, chiefly of Coastal Bermuda grass. This grass has comparatively little value as food for most wildlife, and provides very little cover. Also, a monoculture of one species tends to be more sensitive to variation in environmental conditions, such as drought, than a vegetation cover consisting of many species, each with its own range of tolerance. Thus, restoration of mined surfaces to this type of vegetation may result in a net loss of habitat value, even though revegetation is successful.[41]

The U.S. Fish and Wildlife Service, in a recent evaluation of Texas lignite mining, concluded that "climate and soil conditions of many Texas areas are such that strip mining and reclamation could be accomplished in a manner which would not result in permanent damage to the environment, if strip mining is restricted from rivers and streams, bottom lands are kept intact, proper reclamation techniques are used, and reclamation managers try conscientiously to meet the requirements of the New Surface Mining Bill."[41] However, the regional significance of even the most successful reclamation program must be evaluated in terms of the quality of the unmined habitat surrounding the disturbed area. It is this habitat which must furnish the native plant and animal species needed to recolonize the reclaimed area. Also, it is habitat conditions over large regional areas which determine the overall health and diversity of ecological communities. Successful reclamation of mines of few tens of thousands of acres in size, scattered throughout a larger area, may be wasted if habitat quality in the overall region declines sufficiently over the same period of time.

6.1.3 Regionwide Trends in Habitat Quality

Currently, over much of the Lignite Belt, habitat conditions are poor and populations are subjected to considerable man-made disturbances. Conditions in the Post Oak Savannah have been particularly well documented with respect to lignite mining.

Originally, this vegetation type was predominantly post oak and hickory savannah or forest, integrated with open prairie. Now, however, under the pressure of intensive grazing and cultivation, mesquite has invaded much of the area. A great deal of the original woody cover was cut for building materials, fire wood, and to clear farm land. Forests that remain are often grazed, which keeps them in a highly disturbed state. Young seedlings and understory trees are often unable to survive in sufficient numbers to assure the perpetuation of the canopy.

Under continued grazing, the probable result will eventually be thinning of the overstory and possibly invasion by the mesquite-shortgrass savannah.

Upland areas have been cleared and cultivated for many years, although much former agricultural land has now been allowed to return to grazing. Heavy soil erosion has taken place over a long period of time, and the vegetation now found on the heavily grazed uplands may often be very weedy. In some areas studied, unpalatable species such as Croton may make up the bulk of the annual production. Heavy grazing tends to select against the more palatable grasses and forbs, and favors less valuable weedy species.

Heavy disturbance of the vegetation community has produced changes in the original animal population as well. Faunal communities currently inhabiting the post oak savannah region are not natural assemblages. They have developed under man-made conditions, in response to a considerable degree of stress. Species diversity is high, probably in part the result of the introduction of year-round water supply. The creation of very large amounts of edge habitat through clearing has also helped promote diversity. Total numbers of animals, however, are probably much lower than those originally inhabiting the area. Thus, in spite of high species richness, low abundance may make present-day disturbed faunal communites less stable than the original ones.

In addition to habitat change, larger animals are under considerable stress from hunting and trapping, both legal and illegal. Deer are rarely found in the area, and beaver, fox, and bobcats are hunted and trapped regularly in and out of season. Also, dogs running in packs, either with or without humans in attendance, regularly harass wildlife.

Such circumstances, if allowed to continue and to deteriorate, seem likely to do far more harm to the local ecosystems than mining by itself. However, looked at another way, these conditions suggest that any reasonable attempt to restore wildlife habitat on reclaimed areas could produce habitat superior to that which existed before. Before this can happen, however, there must be an incentive to reclaim for wildlife values, rather than grazing.*

6.2 Aquatic Ecosystems

Impacts of lignite development on aquatic ecosystems are not as easily discussed on a regional level as are terrestrial impacts. The surface-minable deposits of lignite in Texas cross nearly every major river within the state. Species composition, species diversity, and population sizes vary between rivers and within each river depending on a wide variety of environmental parameters. Since Texas has no natural lakes, all of the native fresh water organisms are riverine in nature even though they may reside in man-made impoundments. Some species have been artificially introduced into the Texas river systems from various sources from outside the state. Thus, the impact of lignite mining and use will vary considerably from site to site.

6.2.1 Types of Impacts on Aquatic Ecosystems

The major impacts of mining and mine-mouth power generation on aquatic ecosystems arise from three kinds of disturbance. The process of mining itself may involve draining, filling, or rerouting small streams around the mine. Although the new Surface Mining Control and Reclamation Act generally prohibits mining

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*See Chapter V for a discussion of methods to provide such incentives.

within one hundred feet of a stream channel, exemptions to this provision may be authorized. Impacts from this type of activity include the loss of habitat and downstream siltation.

Another set of impacts arises when off-stream impoundments are built for cooling. According to the Texas Department of Water Resources, cooling-water reservoir capacity is expected to quadruple in the next 50 years. Each impoundment has a small but measurable effect on flow regimes, and on the movement of nutrients and sediments through the drainage system affected. It should be recalled, in addition, that large new main-stem reservoirs will also be constructed over the same time period. The combined effect of all this activity will depend upon its concentration in a given basin. Replacing a flowing water habitat with an artificial lake completely changes the nature of the former. In addition to the natural replacement of species requiring shallow, running water and riffly habitat by organisms adapted to reservoir conditions, most reservoirs are also planted with game species for recreational purposes. Reservoir operation and timing of floodwater release can have a very strong effect on instream flow regimes. This affects not only downstream freshwater habitat, but potentially affects conditions in downstream estuaries.

Occasionally, concern is expressed about acid mine drainage, similar to that experienced in the Appalachian regions. Excessively low pH produces severe habitat damage. Experience in lignite mining to date has not shown such problems to be associated with Texas lignite. In south Texas, however, the lignite may contain considerably more sulfur than that in which mining had taken place up to this time. Whether or not this will result in acid drainage conditions remains to be seen.

6.2.2 Effects of Flow Depletion

While most aquatic impacts are likely to be site-specific, a potentially more widespread effect of lignite development on river ecosystems could arise from overall flow depletion. During the years of normal river flow, the reduction in flow caused by cumulative water use related to lignite is likely to be a small enough percentage of the flow remaining that significant changes in the fresh water biota would not be observed. However, in the long run, flow depletion will increase the frequency of low flow conditions, unless reservoir operation is adjusted to compensate for the change. While Texas river ecosystems are naturally adapted to periods of drought, there is no reason to believe that increasing the frequency of such stresses would not eventually result in harm to the overall ecosystems. Countering this trend is the requirement to preserve fresh water inflows to estuaries sufficient to protect the productivity of the ecosystems there. Thus, the opportunity exists, in passing the fresh water flows downstream, to correct for flow deficiencies induced by consumption along the way.

6.2.3 Trends in Aquatic Habitat Quality

As is the case with terrestrial communities, river ecosystems in Texas are considerably altered from what they originally were. In general, the extensive development of the land around the major rivers has altered both water quality and flow regimes. From the time of the early settlers in the 1800's through the early 1900's, aquatic environments were used as dumping grounds for a great variety of waste material. In addition, they have received large loads of soil from poorly managed agricultural lands and over-grazed pastures. By the first part of the twentieth century, most of the fish had been removed from the rivers by commercial over-fishing or because of habitat degradation. Efforts by the Texas Parks and Wildlife Department have restored many of the depleted populations to reasonable levels. Still, pollution levels in the rivers, along with consumptive water use, strains most of the state's aquatic resources.

6.3 Research Needs

- Estimate present and future demand for wildlife-related outdoor recreation by residents of the large metropolitan areas just outside the Lignite Belt. Evaluate whether this demand could be made to support a system of recreational lands based on reclaimed mined lands. Compare and evaluate means of administering, managing, and financing such a system; give special emphasis to the concept of recreational leasing, similar to hunting leases, which provides income to the landowner and incentives to reclaim and maintain for wildlife habitat.

