Approved Monday, March 20, 1989
Date

MINUTES OF THE SENATE COMMITTEE ON ASSESSMENT AND TAXATION.

The meeting was called to order by Senator Audrey Langworthy, Vice Chairperson at
Chairperson

11:00 a.m./p.m. on Wednesday, March 1, 1989 in room 519-S of the Capitol.

All members were present except:

Senator Dan Thiessen, Chairman (Excused)

Committee staff present:

Don Hayward, Revisor's Office
Chris Courtwright, Research Department
Tom Severn, Research Department
Marion Anzek, Committee Secretary

Conferees appearing before the committee:

Harlan Priddle, Chairman-The Kansas Coal Commission
Bill Giles, District #14, President of the United Mine Workers
Lowell Forbes, Coordinator of United Mine Workers of Wichita
Tom Taylor, Manager-Governmental Affairs, KPL Gas Service
Woody Woodman, representing The Kansas City Power and Light
Connie McGinness, representing Kansas Electric Cooperatives
Jerry Kempf, Director of External Affairs, Sunflower Electric Cooperative, Inc.
Jerry Coonrod, representing Kansas Gas & Electric Company

Senator Audrey Langworthy, Vice Chairperson called the meeting to order and asked for action on the committee minutes before them.

Senator Karr moved to adopt the minutes of February 20, 1989, seconded by Senator Oleen. The motion carried.

Madam Chairperson said we have three related bills today, SB227, SB228 and SB229; and she called upon Senator Martin.

Senator Martin said the three bills are the outgrowth of the study before you, called the Kansas Coal Utilization Study. (ATTACHMENT 1). This is a report to the Kansas Coal Commission, of which he is a member and is chaired by the J.E. Sinor Consultants, Inc.. He turned attention to page 121 which has seven recommendations, made by the commission. These recommendations have been drafted into the bills before you. All three of the bills try to encourage the use of Kansas Coal and help revitalize the Industry. The Senator then read the status of "Clean Coal Technology" on page 79 of the attachment.

Madam Chairperson turned attention to the testimony for SB227 and recognized Harland Priddle, Chairman of the Kansas Coal Commission.

SB227:AN ACT relating to sales taxation; exempting sales of property and services associated with certain coal-fired boiler systems; amending K.S.A. 1988 Supp. 79-3606 and repealing the existing section.

SB228:AN ACT relating to income taxation; allowing credits against corporate liability for certain costs of purchasing and installing a coal burning system.

SB229:AN ACT relating to coal; imposing a tax upon the generation of electricity from coal by electric public utilities; providing for the administration of such tax and the use of revenues derived therefrom.

Harlan Priddle said he would like to compliment the commission, as they matched the funds from the State in less than 6 weeks. He said the 1987 legislature created the Kansas Coal Commission with the purpose of studying ways to expand the existing markets and create new markets for Kansas coal. Funds were appropriated by the legislature to be matched by profit contributions. The major focus of the study was to analyze the current Kansas coal market as it exists today, form an analysis of Kansas mining, transportation and enviromental conditions, and recommend possible actions to aid the State coal industry. Mr. Priddle said the three bills you have

Unless specifically noted, the individual remarks recorded herein have not been transcribed verbatim. Individual remarks as reported herein have not been submitted to the individuals appearing before the committee for editing or corrections.

before you today are a result of this study. The study indicates that the Kansas coal market primarily results from sales to electrical utilities. Kansas coal only comprise about 10% of the total amount of coal burned by Kansas utilities in 1987, and 1988 will probably show a decrease to around 5%, because of the Midway mine closing at LaCygne. Our chief competitor is Wyoming Coal, which comprises over 85% of all coal burned in Kansas utilities in 1987, and may increase to approximately 88% in 1988. (ATTACHMENT 2)

Madam Chairperson recognized Bill Giles, District #14 President of the United Mine Workers.

Bill Giles said the Kansas Coal Commission was created by an act of the 1987 Kansas Legislature. This commission was established to study ways to expand existing markets and create new markets for Kansas coal. Mr. Giles said his handout included an appendix #1, developed by the Kansas Department of Health and Environment. Surface mining and annual coal production sections from 1982 thru 1988 show that Kansas coal production is at the lowest point it has been in seven years. The Commission believes that some state laws need to be changed to be more competitive with neighboring States. SB227 gives a tax incentive on all tangible personal property and services purchased for the purpose of using Kansas produced coal. They urge adoption of this legislation.

SB228 would allow tax credits against corporate liability for certain cost of purchasing and installing a coal burning system while burning Kansas produced coal. He urged support for the passage of SB228.

SB229 imposes a 5¢/ton tax on all coal utilized in the generation of electricity in the State of Kansas. It also defines how it will be collected and what will be done with these monies when collected. (see appendix to handout). They support SB229 and again urge the adoption of all three Senate Bills 227, 228 and 229, so we may try to save the coal industry in the State of Kansas. (ATTACHMENT 3)

Madam Chairperson recognized Lowell Forbes, coordinator of United Mine Workers of Wichita.

Lowell Forbes said he is a working miner respresenting the miner's in Eastern Kansas, and he asked the committee to help save the industry as they have approximately 130 miners laid off now. He said about a decade ago Eastern Kansas had 8 working active mines, and now they have 1. He said the miner's of Eastern Kansas urge this committee to support SB229.

Madam Chairperson called upon Tom Taylor, Manager of Governmental Affairs, KPL Gas Service.

Tom Taylor said KPL Gas Service supports SB227 and SB228. They believe these bills grant a method of encouraging and rewarding those who are able to use Kansas coal, rather than making someone use it or pay a higher price for it.

SB229 is the bill that would levy a 5¢ tax on all coal burned by Kansas Electric Public Utilities to fund a Kansas coal technology fund. This fund would provide grants to state and non-profit institutions to install facilities to burn Kansas coal and to pay for administration of the fund. SB229 would require Kansas electric consumers in every area of the state to subsidize the fund through higher rates. Kansas must have the most competitive electric rates possible. They cannot support SB229 because adding hundreds of thousands of dollars of coal costs adds an unnecessary burden on electric customers and plays a part in taking away their competitive edge. (ATTACHMENT 4)

After committee discussion, Madam Chairperson recognized Woody Woodman, representing The Kansas City Power and Light

Woody Woodman said he concurs with the reports heard today about needing the research. The utilities in the United States are involved to a great deal in coal research, and this is research which can benefit their customers. The 6 companies in Kansas in 1989 will contribute somewhere between $700,000 and $800,000 to the Electric Power Research Institute. This is a national organization which does research and also tracks research done by others. They think this demonstrates that the 6 power companies are contributing to this, and that a lot of the research is done locally. In the case of the Kansas City Power and Light Company, this 5¢/ton tax would add the tax onto the Kansas coal that they burn, approximately a dollar a meter. In addition to the other taxes paid, they also pay $1.00 a ton severence tax. He asked that the committee look along another line. SB229 would add an obstacle, that would make it almost impossible to build a power plant.

He asked the committee to support SB227, and SB228 and he urged the committee's unfavorabe support of SB229.

Madam Chairperson called upon Conni L. McGinness, Director, Legislative Relations, Kansas Electric Coopreratiye, Inc.

Connie McGinness said she was testifying in behalf of Kansas Electric Cooperatives, and she said we are opposed to SB229. The electric cooperative would be affected by this legislation, particularly Sunflower Electric Cooperative in Western Kansas. It would cause the farmers in the western one-third of the state, through their electric bills, to fund an industry's development in Southeastern Kansas, and this concept seemed unfair. They urge the committee to vote against SB229. (ATTACHMENT 5)

Madam Chairperson recognized Jerry Kemp, Director of External Affairs, Sunflower Electric Cooperative, Inc.

Jerry Kempf said he would like to deviate from his written statement, because most of his written testimony has already been covered. He anticipated they will burn about 1M tons of coal this year, and this would be about $50,000 in increased taxes. The consumer rate would increase about $1.00 a meter, and that relates to about 8½¢ a month. They anticipate the State Water Plan will cost them about $100,000. They do not enjoy being a collector of taxes. They are not opposed to paying taxes; they pay over $6½M in various taxes. SB229 is not the right approach for what they are trying to do in the State of Kansas, and he asked the committee to vote against SB229. (ATTACHMENT 6)

After committee discussion Madam Chairperson called upon Jerry Coonrod, Kansas Gas & Electric Company.

Jerry Coonrod said SB229 proposes to levy an additional tax on utilities to fund projects intended to increase the use of Kansas coal. Since the benefits to increase coal mining in Kansas do not accrue directly to citizens who use electricity produced in coal-burning power plants but to all Kansans, it seem more equitable to pay the cost of these proposals from the general fund. They are in support of SB227 and SB228 and opposed to SB229. (ATTACHMENT 7)

After committee discussion Madam Chairperson closed the hearings on SB227, SB228 and SB229 and adjourned the meeting at 12:18 p.m.

GUEST LIST

COMMITTEE: SENATE ASSESSMENT & TAXATION

DATE: Wednesday, 3-1-89

NAME (PLEASE PRINT)	ADDRESS	COMPANY/ORGANIZATION
Lawrence L Brady	Lawrence, KS	[illegible]
Terry Denker	Topeka	Kansas Coal Comm staff
Debbie McCaskill	Topeka	KS. Dept. of Commerce
Shirley Sicilian	Topeka	Ks. Corporation Comm
Whitney Damron	Topeka	[illegible] County
[illegible]	Topeka	Observer
Curt Carpenter	Great Bend	Centel Electric
DAN McGEE	GREAT BEND	CENTEL ELECTRIC
Randy Burleson	Columbus	[illegible] Electric
[illegible]	[illegible]	[illegible]
Lowell Forbes	McCune Ks.	P+M Coal Co.
[illegible] LESH	MORTON KS	KEC
AL GERSTNER	COLBY, Ks	MIDWEST ENERGY
Connie McGinness	Topeka	KS [illegible]
Ken Peterson	"	KS PETROLEUM Coul
Bill Henry	Topeka	KS Engineering Society
Jerry C. [illegible]	HAYS	SUNFLOWER Elec.
[illegible]	Topeka	KG&E
Tom Taylor	Topeka	KPL Gas Service
Jim Ludwig	TOPEKA	[illegible]
DICK COMPTON	HAYS	MIDWEST ENERGY
Gerhard Metz	Topeka	[illegible]
John Luttjohann	"	Dept. of Revenue
Woody Woodman	KCMo	KCPL

KANSAS COAL UTILIZATION STUDY

Prepared for

The Kansas Coal Commission

by

J. E. Sinor Consultants, Inc.

November, 1988

Attachment I
Assessment & Taxation
3-1-89

KANSAS COAL UTILIZATION STUDY

Prepared for

The Kansas Coal Commission

by

J. E. Sinor Consultants, Inc.

November, 1988

J. E. Sinor
J. W. Green
T. C. Borer
T. R. Ellis
D. A. Cozad
D. M. Sinor

CONTENTS

TABLES

FIGURES

EXECUTIVE SUMMARY

KANSAS COAL PRODUCTION IS DECLINING SHARPLY. After peaking at over seven million tons per year in 1918, production declined to 2.0 million tons in 1987. Due to the shutdown of the Midway Mine, 1988 production may be less than 900,000 tons. Locations of Kansas coal fields, coal mines, and coal-burning facilities are shown in Figure A.

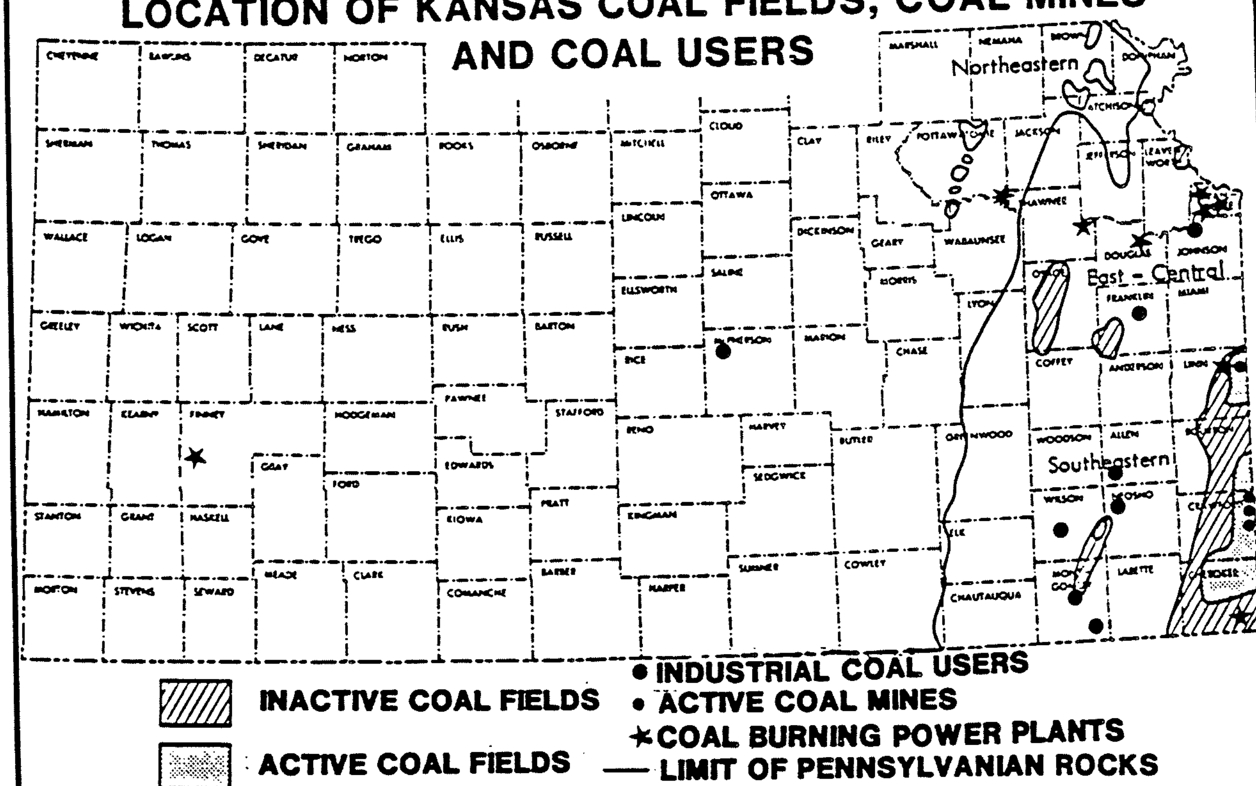
LOSS OF THE COAL MINING INDUSTRY WOULD HAVE A SEVERE IMPACT ON THE ECONOMY OF SOUTHEAST KANSAS. The coal mining industry currently provides approximately 225 direct jobs in Kansas, and it may be estimated that these direct jobs generate another 300 indirect jobs in the region. Unemployment compensation to this many people could total $4 million per year.

KANSAS COAL RESERVES ARE SUFFICIENT FOR MANY YEARS OF PRODUCTION AT CURRENT LEVELS. Measured and indicated strippable reserves at less than a 30:1 stripping ratio are estimated at 400 million tons in the four major coal producing counties along the southeast Kansas border with Missouri. This amounts to a 200-year reserve at current rates. Another 600 million tons may be available.

KANSAS COAL RESERVES REPRESENT VAST POTENTIAL WEALTH FOR THE STATE OF KANSAS. Using the smallest figure of 400 million tons of reserves, we can calculate a potential wealth of $8 billion waiting to be realized (at $20 per ton). This potential will be lost if the Kansas coal industry does not survive. In per capita terms, this amounts to $3,000 per resident of the state.

FIGURE A

LOCATION OF KANSAS COAL FIELDS, COAL MINES AND COAL USERS



ALL KANSAS COAL RESERVES ARE MEDIUM TO HIGH IN SULFUR. Commonly there is three to five percent sulfur present. Environmental control regulations increasingly inhibit the ability of utilities and industries to burn this type of coal.

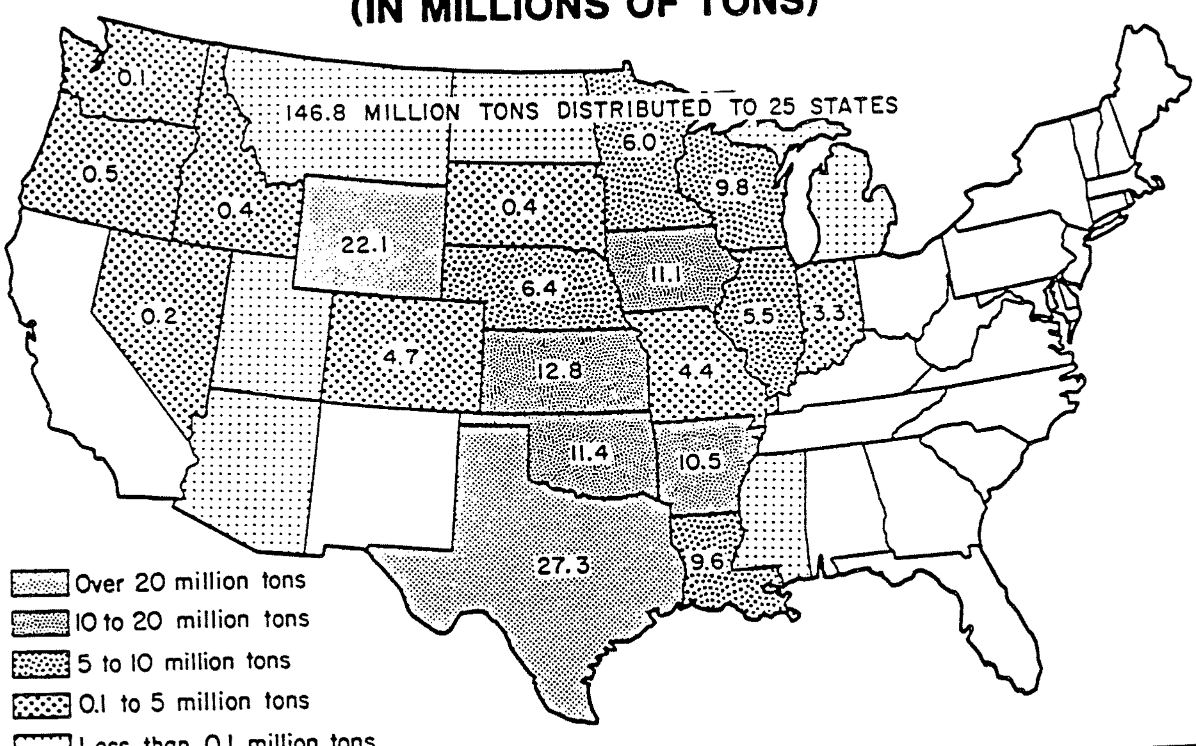
ONLY ABOUT FIVE TO 10 PERCENT OF THE COAL BURNED BY ELECTRIC UTILITIES IN KANSAS IS MINED IN KANSAS. Kansas supplied five percent of the coal used in-state in 1985. The amount of Kansas coal used by the utilities increased to 1.5 million tons in 1987, or ten percent of the total. This statistical increase occurred because production at the Midway Mine shifted from the Missouri side of the border to the Kansas side. This will be partially reversed in the future.

MOST OF THE COAL BURNED BY KANSAS UTILITIES IS SHIPPED FROM WYOMING. Wyoming delivered 12.8 million tons of coal to Kansas in 1987, supplying 85 percent of the total coal used by Kansas utilities. Wyoming coal is low in sulfur and also is generally the lowest-cost coal available. It dominates the regional coal market (Figure B).

KANSAS UTILITIES HAVE NO PLANS FOR NEW COAL-FIRED GENERATING UNITS IN THE NEAR FUTURE. Currently, the state as a whole has excess generating capacity. There is 5,597 megawatts of coal-fired capacity. If electricity demand increases only at the expected rate of 2.3 percent per year, only one small 75-megawatt unit is scheduled before the year 2000, and it is likely to be built in Missouri instead of Kansas.

FIGURE B

DISTRIBUTION OF WYOMING COAL, 1987 (IN MILLIONS OF TONS)



INDUSTRIAL COAL DEMAND IN KANSAS IS LOWER THAN IN SURROUNDING STATES. EIA data indicate 250,000 tons per year in Kansas, compared to 614,000 in Oklahoma and 1,423,000 in Missouri. Locations of large industrial coal users are shown in Figure A. Industrial coal demand in Kansas is largest at cement kilns. Coal is subject to competition from petroleum coke, natural gas and waste solvents in this market. There are no indications of growth in coal demand.

COMMERCIAL AND RESIDENTIAL USE OF COAL IS NOT GROWING. The primary barrier to increased coal use is the high capital cost of equipment, some six to 13 times as high as the cost of equivalent natural gas fired installations. Single buildings, even as large as hospitals, are not coal candidates at current energy prices. Multi-building facilities, such as large business parks and university campuses, may have large enough energy use for coal-burning to be feasible.

KANSAS COAL DOES NOT APPEAR TO BE ABLE TO COMPETE IN THE WORLD COAL EXPORT MARKET. Access to world markets would be through the Port of Catoosa, on the McClellan-Kerr waterway in Oklahoma, 120 miles south of Pittsburg, Kansas. Transportation costs to get Kansas coal loaded on an ocean-going collier in the lower Mississippi River are estimated at over $18 per ton. This would make it uncompetitive in today's world markets where low-cost coal from Colombia, Venezuela, Australia, South Africa and China dominate the scene.

KANSAS COAL MINES ARE COMPETITIVE WITH THEIR COUNTERPARTS IN MISSOURI AND OKLAHOMA. Coal mining conditions in the region are similar, involving thin coal beds with high overburden to coal ratios. Kansas mines have a higher average productivity than those in Missouri and Oklahoma, and are able to maintain their proportionate share of local coal markets in the region. Taxes are lower in Missouri, but no state has a large economic advantage.

THE LONG-TERM COST OF PRODUCTION FOR COAL FROM WYOMING'S POWDER RIVER BASIN IS $0.34 TO $0.53 PER MILLION BTU AT THE MINE MOUTH. This compares to $1.00 at the mine mouth for southeast Kansas coal. Thick seams (50-60 feet compared to two feet or less in Kansas) and low overburden to coal ratios (less than 1:1 compared to over 20:1 in Kansas) make for the lowest cost mining conditions in America. It is estimated that production from existing and planned mines could be increased by 100 percent without straining capacity.

RAILROAD FREIGHT RATES FROM WYOMING ARE EXPECTED TO REMAIN LOW. Immediately after passage of the Staggers Act in 1980, Burlington Northern increased rail rates from the Powder River Basin sharply. When Chicago and North Western gained access to part of the region in 1984, however, rates dropped substantially due to competition. Some coal is now being hauled for considerably less than 1.0 cent per ton-mile. Competition should limit any future increases.

KANSAS COAL MAY BE COMPETITIVE, ON THE BASIS OF DELIVERED COST PER BTU, WITH WYOMING COAL IN EASTERN KANSAS. This includes power plants in Kansas City, Lawrence and Topeka. As the delivery site moves westward, however, Wyoming coal rapidly gains an advantage. Estimated delivered costs at several Kansas power plants are compared in Table A. It is clear that the competitive radius for Kansas coal is limited to the eastern edge of the state.

INTER-FUEL COMPETITION IS IMPORTANT IN THE INDUSTRIAL FUEL MARKET BUT NOT THE UTILITY FUEL MARKET. Even at current depressed world oil prices, the cost

TABLE A

COMPARATIVE LONG-TERM DELIVERED COSTS FOR WYOMING AND KANSAS COALS

Plant	Wyoming Freight $/MMBTU	Wyoming Total $/MMBTU	Kansas Freight $/MMTBU	Kansas Total $/MMBTU
Lawrence	0.78	1.31	0.38	1.34
Nearman	0.81	1.34	0.36	1.32
Tecumseh	0.76	1.29	0.41	1.37
Holcomb	0.81	1.34	0.76	1.72
Jeffrey	0.73	1.26	0.46	1.42
LaCygne	0.91	1.44	0.25	1.21

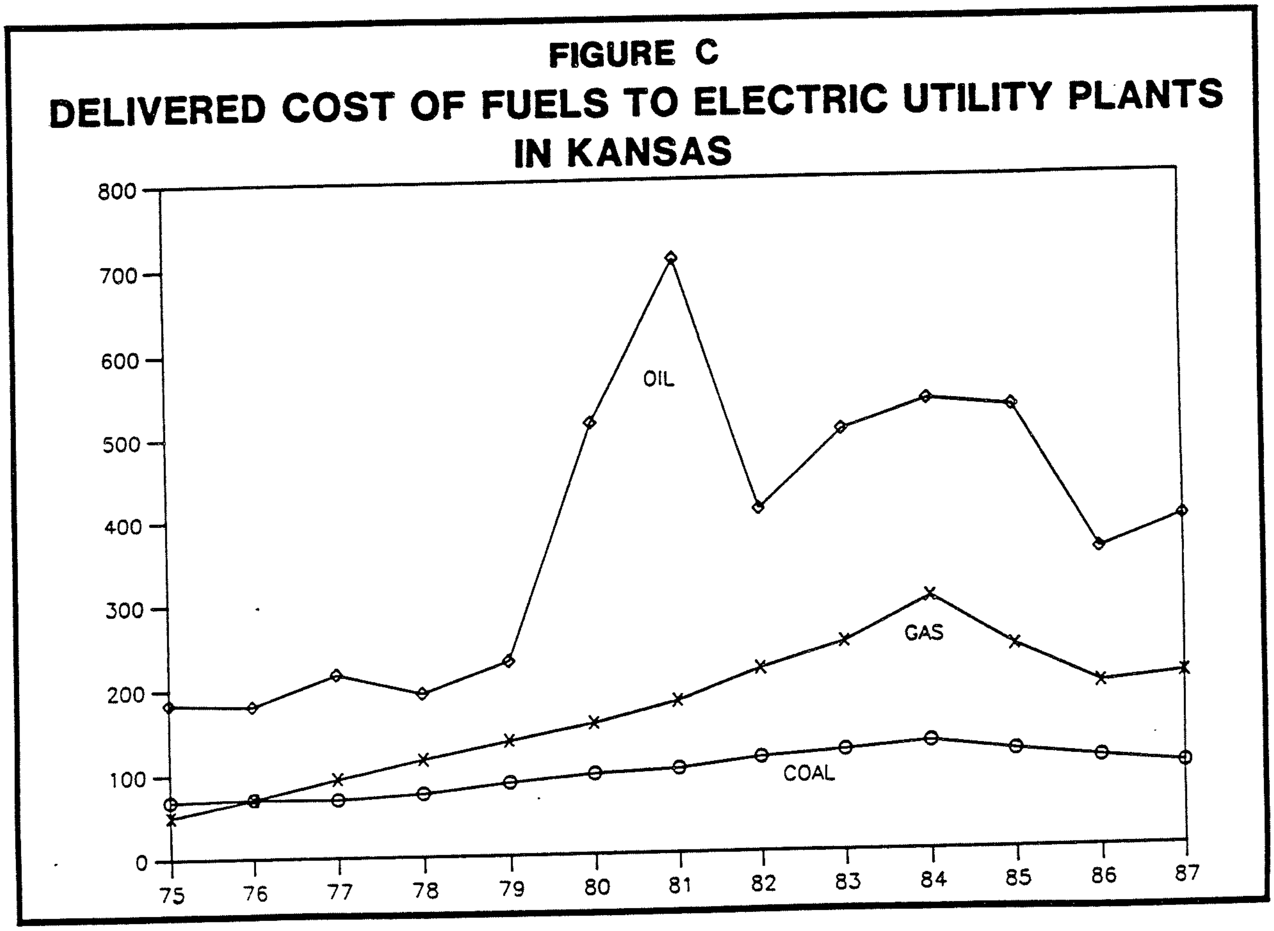
of oil to utilities in Kansas is considerably higher than the cost of coal (Figure C). Natural gas prices should begin to rise by 1990 and will eventually establish some kind of equivalency with oil.

THE POTENTIAL LOSS OF MARKET FOR KANSAS COAL AT THE LACYGNE UNIT NO. 1 WOULD HAVE A MAJOR EFFECT. The facility has been exceeding its allowable sulfur dioxide levels while burning Kansas coal. If the solution which is adopted is to blend in low-sulfur coal, Kansas coal production could drop by half a million tons. Every effort should be made to assist Kansas City Power and Light in reaching a solution which allows the continued burning of Kansas coal.

EMPIRE DISTRICT'S RIVERTON PLANT IS CUTTING ITS USE OF KANSAS-TYPE COAL BY 50 PERCENT. This is the only other utility power plant in Kansas which has been burning Kansas coal in recent years. In 1987, Kansas supplied Riverton with 144,000 tons out of 211,000 total. The future potential will be reduced to 70,000 to 105,000 tons per year.

ACID RAIN LEGISLATION IS DEAD FOR 1988, BUT WILL RETURN IN 1989. Both presidential contenders have endorsed the concept. Senator Byrd, who has succeeded in blocking legislation in the Senate, will no longer be Majority Leader next year. Several older utility plants in Kansas could be forced by such legislation to reduce their emissions of sulfur dioxide and, perhaps, nitrogen oxides.

THE CLEAN COAL TECHNOLOGY PROGRAM OFFERS AN OPPORTUNITY TO OBTAIN FEDERAL FUNDING TO INCREASE THE USE OF KANSAS COAL. Appropriations were approved in September for a third round of Clean Coal Technology funding in fiscal year 1990. High-sulfur coal states such as Ohio, Indiana and Illinois have used this program to leverage state funding for projects designed to increase the burning of in-state coals. Fluidized bed combustion systems have received the most attention. A high priority should be assigned to encouraging the use of fluidized bed combustion systems in Kansas.



STATES ARE USING OR PROPOSING A VARIETY OF INCENTIVES TO ENCOURAGE THE USE OF IN-STATE COAL. These include mandatory burn laws (requiring utilities to burn a certain percentage of local coal), tax credits for consumption of local coal, taxes on coal transportation, grants for demonstration projects, low-interest loans for commercial projects, tax breaks for pollution control equipment, exemptions from sales and property taxes for fluidized bed combustion units, and a variety of other methods of financial assistance.

THE OKLAHOMA MANDATORY BURN LAW HAS BEEN LARGELY SUCCESSFUL. It is expected to result in the purchase of 800,000 tons of coal per year by Oklahoma utilities. The goal of increased consumption of Oklahoma coal has been achieved, although at some cost to Oklahoma utilities.

A MANDATORY BURN LAW WOULD BE MORE DIFFICULT TO INSTITUTE IN KANSAS. Unlike the situation in Oklahoma, many Kansas utility plants would be unable to accept any Kansas coal without exceeding their allowable SO_2 emission levels. This would be true for eight of the 19 utility boilers in the state. The amount of Kansas coal which could be burned under a 10 percent (BTU basis) mandatory burn law, considering environmental restrictions, is shown in Table B. However, it is estimated (Table A) that the Jeffrey and Holcomb plants would qualify for an economic exemption.

LARGE OVERALL BENEFITS TO THE STATE WOULD RESULT FROM DISPLACING IMPORTED COAL WITH KANSAS-MINED COAL. Because of technical, environmental and economic problems which would be encountered by utilities in burning blends, a 10 percent blend is about the maximum amount which would be practical. At any level below 10 percent, the estimated overall economic benefit to the state increases with the amount of Kansas coal utilized (Table C). The effect on the cost of electricity would be different for each power plant, but would generally be relatively modest (Table D). A mandatory burn law is the only action likely to have a large immediate effect on the demand for Kansas coal.

THE OKLAHOMA MANDATORY BURN LAW MAY BE OVERTURNED. The State of Wyoming has filed a motion with the Supreme Court of the United States to have the law struck down as a restraint of interstate commerce. If Kansas considers enacting such a law, the effective date should be postponed until after the court has acted, probably some time next year.

TABLE B

NEW DEMAND FOR KANSAS COAL CREATED BY A 10% (BTU BASIS) MANDATORY BURN LAW

Unit	Tons Per Year
BPU - Nearman	32,400
KP&L - Lawrence	60,400
KP&L - Tecumseh	13,600
KP&L - Jeffrey	534,600
Sunflower - Holcomb	59,900
Total	700,900

TABLE C

ECONOMIC BENEFITS OF A MANDATORY BURN LAW

Percent BTU Value Kansas Coal In Blend	Net Benefit To Kansas Economy, Dollars/Year
2	$4,936,000
4	$9,160,000
6	$13,062,000
8	$16,905,000
10	$20,687,000

TABLE D

EFFECTS OF COAL BLENDING ON ELECTRICITY COSTS
(10% BTU Basis)

Station	Increased Fuel Cost Cents/kWh	Total Increase in Cost of Electricity
Lawrence	-0.020	0.3 %
Tecumseh	-0.012	0.1 %
Jeffrey	+0.014	1.1 %
Holcomb	+0.073	2.4 %
LaCygne #2	+0.0249	0.9 %
Nearman	+0.033	1.1 %

IT IS IN THE OVERALL BEST INTEREST OF THE STATE OF KANSAS TO ENCOURAGE THE USE OF KANSAS-MINED COAL. Economic activity generated by mining would occur in Kansas instead of Wyoming. Over-dependence on imported coal leaves the state's electric utility system vulnerable to increases in severance taxes by the State of Wyoming or to increases in railroad freight rates. As of today, the trend in both these cost factors is downward, but the trend can easily be reversed at some point in the future.

THE LONG-TERM SURVIVAL AND HEALTH OF THE KANSAS COAL MINING INDUSTRY CAN BE ACHIEVED ONLY BY DEVELOPING NEW FACILITIES USING TECHNIQUES SUCH AS FLUIDIZED BED COMBUSTION WHICH CAN BURN KANSAS COAL IN AN ENVIRONMENTALLY ACCEPTABLE MANNER. The over-riding consideration is that no markets for Kansas coal will survive which cannot comply with present and future sulfur emission limits. The second factor is that Kansas coal will never be able to compete economically in markets which are very far away from the coal mines. Consideration of these two factors will clearly distinguish the types of actions which could be useful. A new 100 megawatt fluidized bed combustion unit could create new demand for 250,000 tons per year of Kansas coal, plus 40,000 tons of limestone, and add five or six million dollars per year of primary economic activity to the Kansas economy. The indirect effects could be even larger.

IT IS RECOMMENDED THAT A BROAD PROGRAM OF INCENTIVES BE CREATED TO ENCOURAGE THE BUILDING OF FACILITIES WHICH WOULD USE KANSAS COAL. The primary objectives of the program would include ensuring that the LaCygne Unit No. 1 continues to burn Kansas coal; convincing Empire District Electric to build its next expansion on the Kansas side of the border; making it attractive for electric utilities to obtain future power needs from Kansas coal rather than imported coal or electricity; and encouraging industrial facilities to obtain their energy needs by fluidized bed combustion of Kansas coal. The suggested primary method of accomplishing these objectives is through tax incentives. Such incentives will have a very high benefit to cost ratio, because (1) coal-based developments are not likely to occur otherwise and (2) the end result is not only continuing employment and economic activity in the facility itself, but also in the coal industry. A small burn tax on coal used to generate electricity could be a source of highly valuable up-front funds to assist projects in the early stages.

BASIS FOR THE STUDY

The Kansas Coal Commission requested J. E. Sinor Consultants Inc. to carry out an analysis of the problems and prospects of the Kansas coal mining industry. The objective of the study is to identify opportunities for increased consumption of Kansas coal and to recommend actions which could be taken to assist the industry in grasping those opportunities.

In completing the study, contacts were made with all known producers and consumers of significant quantities of coal in Kansas. On-site visits were made to all currently active coal mines in the state and to most of the coal-burning electric utilities. Other contacts were made in Kansas and adjoining states with regulatory agencies, equipment manufacturers, transportation companies, industrial coal consumers, etc.

Coal deposits in Kansas represent a resource of great potential value to the state. This report attempts to show what can be done to realize that value. It is intended that the results of the study form a basis for legislative actions which could ensure the survival of the Kansas coal mining industry for the overall benefit of the citizens of the state.

THE KANSAS COAL MINING INDUSTRY

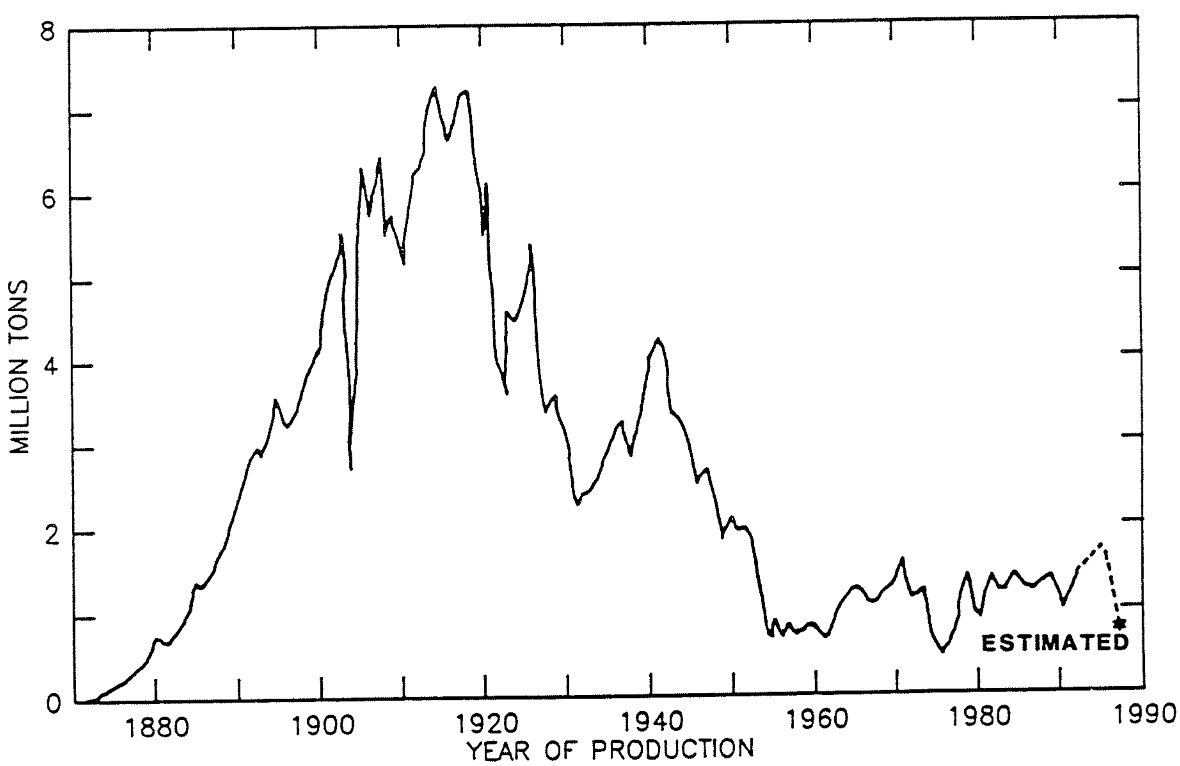
HISTORICAL COAL PRODUCTION

Coal mining began in Kansas in 1869, and grew rapidly to a peak output of over seven million tons per year in 1918 (Figure 1). It then shrank to a recorded low of 0.5 million tons in 1975 before rebounding somewhat. The current trend, however, threatens to establish a new post-1880 low in production (Figure 1).

The early coal mining industry in Kansas was based on underground mining. Profitable seams of coal, three to four feet thick, were worked at depths of only 40 to 65 feet. These seams however, were eventually exhausted. Surface mine production exceeded underground mine production for the first time in 1931. Since 1964, all production has been by strip-mining methods.

Coal demand arose first to fuel railroad locomotives. The railroads were very influential in developing the early mines. Kansas passed a law in 1885 which forbade railroads to own coal land or engage in the coal business. Later, coal production soared to supply the lead and zinc industry in the tri-state mining district where huge quantities of lead and zinc ore were mined. Near the close of the 19th century, Pittsburg had six smelters with 42 furnaces, and was the zinc smelting capital of the United States.

FIGURE 1
KANSAS COAL PRODUCTION 1869-1988



The success of the early coal mining industry in southeastern Kansas was due to several factors. A transportation network of railroads was created to haul the product to markets. A large low-wage labor supply existed after the influx of immigrants whose presence gave the region the nickname "The Little Balkans." Most important, of course, were the abundant deposits of coal in shallow coal beds which were easily mined.

In 1914, United Mine Workers District 14 reported 83 local unions with 10,405 members. About that time, steam shovels and surface mining techniques were widely introduced into the area, raising productivity tremendously and reducing the number of miners needed.

By the advent of World War I, nearly 95 percent of the coal mined in the Pittsburg area was being shipped to the Kansas City metropolitan area. As economic activity declined in the 1920's and 1930's, the number of coal mining companies in Pittsburg, Kansas declined from 31 in 1923 to only 11 by 1936. Coal demand recovered somewhat during World War II, but quickly declined after the war under competitive pressure from cheap, clean, oil and gas.

TABLE 1

PRODUCTION OF COAL BY STATES 1987
(Thousands of Net Tons)

Kentucky	161,541
Wyoming	147,343
West Virginia	136,275
Pennsylvania	74,088
Illinois	59,573
Texas	51,006
Virginia	44,194
Ohio	34,933
Montana	34,662
Indiana	34,401
Alabama	25,534
North Dakota	24,342
New Mexico	18,078
Utah	16,759
Colorado	14,580
Arizona	11,329
Tennessee	6,169
Missouri	4,609
Washington	4,583
Maryland	3,560
Oklahoma	2,756
Louisiana	2,753
Kansas	2,021

Source: National Coal Association, Coal Data 1988 and Energy Information Administrstion, Coal Distribution Report

In 1987, Kansas ranked 22nd among the states in coal production (Table 1). Total coal mined in Kansas through 1988 is estimated to be approximately 320 million tons.

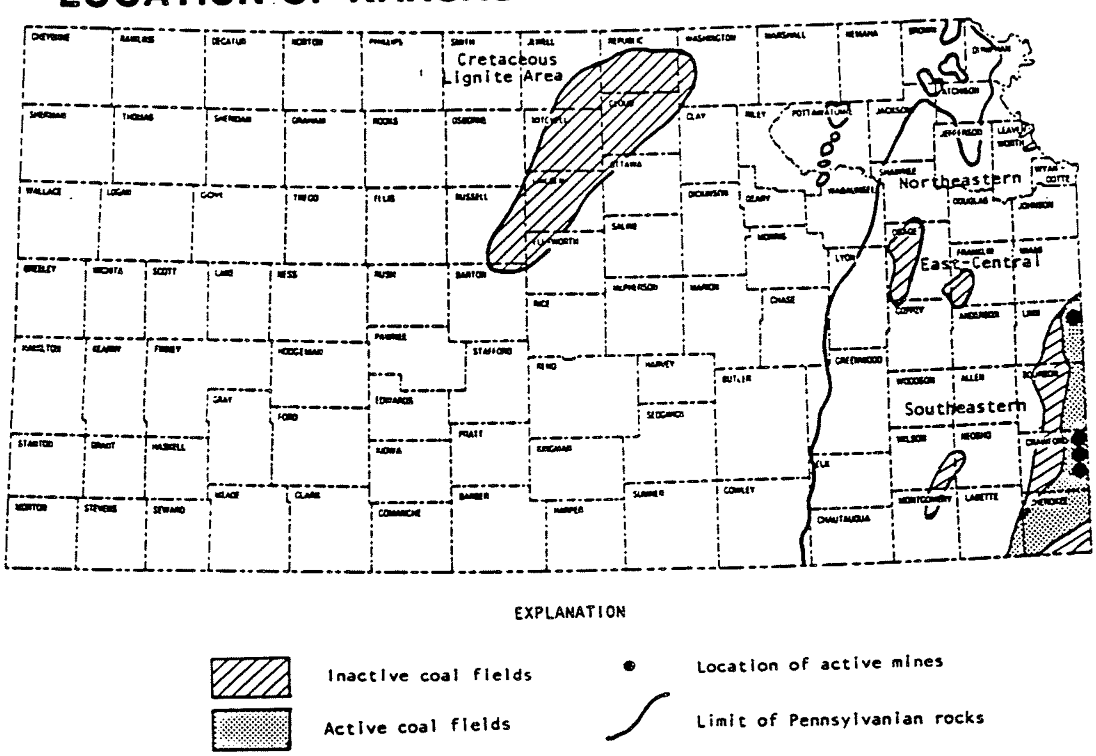
KANSAS COAL RESERVES AND CHARACTERISTICS

Known coal-bearing regions in Kansas are indicated in Figure 2. Only the bituminous coals of extreme southeastern Kansas are economically mineable. Small amounts of lignite and subbituminous coal are present in the north-central and central parts of the state. These beds are thin and discontinuous, with negligible amounts of reserves. The great bulk of Kansas coal reserves are located in the four counties forming the southern boundary with Missouri--Linn, Bourbon, Crawford, and Cherokee. These coals are mostly high volatile A in rank.