- Identify areas of unique or exceptionally valuable terrestrial habitat within the Lignite Belt.

- Experiment on existing surface mines with techniques for restoring wildlife habitat value. Develop combinations of forage species with value to both wildlife and livestock. Develop maintenance programs for lands so reclaimed.

- Evaluate the effect of illegal hunting, trapping, and harrassment by dog packs on the successful reestablishment of wildlife or mined lands.

- Investigate techniques for protecting aquatic/riparian communities during mining of surrounding areas; factors to consider include flow maintenance, water quality, shading and temperature regime, and organic matter influx.

7.0 SOCIOECONOMIC IMPACTS

Summary and Conclusions

- Most lignite-related activity will occur away from large population centers. The Lignite Belt is close enough to metropolitan centers, large cities, and towns that boomtown growth is not likely to be widespread.

- Typically, communities affected by lignite development will experience some degree of strain on housing and municipal services. Some changes in the community's demographic structure will occur. These impacts will probably be most pronounced in the Southern Subregion, and least pronounced in the Gulf Coast Subregion.

- A common problem is mismatching between the taxing entity receiving increased revenues from new plant construction and those which must provide most of the services needed by a growing population. A particular problem arises where a new plant is built by a non-taxable publicly owned entity.

- The cumulative effects of the entire development scenario could have substantial impacts at the subregional level. Growth impacts are likely to be shared among many communities, rather than concentrating on those nearest to new plants and mines.

- Spreading growth among many communities may create additional secondary environmental and socioeconomic impacts.

- Planning at the local level is likely to be more difficult when growth impacts are spread.

7.1 Community-Level Impacts

Figure 7-1 illustrates one overriding feature which is very important in analyzing community impacts: there are no major metropolitan centers on the Lignite Belt itself. Most of the mining and power plant activities in the development scenario will be sited in nonmetropolitan areas. The reader is referred to Figure 4-1 in Chapter III, which shows even more obviously that nonmetropolitan locations will be developed in lieu of metropolitan areas. This characteristic makes it easier to project the type of impacts the individual communities will experience.

No attempt is made here to project impacts in particular towns in Texas. However, some general comments about the major problems may be made, based upon recent literature on the topic. Also, the results of an impact assessment model (BOOM) are presented for a hypothetical community vulnerable to boom-town impact. Finally, the change in one Texas community which has experienced the type of growth under consideration is summarized.

7.1.1 General Overview

The most extreme potential impacts of lignite activity can be anticipated by examining the general body of "boom town" literature. A larger literature into which the "boom town" studies fall is the rural industrialization literature.[42] The most important concepts drawn from both can be applied to developments in Texas.

The impacts of new economic activity in a metropolitan region are relatively minor because the increment of population growth is small relative to the original, or the host population. If there is unemployment or underemployment, there may be no

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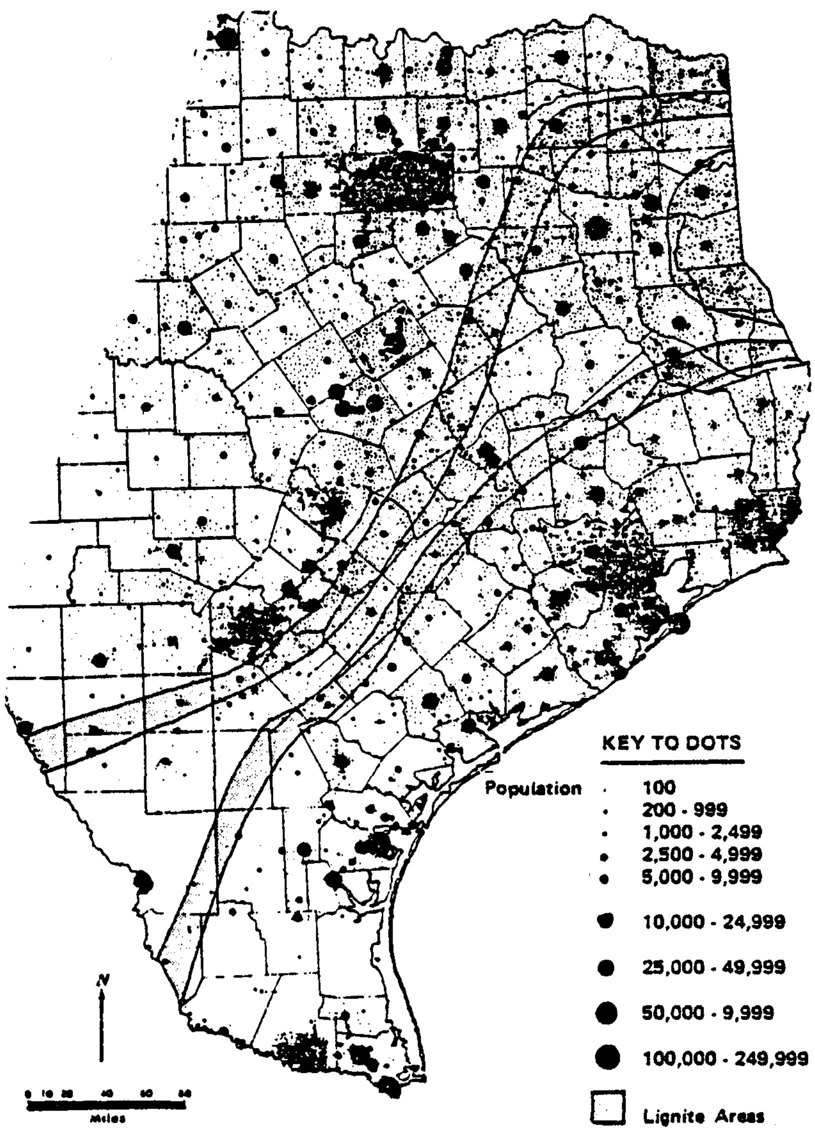

Adapted from: Robert K. Holz, "Population Distribution in Texas: Patterns of Population Distribution", Texas Business Review, June 1973.

02-4322-1

Figure 7-1. Population Distribution, 1970 population growth at all. This is likely to be the case in most of the Gulf Coast Subregion.

The same is not true, however, in sparsely populated nonmetropolitan areas. A new economic activity in a small, isolated town results in almost instantaneous growth which everyone in the region will perceive. Some of the local population may be employed at the new activity, while most of the new jobs will go to inmigrants or long-distance commuters. This type of sudden massive impact is more probable in the sparsely developed Southern Subregions, as can be seem from Figure 7-1.

Most areas in the Northeast, North Central, and Central Subregions will fall somewhere between these two extremes.

Population growth related to new economic activity is not necessarily adverse. Many small towns in nonmetropolitan Texas have experienced net outmigration for decades. They have been left with relatively older populations. New economic activity can mean that former residents who left for lack of employment activity may be able to move back. This "return migration" is a rather common phenomenon in areas which have new activity after a long period of outmigration.

A major impact of the population growth caused by the new activity is on the demographic profile of the community. For an activity with a major construction phase, the profile of the initial immigrants usually differs drastically from the local population.[43] The construction worker profile has a high proportion of single men who form a sharp contrast to the older native population which has a fairly typical male-to-female ratio. Those construction workers who do bring their families tend to have school-age children in greater numbers than the local population.

Community planners need to know the anticipated population increase. The answer is primarily a function of two variables: the number of new jobs and the spatial pattern of population centers.

Most activities have a construction phase and an operation phase. The former typically requires more workers than does the latter. However, the secondary employment effect of construction phases is not as great as that created by the operation phases. Many construction workers will send large portions of their income home rather than spend it at the construction site. Others will commute long distances, thus taking their incomes out of the local area. In contrast, the operation phase typically requires a smaller labor force, but these "permanent" workers will tend to live nearer the activity. This tendency to live nearer the job makes the employment multiplier effect of the operation phase greater than that of the construction phase. Regardless of the phasing, there will be population growth due to the new activity itself and secondary growth to serve the primary growth increment. This secondary growth is supported by increased retail activity, demand for housing and increased public services (schools, police, etc.). Employment estimates for various types of facilities are presented in Table 7-1.

TABLE 7-1. PROJECT CHARACTERISTICS*

Type of Facility	Construction Employment (maximum)	Construction Time	Operation Employment
5 MMT/Year Lignite Mine	200	2-3 years	400
1500 MWe Power Plant	2000	6-8 years	200
300 MCF/Day Gasification Plant	3000	5 years	1200

*These estimates were averaged from several sources and are intended to serve only as guidelines, not predictions.

The second key variable in predicting population growth is the spatial pattern of population centers near the new activity. At one extreme would be a site remote from existing communities. A company town with all the workers living in that town would probably be developed. However, this appears unlikely for most sites in the Texas Lignite Belt. A mine and plant site will generally be within reasonable driving distance from several small towns. The population growth stimulated by the new activity will tend to disperse itself among the respective communities. Distance to work is often used in spatial allocation models, along with the population sizes of competing towns (a surrogate for goods and services available in the towns), to predict where the inmigrants will settle.[44]

7.1.2 Impacts Experienced by Communities

The ability of a community to accommodate growth is reflected in its response to several factors. These range from increased demands for services to changes in social interactions between community members.

7.1.2.1 Housing Demand

The demand for housing in a growth situation can be met in several ways. The most important determinant of the response is the duration of the demand. In rapid growth situations, mobile homes are usually the short-term solution to the housing shortages. This is especially true for those activities with large construction labor requirements and subsequently smaller labor requirements for the operation of the facility. Another partial solution (in the case of a remote facility during the construction phase) is a dormitory for the single workers. The less desirable alternatives to either of these solutions are long-distance commuting and over-crowding.

In areas with high housing demands over short periods of time, mobile homes may be the appropriate solution. For instance, two mobile homes can be co-located on one lot for a short period. Once the "boom" is over, the unneeded homes can be moved elsewhere and a permanent house can be built where two mobile homes previously were. This avoids overbuilding.

Mobile homes gain notoriety when they become a long-term solution to a housing shortage. Mobile homes are generally considered to be inferior environments when compared to permanent housing. Mobile home parks are often unkempt and overcrowded. Mobile homes are smaller than permanent houses. In remote areas, people have to spend more time in these cramped homes because there is little else to do. Interpersonal relationships may tend to become strained as a result.

7.1.2.2 Public Services and Facilities

The housing problem leads to a number of other problems. Most of these are related to providing services and facilities for the housing units and their residents. These problems are often aggregated under the heading "public services and facilities."

When a community is faced with population growth, a number of public services and facilities must be addressed with respect to their ability to serve the anticipated incremental growth. Most nonmetropolitan towns have very little unfilled capacity since population decline rather than growth has been the trend for several decades. Water supply is an obvious limiting factor. New wells may have to be developed to meet household requirements. Even if the water is available, there are often problems with distribution to population growth areas. How a community pays for this type of development is examined in the following section.

A consequence of an expanded water supply is a requirement for wastewater treatment. Septic tanks are a common solution to this problem even within towns. However, septic tanks are often not an acceptable solution in a period of rapid population increase. Hence, a community may have to expand an existing treatment system or construct a new one. These systems are relatively expensive and difficult to finance. Complicating wastewater management is the collection system problem which is similar to the freshwater distribution. This may require simple expansion of the existing system or something much more extensive, such as a lift station (if population growth occurs in the wrong drainage basin).

Public safety can be a major problem in a genuine boomtown situation. The "4 D's" (drunkenness, divorce, depression, and delinquency) often plague boom towns.[26] Hence, the city police department and the county sheriff's office must be expanded because of the population growth and subsequent social problems. Retaining qualified people is difficult because competing jobs (such as company guards) offer higher wages. Fire protection may also be affected by rapid growth. The problems of extending water lines and finding fire-fighters can be serious. Volunteers may be the only source of fire protection.

The level of health care in most small towns is limited more by the quantity and quality of health personnel (physicians, nurses, and dentists) than by the physical facilities. Qualified personnel are difficult to attract and retain in rural areas. When the overall population of a region is low, it is difficult to support a variety of medical specialists. Hence, many residents of nonmetropolitan areas must drive long distances to regional hospitals for specialized care.

In some instances, population growth can be looked upon as a blessing for health care. The new population, after a growth period, may be perceived as large enough to support additional physicians, hence the ratio of qualified health personnel to patients could improve.

As with nearly everything else in a growth situation, the school system may become overcrowded. Physical crowding can be overcome in the short-term by adding temporary rooms. Eventually, new schools have to be built. In an actual boom-town situation, the school system must often be expanded to meet a temporary demand which is greater than the demand for the operation phase. It is that situation which often makes the temporary building more inviting than a permanent structure.

In more remote areas, finding teachers to work in the new classrooms can be a serious problem. Rural areas have always had a problem attracting and retaining qualified teachers. Compounding this situation is the fact that wages paid in the new facility are often much higher than the teacher salaries, making teacher attrition high.

7.1.2.3 Local Government Response

Most of the solutions to these problems require action by government, primarily at the city or county level. These governments usually lack the expertise and finances to provide the needed services.[45]

Small town city managers and county judges are often not professionally trained for these jobs. They sometimes resist change rather than seeking the advice of regional councils of government or staff agencies. Public opinion in the communities they serve often runs against involving larger government entities.[46]

The wages paid to local government professional staffs are often less attractive than those paid at the new facility. Hence, there may be a problem with personnel turnover in the public sector jobs. Few of these governments have planned to accommodate rapid population growth since they have, for the most part, experienced population decline for long periods. Also, there is often the problem of jurisdiction. If population growth occurs outside city limits, the city can do little to control the growth.

An issue involving the equitable distribution of costs and benefits arises when a new facility is sited in one taxing jurisdiction (school/county) and the impacts must be borne by other jurisdictions. If the impact is in one county and the capital investment in another, there is no change in the property tax base for the affected county.

A particular aspect of this problem is the presence in Texas of many publicly owned utilities. These entities are exempt from taxes. In two recent cases, new plants either wholly or partially owned by such utilities have been sited in rural areas. Both the South Texas Nuclear Plant in Matagorda County and the proposed Gibbons Creek Plant in Grimes County have met strong local opposition. Some residents feel that the local communities are being forced to carry an unfair burden in shouldering the costs of providing increased services.[47,48]

Another problem related to financing new facilities is the reluctance of long-time residents of an area to add to their tax load to pay for new facilities to accommodate immigrants.

Finally, it can be a problem if a boom caused by a temporary activity such as construction is to be followed by a lower level of employment during the operation phase. It is possible to over-build during the boom period and have excess capacity after that without the necessary taxpayers to continue payment (the so-called "boom and bust" phenomenon).

A problem common to nearly all energy-related developments is the lack of land-use control mechanisms. Counties in Texas do not have formal land-use control authority. Towns sometimes have zoning authority but it never extends far enough into the surrounding countryside to be very effective. A rapid-growth situation often leads to haphazard, low-density development of the areas peripheral to the affected town, creating problems providing services and facilities as well as adverse aesthetic impacts.

Another potentially serious problem faced by local communities is uncertainty. Those responsible for the final authorization of the new facility often hesitate to announce that project until the last moment because of their uncertainty (due to financing, marketing, and regulatory requirements). That creates uncertainty at the local level and decisive mitigating measures are postponed.

There are other planning problems which governments in rapid growth areas are poorly equipped to solve, such as a lack of adequate solid waste disposal systems and stress on the existing transportation network. These problems make it just that much more difficult for government to act responsibly. These problems are partially the cause of a certain amount of animosity which will develop between "oldtimers" and "newcomers."