Figure 3 gives the stratigraphy of the region. As seen, the coal beds are numerous, but thin and widely separated. As a result, multiple seam mining is common, and the ratios of overburden to coal in Kansas coal mines are among the highest in the United States (typically 20 to 30 to one). All the important coal resources are in Middle and Upper Pennsylvanian age rocks. Some 53 different coal beds have been identified, and at least 14 have been mined in the past. Currently only four coal beds are being mined, as indicated in Figure 3. Kansas coals are predominantly flat-lying and relatively free of faulting.

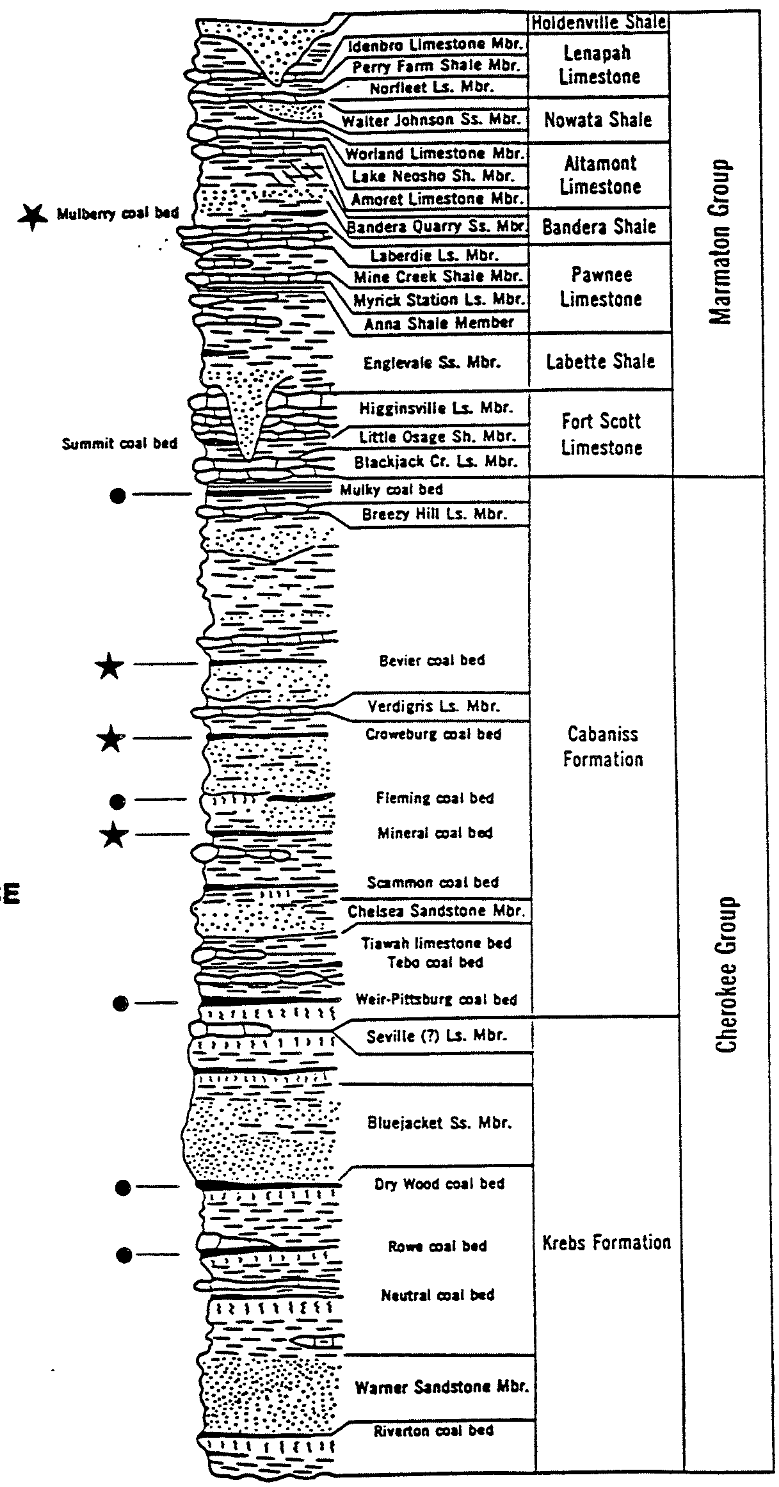
FIGURE 2

LOCATION OF KANSAS MINES AND COAL FIELDS



SOURCE: KEYSTONE INDUSTRY MANUAL

FIGURE 3
COALS OF ECONOMIC IMPORTANCE IN SOUTHEASTERN KANSAS



● COALS OF POTENTIAL ECONOMIC IMPORTANCE

★ COALS CURRENTLY BEING MINED IN KANSAS

TABLE 2

STRIPPABLE RESERVES OF KANSAS COAL BY COUNTY AND BY COAL BED
(Millions Of Tons At 30:1 Stripping Ratio)

County, Coal Bed	Measured	Indicated	Inferred
Cherokee			
Rowe	2.56	12.07	54.22
Dry Wood	0.81	4.34	18.12
Weir-Pittsburg	9.81	31.90	43.35
Mineral	17.28	17.39	90.63
Fleming	0.59	1.32	10.47
Croweburg	6.24	4.40	32.43
Bevier	28.94	12.91	14.54
Total	66.23	84.33	263.76
Crawford			
Rowe	1.27	3.47	12.86
Dry Wood	0.56	2.00	1.75
Weir-Pittsburg	1.05	4.11	-
Mineral	34.91	6.68	41.05
Fleming	0.60	1.35	8.39
Croweburg	0.36	12.54	21.80
Bevier	2.54	24.69	40.43
Mulky	1.00	1.00	--.--
Total	42.29	55.84	126.28
Bourbon			
Mineral	1.29	1.03	--.--
Fleming	1.81	--.--	--.--
Croweburg	--.--	2.21	--.--
Bevier	0.14	8.53	4.61
Mulky	3.22	9.24	38.39
Mulberry	--.--	--.--	16.39
Total	6.46	21.01	59.39
Labette			
Mineral	-	0.64	-
Bevier	-	8.23	-
Total	-	8.87	-
Linn			
Mulberry	30.55	67.05	140.98
Miami			
Mulberry	-	-	4.58
Montgomery			
Thayer	0.87	3.93	9.08
Nesho			
Thayer	0.23	0.90	2.93
Wilson			
Thayer	0.43	1.30	4.00
Douglas			
Blue Mound	0.53	0.78	1.82

Source: Kansas Geological Survey, 1976

Strippable reserves by county and by coal bed are summarized in Table 2 for the major coal producing counties in southeastern Kansas. This table shows bituminous coal reserves for strip mining in the demonstrated (measured plus indicated) reliability class to be approximately 400 million tons with an overburden to coal thickness ratio of 30:1 or less. In addition, there are over 600 million tons of inferred coal reserves in these counties with a 30:1 overburden ratio or less. These reserve figures are for coal beds with a thickness of at least 12 inches. For the foreseeable future, coal mining is expected to be concentrated in the counties listed in Table 2. However, for the state as a whole, the demonstrated reserve figure is approximately 520 million tons, with another 800 million tons of inferred coal reserves.

Using only the smallest of the above figures--400 million tons of demonstrated reserves in the key southeastern counties--we can calculate a potential wealth of $8 billion waiting to be realized (at $20 per ton). This potential will never occur if the Kansas coal mining industry does not survive.

Most coal production in Kansas in recent years has been from the Rowe, Mineral, Fleming, Croweburg, Bevier, and Mulberry coal beds. This trend differs significantly from the historical coal production in Kansas where nearly two-thirds of the coal mined was from the Weir-Pittsburg coal bed. With most of the strippable Weir-Pittsburg coal removed and a large part of the easily mineable underground portion worked, a large portion of future coal production will probably be obtained from the Mineral, Croweburg, Bevier, and Mulberry coals.

Although areas exist in several Kansas counties that have the potential for deep mining of coal, these areas were not included in this review. Reasons for this omission were the general lack of data on these deep coal areas, and the importance in the near future of the stripping coals in the state.

Two important characteristics about Kansas coal must be considered by anyone interested in mining or using Kansas coal:

1. All coal reserves in Kansas are believed to be medium- to high-sulfur coal. Commonly there is three to five percent sulfur in most commercial Kansas coals.

2. Most of the coal reserves in Kansas that can be strip-mined are thin-bedded coals (less than 28 inches). A few areas, however, especially in the Mulberry coal, are of intermediate thickness (28-42 inches).

Many Kansas coals have good coking properties, but yield unacceptable products due to the high sulfur content. Average seam properties for the three seams currently being mined in Crawford County are shown in Table 3. Of interest in addition to the sulfur content are the relatively high ash content and low ash fusion temperature. These make the coal troublesome to burn in conventional pulverized coal furnaces. As average ash analysis is shown in Table 4. The high silica and iron oxide contents are also unfavorable for boiler operations.

TABLE 3

AVERAGE SEAM PROPERTIES FOR FOUR KANSAS COAL SEAMS
(As-Received Basis)

	Mineral	Croweburg	Bevier	Mulberry
Moisture	2.9	2.6	3.9	6.8
Vol Mat	36.1	35.9	36.0	32.3
Fixed C	48.2	44.5	48.6	39.4
Ash	12.8	17.2	11.5	21.4
Ultimate:				
H	5.1	4.8	5.0	4.6
C	69.2	66.2	68.6	57.2
N	1.2	1.2	1.3	1.1
O	7.3	6.7	10.8	11.2
S	4.4	4.2	2.7	4.5
BTU	12,634	11,920	12,253	10,310
FSI	8.4	7.6	8.2	3.3
Ash Fusion °C:				
Initial Def	1,084	1,072	1,165	1,112
Softening	1,130	1,115	1,188	1,158
Fluid	1,178	1,155	1,218	1,187
Sulfur Form:				
Sulfate	0.20	0.28	0.34	0.45
Pyrite	2.99	3.06	1.22	2.35
Organic	1.17	0.86	1.14	1.73

Source: Kansas Geological Survey, Missouri Department of Natural Resources

TABLE 4

AVERAGE ANALYSIS OF ASH IN SOUTHEAST KANSAS COAL
(Percent)

Ash	16.2
SiO_2	26
Al_2O_3	11
CaO	13
MgO	0.68
Na_2O	0.28
K_2O	1.5
Fe_2O_3	34
TiO_2	0.49
SO_3	6.9

KANSAS COAL MINES

As of late summer, 1988, there are only four operating coal mines in Kansas. Their locations are shown in Figure 2.

The Pittsburg and Midway Coal Mining Company

The Pittsburg and Midway Coal Mining Company (P&M) operates the Midway Mine in Linn County, Kansas and in Missouri. P&M was founded in Pittsburg, Kansas in 1885 and is now a unit of Chevron Corporation. By far the largest mine in the state, the Midway Mine was developed in 1972 solely to supply a mine-mouth electrical power plant, the LaCygne No. 1, operated by Kansas City Power and Light (KCP&L). It has no other customers. There are 29,000 acres in Missouri and Kansas dedicated to the KCP&L contract, which runs through the year 2002. Approximately 29 million tons have been produced to date.

The mine has two very large walking draglines, one with a 110 cubic yard bucket and one with a 73 cubic yard bucket. The draglines are used to strip overburden down to 12-18 inches from the 24 inch thick Mulberry coal seam, the only one being mined. Rubber tired front loaders are used for the final stripping and loading into 120-ton bottom-dump haul trucks which transport the coal to the power plant. Average overburden thickness is 45-50 feet, and the overburden to coal ratio is 21:1. The run-of-mine coal shipped to the power plant runs about five percent sulfur, 22 percent ash, and 10,500 BTU per pound.

In 1987, the Midway Mine produced 1.63 million tons of coal--1.4 million tons of which came from the Kansas side, and 0.23 million tons from the Missouri side. In the future, the ratio is likely to be 60 percent Kansas and 40 percent Missouri, as the large dragline will be stationed on the Kansas side and the smaller one on the Missouri side. This is assuming that full production is resumed. Currently the mine has been shut down since March 28, 1988, and only reclamation work is being carried out. The shutdown is discussed in a later section titled "The Outlook for Kansas Coal."

The Midway Mine employs 191 workers, 155 of which are union members. Approximately 58 percent are Kansas residents and 42 percent are Missouri residents.

Mackie-Clemens Fuel Company

The Mackie-Clemens coal tipple in Crawford County was built in 1938, and at one time handled over one million tons of coal per year. At present, the mine is producing 350,000 to 375,000 tons per year. Equipment includes two electrically-powered 11 cubic yard draglines, two D-10 bulldozers and several 100-ton bottom-dump haul trucks.

Draglines are used to strip shallow overburden above the top seam, then the bulldozers push the 20 feet of interburden between seams across the strip pit to uncover the bottom seam. Wheel loaders pick up the coal and dump it in the haul trucks. All the coal is washed before shipping to the customer. The Bevier is not always present, but where available can be washed to about 2.5 percent sulfur. The major beds being mined are the Mineral and the Croweburg, which run about 3.5 percent sulfur.

The mine is a union mine and employs about 74 people. Only one strip pit is active, about nine miles from the tipple.

Alternate Fuels Inc.

Alternate Fuels is a closely held corporation which produces about 250,000-275,000 tons per year in Crawford County. The mine site is about five miles east of Arma. Most of their coal property is leased from railroads.

Operations are similar to those at Mackie-Clemens, utilizing small draglines, bulldozers and scrapers. The three coal beds mined are the Bevier (18 inches thick), the Croweburg (11 inches thick) and the Mineral (18 inches thick). Mining is limited to a 35-40 foot high wall.

Alternate Fuels is a non-union operation and employs only 42 people. These employees are all residents of Kansas.

All their coal is washed and reject is returned to the pit. The mine is about 13 miles from a rail siding. Approximately two-thirds of shipments go out by rail and one-third by truck.

Quality Coal

This is a recent startup with no production history. Bulldozers and front loaders are being used to mine the Bevier seam, which can be washed to 1.8-2.4 percent sulfur and 12,800 BTU per pound. Total reserves of this coal available in the area are probably less than two million tons.

CURRENT PRODUCTION AND MARKETS

The shutdown of the Midway Mine on March 28th will greatly skew 1988 Kansas coal production statistics. Had the shutdown not occurred, we estimate that 1988 production would have gone to the following end-uses:

Electric Utilities in Kansas	1,410,000	
Cement Plants in Kansas	185,000	
Other Industrial Facilities in Kansas	35,000	
Out-of-State Shipments	200,000	
	1,830,000	tons

If the Midway Mine does not restart before year-end, then the actual 1988 figures may look as follows:

Electric Utilities in Kansas	470,000	
Cement Plants in Kansas	185,000	
Other Industrial Facilities in Kansas	35,000	
Out-of-State Shipments	200,000	
	890,000	tons

UTILITY COAL MARKET IN KANSAS

COAL CONSUMPTION AT KANSAS UTILITIES

There are five electric utilities which operate coal-fired power plants in the state of Kansas. A sixth utility, Kansas Gas and Electric is a part owner of several coal-fired facilities which are operated by other utilities.

Coal receipts at electric utilities operating in Kansas for the last six years are summarized in Table 5. Because Kansas City Power and Light and Empire District Electric operate in both Kansas and Missouri, their totals include coal delivered to stations in both Kansas and Missouri.

Deliveries specific to Kansas in 1987 are broken down by plant site in Table 6. It shows that 15,033,100 tons of coal were delivered to nine electric power plants located in the State of Kansas. Locations of these plants are shown in Figure 4. By far the largest consumer is the Jeffrey Energy Center, operated by Kansas Power and Light, which took over 8,000,000 tons, more than one-half the total for the state. More than one-half the remainder was taken by the next largest plant, the LaCygne facility operated by Kansas City Power and Light. Seven smaller power plants then account for the remaining 22 percent of coal consumption. Some of these smaller units now operate at low annual capacity factor because of their age and size.

Total coal-fired electrical generating capacity at the nine plant sites is 5,597 megawatts. This is generated by 20 individual boilers, which are listed by size and year of construction in Table 7. Some of the plant sites also contain gas-fired electrical generating units which are not accounted for here. The last coal-fired unit was built in 1983. A historical summary of the buildup of coal-fired electrical generating capacity in the State of Kansas is given in Table 8.

Table 9 displays the origin of coal received at each of the nine Kansas electric utility power plants. The table shows coal received in 1986 and 1987 at each plant, the number of tons, the percent of coal quantity received from each state, the delivered cost, and the coal's characteristics.

Kansas supplied five percent of the coal used in-state in 1985. The amount of Kansas coal used by Kansas utilities increased to 1,538,900 tons in 1987, which is 10 percent of the total coal used by utilities. This statistical increase is due almost entirely to production at the Midway Mine having shifted from the Missouri side of the border to the Kansas side. The reverse will occur in the future.

Missouri and Oklahoma both have declined in the amount of coal supplied to Kansas utilities from 1985 to 1987. Missouri has gone from supplying five percent of the coal used by Kansas utilities in 1985 to two percent in 1987. Oklahoma coal to Kansas has gone from one percent to less than one percent in 1987.

Illinois delivered 480,400 tons of coal in 1987 (three percent of Kansas utility coal use).

TABLE 5

COAL RECEIPTS AT ELECTRIC UTILITIES OPERATING IN KANSAS

Utility, Year	Quantity Delivered 1,000 Short Tons	Quantity Delivered % on Contr	Average Quality BTU Per Lb	Average Quality Ash Wt Pct	Average Quality Sulf Wt Pct	Average Price in Dollars Per Ton Contr	Average Price in Dollars Per Ton Spot	Average Price in Dollars Per Ton Total
Empire District Electric Co.								
1982	748	72.6	11,084	20.4	5.1	23.72	33.49	26.40
1983	833	61.5	11,048	19.8	4.8	21.85	31.74	25.66
1984	948	54.4	11,228	19.6	5.0	25.27	30.27	27.55
1985	822	60.2	11,033	20.4	4.8	23.50	31.80	26.80
1986	832	52.9	11,203	18.0	4.6	25.38	31.30	28.17
1987	849	53.3	11,187	18.6	4.5	24.04	32.70	28.08
Kansas City, City of								
1982	1,227	94.8	9,561	8.7	1.5	34.46	36.93	34.58
1983	1,270	-	9,394	8.0	1.1	-	38.21	38.21
1984	1,306	51.6	9,736	8.7	1.4	42.15	43.16	42.64
1985	1,491	100.0	9,248	7.5	1.1	33.70	-	33.70
1986	1,239	86.3	9,116	5.8	0.8	23.19	32.76	24.51
1987	1,338	98.4	9,222	7.3	1.0	26.75	34.12	26.87
Kansas City Power & Light Co.								
1982	8,003	88.1	9,188	12.0	2.2	22.75	21.64	22.62
1983	7,150	89.9	9,192	9.8	1.7	25.53	20.42	25.01
1984	8,485	84.2	9,193	10.2	1.7	25.47	21.77	24.88
1985	7,480	81.7	9,119	10.8	1.8	23.06	23.00	23.05
1986	7,260	88.1	8,897	10.9	1.7	19.39	18.24	19.25
1987	8,589	76.5	8,944	9.5	1.5	17.84	18.31	17.95
Kansas Power & Light Co.								
1982	6,268	100.0	8,766	6.2	0.4	23.76	-	23.76
1983	8,030	100.0	8,660	5.7	0.4	23.99	-	23.99
1984	9,160	100.0	8,652	5.6	0.4	25.87	-	25.87
1985	8,684	100.0	8,565	5.2	0.4	23.22	-	23.22
1986	8,522	100.0	8,571	5.2	0.4	23.15	-	23.15
1987	8,848	100.0	8,635	5.0	0.4	22.72	-	22.72
Sunflower Electric Coop Inc.								
1983	415	100.0	8,220	5.8	0.4	25.57	-	25.57
1984	918	100.0	8,244	5.9	0.4	24.82	-	24.82
1985	895	100.0	8,258	5.8	0.5	24.54	-	24.54
1986	795	100.0	8,319	5.5	0.4	24.18	-	24.18
1987	902	100.0	8,282	5.6	0.4	17.47	-	17.47

Source: Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1987

TABLE 6

COAL DELIVERED TO KANSAS UTILITY STATIONS IN 1987

Utility, Plant	Tons	Cents/ MMBTU	$/Ton	%S
Empire District Electric, Riverton	211,300	146.2	34.59	1.84
City of Kansas City, Kaw	83,300	207.6	46.76	2.37
City of Kansas City, Quindaro	338,900	217.8	48.87	2.43
City of Kansas City, Nearman	915,800	102.0	16.92	0.32
KCP&L, LaCygne	3,733,200	111.9	19.81	2.43
KP&L, Lawrence	690,100	152.1	33.27	0.85
KP&L, Tecumseh	155,600	147.9	32.41	0.88
KP&L, Jeffrey Energy Center	8,002,800	128.8	21.62	0.33
Sunflower Electric Coop., Holcomb	902,100	105.5	17.47	0.35

Source: EIA, Cost & Quality of Fuels for Electric Utility Plants 1987

FIGURE 4

LOCATIONS OF COAL-FIRED ELECTRIC POWER PLANTS IN KANSAS

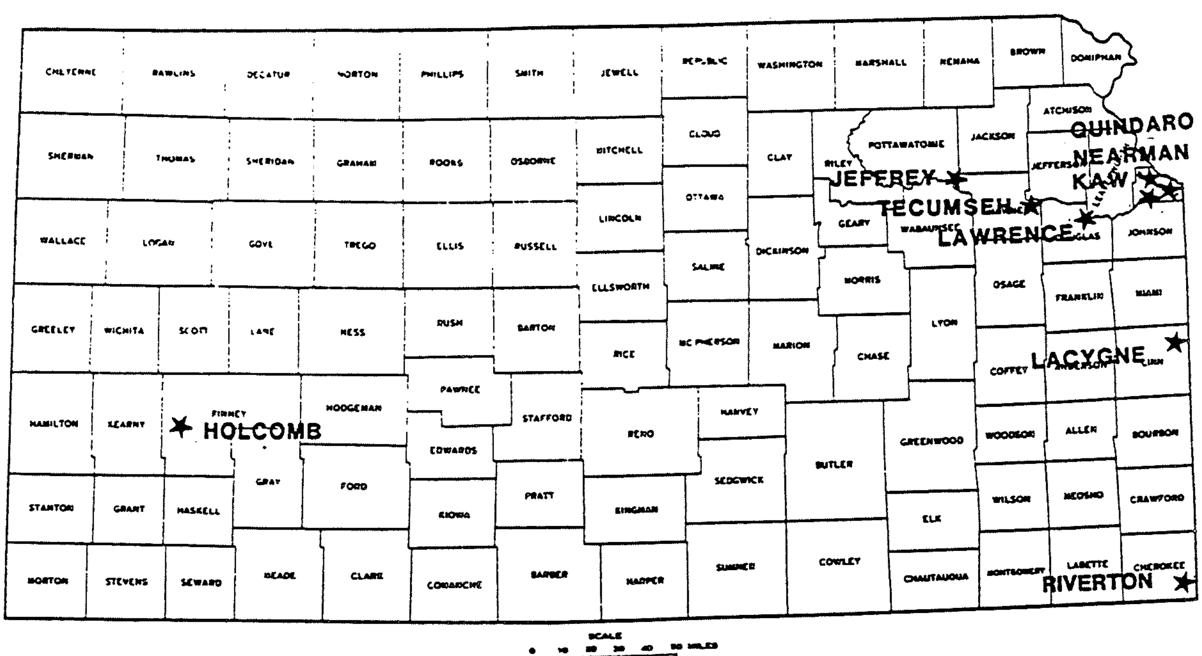


TABLE 7

COAL-FIRED ELECTRIC UTILITY BOILERS IN THE STATE OF KANSAS

Utility/Station/County	Unit	Size	Year Built
Empire Dist. Elec. Co.			
Riverton-Cherokee Co.	7	37.5 MW	1953
	8	50.0 MW	1953
Kansas City, City of			
Kaw-Wyandotte Co.	1	46.0 MW	1955
	2	50.0 MW	1957
	3	65.0 MW	1962
Nearman Creek-Wyandotte Co.	1	262.0 MW	1981
Quindaro-Wyandotte Co.	1	76.5 MW	1966
	2	145.0 MW	1971
Kansas City Power & Light			
LaCygne-Linn Co.	1	893.4 MW	1973
	2	685.2 MW	1977
Kansas Power & Light Co.			
Jeffrey Energy Center	1	720.0 MW	1978
Pottawatomie Co.	2	720.0 MW	1980
	3	720.0 MW	1983
Lawrence-Douglas Co.	3	49.0 MW	1954
	4	113.7 MW	1960
	5	403.2 MW	1971
Tecumseh-Shawnee Co.	7	81.6 MW	1957
	8	149.5 MW	1962
Sunflower Elec. Coop. Inc.			
Holcomb-Finney Co.	1	319.4 MW	1983
TOTAL		5,597.0 MW	

TABLE 8

INSTALLATION OF COAL-FIRED ELECTRIC GENERATING UNITS IN KANSAS

Year	MW Added	Accumulated MW Capacity
1939	10.0	10.0
1950	37.5	47.5
1954	99.0	146.5
1955	46.0	192.5
1957	131.6	324.1
1960	113.7	437.8
1962	214.5	652.3
1966	76.5	728.8
1971	548.2	1,277.0
1973	893.4	2,170.4
1977	685.2	2,855.6
1978	720.0	3,575.6
1980	720.0	4,295.6
1981	262.0	4,557.6
1983	1,039.4	5,597.0

Source: DOE/EIA-0095 Inventory of Power Plants in the United States

TABLE 9

ORIGIN OF COAL RECEIVED AT KANSAS ELECTRIC UTILITY PLANTS 1986-1987

Plant, State	Year	1,000 Tons	Pct.*	BTU/Lb	Pct. Sulfur	Cents/MMTBU
Riverton						
Kansas	86	132.6	47	12,123	2.64	132.6
	87	144.2	68	11,915	2.47	132.6
Missouri	86	51.6	18	12,008	2.91	135.5
	87	none	0	-	-	-
Oklahoma	86	95.9	34	11,960	2.74	136.3
	87	67.1	32	11,648	0.48	176.0
Kaw						
Illinois	86	79.1	100	11,559	2.48	156.5
	87	83.3	100	11,264	2.37	207.6
Nearman						
Wyoming	86	954.7	100	8,416	0.29	122.0
	87	915.8	100	8,297	0.32	102.0
Quindaro						
Illinois	86	204.8	100	11,437	2.48	168.3
	87	338.9	100	11,220	2.43	217.8
LaCygne						
Illinois	86	none	-	-	-	-
	87	58.2	2	11,019	3.38	123.2
Kansas	86	953.2	31	9,237	5.08	119.3
	87	1,394.7	37	9,285	5.09	126.2
Missouri	86	459.9	15	9,249	5.07	119.0
	87	235.2	6	9,162	4.84	125.8
Wyoming	86	1,653.7	54	8,444	0.34	118.2
	87	2,045.1	55	8,458	0.31	99.0
Jeffrey Energy Center						
Wyoming	86	7,654.9	100	8,327	0.34	129.6
	87	8,002.8	100	8,391	0.33	128.8
Lawrence						
Wyoming	86	693.5	100	10,723	0.70	172.6
	87	690.1	100	10,940	0.85	152.1
Tecumseh						
Wyoming	86	173.9	100	10,731	0.71	172.5
	87	155.6	100	10,960	0.88	147.9
Holcomb						
Wyoming	86	794.8	100	8,319	0.38	145.4
	87	902.1	100	8,282	0.35	105.5
Total State						
Kansas	86	1,085.8	8			
	87	1,538.9	10			
Missouri	86	511.5	4			
	87	235.2	2			
Oklahoma	86	95.9	1			
	87	67.1	0			
Illinois	86	280.9	2			
	87	480.4	3			
Wyoming	86	11,925.5	86			
	87	12,711.5	85			

*Percent of Quantity may not total 100 due to rounding.

Source: DOE/EIA-0191, Cost and Quality of Fuels for Electric Utility Plants, 1986-1987

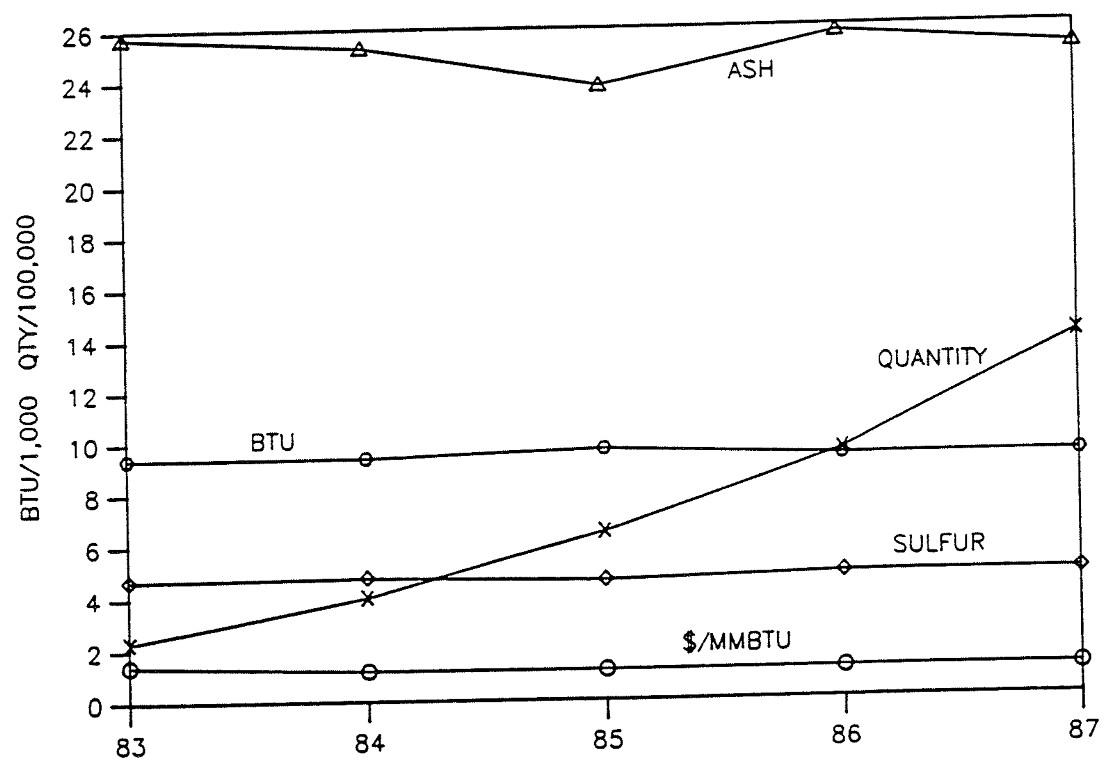
Wyoming is supplying the majority of Kansas utility coal. Wyoming delivered 12,711,500 tons of coal to Kansas in 1987, supplying 85 percent of the total coal used by Kansas utilities.

Characteristics and delivered prices of coal to power plants from individual sources is reported to the Department of Energy each month on Form 423. The data series dates back to July 1972. J. E. Sinor Consultants Inc. has collected that data and aggregated it by year. As an example of the information available, Figure 5 shows deliveries of Kansas coal to the LaCygne power plant from 1983 to 1987.

As seen in Table 9, the Riverton plant received 68 percent of its coal from Kansas and 32 percent of its coal from Oklahoma in 1987. Riverton also received coal from Missouri in 1986. The Tecumseh plant receives 100 percent of its coal from Wyoming. The Nearman plant received 100 percent of its 1987 coal supply from Wyoming. The Quindaro plant receives 100 percent of its coal supply from Illinois. The LaCygne plant has been receiving coal from four states. Thirty-seven percent of the coal needed at LaCygne was coming from in-state in 1987, six percent from Missouri, 55 percent from Wyoming and two percent came from Illinois. The Lawrence plant is receiving 100 percent of its coal from Wyoming. The Kaw plant receives 100 percent of its coal from Illinois. The Holcomb plant is receiving 100 percent of its coal from Wyoming. The Jeffrey plant receives relatively low-cost coal and consistent quality coal from Wyoming.

FIGURE 5

LACYGNE PLANT: COAL FROM KANSAS



EMPIRE DISTRICT ELECTRIC COMPANY

Utility Description

The Empire District Electric Company is an investor-owned utility incorporated in the State of Kansas. It serves 111,000 customers in a 10,000-square-mile region of southwestern Missouri, southeastern Kansas, northwestern Arkansas and northeastern Oklahoma.

Most of the electric revenues from the company's customers come from Missouri (86 percent), followed by Kansas (seven percent). Oklahoma (four percent) and Arkansas (three percent). Customers cover a broad scope including manufacturing, industry, agriculture, residences and commercial businesses.

Empire is based in Joplin, Missouri, with a metropolitan area population of 134,000.

In 1987 kilowatt-hour sales to service area customers increased 6.1 percent, while total kilowatt-hour sales increased 17.2 percent. Summer 1987 peak demand was 610.1 megawatts. The service area growth was led by increased kilowatt-hour sales to commercial customers (up 8.0 percent). Industrial sales increased by 6.2 percent as industry diversified through plant expansions and new companies. Off-system kilowatt-hour sales to other electric systems for the year were up 61 percent due to one major contract.

Empire's generating plants included the Asbury plant (212,000 kilowatt capacity) in Missouri, the Riverton plant (aggregate generating capacity of 155,300 kilowatts) in Kansas, the Empire Energy Center (aggregate generating capacity of 180,000 kilowatts) in Missouri and a hydroelectric generating plant at Ozark Beach, Missouri (aggregate generating capacity of 16,000 kilowatts). The company also has a 12 percent ownership interest (80,000 kilowatt capacity) in Unit No. 1 at the Iatan Generating Station northeast of Kansas City, Missouri.

Fuel Supply

Coal provides over 95 percent of Empire's total generation requirements. The company is currently studying the use of western coal at both the Asbury and Riverton plants. The Iatan fuel supply has been western coal since 1980. The Asbury coal has been supplied from Missouri under a 20-year contract which expires in 1989. The company is considering whether to exercise the renewal option in that contract. A second contract supplies the Iatan plant until 2003. Coal for the Riverton plant is purchased locally through spot contracts.

The generating plant located at Riverton, Kansas has five steam-electric generating units with an aggregate generating capacity of 140,800 kilowatts and one combustion turbine unit with a generating capacity of 14,500 kilowatts. Two of the steam-electric generating units at the Riverton plant totaling 89,300 kilowatts of capacity burn coal as a primary fuel and have the capability of burning natural gas. The remaining three steam-electric generating units at this plant are operating only during periods of system peak load and burn only natural gas or oil as an alternate fuel. The combustion turbine unit at the Riverton plant is capable of burning either natural gas or oil.

The company received approval from the Kansas Corporation Commission and will install two refurbished combustion turbine units at its Riverton Generating Station. Installation of the turbines, which began in early 1988 and will be completed later in the year, will add a total of about 35 megawatts of capacity at an estimated cost of approximately $7.3 million.

The Riverton plant's fuel requirements are expected to continue to be primarily supplied by coal, with the remainder supplied by natural gas. The average cost per ton of coal burned at the plant was $33.97 in 1987, $32.47 in 1986, $32.35 in 1985, $29.90 in 1984 and $32.75 in 1983.

Generally, the Riverton plant burns coal specified at 12,000 BTU per pound, 1.5 percent maximum sulfur, 12.0 percent ash and 30 percent volatiles. In July, 1987, the plant burned coal from Alternate Fuels, Mackie-Clemens Coal and American Central Energy with the delivered cost ranging from $24.53 to $40.99 per ton. In April, 1988, the plant was paying $33.12 per ton for 11,515 BTU per pound, 0.45 percent sulfur and 11.00 percent ash coal. This was $1.438 per million BTU.

In May it was announced that the plant had been negotiating with Burlington Northern to get low-cost rail contracts from Wyoming and the western slope of Colorado. In July, 1988, it was announced that Peabody's Rochelle Coal Company in Wyoming would supply 300,000 tons of coal to Riverton over the next year. The coal would be 8,800 BTU per pound and 0.25 percent sulfur. In September, 1988, it was announced that Empire District Electric was seeking bids for 65-80,000 tons of truck-delivered coal from Kansas, Missouri or Oklahoma sources.

Environmental

The current limit on the amount of Kansas coal burned at the Riverton plant is determined by environmental regulations. The sulfur discharge limit for the plant is three pounds of SO_2 per million BTU (whereas plants subject to New Source Performance Standards may emit no more than 1.2 pounds SO_2 per million BTU). This limit has been met in the past by blending Kansas coal with low-sulfur (0.5 percent) Oklahoma coal.

The two coal-fired boilers at Riverton are pulverized coal furnaces, a 50 megawatt Combustion Engineering unit, and a 40 megawatt Foster Wheeler unit. These boilers experienced serious slagging problems with certain Kansas coals (Bevier seam) in the past.

Empire has adopted a policy of limiting stack emissions to 2.0 pounds of SO_2 per million BTU. They intend to achieve this by blending low-sulfur Wyoming coal with local (Kansas, Missouri, Oklahoma) coals. If they attempted to burn 100 percent Wyoming coal, they might experience difficult operation of the electrostatic precipitator.

Capacity Planning and Outlook

Empire expects demand growth on their system to average 2.75 percent per year for the foreseeable future. At this rate, they would need to add about 75 megawatts of on-system capacity in the mid-1990's. The company has recently considered purchased capacity; joint ownership of generating facilities; and on-system installations such as hydro, fluidized bed combustion, co-generation, municipal solid waste, life extension of existing plants and other technologies which might be possible at the turn of the century.

Because area utilities now have excess capacity they decided to purchase additional electricity rather than expand capability at this time. In March of 1987, Empire entered into an agreement with Associated Electric Cooperative to purchase electricity in amounts to be adjusted annually until the year 2000, with purchase amounts ranging from 100 to 200 megawatts.

In anticipation of possible acid rain legislation, the company is presently considering a change from local to western coal sources. Projected construction expenditures for 1988 and 1989 include estimated expenditures of approximately $3 million and $20 million, respectively, for new rail equipment at the company's Riverton and Asbury generating stations to facilitate such a change.

The first option for on-system expansion will probably be the addition of heat recovery units to the oil-fired turbines in Missouri. After that, possibilities include a 75 megawatt fluidized bed combustion unit at Riverton, or else participation in a proposed 660 megawatt expansion of the Iatan plant in Missouri.

Current plans are not to retire any of the Riverton units, even in the next 20 years.

KANSAS CITY BOARD OF PUBLIC UTILITIES

Utility Description

The Kansas City Board of Public Utilities (BPU) is a municipal utility which operates three coal-fired power plants in Kansas City, Kansas. The utility serves 55,484 residential electric consumers, 4,111 commercial establishments, and 649 industrial and other electric customers.

Total kilowatt-hour sales for 1987 were 2,278,011,823, representing a 3.5 percent increase over 1986.

The BPU coal-fired power plants include:

Kaw River: Two pulverized coal units at 35 megawatts each, and one 55 megawatt cyclone unit

Nearman Creek: One 235 megawatt pulverized coal unit

Quindaro: One 73 megawatt cyclone unit and one 135 megawatt pulverized coal unit

Fuel Supply

The Kaw and Quindaro power plants at one time used Kansas coal. They burned both natural gas and coal. When natural gas prices zoomed in 1979, gas consumption was cut back, with the result that sulfur emissions increased. The BPU began buying coal from Illinois for these plants from the Brushy Creek Mine in Illinois, operated by Kenellis Energy.

The Kaw River plant in December, 1987, had a delivered cost to the plant of $45.01 per ton or $2.07 per million BTU. Coal delivered to this plant and to the Quindaro plant from the Brushy Creek Mine is probably the most expensive coal being received by Kansas power plants.

The Quindaro plant in 1987 also took its coal from the Brushy Creek Mine in Illinois. In December, 1987, its delivered cost to the plant was $45.00 per ton or $1.98 per million BTU.

The Nearman Creek plant was designed for Wyoming coal. Exxon coal from the Rawhide Mine was being supplied in 1986 for $20.71 per ton with 8,232 BTU per pound, 0.25 percent sulfur and 5.0 percent ash. The Kansas City Board of Public Utilities has a long-term contract through 2001 with Exxon for about 700,000 tons per year.

The plant has a transportation contract with Burlington Northern. In late 1986 it was receiving Exxon coal from Wyoming with a transportation cost of $16.67 per ton or 2.13 cents per ton-mile. Part of the transportation haul is on the Missouri Pacific. In late 1987, the transportation cost had not changed much, i.e., about 2.11 cents per ton-mile.

In October, 1987, it was announced by Western Fuels Association, the fuel buyer for the plant, that Exxon's Rawhide Mine would supply 200,000 tons of spot coal at a delivered cost just about $15 per ton. This was approximately $2.50 less than contract shipments from the same mine. The rail cost for this spot purchase was estimated at $12.00 per ton.

In September, 1988, it was announced that BPU had agreed to purchase 150,000 tons of coal from Exxon above its long-term contract quantity. They are obligated to purchase for the Nearman power plant a minimum of 720,000 tons per year for the period January 1, 1983 through December 31, 1999. The purchase price of the coal is computed from a base amount, adjusted for certain variations in costs of production from the base amount as described in the supply agreement and are subject to renegotiation at the end of each forty-eight month period.

The BPU, together with another municipal electric utility (Sikeston, Missouri), has made long-term coal supply arrangements with Western Fuels-Illinois (Western-Illinois) to supply the needs of its Kaw and Quindaro power plants. The coal purchase agreement with Western-Illinois, which expires in 1997 with an option to renew for an additional ten years, provides that 50 percent of the coal mined at Western-Illinois's southern Illinois mine will be reserved for the BPU in return for payment of 50 percent of the total cost of production as defined in the agreement, which costs include the debt service requirements incurred by Western-Illinois in acquiring coal reserves and developing and equipping the mine. The arrangement also requires that in the event the southern Illinois mine is shut down, the BPU will pay 50 percent of the fixed costs associated with the debt service of the mine and 50 percent of the costs associated with maintaining the safety and operational readiness of the mine. Enough reserves are dedicated to the mine to allow it to operate for five years beyond 1997. When the debt service is retired in 1997, the BPU expects a large decrease in the cost of coal.

Because of the continuing decline in coal prices in the marketplace and the high costs associated with the continued operation of the relatively new southern Illinois mine, the decision was made in 1985 to temporarily suspend production from the mine. Mine production was suspended in December 1985. The BPU's share of the continuing debt service and safety and operational readiness costs related to the mine was approximately $700,000 per month until production from the mine was resumed in September 1986.

In February of 1987, Western-Illinois declared Sikeston to be in technical default on its obligations to Western-Illinois to pay its percentage of debt service and mine operating costs. In July 1987, Sikeston was no longer in technical default on its obligations to Western-Illinois.

The coal expected to be purchased for the Kaw, Quindaro and Nearman plants of approximately 303,000 tons from the spot market, 360,000 tons mined from the southern Illinois mine, and the BPU's commitment to purchase at least 720,000 tons for the Nearman plant is equal to the expected production requirements of 1,383,000 tons in 1988.

Environmental

None of the BPU power stations are equipped with scrubbers. They have no capability for coal blending. Nearman is an NSPS plant and restricted to 1.2 pounds SO_2 per million BTU. This is met by using low-sulfur Wyoming coal.

The limits for Kaw and Quindaro are 3.0 pounds SO_2 per million BTU. The Environmental Protection Agency has ordered stack testing for these units and doubts that they are in compliance with their present coal. The BPU has argued that it is not subject to the 3.0 limit because of "grandfather" provisions in the Kansas State Implementation Plan, but it seems unlikely they will win this argument.

The run-of-mine sulfur content for the Brushy Creek Mine is about 3.5 percent sulfur. It is being washed down to 2.5 to 2.6 percent sulfur. Reject runs 22 percent.

If acid rain legislation is passed, the BPU would probably put the Kaw boilers back on natural gas exclusively. These boilers are designed for 11,000-12,000 BTU coal with low ash fusion temperature and would not be able to burn Powder River Basin coal. The Quindaro station would also have a difficult time burning Powder River Basin coal, and could do so only with a significant derating of capacity.