7.1.2.4 <u>"Oldtimers" vs. "Newcomers"</u>

The problems discussed thus far are related to the effects people have on social and economic systems. However, a rapid growth situation also affects people socially and physiologically. This was suggested in the discussion of public safety through the identification of the 4 D's.

A recent review by Freudenburg[49] highlights these social problems that are difficult to quantify yet very real in the final analysis. Sudden change, regardless of whether or not it is caused by energy development, is often difficult to accommodate. This applies both the newcomers and the oldtimers in the boom town situation. Freudenburg concluded his review by hypothesizing that social disruption:

- Is socially related to the size and suddenness of the development;
- Is inversely related to the population density of the impact region;
- Is inversely related to the percent of jobs going to people already living in the region;
- Is directly related to the level of skills required; and
- Is directly related to number of inmigrants to the region.

The social disruption affects both newcomers and oldtimers. Both must adapt to changing environments. Jealousy is inevitable because one group (newcomers) causes the change while the other group (oldtimers) feels "invaded" and have to react. Old local residents often cannot compete financially since many are on fixed incomes and cannot pay inflated food and housing costs. Oldtimers usually have lower job skills precluding their employment in higher paying jobs. Newcomers have few friends and feel powerless against the established social and political order. Oldtimers fear that the established political order and value systems will be eroded.

7.1.3 A Boom Town Simulation

The socioeconomic impacts of energy-related developments at any site along the Texas Lignite Belt will probably not be as severe as similar situations have been in the West, primarily because the Lignite Belt contains a more dense pattern of communities to absorb growth-related stress (see Figure 7-1). However, a model to simulate boom town conditions in a hypothetical community will help to highlight major problems which could develop.

The BOOM model was originally developed by the Los Alamos Labs[50] and has recently been adapted by the Center for Energy Studies at The University of Texas at Austin for use in Texas. The most useful feature of the model is that it simulates various social and economic indicators for a hypothetical community over time. It is based upon an elaborate set of equations which have been derived to capture the complex interrelationships among various components of the socioeconomic environment (housing, public finance, retail trade and services, the new economic activity, and population growth). A change in any one of the components affects the others both directly and indirectly through the predefined set of equations. The model is not intended to unravel the detailed behavior of any one sector. Rather, it shows how they interact and affect one another. A detailed presentation is beyond the scope of this report. However, a brief discussion of the public service sector shows how the boom town problem can develop.

An aggregate measure of the public service sector considers those elements highlighted in Figure 7-2(a). Each of these components has a number of inputs defined by equations. For instance, education includes all those elements shown in Figure 7-2(b). The model uses data descriptive of any community under consideration. Standard planning parameters are also incorporated to calibrate the model. Output from the model can include estimates of impacts on individual components (for instance, capital costs for new schools or wastewater treatment facilities), or on all components together. The user can then change input data and parameter values to simulate various policy options.

An example BOOM simulation is presented to show how the "boom and bust" cycle would work in a hypothetical town of 10,000 in an isolated area. This simulation is not intended to depict any particular situation in Texas. The hypothetical project under consideration is a 1500-MWe power station located so that only one town would be affected. The model has been designed to show the town's public service capacity as being adequate before any new activity begins. Figure 7-3 shows the excess capacity without the new activity. Figure 7-4 illustrates the "boom and bust" cycle caused by a construction phase followed by a less significant operation phase. The excess in public services after the construction phase is over is obvious.

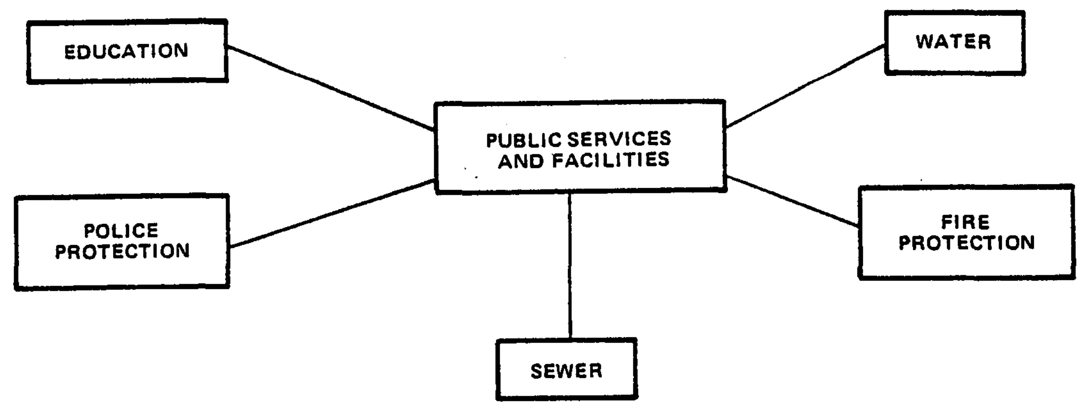

Figure 7-2a.

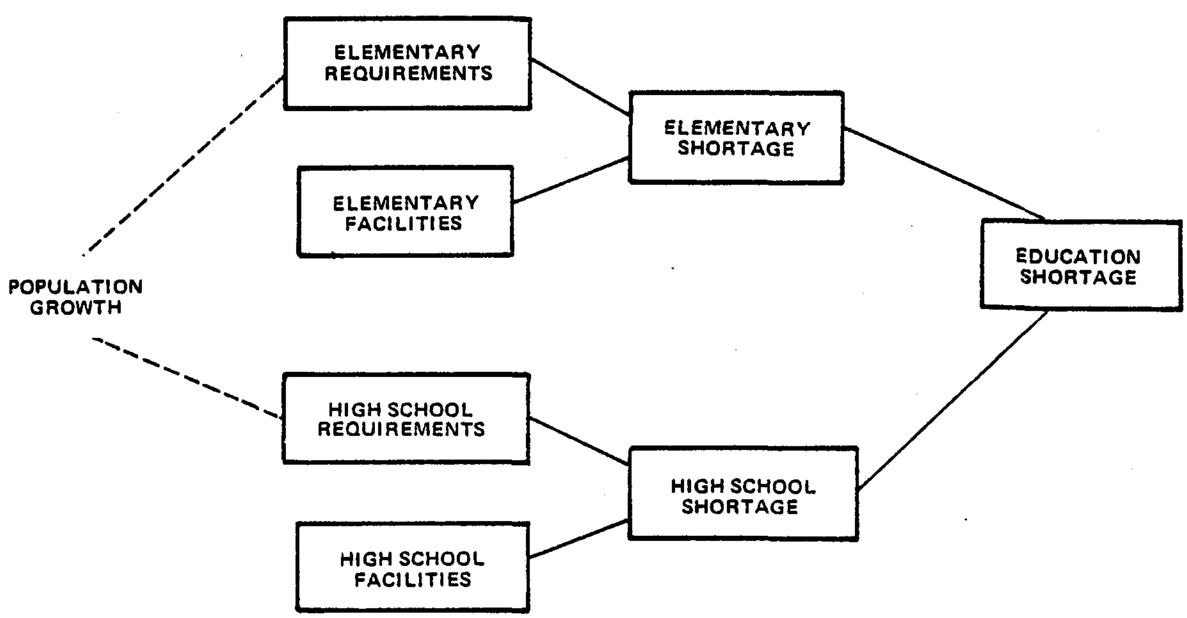

Figure 7-2b.