Capacity Planning and Outlook

The Kansas City Board of Public Utilities is expecting future load growth of only one percent to two percent per year. This is not enough to justify a new base-load unit in the near future.

In the fall of 1987, the BPU instituted a demand-side management project to further delay the need for new construction. Incentives will be developed to shape time-of-day usage patterns so as to reduce peak capacity requirements.

A study is currently in progress to see if any of the older units at Kaw and Quindaro should be retired. No changes would be expected for several years, anyway. The study is scheduled for completion at the end of 1988.

The Kaw and Quindaro stations have limited space for additions or expansion; Nearman Creek, however, could accommodate up to four more units. Sufficient space is available with coal tracks, etc.

If capacity expansion becomes necessary, the BPU feels that a gas turbine is the only option currently compatible with their load growth curve. Another possibility would be the purchase of part ownership of another utility's plant. However, being a municipal utility, the BPU is sensitive to the question of local jobs, and might hesitate to buy a unit outside the city. All these options are being investigated in the previously-mentioned study due by year-end.

In 1983, the BPU entered fifteen-year power sales agreements with the Kansas Municipal Energy Agency (KMEA) and the City of Columbia, Missouri (Columbia). Both agreements provide for fifteen-year extensions or extensions to the useful life of the BPU's Nearman plant, which ever is longer, but not to exceed forty years. KMEA and Columbia have agreed to purchase 15.96 percent and 8.51 percent, respectively, of the electrical output of the Nearman plant for the remaining life of the agreement.

Recently, rumors have circulated that the BPU electrical system may be sold. If the system is purchased by an investor-owned utility with significant excess capacity of its own, the continued operation of the older BPU units could be at risk.

KANSAS CITY POWER AND LIGHT

Utility Description

Kansas City Power & Light Company (KCP&L), a Missouri corporation, is a medium-sized public utility engaged in the generation, transmission, distribution and sale of electricity. Headquartered in Kansas City, Missouri, the company generates and distributes electricity to about 397,000 customers in a 4,700-square-mile area located in western Missouri and eastern Kansas. Population of the service area is about 850,000. Customers include 349,000 residences, 45,000 commercial firms and 3,000 industries, municipalities and other electric utilities. Steam is generated and distributed to 117 businesses in the downtown Kansas City, Missouri area. About 30 percent of the total kilowatt-hour load is in the State of Kansas.

Total kilowatt-hour sales in 1987 were up 5.4 percent over 1986. Peak demand at 2,531 megawatts was up by 6.7 percent over 1986. The company's 1987 maximum system net hourly peak load of 2,531 megawatts occurred on July 31, 1987. The accredited generating capacity of the company's electric facilities in the summer (when peak loads are experienced) of 1987 under MOKAN Power Pool standards was 2,937 megawatts. Generating facilities owned by KCP&L are listed in Table 10.

LaCygne Units 1 and 2 are the only facilities operated in Kansas. Both are owned jointly with Kansas Gas and Electric. LaCygne Unit No. 1 is a 840 megawatt cyclone boiler unit built as a mine-mouth facility to consume coal from the adjoining Midway Mine owned by Pittsburg and Midway Coal Mining Company. LaCygne Unit No. 2 is a 630 megawatt pulverized coal unit designed to burn Wyoming coal.

Fuel Supply

The company's latest fuel budget anticipates that its fuel requirements during 1988 will be approximately 74.4 percent coal, 0.2 percent gas, 0.5 percent oil, and 24.9 percent nuclear. These fuel statistics exclude fuel used to generate steam heat; such fuel for steam accounts for about one percent of the company's total requirements.

Conversion of the three units at Montrose Station from high- to low-sulfur coal operation was completed during the year. With the exception of LaCygne Unit No. 1, all the company's coal-fired capacity is now fueled with low-sulfur coal.

The company's projections for 1988 are that 8.5 million tons of coal will be burned at all of the company's generating units (including jointly-owned units), of which 5.9 million tons will be burned for its own account. The company has contractual commitments and options for approximately 74 percent of its anticipated coal usage in 1988 with the remainder to be supplied by spot purchases.

The contractual arrangements for coal for the company's account are given in Table 11.

In June, 1987, it was announced by Kansas City Power & Light that it would save $250 million in coal transportation costs over 10 years under renegotiated contracts with Burlington Northern for LaCygne Unit No. 2. The utility said it had a 14-year contract for 10.8 million tons or about 770,000 tons per year. The transportation savings resulted from increased competition in the rail transportation industry and from larger contracted tonnage.

In December, 1987, the plant was paying 1.76 cents per ton-mile, or about $15.38 per ton, to transport coal from AMAX mines in Wyoming. In April, 1988, the delivered cost, including transportation, to the plant from the same source was $18.79 per ton for 8,565 BTU per pound, 0.33 percent sulfur and 5.00 percent ash coal.

The LaCygne Unit No. 1 also took coal from Old Ben Coal's Illinois mines in 1987 and 1988. This coal was costing more than $27.00 per ton delivered.

Environmental

LaCygne Unit No. 2 has an electrostatic precipitator only, and is subject to the NSPS limit of 1.2 pounds of SO_2 per million BTU fired. LaCygne Unit No. 1 is equipped with a flue gas desulfurization scrubber, and is subject to a stack emission limit of 3.0 pounds of SO_2 per million BTU.

Effective May 1, 1988, the Kansas Department of Health and Environment (KDHE) imposed continuous emission monitoring of the stack emissions from LaCygne Unit No. 1. Preliminary air quality tests were conducted in the summer of 1987 at the LaCygne Unit No. 1, and an analysis of these tests indicated that the LaCygne Unit No. 1 stack was not in compliance on a continuous basis with the sulfur dioxide and particulate emission standards while burning exclusively the coal under contract from Pittsburg and Midway Coal Mining Company (P&M).

Consequently, in late 1987, the company met with KDHE concerning a variance from these emissions standards, or other appropriate regulatory actions, for LaCygne Unit No. 1 based on implementation of the following program to assure full compliance with the state regulations:

1. Investigation of modifications to the scrubber equipment to improve the operating efficiency of the unit; and

TABLE 10

ELECTRIC GENERATING FACILITIES AT KANSAS CITY POWER & LIGHT

Existing Units	Year Completed	Estimated 1988 Megawatt (MW) Capacity	Fuel
Base Load			
Wolf Creek	1985	530(a)	Nuclear
Iatan	1980	469(a)	Coal
LaCygne 2	1977	315(a)	Coal
LaCygne 1	1973	343(a)	Coal
Hawthorn 5	1969	450	Coal/Gas
Montrose 3	1964	160	Coal
Montrose 2	1960	150	Coal
Montrose 1	1958	150	Coal
Peak Load			
Northeast 17 and 18(b)	1977	95	Oil
Northeast 13 and 14(b)	1976	95	Oil
Northeast 15 and 16(b)	1975	95	Oil
Northeast 11 and 12(b)	1972	85	Oil

(a) Company's share of jointly-owned unit.
(b) Combustion turbines.

TABLE 11

KANSAS CITY POWER AND LIGHT COAL CONTRACTS

Supplier and Surface Mine Location	Year of Expiration	Undelivered Maximum Quantities (Tons)	1988 Contract Nominations (Tons)	1987 Average Sulfur Content of Coal %
Rochelle Coal Company Wright, Wyoming	1999	9,200,000	1,100,000	0.2
Pittsburg & Midway Coal Mining Company LaCygne, Kansas	2002	25,329,000[a]	815,000[a]	5.0
Amax Coal Company Gillette, Wyoming	1996	6,405,000[a]	855,000[a]	0.3
ARCO Coal Company Wright, Wyoming	2003	25,760,000[a]	1,610,000[a]	0.4
Total		66,694,000	4,380,000	

[a]Company's share of coal under contract for jointly-owned units.

2. Implementation of a fuel blending program to consist of burning a combination of medium sulfur coal with the high sulfur, low heat content P&M coal.

The scrubber at LaCygne No. 1 is an early vintage Babcock and Wilcox design, with a design sulfur removal efficiency of 80 percent. It consists of eight modules and uses local limestone as the scrubbing medium. Current operating efficiency appears to be about 75 percent. In an effort to improve efficiency, KCP&L is now cleaning scrubber modules continuously, with one module cleaned every eight-hour shift. High-pressure hoses, hammers and chisels are used to remove the rock-like scale deposits. Approximately 51 people are devoted to the scrubber operation.

Capacity Planning and Outlook

Kansas City Power and Light is unable to meet present peak needs without buying outside power.

In a planning document adopted in 1987, KCP&L states that it plans to defer as long as possible construction of new baseload capacity. The plan focuses on several options to meet increased customer electrical needs through the year 2006. Major elements of the plan include:

Capacity Purchases--Off-system purchases will be the major capacity strategy in the short term. Current cost for purchased power is much less than the fixed cost of new generation. The company may contract to buy up to 525 megawatts through 1995 and possibly beyond.

Unit Uprating--They are studying the feasibility of boosting output by 18 megawatts at the baseload LaCygne Station through various hardware modifications to Unit No. 2. In addition, they are considering pursuing the relicensing of Wolf Creek nuclear generating station to operate at five percent greater capacity.

Unit Rehabilitation--Studies indicate that they could economically reactivate units No. 3 and No. 4 at Hawthorn Station as natural gas-fired peaking units. For a relatively low capital outlay, this would gain 221 megawatts of peaking capacity. Plus, they would have the flexibility at a later date to convert the units to burn low-sulfur western coal if desirable.

Waste-to-Energy Facility--KCP&L is investigating the feasibility of a waste-to-energy facility developed jointly with Wheelabrator Environmental Systems Inc. of New Hampshire.

Load Management--To help reduce the need for additional capacity by shaving peak load growth, the plan recommends an integrated program of load management and rate design. This includes the cycling of residential air cooling compressor units.

Unit Additions--The plan anticipates the need to add some combustion peaking turbines over the next two decades, plus some baseload capacity near the turn of the century.

KANSAS GAS AND ELECTRIC

Utility Description

Kansas Gas and Electric (KG&E) is an investor-owned electric utility whose service area covers the southeastern portion of the State of Kansas, including the Wichita metropolitan area. Electric service is provided to 249,931 retail customers and at wholesale to 27 communities and 12 other electric utilities.

The company operates no coal-fired plants, but owns a 50 percent interest in the LaCygne plant operated by Kansas City Power and Light, and a 20 percent interest in the Jeffrey Energy Center operated by Kansas Power & Light. Details concerning these plants are discussed under those utilities.

The total active capability of the KG&E system is 2,428 megawatts, including 530 megawatts nuclear (47 percent of the Wolf Creek plant), 1,061 megawatts coal, 834 megawatts natural gas, and three megawatts oil-fired diesel generation.

Total electric sales for 1987 were five percent higher than in 1986.

Capacity Planning and Outlook

The company probably has adequate capacity reserves for at least 5-10 years of expected load growth. Peak demand in 1987 was 1,653 megawatts on August 3, at which time the company's reserve capacity amounted to 746 megawatts. The company therefore has no current plans for additional generating units. The company's extra capacity has resulted, in large part, from its response to the gas shortage of the 1970's, which threatened to end the use of natural gas as fuel for its generation. In the early 1970's, KG&E's generating capacity was natural gas fueled with oil as a backup. The company's gas suppliers warned that they would not be able to meet the company's future gas needs. The natural gas shortage became so serious that Congress, in 1978, banned the use of gas in large utility boilers including those of the company after January 1, 1990. With the easing of the natural gas shortage, Congress, late in 1981, repealed this 1990 deadline. By this time, the company's construction of coal and nuclear generating facilities had proceeded to the point where cancellation was not economical.

Although KG&E is not currently the operator of any coal-fired capacity, there is no reason they would not assume the role of operator at a new plant. A mothballed 70 megawatt gas unit at Neosho, Kansas could be a favorable future site for a small fluidized bed combustion unit.

In September 1987, KG&E sold and leased back its 50 percent undivided interest in LaCygne Unit No. 2. The lease has an initial term of 20 years, with various options to renew the lease or repurchase the 50 percent undivided interest.

KANSAS POWER AND LIGHT COMPANY

Utility Description

The Kansas Power and Light Company (doing business as KPL Gas Service) is an investor-owned combination natural gas and electric utility serving customers in Kansas, Missouri, Oklahoma and Nebraska. The company's corporate headquarters is located in Topeka, Kansas. Retail electric service is provided to approximately 295,000 customers in 322 Kansas communities

Total net electric generating capability was 2,505 megawatts at year-end. During 1987, some 98 percent of KPL Gas Service's electricity was produced from low sulfur coal, the remainder from natural gas. All the company's electricity is generated with fossil fuels and there are no power plants under construction.

The company's system comprises 13 fossil fueled steam generating units and seven combustion peaking turbines located at five generation stations (see Table 12). Four units and an exhaust turbine of the 13 fossil fueled units have been "mothballed" for future use. The company has contracts for the sale, purchase or exchange of electricity with 11 other utilities. The company also serves 37 municipal and 17 rural electric cooperatives.

The company's 1987 customer load at peak hour occurred on August 3, 1987 and amounted to 1,917 megawatts. The company's net generating capacity together with power available from firm interchange and purchase contracts, provided a capacity margin of approximately 19 percent of system peak responsibility at the time of the peak.

Total electric sales in 1987 were 8.6 billion kilowatt hours, a one percent gain from 1986.

Fuel Supply

The company's coal-fired units comprise 1,979 megawatts of the total 2,505 megawatts of generating capacity. However, they have been, and are expected to, account for 98-99 percent of total fuel consumption.

The company has a long-term (through year 2013) coal supply contract with AMAX, Inc. (AMAX) to supply low sulfur coal from AMAX's mines (approximately 697 railroad miles from the company's facilities) to fuel the Jeffrey Energy Center (JEC) units for their expected lives. The contract contains a schedule of minimum annual delivery quantities, which correspond to about 25,000 tons per day. The coal to be supplied is surface mined and has an average BTU content of approximately 8,400 BTU per pound and an average sulfur content of 0.34 percent. The price of coal purchased under the AMAX contract is subject to escalation. The average delivered cost of coal under the contract was approximately $1.29 per million BTU or $21.59 per ton (approximately 49 percent is for railroad freight charges) during 1987. The freight charges amount to 1.51 cents per ton-mile.

The company has a lease agreement with the Union Pacific Railroad (UP) whereby UP will supply unit trains for the shipment of AMAX coal to JEC. The agreement will expire December 31, 1992.

TABLE 12

ELECTRIC GENERATING FACILITIES AT KANSAS POWER AND LIGHT COMPANY

Name and Location	Unit No.	Year Installed	Principal Fuel	Unit Capacity (MW)
Tecumseh Energy Center:				
Steam Turbines	7	1957	Coal	77
	8	1962	Coal	122
Combustion Turbines	1	1972	Gas--Oil	19
	2	1972	Gas--Oil	19
Lawrence Energy Center:				
Steam Turbines	2	1952	Gas--Oil	0 2/
	3	1954	Coal	53
	4	1960	Coal	107
	5	1971	Coal	330
Hutchinson Energy Center:				
Steam Turbines	1	1949	Gas--Oil	0 2/
	2	1949	Gas--Oil	0 2/
	3	1949	Gas--Oil	0 2/
	4	1965	Gas--Oil	190
Combustion Turbines	1	1974	Gas--Oil	50
	2	1974	Gas--Oil	50
	3	1974	Gas--Oil	50
	4	1975	Oil	80
Abilene Energy Center:				
Combustion Turbine	1	1973	Gas--Oil	68
Jeffrey Energy Center: 1/				
Steam Turbines	1	1978	Coal	425
	2	1980	Coal	430
	3	1983	Coal	435
Total				2,505

1/The amounts shown represent the Company's 64% share.
2/These units have been "mothballed" for future use.

The coal fired units at the KP&L's Tecumseh and Lawrence generating stations have an aggregate generating capacity of 689 megawatts. The company contracted with Arch Mineral Corporation (Arch Mineral) for low-sulfur coal through March 31, 1989 which is surface mined at Arch Mineral's Seminoe II Mine in Hanna, Wyoming, approximately 833 railroad miles from the company's facilities. The coal has an average sulfur content of 0.89 percent and is guaranteed to furnish 11,000 BTU per pound. The average delivered cost of the coal was approximately $1.43 per million BTU or $31.28 per ton during 1987. The transportation cost amounts to 1.75 cents per ton-mile.

In 1991, Lawrence and Tecumseh will start using coal from AMAX's Belle Ayre and Eagle Butte Mines.

Environmental

The federal sulfur dioxide standards applicable to the company's newer JEC units prohibit the emission of more than 1.2 pounds of sulfur dioxide per million BTU of heat input. Federal particulate matter emission standards applicable to the JEC units prohibit: (1) the emission of more than 0.1 pounds of particulate matter per million BTU of heat input and (2) and opacity greater than 20 percent. Federal nitrogen oxides emissions standards applicable to the JEC units prohibit the emission of more than 0.7 pounds of nitrogen oxides per million BTU of heat input.

The JEC units have met: (1) the sulfur dioxide standards through the use of low sulfur coal; (2) the particulate matter standards through the use of electrostatic precipitators; and (3) the nitrogen oxides standards through boiler design and operating procedures. The JEC units are also equipped with low-efficiency flue gas scrubbers providing additional sulfur dioxide and particulate matter emissions reductions.

The Kansas Department of Health and Environment regulations applicable to the older generating facilities at Lawrence and Tecumseh prohibit the emission of more than 3.0 pounds of sulfur dioxide per million BTU of heat input. The company has contracted to purchase low sulfur coal which will comply with such limits at Lawrence and Tecumseh. All facilities burning coal are equipped with either flue gas scrubbers and/or electrostatic precipitators.

Two of the units at the Lawrence plant (115 megawatts and 350 megawatts) are equipped with scrubbers. The third Lawrence unit (70 megawatts) and the two Tecumseh units (80 megawatts and 150 megawatts) are equipped with electrostatic precipitators only.

Both the Lawrence and Tecumseh plants originally burned Kansas coal from P&M's Mine 19 in southeastern Kansas. When the mine shut down, they switched to low-sulfur Wyoming coal.

In 1987, the Lawrence Energy Center became the first generating plant in the nation to be retrofitted with a new technology to reduce nitrogen oxides emissions. As part of a two-year, $4 million national demonstration project, 20 new-design burners were installed in the plant's largest generating unit. A $1.5 million investment in the test program by KP&L was supplemented by $2.5 million in funding by the Kansas Electric Utilities Research Program and the Electric Power Research Institute.

Capacity Planning and Outlook

Kansas Power and Light does not contemplate any significant expenditures in connection with construction of any major generating facilities through 1992. Although the company's management believes, based on current load-growth projections, it will maintain adequate capacity margins through 1992, in view of the lead time required to construct large operating facilities, KP&L may be required before 1992 to consider whether to reschedule the construction of Jeffrey Energy Center Unit 4 or alternatively either build or acquire other capacity.

SUNFLOWER ELECTRIC COOPERATIVE

Utility Description

Sunflower Electric is a Cooperative located in western Kansas. It sells electricity only to cooperatives and cities. These wholesale customers serve approximately 44,000 retail customers in the region.

Sunflower operates one coal-fired plant with a capacity of 296 net megawatts, at Holcomb, Kansas. The plant was built in 1983 and is designed for Powder River Basin, Wyoming coal.

Fuel Supply

Sunflower's coal is purchased through Western Fuels Association (WFA). The original supply contract was with Mobil's Rojo Caballo Mine. The initial contract was signed in 1980. The initial contract price of $5.95 per ton had escalated to $8.76 per ton by December, 1986. At that time, WFA and Mobil agreed to a $4.00 per ton price until January, 1989 (plus escalation). The minimum annual tonnage was reduced from one million to 675 thousand. Mobil was also to receive three settlement payments of $2.58 million each in 1986, 1987 and 1988.

In 1987, WFA again claimed hardship. The agreement was changed to $4.00 per ton through January, 1989 with no escalation and another settlement charge was negotiated.

In July, 1988, WFA filed suit against Mobil claiming breach of contract by providing incorrect price information during contract negotiations invoked by the utility under the above hardship claim. This claim involves certain severance tax refunds to Wyoming producers ordered by the Wyoming Supreme Court in January, 1988. WFA is seeking $1 million in damages plus cancellation of the Mobil contract.

As of July, 1988, Sunflower was taking all of its coal requirement on the spot market from Exxon's mine in Wyoming.

WFA is also seeking to renegotiate its rail transportation contract with Burlington Northern and Atchison, Topeka and Santa Fe. In late 1987, Sunflower was paying about 1.75 cents per ton-mile for transportation of the Mobil coal to the Holcomb plant.

In September, 1988, Mobil Coal Producing asked the U.S. District Court for Wyoming to enter judgment against Western Fuels for at least $3.3 million in settlement of their coal contract dispute.

Also in September, 1988, it was announced that Sunflower had signed a coal supply agreement with Elk River Resources to supply 400,000 tons of Wyoming coal from the Cordero Mine through the end of 1988. This coal replaces coal from Mobil halted under the above dispute.

Environmental

The Holcomb Plant uses a dry spray scrubber with baghouse for pollution control. The spray scrubber is manufactured by Joy-Niro. Lime slurry is sprayed into a tower ahead of the baghouse. The slurry consists of slaked pebble lime from Oklahoma, plus recycle fly ash.

The emissions permit for the plant specifies 0.48 pounds of SO_2 per million BTU plus maintaining at least 70 percent sulfur removal efficiency. Current emissions are estimated at 0.2 pounds of SO_2 per million BTU.

Capacity Planning and Outlook

Sunflower Electric Cooperative is in financial difficulty. They have recently restructured their debt. In August, 1988, Sunflower filed a confidential plan with the Kansas Corporation Commission for recovery from near bankruptcy. The plan involves rate cuts, improved load factors, settling lawsuits and finding buyers for 100 megawatts of surplus power.

In July, 1988, Sunflower signed a 20-year agreement with the Western Area Power Administration (WAPA) for Sunflower to transmit Kansas allotments of WAPA's power (up to 50 megawatts) to 25 members of the Kansas Electric Power Cooperative, Kansas Municipal Energy Agency and individual municipal utilities. Sunflower will receive $1.5 million per year.

In September 1988, the inspector general of the Agriculture Department issued subpoenas to 11 electric cooperatives in a federal investigation of the tax status and safe-harbor leasing practices of Oglethorpe Power Corporation. Oglethorpe and Sunflower Electric Cooperative are major recipients of loan guarantees from the Agriculture Department's Rural Electrification Administration. Safe-harbor leasing relates to provisions in the 1981 tax law, under which an electric cooperative could sell parts of a power-generating unit to another company and then lease it back, allowing the buyer to receive a tax benefit. To engage in such transactions, cooperatives had to give up their tax-exempt status.

In April, 1985, Kansas Power and Light filed suit against Sunflower, for recovery of delinquent payments under an agreement in effect from 1980 to 1986 for the purchase of electric capacity at the Jeffrey Energy Center. These delinquent payments, including interest, totaled $5,609,000 as of December 31, 1987. Sunflower contests liability and has filed a counterclaim against the KP&L seeking damages. A partial summary judgment regarding Sunflower's defenses has been entered in KP&L's favor.

In light of these difficulties, it is unlikely that Sunflower will be undertaking capacity additions in the very near future.

REGIONAL COMPARISONS AND OUTLOOK

Regional Fuel Use By Electric Utilities

Coal has been providing a greater percentage of the fuel burned by electric utilities in the Kansas region at least since 1976. Table 13 displays the percent of total fuel use provided by coal, oil and gas in each state of the study region from 1979 through 1987. Nuclear is ignored in these calculations because of the uniqueness of the fuel use in nuclear plants. Oil as a fuel for electric utility plants has been phased out in all region states except Missouri where it constitutes only one percent of total utility fuel use.

Arkansas has gone from 24 percent coal use in 1979 to a peak of 97 percent in 1984. Coal use then decreased to 86 percent in 1987. Gas has made up the difference from the decline in Arkansas coal use.

TABLE 13

FUEL USE BY ELECTRIC UTILITIES IN THE STUDY REGION

	1987	1985	1983	1981	1979
Coal					
KS	96	94	85	76	57
NE	99	99	99	96	83
MO	99	99	98	98	94
AR	86	93	91	61	24
OK	52	52	49	36	15
Oil					
KS	0	0	1	1	5
NE	0	0	0	1	5
MO	1	1	1	1	3
AR	0	0	1	4	46
OK	0	0	0	0	0
Gas					
KS	4	6	14	23	38
NE	0	1	1	3	11
MO	0	0	1	1	4
AR	14	6	18	35	29
OK	48	48	51	64	85

Source: DOE/EIA-0125 Coal Distribution 1979-1987

Kansas has gone from 57 percent coal use in 1979 to 96 percent in 1987 (Figure 6). This shift has come at the expense of oil and natural gas; there has been no oil-fired generation of electricity since 1985.

Nebraska has gone from 83 percent coal use in 1979 to 99 percent in 1983. Natural gas has declined to under one percent of the market in 1987, making Nebraska almost exclusively using coal for their generating capacity.

Oklahoma, a recent entry to the coal-fired generation market, went from 15 percent coal use in 1979 to 52 percent in 1984 and 1985 as several large coal-fired power plants came on-line. Coal has replaced natural gas; there was no oil used as a fuel from 1979 to 1987.

The accumulative capacity of coal-fired electric generating units for each state in the study region are shown in Figure 7.

Kansas first brought a 10 megawatt unit coal-fired on-line in 1939. The most recent capacity additions totaled 1,039.4 megawatts in 1983. The state has a total of 5,597.0 megawatts of coal-fired generating capacity.

Nebraska has generating units as old as 1948. The newest additions in Nebraska came on-line in 1982, generating 109.8 megawatts of electricity. Nebraska's accumulative total coal-fired generating capacity is 3,121.5 megawatts.

FIGURE 6

PERCENT FUEL USE BY ELECTRIC UTILITIES IN KANSAS

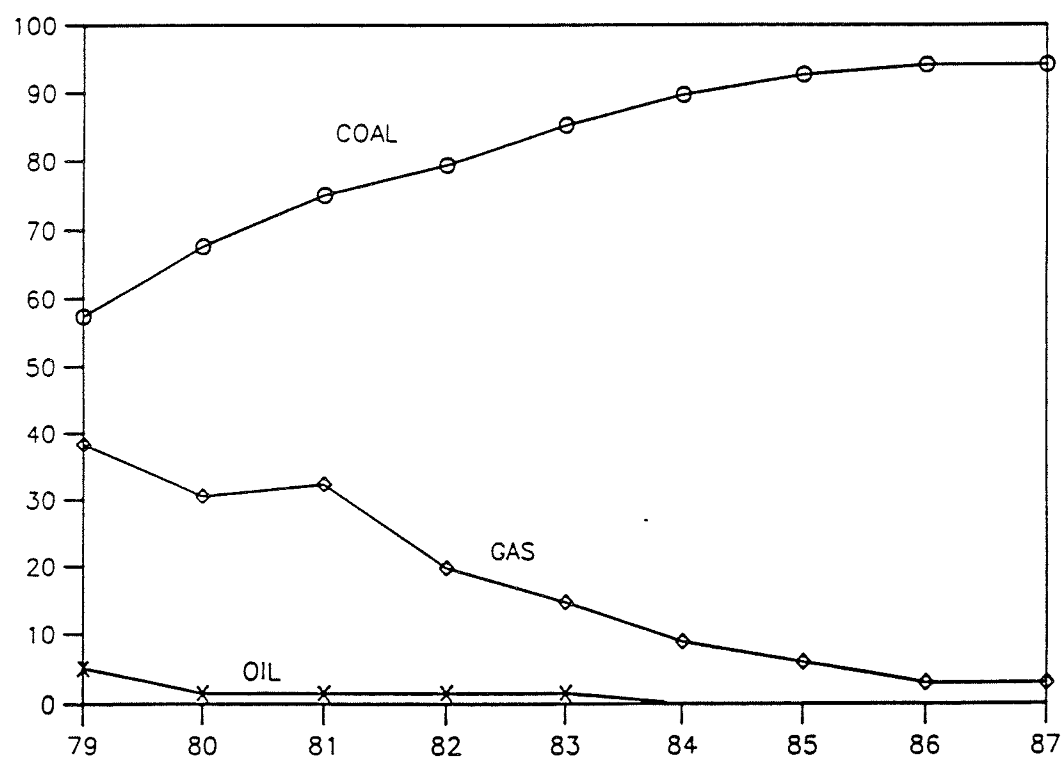
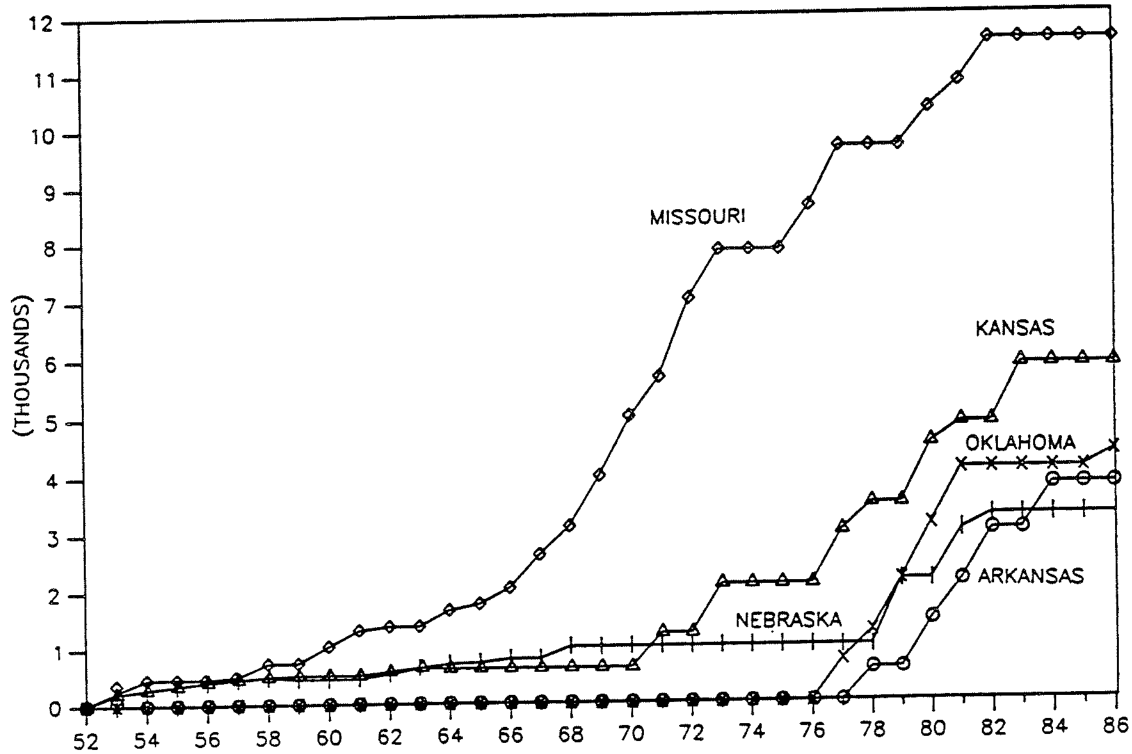


FIGURE 7
COAL-FIRED ELECTRIC CAPACITY ACCUMULATIVE TOTALS



Oklahoma and Arkansas both have relatively new coal-fired generating units. Oklahoma is using generating units only as old as 1977 and the oldest unit used in Arkansas came on-line in 1978. Oklahoma has an accumulative total of 5,357.4 megawatts and Arkansas has an accumulative total of 3,758.0 megawatts.

Missouri has the greatest number of coal-fired electric generating units, with an accumulative total of 11,518.8 megawatts of coal-fired generating capacity.

Potential New Coal-Fired Capacity

There will be very little new coal-fired capacity built in the region during the next 10 years according to scenario tables maintained by J. E. Sinor Consultants Inc. These tables are based on announced plans for capacity additions, estimated retirement dates of existing plants, electricity demand trends, and interfuel competition. As shown in Table 14, only one small plant in Kansas and one large unit in Missouri are expected by 1998. Arkansas, Nebraska, and Oklahoma have no new units scheduled to come on-line in the next 10 years.

For the year 2000 and later, potential additions in Kansas are shown in Table 15.

TABLE 14

NEW COAL-FIRED GENERATING CAPACITY TO 1998

State and Date		Plant	Size MW	Coal Required Tons/Year
Arkansas		No Coal Units Before 1998		
Kansas	1992	Riverton	75.0	150,000
Missouri	1996	Watson	630.0	1,500,000
Nebraska		No Coal Units Before 1998		
Oklahoma		No Coal United Before 1998		

TABLE 15

POTENTIAL NEW COAL-FIRED GENERATING CAPACITY IN KANSAS
(For Post-2000 Startup)

Year	Plant	Size, MW	Coal Required, Tons/Year
2000	Nearman Creek #2	275	700,000
2000+	Site X	650	1,500,000
	Jeffrey #4	680	1,500,000
	Holcomb #2	275	800,000
	State Total	1,880	4,500,000

Distribution of Coal

A substantial amount of Bureau of Mines (BOM) District 19 (see Table 16 for key to districts) coal has always been used in Arkansas generating plants. District 19 coal use in Arkansas generating plants doubled between 1980 and 1982, continuing to increase until 1987.

The major supply of coal to Nebraska's generating plants is also coming from district 19 (99 percent). Although districts 4 (Ohio), 9 (Kentucky), and 15 (Kansas, Missouri, and parts of Oklahoma) have supplied coal in the past, only districts 16, 17 (Colorado), and 19 are supplying Nebraska's generating plants in 1987.

Kansas utilities currently receive coal from BOM districts 10 (Illinois), 15 (Kansas, Missouri, and parts of Oklahoma), and 19. The primary source of coal is from Wyoming.

District 19 also supplies Missouri with coal for their utilities; however, Missouri utilities are receiving a substantial amount of coal from district 10, as well as from districts 8, 9 (Kentucky), and 15.

Oklahoma utilities receive most of their coal from BOM district 19 (Wyoming); smaller amounts have historically come from districts 14 (Arkansas and part of Oklahoma) and 15. The mix will change with a new Oklahoma law which requires that 10 percent of utility coal be from local sources.

TABLE 16

U. S. BUREAU OF MINES COAL PRODUCING DISTRICTS

District	
4	Ohio
6	Northern West Virginia
7	Parts of West Virginia and Parts of Virginia
8	Eastern Kentucky
9	Kentucky
10	Illinois
11	Indiana
14	Arkansas and Parts of Oklahoma
15	Kansas, Missouri, Texas, Part of Oklahoma
16&17	Colorado
19	Idaho and Wyoming
22&23	Montana, Oregon and Washington

Figure 8 shows the distribution of coal shipped from Wyoming in 1987. Wyoming coal supplied an estimated 100 percent of electric utility coal demand in Arkansas for 1987, 99 percent of electric utility coal demand for Nebraska, 85 percent of demand for Kansas, 20 percent of demand for Missouri, and 94 percent of electric utility coal demand for Oklahoma.

Cost of Residential Electricity

For the six utility companies operating in Kansas, the average cost of electric service is presented in Table 17. The table is broken down into average cost for 250 kilowatt hours, 500 kilowatt hours, 750 kilowatt hours, 1,000 kilowatt hours and 2,500 kilowatt hours. In some cases, both summer and winter rates are given.

Empire District Electric has the lowest cost of service (the utility average is shown--it is assumed that this rate applies to Kansas customers). Empire charged only $17.16 for 250 kilowatt hours and $122.51 for 2,500 kilowatt hours. By contrast, electricity from Sunflower Electric was the highest cost. Electricity bills in Garden City, using Sunflower power, were $37.50 for 250 kilowatt hours and $300.25 for 2,500 kilowatt hours, over twice the Empire rate. Rates at the other Kansas utilities are mostly about halfway between these two extremes.

National and Regional Projections

The North American Electric Reliability Council (NERC) annually publishes 10-year forecasts of electric demand for the nine electric reliability councils which comprise the United States electric utility network. For the decade from 1974 to 1984, expected growth rates were consistently over-estimated, and each year's

FIGURE 8
DISTRIBUTION OF WYOMING COAL, 1987
(IN MILLIONS OF TONS)

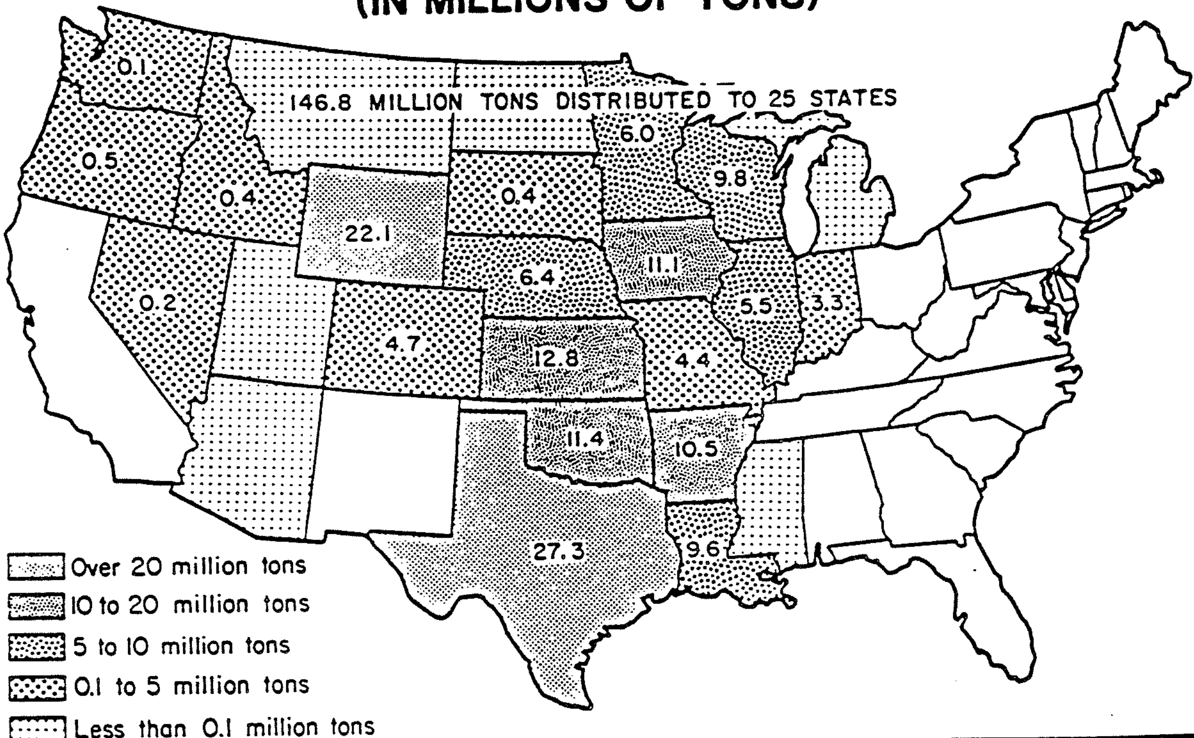


TABLE 17

TYPICAL ELECTRIC BILLS FOR UTILITY COMPANIES IN KANSAS
(In Dollars)

Utility	250 kWh	500 kWh	750 kWh	1000 kWh	2500 kWh
Empire Dist. Elec. Co.	17.16	30.99	38.27	46.71	100.80
	17.16	30.99	40.34	51.55	122.51
Garden City (Power from Sunflower Elec.)	36.18	64.60	93.03	121.45	241.69
	37.00	66.25	95.50	124.75	300.25
Kansas City Power & Light	25.07	44.15	51.91	67.23	112.49
	27.36	48.72	55.35	71.80	198.41
Kansas Gas & Elec. Co.	28.58	49.16	69.75	90.34	213.86
	28.58	49.17	73.41	97.65	243.12
Kansas Power & Light	21.01	38.43	55.83	71.80	198.41
Total State Average	25.60	45.47	61.76	79.51	173.45

*First line is for winter months and second line is for summer months

Source: DOE/EIA-0040 (87) Typical Electric Bills, January 1, 1987 forecast was significantly reduced from the previous year's. As seen in Figure 9, projected growth rates were over 7.6 percent per year in 1974. As the effects of higher energy prices, the resulting conservation, and restructuring of United States industry took hold in succeeding years, the forecast growth rate dropped to 2.5 percent per year by 1984. And yet each year, demand failed to achieve the previous year's forecast.

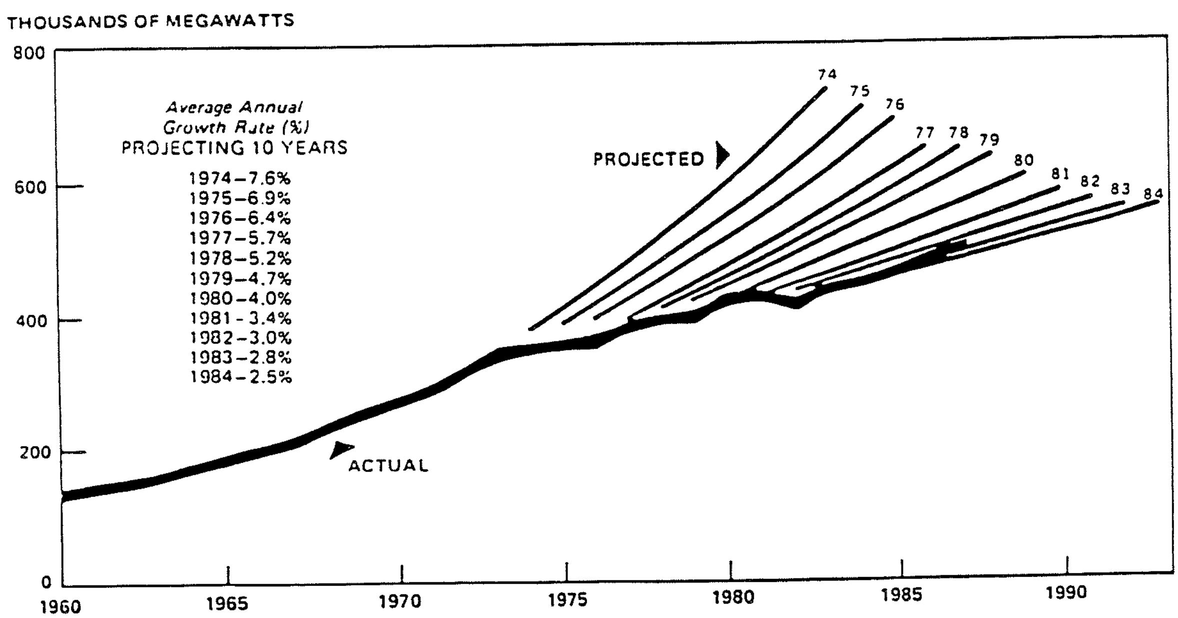
Since 1984, however, actual demand growth has achieved or exceeded NERC forecasts. As seen in Figure 9, the actual 1987 peak demand corresponds to the forecasts which were made in 1982 and 1983. Table 18 compares actual 1986 to 1987 demand growth with the NERC forecast. In all three categories, summer peak, winter peak, and annual net energy for load, the increase from 1986 to 1987 was appreciably greater than the NERC forecast.

It would appear that the era of decreasing expectations for electricity is over, and that future demand forecasts can be made with more certainty than during the 1974-1984 decade.

The latest 10-year NERC forecast is summarized in Table 19. Forecasts are given for the total United States, for the Southwest Power Pool (comprising western Mississippi, Arkansas, southeast Missouri, western Missouri, Louisiana, Oklahoma, southeast Texas, northeast Texas, and the Texas panhandle), and for the Northern Subregion of the Southwest Power Pool (comprising Kansas and western Missouri).

FIGURE 9

COMPARISON OF NERC'S ANNUAL TEN-YEAR FORECASTS TO ACTUAL U.S. SUMMER PEAK DEMAND



SOURCE: NERC, ELECTRIC POWER SUPPY & DEMAND

TABLE 18

FORECAST AND ACTUAL PEAK ELECTRICITY DEMAND FOR 1987 (TOTAL UNITED STATES)

	Summer Peak Thousand MW	Winter Peak Thousand MW	Annual Load Billion kWh
1986 Actual	477	423	2,532
Forecast Growth, %	1.6	5.0	2.3
1987 Forecast	484	444	2,589
1987 Actual	496	448	2,644
Actual Growth, %	4.0	6.0	4.4

Source: North American Electric Reliability Council

TABLE 19

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL FORECASTS

	1987 Actual	1997 Forecast	Percent Growth
Summer Peak Demand, 1,000 MW			
Total U. S.	496	594	1.9
Southwest Power Pool	48	57	1.9
Northern Section	11.6	14.5	2.3
Winter Peak Demand, 1,000 MW			
Total U. S.	448	548	2.0
Southwest Power Pool	34.5	43.9	2.2
Northern Section	8.2	10.7	2.4
Net Energy for Load, Billion kWh			
Total U. S.	2,643	3,210	2.0
Southwest Power Pool	228	273	1.9
Northern Section	50	63	2.3
Planned Summer Capacity, 1,000 MW			
Total U. S.	650	728	1.3
Southwest Power Pool	65	68	0.4
Northern Section	15.6	17.1	1.0

The Northern Subregion is expected to have a greater rate of growth in electricity demand (2.3 percent per year) than either the total Southwest Power Pool or the total United States. However, planned capacity additions (both utility and non-utility) are considerably below the expected rate of demand growth in all cases. For the Northern Subregion, the rate of planned capacity additions at 1.0 percent per year is less than half the expected demand growth rate. Because the Subregion now has more reserve margin than needed, this discrepancy will cause no immediate problems. If the forecast is accurate, however, it means that reserve margin for summer peak demand will be disappearing at an average of 1.3 percent per year. Thus, if only the forecast 1,500 megawatts are added by 1997, the reserve margin would drop from 34 percent in 1987 to only 18 percent in 1997.

INDUSTRIAL COAL MARKET

NATIONAL AND REGIONAL INDUSTRIAL COAL DEMAND

Coal demand in the United States has become a one-dimensional market. Of 1987's total consumption of 841 million tons, 721 million went to the electric utility sector. Coal consumption by electric utilities continues to grow. By contrast, coal consumption in the industrial sector (exclusive of coke plants), amounted to only 75 million tons in 1987, and has been stagnant for the four years prior to 1988. First quarter 1988 figures for industrial coal demand show a 6.8 percent increase over the corresponding period in 1987.

Industrial coal consumption in Kansas and surrounding states is listed in Table 20. Kansas industry consumes less coal than any other state in the region.

Industrial demand (excluding coke) for heating and processing is expected to grow over the next 25 years as the price differential between coal and oil and gas increases. The major industrial coal consuming sectors are: chemicals; cement, stone, clay and glass; paper; primary metals; and food. Industrial coal demand may be divided into categories of use. These are: steam raising, process heat, electricity, space heating, and feedstocks. Steam raising accounts for about one third of industrial use and is expected to remain at this share. Industrial coal consumption by industry is shown in Table 21. Industrial coal demand is extremely sensitive to economic growth and incentives for capital investments. Cogeneration facilities will provide future industrial demand growth, if the consumption is allocated to the industrial sector. Industrial coal demand growth beyond 1990 is projected to be between 1.0 and 1.5 percent. This growth rate is projected to be less than overall economic growth rates, in part because of movement away from heavy industries toward hi-tech and service industries and because of more efficient industrial energy utilization.

The only industries using significant quantities of coal in Kansas are cement kilns, petroleum refineries, and the stone, clay and glass industry.

Regional Industrial Coal Sources

Arkansas industrial plants have used coal from Bureau of Mines (BOM) districts 9, 10, 14, and 15 (see Table 16 for key). Arkansas industries are receiving the majority of their coal from BOM district 15 (48 percent in 1987).

Coal for industrial plants in Nebraska is coming from BOM districts 16, 17, 19, 22, and 23; the majority of industrial plant coal needs is being met by districts 22 and 23.

Kansas industrial coal users have received their fuel from BOM districts 8, 10, 11, 14, 15, and 16 and 17. The primary source is district 15.

Coal for industrial plants, residential and commercial uses in Missouri is being received from districts 7, 8, 9, 10, 11, 14, and 15.

Oklahoma industries have historically used a wider range of sources for their coal, receiving coal from BOM districts 8, 14, 15, 16, and 17 and 19. The primary source seems to be district 15.

TABLE 20

INDUSTRIAL COAL CONSUMPTION IN THE REGION
(Thousand Tons)

Year	KS	MO	NE	OK	AR
1970	103	1,921	240	0	0
1971	83	1,753	193	3	2
1972	94	2,141	218	3	2
1973	133	1,875	312	170	97
1974	143	1,907	319	177	115
1975	134	2,065	308	20	40
1976	90	2,180	604	69	167
1977	169	2,158	553	231	245
1978	104	1,813	576	384	310
1979	218	1,823	538	391	345
1980	331	1,595	269	264	296
1981	354	1,715	376	676	358
1982	372	1,454	325	669	350
1983	286	1,524	216	585	436
1984	310	1,717	280	707	396
1985	363	1,798	261	852	379
1986	261	1,687	339	763	344
1987	251	1,423	-	614	302

Source: State Energy Data Report, EIA 0214, and Quarterly Coal Report

TABLE 21

INDUSTRIAL COAL CONSUMPTION 1985-2010
(Millions Of Short Tons)

Industry	1985	1990	1995	2000	2010
Chemicals	19.7	20.8	23.2	26.0	33.1
Cement	16.1	18.7	19.0	19.6	20.8
Paper	12.0	14.9	15.5	16.7	19.1
Primary Metals	8.4	9.5	9.3	9.3	9.5
Food	5.5	6.7	7.0	7.4	8.4
Other	10.3	12.5	13.0	14.9	18.1
Total	72	83	87	94	109

Source: National Coal Association, Coal 2000. Modified by J. E. Sinor Consultants Inc. Totals may not add due to rounding

CEMENT KILNS

National and Regional Data

The portland cement industry represents the one "natural" market for Kansas coal. Depending on the other raw materials used in the cement kiln, relatively high-sulfur coals can be used with no problem because the sulfur is merely incorporated into the product. Thus the primary factor limiting the value of Kansas coal in other applications is much less important in the cement industry.

A number of cement kilns are located in the "Kansas cement belt" within convenient market distance of the southeast Kansas coal fields (Figure 10).

Over the last 15 years, the portland cement industry has converted from a mostly gas-fired industry to an almost completely coal-fired industry (Table 22). Also shown in Table 21 are the effects of foreign competition on the United States cement industry. The industry's capacity utilization has declined significantly, the number of operating plants has dropped sharply and the number of operating kilns has dropped even more steeply. Fewer but larger kilns remain, keeping overall capacity constant. The industry trends do not bode well for small producers, such as some of the plants in Kansas.

Coal sources for the cement plants shown in Figure 10 are listed in Table 23. The plants in eastern Missouri are on the Missouri river and obtain coal economically by barge from the Ohio River Valley.

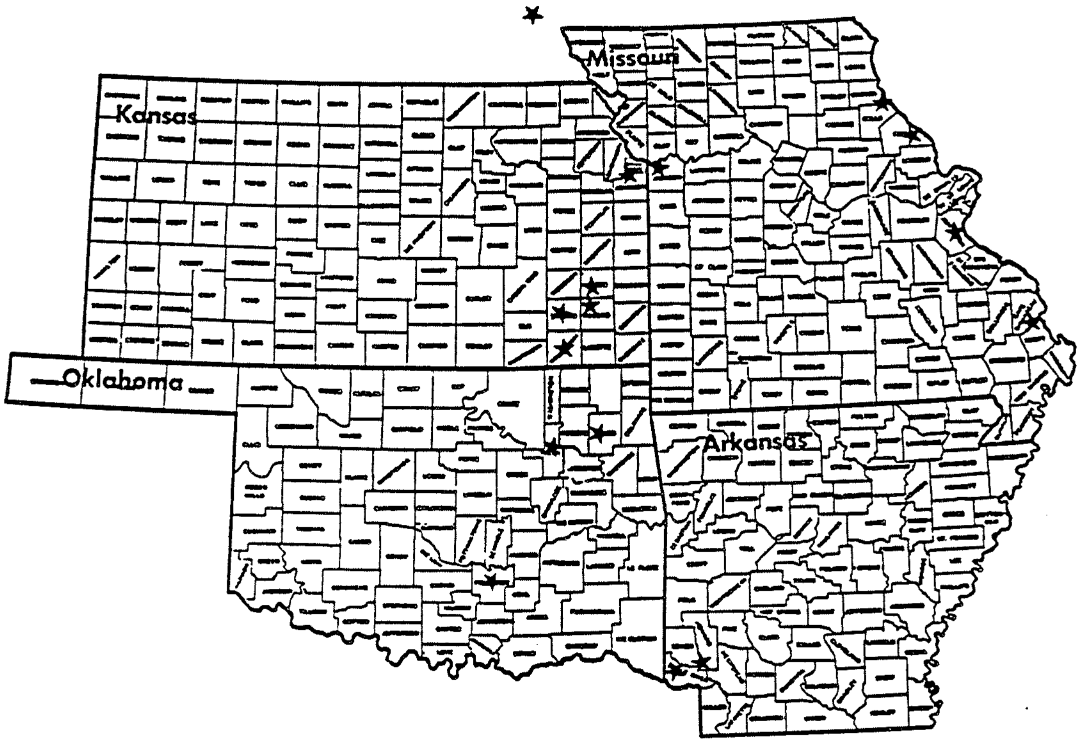
TABLE 22

CEMENT INDUSTRY HISTORICAL DATA

	1973	1981	1986
Clinker Capacity (1,000 Tons)	85,167	89,531	88,700
Capacity Utilization	90.0%	74.1%	78.4%
Number of Plants	166	144	124
Number of Kilns	471	327	248
Average Capacity per Kiln (1,000 Tons)	191	294	345
Kiln Fuel Used, Percent:			
Year	1972	1985	
Coal	38.1	85.8	
Coke	0.6	6.1	
Oil	13.1	1.7	
Natural Gas	48.3	5.4	
Waste	0	1.0	

Source: Portland Cement Association

FIGURE 10
REGIONAL CEMENT PLANT LOCATIONS



Kansas Cement Kilns

Ash Grove Cement Company, Chanute. This plant burns about 75,000 tons of coal per year. Specs are 12,500 BTU per pound minimum, three percent sulfur maximum, 12 percent ash maximum, and five percent to eight percent moisture. Deliveries are by truck and the source is usually southeast Kansas or northeast Oklahoma. The 1986 supplier was Clemens Coal Company in Kansas.

Lafarge Corporation, Fredonia. This plant burns about 50,000 tons per year. Delivery is by truck. The plant usually burns prepared 2 X 0 coal with maximum 30 percent fines. Specs are 11,000 BTU per pound minimum, three percent sulfur maximum, 15 percent ash maximum, 12 percent moisture maximum, 25 to 40 percent volatiles, and 50 to 75 grind. The plant usually purchases coal under five year contract from producers in Kansas.

Monarch Cement Company, Humboldt. This plant burns about 18,000 tons per year of truck delivered Kansas coal. They have had long term contracts with Cherokee Coal Company and Clemens Coal Company. Specs are 12,000 BTU per pound minimum, 2.6 percent sulfur maximum, 10 to 12 percent ash, six percent moisture, 28 to 30 percent volatiles and 55 grind.

TABLE 23

COAL SOURCES FOR REGIONAL CEMENT PLANTS

Plant Location	Coal Source
Oklahoma	
Ada	Oklahoma
Pryor	Oklahoma
Tulsa	Oklahoma
Arkansas	
Foreman	Oklahoma
Saratoga	Arkansas
Nebraska	
Louisville	Colorado
Missouri	
Hannibal	Illinois, Kentucky
Clarksville	Illinois
Cape Girardeau	Illinois
Festus	West Virginia, Indiana
Sugar Creek	Kansas
Kansas	
Freedonia	Kansas, Missouri
Chanute	Kansas, Oklahoma
Humboldt	Kansas
Independence	Kansas, Oklahoma
Bonner Springs	Kansas

Heartland Cement, Independence. This plant uses approximately 15-30,000 tons per year. Their 1987 supply was through Royal Fuels from Cherokee Coal Company. The plant is currently operating only part-time. The coal supply sometimes comes from Oklahoma and sometimes from Kansas and is delivered by truck.

Lone Star Industries, Bonner Springs. This plant normally burns approximately 66,000 tons per year of coal and 21,000 tons of petroleum coke. The current mix is about 40,000 tons of each. Delivery can be by truck or barge; the coal is usually delivered by truck and the petroleum coke by barge.

Missouri Portland Cement, Kansas City. Specs at this plant are 11,500-11,700 BTU per pound, less than 2.8 percent sulfur, 11 to 12 percent ash, seven percent moisture and volatiles in the low 30's. The plant uses about 50,000 tons of coal and 30,000 tons of petroleum coke per year. The petroleum coke supply may be switched to coal. Delivery can be by truck or barge. The plant was supplied in 1986 by Kansas producers, Bill's Coal and Cherokee Coal. The 1987 contract was awarded to Binford-Nightingale for coal from Warrick County Coal, Elderfield, Indiana for barge delivery. The 1988 contract for 60,000 tons was to Alternate Fuels from the Croweburg No. 1 mine, Crawford County, Kansas. The 1988 delivered specs are 11,500 BTU per pound, 2.8 percent sulfur, 10 percent ash and 10 percent moisture.

Fuel Usage in Kansas Cement Kilns

Fuel usage in the Kansas cement industry is shown in Table 24. It can be seen that Kansas coals are holding coal's share of the kiln fuel market quite well against competition from Missouri and Oklahoma coals. There are, however, two major competing fuels, and a possible third.

Petroleum coke is a major competing fuel. Essentially a waste product of petroleum refining, the price of petroleum coke depends upon the vagaries of the export market to Europe. When this market is up, much United States petroleum coke is exported, and prices rise across the country. This affects even landlocked refineries such as those in the Kansas region. There are refineries with cokers at El Dorado, Coffeyville, Wichita, and McPherson, Kansas, and at Ponca City and Tulsa, Oklahoma. When the export market is down and coke prices fall, the refineries still must dispose of their coke at any price, and it becomes a very competitive fuel. Coal will always have to compete against petroleum coke in a cyclic manner.

A new competitive fuel which has just arisen, is the burning of waste solvents in cement kilns. Under increasingly complex and strict hazardous waste control laws, many firms are finding it very difficult to dispose of waste solvents of various types. A cement kiln makes an ideal disposal vehicle because the high operating temperatures completely incinerate all organic materials and the solid residue if any is simply incorporated into the cement. Large quantities of such solvents are available at low or perhaps even negative cost as kiln fuel. At least two cement plants in Kansas are obtaining part of their fuel requirements from this source. It would appear that, to whatever extent they are available and allowed to be burned, waste solvents will displace coal.

TABLE 24

FUEL USAGE IN THE KANSAS CEMENT INDUSTRY
(Tons Per Year Coal Equivalent)

Company/Location	Coal/Source	Coke	Waste
Lafarge, Freedonia	37,000 KS 13,000 MO		50,000
Ash Grove, Chanute	35,000 KS 35,000 OK	18,000	10,000
Monarch, Humboldt	18,000 KS	60,000	
Heartland, Independence	15,000 KS 15,000 OK		
Lone Star, Bonner Springs	40,000 KS	40,000	
Totals	145,000 KS 13,000 MO 50,000 OK	118,000	60,000
Percentages:	38% KS Coal 3% MO Coal 13% OK Coal 31% Pet. Coke 15% Waste Solvents		

The third possible contender is the former fuel of choice--natural gas. Although our current survey (Table 24) did not reveal any significant use of natural gas in cement kilns, there are cases in other industries where current low natural gas prices have tipped the balance in favor of natural gas over coal. However, we do not expect natural gas prices to remain in this range for much longer, and do not consider natural gas to be a long-term threat for the cement kiln market, where coal handling facilities are already in place.

OTHER INDUSTRIAL COAL USERS

Other Industry in Kansas

The Energy Information Administration identifies 250,000 tons per year of industrial coal consumption in the State of Kansas (Table 20). We calculate the total to be closer to 300,000 tons per year, and possibly as high as 330,000 tons. Some 208,000 tons are accounted for by the cement industry (Table 24). Other known users are discussed below.

The Farmland Industries Refinery at Coffeyville receives coal from Oklahoma under long-term contract. There are no plans to buy spot market coal. Coal specs are 12,000 BTU per pound minimum and one percent sulfur. The plant burns about 25,000 to 40,000 tons per year and can receive coal via truck or on the KATY railroad. Although the refinery produces 150,000 tons of petroleum coke per year, it cannot burn its own coke on its stoker grate, even at 10 percent concentration, because of severe slagging. At one time, the refinery burned as much as 60,000 tons of coal per year, but they now use significant quantities of natural gas.

Buildex has light-weight building aggregate plants at Ottawa and Marquette, Kansas. They operate in response to demand from the construction industry, and consume up to 20,000 tons per year each when running. All coal is supplied by Mackie-Clemens Fuel Company.

The Sunflower Ordnance Plant at DeSoto, Kansas uses 50,000 to 70,000 tons of coal per year. Usage has been down recently because of problems with an old coal boiler and the electrostatic precipitator. They are not particularly limited by sulfur content, but the key specification is ash, which must be below nine percent. Kansas coals have had a problem meeting this specification, and coal is now being obtained from Oklahoma. This contract expires in March, 1989.

The Kansas Army Ammunition Plant at Parsons, Kansas uses a very small amount of coal, less than 1,000 tons per year.

In summary, the Other Industrial category accounts for a highly variable amount of coal consumption, anywhere between 95,000 and 160,000 tons per year. Most of this coal is being supplied from Oklahoma, because of Kansas problems in meeting either a sulfur specification or an ash specification.

Other Industry in the Region

Some information on the makeup of the industrial sector in the region of interest is available from the 1981 Census of Manufacturers. The major industries (as determined by value added during manufacturing) in each state are listed by Standard Industrial Classification (SIC) Number in Table 25. Also shown in the table are the types of fuel reported as consumed by each industry. The same data have been re-aggregated in Table 26 to show for each industry the major Standard Metropolitan Areas in which they are located. The usefulness of the data in Tables 25 and 26 is that they provide leads to general classes of industries which could be candidates for conversion to coal-firing. If one member of a particular SIC class is found to be using coal at a specific location, then other members of the same class at the same or other locations may be considered candidates for coal consumption.

A specific list of major industrial coal users in each state of the region is given in Table 27. This list is not exhaustive, and has not been currently verified outside Kansas, but it gives a good idea of the composition of the industrial coal-using sector. We see, for example, that Oklahoma paper and rubber tire plants use coal. Because the paper industry is not present in Kansas, there is no opportunity for the in-state coal market, but the tire industry is represented. It would therefore be worthwhile to investigate why coal is used at an Oklahoma tire plant but not in Kansas.

TABLE 25

MAJOR INDUSTRIES BY STATE AND FUELS CONSUMED BY EACH

Arkansas

SIC 20 Food and kindred products
- electrical energy

SIC 24 Lumber and wood products
- distillate fuel oil
- liquefied petroleum gases

SIC 26 Paper and allied products
- electricl energy
- distillate fuel oil
- natural gas

SIC 28 Chemicals and allied products
- residual fuel oil
- natural gas

Kansas

SIC 20 Food and kindred products
- electrical energy

SIC 28 Chemicals and allied products
- electrical energy
- residual fuel oil
- natural gas

SIC 29 Petroleum and coal products
- electrical energy
- natural gas

SIC 30 Rubber and miscellaneous plastic products
- electrical energy

SIC 32 Stone, clay and glass products
- distillate fuel oil
- liquefied petroleum gases
- coal

SIC 37 Transportation equipment
- electrical energy

Nebraska

SIC 20 Food and kindred products
- electrical energy
- distillate fuel oil
- residual fuel oil
- natural gas
- liquefied petroleum gases

SIC 28 Chemicals and allied products
- electrical energy

Missouri

SIC 20 Food and kindred products
- electrical energy
- residual fuel oil
- natural gas

SIC 28 Chemicals and allied products
- electrical energy
- natural gas

SIC 32 Stone, clay and glass products
- electrical energy
- distillate fuel oil
- coal

SIC 33 Primary metal industries
- electrical energy
- coke and breeze
- natural gas
- liquefied petroleum gases

Oklahoma

SIC 26 Paper and allied products
- electrical energy

SIC 28 Chemicals and allied products
- natural gas

SIC 29 Petroleum and coal products
- electrical energy
- natural gas

SIC 30 Rubber and miscellaneous plastic products
- electrical energy
- coal

SIC 32 Stone, clay and glass products
- electrical energy
- coal

SIC 33 Primary metal industries
- electrical energy

SIC 34 Fabricated metals
- electrical energy

SIC 35 Machinery, except electrical
- liquefied petroleum gases

TABLE 26

MAJOR INDUSTRIES BY STANDARD METROPOLITAN AREAS

SIC 20 Food and Kindred Products
- Fort Smith, AR-OK
- Kansas City, MO-KS
- Lincoln, NE
- Little Rock, AR
- Oklahoma City, OK
- Omaha, NE
- Springfield, MO
- St. Joseph, MO
- Texarkana, TX-AR
- Topeka, KS

SIC 24 Lumber and Wood Products
- Texarkana, TX-AR

SIC 25 Furniture and Fixtures
- Fort Smith, AR-OK

SIC 26 Paper and Allied Products
- Fort Smith, AR-OK

SIC 28 Chemicals and Allied Products
- Kansas City, MO-KS
- St. Louis, MO

SIC 29 Petroleum and Coal Products
- St. Louis, MO
- Wichita, KS

SIC 33 Primary Metal Industries
- Omaha, NE
- St. Louis, MO

SIC 32 Stone, Clay and Glass Products
- Kansas City, MO-KS
- Oklahoma City, OK
- St. Louis, MO
- Tulsa, OK

SIC 34 Fabricated Metal Products
- Kansas City, MO-KS

SIC 35 Machinery, Except Electrical
- Fort Smith, AR-OK
- Oklahoma City, OK
- Fort Smith, AR-OK
- Oklahoma City, OK

SIC 36 Electrical and Electronic Equipment
- Kansas City, MO-KS

SIC 37 Transportation Equipment
- Oklahoma City, OK
- Wichita, KS

TABLE 27

MAJOR COAL USING INDUSTRIAL FACILITIES, BY STATE

Company	Town	Estimated Consumption Tons/Year
KANSAS		
Ash Grove Cement Co.	Chanute	68,000
Buildex	Marquette	20,000
Farmland Industries Inc.	Coffeyville	60,000
Lafarge Corp.	Fredonia	50,000
Heartland Cement Co.	Independence	21,000
Lone Star Industries Inc.	Bonner Springs	66,000
Monarch Cement Co.	Humboldt	20,000
Sunflower Ordinance	De Soto	50,000
State Total		355,000
OKLAHOMA		
Blue Circle Inc.	Tulsa	100,000
Fort Howard Paper Co.	Muskogee	300,000
Goodyear Tire	Lawton	27,000
Ideal Basic Industries	Ada	90,000
Lone Star Industries Inc.	Pryor	120,000
St. Clair Lime Co.	Marble City	36,000
State Total		673,000
ARKANSAS		
Arkansas Eastman	Batesville	25,000
Arkansas Lightweight Aggregates	West Memphis	21,000
Ash Grove Cement Co.	Foreman	180,000
Nekoosa Papers Inc.	Ashdown	140,000
Arkansas Charcoal Inc.	Paris	Unknown
State Total		366,000
MISSOURI		
American Cyanamid Co.	Hannibal	60,000
Anheuser-Busch Inc.	St. Louis	100,000
Central Electric Power	Chamois	60,000
Chrysler Corp.	Fenton	35,000
Continental Cement	Hannibal	140,000
Dundee Cement Co.	Clarksville	275,000
General Motors Corp.	St. Louis	Unknown
	Wentzville	Unknown
Hercules Inc.	Louisiana	40,000
Lone Star Industries	Cape Girardeau	210,000
Mallinckrodt Chemical	St. Louis	40,000
Mississippi Lime	St. Genevieve	300,000
Missouri Portland Cement	Independence	55,000
Monsanto Company	St. Louis	55,000
Petrolite Corp.	Webster Groves	10,000
Resco Products Inc.	Bonne Terre	17,500
Washington University	St. Louis	10,000
California Manufacturing	St. James	Unknown
River Cement Company	Festus	150,000
University of Missouri	Columbia	150,000
University of Rolla	Rolla	7,500
State Total		1,565,000
NEBRASKA		
Ash Grove Cement	Louisville	90,000
Ideal Basic Industries	Superior	50,000
Western Sugar Co.	Mitchell	50,000
	Scottsbluff	50,000
	Baird	50,000
State Total		290,000

COMMERCIAL, RESIDENTIAL, EXPORT POTENTIAL

COMMERCIAL, RESIDENTIAL

For the United States as a whole, commercial and residential coal consumption amounts to less than one percent of total coal demand. Consumption of coal in this sector has been falling in most states in the region as well as nationwide and is expected to continue to decline. The end-use for coal in this sector is primarily space heating. Coal continues to be replaced by natural gas for this use.

Commercial and residential coal use by state is listed in Table 28. Only in Missouri is there significant coal use in this sector. Expansion in the near future is unlikely because of the much higher cost of coal-burning equipment compared to oil- and gas-burning equipment in the small sizes needed for commercial and residential use.

A recently completed study for the United States Department of Energy assessed the economic feasibility of installing coal-burning equipment at two specific commercial-type facilities, a high school and a hospital. The hospital, because of its larger energy demand, showed the most favorable results.

Health care facilities appear to be a good target market for coal-based energy systems because they are large users of both electric and thermal energy on a continuous basis. The demand for thermal energy is also more uniform in health care facilities compared to the buildings in other segments of the commercial market. Because of their large and uniform thermal and electric loads, hospitals are also a good target market for cogeneration applications.

The health care facility studied is a 300-bed hospital consisting of eight buildings (and a multistory parking garage) with the conditioned space totaling slightly over 400,000 square feet. The hospital peak thermal demand is 26 million BTU per hour. However, more than 97 percent of the time, the hospital's thermal demand is less than 15 million BTU per hour. For the fiscal year 1985-1986 the hospital's actual annual cost for natural gas was about $378,000. The hospital's actual annual electricity bill for the same fiscal year was about $605,000.

TABLE 28

COMMERCIAL AND RESIDENTIAL USE OF COAL - 1986
(Thousands Of Tons Per Year)

State	Commercial	Residential
Arkansas	0	0
Kansas	1	0
Missouri	68	37
Nebraska	3	1
Oklahoma	3	1

Several combinations of energy application and coal technology were evaluated:

Applications

- Heating only
- Heating and cooling
- Heating, cooling, cogeneration

Technologies

- Stoker grate
- Fluidized bed combustion boiler (AFBC)
- Slurry fired modified oil boiler
- Slurry fired AFBC

For each case a complete combustion system, including fuel and ash handling systems, was sized and specified. Equipment layouts were completed and detailed construction costs were calculated for any site and building work required. The coal-based systems were designed to meet the federal, state, and local environmental laws, the wastewater and solid waste disposal regulations, and other rules and regulations governing construction of solid fuel-burning facilities.

The performance characteristics of a coal-fired AFBC boiler were compared to the performance characteristics of a high-efficiency gas boiler for the hospital. The steady-state efficiency and the operating efficiency of the AFBC system approaches that of a high-efficiency gas boiler. The steady-state and operating efficiency of stoker boilers are about 10 percentage points less than those of AFBC boilers. The steady-state and operating efficiency of slurry-fired boilers are three percentage to five percentage points less than those of AFBC boilers.

Results of the study showed that coal-based energy systems cannot currently compete with gas systems for the hospital. For coal-based energy systems to become competitive, their annual operating costs including depreciation, labor, and fuel/sorbent costs must be reduced by a minimum of 30 percent; or else the gas prices have to soar to the \$6 per million BTU to \$10 per million BTU range.

The capital costs of coal-based systems for heating applications were found to be six to 13 times higher than the capital cost of high-efficiency gas systems. The higher capital cost for these systems is caused mainly by the need for a new boiler room for housing the coal-based systems and by the need for additional equipment for fuel, solid waste, and flue-gas handling and cleaning. A fluidized bed combustion unit for coal was calculated to cost \$2,500,000, a fluidized bed unit burning coal slurry was \$2,250,000, and a standard coal stoker \$2,125,000, compared to a cost of less than \$250,000 for a gas-fired system.

The operating cost of coal-based energy systems was found to be higher than the operating cost of the high-efficiency gas system by 36 percent to 50 percent. When depreciated over 20 years, the capital cost accounts for 10 percent to 20 percent of the operating cost of the coal-based energy systems compared to two percent of the operating cost of gas systems. The labor cost of the coal-based systems is eight percent to 30 percent higher than the labor cost for the high-efficiency gas system. The fuel/sorbent costs for the AFBC and stoker coal-fired systems are 24 percent to 55 percent lower than the fuel cost for the high-efficiency gas system. But the fuel/sorbent costs of coal slurry-fired systems are two percent to 25 percent higher than the fuel costs for the high-efficiency gas system.

Overall, the study found that the hospital's annual energy cost would be 10 percent to 30 percent higher for coal-based energy systems compared to the high-efficiency gas system, when using current fuel prices.

Although coal-based cogeneration systems still are not competitive with high-efficiency gas systems, they are more economical than heating and heating and cooling applications. Figure 11 shows that coal-fired AFBC systems for cogeneration applications could result in energy cost savings for the hospital at natural gas prices of $6 per million BTU and higher. Using Gas Research Institute projections of fuel prices, however, coal-based energy systems cannot compete with high-efficiency gas systems in the next decade, unless capital and operating costs can be reduced by applying new and innovative techniques to their design, manufacture, and operation.

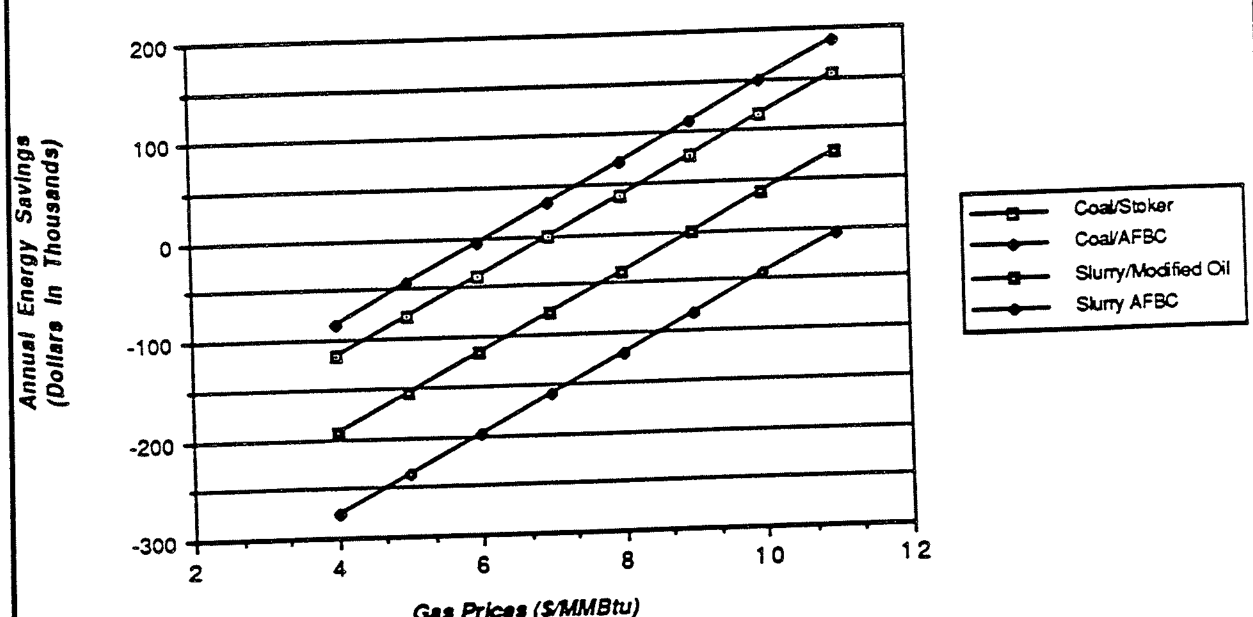
The economics of coal-based energy systems are not the only impediment to the installation of coal-based technology at a hospital. Some of the other impediments include:

- Solid waste disposal
- Transport and transfer of fuel and solid wastes
- Complicated and varying environmental permitting procedures
- Land and space requirements

FIGURE 11

HOSPITAL ENERGY COST SAVINGS AS A FUNCTION OF GAS PRICES

Cogeneration Applications Compared to a High-Efficiency Gas System



SOURCE: SHELADIA ASSOCIATES

Transporting and transferring fuel and solid wastes to and from the site is a major impediment to coal-based technologies for the commercial sector. The fuel delivery and solid waste disposal infrastructure simply do not exist. In addition, commercial building operators are concerned about the number of delivery trucks and their impact upon local traffic, and about possible negative reactions from citizen groups. The land and space required for fuel, sorbent, and solid waste handling and storage, as well as flue-gas cleanup, are also an impediment to coal-based techniques for the commercial sector. Coal-based systems cannot be installed in many of the boiler rooms in existing buildings because of space and land limitations.

The above factors may be of importance at some sites but not others. Of universal importance, however, are the higher capital and operating costs for coal-fired systems. It appears highly unlikely that a market for Kansas coal can be developed in the commercial and residential sector.

EXPORT POTENTIAL

Water-Borne Transport System

None of the southeast Kansas coal mines have direct access to waterways which would allow them to ship to overseas customers. The United States inland waterway system is shown in Figure 12. The nearest branch of the system for southeast Kansas would be the McClellan-Kerr Waterway on the Arkansas-Verdigris River system. It terminates at the Port of Catoosa, near Tulsa, Oklahoma. The highway distance between Pittsburg, Kansas and the Port of Catoosa is approximately 120 miles.

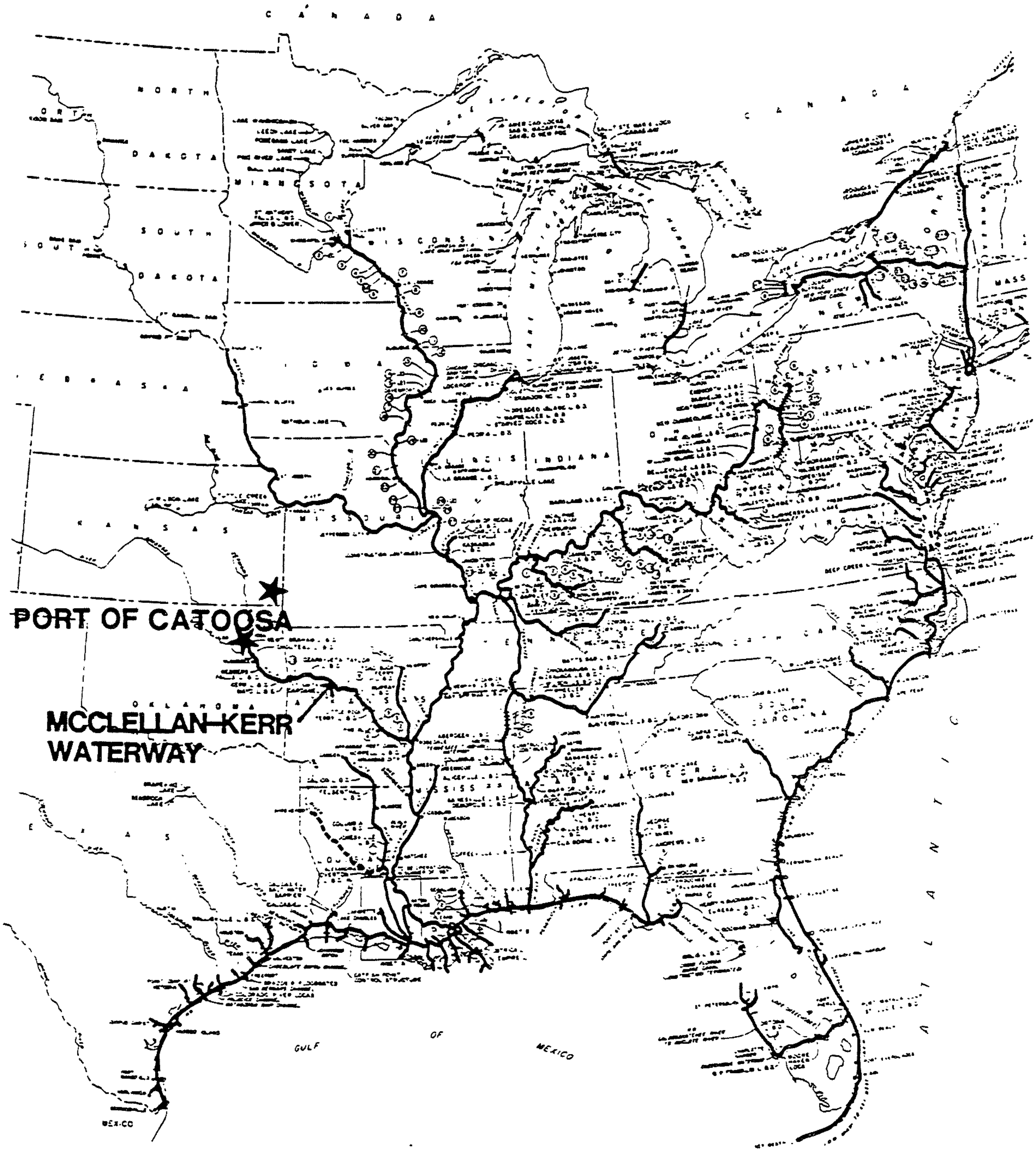
There are no coal loading facilities at the Port of Catoosa. It would cost approximately $1.5 million to install such facilities. However, there are bulk loading facilities which can be used for coal at the Conagra and Rogers terminals two and eight miles downstream, respectively.

Estimated costs to get coal from Pittsburg, Kansas to an overseas export terminal include $11.50 for trucking to the barge terminal, $0.75 to $1.00 loading fee to transfer from truck to barge, and $5.00 for barge transport to New Orleans. This makes a total transport cost of approximately $17.50 per ton to put the coal free alongside ship (f.a.s.) in the lower Mississippi River. The coal can either be unloaded from the barges to a river terminal for temporary storage and later loading on a ship, or else mid-stream transfer can be made directly from barge to ship. This transfer step adds another $1 to $2 per ton to the cost.

In moving through the waterway system, a major concern is avoiding the need for intermediate storage. A typical coal barge will hold 1,400 tons of coal, or the amount hauled by 57 highway-type coal trucks. In turn, a 100,000-ton oceangoing bulk carrier will hold the contents of 71 barges. To keep costs in line, coal shippers must avoid intermediate storage and rehandling, and must also avoid demurrage charges by ships or towboats waiting to be loaded.

The distances involved are such that shipment by railroad could be a competitive alternative. The railroad distance between Pittsburg, Kansas and New Orleans, Louisiana is approximately 750 miles. At $0.02 per ton-mile, the cost of rail shipment to an export port would be $15.00 per ton. Adding $3.50 for trucking cost from mine to rail siding gives a total of $18.50 per ton.

FIGURE 12
UNITED STATES INLAND WATERWAY SYSTEM



Alternatively, shipment by rail from Pittsburg to a barge terminal in Oklahoma could be the lowest cost route. The rail distance would be 135 miles. Using $0.05 per ton-mile for such a short rail haul, we calculate $3.50 for trucking from mine to rail, plus $6.75 for rail to the barge terminal, for a total of $10.25 at the barge, compared to $11.50 for the all truck route.

United States Coal Exports

United States coal exports, which were 53.6 million tons in 1973, rose to 79.6 million tons in 1987. However, the intervening years saw United States coal exports as high as 112.5 million tons in 1981 and as low as 40.7 million tons in 1978. The high level of United States coal exports immediately after and during the significant increases in world oil prices in the early 1980's was short-lived. The United States, which had always enjoyed a major share of the world coal trade market because it was considered a reliable source of high-quality coal, lost that status in 1984, as lower priced coal came into the market and new suppliers of coal emerged. Australia replaced the United States as the world's largest exporter.

The year 1982 was a pivotal one for United States coal exports. The previous upward trend in exports was reversed in 1982, with a decline of 6.2 million tons. After a sharp drop of 28.5 million tons in 1983 to about 78 million tons, United States coal exports increased to a level of 93 million tons by 1985 and then dropped again to about 80 million tons in 1987, substantially below the level at the start of the six-year period (Table 29).

World coal trade during the 1982 to 1987 period increased by about 83 million tons, from 292 million tons in 1982 to 375 million tons in 1987. The United States share of world coal trade declined from 36.4 percent in 1982 to 21.2 percent in 1987. The United States share declined in both the steam and metallurgical coal markets, by 15.0 and 14.5 percentage points, respectively.

TABLE 29

U. S. COAL EXPORTS, 1982-1987

Year	Steam Coal		Metallurgical Coal		Total Exports	
	Percent of World Total	Million Tons	Percent of World Total	Million Tons	Percent of World Total	Million Tons
1982	29.3	41.7	43.1	64.6	36.4	106.3
1983	19.8	27.8	34.7	50.0	27.3	77.8
1984	14.7	24.5	34.4	57.0	24.5	81.5
1985	16.9	32.4	33.7	60.3	25.0	92.7
1986	15.7	30.5	31.5	55.0	23.2	85.5
1987	14.3	27.9	28.6	51.7	21.2	79.6

Source: EIA Annual Outlook for U. S. Coal 1988

In 1982, United States coal exports decreased by 6.2 million tons to 106.3 million tons, while world coal trade increased slightly, by 3.6 million tons. As a result, the United States share of world coal trade decreased to 36.4 percent from the previous year's 39.0 percent. This decrease can be attributed to several factors including the re-entry of Poland into a weak European market. The slow rate of United States steam coal exports to Western Europe decreased by five million tons, but this drop was partially offset by increases of about 1.8 million tons to Canada and about 0.7 million tons to Asia (mostly to Taiwan). The turn-around in United States coal exports to Canada was attributed to a greater use of coal-fired power plants to offset a temporary shutdown of some nuclear-powered generating units.

United States exports of metallurgical coal to Western Europe declined by 3.5 million tons, and those to Asia increased by 0.3 million tons. The major importers of United States metallurgical coal were Japan, Canada, Brazil, and Italy, which together accounted for 53.2 percent of total United States metallurgical coal exports in 1987.

United States coal exporters continue to face severe competition for markets around the world. Despite the decline in the value of the United States dollar, United States coal is at a disadvantage on a delivered price basis. Because of fierce competition among coal-exporting countries, world coal prices have been forced to levels at which some United States producers cannot compete. Because of worldwide excess capacity, which arose from over ambitious mining investments in the past 10 years, the price of internationally traded coal will probably remain under pressure for the foreseeable future. In fact, the average price of United States export coal (free along-side ship, f.a.s.), with the exception of steam coal exported to South America, has decreased between 21 and 30 percent from 1983 to 1987 (Table 30).