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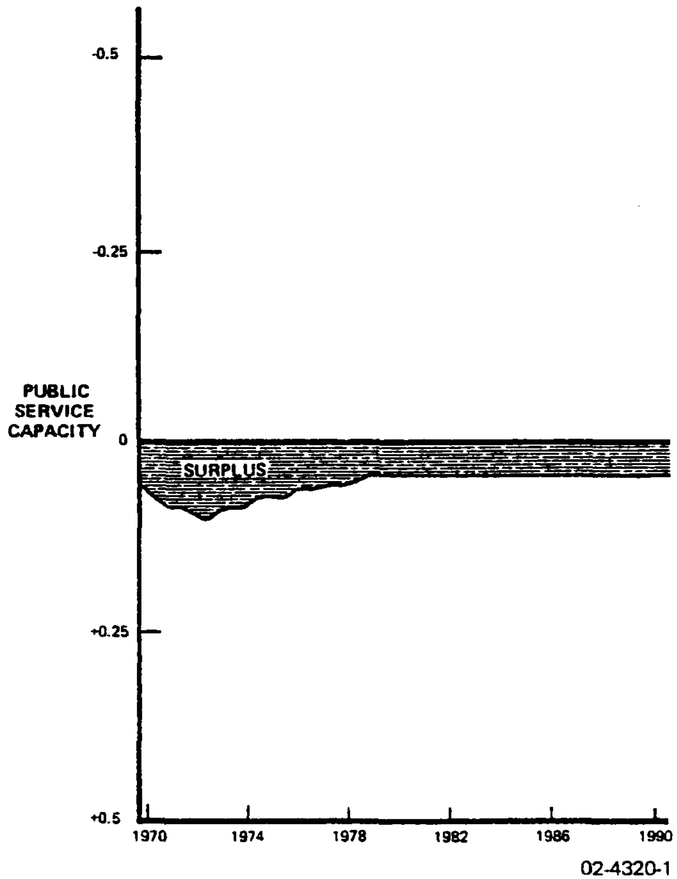

Figure 7-3. Quasi-Equilibrium (Without Energy Development) Simulation

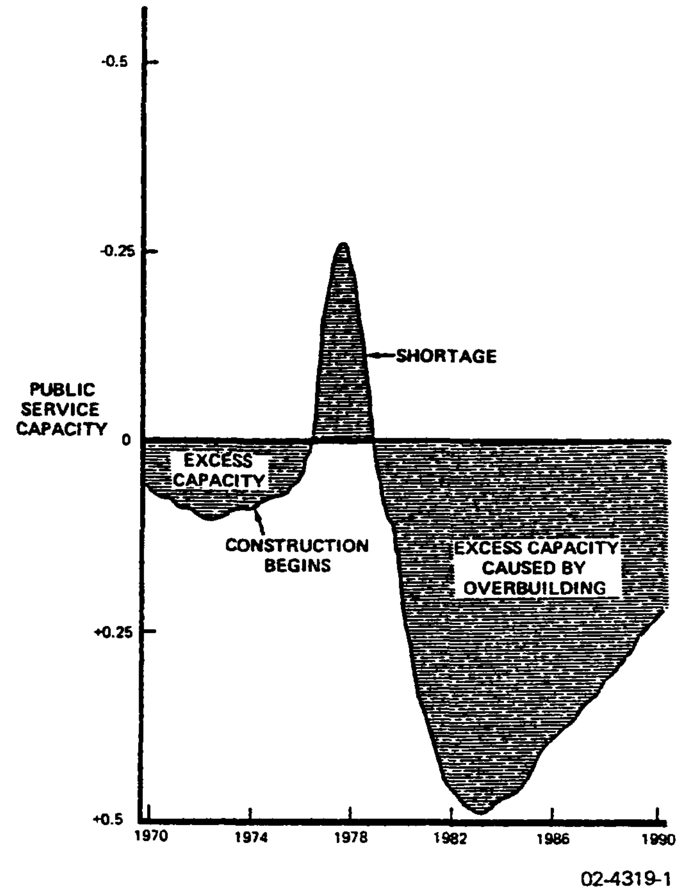

Figure 7-4. Worst Case Boomtown Simulation

Which particular public sector activities are inadequate is not important. Important is the concept that a community can provide services and facilities for a short term which will not be needed after the construction phase is over. This unused capacity becomes an even greater burden for the community because it cannot make the payments, which in turn creates other problems.

This delineation of a boom and bust cycle is important because it serves as a "worst case" scenario for the assessment of community impacts of lignite development. Only in South Texas (where the density of population and communities is low) could a boom and bust cycle similar to boom towns of the West be experienced. However, minimal development is projected for that region. The remainder of the lignite region might experience temporary booms, but the activity will be dispersed over so many small towns that the possibility of severe impacts are minimal.

7.1.4 The Mount Pleasant Experience: A Case Study

The socioeconomic impacts on one nonmetropolitan community in Texas where lignite development has occurred have been fairly well documented.[51] The types of problems which occurred there are representative of what might happen in a similar situation. The town of Mount Pleasant in Titus County has experienced the impacts discussed in the previous sections resulting from the simultaneous development of two power plants and a lignite mine located in the county. The population of Titus County increased 26 percent, from 16,702 in 1970 to 21,000 in 1976, while the population of Mount Pleasant increased 43 percent, from 9,549 to 13,700, over the same two-year period.

Housing this population increase was a significant problem since there were no available units. Four hundred mobile homes in ten parks provided a partial solution. Other mobile homes were located throughout the county on individual lots. Yet, there was still a housing construction boom. In Mount Pleasant, 625 single-family units and 500 apartments were built by 1975. Another 1,000 homes were built outside the city limits. Housing supply eventually surpassed demand in 1975.

Financing this housing construction was difficult for local institutions. Deposits by inmigrants did not equal the demand for loans for several years and the financial institutions had to incur some short-term debts. In the long run, these institutions realized substantially increased deposits and profits. In the meantime, however, they changed significantly the way in which they did business.

As housing developed on the periphery of Mount Pleasant, the traditional geographic pattern of the city changed. Retail establishments located on the periphery to be near the new population and to avoid a stagnating central business district. The competitive pressures forced many of the older establishments to abandon their central locations and relocate on the periphery. One aspect of this geographical change was that people without cars who had relied upon the central business district were inconvenienced, since Mount Pleasant had no public transportation.

Rapid growth also presented problems for city and county government. A ban on mobile homes within the city was lifted as a short-term solution to the housing problem. However, in a period when land-use control within the extraterritorial jurisdiction (ETJ) of the city was not exercised, considerable haphazard growth occurred. Even with changes in government leadership, severe problems with community services and facilities were encountered. A water shortage became worse. City sewer treatment, already inadequate, became more overloaded.

Solid waste was a problem both with respect to collection and disposal. Traffic flow on city streets changed drastically and major routing changes had to be made. The county highway system was even more severely affected because heavy trucks began using roads designed for lighter loads. Crime increased dramatically, requiring law enforcement manpower additions and new jail construction. Fire protection service declined in quality and fire insurance rates were subsequently increased.

The Mount Pleasant Independent School District profited greatly from the growth. The tax base increased substantially but the enrollment did not increase proportionately (many of the newcomers were single, without children). The physician per patient ratio improved as demand grew. Future health care will improve since a hospital district was formed to build a new hospital.

City government had to revalue and reassess property to raise enough money for the additions to facilities and services. Bonds had to be sold to pay for water and wastewater improvements. User rates for all services were increased. Titus County had similar financial problems because it needed capital improvements. However, taxes were not increased because the assessed valuation of property increased dramatically with the additions of the major projects.

In summary, the Mount Pleasant area changed drastically in a four-year period due to lignite-related population growth. The conservative city and county governments were replaced by those more able to cope with change. Values changed drastically with the influx of outsiders. Older residents had little choice in the matter as their community changed. Thus far, there has not been a bust part of the boom and bust cycle because the economic activity continues today.

Although their severity will differ considerably from place to place,* problems of this kind are typical of what a non-metropolitan community can expect. However, Mount Pleasant was better equipped to cope because of its size at the beginning of the change (8,500). A smaller town hit with the same population growth would be much more severely affected. Also, much of the population growth attributable to the economic growth occurred in surrounding counties, so that Mount Pleasant did not receive the full impact of the activity.