Approximately 95 percent of United States coal exports are produced in Appalachia, with about 70 percent coming from Central and Southern Appalachia (Figure 13). Exports produced in Northern Appalachia were considerably higher in 1982 than 1987, declining to 18.6 million tons in 1987, while those from Central

TABLE 30

AVERAGE PRICE OF U. S. COAL EXPORTS BY DESTINATION 1982-1987

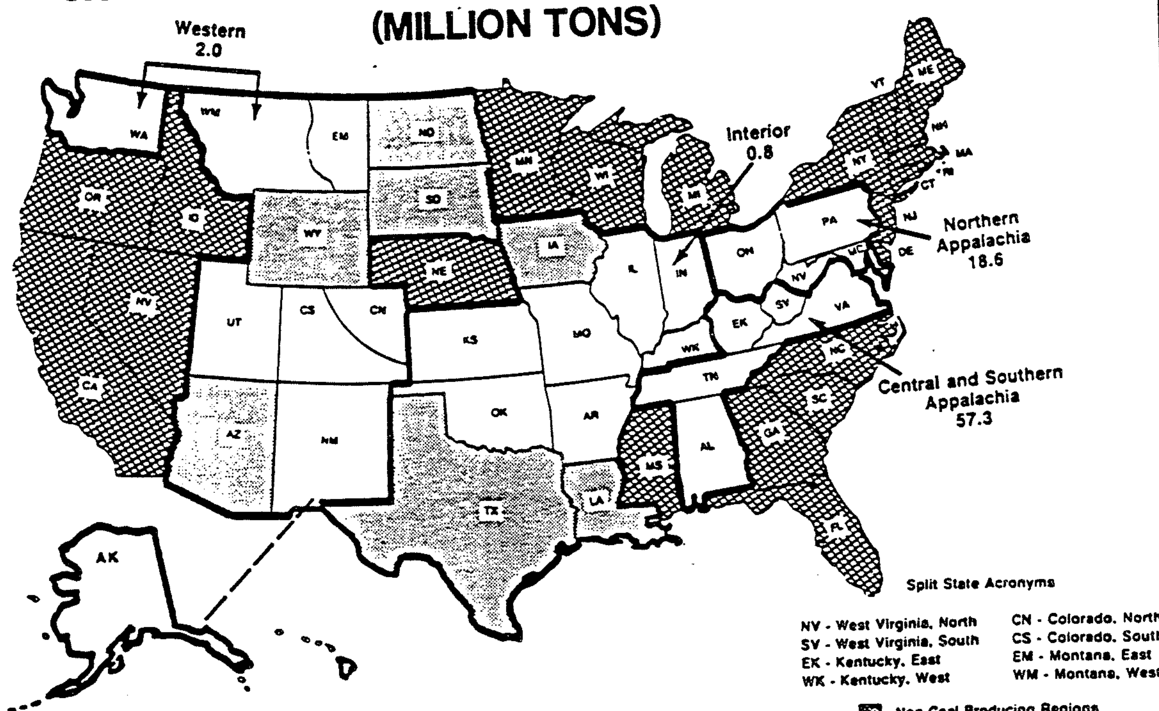
	1982		1985		1987	
Destination	Steam Coal	Metallurgical Coal	Steam Coal	Metallurgical Coal	Steam Coal	Metallurgical Coal
Canada	59.88	75.56	52.05	54.66	39.92	44.65
Western Europe	56.49	71.33	44.55	52.95	39.37	43.77
Asia	56.29	71.05	41.99	54.05	38.61	46.17
South America	90.71	75.55	57.95	53.29	59.79	43.94
Eastern Europe	54.65	60.51	52.84	49.52	-.-	42.70

Based on the free alongside ship (f.a.s.) value.
Source: Bureau of the Census

FIGURE 13

U.S. COAL EXPORTS BY PRODUCING REGION, 1987

(MILLION TONS)



SOURCE: ENERGY-INFORMATION ADMINISTRATION, FORM EIA-6 "COAL DISTRIBUTION REPORT"

and Southern Appalachia dropped by 13.2 million tons to 57.3 million tons. Exports from the Interior region declined over this time period by about two million tons, while those from the Western region decreased slightly, to about two million tons.

Although the United States is a high-cost supplier, largely due to high labor costs and transportation costs (from mine to port), it has always been the world's swing supplier because of its ability to ship large amounts of coal on short notice. During periods of oversupply, however, coal importers do not strive to diversify their sources of supply. As new suppliers enter the market with low-priced coal, it seems unlikely that the United States will regain its prominence in world coal trade unless shortages from other suppliers occur. The potential for growth in United States coal exports, which looked optimistic in the early 1980's, has not been realized.

The Energy Information Agency (EIA) predicts that total exports (steam coal plus metallurgical coal) will rise slowly, reaching 91 million tons by the year 1995 and then remaining at that level through the year 2000. Due to increased competition from other coal-exporting countries, it is no longer expected that United States steam coal exports will keep pace with the expanding world steam coal market. United States steam coal exports are projected to rise to 34 million tons by 2000, six million tons above the 1987 level. Unlike the steam coal market, little growth is expected in the world metallurgical coal market. United States metallurgical coal exports are projected to maintain their current market share, rising to 56 million tons by the year 2000, compared with 52 million tons in 1987.

These projections for United States coal exports in the year 2000 are substantially below the EIA 1987 projections. The principal difference is that steam coal exports are now expected to reach only 34 million tons in 2000, compared with the EIA 1987 projection of 51 million tons. Although there was a slight reduction in the forecast for total world steam coal trade, most of the change in the forecast for United States exports is due to the emergence of China as a major exporter of steam coal to Asia and Venezuela as a supplier to Western Europe. These new exporters will add to the competition already provided by low-cost producers such as Australia, South Africa, and Colombia. China exported 12 million tons of coal in 1987. This represents a doubling of 1986 shipments. Colombia and China combined exported 23 million tons, compared to 16 million tons in 1986.

The current EIA projection for United States exports of steam coal corresponds closely to forecasts by Data Resources Inc. and Wharton Econometrics, who predict 37 and 36 million tons in the year 2000, respectively.

Kansas Export Potential

On the surface, it might appear that southeast Kansas coal could be competitive on the basis of f.a.s. price at lower Mississippi terminals. An f.o.b. mine price of \$20 per ton, combined with transportation cost of \$18.50 as computed in the previous section, leads to a total of \$38.50 per ton, compared to the average price of \$39.37 for United States steam coal exported to Europe in 1987 (Table 30). However, the sulfur content in Kansas coal will make it extremely difficult to market.

As noted in Figure 13, almost no coal is being exported from the Interior Producing Region. Although large quantities of coal are produced in Illinois, Indiana and Western Kentucky within easy reach of the low-cost river barge transportation system, these coals have been unsuccessful in the export market. Kansas coal would be less attractive in terms of both sulfur content and cost f.o.b. barge.

Outbound coal shipments on the McClellan-Kerr Waterway were 593,000 tons at the Oklahoma border in 1986. However, it is not known that any of this coal was shipped overseas. Most of it was destined for electric utilities in Florida.

The average sulfur content of United States steam coals imported by Japan is less than one percent. It is unlikely that Kansas coal can be exported in any significant quantity.

It has been proposed that it might be useful to use high-BTU Kansas coal to "top-off" rail cars of low-BTU western coal passing through the region. This would be a means of bringing up the average BTU level to meet a particular specification. Although this might be technically feasible, it would involve complex contract arrangements for the rail transport. If a customer desired such a blend, they would be more likely to accomplish the blending at the receiving site, where more control could be exercised.

COMPETITIVE ANALYSIS

MINING

A competitive cost analysis was carried out to show how the cost of production in Kansas compares to other areas. There are basically two comparisons of interest:

- Local competition with mines in Oklahoma and Missouri
- Competition for the Kansas utility market with mines in Wyoming

A third competitive area is the southern Illinois Basin, but no detailed comparisons were made for this area.

Kansas Coal Mining

In order to study the influence of various factors on the cost of coal production in Kansas, a simplified cost model was developed. Information obtained from active mines in Kansas, from generalized cost correlations in the literature, and from various other sources was used to estimate production costs for two hypothetical mines: one producing 300,000 tons per year and one producing 1,000,000 tons per year.

On an operating cost basis, there appeared to be little economy of scale in this size range. An inverse economy of scale factor arises because the small mine is not subject to the Kansas severance tax of $1 per ton, while the large mine must pay the tax. A simulated breakdown of costs is shown in Table 31. The largest single item is the cost of labor.

TABLE 31

ESTIMATED MAJOR EXPENSES FOR A 300,000 TON PER YEAR KANSAS MINE

Mining Machinery	$350,000
Other Equipment	10,000
Land Purchases and Leases	300,000
Royalties	350,000
Chemicals & Explosives	300,000
Fuel & Electricity	700,000
Finance & Insurance	500,000
Maintenance & Repair	900,000
Wages & Salaries	2,000,000
Reclamation	500,000

Costs quoted for reclamation vary widely because different companies assign different costs to reclamation versus mining. Reclamation costs are quoted from $3,000 to $15,000 per acre. The per-acre cost depends on whether it is calculated on the basis of actual acres disturbed, total acres in the permit area, etc. Actual costs depend on how much of the land is classified as prime farmland (48 inches of topsoil must be replaced), or wetlands (cannot be mined).

Using the cost model developed here, the mine-mouth cost of typical Kansas coal was calculated to be $20.38 per ton for the 300,000 ton per year mine and $20.21 for the 1,000,000 ton per year mine. These are operating costs only and do not include depreciation or return on initial investment.

Regional Comparisons

In competing for local markets in the Kansas, Missouri, Oklahoma area, Kansas coal mines appear to be on relatively even footing with those in adjoining states. Because labor is the largest cost item, productivity is an important measure of competitive position. As seen in Table 32, Kansas coal mines have had a higher average productivity than those in adjoining states. This is reflected in the average f.o.b. mine price for the coal, also shown in Table 32. The coal mining industry as a whole has made great strides in increasing productivity in recent years. According to Bureau of Labor Statistics data, the average worker productivity index for coal mining increased by 40 percent between 1982 and 1986, compared to an increase of less than 20 percent for all United States manufacturing industries. Only those coal mines which have participated in these productivity games are likely to remain competitive.

Mining conditions, reserves, coal properties, and reclamation requirements are similar in Kansas, Missouri and Oklahoma, so that no state has a particular ad-

TABLE 32

AVERAGE OUTPUT PER MAN-SHIFT AND F.O.B MINE PRICE, 1986

	Tons Per Man-Day	Dollars Per Ton
Arkansas	14.68	
Kansas	23.31	$25.65
Missouri	18.63	$29.67
Oklahoma	17.19	$28.23

Source: National Coal Association, Coal Data 1988 vantage. Missouri has the largest strippable reserves at 1,700 million tons, compared to 400 million in Kansas and 600 million in Oklahoma. Missouri does not place a severance tax on coal. Oklahoma has an advantage in that the average sulfur content of the strippable reserves is under three percent, compared to about four percent in Kansas and Missouri.

It may be concluded that the Kansas coal mining industry is competitive with the industry in adjoining states and should be able to win its fair share of local markets which can accept high-sulfur coal.

Comparison to Wyoming

In contrast to the productivity figures in Table 32, the average productivity for Wyoming in 1986 was 134 tons per man-day, and at the best mines it is now over 300 tons per man-day. Thick coal seams and low overburden to coal ratios provide unmatched mining conditions. In addition, the mines are non-union, and have adopted very efficient labor practices, such as 12-hour shifts. The average labor cost in a ton of Powder River Basin coal is less than $1.00, compared to over $6.00 indicated in Table 32 for Kansas.

Costs were computed for three cases in the Powder River Basin:

- A new five million ton per year mine
- A new 10 million ton per year mine
- Adding five million tons per year to an existing mine

A new 10 million ton per year mine is estimated to cost $137 million plus $34 million in pre-production stripping expense. Calculated mine-mouth prices for the three cases listed above are given in Table 33, where they are compared to the previously estimated costs for Kansas.

TABLE 33

COMPARISON OF F.O.B. MINE COAL COSTS

Powder River, New 5 MTPY Mine, 10% DCFROR	$8.97
Powder River, New 10 MTPY Mine, 10% DCFROR	$5.67
Powder River, Add 5 MTPY to Existing Mine, 0% DCFROR	$5.39
Kansas, 1 MTPY from Existing Mine, 0% DCFROR	$20.21
Kansas, 0.3 MTPY from Existing Mine, 0% DCFROR	$20.38

Note: Includes severance taxes

It is clear that coal from Wyoming's Powder River Basin is an awesome competitive force in any region to which the coal can be shipped with reasonable transportation costs. Existing mines in the Powder River Basin could increase output by several tens of millions of tons per year without having to open any new mines (Table 34). Coal prices at the Powder River Basin mines should be competitive for a long time to come. At this price, and with the lowest unit train freight rates in force, coal could be delivered to all the major power plants in Kansas for less than $1.00 per million BTU. Short-term contracts have been signed recently at prices of less than $4 per ton.

TRANSPORTATION

The key to competitiveness of Powder River Basin coals is the cost of railroad transport. Following the passage of the Staggers Rail Act of 1980, railroad coal hauling rates, in general, increased dramatically. Prior to the Staggers Act, railroads had been unable to increase their rates fast enough during the era of high inflation to achieve "revenue adequacy." More recently, however, contract rail rates have dropped for coal originated in Wyoming's Powder River Basin. The question remaining to be answered is whether these rail rates will again increase faster than the general rate of inflation in the future.

It is clear that if the definition of "revenue adequacy" in the Act is to be achieved, further large increases in rail rates are still to occur. However, adequacy targets built into the Act, although considered appropriate for the inflationary era in which the Act was passed, are unreasonably high for an era of lower inflation rates.

For established movements of particular products by railroad, rates can be obtained from the carrier in the area. Specific points of origin and destination are required. Information on contract rates, however, usually is not available. These rates vary depending on whether the railroad or the shipper owns the car, the interchanges required with other rail lines, the condition of specific sections of track and the allowable speed thereon, the state of congestion at any terminals involved, etc. Thus, specific estimates for a contract movement are complex and difficult to calculate, and are not freely provided by the railroads.

In general, railroad tariffs per ton-mile vary greatly for short hauls and decrease significantly (perhaps by a factor of three) as the length of haul increases to about 1,000 miles. Beyond 1,000 miles the rate per ton-mile usually remains constant.

Typical cost elements for a unit train contract are given in Table 35. Almost 80 percent of the total cost associated with unit trains is related to operating costs, which should generally rise with inflation. It costs 20 to 30 percent more to ship in railroad-owned cars than in customer-owned cars. Many shippers therefore purchase and maintain their own cars. Shipper-owned cars can be maintained by the owners, by the railroad, or by the car manufacturer, depending on the needs of the shipper. The engines are usually supplied by the railroads. If less than unit train quantities are shipped, single-car rates are about double unit train rates. Only small discounts are made for multi-car shipments.

The railroads have demonstrated an extreme sensitivity to the presence or absence of competitive modes of transportation. In the absence of shipping alternatives, "captive shippers" have been forced to accept large rate increases since

TABLE 34

POWDER RIVER BASIN PRODUCTION AND CAPACITY: 1984

Mine	Production (MTPY)	Capacity (MTPY)
Black Thunder	21.20	24.00
Coal Creek	1.80	8.00
Cordero	10.39	18.00
Jacobs Ranch	14.37	18.00
North Antelope	3.00	6.00
Dave Johnston	3.34	3.70
Antelope*		12.00
Keeline*		3.00
North Rochelle*		8.00
Rochelle		12.00
Belle Ayr	13.42	16.00
Caballo	8.16	12.00
Caballo Rojo	3.45	7.50
Big Horn	2.52	4.50
Buckskin	3.52	4.50
Clovis Point	1.56	4.50
Eagle Butte	13.40	15.00
Ft. Union	0.30	1.20
Rawhide	9.35	24.00
Wyodak	2.90	10.00
Dry Fork*		15.00
East Gillette*		12.30
Rocky Butte*		20.00
South Rawhide*		8.20
Total Powder River: Wyoming	112.68	267.40
Absaloka	3.62	9.00
Big Sky	3.95	4.60
Decker	10.30	16.00
Rosebud	11.96	15.00
Spring Creek	2.96	7.00
Total Powder River	145.47	319.00

*Planned mines expected to be in production soon. For these mines, capacity values shown are design rather than current.

Source: U. S. Bureau of Land Management, 1987

TABLE 35

UNIT TRAIN COST ANALYSIS

Category of Expense	Cost Per Carload ($)	Percentage Of Carload Cost
Clerical Expenses	12.93	
Clerical Claims	3.62	
Loss and Damage Claims	0.41	
Terminal--Train Supplies and Special Services	0.61	
Loop Track--Other Than Fuel and Locomotive Maintenance	0.77	
Yard Switching	8.29	
Other Road Switching	0.04	
Subtotal	26.67	2.4
Fuel Cost	406.85	(36.4)
Locomotive Maintenance	82.35	(7.4)
Maintenance of Way	209.62	(18.8)
Other--Gross Ton-Mile Expenses	12.49	
Other--Locomotive Expenses	22.40	
Train Mile--Other Than Wages	35.39	
Train Supplies and Expenses--Running	13.52	
Train Crew Wages	165.02	(14.8)
Helper Services	2.85	
Subtotal	950.49	85.1
Car Inspection	18.34	
Car Repairs--User Responsibility	11.18	
Railroad Car Ownership	4.03	
Locomotive Ownership	66.19	
Caboose Ownership	0.59	
Other Equipment Ownership	4.17	
Road Property Ownership	33.51	
Property Other Than Road Ownership	1.54	
Subtotal	139.55	12.5
TOTAL	1,116.71	100

Source: Restated from decision of Administrative Law Judge in Docket No. 38738. Western Farmers Electric Cooperative versus Burlington Northern Railroad Co. (Nov. 16, 1982).

deregulation. Only the presence of competition, either from other railroads or other modes of transport, provides an effective bargaining tool. This was illustrated clearly when in 1984, the C&NW began service to the southern part of the Powder River Basin, providing origin service competition to mines in this region. Railroad rates for hauling coal from the southern Powder River Basin fell substantially following the entry of the C&NW into that market. In September 1983 Arkansas Power & Light Company signed a contract providing significantly lower coal-hauling rates for moving coal from the southern Powder River Basin by virtue of the competition afforded by the C&NW's entry into the market. The utility estimated that savings in electricity generation cost of $1.65 billion through the year 2016 would result from the more favorable terms.

These factors suggest that service by only one railroad in the Powder River Basin led to higher rates than would have been possible in more competitive circumstances.

In view of these factors, the Office of Minerals Policy Analysis and Program Coordination of the Bureau of Land Management undertook a study of the relationship between the federal coal program and the development of western coal and rail transportation rates.

Their analysis of the change in rail rates relative to variable cost for different areas of the Powder River Basin indicates that the heightened competition for coal hauling opportunities has significantly reduced the rates charged for shipping coal from the southern Powder River Basin, largely through reduced rail carrier margins. Between 1984 and 1985, the first year of origin competition, rail rates relative to variable cost--an indicator of railroad profit margin--declined almost 10 percent in the southern part of the basin. Contract rates paid by shippers (weighted by shipment tonnage) declined almost 20 percent before the end of the first year of service by C&NW. Rate reductions as high as $7 per ton were not unusual.

Coincident with the introduction of origin rail competition, consumers have increased their purchases of coal from the southern part of the Powder River Basin; this suggests that the origin competition caused increased production of coal. Therefore future increases in coal purchases from the Powder River Basin are likely as the effect of origin rail competition strengthens through additional transportation contract negotiations and the extension of dual railroad service to additional mines in the Powder River Basin.

The Bureau of Land Management concludes that the combination of increasingly competitively priced transportation services and low production cost for Powder River Basin coal will tend to restrict transportation market power in setting rates for the movement of coal from other western coal regions. Therefore the direct origin competition for coal movements originating in the Powder River Basin has the potential to intensify competitive pressure on coal production in other western coal basins.

In general, competition tends to drive prices down to the level of costs (including an adequate return on invested capital). Effective competition in the hauling of western coal can reduce rates relative to costs. It also tends to foster improvements in productivity that reduce costs.

We conclude that the establishment of effective competition for the transport of Powder River Basin coal has caused a permanent lowering of railroad rates. Rate increases in the future will be limited to inflationary factors.

Recent unit train freight rates for delivery to regional power plants are shown in Table 36. The range is from less than one cent per ton-mile to slightly over three cents. The very lowest rates are possible when only one railroad is involved. It is obvious that contract rates vary widely even for hauls of the same distance. In order to assess the general competitive situation, a table of comparative freight costs was constructed (Table 37) showing relative freight costs from a Wyoming location and a Kansas location to each of the power plant locations. Assumed freight rates are 1.75 cents per ton-mile from Wyoming under a large-volume unit train contract and 4.0 cents per ton-mile in Kansas under small-volume multiple car movements. This type of comparison would show whether Kansas coal could be competitive enough to qualify under a mandatory 10 percent blending law which requires the coal to be available at no more than the long-term contract cost from Wyoming. In addition it is assumed that the Kansas mine does not have rail loading facilities at the mine, and incurs a cost of $3.50 per ton for trucking to and loading on the railroad.

Total delivered costs are compared in Table 38. The Wyoming mine was assumed to be a new five million ton per year mine, earning full return on investment as per Table 33. The Kansas mine was assumed to be covering operating costs as per Table 33 plus depreciation, profit, and taxes at $25 per ton.

It is clear from Table 38, under the assumptions used, that the competitive radius for Kansas coal is limited to the eastern part of the state. It should be possible to supply Kansas coal to the LaCygne plant at a lower cost than from Wyoming. For plants in Kansas City, Lawrence, and Tecumseh the competition could be close. Moving westward, Wyoming coal quickly gains an advantage. Kansas coal will never be competitive at Holcomb, and will have difficulty at Jeffrey.

TABLE 36

RAILROAD FREIGHT RATES TO REGIONAL POWER PLANTS

Movement	Year	Miles	Cents/ Ton Mile	Carrier
Wyoming to Nebraska City, NE	1988	703	0.92	BN
Wyoming to Gerald Gentleman, NE	1988	437	2.09	BN
Colorado to Labadie, MO	1987	1,227	2.04	DRGW & MP
Wyoming to White Bluff, AR	1987	na	1.69	C & NW
Wyoming to Muskogee,OK	1987	na	1.65	C & NW
Wyoming to Muskogee, OK	1987	na	1.63	C & NW
Wyoming to Sooner, OK	1987	na	1.69	C & NW
Wyoming to Sooner, OK	1987	na	1.54	C & NW
Wyoming to Northeastern, OK	1987	na	1.72	BN
Wyoming to Northeastern, OK	1987	na	1.67	BN
Wyoming to Iatan, MO	1987	na	1.82	BN
Wyoming to LaCygne, KS	1987	873	1.76	BN & KCS
Wyoming to LaCygne, KS	1987	866	1.78	BN & KCS
Wyoming to Jeffrey, KS	1987	693	1.51	BN
Wyoming to Nearman, KS	1987	782	2.11	BN & MP
Wyoming to Lawrence, KS	1987	810	2.31	UP & ATSF
Wyoming to Lawrence, KS	1987	810	2.33	UP & ATSF
Wyoming to Lawrence, KS	1987	810	2.40	UP & ATSF
Wyoming to Lawrence, KS	1987	810	3.32	UP & ATSF
Wyoming to Tecumseh, KS	1987	833	2.31	UP & ATSF
Wyoming to Tecumseh, KS	1987	833	2.33	UP & ATSF
Wyoming to Tecumseh, KS	1987	833	2.40	UP & ATSF
Wyoming to Tecumseh, KS	1987	833	3.32	UP & ATSF
Wyoming to Holcomb, KS	1987	781	2.19	BN & ATSF
Wyoming to Holcomb, KS	1987	775	2.20	BN & ATSF
Wyoming to Iatan, MO	1986	na	1.84	BN
Wyoming to Sooner, OK	1986	na	1.71	C & NW
Wyoming to Sooner, OK	1986	na	1.55	C & NW
Wyoming to Jeffrey, KS	1986	693	1.51	BN
Wyoming to Jeffrey, KS	1986	715	2.70	UP
Wyoming to Nearman, KS	1986	782	2.01	BN
Illinois to Kaw, KS	1986	421	3.11	ICG
Illinois to Kaw, KS	1986	421	3.29	ICG
Illinois to Quindaro, KS	1986	421	2.96	ICG & MP
Illinois to Quindaro, KS	1986	421	3.02	ICG & MP
Wyoming to Holcomb, KS	1986	781	2.21	BN & ATSF
Wyoming to Holcomb, KS	1986	775	2.23	BN & ATSF
Wyoming to Holcomb, KS	1986	692	2.47	BN & ATSF
Wyoming to Kansas City, KS	1985	830	0.80	BN
Wyoming to Kansas City, KS	1985	784	0.94	C & NW/UP
Wyoming to Kansas City, KS	1985	908	0.93	UP
Wyoming to Kansas City, KS	1985	994	1.19	D & RGW
Wyoming to Kansas City, KS	1985	1,165	1.17	D & RGW
Wyoming to Kansas City, KS	1985	1,180	1.01	ATSF
Wyoming to Kansas City, KS	1985	839	1.02	ATSF

Source: Various Newsletters and Government Reports

TABLE 37

COMPARATIVE TRANSPORT CHARGES FOR WYOMING AND KANSAS COALS

Plant	Rail Miles Wyoming	Rail Miles Kansas	Freight Wyoming $/Ton	Freight Kansas $/Ton
Lawrence	750	150	13.12	9.50
Nearman	780	140	13.65	9.10
Tecumseh	730	170	12.77	10.30
Holcomb	780	390	13.65	19.10
Jeffrey	700	200	12.25	11.50
LaCygne	870	70	15.22	6.30

TABLE 38

COMPARATIVE LONG-TERM DELIVERED COSTS FOR WYOMING AND KANSAS COALS

Plant	Wyoming Freight $/MMBTU	Wyoming Total $/MMBTU	Kansas Freight $/MMTBU	Kansas Total $/MMBTU
Lawrence	0.78	1.31	0.38	1.34
Nearman	0.81	1.34	0.36	1.32
Tecumseh	0.76	1.29	0.41	1.37
Holcomb	0.81	1.34	0.76	1.72
Jeffrey	0.73	1.26	0.46	1.42
LaCygne	0.91	1.44	0.25	1.21

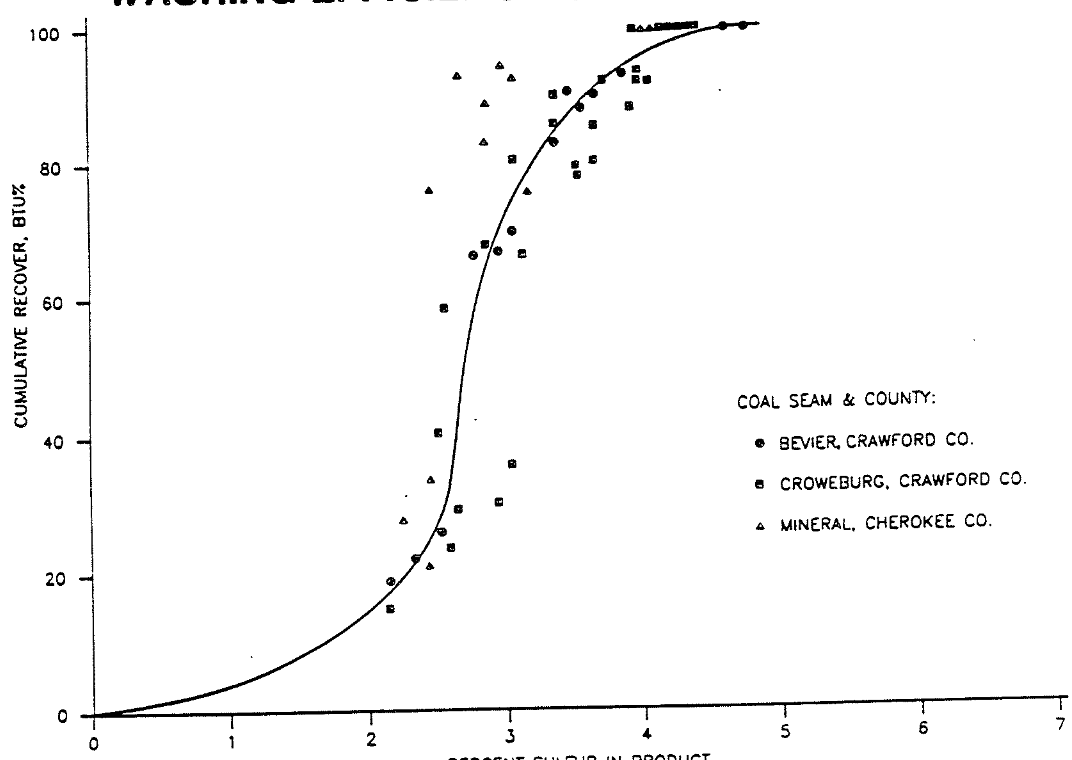
SULFUR

A competitive delivered price is not sufficient to make a sale if the sulfur content of coal is unacceptable, and this is the problem for Kansas coal in most applications. The number of facilities which can burn Kansas coal without flue gas desulfurization dwindles steadily as old plants are retired and as environmental standards are tightened. Users with borderline capability for high-sulfur coal will prefer Oklahoma coal over Kansas coal because of its lower sulfur content.

The only way to reduce the sulfur handicap for Kansas coal would be to find an inexpensive technique for sulfur removal. The washability of several samples of Kansas coal is shown in Figure 14. One sample from the Mineral bed in Cherokee County showed unusually good response, with an indicated recovery of over 90 percent at 2.8 percent sulfur. However, this sulfur level is still too high to be able to compete with many Oklahoma and Illinois coals.

FIGURE 14

WASHING EFFICIENCY OF KANSAS COAL



SOURCE: USBM RI-8118

INTERFUEL COMPETITION

In addition to competing with coals from other states, Kansas coal must hold its own against other fuels available within the state. At the utility power plant level, coal is probably secure in its domination of the base-load fuel market. Costs of coal, oil and gas delivered to electric utility plants in Kansas are shown in Table 39. Oil is clearly not in the competitive range. Even though world oil prices in October 1988 have dropped to two-year record lows of less than $14 per barrel, this is still over $2.00 per million BTU and should not pose a threat to the utility coal market in Kansas. In areas with higher cost coal, oil may again begin to displace some coal, creating an overall depressing effect on the spot coal market.

Natural gas in Kansas was cheaper than coal in 1975 and 1976. At current prices it will not displace coal as a base-load fuel. The American Gas Association has released an issues briefing, Natural Gas Production Capability 1988-1990, that projects the natural gas supply surplus (the gas "bubble") to be 1.5 trillion cubic feet in 1988. For full year 1989 the bubble is estimated to be about 600 billion cubic feet (annualized estimate) and the bubble will be essentially zero by 1990 (full year estimate) (see Figure 15). At that time gas supplies and requirements on a national average basis will be in approximate balance.

Two factors will cause the bubble to shrink: (1) declining domestic production capability due to reduced drilling (the product of low energy prices and shut-in gas production); and (2) higher gas demand due to lower natural gas prices and increased gas market share. By 1989, the bubble will have shrunk enough to

TABLE 39

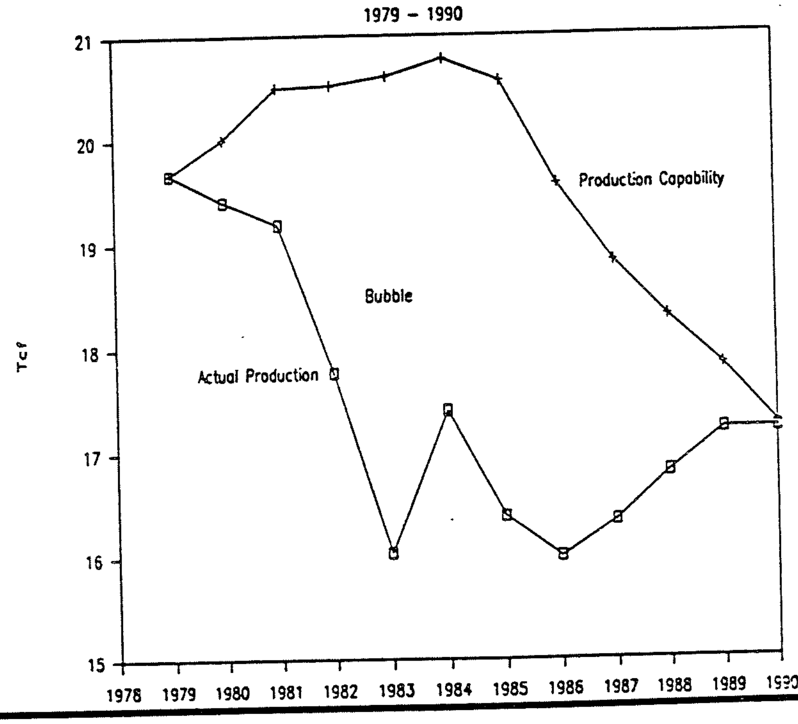
DELIVERED COST OF FUELS TO ELECTRIC UTILITY PLANTS IN KANSAS 1975-1987
(Cents Per Million BTU)

	Coal	Oil	Gas
1975	67.1	173.5	47.9
1976	74.2	168.4	71.3
1977	74.9	214.5	101.2
1978	89.8	198.8	121.6
1979	99.4	237.7	144.0
1980	107.1	529.6	177.8
1981	118.4	711.7	219.4
1982	134.1	423.1	248.4
1983	141.9	516.5	295.4
1984	150.4	559.5	322.1
1985	140.1	554.8	288.4
1986	131.9	335.7	205.0
1987	126.7	387.0	217.5

Source: DOE/EIA-0191, Cost & Quantity of Fuels for Electric Utility Plants, 1975-1987

FIGURE 15

NATURAL GAS PRODUCTION AND PRODUCTION CAPABILITY



spur drilling activity which will, after 1990, reverse the decline in production capability.

The conclusion to be reached is that gas prices are likely to increase in the near future until such time as they become competitive with either: (1) petroleum; or (2) the cost of production from new wells. In either case, gas should not displace coal as a base-load fuel in existing power plants. Due to much lower capital costs, however, gas-fired combined cycle units are likely to be preferred for small to medium (100 megawatt) additions to generating capacity. Gas-fired plants are estimated to cost $600 to $700 per kilowatt versus $1,200 to $1,500 for coal-burning plants.

As noted in the earlier section on the commercial and residential fuel market, high capital and operating costs make coal systems noncompetitive in this sector of the energy market. This situation is not likely to change in the foreseeable future.

It is in the industrial fuel market that real interfuel competition exists. In cement plants, the major competitor is petroleum coke. When oil prices and coke demand are down, coal will lose market share. This is a cyclic occurrence which will continue in the future.

Natural gas prices in Kansas are low enough that some substitution of gas for coal in the industrial sector is occurring. The refinery at Coffeyville is burning some gas in place of coal. However, we believe that gas prices relative to coal will begin to increase in 1989, removing some of this competitive pressure. For new industrial or large business park facilities, the capital cost difference will continue to favor natural gas until prices have increased substantially.

THE OUTLOOK FOR KANSAS COAL

Preceding sections have outlined the markets for Kansas coal in the electric utility, industrial, commercial and residential sectors of the energy market. It is clear from that discussion that Kansas coal will find it very difficult to compete for the utility power plant market outside the immediate southeast Kansas area. Low-cost, low-sulfur coal from Wyoming, moving at low-cost unit train freight rates will be in abundant supply for the foreseeable future.

For smaller users, who do not qualify for unit train freight rates, Kansas coal can be a competitive fuel provided the high sulfur content is acceptable. However, the sulfur problem is serious and getting more severe all the time.

THE LACYGNE PLANT/MIDWAY MINE SITUATION

The LaCygne Unit No. 1 operated by Kansas City Power and Light (KCP&L) is the largest single consumer of Kansas-mined coal. However, the Midway Mine operated by Pittsburg and Midway Coal Mining Company (P&M) was shut down on March 28th after KCP&L requested that P&M reduce the rate of delivery under the contract, which P&M refused, and KCP&L subsequently refused to accept any more coal for the time being. A petition for declaratory judgment was filed by KCP&L to reduce the amount of coal required to be purchased under the minimum obligations of the contract. These minimum obligations are 1.63 million tons per year, reducing to 1.34 million tons per year in 1996 and 1.26 million tons per year in 1997.

The original coal specifications in the contract called for a maximum of 4.5 percent sulfur and 20.7 percent ash. The flue gas desulfurization scrubber at LaCygne No. 1 was designed to this specification. Because the coal quality in the reserves dedicated to the plant turned out to be worse than expected, the original 1968 agreement was amended in 1977 to allow up to 5.5 percent sulfur and 28.0 percent ash. At that time, KCP&L had been told by the Kansas Department of Health & Environment (KDHE) that the LaCygne No. 1 was "grandfathered" and not subject to a specific sulfur dioxide emission limit. In 1981, however, KDHE amended its regulations to remove the exemption clause which applied to LaCygne No. 1.

In 1987, new continuous emission monitoring requirements were imposed, with hourly results to be reported starting November 1, 1988. Tests at the LaCygne No. 1 stack revealed that it was exceeding the sulfur dioxide emission limit of 3.0 pounds per million BTU. The reason for the exceedance would appear to be a combination of higher sulfur and ash than the scrubber was designed for (the scrubber removes fly ash as well as SO_2, and the ash is recirculated in the scrubber solution) coupled with a failure to meet original design performance.

In spite of the large amount of effort devoted to the problem, KCP&L has been unable to bring the scrubber efficiency up to the level needed. This scrubber is a first-generation design, one of the earliest installed in the United States. It has become an "orphan" in that the manufacturer is no longer providing technical support.

In order to bring the plant into legal compliance, KCP&L has started blending Illinois coal which has a lower sulfur content than the Midway coal. However, the Illinois coal is not a low-sulfur coal, and a large fraction must be blended in to achieve the desired sulfur reduction by blending alone.

Preliminary indications are that coal deliveries from the Midway Mine might have to be held to 900,000 tons per year or less under the blending arrangement.

Other possible solutions include: a modification or replacement of the scrubber to improve its performance; building a washing plant to reduce the sulfur level in the run-of-mine coal; using a lower-sulfur blending coal than the Illinois coal (would have to have suitable ash fusion temperature and ash level for the slagging cyclone burners).

If the Midway mine take is reduced to 900,000 tons per year, this will represent a loss of 700,000 tons per year. Assuming a 60/40 Kansas/Missouri split, the result will be a long-term loss of 540,00 tons per year in Kansas. This is a larger amount that is likely to be added by a mandatory burn law or any other action which could be taken to stimulate the Kansas coal market. Although the final outcome is unpredictable at this point, it seems most likely that the production cut will occur. There are no known solutions to the scrubber performance, and adding a washing plant would increase the cost of coal significantly because of the amount which would be rejected.

THE EMPIRE DISTRICT SITUATION

In 1987 the United States Environmental Protection Agency District 7 ruled that the Riverton plant was subject to a sulfur dioxide limitation of 3.0 pounds per million BTU. The plant then began burning a mixture of Kansas coal and northeast Oklahoma coal. However, they found some violations of the stack limit. Subsequently they are burning a 50/50 mixture of Wyoming coal and Kansas coal. This mixture should give them a stack concentration of less than 3.0 pounds of SO_2 per million BTU. Although they are under no requirement to reduce emissions below this level, Empire has made a tentative policy decision to not exceed 2.0 pounds per million BTU. The Wyoming coal they have been buying from Peabody's Rochelle Mine is costing less, delivered to the plant, than the local coals, so there is no economic incentive to stay at a higher sulfur level. Some Kansas-type coal would be necessary to keep the heat rate up and also avoid problems with the precipitator. The Rochelle coal has only about 0.25 percent sulfur, but even so, a stack limit of 2.0 pounds of SO_2 per million BTU means that the maximum amount of a 3.0 percent sulfur Kansas coal that could be burned would be 35 percent, on a BTU basis. To continue to run a 50/50 blend, the Kansas coal would have to be less than 2.2 percent sulfur.

It may be concluded that the potential market for Kansas coal at the Riverton plant has been permanently reduced to no more than 50 percent and perhaps no more than 35 percent of the total.

In 1987, Kansas supplied Riverton with 144,000 tons out of 211,000 total. The future potential will be reduced to 70,000 to 105,000 tons per year.

Empire's Asbury plant, just across the border in Missouri, is a potential market for Kansas coal in the future. This plant is effectively unlimited with respect to sulfur dioxide in the stack (12.0 pounds per million BTU). It has been supplied with most of its coal requirements from a nearby mine under a 20 year contract which expires in 1989. Empire plans to start blending Wyoming coal at Asbury on a 50/50 basis, the same as at Riverton. The other 50 percent of the requirement for the 200 megawatt plant will be open for competition between Missouri, Kansas and Oklahoma suppliers. In 1987 Asbury received 450,000 tons of coal from Missouri and 185,000 tons from Kansas. If Kansas producers could capture the entire 50 percent share for local coal, this would be an increase of 132,000 tons per year.

THE ACID RAIN SITUATION

The Clean Air Act, as amended in 1977, set December 31, 1987, as the deadline for United States cities to reduce ozone levels to a standard set by the Environmental Protection Agency (EPA). With more than 60 cities failing to meet the deadline, the stage was set for a comprehensive review of the Clean Air Act. That, plus continued pressure from Canada and northeastern states over the acid rain problem has resulted in major attempts to push acid rain legislation through Congress in 1988. With both George Bush and Michael Dukakis having issued position statements in support of acid rain legislation, any bill passed by Congress is likely to be signed into law.

Until both houses of Congress agree on a single bill, it is only possible to speculate on the eventual outcome. However, as of October 1, 1988, the bill which was receiving the most attention is Senate 1894, the "Mitchell" bill. There were indications that Senate Majority Leader Byrd would agree to allow a compromise version of the bill to reach the Senate floor for a vote. Instead on October 4, Senator Mitchell acknowledged there would be no legislation this year.

As originally introduced, Senate bill 1894 covers ozone, carbon monoxide, acid rain and other air pollution issues. The proposal would extend the ozone attainment deadline three, five, ten or fifteen years, depending on the severity of the pollution problem. (Only Houston and Los Angeles might qualify for the 15-year extension.) To be eligible for an extension, a state would have to submit a new implementation plan that includes a requirement for the most stringent available pollution controls for new and modified major sources, regardless of cost. In addition, the states would have to require retrofit controls (controls unavailable at the time the equipment was manufactured) for existing sources of hydrocarbons and nitrogen oxides; controls on small sources, such as dry cleaners and metalworking shops; stringent annual vehicle inspection and maintenance programs; "Stage II" double-hose systems at gasoline pumps to capture refueling vapors; phased-in use of alcohol and natural gas for certain business vehicle fleets; and any other measures necessary to meet the new deadlines.

To qualify for a three-year extension, an area would have to impose most, but not all, of these controls. To qualify for a five-year extension, an area would have to impose all of them. To qualify for a longer extension, an area would have to impose all of them plus additional emission controls and transportation measures, such as gasoline rationing, road user charges, pools, parking surcharges, vehicle-restricted periods, high-occupancy-vehicle restrictions on commuter routes, alternate driving days, area-wide ride sharing, public transit improvements, mandatory employer-participation in such programs as staggered working hours and compressed work weeks, controls on fleet-vehicle operations, and others.

For acid rain, the bill would require a three-phase reduction in sulfur dioxide emissions, culminating in a 12 million ton reduction by the year 2000, along with a four million ton reduction in nitrogen oxide emissions. In addition, all states must achieve stringent SO_2 emission limits and impose new source technology on all forty-year old plants.

On July 13, Senator Mitchell and 27 other senators unveiled an "Acid Rain Compromise" in an effort to move Senate 1894 onto the floor for action. The compromise involved a 10 million ton reduction in SO_2 instead of the 12 million originally called for, and a three million ton reduction in NO_x over a 12 year period (phased for 1994 and 2000). The utility industry says that changing the required SO_2 reduction from 12 to 10 million tons will cut the costs in half. A 50 percent federal subsidy for capital costs associated with the required emission reductions is to be funded by a fee on electricity generation and based on each state's annual average SO_2 emission rate (but exempting nuclear, hydroelectric, and scrubbed generation) and is to be used to limit residential rate increases to no more than 10 percent. The plan is also expected to increase funding for Clean Coal Technologies above the existing $2.5 billion program level, provide for a job protection program including enhanced unemployment benefits, re-education, relocation and retraining of coal miners and to exempt states that have enacted acid rain laws from the bill's emission reduction and fee requirements.

Senator Mitchell also agreed to eliminate a provision in Senate 1894 requiring 40-year-old power plants to retrofit expensive emission control equipment in order to meet NSPS standards; this concession could save utilities as much as $2 billion by allowing the 40-year-old plant to keep running as is.

Under the electricity tax customers would pay according to how cleanly their particular utility burns its fuel. This was a key provision intended to reward those utilities and states that have already taken steps to reduce their SO_2 and other emissions.

The new timetable for reducing SO_2 emissions would require 4.5 million tons of reductions by 1994, with the remaining 5.5 million tons to be reduced by 2000.

Earlier proposals by Governors Cuomo of New York and Celeste of Ohio and introduced as HR 5032 called for a similar 10 million ton reduction of SO_2 and a three million ton reduction of NO_x but over a 15 year period (phased for 1993, 1998 and 2003). Their proposal also provides funds to states to make grants or low interest loans to help defray up to 50 percent of the capital costs of technological systems of continuous emission reduction including repowering. Funds are to be derived from a tax on the petroleum industry.

The House acid rain bill, HR 2666, requires a two-phase SO_2 emission reduction, with an ultimate goal of 10 million tons by 1997. It achieves this through statewide average emission rate requirements for 1993 and 1997. Nitrogen oxide reductions are mandated through a stringent emission rate effective in 1997 as well. The bill also imposes a nationwide tax on electricity of 0.5 mills per kilowatt-hour, in order to subsidize the emission reductions.

To sum up, some sort of acid rain legislation appears inevitable when Senator Byrd steps down as Majority Leader next year, with the best bet at present on a mandated reduction of 10 million tons of sulfur dioxide per year. This will be achieved by requiring all utility boilers less than 40 years old to comply with New Source Performance Standards. A tax on electricity would be enacted to help defray the capital costs involved in achieving the reductions.

For most Kansas utilities, it seems likely that fuel switching will be the easiest route to compliance with any acid rain legislation, and that a 50 percent grant for the capital cost of scrubbers will be ineffective. The Empire Riverton plant would go to using as much Wyoming coal as needed, and cut boiler output if necessary.

The Board of Public Utilities would probably put the Kaw station back on natural gas because the cyclone burner would not work well with Powder River Basin coal. At Quindaro, they would probably convert to Wyoming coal and take a capacity loss.

The Lawrence and Tecumseh stations of Kansas Power and Light are already slated to start taking some Powder River coal in 1991.

The station facing the most difficult problem is Kansas City Power and Light's LaCygne No. 1. The actions they have taken to date in trying to renegotiate the Midway Mine contract and bringing in Illinois coal are only stopgap measures.

If the acid rain bill passes, they will have to do something entirely different. That could include trying to get enough Wyoming coal to work in the LaCygne cyclone burners so that the scrubber effluent would be below 1.2 pounds of SO_2. That would require at least a 50:50 mixture. If this approach is not technically feasible, then a rebuild or replacement of the scrubber system could be the only solution. This, of course, is the one solution which would result in the continued use of a large amount of Kansas coal.

CLEAN COAL TECHNOLOGY ASSESSMENT

Because one of the biggest marketing problems for Kansas coal is its sulfur content, the status of "Clean Coal Technology" was reviewed. The term "Clean Coal Technology" covers a wide range of techniques being developed to make coal a more environmentally acceptable fuel. It includes methods of removing ash and sulfur prior to combustion, methods of clean burning, methods of improving combustion efficiency, methods of removing sulfur oxides, nitrogen oxides and ash from stack gases, etc.

A national Clean Coal Technology program was begun with the appropriation of $400 million dollars of federal cost-sharing funding in 1986. In 1987 President Reagan announced an expanded program, to involve $2.5 billion in federal funds over a period of five years. A solicitation for Round 2 proposals was then issued in February 1988, with an appropriation of $536 million. In September, 1988, the president signed an appropriations bill that allocates $575 million for a third solicitation in fiscal year 1990.

FIRST ROUND SUMMARY

A summary of the 51 proposals received in Round 1 is given in Table 40. Of these, eleven were eventually awarded funding, including: The American Electric Power Service Corporation's project at the currently idle Tidd Facility. It involves installing a pressurized fluidized bed combustion unit, with the capability to remove 90 to 95 percent of sulfur dioxide from coal combustion gases before they leave the boiler. The technology is also expected to increase the plant/s power output and reduce nitrogen emissions. The project is expected to cost $167.6 million.

The Coal Tech project at the Keeler Boiler Manufacturing Company will replace a standard oil burner with a newly-designed coal combustor. The innovative combustor will be attached to the outside of a boiler and is designed to remove ash and other impurities before they can build up in the boiler. Sulfur will be captured inside the combustor, and nitrogen oxides will be reduced also. Total cost of Coal Tech's 25-month project is estimated at $785,984.

Babcock & Wilcox's demonstration project will be conducted on a commercial-scale 105 megawatt, coal-fired boiler installing the LIMB (Limestone Injection Multistage Burner). An EPA-sponsored test will be run using one coal and sorbent combination. Funding from the Clean Coal Technology program will then be used to extend the tests using three additional coals and four additional sorbents.

The Clean Coal effort will also add a new Coolside sorbent injection system to the commercial-scale facility. Until now, the Coolside process has been tested only at the 0.1-megawatt and 1-megawatt scale. The project is expected to cost $19.4 million, not including the EPA-funded portion.

Ohio-Ontario Clean Fuels Inc. will construct a prototype commercial plant that will coprocess coal and residual petroleum to produce clean liquid fuels. The plant, to be located in Warren, Ohio, will blend 800 tons per day of coal with residual oil. The project will cost $225.7 million.

TABLE 40

PROPOSALS SUBMITTED IN ROUND 1 OF CLEAN COAL TECHNOLOGIES PROGRAM

Technology	No. Proposals	Sponsors
Gasification		
IGCC	4	Consolidation Coal Company and Foster Wheeler; M.W. Kellogg Company; General Electric Company*; Calderon Energy Company*
Fuel Cell	3	ZTEK Corporation; PPG Industries, Inc.; Westinghouse Electric Corporation
UCG	1	Energy International, Inc.
Other	4	Dravo Wellman Company*; Sanitech, Inc.*; Questar Synfuels Corporation; TVA*
Liquefaction	2	Ohio Ontario Clean Fuels, Inc.*; ChemCoal Associates*
Fluidized Bed	9	American Electric Power Service Corporation*; Tallahasse (Florida) Electric Department; University of Cincinnati*; Wisconsin Electric Power Company*; Energotechnology Corporation; Colorado-Ute Electric Association; University of Missouri; Southwestern Public Service Company; Community Central Energy Corporation
In-Bed Sulfur Capture	2	Babcock & Wilcox Company*; Energy and Environmental Research Corporation*
Flue Gas Desulfurization	3	NOXSO Corporation*; Recovery Systems, Ltd.; TVA*
Coal Cleaning	6	Stirling Energies, Inc.; Combustion Engineering, Inc.; Western Energy Company; Community Central Energy Corporation; Atlantic Research Corporation; McDonnell Douglas Energy Systems, Inc.
Coal Refuse Recovery	4	American Minerals Inc.; North Marion Development, Inc.; Coal Technology Corporation; United Coal Company
Iron Smelting	3	Minnesota Department of Natural Resources; Pennsylvania Coke Technology, Inc.; Weirton Steel Corporation
Other	5	Cleveland Electric Illuminating Company (compressed air storage); Dow Corning Corporation (silica ore reduction); University of Florida (coal-water slurry); Coal Technology Corporation (cyclone combustor); TRW Inc. (slagging combustor)
Not Publicly Released	5	Chemion Corporation; The National Lime Association; FMC Corporation; Elgin-Butler Brick Company; Charwill Corporation

*Projects that also applied for assistance in Ohio's Clean Coal Program

The project to be pursued by Energy International Inc. will convert steeply dipping seams of underground coal into a gas which, when piped to the surface and cleaned, will be used to manufacture ammonia and urea fertilizer.

M. W. Kellogg proposed a demonstration project--termed the Appalachian Project--that will link a coal gasifier, hot gas cleanup system, and gas turbine.

Steam generated from the turbine exhaust will be fed to a steam turbine and used to generate electricity in a combined cycle configuration.

The State of Minnesota's Department of Natural Resources proposes to demonstrate an advanced iron-making process. Based on a two-component system which incorporates techniques drawn from coal gasification technology, the Minnesota project would be located at the USX Corporation (formerly U.S. Steel) taconite processing plant at Mt. Iron, Minnesota.

The Colorado-Ute proposal is for federal cost-sharing for operating a utility-size circulating fluidized bed combustion boiler at its Nucla Station in southwestern Colorado. The technology is capable of burning a wide range of coals while removing potential pollutants inside the boiler. The demonstration plant has been constructed and the federal funds will be used to support several demonstration test runs.

Consolidation Coal Company teamed with Foster Wheeler Development Corporation to propose a coal gasification-combined cycle power plant that would be located in Morgantown, West Virginia. The plant would be designed to convert 500 tons per day of high sulfur coal into electric power, using both gas and steam turbines. Steam from the plant would also be routed to several buildings laboratories on the West Virginia University campus. The proposed plant would be based on the U-Gas coal gasification process.

TRW's proposal would be to demonstrate an advanced coal combustor that could be attached to existing coal, oil and, perhaps, gas-designed boilers. The slagging combustor technology is similar to a unit currently being developed for commercial sale by TRW. The proposed demonstration effort will add several techniques designed to remove potential sulfur pollutants. Limestone, which acts as a sulfur absorber, would be injected into the combustion gases before they are sent into the boiler. In addition, a sulfur capture device, a spray dryer, could be installed in conjunction with the combustor to remove additional sulfur, permitting the technology to meet New Source Performance Standards imposed under the Clean Air Act.

SECOND ROUND SUMMARY

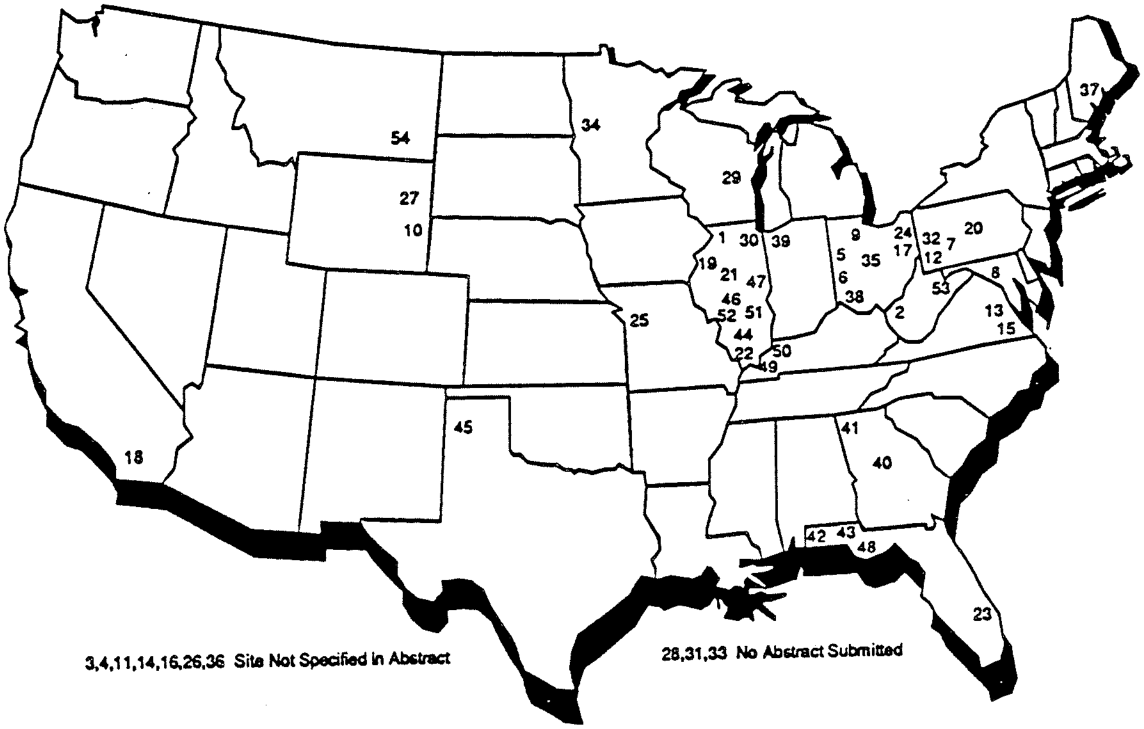
Under the Clean Coal Technology Round 2 solicitation in 1988, 54 proposals (Table 41) were received from 20 states (Figure 16). Kansas was not included. In September, the Energy Department announced 16 winners. They include: American Electric Power's $579 million repowering of the Philip Sporn Plant in New Haven, West Virginia. It is designed to replace two 1950's-era 150 megawatt boilers with a 330-megawatt pressurized fluidized-bed combustion (PFBC) boiler in a combined cycle. Startup of the Sporn project is planned for late 1995.

TABLE 41

CLEAN COAL TECHNOLOGY ROUND 2 SUBMISSIONS

Submitter	Project Title
Allison Gas Turbine, GM; Union Electric Corp.; Foster Wheeler Devl. Corp., Bechtel North American Power Co.	Venice Advanced Pressurized Fluidized Bed Combustion Demonstration Project
American Electric Power Service Corporation	Philip Sporn Plant Pressurized Fluidized Bed Combustion Repowering Project
Babcock & Wilcox Co. Alliance, OH	Full Scale Demonstration of Low NOx Cell Burner Retrofit
Babcock & Wilcox Co. Alliance, OH	Demonstration of Reburning for Cyclone Boiler NOx Control
Babcock & Wilcox Co. Alliance, OH	Furnace Limestone Injection, Dry Scrubbing
Babcock & Wilcox Co. Alliance, OH	5 MWe Demonstration of SOx-NOx Rox Box Process
Bechtel National, Inc. San Francisco, CA	Combined Zone Dispersion Flue Gas Desulfurization Demon.
Bethlehem Steel Corp. Bethlehem, PA	Innovative Coke Oven Gas Cleaning System of Retrofit Applications
Southern Company Services Birmingham, AL	Demonstration of Selected Catalytic Reduction Technology for the Control of Nitrogen Oxide Emissions
Southern Company Services Birmingham, AL	180 MW Demonstration of Advanced Tangentially-Fired Combustion Techniques for the Reduction of Nitrogen Oxide Emissions from Coal-Fired Boilers
Southern Illinois University, Carbondale, IL	Coal Mine/Preparation Waste Fueled Power Plant Expansion
Southwestern Public Services Co., Amarillo, TX	Nichols Station Unit 3 Circulating Fluidized Bed Project
A. E. Staley Manufacturing Division of Staley Continental, Inc. Decatur, IL	Decatur Plant Utilities Repowering and Cogeneration Demonstration Project (Multisolid Fluidized Bed Combustion)
Sunlaw Energy Corp., Institute of Gas Technology Foster Wheeler Corp.	Chanute Air Force Base Integrated Gasification Combined Cycle Project
Tallahassee, City of Tallahassee, FL	A. B. Hopkins Generating Station Circulating Fluidized Bed Replacement Boiler
Tennessee Valley Authority Chattanooga, TN	160 MW Atmospheric Fluidized Bed Combustion Demonstration Test Program
TransAlta Resources Investment Corp. Calgary, Alberta, Canada	Low NOx/SOx Burner Retrofit for Utility Cyclone Boilers
Ultrasystems Engineers & Constructors Inc. Irvine, CA	Pilot Project for Demonstrative Use of Selective Catalytic Reduction to Control Nox Emissions from an Existing Cyclone Electric Utility Boiler
Virginia Electric Power Co., Island Creek Corp. Bechtel North American Power Corp., Electric Power Research Institute	Integration of Multiproduct Coal Cleaning & Fluidized Bed Combustion
Western Energy Co. Butte, MT	Advanced Conversion Process Demonstration
Duquesne Light Company Pittsburgh, PA	Coal Optimization Process for Emission Reduction (COPER Project)
Energy Partners, Inc. Washington, DC	Retrofit an Existing Industrial Boiler w/TAS Coal Micronization System
En-R-Tech International Bolingbrook, IL	The En-R-Tech Clean Coal Emission Program
Florida Power & Light Co./ Florida Coal Gasification Inc., Miami, FL	Florida Coal Gasification Advancement Project
Frontier Energy Corp. Willoughby, OH	Coal/Heavy Oil Hydrogenation Plant Co-Processing High Technology
Independence, City of Missouri Power & Light Dept., Independence, MO	Combined Cycle Circulating Fluidized Bed with Air Cooled External Heat Exchanger
Helipump, Inc. Cleveland, OH	An Innovative NOx and SOx Control with an All Solid State Electro Catalytic Modular IGR
K-Fuel Partnership Denver, CO	Coal Processing Utilizing the K-Fuel Process to Produce High BTU, Low Sulfur Fuel from Low Ranked Subbituminous Coal
Lignite Research Council North Dakota	Partial Application for Fluidized Bed Cogeneration in Conjunction with Great Plains Coal Gasification Plant
Manitowoc Public Utilities Manitowoc, Wisconsin	Clean Coal Technology Re-Powering Project via Atmospheric Circulating Fluidized Bed
M-C Power Corp. Chicago, IL	Coal Fired IMHEX Molten Carbonate Fuel Cells for Combined Cycle Repowering
Minnesota Power	Coal Beneficiation Demonstration-Hot Water Drying Technology
Modular Power Plant Limited Partnership New York, NY	Homer City Modular Fluidized Bed Power Plant Project
Montana State University	SO_2 and NOx Removal with Petroleum Pitch
Northern States Power Co. Minneapolis, MN	An Integrated Post Combustion Environmental Control System
NOXSO Corporation Library, PA	NOXSO Flue Gas Cleanup Process
Otisca Industries Syracuse, NY	Production of Compliance Otisca Fuel/Coal Water Slurry from High Ash and Sulfur Coal and Its Combustion in Retrofitted Industrial Boilers
Passamaquoddy Tribe Thomaston, ME	Passamaquoddy Innovative Clean Coal Technology Programs Application (Recovery Scrubber)
Pedco, Inc. Cincinnati, OH	Industrial Demonstration of the Pedco Rotary Cascading Bed Boiler
Pure Air c/o Air Products & Chemicals, Inc., Allentown, PA	Advanced On-Site Flue Gas Desulfurization Process
Southern Company Services Birmingham, AL	100 MW Demonstration of Innovative Application of Technology for Cost Reductions to the Chiyoda Thoroughbred-121 Flue Gas Desulfurization Process
Southern Company Services Birmingham, AL	500 MW Demonstration of Advanced Wall Fired Combustion Techniques for the Reduction of Nitrogen Oxide Emissions from Coal-Fired Boilers
Calderon Energy Co. Bowling Green, OH	Calderon Method for Repowering Coal Burning Facilities as a Novel Integrated Gasification Combined Cycle Process
Char-Fuels Associates, Ltd. Englewood, CO	Dave Johnston Charfuel Demonstration Project
CLI Corporation Pittsburgh, PA	Advanced Integrated Fine Coal Cleaning Process
Coal Dynamics Corp. Camp Hill, PA	Controlled Burnout and Electrical Energy Production of the Plummer/ Puritan Mine Fire
Cogentrix/Coastal Joint Venture, Charlotte, NC	The Williamsburg Project (Coal Micropulverization Boiler Project)
Combustion Engineering Co. Windsor, CT	Demonstration of a Pulverized Coal NOx Reduction Reburn System on a Cyclone Boiler
Combustion Engineering Co. Windsor, CT	Demonstration Project for Post Combustion Dry Sorbent Injection Technology
Combustion Engineering Co. Windsor, CT	Innovative Clean Coal Gasification Repowering Project
Combustion Engineering Co. Windsor, CT	Commercial Demonstration of WSA-SNOx Technology
Cool Water Coal Gasification Program, Daggett, CA	Cool Water Gasification Extended Demonstration and Development Program
Cyclean, Inc. Georgetown, TX	Microwave Applications for Clean Coal Technologies

FIGURE 16
ROUND 2 CLEAN COAL TECHNOLOGY PROPOSALS



Combustion Engineering Inc.'s $309 million coal gasification, combined cycle repowering of the City Water, Light and Power Lakeside station in Springfield, Illinois. The system will power a 40-megawatt gas turbine coupled to a heat recovery steam generator. A hot gas cleanup system will be employed.

A joint venture of Air Products and Chemicals Inc. and Mitsubishi Heavy Industries America Inc., for an advanced wet limestone flue gas desulfurization (FGD) system at Northern Indiana Public Service Company's 529-megawatt Mitchell plant in Gary, Indiana. The three-year demonstration is planned to show that capital costs for advanced FGD systems can be trimmed to $135 to $150 per kilowatt.

Southwestern Public Service Company, to replace an 18-year-old, 256-megawatt boiler fired by gas with a circulating fluidized-bed combustion (CFBC) boiler at its Nichols plant near Amarillo. The utility asked the Department of Energy to support 38 percent of the $135 million project.

Combustion Engineering Inc., will demonstrate three dry sorbent injection technologies: in-duct injection, in-duct spray drying and convective pass injection at the 180-megawatt unit 2 of Virginia Power's Yorktown plant. One of the goals of this $37 million project is to reduce SO_2 emissions from the Yorktown site by at least 50 percent.

Georgia Power's 100-megawatt Yates unit 1 will be retrofitted with a Chiyoda Thoroughbred-121 FGD process. One of the goals of the $35.8 million project is 90 percent SO_2 control with high reliability. The utility will burn 2.9 percent sulfur coal.

Snamprogetti USA Inc. and Combustion Engineering's $31 million joint venture to demonstrate the WSA-SNOX technology at Ohio Edison's Niles station. WSA-SNOX is a flue gas cleanup technology which catalytically removes SO_x and NO_x. No sorbents are used and no waste byproducts are formed. Only a commercial-grade sulfuric acid is produced and can be sold.

Bethlehem Steel Corporation's Sparrows Point plant demonstration of coke oven gas desulfurization. The $35 million project will combine coke oven gas desulfurization and sulfur recovery with ammonia recovery and destruction.

Post-combustion NO_x control at Gulf Power's Plant Crist near Pensacola, Florida. Although changing the combustion process is usually the most cost effective to reduce NO_x emissions, post-burn techniques show potential for higher reductions. Southern's selective catalytic reduction process will be demonstrated between a 75-megawatt unit and a 320-megawatt unit. The technology has the capability of reducing NO_x by 90 percent.

TransAlta Resources Investment's $13.6 million retrofit of a 33-megawatt cyclone boiler at Southern Illinois Power Cooperative's Marion plant. Two Low NO_x/SO_2 (LNS) burners, each rated at 200 million BTU per hour, will be retrofitted to two Babcock & Wilcox boilers to reduce NO_x and SO_2 emissions up to 90 percent.

Southern Company Services to use a demonstration of three advanced NO_x control techniques for retrofit to wall-fired, pulverized-coal boilers. The 500-megawatt demonstration will be at Georgia Power's Hammond plant unit 4. The performance of each technology will be judged separately, then in combined operation. The combination is expected to reduce NO_x emissions by at least 60 percent.

Babcock & Wilcox Company to demonstrate a retrofit technology to control NO_x emissions from the cyclone-fired boiler at Wisconsin Power & Light's 100-megawatt Nelson Dewey unit 2. The technology involves injecting a supplemental fuel into the main furnace above the cyclone region to produce a secondary combustion zone where a reducing atmosphere exists.

Babcock & Wilcox Company's five-megawatt demonstration of simultaneous control of SO_2, NO_x and particulate emissions using the SNRB process in one high-temperature baghouse. Backers estimate SO_2 removals of 50 percent or more, with NO_x removals as high as 90 percent.

The Passamaquoddy Tribe-Dragon Products Company of Thomaston, Maine, for a retrofit scrubbing system that reduces SO_2 emissions by more than 90 percent. The system substitutes biomass ash for limestone as the scrubbing agent.

Southern Company Services' 180-megawatt demonstration of NO_x reduction techniques for tangentially fired units. Three techniques of NO_x reduction will be demonstrated in a pattern similar to that planned for wall-fired boilers.

Otisca Industries Ltd.'s demonstration of Otisca Fuel, an ultra clean coal-water slurry made from eastern bituminous coal. The fuel will be demonstrated using retrofitted industrial boilers. The project will demonstrate the manufacture and use of 40,000 dry tons of ultra-low sulfur and ash fuel.

IMPLICATIONS FOR KANSAS COAL

The Clean Coal Technology proposals submitted and the winners selected from them represent industry's and the Department of Energy's respective judgments on the direction of technological progress in this field. In both rounds, the number of proposals involving fluidized bed combustion (FBC) outnumbered those involving integrated coal gasification combined cycle (IGCC) by over two to one. In both rounds, the Department of Energy selected two FBC projects and one IGCC project. The two FBC projects in Round 2 involve a 256 megawatt and a 330 megawatt unit, indicating the continuing maturity of this technology.

Round 2, which emphasized technology for retrofit applications, drew 14 proposals in the area of post-combustion flue gas cleanup. Six awards were made, three for SO_2 control systems, one for an NO_x control system, and two for combined NO_x, SO_x control systems. In addition four awards were made in the area of burner system modifications for NO_x control. This all indicates a higher level of interest in NO_x control than has been present in the past. Several Kansas utility stations operate cyclone furnaces, which are vulnerable to NO_x control regulations because the high operating temperature in cyclone burners creates excessive nitrogen oxides.

Coal beneficiation proposals have not been well received, with only one selected for funding. This reinforces the conclusion that "deep cleaning" technologies are not yet competitive with post-combustion cleanup systems. A review of coal cleaning technologies discussed at the Second International Conference on Processing and Utilization of High-Sulfur Coals, held in 1987, did not reveal any recent advances which would be especially suitable for high-sulfur Kansas coal. Coal cleaning processes include gravity-based systems such as cyclones, spirals, jigs and concentrating tables; electromagnetic processes such as high gradient magnetic separation and electrostatic separation; flotation processes of various types; flocculation and agglomeration processes; chemical beneficiation processes using caustic acids, oxygenated acids and other chemicals. Although many of these processes would reduce the sulfur level in Kansas coal, the effect would be relatively small and would not produce a compliance coal. If post-combustion cleanup measures will be required anyway, it is not likely to be economical to also beneficiate ahead of combustion. Deep-cleaning processes which could produce a clean fuel are very expensive, \$3 or \$4 per million BTU.

Kansas coal is already in the position of having to compete against lower-sulfur coals on a simple cents per BTU basis. The addition of any beneficiation process step would immediately make the Kansas coal uncompetitive on price. Thus research on beneficiation is not recommended. The most desirable market for Kansas coal is one in which sulfur content is not a significant pricing factor. Thus a cement kiln which can accept high-sulfur coal is an ideal market because the Kansas coal need compete only on the basis of cents per BTU. With respect to the Clean Coal Technology program, this means that the best technologies are those for which, once the capital investment is made, operating costs are not sensitive to sulfur levels.

A fluidized bed combustor would not be overly sensitive to sulfur level, but the amount of limestone required to be added to the bed would be directly proportional to the sulfur level. An ideal flue gas cleanup system would be one which produces a valuable byproduct proportional to the sulfur input, thus negating extra operating costs for higher sulfur coal. An example of this might be the WSA-SNOX process which catalytically removes SO_x and NO_x without sorbents and produces sulfuric acid for sale. Once such a system were installed with a design capacity to handle the sulfur level in Kansas coal, there would probably be no economic advantage to using a lower-sulfur coal. It would be very useful if a Kansas project involving such technology would apply for funding under the upcoming Clean Coal Technology Round 3.

Of those technologies already available commercially, it is clear that fluidized bed combustion systems are rapidly winning wide acceptance, and can provide a market for Kansas coal. A high priority should be given to encouraging new fluidized bed combustion installations in Kansas.

POSSIBLE ACTIONS TO AID THE COAL INDUSTRY

TYPES OF AID

If the state decides it is in the public interest to aid the coal industry, there are a variety of ways in which aid could be offered. They may be broadly categorized as:

- Relief from taxes (property, income, severance etc.)
- Regulatory relief (easier permitting, lower bonds, etc.)
- Direct subsidies (payments per ton produced, below-market loans, etc.)
- Restraint of competition (import tariffs, etc.)
- Forced markets (mandatory percentage burns, forced conversions to coal, etc.)
- User incentives (tax credits for use of native coal, aid for new coal-burning facilities or conversions to coal, etc.)

Each type of aid differs with respect to effectiveness (results per dollar of aid provided) and with respect to who bears the ultimate costs. Tax relief, direct subsidies, and user incentives will normally be funded through state budgets, with the result that costs are distributed among all taxpayers in the state. Costs related to mandatory burns or import tariffs will impact the electric utilities, who may be able to pass the cost through to consumers of electricity, but if not, the utility's shareholders will be burdened with the cost. Regulatory relief may not seem to carry a cost, but if the relief results in a deterioration of environmental control standards then the effect may be postponed to the future and may be widely distributed, even outside the State of Kansas.

ACTIONS IN OTHER STATES

Several types of legislation have been enacted, and others proposed, in states having a coal mining industry. The following survey covers the more significant approaches.

Arkansas

Arkansas passed a "mandatory burn" law in 1987 which requires that all coal-burning electric utilities burn a certain percentage of Arkansas-mined coal. The required percentage starts at three percent in 1988, goes to six percent in 1989, and then to 10 percent in 1990. Percentages are calculated on a BTU basis.

Compliance is waived if the cost of electricity would be increased, or if violations of environmental control regulations would result, or if the utility would be unable to fulfill any contractual commitments for purchase of coal which were in place at the time the law was passed.

As a result of the law, a new lignite mine is being developed as a possible source of Arkansas fuel for the White Bluff generating station.

Colorado

Colorado in 1988 passed a 40 percent reduction in coal severance taxes (tax rate was $0.81 per ton and is indexed for inflation) to be effective for a period of six years. The first 100,000 tons produced is exempt.

Consideration is being given to a $1.00 per ton tax credit for using state coal.

Illinois

An Illinois law excludes transportation cost of coal from the electric utility automatic fuel adjustment clause. As a result of this law, increases in transportation costs of coal will not be recaptured automatically by monthly adjustments in electric rates but must be anticipated by the utility and approved by the Commerce Commission in rate hearings. Since transportation costs are a much larger portion of total costs of low sulfur Western coal than of Illinois coal, the law is expected to make high sulfur Illinois coal more competitive with the higher total-cost Western coal.

Other coal incentives provided by Illinois include $2.5 million per year in grants for coal research; a $100 million fund which provides up to 20 percent of the cost of demonstration projects for new technology; a low-interest loan fund for commercial projects which will use Illinois coal; coordinated permit reviews and assistance in siting new projects; tax breaks for pollution control equipment; and creation of an Office of Coal Development and Marketing to promote the sale and use of Illinois coal.

Indiana

Indiana has deregulated the disposal of coal ash; allows utilities to recover as an operating expense any research and development designed to increase the use of Indiana coal; gives full allowance in Construction Work in Progress for pollution control equipment designed to allow burning of Indiana coal; and provides a below-market-rate revolving loan fund to aid technologies using Indiana coal.

For a period, Indiana gave an exemption from property taxes to anyone building a fluidized bed combustion unit. Currently under consideration are measures which would allow utilities to put into their rate base immediately any expenditures for Clean Coal Technology.

Another Indiana law requires that all state institutions purchasing coal must buy Indiana coal. An exemption is allowed if the institution is under a requirement to burn low-sulfur coal.

Iowa

Iowa statutes require all state, county, city or school district agencies buying coal to buy Iowa-mined coal if available at the same cost as elsewhere and in the quality required.

Missouri

Missouri held hearings in 1986 and explored a number of different ways to aid the coal industry, but nothing was passed.

Montana

Montana has had the highest coal severance tax in the nation--30 percent for subbituminous coal and 20 percent for lignite. In 1987 legislation was passed to reduce the severance tax in five percent increments provided coal companies produced and sold at least 32.2 million tons of coal during the year ending June 30, 1988. That goal was met, and is to trigger further reductions in the severance tax (to 20 percent in 1990 and to 15 percent in 1991).

Ohio

The Ohio Coal Development Office has undertaken an extensive program to develop clean coal technologies suitable for use with Ohio coal. Emphasis is on research and development needed to bring near-term technologies over the last hump to commercialization. In 1985 a $100 million bond issue was passed with a 2:1 majority. So far some 40 projects have been aided. The Office has participated in nine pilot or demonstration scale projects involving limestone injection, catalytic SO_x/NO_x reduction, fluidized bed combustion, coal beneficiation, coal/oil coprocessing, retrofit slagging coal combustion, etc.

Oklahoma

In 1986 Oklahoma passed a law requiring Oklahoma electric utilities to burn a minimum of 10 percent Oklahoma coal, calculated on a BTU basis. An exception to the requirement is allowed if the cost of Oklahoma coal would be more than five percent higher (delivered to the plant) than coal obtainable out of state. Experience with this law is described in a later section. It has been proposed to amend this law so that the 10 percent is calculated on a tonnage basis rather than a BTU basis.

Oklahoma has also considered various ways of enacting a $1 per ton tax credit for use of in-state coal, such as: $1 per ton of Oklahoma coal purchased when the cost exceeds the energy cost of existing long-term contracts for out-of-state coal; $1 per ton of Oklahoma coal purchased in excess of the 10 percent requirement; $1 per ton of Oklahoma coal purchased in excess of the amount purchased in 1984.

Also considered was a ton-mile tax on all coal transported by railroad within the state, with a provision that the tax could not be passed through to consumers of electricity.

Pennsylvania

Pennsylvania provides special assistance to utilities which convert to coal or add to coal burning capabilities. Through Construction Work in Progress they can recover 50 percent of the undepreciated cost of the original investment prior to completion of the project.

Bills under consideration would allow a $1 credit against the gross receipts tax for each ton of Pennsylvania coal used in excess of the quantity consumed in a past base period. This would increase to $2 per ton later. Also being considered is a tax credit for research and development which would result in increased use of Pennsylvania coal.

Another proposal is to allow businesses a credit against corporate income tax of 25 percent of the cost of installing a coal-burning system. Similarly, individuals could receive a tax credit of 40 percent of installed cost (no greater than $10,000) of coal-burning equipment for their home.

THE OKLAHOMA BLENDING LAW

Legislation

In March of 1986 Governor George Nigh signed into law a bill which requires Oklahoma electric utilities to burn a minimum of 10 percent Oklahoma coal in their coal-fired generators. Before this legislation was introduced, the state's utilities had been purchasing Wyoming coal exclusively.

The new law became effective on January 1, 1987. Prior to this date, however, the utilities began conducting test burns of Oklahoma coal blended with the Wyoming product.

The 10 percent minimum is to be calculated on a BTU basis. This means that Oklahoma coal is to contribute no less than 10 percent of the BTU total. Since the Oklahoma utility coal is about 40 percent greater in BTU value than the Wyoming product, in effect the likely result will be an Oklahoma coal contribution of about seven percent of the mixture computed on a tonnage basis.

An "economic out" is provided if the cost of Oklahoma coal would be more than five percent higher than the long-term contract cost of out-of-state coal on a BTU basis. The statute itself is not specific about how this comparative cost is to be calculated. The Oklahoma utilities expressed the opinion that the cost should be calculated "at the busbar," that is, after allowing for all the extra costs involved with handling, blending and burning a second coal within the power plant. However, sponsoring legislators indicated that their intent was for coal cost to be compared only on the basis of delivery to the power plant.

There are no provisions in the law for lack of blending capability or inability to meet environmental standards. Because the Oklahoma power plants were all burning low-sulfur Wyoming coal, it was known that they could blend in at least 10 percent Oklahoma coal without exceeding their emission limits on the average.

The Oklahoma law has no penalties for noncompliance. It is essentially a "sense of the legislature" declaration.

Economic Feasibility

Because of the absence of long-haul rail charges and the greater BTU value, supporters of the new law expected Oklahoma coal used in the state's utilities to be less costly than Wyoming coal.

Average delivered coal costs to Oklahoma power plants in 1987 are listed in Table 42. In all cases Oklahoma coal was found to be available at no more than the allowable five percent above the cost of Wyoming coal. In two cases, the Oklahoma coal was actually cheaper.

TABLE 42

DELIVERED COST OF COAL TO OKLAHOMA POWER PLANTS, 1987

Utility/Plant	Wyoming Coal Cents/MMBTU	Oklahoma Coal Cents/MMBTU
Oklahoma Gas & Electric		
Muskogee	146.3	137.9
Sooner	161.2	165.9
Grand River Dam Authority		
GRDA 1	145.2	107.8
Public Service Co. of Oklahoma		
Northeastern	164.7	170.9
Western Farmers Electric Coop		
Hugo	175.5	184.6

Source: EIA Cost and Quality of Fuels for Electric Utility Plants, 1987

Utility Experience

Oklahoma utilities have claimed that burning 10 percent Oklahoma coal in their power plants has increased their operating costs in a number of ways. Grand River Dam Authority (GRDA) said they had some problems at one unit due to the higher ash level. Oklahoma Gas and Electric (OGE) stated that ash piping which used to last four years wore out in only one year.

According to OGE, they had to invest some $7.4 million in new facilities to be able to blend the coal and comply with environmental regulations. On an annualized basis, this amounts to 13 cents per million BTU of Oklahoma coal burned.

Using a 10 percent blend (BTU basis) OGE found that they exceeded sulfur dioxide emission limits eight times in 1987, even though the average emissions were well below permit limits. It is understood that one utility was fined for an exceedance.

Western Farmers Electric Cooperative (WFEC) said the pulverizer running on Oklahoma coal was experiencing vibration problems. GRDA said their pulverizers handling Oklahoma coal were experiencing a 50 percent decrease in the life of the wear and grinding elements.

GRDA estimated extra costs of $1.8 million dollars per year, including $664,000 in extra operating costs, $100,000 in repair costs for the bottom ash system crusher, $55,000 for replacement of flight bars in the bottom ash drag chain conveyor and $235,000 in added replacement costs for atomizer disc wear liners in the flue gas desulfurization system (FGDS). The effect on electricity was calculated to be an increase of 0.96 mills per kilowatt hour.

Non-equipment related costs in the $1.8 million due to switching from Wyoming to Oklahoma coal would be the loss of tonnage bonus provisions in the railroad shipping contract, causing the delivered cost of the Wyoming coal to increase.

Because of the higher sulfur content in Oklahoma coal, the amount of lime required in the FGDS increased by 33 percent for a 10 percent coal blend, and the amount of power required for the FGDS atomizer increased proportionately.

Utilities which sell their fly ash to ready mix cement plants might find the ash from blended coal to be unacceptable.

Coal Industry Experience

Most representatives of the Oklahoma coal mining industry state that the mandatory burn law has been the salvation of the industry. It has not allowed the industry to expand production, but has merely compensated for losses in other markets.

Oklahoma coal production declined from 4.6 million tons in 1984 to just 3.0 million tons in 1986. In 1987, the first year of the mandatory burn law, production was still only about three million tons but 600,000 of that probably resulted from the law. At full compliance, the law should result in the purchase of about 800,000 tons of Oklahoma coal by Oklahoma utilities.

It may be noted that the burn law does not necessarily favor existing small mine operators. The quantities involved are large enough to interest the major companies. Thus the low bidder for 150,000 tons per year to be supplied to GRDA this year was Amax Coal.

Wyoming Lawsuit

The State of Wyoming has filed a motion before the Supreme Court of the United States, claiming the Oklahoma mandatory burn law to be an unconstitutional restraint of interstate commerce.

It is impossible to predict how long it will take to obtain a ruling. Oklahoma filed an answer at the end of August, and Wyoming will then respond. The court will then assign a judge to act as referee during discovery proceedings, etc. As a guess, it might then take eight or nine months for a ruling.

The authors of this study cannot provide a legal opinion on the outcome. However, it is immediately obvious that the case resembles other legislation which has been disallowed. Earlier this year the Supreme Court struck down an Ohio law as an unconstitutional restraint of interstate commerce. The law provided a tax credit for gasohol, provided that the ethanol used was manufactured in Ohio, but not if it was obtained from outside the state. The vote of the court was 9 to 0. Thus one must admit at least a reasonable possibility that the Oklahoma mandatory burn law could be nullified. It would appear even more likely that the tax credit law allowing a $1 per ton tax credit for burning coal produced in Oklahoma, will be struck down.

BLENDING ANALYSIS FOR KANSAS UTILITIES

Maximum Possible New Kansas Coal Demand

Without making any allowance for technical or economic feasibility, the maximum possible increase in demand for Kansas coal due to a mandatory 10 percent blending law is shown in Table 43. The Oklahoma blending law is written on the basis that 10 percent of the BTU value of the coal burned must be derived from in-state coal. The results from such an approach are shown in the first column of the table. If, instead, a law were written to require that the coal burned consist of 10 percent in-state coal on a weight basis, the results would be as shown in the second column.

Because the Empire District's Riverton plant and Kansas City Power and Light's LaCygne No. 1 unit already burn more than 10 percent Kansas coal, a mandatory blending law would have no effect on them.

The effect on LaCygne No. 2 would depend on how a law is worded. The Oklahoma blending law states that any "entity" producing electric power from coal shall burn 10 percent in-state coal. The entity which owns LaCygne No. 2 is Kansas City Power and Light. Because Kansas City Power and Light's only other facility in the State of Kansas is LaCygne No. 1, which burns a high percentage of Kansas coal, Kansas City Power and Light could comply with a law similar to the Oklahoma law without burning any Kansas coal in LaCygne No. 2 and without any increased use of Kansas coal. Only if the law were written to require that each individual boiler burn a blend containing Kansas coal would LaCygne No. 2 be affected.

TABLE 43

MAXIMUM POSSIBLE NEW KANSAS COAL DEMAND CREATED BY A 10 PERCENT MANDATORY BURN LAW

(Based on 1987 Coal Use, Tons Per Year)

Station	10 Percent BTU Basis	10 Percent Weight Basis
KP&L-Lawrence	62,913	68,346
KP&L-Tecumseh	14,211	15,413
KP&L-Jeffrey	559,036	766,512
Sunflower-Holcomb	62,260	86,334
KCP&L-LaCygne #2	144,145	196,290
BPU-Nearman	63,320	87,667
BPU-Quindaro	31,687	33,656
BPU-Kaw	7,819	8,276
	945,392	1,247,080

Blending Limits Due to Sulfur Emissions

The ability of Kansas utilities to burn a blend of Kansas coal with the coal currently being used is a much more complex question than was the case in Oklahoma. In Oklahoma, all the plants were built under New Source Performance Standards (NSPS), and all are using low-sulfur Wyoming coal. Furthermore, Oklahoma coals are available with a lower sulfur content than Kansas coals. Thus, it has been calculated that as much as 24 percent (by energy content) of Oklahoma coal could be burned by the utilities without exceeding, on the average, the limit of 1.2 pounds of SO_2 per million BTU. Therefore the mandatory burn law did not have to consider variations between utilities.

By contrast, some of the Kansas plants are already in violation of their air quality permits, some already use Kansas coal, and some use coals from Illinois and the Hanna Basin in Wyoming, which have higher sulfur levels than coal from the Powder River Basin.

The current situation in Kansas is summarized in Table 44. All coal-burning utility boilers in the state are listed, along with the coal source, the sulfur content of the coal, the scrubber efficiency when a scrubber is present, and the calculated plant emissions in terms of pounds of sulfur dioxide per million BTU of fuel consumed. Also listed is the amount of sulfur emissions which are per-

TABLE 44

CALCULATED SULFUR EMISSIONS AND PERMIT LIMITS FOR KANSAS UTILITY BOILERS

Utility	Station/ Boiler	Coal Source	% Sulfur	Scrubber Efficiency	Lb SO_2/ MMBTU	Permit Limit
Empire	Riverton 8	50/50 KS/OK	2.04	--	3.30	3.0
Empire	Riverton 7	50/50 KS/OK	2.28	--	3.66	3.0
KP&L	Lawrence 3	Seminoe #2, WY	0.88	--	1.58	3.0
KP&L	Lawrence 4	Seminoe #2, WY	0.88	73%	0.42	3.0
KP&L	Lawrence 5	Seminoe #2, WY	0.88	52%	0.76	3.0
KP&L	Tecumseh 8	Seminoe #2, WY	0.88	--	1.59	3.0
KP&L	Tecumseh 7	Seminoe #2, WY	0.88	--	1.60	3.0
KP&L	Jeffrey 1	Belle Ayr, WY	0.34	60%	0.318	1.2
KP&L	Jeffrey 2	Belle Ayr, WY	0.34	60%	0.318	1.2
KP&L	Jeffrey 3	Belle Ayr, WY	0.34	60%	0.318	1.2
Sunflower	Holcomb	Rojo Caballo, WY	0.49	80%	0.23	0.48
KCP&L	LaCygne 2	Belle Ayr, WY	0.40	--	0.95	1.2
KCP&L	LaCygne 1	P&M Midway, KS	4.74	80%	1.98	3.0
BPU	Nearman	Rawhide, WY	0.30	--	0.73	1.2
BPU	Quindaro 2	Brushy Creek, IL	2.5	--	4.7	3.0
BPU	Quindaro 1	Brushy Creek, IL	2.5	--	4.7	3.0
BPU	Kaw 3	Brushy Creek, IL	2.5	--	4.7	3.0
BPU	Kaw 2	Brushy Creek, IL	2.5	--	4.7	3.0
BPU	Kaw 1	Brushy Creek, IL	2.5	--	4.7	3.0

mitted. It can be seen that seven of the 19 utility boilers in the State of Kansas are already in violation of their air quality permits. An eighth, LaCygne No. 1, does not appear to be in violation on the basis of the calculations in Table 44, but it too, is known to be in violation due to below-design performance of the scrubber. Thus, it would be legally impossible for eight of the 19 boilers to increase their use of Kansas coal in conjunction with present coal sources.

Sulfur dioxide emissions in Table 44 were calculated with a 2.5 percent allowance for sulfur remaining in the ash. Depending on the boiler design and the coal being used this may or may not be a reasonable value. Calculations for the following tables use the more conservative approach of assuming that all sulfur in the coal appears as sulfur dioxide in the flue gas.