7.1.5 Variability in Community Impacts

The severity of socioeconomic impacts will vary with the size and type of facility located near a community. A lignite mine for export will present the fewest problems since it involves the fewest people and because it does not have a "bust" component. A gasification facility would have the greatest impact based upon the size of the construction and operation crews. Intermediate in severity would be a 1500-MWe power plant. Both the power plant and gasification facility potentially have substantial socioeconomic impacts associated with their construction and operation. The socioeconomic problems associated with any of these three activities are related to the population growth, not the facility itself.

The most obvious impacts are those on local governments. Services and facilities become overburdened and the governments involved often have nèither the financial resources

*In contrast to the Mount Pleasant experience, development of the South Texas Nuclear Project in remote Matagorda County produced considerably less strain than had been anticipated, although qualitatively the same range of impacts was felt. [48]

nor the expertise to solve the problems. When the assistance becomes available, it is often too late to be effective. Also, because of political boundaries and other institutional barriers, the community required to provide the services and facilities may not be receiving the proper tax benefits.

Another potential problem is related to the "boom and bust" cycle. A construction phase followed by a significantly less labor-intensive operations phase could cause the over-development of services and facilities. The potential for this type of situation along the Texas Lignite Belt is not great. However, that potential must be acknowledged in the planning process.

Finally, lignite development will inevitably cause change in the character of life in that region. There will be aesthetic and visual changes as well as changes in the values of the people. Low-density sprawl of housing changes the rural landscape. Whether or not these changes are good or bad is for the individual to determine. Yet, to recognize that change is inevitable and that it affects various groups differently is important in planning for it.

7.2 Regional and Subregional Impacts

The preceding discussions show that the boom-town phenomenon at the community level is not expected to become a serious problem in Texas. The main reason is the tendency for impacts to be spread over larger areas, reducing the pressure on individual cities and towns. At the regional and subregional levels, however, this same tendency may result in significant cumulative effects, as the whole development scenario unfolds.

7.2.1 Subregional Development Patterns

The lignite development scenario projects seven 1500-MWe power plants will be built through 1985 and that 14 more will be built through 2000. Those projected by 1985 are already announced or under construction, and their sites are known. However, the locations of the other 14 are uncertain.

Figure 7-5 shows, by subregion, how construction of the facilities might be phased from 1985 through 2000. A six-year construction period for each 1500-MWe plant is assumed.

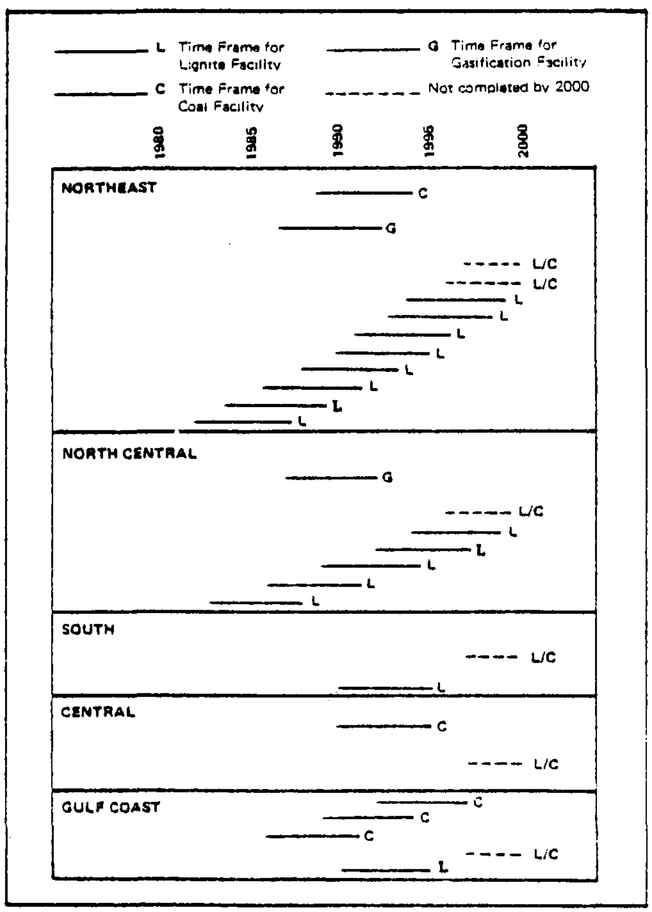

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Figure 7-5. Hypothetical Lignite/Coal Facility Construction By Subregion 1985-2000

Although the scenario stops at the year 2000, other facilities will continue to come on line after that year. Construction for some of these plants would begin before 2000, as indicated by the dashed lines on the figure.

The figure is based on several simplifying assumptions. First, it is assumed that plant construction would be evenly staggered through time. In reality, of course, a certain amount of bunching up would occur. Second, no time lags are assumed between building the three 500-MWe units comprising each plant. In the past, such gaps have often occurred.

Most important, the construction activity related to industrial coal and lignite use is not included. Without knowing the kinds of facilities to be built, and their sizes, it would be misleading to try to include them in this chart. However, judging only by the amount of industrial coal and lignite use projected, facility constuction will add significantly to the total. In the Northeast Subregion, industrial coal and lignite use is 15 percent of that projected for utilities, while in the North Central Subregion it is 30 percent of utility use. Although projected industrial use is very small in both the Southern and Central Subregions, in the Gulf Coast half again the volume of coal and lignite goes to industry as to utilities.

7.2.2 Measures of Subregional Impact

While the development scenario involves impacts in both the construction and operating phases, the construction phase impacts are likely to be the more important at the subregional level. Construction impacts occur first, and involve more workers. The scope of the present study does not permit a detailed investigation of all relevant measures of impact.

However, a comparison of projected cumulative employment levels with the available workforce gives a rough index of the potential socioeconomic impacts that might be expected.

Figure 7-5 suggests that the Gulf Coast, Central, and Southern Subregions will be relatively unaffected at the subregional scale by the levels of development projected there. The situation is more complex in the Northeast and North Central Subregions. In the North Central there might be as many as three construction events at one time. If all three were to coincide with their peak construction phases, there would be as many as 7500 (1.5 workers/MWe) workers employed in construction at any one time. For the entire North Central Subregion, with a labor force of 1,794,000, this does not present a manpower problem. However, for the nonmetropolitan counties in the North Central Subregion, with a total labor force of 81,000 people, 7500 new jobs does represent a substantial increase. There may also be considerable secondary employment growth associated with that initial growth. Part of the labor would come from the surrounding metropolitan areas (Austin, Temple-Belton, Waco, Bryan-College Station). However, much of that area is effectively beyond commuting distance from metropolitan areas.

The situation is similar in the Northeast Subregion. By the end of the 1990's there could be four or five power plant projects underway simultaneously. That subregion has a total labor force of only 365,000 people in 1978, 212,000 of which are in the nonmetropolitan counties. Five 1500-MWe power stations under construction at any one time might create as many as 12,000 construction jobs in the region and generate a significant number of secondary jobs. That increase would have to be considered a source of concern if these nonmetropolitan regions did not change substantially between now and 1995. The impacts which occur in the early 1980's at isolated sites should be watched carefully to determine whether or not a regional approach to accommodate the development in the 1990's will be necessary.

7.2.3 Factors Mitigating the Extent of Subregional Impact

These rough figures do not by themselves convey a sense of how widespread construction-related impacts may be in the Northeast and North Central Subregions. The intensity and distribution of impact depends on the geographic pattern of construction activity. The clustering of development is in itself important. However, in addition, the relative economic development of the immediately surrounding region has a great deal to do with how well the impact can be absorbed.

If mine-mouth power plant development proceeds as projected in the development scenario, then there may be a tendency toward clustered development. The reader is referred to Figure 3-2 in Chapter I, where is may be seen that clustering around lignite deposits is already evident. A breakdown of this trend, such as might develop if air quality concerns dictate control of regionwide source spacing, might result in more scattered siting. However, subregional development levels are based on projected subregional demand growth. Therefore, only a very extreme form of regulation would greatly alter the total amount of construction in the Subregions.