In order to allow for the variability of Kansas coal, calculations were made for three different sulfur levels. A level of 4.7 percent sulfur is representative of the Midway Mine, a level of 3.7 percent sulfur represents run-of-mine from the Mineral and Croweburg seams in Crawford County, and 3.0 percent sulfur represents a washed product from those seams. Calculated emissions from burning blends of three, six and 10 percent by weight of Kansas coal at each of the three sulfur levels are shown in Table 45.

Because of their high permit limits, the Lawrence, Empire, and Tecumseh stations could all accept 10 percent of even the highest-sulfur Kansas coal. However, all of these plants are at risk of having their allowable emissions lowered if acid rain legislation is passed. Calculations for the Riverton plant in Table 45 are based on Wyoming coal as the base coal rather than Oklahoma coal as in Table 44. Riverton has been testing Wyoming coal.

Because of their combination of low sulfur coal plus scrubbers the Jeffrey and Holcomb plants could also accept 10 percent of the highest-sulfur coal without exceeding 1.2 pounds of SO_2 per million BTU. It is not clear whether the Holcomb plant would be allowed to go above 0.48.

TABLE 45

CALCULATED SULFUR DIOXIDE EMISSIONS WHEN BURNING BLENDS OF KANSAS COAL

Percent Sulfur in Kansas Coal	3.0			3.7			4.7		
Weight % Kansas Coal	3	6	10	3	6	10	3	6	10
KP&L - Lawrence 3	1.71	1.81	1.96	1.75	1.90	2.09	1.81	2.00	2.27
KP&L - Lawrence 4	0.46	0.49	0.53	0.47	0.51	0.56	0.49	0.54	0.61
KP&L - Lawrence 5	0.82	0.87	0.94	0.84	0.91	1.00	0.87	0.96	1.09
Empire - Riverton 7&8	1.36	1.52	1.72	1.41	1.62	1.88	1.49	1.76	2.11
KP&L - Jeffrey 1,2&3	0.40	0.47	0.56	0.42	0.51	0.62	0.45	0.56	0.71
BPU - Nearman	0.91	1.09	1.31	0.96	1.18	1.47	1.03	1.33	1.71
KCP&L - LaCygne 2	1.13	1.30	1.51	1.18	1.40	1.67	1.26	1.54	1.90
Sunflower - Holcomb	0.40	0.45	0.51	0.42	0.48	0.56	0.44	0.52	0.63
KP&L - Tecumseh 7&8	1.71	1.81	1.96	1.75	1.90	2.09	1.81	2.00	2.27

The remaining two facilities, LaCygne No. 2 and Nearman, are not equipped with scrubbers. Neither could accept 10 percent of even a three percent sulfur coal.

In summary, of 19 coal-fired utility boilers in the State of Kansas eight would be unable to burn additional amounts of Kansas coal, five could accept at least 10 weight percent of Kansas coal due to high allowable emissions, four could accept at least 10 percent Kansas coal due to having FGD scrubbers, and two could only accept much less than 10 percent Kansas coal by weight.

The situation is basically the same if the percentage of Kansas coal is calculated on the basis of BTU percentage rather than weight. Any plant which could accept 10 percent by weight could accept 10 percent on a BTU basis. However, the Nearman and LaCygne No. 2 boilers still could not accept a 10 percent blend even when calculated as BTU percent rather than weight percent. It would be difficult to fashion legislation which would be seen as equitable when the effects would be so different for different utilities. Those utilities with the most polluting plants would be required to do nothing, while those with the cleanest plants would be required to make expenditures for blending Kansas coal and thereby increase their emissions.

New continuous emission monitoring requirements will make it impossible for a facility to burn a blend whose average sulfur emissions are equal to the permitted quantity. Allowance must be made for variations about the average sulfur levels in the coals, and for variations in the accuracy with which the blends can be mixed. At no time can the combined variances cause a sulfur dioxide concentration above the permitted level. Blending operations such as those now being carried out at the Riverton and LaCygne No. 1 units are producing approximately 50:50 blends with an accuracy of plus or minus 10 percent. That is, the actual blend ratio in the boiler at any point in time could be anywhere between 60:40 and 40:60. Obviously, a more sophisticated blending system would be required for operating near a plant's emission limits. Oklahoma utilities have reported exceedances of a 1.2 pounds SO_2 emission limit even though the average

TABLE 46

MAXIMUM NEW DEMAND FOR KANSAS COAL CONSIDERING ENVIRONMENTAL LIMITS
(Tons Per Year)

Unit	10% BTU Basis	10% Tonnage Basis
BPU - Nearman	42,400	42,400
KP&L - Lawrence	62,913	68,346
KP&L - Tecumseh	14,211	15,413
KP&L - Jeffrey	559,036	766,512
Sunflower - Holcomb	62,260	86,334
KCP&L - LaCygne #2	33,400	33,400
Total	774,220	1,012,405

emission rate when burning blends was approximately 1.0 pounds SO_2 per million BTU. Thus, depending upon the sulfur variability in the coal being burned, a reasonable safety margin would be at least 10 percent and perhaps as much as 20 percent of the emission limit. In other words, a unit with a 1.2 pound emission limit would not be required to blend Kansas coal beyond a concentration which would give an average emission rate of 0.96 to 1.08 pounds of SO_2. Similarly a unit with a limit of 3.0 would not be required to go past 2.7. With such a margin, the amount of Kansas coal which could be burned by the LaCygne No. 2 unit would be only 0 to 1.7 weight percent, and the amount which could be burned at Nearman would be 3.0 to 4.7 weight percent.

The potential effect on demand for Kansas coal is shown in Table 46. In constructing the table, it was assumed that the Riverton and LaCygne No. 1 units would continue to burn the maximum amount of Kansas coal possible within their permit limits. Therefore the passage of a mandatory 10 percent burn law would not affect them in any way.

It is apparent from Table 46 that a mandatory burn law would create very much a one-utility effect. Plants operated by Kansas Power and Light would account for 84 percent of the total demand allowable within emission limits as described above. The Jeffrey Energy Center alone accounts for 76 percent of the total in Table 46.

Coal Quality Effects

Sulfur content is the coal quality parameter which determines how much Kansas coal can be legally burned in a given blend. There are other considerations, however, which may either limit the amount which can be burned or else cause significant increases in operating costs.

Boilers which were originally designed for Kansas coal, and then switched to low-sulfur Wyoming coal should be able to blend in 10 percent Kansas coal with minimal boiler problems. Boilers designed for the Wyoming coal could experience a variety of effects. These effects may be related to sulfur content, ash level, chemical composition of the ash, melting point of the ash, moisture content, volatile matter content, and grinding characteristics of the coal.

Corrosion

All bituminous coals contain enough sulfur and alkali metals to cause corrosive deposits on superheaters and reheaters. Those containing more than 3.5 percent sulfur and 0.25 percent chlorine may be particularly troublesome. The chlorine and sulfur level in Kansas coal puts it into the potential problem range. Sulfur can contribute to different behavior problems in boilers referred to as fouling, slagging and corrosion.

Fouling and Slagging

In general terms fouling is the uncontrollable buildup of ash deposits in the convective pass of a steam generator. Slagging is the uncontrollable buildup of ash deposits in the radiant furnace of a steam generator.

Fouling and slagging behavior may force a boiler to be operated at reduced capacity or undergo excessive downtime for cleaning and repair. Kansas coals have a low ash fusion (melting point) temperature. This means that ash may still be in the molten state as it is carried into the upper furnace and the convection tube section of the boiler, where it will form sticky, troublesome deposits. If a furnace has a dry bottom ash removal system, lower than expected ash fusion temperatures may cause problems here also.

It is not possible to predict exactly what the ash fusion temperature will be when two very dissimilar coals, such as the typical Kansas and Wyoming coals, are mixed. A phenomenon known as "eutectic droop" may occur, in which the blended coal has a lower ash fusion temperature than either of the coals alone. Because the Kansas coal ash is high in iron while the Wyoming is high in calcium, such behavior is a strong possibility. The result could be increased slagging, reduced heat transfer, lower efficiencies, increased tube wear, etc.

The prediction of whether a particular coal or coal blend will cause fouling and slagging problems is by no means precise; however, a number of fouling and slagging indices have been developed which are general indicators of ash fouling and slagging potential. Table 47 lists several of these indices, calculated values, and indicated fouling and slagging tendencies for raw Kansas and Wyoming coals and blends of Kansas and Wyoming coals which could be burned in Kansas utility boilers. Some of the indices are applicable to only eastern or western coals and an entry of N/A is entered where they are not applicable. The base/acid ratio

TABLE 47

FOULING AND SLAGGING POTENTIAL OF RAW COALS AND KANSAS COAL BLENDS

	Kansas	Seminoe	Belle Ayr	10% Kansas/ 90% Seminoe	10% Kansas/ 90% Belle Ayr
Fouling Indices:			Fouling Tendency		
% Na_2O	0.17 N/A	0.25 Low	1.66 Medium	0.24 Low	1.51 Medium
% Ash	N/A	9.4 Low	7.1 Low	9.5 Low	7.6 Low
B/A x % Na_2O	0.19 Low	N/A	N/A	N/A	N/A
% Chlorine	0.33 Low-Med.	N/A	N/A	N/A	N/A
Slagging Indices:			Slagging Tendency		
T-250	2003 Severe	2243 High	2210 High	2218 High	2189 High
B/A	N/A	0.75 Medium	0.86 Medium	0.78 Medium	0.89 Medium
Fe_2O_3/CaO	N/A	0.52 Med.-High	0.23 Low	0.7 Med.-High	0.39 Medium

of the ash is abbreviated B/A in the table. T-250 is the temperature at which molten coal ash has a viscosity of 250 poise (will barely flow on a horizontal surface) and is an indicator of the slagging potential of coal ash.

Based on the results presented in Table 47 it would appear that fouling would not be a major problem for blends containing Kansas coal since the indicated fouling tendency of such blends is low to medium. This is the same fouling tendency as that calculated for the raw Seminoe and Belle Ayr mine coals presently burned by Kansas utilities. Slagging tendencies of blends containing Kansas coal would also appear to be the same as the raw Seminoe and Belle Ayr mine coals with values indicated by the indices of medium to high slagging.

Ash Level

Boilers designed for low-ash coals may have boiler tubes spaced closely together. Increasing the ash level by blending in higher-ash Kansas coal could increase the fouling and slagging in such systems. However, the ash content in terms of pounds of ash per million BTU fired does not appear to be significantly different.

Moisture, Volatile Matter, Heat Content

Excessive moisture may cause problems in the pulverized coal feeding system, low volatile matter may cause combustion to occur too late in the furnace, and low heat content may overload the coal feeding and ash handling systems. For all three of these parameters, the effect of Kansas coal would be neutral or positive. The moisture is lower and the heat content higher than for Wyoming coals, and the volatile matter is equivalent.

Grinding

Harder Kansas coals may cause increased wear in the grinding and pulverizing system. This will be offset to at least some extent by the fact that fewer tons of coal will have to be ground.

The blending of three to 10 percent Kansas coal would not be expected to have a significant effect on the crushing operations of the utility plants. This is based on the Hardgrove grindability, moisture content, coal BTU value and ash silica content of the blend compared to the coal presently being burned. The above factors largely determine pulverizer capacity, input power, wear and drying air requirements.

Summary

Kansas utilities presently burn a variety of coals including Kansas coal, Powder River Basin and Hanna Basin Wyoming coals, southern Illinois coal, and Oklahoma coal. The plants which are candidates for using Kansas coal in blends include the following:

Kansas Power and Light	Tecumseh
Kansas Power and Light	Lawrence
Kansas Power and Light	Jeffrey
Board of Public Utilities	Nearman
Kansas City Power and Light	LaCygne No. 2
Sunflower Electric	Holcomb

The proximate, ultimate, mineral ash analyses and other predicted data for the coals presently burned in these candidate plants along with the data for a typical Kansas coal were run through the $COAL blending program. An example of the output is shown in Table 48. The values for T-250 and ash fusion temperatures are actual measured values for the raw coals but have been calculated for the blends using a series of correlations based on the mineral ash analyses of the blends.

TABLE 48

ANALYSES AND PREDICTED PROPERTIES OF A 10% BLEND OF KANSAS AND POWDER RIVER COALS

Coal	Belle Ayr, WY	Croweburg, KS	Blend
% Blend Level	50.0	50.0	100.0
% Yield of Raw Coal	Raw	Raw	Raw
BTU/Lb	8,300	12,500	8,720
Wt % H_2O	30.68	7.00	28.31
Wt % Ash	4.93	10.10	5.45
Wt % Volatiles	33.66	33.80	33.67
Wt % Sulfur	0.50	3.70	0.82
Lb SO_2/MMBTU	0.88	5.92	1.55
Wt % P_2O_5	0.80	0.38	0.76
Wt % SiO_2	29.87	28.57	29.74
Wt % Fe_2O_3	5.45	38.78	8.78
Wt % Al_2O_3	13.02	14.22	13.14
Wt % TiO_2	1.30	0.78	1.25
Wt % CaO	23.66	8.12	22.11
Wt % MgO	7.15	0.62	6.50
Wt % K_2O	0.25	1.13	0.34
Wt % Na_2O	1.66	0.17	1.51
Wt % SO_3	16.27	6.63	15.31
Ash Type	Lignitic	Bituminous	Lignitic
Slagging Factor Rs	0.2	3.8	0.4
Slagging Potential	Medium	Severe	Medium
Fouling Factor Rf	1.66	0.2	1.51
Fouling Potential	Medium	Low	Medium
T-250, °F	2,210	2,003	2,189
Ash Fusion, Reducing			
Initial Deformation	2,125°F		2,145°F
Softening			2,159°F
Hemispherical			2,177°F
Fluid	2,224°F		2,198°F
Ash Fusion, Oxidizing			
Initial Deformation	2,178°F		2,210°F
Softening			2,227°F
Hemispherical			2,226°F
Fluid	2,302°F		2,225°F

In general it appears that a major effect of requiring that a percentage of Kansas coal must be burned by the utilities is the additional investment required in the material handling system to handle the blending of two or more coals. This is due to the fact that most of the utility plants were designed for only one coal. If Kansas coal were to be blended with the coal presently being burned then additional or new receiving, storage, reclaiming, and blending systems would likely be required. It was not determined in this study if space requirements for these new or additional facilities is available at each of the utility plants.

It is impossible to predict the exact effects of a coal blend on boiler operation. These effects can only be determined by making actual test runs in the boilers. Although the generalized correlations used here suggest that up to 10 percent Kansas coal could be successfully blended, it is entirely possible that significant problems could arise in any particular case. There have been examples where a 10 percent blend did not create a problem, but a five percent blend did. The pattern is unpredictable when blending very dissimilar coals, and every boiler design can be affected differently.

A comprehensive computer program to study the impacts of coal quality on power plant performance has been developed by Black & Veatch of Kansas City, Missouri, for the Electric Power Research Institute. Units which it shows can be affected by coal quality include conveyors, feeders, pulverizers, exhauster mill fans, forced draft, induced draft, primary air and scrubber booster fans, soot blowers, bottom ash and fly ash systems, precipitators, flue gas desulfurization systems, etc.

Economic "Out"

All of the mandatory burn laws which have been considered include some form of economic escape clause, so that a utility will not be forced to burn in-state coal if it would be significantly (zero to five percent) more expensive than their current long-term contracts for imported coal.

Delivered prices of coal in 1987 were given in Table 9, and the estimated costs of Kansas coal were given in Table 38. Results from those two tables are combined in Table 49. According to this comparison, all of the power plants would be able to claim an economic "out" for costs exceeding five percent of current costs except for the Lawrence and Tecumseh stations. It these two stations were the only ones affected, the total increased demand for Kansas coal would be only 74,000 tons per year.

Busbar Costs

The cost of coal itself is only one ingredient of the total cost to the consumer which may result from instituting a mandatory blending law. A common point of reference for comparing electricity costs is the cost at the busbar.

The total cost of producing electricity can vary widely depending on the location, size, financing terms, technology, fuel, age, and utilization pattern of a plant. The busbar is a heavy, metallic conductor in the plant switchyard used to connect the output side of the generators to the voltage transformers which are part of the transmission and distribution system. The busbar is a convenient reference point for measuring generating cost, because it is the point at which electricity leaves the plant.

TABLE 49

COMPARISON OF ESTIMATED KANSAS COSTS TO CURRENT WYOMING COSTS

	Estimated Kansas Coal Cost $/MMBTU	1987 Delivered Coal Cost $/MMBTU
Lawrence	1.34	1.52
Nearman	1.32	1.02
Tecumseh	1.37	1.48
Holcomb	1.72	1.05
Jeffrey	1.42	1.29
LaCygne	1.21	0.99

The regulatory costs for electricity generation consist of operation and maintenance expenses, fuel expenses, depreciation, taxes, and a return on the utility's rate base as determined by the regulators. A description of the components follows:

Operation and Maintenance Expenses - recurring expenses to operate and preserve the physical condition or operating efficiency of the plant. Costs include operators' wages and benefits, plant maintenance, security, supervision, materials (such as spare parts), and supplies consumed during plant operation and maintenance, except fuel.

Fuel Expenses - cost of fuel used to produce electricity. Coal fuel costs consist of the costs of purchasing, handling, preparing, and transporting the coal.

Depreciation - an annual charge based on straight-line depreciation of the original cost of the plant over its service life.

Taxes - including federal, state, and local income, property, sales and other taxes.

Return on Rate Base - covers interest payments and a return on preferred and common stock after taxes.

Operating, maintenance and fuel expenses for three Kansas power plants, as reported to the Energy Information Administration, are given in Table 50.

Average values for all the components of busbar electricity cost for coal-fired power plants in the United States are given in Table 51. Comparison of the Operating, Maintenance and Fuel components in Tables 50 and 51 shows that the Kansas plants exhibit a range of values corresponding roughly to the national average.

In order to approximate the effect of capital investment on busbar electricity cost, the values in Table 51 were assumed to correspond to the average existing plant cost of $714 per kilowatt.

TABLE 50

HISTORICAL PLANT COST AND PRODUCTION EXPENSES FOR SELECTED STEAM-ELECTRIC PLANTS, 1986

Name of Utility	Kansas City Power & Light Co		Kansas Power & Light Co.			
Name of Plant	LaCygne		Jeffrey Energy Cntr		Lawrence	
General Operating Characteristics						
Generation (Million kWh)	4,477.4		11,843.0		1,244.1	
Plant Factor Based on Nameplate Rating (%)	32		63		23	
Net Peak Demand on Plant - 60 Minutes (MW)	1,280.0		1,962.0		453.0	
Historical Plant Cost (Thousand Dollars)						
Land and Land Rights	3,735		3,287		403	
Structures and Improvements	26,536		215,835		15,955	
Equipment	447,693		845,913		75,756	
Total	477,964		1,065,035		92,113	
Cost per kW of Installed Capacity ($)	303		493		150	
	$1,000	Mills/ kWh	$1,000	Mills/ kWh	$1,000	Mills/ kWh
Power Production Expenses						
Operation Expenses						
Operation Supervision and Engineering	1,184	0.26	950	0.08	84	0.07
Coolants and Water	-	-	-	-	-	-
Steam Expenses	3,031	0.68	3,635	0.31	1,471	1.18
Steam from Other Sources	-	-	-	-	-	-
Steam Transferred (CR)	-	-	-	-	-	-
Electric Expenses	961	0.21	2,144	0.18	907	0.73
Miscellaneous Steam Power Expenses	2,293	0.51	2,263	0.20	338	0.24
Rents	90	0.02	-1	-	-	-
Maintenance Expenses						
Maintenance Supervision and Engineering	1,102	0.25	1,022	0.09	102	0.08
Maintenance of Structures	2,318	0.52	238	0.02	284	0.23
Maintenance of Boiler Plant	21,186	4.73	8,864	0.75	2,648	2.13
Maintenance of Electric Plant	2,146	0.48	3,007	0.25	347	0.28
Maintenance of Miscellaneous Steam Plant	789	0.18	838	0.07	231	0.19
Total, Exclusive of Fuel	35,100	7.84	23,015	1.95	6,526	5.25
Fuel	75,376	16.83	173,802	14.68	28,124	22.61
Total Production Expenses	110,475	24.67	196,816	16.62	34,651	27.85
Plant Characteristics						
Average BTU per kWh Net Generation	11,769		11,089		12,335	
Plant Hours Connected to Load	8,348		8,760		8,033	
Average Number of Employees	343		378		135	
Initial Year of Plant Operation	1973		1978		1939	

Source: Energy Information Administration/Historical Plant Cost & Annual Production Expenses for Selected Electric Plants 1986

TABLE 51

AVERAGE COMPONENTS OF BUSBAR ELECTRICITY COST FOR COAL-FIRED POWER PLANTS

	Cents/kWh
Operation Expenses	0.25
Maintenance Expenses	0.35
Fuel	1.71
Capital Charges	
Depreciation	0.43
Taxes	0.81
Interest	0.42
Net Income	0.62
Subtotal	2.27
Total	4.58

Source: Averaged from data in "Historical Plant Cost and Production Expenses for Selected Electric Plants, 1986"

The magnitude of additional capital and operating costs which would be required to burn a blend of Kansas coal can be expected to vary widely, depending on a utility's existing configuration. In Oklahoma, the Grand River Dam Authority required no new equipment, because their plant had been designed to burn a blend of coals in the first place. Seven different coal silos can each feed to all of the pulverizers, so it was only necessary to dedicate one silo to Oklahoma coal.

At Public Service Company of Oklahoma, the stacker-reclaimer system is a straight-line system. It was possible to stack Oklahoma coal at the end of the line and use the existing emergency stacker-reclaimer for feeding Oklahoma coal onto the conveyor. If need for the emergency reclaimer arises, then blending is halted temporarily. Thus no major new capital investment was required.

At Western Farmer's Electric Cooperative, an existing bunker and cross-feed conveyor is used for the Oklahoma coal to be blended. They have no scrubbers and purchase compliance Oklahoma coal. Thus their capital costs were minimal also.

At Oklahoma Gas and Electric, new blending facilities were built at both the Muskogee and Sooner plants, at a total cost of 7.4 million dollars. The blending system consists of a simple grizzly over a conveyor which ties in to the existing coal reclaim system.

The Oklahoma Gas and Electric case was taken as a conservative (i.e. upper) estimate of capital cost; and busbar costs due to capital charges were derived from Table 51. Possible increased costs for ash and waste handling and disposal were ignored. In addition to capital charges, a major cost item for plants with flue gas desulfurization systems will be the purchase of additional lime or limestone to remove the sulfur emitted from Kansas coal. For a coal sulfur level of 3.7 percent, and a stoichiometric ratio of lime to sulfur, approximately seven tons of lime are required for every 100 tons of Kansas coal. This amounts to a charge of about $3.85 per ton of Kansas coal burned.

Putting all the various costs together, a value was calculated for the increase in the busbar costs of electricity, as shown in Table 52. The percentage increase shown is based on an average busbar cost, not a specific value calculated for each facility. As seen, the estimated increase in the busbar cost of electricity ranges from less than one percent to about 2.4 percent if a 10 percent blend (BTU basis) of Kansas coal is burned wherever allowed by environmental restrictions (quantities given in Table 46).

TABLE 52

BUSBAR COSTS OF COAL BLENDING
(10% BTU Basis)

Station	Increased Fuel Cost Cents/kWh	Other Costs $/Year	Total Increase Mills/kWh	Percent Increase at Busbar
Lawrence	-0.020	449,205	0.15	0.3
Tecumseh	-0.012	49,740	0.04	0.1
Jeffrey	+0.014	4,192,770	0.49	1.1
Holcomb	+0.073	466,949	1.08	2.4
LaCygne #2	+0.024	504,509	0.40	0.9
Nearman	+0.033	221,619	0.49	1.1

TRANSPORTATION REGULATION

Transportation Taxes

Kansas coal markets are being lost to Wyoming coal because of the latter's low sulfur content, low f.o.b. mine price, and low transportation cost. Because of lareg-volume unit train contracts, Wyoming coal moves through Kansas at about half the ton-mile rate paid on a typical Kansas coal movement. A uniform tariff or ton-mile rate for coal shipments would improve the competitive position of Kansas coal. Since the deregulation of the railroad industry, however, uniform tariffs have disappeared and been replaced by individual contract negotiations. There is probably no way to force the railroads to lower rates for in-state coal hauls.

An alternative method of improving the relative position of Kansas coal would be to raise the cost per mile of all coal shipped. Wyoming (and other out-of-state) coal shipments must travel more miles and therefore would be more affected by a ton-mile, or similar tax. Examples of such taxes may be seen in Nebraska (N.S. 74-1320) which levies a $0.075 per train-mile tax and a $100 per year per grade crossing tax. Instead of a train-mile tax, a ton-mile tax would be more effective at targeting coal shipments specifically instead of all railroad freight. However, any such tax would also have an impact on shipment of Kansas grains and other commodities. It may be questionable whether a tax could single out coal alone as the only commodity to be affected. Such a tax has been proposed, but not passed, in Oklahoma. The proposed legislation simply stated that all coal transported by rail within the state shall be subject to a per-ton mileage fee.

Utility Pass-Through

Another technique for targeting utility coal shipments directly would be to remove transportation charges from the allowable electricity rate base. This puts increased pressure on utilities to hold down their total transportation costs, and would favor a high mine cost but low transport cost local coal over a low mine cost but high transport out-of-state coal. Oklahoma proposed that the ton-mile tax mentioned above be excluded from the rate base; and Illinois law excludes transport costs from the automatic fuel adjustment clause.

Bidding Procedures

There is apprehension among Kansas coal producers that railroads can structure their bidding to favor long distance shipments, and therefore total railroad cash flow, against shorter in-state shipments. There is little doubt that this could be possible in certain instances. It is clear from the record that during Burlington Northern's monopoly on shipments from the Powder River Basin it charged much higher prices than after the Chicago and North Western obtained access to the same mines. This proves that railroad market power can exist, and also that the cure is inter-railroad competition. Because the Kansas coal region is served by several railroads, the chances of any one railroad being able to enforce discriminatory freight rates in one part of the system to its benefit in another part of the system appears remote. In 1984, Kansas ranked sixth in the nation in railroad miles with nearly 4.0 percent of total United States trackage. Ten carriers operate over a system of almost 7,000 miles, hauling more than 150 million tons of goods and commodities during 1985.

Kansas coal producers could compete more effectively for utility coal supplies if railroad rates were known ahead of time. The Kansas Corporation Commission could require that utilities receive and publish bids for coal transport before final bids for coal supply are received.

UTILITY RESTRUCTURING

The highest cost coal being burned in Kansas is that being supplied to the Board of Public Utilities from the Brushy Creek Mine in Illinois. Kansas coal producers could effectively compete with this coal on the basis of cents per BTU delivered. The coal is being supplied under long-term contract, and therefore is not vulnerable to replacement. If the Board of Public Utilities power plants are sold to another utility, however, it is possible that the coal supply contract could be bought out or restructured so that a mix of Wyoming and Kansas coal could be used at lower cost. Although the same moves could perhaps be made without any change in ownership, such changes are usually more easily accomplished if extensive other changes are occurring at the same time. There is no obvious role that the state could play in this process, except to encourage re-examination of the coal contract if and when any such restructuring occurs.

COAL USER INCENTIVES

Long-term markets for Kansas coal can be assured only if there are coal burning facilities in place which can burn Kansas coal while meeting all applicable environmental regulations. Such facilities are not being built. Several eastern states are tackling this problem head-on with a variety of incentives to industries and utilities to install systems capable of using local coals. The major barrier to be overcome in almost all cases is the high capital investment required. The incentives being offered to overcome this barrier include direct construction aid grants, low-cost financing through industrial revenue bonds or loan funds, accelerated depreciation, allowance as Construction Work in Progress, income tax credits for the cost of equipment, and exemptions from sales tax and ad valorem tax.

Fluidized bed combustion (FBC) systems appear to be the most promising technology for application in the Kansas region. Empire District Electric is considering a 75-megawatt FBC system which could be installed at the Riverton plant. However, at the present time it is much more likely that the system would be installed in Missouri than in Kansas. Missouri exempts equipment for electric utility plants from sales tax. It appears that the 1987 Kansas legislation which exempts manufacturing equipment does not apply to electric utilities. Also, the property taxes on a plant built in Kansas would be about three times higher than on the same unit built on the Missouri side of the border. On a $100 million investment the tax rate would be $3 million per year instead of $1 million (Kansas assessed valuations are being revised as of January 1, 1989, and it is not known what the comparison will be after that point). These differences provide strong motivation to place any such plant in Missouri rather than Kansas. Although Kansas coal producers could still compete to supply the fuel, Missouri coal mines would obviously have an advantage.

The University of Missouri at Columbia has installed a 25-megawatt FBC cogeneration system. It was financed by revenue bonds issued by the university. The university also has four coal stokers and uses 150,000 tons of coal per year. The University of Missouri at Rolla burns a combination of coal and wood chips. Several universities in the Illinois Basin are installing fluidized bed boilers to use local coals. No universities in Kansas burn coal, although Kansas State University did study the possibility briefly several years ago.

A problem for industrial FBC applications is a United States Environmental Protection Agency regulation promulgated in December, 1987 requiring that new industrial boilers be installed with 90 percent reduction of SO_2 emissions. Although 90 percent removal has been demonstrated with limestone injection in FBC systems, they have not yet been proved to operate consistently at that level.

REGULATORY EFFICIENCY

The time and expense involved in permits for coal mining can be a significant impediment for small coal producers in Kansas. The large number of acres disturbed per ton of coal mined assures that permitting activities will be a larger cost than in areas with thicker coal beds. The time required to obtain permits is important because Kansas coal operators depend on spot sales which sometimes do not allow long lead times for delivery. In Kansas the Office of Surface Mining averages six to eight months to process a permit, and must depend on uncompensated overtime by employees to make that schedule. In Missouri, the average is said to be only four months if baseline water quality data are available.

Missouri has 12 active mines compared to four in Kansas, which may allow a more stable work load with a larger staff. Nevertheless, it appears that staffing may be inadequate in Kansas.

COST/BENEFIT ANALYSIS

EMPLOYMENT EFFECTS

The previous section enumerated a number of actions which could be taken to aid the Kansas coal industry. Any action involves a cost to some entity or group in some place. It is the task of any legislative proposal to be sure that the overall benefits to the State of Kansas will be larger than the overall cost of the proposed action to the State of Kansas.

Benefits of a healthy coal mining industry include the income from direct employment and operating expenditures by the mines. Mining is one of the few industries which are direct generators of wealth. Coal left in the ground untouched has no tangible value to anyone. If properly mined, it creates wealth which did not exist before.

Kansas coal mines employ over 330 people, over 70 percent of whom are residents of Kansas. The estimated payroll to Kansas residents is approximately $11 million per year. In addition, purchases of goods and services within Kansas are estimated to run another $13 million per year. Based on a survey of 17 Oklahoma mines, it is estimated that the goods and services expenditures would be 28 percent in the construction and mining machinery sector, 19 percent in the petroleum products sector, 11 percent in the chemical products sector, 10 percent in the machinery repair sector, nine percent in the automobile repair and services sector, six percent in the transportation and warehousing sector, four percent in the real estate and rental sector, three percent in the finance and insurance sector, and 10 percent miscellaneous.

Various studies of the socioeconomic impact of energy projects suggest that the "ripple effect" of primary employment in such industries is an additional 1.5 jobs in the trade and services sector for each direct employee. If we apply this multiplier to the number of Kansas residents employed directly in the coal mines, the result is 575 jobs in Kansas which depend on coal mining.

The unemployment rate in Kansas has been significantly lower than that of the United States since 1984. However, by January and February, 1988, the latest data available in our data base, the Kansas rate of unemployment was very close to the United States rate. The rate in Kansas in February was 5.5 percent while the rate in the same month in the United States was 5.7 percent.

The rate in Cherokee County has been much higher than Kansas and the United States. It was as high as 10.27 percent in 1986 and had only dropped to 7.9 percent in February, 1988. The rate in Crawford County is also higher than Kansas and the United States but lower than Cherokee County. The unemployment rate in Crawford County was as high as 7.6 percent in 1984 and was at 7.00 percent in February, 1988. The rate in Labette County was as high as 7.14 percent in 1986 and was at 5.9 percent in February, 1988. The rate in Linn County was as high as 9.64 percent in 1986 and was at 11.80 percent in February, 1988. Cherokee and Linn Counties have significant unemployment problems but the unemployment rates in all four counties are higher than the average for Kansas and for the United States.

In 1986, Kansas had an estimated population of 2.46 million. Among the 627 incorporated cities, 50 have a population of more than 5,000, 34 more than

10,000, 12 more than 25,000 and five exceed 50,000. The annual population growth rate for the State of Kansas from 1970 to 1985 was 0.56 percent per year and the trend projection fit the actual growth line with an adjusted R squared (accuracy) of 97 percent, i.e., the variation in population was 97 percent explained by the passage of time.

The plot for Cherokee County shows an upward trend with a forecast population of approximately 23,000 by the year 2000. Crawford County data shows a decrease of 1,000 people between 1972 and 1973 with erratic growth from then on, but on a slightly increasing trend (Figure 17). The plots for Labette County and Linn County also demonstrate fluctuations between 1970 and 1985 with Labette forecasted to approach a population around 26,500 in 2000 and Linn approaching 9,000 in the year 2000 (Figure 18).

Population growth in the United States is positive but the growth rate is negative, i.e., the population is growing but the rate at which population is growing is slowing down. The population growth rate in Kansas is lower than in the United States (0.56 percent versus 1.03 percent) but it is growing rather than slowing down (0.03 percent versus -0.01 percent). This means that the population of the United States is increasing but at a decreasing rate while the population of Kansas is increasing at an increasing rate.

From the plots showing the four counties that will be most affected by changes in Kansas coal production, the population growth has been very erratic for all four counties (Figures 17 and 18). Each of the counties has had at least three years of negative growth within the data period. The trends for Cherokee, Crawford, and Linn Counties are all showing a declining growth rate, with only Labette County showing a positive overall trend.

Per capita income growth in Crawford and Linn Counties followed the pattern for the state through 1983, the latest year available.

Based on the total population, the unemployment rate, and population and income trends, the loss of 575 jobs in Crawford and Linn Counties would have the most serious effect in Linn County, where an increase of over 3.5 percent in the unemployment rate would result, and a lesser effect in Crawford County, where the unemployment rate would increase by less than two percent.

On the other hand, an increase of 700,000 tons per year due to a mandatory burn law could be concentrated in Crawford County, where the result would be an increase of 400 total jobs and should drop the unemployment rate by over two percent.

MANDATORY BURN BENEFITS

The benefits of a mandatory burn law can be calculated in a straight forward way and are very impressive, if the law is successful. If such a law were implemented, and the results were as was shown in Table 46, new demand for over 700,000 tons of Kansas coal per year would be created. This would eliminate the importing of over 1,000,000 tons per year of Wyoming coal. A good part of the cost of the Wyoming coal is transport cost, and it may be argued that some of that expenditure remains in Kansas. Ignoring that factor, however, we would see a transfer of over $20,000,000 per year from the economy of other states and out-of-state railroads back to the economy of Kan-

FIGURE 17

POPULATION AND FORECAST FOR CRAWFORD COUNTY

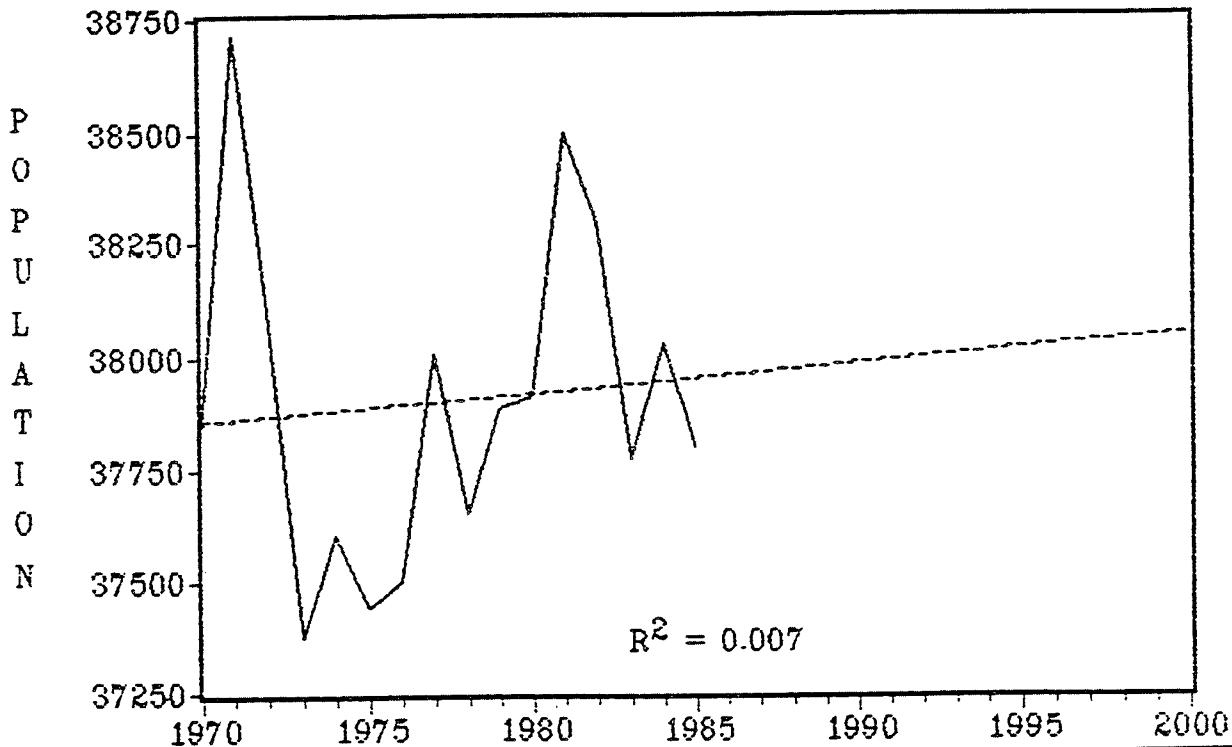
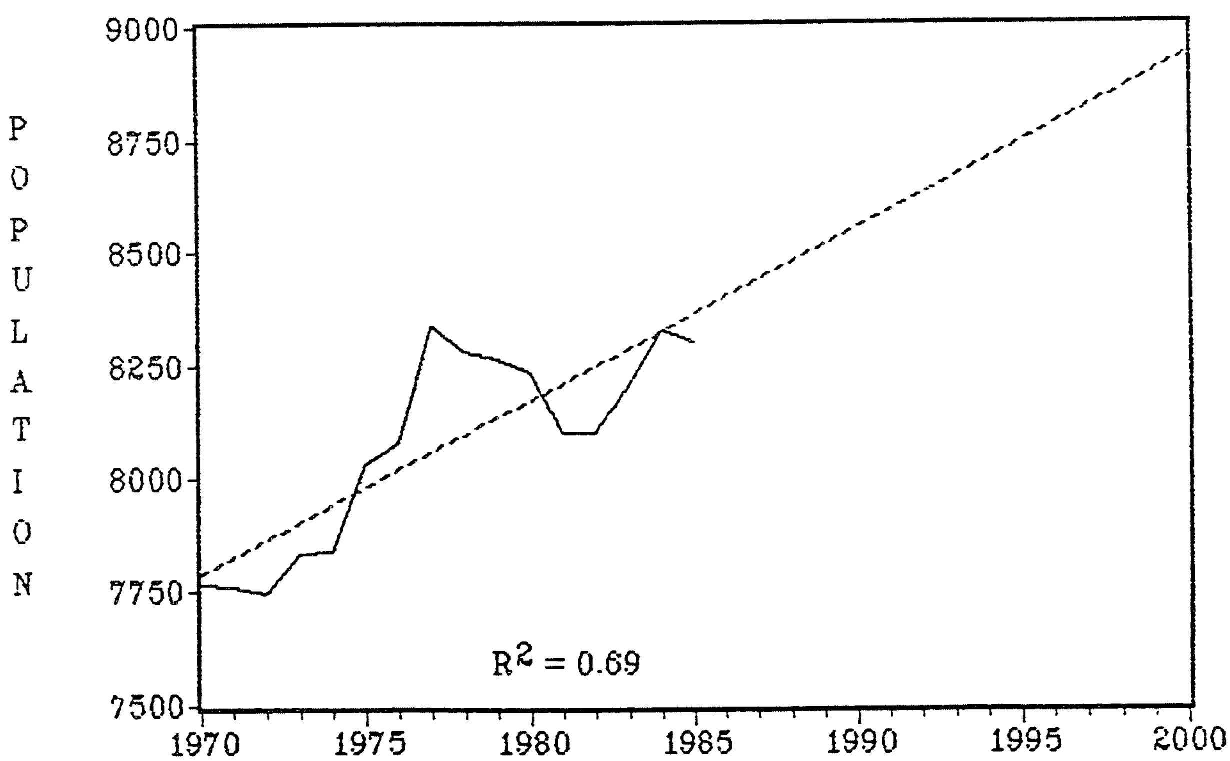


FIGURE 18

POPULATION DATA AND FORECAST FOR LINN COUNTY



sas. If the Kansas coal is supplied at no increase in cost, this is an unarguable economic benefit for the state.

If 400 total direct and indirect jobs are generated, at a value of $25,000 per year each, the total economic activity generated from employment alone is $10,000,000 per year.

If the law allows Kansas coal to cost more (say up to five percent more) then the benefits are less clear cut, because costs begin to be transferred within Kansas, from the Kansas coal miners to the Kansas electrical consumers.

The actual economic benefit which would result depends upon the alternative uses for the capital and human resources which would be employed. The simplest case is to assume that they would not otherwise be employed. Thus, without a blend law the equipment is assumed to be available, and the personnel are assumed to be unemployed. The direct benefit to the state economy can then be determined as the sum of payments not made for imported coal, plus savings due to eliminating unemployment benefits, minus any amount by which the delivered cost of Kansas coal exceeds the cost of the imported coal and minus any increased utility cost for blending and sulfur removal. Calculated results are shown in Table 53.

Although the table clearly shows large overall benefits to the state economy in all cases, there could be substantial costs incurred by the utilities. In addition to any increase in coal and lime costs some would have to add equipment and instrumentation for blending. Oklahoma Gas and Electric testified that their startup costs were $7.43 million with annual cost of $1.4 million for blending in 400,000 tons per year. Any major damage to a boiler could be much more expensive. However, some utilities are able to accomplish blending at relatively little cost.

TABLE 53

ECONOMIC BENEFITS OF A MANDATORY BURN LAW

Percent BTU Value Kansas Coal In Blend	NetBenefit To Kansas Economy, Dollars/Year
2	$4,936,000
4	$9,160,000
6	$13,062,000
8	$16,905,000
10	$20,687,000

There are three ways in which these costs can be distributed. The simplest way is to take the Oklahoma approach, and ignore the cost question, simply requiring the utilities to begin blending. Some of their costs can then be passed through to electric consumers, if approved by the Kansas Corporation Commission. Any costs which are not allowed to be passed through will have to be absorbed by the utility stockholders. To the extent that many of them reside out-of-state, some of the burden can be passed out of Kansas to other states.

The third approach is the one which has recently been instituted in Oklahoma, where a one dollar per ton tax credit for burning Oklahoma coal has been enacted. This allows the utility to recover some of its cost by passing the burden through to the state's general taxpayer.

From the standpoint of the utility company and the electricity consumer, a mandatory blend law should be structured with an "economic out" on the basis of cost of electricity at the busbar, rather than on the cost of coal at the coal pile. That is, one should calculate the delivered price of Kansas coal, plus all the additional capital and operating costs associated with blending, and convert this to the cost of electricity at the busbar (the total cost of electricity measured at the point where it leaves the plant). Blending should be required only if the cost of electricity at the busbar would not be substantially more when using blended coal, than it now costs using current coal sources. From the overall national point of view, this is a correct position.

The individual electricity consumer may see little reason to pay a higher electric bill so that a Kansas coal miner can displace a Wyoming coal miner. From the utility company's point of view there is little or nothing to be gained. Goodwill from the coal industry will be offset by hostility from customers if their electric rate goes up, objections from regulators and the populace if emissions go up, and demands from stockholders that they not be saddled with the costs. The utility will of course object to undertaking the trouble and expense of blending with no reward in sight.