The diversity of a town or a county's economic base, the variety and extent of the goods services it can provide to an industrial or utility project, its population size, and the complexity of its governmental framework, can be though of collectively as measuring its ability to accept growth.[52] In this respect, the Northeastern and North Central Subregions are not homogeneous. Some small communities, such as Mount Pleasant, prior to the advent of power plant construction, have experienced little change or a decline in their economic base in recent decades. Others, like Navasota, in Grimes County, have attracted a variety of industries and have healthy growing economics.[47] The Tyler-Longview-Marshall area in the Northeast Subregion, and Bryan-College Station and Waco-Temple-Belton in the North Central, have recently experienced considerable growth and diversification.

These major centers, with their larger growth capacities, are located very conveniently with respect to possible clustered development along the Lignite Belt. Tyler-Marshall-Longview, located between the two major outcrops of Wilcox lignite, could serve as growth centers for the entire subregion. Bryan-College Station is likewise located between the Wilcox and Yegua-Jackson belts in the North Central Subregion. Acting as secondary growth centers could be the communities of Palestine, Nacogdoches, Lufkin, Sulfur Springs, Mount Pleasant, and Texarkana.

Development in South Texas will probably be much more disruptive to the individual towns that in the other regions. First, the metropolitan centers are far from the Lignite Belt. Commuting would be less of a solution. Second, the density of towns is significantly lower. The fewer the towns to disperse the impacts, the greater the impacts on any one town. This situation more closely approximates the boom town situation of the West. From this perspective it is fortunate that little development is projected for that region.

7.2.4 Larger Implications of Regional and Subregional Growth Patterns

Spreading the impacts of economic growth could under some circumstances, create some secondary environmental and social impacts, also on a subregional scale. A detailed and predictive analysis of these impacts was beyond the scope of this report. However, a number of potential concerns may be listed which might warrant further study.

- Wastewater Management As more and more communities experience growth, upgrading and expansion of sewage treatment systems could become a widespread problem. Difficulties in identifying planning horizons, delays in obtaining federal funds, and construction holdups could result in temporary system inadequacies which could result in temporary water quality problems. The extent of such problems would depend on the regionwide relationship between available capacity and needed expansions.

- Aesthetics and Quality of Life The extent to which growth changes the quality of life for better or worse is a matter of individual perception. However, spreading growth among more communities will mean that changes in the quality of life will be more widespread. These will range from the aesthetics of new commercial and housing developments, plants and mines to more subtle social changes resulting from changed population structures and community attitudes. This study will not presume to qualify these changes as good or bad. Nevertheless, it is clear that it may be more and more difficult to find communities in which older ways of life persist unchanged.

- Energy Export A somewhat more abstract impact arises because the demand which will drive lignite development is in the metropolitan centers to the west (the San Antonio to Dallas urban belt) and southeast (Houston to Beaumont). Energy will be "exported" to those demand centers, where many other jobs will be created as a consequence of that development. Fewer jobs, in proportion to energy produced, may be created along the Lignite Belt. This may be construed by some as a regional inequity.

Another aspect of this question is that communities affected by rapid growth will have to expand services and facilities to meet the demand created by metropolitan areas. Some would argue that the metropolitan users should pay for the socio-economic impacts associated with lignite development in non-metropolitan areas. While regional questions such as this are more difficult to resolve, they are important considerations in the total impact assessment.

7.2.5 Implications for Planning

As has been pointed out, the extent and distribution of cumulative scenario impacts is highly sensitive to both geographic and temporal factors. Thus, even though impacts may be felt cumulatively, it may prove difficult to anticipate them with the accuracy that adequate planning may require. Utility siting announcements usually precede construction by one to several years, because of the forecasting requirements of regulatory agencies. Industries are not so obligated.

An important aspect of Figure 7-5 is the length of time over which high levels of activity are expected to persist. Over this entire period, planners will be operating in a relatively fast-response mode, reacting to new developments as they arise. Also, impact-spreading implies that each county or community is liable, to a greater or lesser degree, to impacts from construction in areas outside their jurisdiction. Thus, planners will not have clear-cut targets to deal with, a situation which may persist indefinitely.*

Finally, the question naturally arises of whether a regionally distributed lignite boom is subject to a subsequent

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*This situation contrasts sharply with that of a typical boom town.

bust. This question cannot be answered without extensive further study. However, it can be pointed out that the tendency to "bust" will depend very much in how lignite growth affects the overall economic development of the subregions. If it provides the impetus for varied economic growth and industrial expansion, a bust will be less likely as the resource is depleted.

7.3 Research Needs

- More thorough evaluation of the carrying capacity of the Lignite Belt region as a whole to support energy growth. Major intraregional differences in growth capacity need to be related to probable future development patterns.
- Detailed assessment of sources of aid in planning and financing new services, for use by individual communities. Evaluation of need to streamline the system, disseminate information concerning available help.
- Identification of individual counties and communities which appear likely to become subregional growth centers as a result of the dispersion of the socioeconomic impacts of energy development.
- Identification and evaluation of ways to diversify the Lignite Belt's economic base, so as to forestall or avoid "bust" conditions when the lignite is gone.

8.0 POLICY ISSUES RELATED TO IMPACTS

The preceding sections have shown that some of the impacts which may reasonably be expected from the development scenario may not be effectively mitigated by existing institutions and policies. These problems without immediate solutions are likely to become issues in the evolution of environmental and energy policy. Seven such problems are stated below, which cover a range of impacts at a generally high level.

In addition, the implementation of existing policy involves a number of unresolved questions, especially in areas where the enabling legislation is new and is undergoing interpretation. Jurisdicational problems, problems of definition, and problems of efficiency of implementation arise as Texas seeks to adapt to the development of national policy. Four issues relating to problems of this kind are set forth below.

All of these issues are discussed in detail in Chapter V. There, more thorough assessments are given, including alternatives for resolution of the issues, and implications of implementing them.

8.1 Issues Related to Finding Solutions for Developing Problems

> Atmospheric Sulfates. Sulfates formed from power-plant SO_2 emissions contribute to regional TSP loadings and are associated with a variety of impacts, including visibility, acid rainfall, and human health. However, mechanisms relating power-plant emissions to their ultimate expression in these effects are very imperfectly known. Should an attempt be made now to regulate sulfates?

Without a relatively complete and realistic theoretical understanding of the atmospheric chemistry involved in the formation of atmospheric sulfates, any attempt to regulate ambient sulfate levels must be relatively arbitrary. However, problems related to sulfate in the atmosphere may be upon us before these processes are known well enough to be modeled. Modeling is needed not only to predict and regulate impacts from single sources, but to devise realistic control strategies and evaluate compliance.

The Clean Air Act Amendments of 1977 require EPA to study the impacts of sulfates on health, welfare, and visibility, and several states have enacted sulfate standards. EPA's decision to regulate or not to regulate sulfates at this time will have to be made under conditions of significant ignorance of key aspects of the situation.

> Infrastructural Financing. Energy development in the Lignite Belt is expected to result in significant needs for additional services and facilities provided by local government. These needs will be dispersed through the Lignite Belt, continuing over the entire study period. Some communities will experience greater growth impacts than others. Problems arise in anticipating capital needs and obtaining funds.

The principal financing problems experienced by communities affected by lignite development have related to timing and equity. Timing problems arise because the heaviest demands for services and facilities typically occur in the construction phase of a large project. Tax revenues from the property, however, do not peak until construction is complete.

Equity problems arise in two ways. First, the site chosen for the project may lie outside the taxing jurisdiction of those government entities which will have to absorb most of its impacts. Secondly, a number of utilities in Texas are owned and operated by Tax-exempt government entities.

Flow Reduction and Water Quality. Reduction in in-stream low flows can reduce assimilative capacity for existing and future waste loads. To continue to meet stream standards, waste loads in heavily burdened streams may have to be reallocated. The costs of improved cleanup would thus be imposed upon existing permittees by consumptive users. In principle, this problem could be alleviated by joint water management and waste-load allocation. There may be practical constraints, however, to implementing such a program.

In the past, permanent changes in flow regimes due to consumptive water use have not been a major consideration in wasteload allocation. In basins where assimilative capacity is already heavily committed, progressive declines in low flows may require repeated readjustments in wasteload allocations. The cumulative expense involved in this kind of reactive approach to maintaining stream standards may be relatively high. If flows could be managed as well, at least to the extent that changes in assimilative capacity could be planned, it would be possible to allocate wasteloads in a forward-looking manner. To the extent that fewer dischargers would be faced with a need to retrofit for better effluent cleanup, the cumulative cost of clean water might be reduced. Neither the State of Texas nor EPA, however, endorse the concept of flow augmentation as a means of pollution control.*

Wildlife Impacts of Reclamation. Habitat conditions over much of the Lignite Belt are poor for wildlife, and could be improved by reclamation. At the same time, there is a large and growing need for wildlife- and aesthetics-based on outdoor recreation. How can this need be turned into a potential economic incentive for landowners to include wildlife values in postmining land uses?

*Note, however, that the existing problem of increased water throughput to prevent high TDS levels in blowdown from power plant cooling systems, discussed in Section 5.0, essentially reflects a flow (or throughput) augmentation approach to pollution control.

As discussed in Section 6.0 above, reclamation potential is good over much of the Lignite Belt. However, most landowners consider that reclamation of mined land to monocultures of cultivated forage grasses is their most profitable choice. This type of cover is of very low value to wildlife.

The tradition of leasing hunting privileges is well established in Texas, and can constitute an important source of income for some ranchers. If similar value could be realized from leases for recreational privileges--hiking and camping--it might provide an incentive for farmers and ranchers to develop wildlife habitat, rather than monocultures. Such uses can be integrated with grazing, if properly managed. Not only are incentives needed to specify wildlife habitat as an end use in reclamation, but continuing incentives to maintain and manage it are also required.

> Control of Boom-Town Growth. For communities which are relatively isolated, nearby energy development may cause a sudden spurt of economic and population growth, followed by a sharp decline as construction is completed. Later, a second decline may follow the depletion of the local lignite resource. What can be done to reduce the abruptness of this boom-bust cycle?

It was pointed out in Section 7.0 that boom-town growth such as that experienced by communities in energy-rich western states is not likely to be a widespread problem in Texas. However, for those few communities which are not so located as to allow population impacts to be spread among surrounding towns and cities, boom-and-bust cycles could be serious problems.

Energy "Export" from Rural Areas. Mining and mine-mouth use of lignite will tend to focus the impacts of lignite development on producing regions. These areas are in general rural, and much of the power produced there will go to users in distant metropolitan areas. To a degree, the jobs produced through the use of the lignite resource will "leak" away from the Lignite Belt to better developed areas.

The concept of resource-rich rural areas as "energy colonies" of more advanced urban areas rests on the assumption that the rural areas will not experience diverse economic growth as a result of energy development. More study is required to determine to what extent this may be true of the Lignite Belt. Potential economic diversification is a key factor in balancing costs and benefits for the lignite belt.

Aesthetics. Lignite development and attendant population growth will alter the looks of the lignite belt. Potential declines in visibility would also have an aesthetic impact. Presently, Texans appear willing to accept a degree of aesthetic change. Most, however, have not yet experienced the degree of change that may take place. Will this attitude change as development proceeds?

Aesthetic impacts of energy development are a matter of personal opinion. They are also extremely persistent, measured in human lifetimes. In addition, they tend to affect a larger part of the population than that which benefits directly from the change. Mitigation potential is relatively limited; they cannot be treated, assimilated, or paid for. These factors make them unique among the range of impacts accompanying energy development.

As the aesthetic impacts of lignite development begin to be felt in more than a few communities, the present favorable attitudes may change. This reaction is likely to vary considerably from place to place. The attitudes of big energy developers, and their willingness to work with local residents, will probably influence the response.

8.2 Issues Related to Administering Existing Policy

> Approval of State Surface Mining Program. The Federal Surface Mining Control and Reclamation Act allows for administration by the states, provided that the states' proposed programs are approved by the Office of Surface Mining. To conform to federal requirements, Texas must essentially duplicate the federal program. This program contains elements which are considered by some to be inappropriate for Texas. The alternative is federal administration in Texas.

A continuing problem in developing a national system of regulating surface mining has been the difficulty of matching a consistent set of national standards with mining conditions that vary widely from state to state. Of particular concern in Texas have been requirements to control suspended solids in mine runoff and to segregate and replace certain layers of topsoil and overburden.

The state viewpoint favors maintaining some ability to adapt the application of the strip mining program to the specific conditions encountered. Obtaining authorization to administer the program is a key objective. Texas has a surface mining statute of its own, passed prior to the SMCRA but containing, by design, most of the concepts subsequently enacted in the federal law. State-federal conflicts have arisen over the need to rewrite the Texas law to increase its detailed resemblance to the federal statute.

Lands Unsuitable for Mining. Under the lignite development scenario, about 350,000 acres might ultimately be disturbed by mining. The state's land area has not been extensively studied by environmental scientists, particularly ecologists. Should the Railroad Commission attempt now to identify areas unsuitable for mining or continue to make this judgment on a case-by-case basis?

Under the Texas surface mining legislation, the Railroad Commission is authorized to make a prospective designation of areas unsuitable for surface mining. The right to petition that areas be so designated is granted the public under both the federal and state statutes. Lands may be considered unsuitable because of potential damage of important historic, cultural, ecological, scientific, or aesthetic values. Lands important to long-range watershed stability or to agriculture, or subject to natural hazards such as flooding, may also be so designated. At present, considerable uncertainty exists as to the extent of potentially unsuitable lands, and their significance to mining.

Solid Waste Management. Large volumes of solid waste, containing leachable salts, must be disposed of as coal- and lignite-burning increases. Much of this waste would logically be disposed of in or near the Lignite Belt, a region of complex hydrology not well understood on a fine scale. What measures are needed to insure against groundwater contamination?

The detailed body of regulations called for by the Resource Conservation and Recovery Act (RCRA) are still in the formative stages, and may take several years to finalize. In developing these regulations, it is important not only to provide adequate protection to the environment, but to avoid unnecessary costs. Meeting these goals requires a more thorough knowledge of the movement of potential contaminants through the soil-water environment. Also needed is a realistic method of testing wastes to determine appropriate disposal and containment procedures. This latter step is a key element in the process of matching control efforts to the level of environmental protection needed.

> Multiple Permitting. Several state agencies have statutory responsibilities relating to site approval for mines and associated energy-conversion facilities. Each is concerned only with impacts that fall within its jurisdiction. Currently, there is no formal governmental mechanism for coordinating these decisions. Should one be established?

Both regulators and project developers are hampered by the delays and uncertainties related to multiple permitting. Also, the overall impact of a proposed project may not be reviewed specifically. Impacts not covered by a specific permit can also be inadequately addressed. Coordinated permit review would offer a way to avoid these difficulties, while potentially streamlining the siting process.

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16. ABSTRACT

This three volume report contains the results of a project to assess the probable impacts of expected future development of Texas lignite resources. This multi-disciplinary, policy-oriented study considered possible lignite extraction and utilization options through the year 2000. The research team attempted to identify and characterize the amjor environmental, socio-economic, public health and institutional impacts which could result from this process and the policy issues created or aggrevated by these impacts. Alternative solutions to policy problems are outlined with probable consequences of each.

Volume I contains Technical Analyses, including: evaluation of the potential for use of lignite, the likely siting patterns of lignite facilities, and the environmental and socio-economic impacts of lignite use. Volume II contains Policy Anslyses which identify major public policy issues related to lignite use in Texas and discuss the alternative policies available for resolving the issues. Volume III contains technical working papers.

17. KEY WORDS AND DOCUMENT ANALYSIS

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