It is unfortunately impossible to state exactly what the effect of blending would be on the busbar cost of electricity. No boiler engineer can say in advance precisely what extra maintenance and repair costs will or will not arise. However, capital and operating costs associated with the mechanics of blending can be estimated. This was accomplished in Table 52. Just as a mandatory burn law should provide an economic out if the delivered price of local coal is more than, say one to five percent above the cost of other coal, there should also be an economic out if the utility can show a visible (say 1.5 percent) effect on the busbar cost of producing electricity.

If passed through to the consumer, high rates for electricity not only hurt the consumer's pocketbook, but also hurt the state's competitive position in attracting industry and business. Kansas electricity rates are already relatively high for the region (Table 54). Only Arkansas has higher rates at 250 and 500 kilowatt-hours per month, and Kansas rates are highest of all at 2,500 kilowatt-hours per month. If there truly is a benefit, and Table 53 strongly suggests there is, to producing coal in-state rather than importing it, then it would be a mistake to transfer all the costs of this benefit onto any one group, such as the electric consumers or the utilities.

TABLE 54

TYPICAL MONTHLY RESIDENTIAL ELECTRICAL BILLS AND RANKING BY STATE FOR 1987

	250 kWh		750 kWh		2,500 kWh	
State	$/Mo.	Rank	$/Mo.	Rank	$/Mo.	Rank
Arkansas	25.12	44	61.45	41	150.46	26
Kansas	23.25	36	57.33	32	169.34	35
Missouri	21.80	28	51.73	22	126.73	9
Nebraska	19.13	18	43.40	9	102.21	1
Oklahoma	23.21	34	51.74	23	125.67	7
Texas	20.25	22	51.24	21	133.07	12

Source: DOE/EIA-0040(87), Typical Electric Bills, 1987.
Note: Lowest bill has rank of "1"; highest bill has rank of "51".

If some of the benefits could be transferred to the utilities, then they might not fight the measure, as they will be compelled to do otherwise. It should be possible to create a win/win situation for coal producers versus utilities instead of the win/lose situation produced in Oklahoma. The benefits of increased jobs and economic activity in Kansas will not accrue to any one group within the state. Therefore the state as a whole must be presumed to be the benefiter who could best share the results. There are various ways in which this could be done. A tax credit per ton of coal burned is one. A credit for the costs of coal blending equipment is another. Another way would be to allow an increase in the utility's rate of return depending on how many tons of Kansas coal are used.

NEW FACILITY INCENTIVES

Incentives for building new facilities which use Kansas coal will generally have to be provided by the state, although local property tax relief can be effective also. In calculating the costs of incentives for new development, the question arises: why provide incentives if the development will occur anyway? It is easy, especially for local governments, to forego all taxes as an incentive for a new development, and then find that they are unable to raise from other sources the taxes required to service the new development. In the case of facilities which burn Kansas coal, however, it is clear that no such development is occurring. Therefore offering incentives is not giving away taxes that would otherwise be collected. In this situation tax incentives are not a cost, in that they do not reduce current revenues. The benefit to cost ratio is therefore very high.

For example Empire District Electric is unlikely to build a new fluidized bed boiler unit in Kansas given that they would have to pay much higher sales and ad valorem taxes than in Missouri. These taxes, therefore, will never be realized in Kansas. In offering to forego these taxes as an incentive, the cost is actually zero. If the facility is built, then some other way of raising taxes must be found, but the net benefits to the state (not necessarily to local taxing entities, without other means of raising taxes) will always be positive.

Direct capital construction grants are the most expensive, but probably the most effective incentive around. The power of such grants can be multiplied by tying into federal funding for the Clean Coal Technology program. Typically a state grant of one dollar will bring forth an additional two or three dollars of federal funds. There is no well-accepted way of calculating a benefit/cost ratio for such grants, but considering that a permanent new market for Kansas coal would result, an appreciable fraction of the facility cost could be justified as an incentive.

Other construction incentives such as tax credits, loans, etc. are less expensive but also less effective. When successful, their benefit/cost ratio is higher than that of direct grants, but the point is moot if no activity results.

A direct way of raising funds for new facility incentives would be to impose a burn tax on coal used for generating electricity. A flat tax per ton would also give some market advantage to Kansas coal over Wyoming coal because of the Kansas coal's higher BTU value per ton. A burn tax of as little as 10 cents per ton could raise over a million dollars per year for coal user incentives. Funds of this magnitude could be extremely effective in aiding the early stages of potential new coal-burning projects.

An example of the benefits which can accrue from encouraging a fluidized bed combustion facility capable of burning local coal may be seen in the cogeneration plant under construction at Poteau, Oklahoma. This 300 megawatt unit will consume some 500,000 tons of Oklahoma coal per year. In addition, the coal producers will also supply limestone to the plant. The plant itself will cost $475,000,000, and when complete will have 80 permanent employees with a payroll of $5,000,000.

CONCLUSIONS AND RECOMMENDATIONS

DECLINING COAL MARKETS

Markets for Kansas coal are disappearing rapidly for two reasons. First, increasingly stringent pollution control regulations make it impossible for many users to continue burning high-sulfur coal. Nearly inevitable acid rain legislation will make this situation worse. Second, low-cost coal from other areas, especially Wyoming, is being delivered to Kansas in unit trains on a lower cost per BTU basis.

The only "natural" market for Kansas coal is Kansas cement kilns, which are located far from other coal fields and can accept the sulfur. This market is subject to competition from petroleum coke, natural gas, and waste solvents, but is relatively secure for the future.

UTILITIES HOSTAGE TO OUTSIDE SUPPLIERS

Kansas electric utilities face the potential danger of becoming hostage to forces outside the state for fuel supplies. With almost all Kansas utility coal coming from Wyoming, the State of Wyoming has the power, through coal taxes, to transfer much of the cost of its state government to the citizens of Kansas. Wyoming mines are numerous and competitive and cannot exert market dominance, but the state could do so. Severance taxes grew from five percent of Wyoming tax revenue in 1971 to 29 percent in 1981. The first coal severance tax levied was one percent in 1969, and grew to 10.5 percent for surface coal and 7.25 percent for underground coal in 1987. In 1988 the rates declined to 8.5 percent and 5.25 percent, respectively. There is little to limit the ability to make increases in the future. If Wyoming should institute a 30 percent severance tax such as was in force in Montana until recently, the effect on Kansas would be over $30 million per year. In addition to severance taxes, counties levy an ad valorem tax averaging 6.5 percent of the value of coal shipped. Wyoming has no corporate income tax.

The other key element in Wyoming's capture of the utility coal market is railroad rates. Immediately after passage of the Staggers Act in 1980, Burlington Northern increased rail rates from the Powder River Basin sharply. With the entry of another railroad into the region in 1985, rates declined. With only one other railroad having access to the region, however, the potential for large railroad rate increases in the future is clear.

STATE INTEREST IN DIVERSITY OF FUEL SOURCES

Over-reliance on any one fuel source for electricity could make the state vulnerable to supply and price disruptions. It is in the state's interest to make sure this does not occur. The State of California, for example, has developed a system diversity policy, enforced through the California Energy Commission, to ensure diversity of sources in the electrical supply system. Kansas-mined coal should be a keystone to such considerations in Kansas. Without state action, however, the coal industry will continue to wither.

A MANDATORY BURN LAW WOULD CREATE OVERALL BENEFITS TO THE STATE

A mandatory burn law, or a law requiring coal-fired electric utilities to burn a certain minimum percentage of Kansas-mined coal, should create overall economic benefits to the state. The direct benefit comes from reducing the amount of money which must be sent outside the state to pay for imported coal. If Kansas coal could be supplied to the utilities at no increase in cost a very large benefit on the order of a $20 million per year increase in the state's economic product could result. Even if the Kansas coal were considerably more expensive, an overall benefit could still result because the law would reduce the relatively high unemployment rate in southeast Kansas and increase the utilization of existing capital equipment and resources. All cases examined in this study, up to a 10 percent blend by weight, produce positive economic results for the state.

OUTCOME OF MANDATORY BURN LAW UNCERTAIN

A mandatory burn law, such as enacted in Oklahoma and Arkansas, seems to provide a simple, stroke-of-the-pen way to increase local coal consumption significantly. Overall benefits to the state economy of such a law should be substantial. However, the situation in Kansas makes such a law difficult to institute. Many Kansas coal-fired boilers are old, and are having difficulty meeting sulfur dioxide emission limits. It would be legally impossible for them to start burning higher-sulfur Kansas coal. Figures 19 and 20 illustrate the maximum increased demand for Kansas coal would result from a mandatory burn of 10 percent by BTU content and by weight, respectively. Facilities already burning Kansas coal would not be affected and are not shown. Figures 21 and 22 show the effect of existing limits on increased sulfur dioxide emissions.

Only one utility station in Kansas, Jeffrey Energy Center operated by Kansas Power and Light, appears capable of accepting a large amount of Kansas coal. It accounts for 560,000 tons per year of the total 760,000 tons per year that would be mandated by a 10 percent (BTU basis) law. The closeness of this plant to Wyoming, and its distance from southeast Kansas, may make it impossible for Kansas coal to be competitive. Estimates made in this report suggest that Kansas coal would be more than five percent more costly at the plant. If the Jeffrey Energy Center is exempted, there might not be enough increase resulting from a mandatory burn law to make it worthwhile.

STRUCTURE OF MANDATORY BURN LAW

The purpose of enacting a mandatory burn law (or any other law for that matter) should be related to overall benefits to the State of Kansas. It must therefore contain provisions to avoid uneconomic arrangements. One such provision would be a test for delivered price of coal (on a BTU basis) to the stockpile. Kansas coal should cost no more than, say, five percent above the cost of other coal.

A second such provision would be a test for the busbar cost of producing electricity. Burning Kansas coal should increase the cost of electricity no more than, say 1.5 percent, when the cost of equipment and operating expense to accomplish the blending is considered.

A third such provision would limit the amount of Kansas coal required to be burned to that which, on the average, would cause sulfur dioxide emissions at the plant to be no more than 80 to 90 percent of the legally allowed maximum.

FIGURE 19

MAXIMUM POSSIBLE NEW DEMAND FOR KANSAS COAL

(10 Percent BTU Basis)

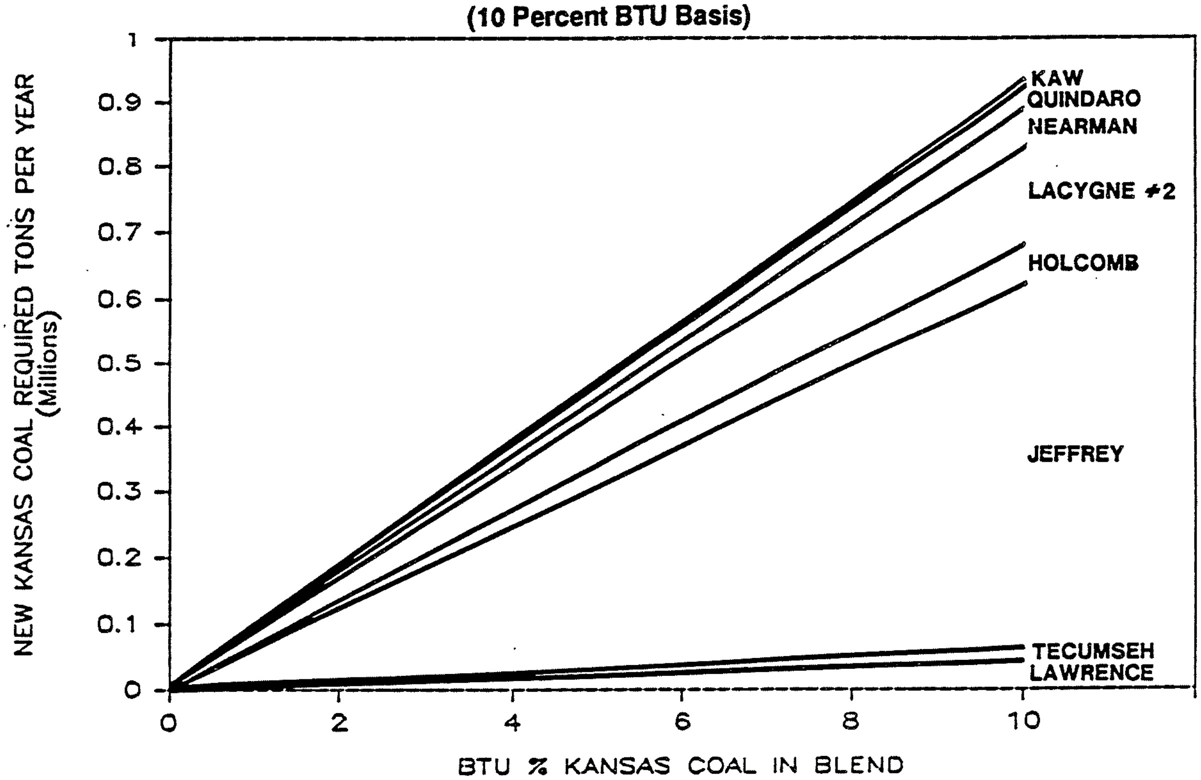
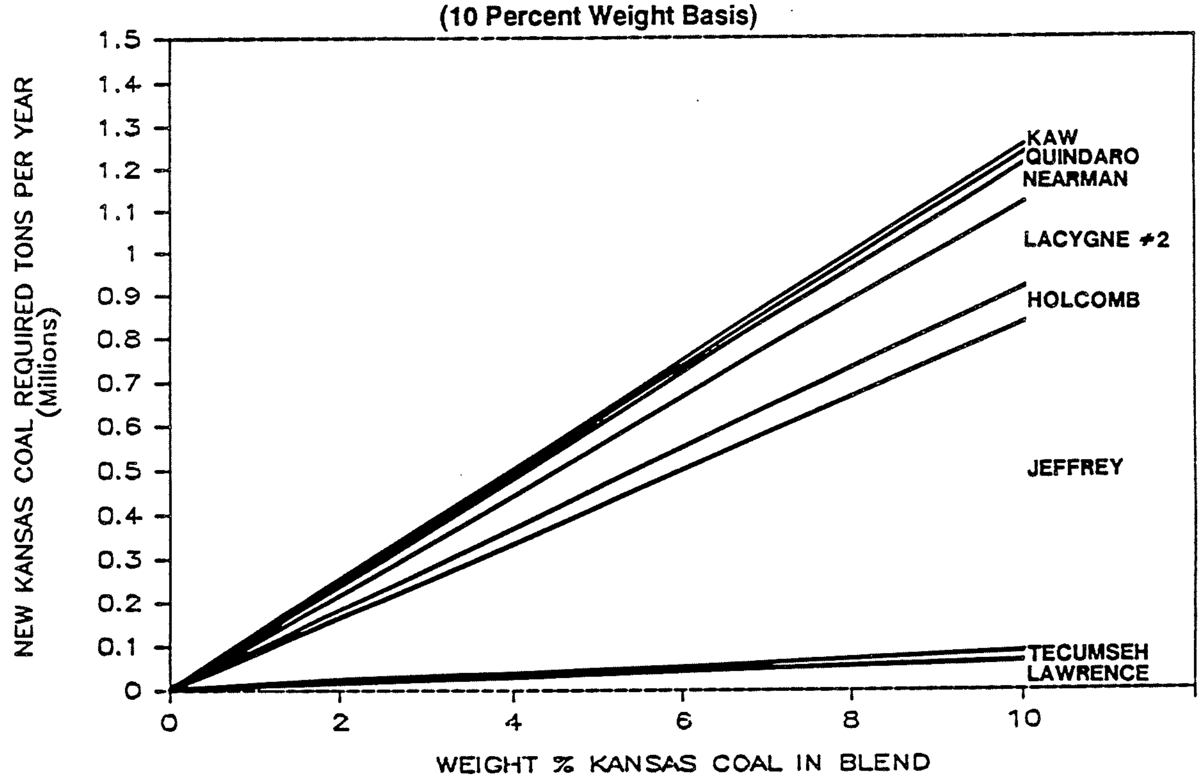


FIGURE 20

MAXIMUM POSSIBLE NEW DEMAND FOR KANSAS COAL

(10 Percent Weight Basis)



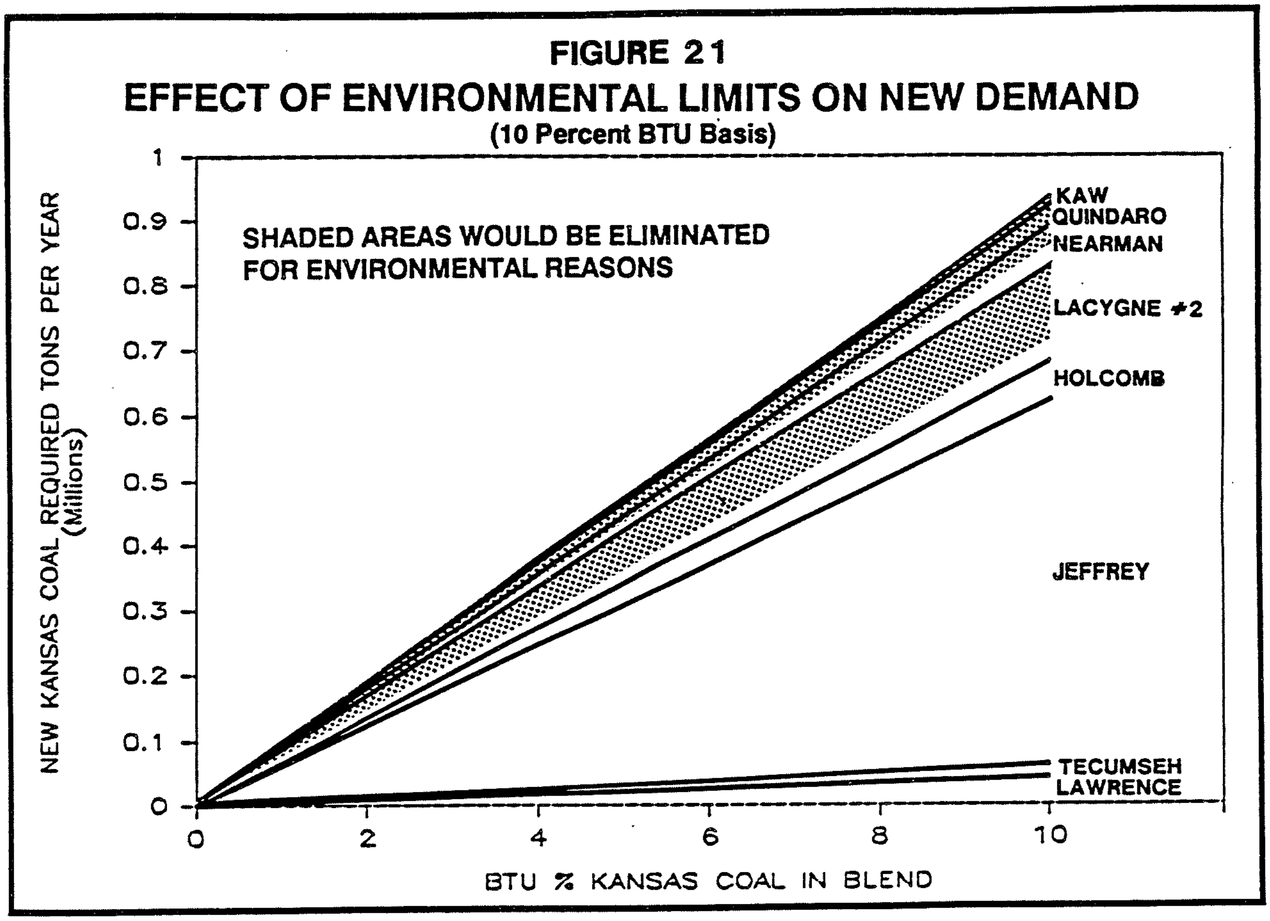


FIGURE 21
EFFECT OF ENVIRONMENTAL LIMITS ON NEW DEMAND
(10 Percent BTU Basis)
SHADED AREAS WOULD BE ELIMINATED FOR ENVIRONMENTAL REASONS
NEW KANSAS COAL REQUIRED TONS PER YEAR (Millions)
BTU % KANSAS COAL IN BLEND
KAW
QUINDARO
NEARMAN
LACYGNE #2
HOLCOMB
JEFFREY
TECUMSEH
LAWRENCE
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
0
2
4
6
8
10

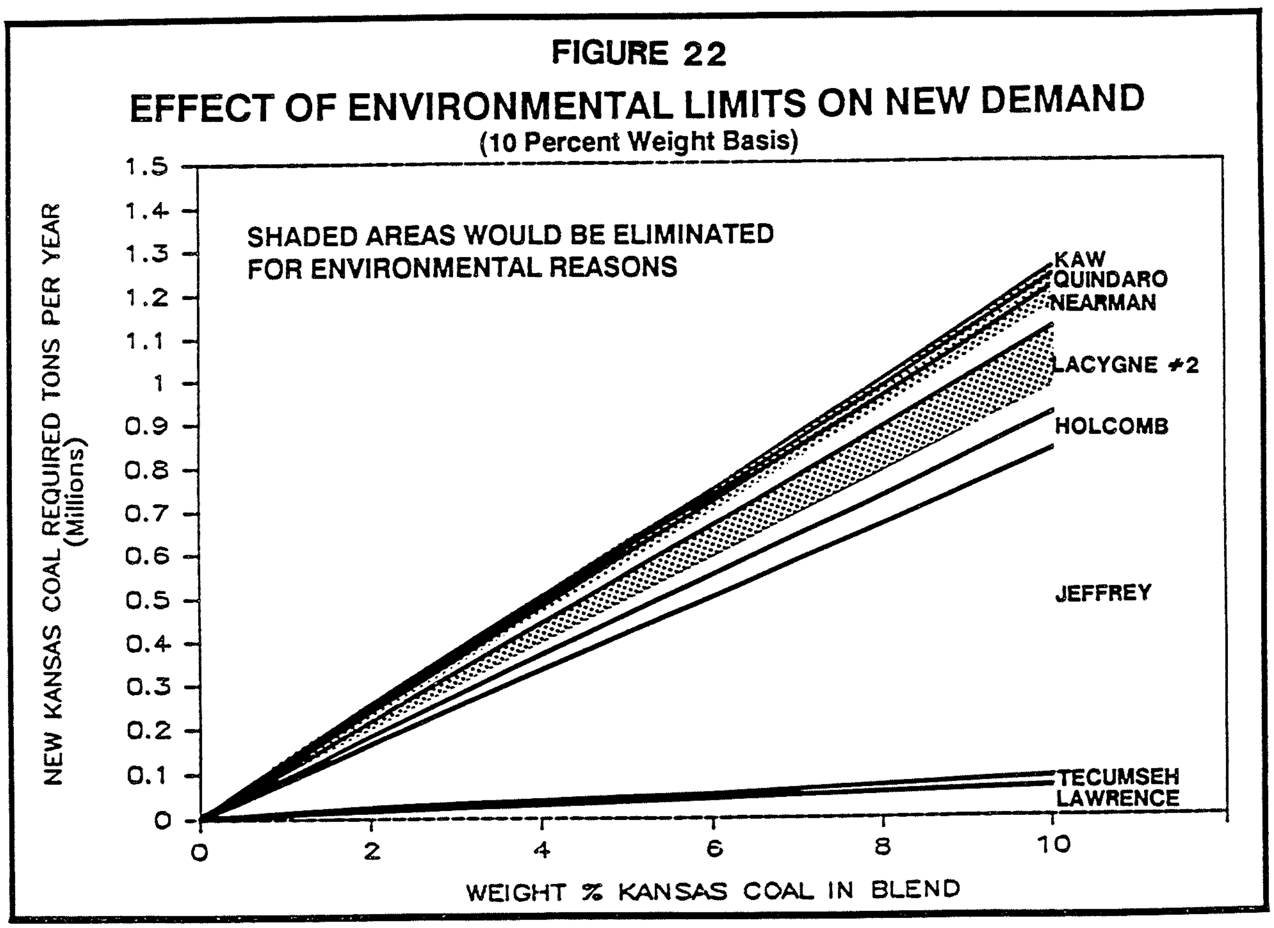


FIGURE 22
EFFECT OF ENVIRONMENTAL LIMITS ON NEW DEMAND
(10 Percent Weight Basis)
SHADED AREAS WOULD BE ELIMINATED FOR ENVIRONMENTAL REASONS
NEW KANSAS COAL REQUIRED TONS PER YEAR (Millions)
WEIGHT % KANSAS COAL IN BLEND
KAW
QUINDARO
NEARMAN
LACYGNE #2
HOLCOMB
JEFFREY
TECUMSEH
LAWRENCE
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
1.1
1.2
1.3
1.4
1.5
0
2
4
6
8
10

Because diversity of fuel sources and security of domestic fuel supply are in the interests of the electricity consumer, some of any additional costs due to burning Kansas coal should be passed through to the consumer. Because the jobs and economic activity resulting from coal production are in the interests of the state as a whole, some of any additional costs should be assumed by the state, such as through tax credits for the installation of blending equipment or for the purchase of Kansas coal. The law should be structured in such a way as to provide utilities with an economic incentive to comply with the law rather than avoid it.

LAW MAY BE OVERTURNED

There is a good probability that the Oklahoma mandatory burn law will be ruled unconstitutional next year. Because utilities could be forced to make major expenditures to install blending capability, and because coal companies would have to make investments to expand capacity, the effective date of such a law should be some time after a ruling is issued on the Oklahoma law.

DIRECT ASSISTANCE TO COAL PRODUCERS

This study finds little in the way of direct aid to coal producers that would have a significant effect. Taxes are lower in Missouri and this has some effect. It does not, for example, influence the Midway Mine's choice of which side of the border to operate on. That choice is dictated by geologic conditions.

Reducing the time required to process mining permits would be of benefit to the smaller mines. It seems to take more time in Kansas than in Missouri.

A real benefit to smaller mines would be state assistance in proving, on an area basis, that a partial soil substitute is as effective as 48 inches of topsoil for reclamation. Smaller mines cannot afford test plots to prove equal vegetative productivity, and therefore have no choice but to store and replace 48 inches of topsoil on prime farmlands.

Coal severance taxes do not apply to small mines (under 350,000 tons per year), therefore no tax relief is possible.

CLEAN COAL TECHNOLOGY

Deep cleaning of coal, that is, beneficiation of Kansas coal to produce fuel with a low enough sulfur content to meet New Source Performance Standards is not rated as promising.

Of all clean coal technologies under development, fluidized bed combustion is far out in front, and is commercially proven on industrial and small utility scale (75-100 megawatts). Demonstrations at the medium-size utility scale (300 megawatts) are on the way.

Fluidized bed combustion systems should be an ideal way for industrial and small utility coal users to include Kansas coal as a fuel option. A number of universities are installing fluidized bed systems at their power plants. The University of Missouri has installed a 25-megawatt fluidized bed cogeneration system to burn high-sulfur Missouri coal. The University of Cincinnati is installing a fluidized bed boiler which will burn high-sulfur Ohio coal to produce 150,000 pounds of steam per hour. Purdue University is installing a fluidized bed boiler which will burn high-sulfur Indiana coal to produce 200,000 pounds of steam per hour. The University of Northern Iowa is installing a 100,000 pound per hour fluidized bed boiler capable of burning Iowa coal. A similar project at a Kansas university could spearhead state efforts to utilize this technology.

ASSISTANCE TO NEW OR EXPANDED COAL USERS

If the Kansas coal mining industry is to survive for the long term, there must be coal-burning facilities technically and legally capable of burning high-sulfur coal, located within economical shipping distance from the mines.

The primary recommendation of this study is that the State of Kansas become involved with projects to build or expand the capability to burn Kansas coal. Most states with deposits of high-sulfur coal have developed very active programs of this type. Large amounts of money are available on a cost sharing basis from the federal government's Clean Coal Technology program.

The large initial capital cost of coal burning systems provides a barrier to their adoption. State assistance can be provided in the form of direct construction grants, tax credits, regulatory treatment of costs for utilities, and loans and bond funds. All these forms of aid can contain the proviso that the project must be constructed so as to be capable of meeting all environmental regulations while burning (say) a 3.5 percent sulfur Kansas coal. Once the capital structure is in place, Kansas coal producers will have to compete with others to provide the most economical fuel supply. We believe they should be able to do so.

A strong effort should be made to ensure that utilities which operate in other states besides Kansas will site future facilities in Kansas and make them capable of burning Kansas coal.

Funding for an incentive program can come from a variety of sources. A tax on coal burned for electricity acknowledges that electric consumers will benefit from increased diversity and security of fuel supply. A ton-mile tax on coal transport acknowledges that there is a disbenefit to having the state rely on far-away fuel sources, and it somewhat levels the playing field for Kansas coal producers who must pay higher ton-mile freight rates. Allocations from the state's general fund acknowledge the economic benefit of producing coal in-state rather than importing it. Tax credits, tax deferrals, tax holidays, and tax exemptions require no direct funding from other sources.

Specifically, it is recommended that:

1. A sales tax exemption be provided for all coal-fired utility and non-utility boiler systems which are designed to meet all environmental control regulations while burning Kansas-mined coal.

2. A reciprocal tax rate system be established for utilities which operate in both Kansas and other states. This would insure that if such utilities build new facilities in Kansas to use Kansas coal, then to the extent that electricity from such facilities is supplied to other states, the utility will not be taxed at a higher rate than if it had built the plant in the state which receives the electricity. This will require coordination of state taxes with local ad valorem taxing authorities.

3. A credit against corporate income tax be allowed for 25 percent of the capital cost of installing a commercial or industrial coal-burning system capable of meeting all environmental regulations while burning Kansas coal.

4. A direct grant-in-aid be provided to any project which qualifies for federal cost-sharing under the Clean Coal Technology program and involves a technology which would increase the use of Kansas coal.

5. A coal technology fund be established to provide aid to universities or other non-profit institutions who desire to install facilities to burn Kansas coal.

6. In order to provide funds for (4) and (5) above, either a tax on coal burned for electricity could be levied or a ton-mile tax on coal transport by railroad could be levied, or funds could be provided from general revenues.

7. The Kansas Corporation Commission be instructed to institute favorable rate treatment for modifications, expansion, or new construction of electric utility facilities which are designed to use Kansas coal. This should specifically apply to LaCygne Unit No. 1, so that unit will be able to burn all Kansas coal rather than converting either wholly or partially to imported low-sulfur coal.

Testimony

Presented to:

The Senate Assessment & Taxation Committee

on Senate Bills 227, 228 and 229

by

Harland E. Priddle
Secretary of Commerce

March 1, 1989

Attachment 2
Senate Assessment and Taxation
Wednesday, March 1, 1989

Good morning ladies and gentlemen. I am happy to be here today as Chairman of the Kansas Coal Commission. I would like to brief you on the origin of the three bills you are considering and explain what they hope to accomplish.

The 1987 Kansas Legislature created the Kansas Coal Commission to study ways to expand existing markets and to create new markets for Kansas coal. Funds were appropriated, to be matched by private contributions, for the purpose of conducting a study to address these issues. The commission hired J.E. Sinor Consultants, Inc. of Niwot, Colorado, to conduct the Kansas Coal Utilization Study.

The major focus of the study was to analyze the current Kansas coal market, perform a competitive analysis of Kansas mining, transportation, and environmental conditions, and recommend possible actions to aid the state's coal industry. The three bills you are considering are a result of the study recommendations for improvement in the Kansas coal industry.

The study indicates the Kansas coal market primarily results from sales to electric utilities. In 1987, approximately 1.67 million tons of the 2.02 million tons of coal mined in Kansas were sold to electric utilities. Approximately 355,000 tons were sold to industrial users. Although the majority of sales are to utilities, Kansas coal only comprised about 10.2% of the total amount of coal burned by Kansas utilities in 1987. Figures for 1988 will show a decrease in this percentage to approximately 5% because of the shutdown of the Midway mine at LaCygne. The attached table indicates Wyoming coal comprised over 84.5% of all coal burned in Kansas utilities in 1987 and may increase to approximately 88% in 1988.

Environmental concerns are the major reason to this dependence on Wyoming coal. Kansas mined coal typically contains between 2.5 and 6 percent sulfur as compared to .3 to 1.0 percent for Wyoming coal. Environmental standards regarding sulfur emissions have caused significant fuel source switching. The other important factor which contributes to the dependence on Wyoming coal is the cost. Tables 37 and 38, which are attached to my testimony, compares the long term delivered cost of Wyoming and Kansas coal to the major power plants in Kansas. The data indicates that Kansas coal is price competitive (absent the environmental constraints) with Wyoming coal at the eastern plants in Kansas. Given the advance of new technology, which is at the heart of these bills, environmental concerns with Kansas coal may be relieved to the point that Kansas mines can compete for at least the utility coal markets in the eastern third of Kansas.

The outlook for electric utility sales is not good under the present circumstances. The major in-state electric utility user has recently entered into litigation to decrease the amount of Kansas coal purchased through a long term contract. This decrease is said to be necessary because the utility can not burn as high a percentage of Kansas coal and meet sulfur dioxide emission limits. Additional utility outlets for Kansas coal is not promising either with only one new boiler slated to come on line within the region or state by 1995.

It is this particular unit which is the basis for two of the bills before the committee. Empire District Electric Company is considering the installation of a fluidized bed combustion system either in Missouri or Kansas. The adoption of SB 227 and SB 228 would provide some tax incentives to Empire and other electric utilities for the installation of coal burning equipment capable of meeting all environmental standards while burning Kansas coal.

Because of the high sulfur in Kansas coal, usage will continue to decline unless new technology, which is being developed, can be installed. Existing electric generating units would also be potential targets for retrofitting and modification. The implementation of tax incentives to reward these changes would improve the chances for Kansas coal to compete in the marketplace.

The implementation of this new technology will also demand the infusion of capital and research and development monies by coal users. One avenue to address these costs is contained in SB 229. A five cent per ton tax on all coal burned would allow the creation of a coal technology fund to be used to stimulate the development and installation of clean coal technology. Coupled with federal Clean Coal Technology funds, these monies could encourage the technological advancement necessary to overcome environmental concerns with Kansas coal. The end result would be a larger market for Kansas coal and upgraded industrial and utility combustion equipment.

Although brief, I hope this testimony helps set the purpose for this proposed legislation. I or my staff is available to answer any questions you may have.

TABLE 37

COMPARATIVE TRANSPORT CHARGES FOR WYOMING AND KANSAS COALS

Plant	Rail Miles Wyoming	Rail Miles Kansas	Freight Wyoming $/Ton	Freight Kansas $/Ton
Lawrence	750	150	13.12	9.50
Nearman	780	140	13.65	9.10
Tecumseh	730	170	12.77	10.30
Holcomb	780	390	13.65	19.10
Jeffrey	700	200	12.25	11.50
LaCygne	870	70	15.22	6.30

TABLE 38

COMPARATIVE LONG-TERM DELIVERED COSTS FOR WYOMING AND KANSAS COALS

Plant	Wyoming Freight $/MMBTU	Wyoming Total $/MMBTU	Kansas Freight $/MMTBU	Kansas Total $/MMBTU
Lawrence	0.78	1.31	0.38	1.34
Nearman	0.81	1.34	0.36	1.32
Tecumseh	0.76	1.29	0.41	1.37
Holcomb	0.81	1.34	0.76	1.72
Jeffrey	0.73	1.26	0.46	1.42
LaCygne	0.91	1.44	0.25	1.21

TABLE 9

ORIGIN OF COAL RECEIVED AT KANSAS ELECTRIC UTILITY PLANTS 1986-1987

Plant, State	Year	1,000 Tons	Pct.*	BTU/Lb	Pct. Sulfur	Cents/MMTBU
Riverton						
Kansas	86	132.6	47	12,123	2.64	132.6
	87	144.2	68	11,915	2.47	132.6
Missouri	86	51.6	18	12,008	2.91	135.5
	87	none	0	-	-	-
Oklahoma	86	95.9	34	11,960	2.74	136.3
	87	67.1	32	11,648	0.48	176.0
Kaw						
Illinois	86	79.1	100	11,559	2.48	156.5
	87	83.3	100	11,264	2.37	207.6
Nearman						
Wyoming	86	954.7	100	8,416	0.29	122.0
	87	915.8	100	8,297	0.32	102.0
Quindaro						
Illinois	86	204.8	100	11,437	2.48	168.3
	87	338.9	100	11,220	2.43	217.8
LaCygne						
Illinois	86	none	-	-	-	-
	87	58.2	2	11,019	3.38	123.2
Kansas	86	953.2	31	9,237	5.08	119.3
	87	1,394.7	37	9,285	5.09	126.2
Missouri	86	459.9	15	9,249	5.07	119.0
	87	235.2	6	9,162	4.84	125.8
Wyoming	86	1,653.7	54	8,444	0.34	118.2
	87	2,045.1	55	8,458	0.31	99.0
Jeffrey Energy Center						
Wyoming	86	7,654.9	100	8,327	0.34	129.6
	87	8,002.8	100	8,391	0.33	128.8
Lawrence						
Wyoming	86	693.5	100	10,723	0.70	172.6
	87	690.1	100	10,940	0.85	152.1
Tecumseh						
Wyoming	86	173.9	100	10,731	0.71	172.5
	87	155.6	100	10,960	0.88	147.9
Holcomb						
Wyoming	86	794.8	100	8,319	0.38	145.4
	87	902.1	100	8,282	0.35	105.5
Total State						
Kansas	86	1,085.8	8			
	87	1,538.9	10			
Missouri	86	511.5	4			
	87	235.2	2			
Oklahoma	86	95.9	1			
	87	67.1	0			
Illinois	86	280.9	2			
	87	480.4	3			
Wyoming	86	11,925.5	86			
	87	12,711.5	85			

*Percent of Quantity may not total 100 due to rounding.

Source: DOE/EIA-0191, Cost and Quality of Fuels for Electric Utility Plants, 1986-1987

TABLE 14

NEW COAL-FIRED GENERATING CAPACITY TO 1998

State and Date		Plant	Size MW	Coal Required Tons/Year
Arkansas		No Coal Units Before 1998		
Kansas	1992	Riverton	75.0	150,000
Missouri	1996	Watson	630.0	1,500,000
Nebraska		No Coal Units Before 1998		
Oklahoma		No Coal United Before 1998		

TABLE 15

POTENTIAL NEW COAL-FIRED GENERATING CAPACITY IN KANSAS
(For Post-2000 Startup)

Year	Plant	Size, MW	Coal Required, Tons/Year
2000	Nearman Creek #2	275	700,000
2000+	Site X	650	1,500,000
	Jeffrey #4	680	1,500,000
	Holcomb #2	275	800,000
	State Total	1,880	4,500,000

Distribution of Coal

A substantial amount of Bureau of Mines (BOM) District 19 (see Table 16 for key to districts) coal has always been used in Arkansas generating plants. District 19 coal use in Arkansas generating plants doubled between 1980 and 1982, continuing to increase until 1987.

The major supply of coal to Nebraska's generating plants is also coming from district 19 (99 percent). Although districts 4 (Ohio), 9 (Kentucky), and 15 (Kansas, Missouri, and parts of Oklahoma) have supplied coal in the past, only districts 16, 17 (Colorado), and 19 are supplying Nebraska's generating plants in 1987.

Kansas utilities currently receive coal from BOM districts 10 (Illinois), 15 (Kansas, Missouri, and parts of Oklahoma), and 19. The primary source of coal is from Wyoming.

District 19 also supplies Missouri with coal for their utilities; however, Missouri utilities are receiving a substantial amount of coal from district 10, as well as from districts 8, 9 (Kentucky), and 15.

Oklahoma utilities receive most of their coal from BOM district 19 (Wyoming); smaller amounts have historically come from districts 14 (Arkansas and part of Oklahoma) and 15. The mix will change with a new Oklahoma law which requires that 10 percent of utility coal be from local sources.

Appendix #1

3-9

KANSAS DEPARTMENT OF HEALTH AND ENVIRONMENT

SURFACE MINING SECTION

ANNUAL COAL PRODUCTION
(TONS)

December 31,1988

Active Mines	1982	1983	1984	1985	1986	1987	1988
Alternate Fuels, Inc.							
Croweburg Mine	205,000	195,180	215,000	202,000	216,527	256,999	227,953
Bill's Coal Co.							
Ft. Scott Mine	114,984	236,740	164,538	-0-	-0-	-0-	-0-
Fulton Mine	101,308	-0-	-0-	-0-	-0-	-0-	-0-
Chetopa Mine	120,309	67,233	-0-	-0-	-0-	-0-	-0-
Iron Horse Mine	-0-	38,277	212,242	80,334	558	-0-	-0-
Clemens Coal Co.							
Mine 22	298,730	222,802	256,474	218,512	245,214	353,174	190,888
Oswego Coal Co.							
Alpha Mine	8,024	83,515	39,941	-0-	58,400	-0-	-0-
P&M Coal Mining Co.							
Midway Mine	544,937	461,306	418,059	487,917	953,706	1,394,753	279,821
Ranchers Coal Inc.							
Alpha Mine	-0-	-0-	-0-	-0-	-0-	5,111	1,627
Zimmerman							
G&Z Mine	-0-	-0-	-0-	201	6,908	11,301	1,234

Attachment 3
Senate Assessment and Taxation
Wednesday, March 1, 1989

<u>Quality Coal, Inc.</u>							
Santa Fe Mine	-0-	-0-	-0-	-0-	-0-	-0-	32,818
<u>No Mining Activities</u>							
<u>Alliance Resources</u>							
Bone Creek Mine	-0-	-0-	-0-	-0-	-0-	-0-	-0-
<u>Fuel Dynamics</u>							
Golden Eagle	-0-	-0-	-0-	-0-	-0-	-0-	-0-
<u>Pat's Coal Company</u>							
Drywood Mine	2,631	-0-	-0-	-0-	-0-	-0-	-0-
TOTALS:	1,395,923	1,305,053	1,306,255	988,965	1,481,317	2,021,338	734,34

TESTIMONY

PRESENTED TO:

THE SENATE ASSESSMENT AND TAXATION

COMMITTEE

ON SENATE BILLS 227, 228, AND 229

BY

WILLIAM GILES
DISTRICT #14 PRESIDENT OF THE

UNITED MINE WORKERS OF AMERICA

AND

A MEMBER OF THE KANSAS COAL COMMISSION

MARCH 1, 1989

GOOD MORNING LADIES AND GENTLEMEN. MY NAME IS BILL GILES AND I AM THE DISTRICT #14 PRESIDENT OF THE UNITED MINE WORKERS OF AMERICA WHICH REPRESENTS COAL MINERS IN THE STATE OF KANSAS. ALSO, I AM APPOINTED BY THE GOVERNOR TO SERVE ON THE KANSAS COAL COMMISSION.

THE KANSAS COAL COMMISSION WAS CREATED BY AN ACT OF THE 1987 KANSAS LEGISLATURE. THIS COMMISSION WAS ESTABLISHED TO STUDY WAYS TO EXPAND EXISTING MARKETS AND CREATE NEW MARKETS FOR KANSAS COAL.

AS YOU CAN SEE BY THE ATTACHED SHEETS OF THIS STATEMENT FROM THE KANSAS DEPARTMENT OF HEALTH AND ENVIRONMENT, SURFACE MINING SECTION, ANNUAL COAL PRODUCTION, FROM 1982 THRU 1988 THAT KANSAS COAL PRODUCTION IS AT THE LOWEST POINT IT HAS BEEN IN SEVEN (7) YEARS.

WHEN THE KANSAS COAL COMMISSION WAS LOOKING INTO WAYS TO HELP PRESERVE THE KANSAS COAL MARKET, WE LEARNED THAT SOME STATE LAWS NEEDED TO BE CHANGED TO BE MORE COMPETITIVE WITH NEIGHBORING STATES.

SENATE BILL NO. 227 GIVES A TAX INCENTITIVE ON ALL TANGIBLE PERSONAL PROPERTY AND SERVICES PURCHASED FOR THE PURPOSE OF USING KANSAS PRODUCED COAL. WE URGE YOU TO ADOPT THIS LEGISLATION.

SENATE BILL NO. 228 WOULD ALLOW TAX CREDITS AGAINST CORPORATE LIABILITY FOR CERTAIN COST OF PURCHASING AND INSTALLING A COAL BURNING SYSTEM WHILE BURNING KANSAS PRODUCED COAL. ALSO, ADDITIONAL CREDITS TO HELP IN THE CAPITAL COST OF EQUIPMENT TO RETROFIT

OR MODIFY ANY EXISTING COAL BURNING SYSTEM WHILE BURNING KANSAS COAL. WE URGE THIS COMMITTEE TO ADOPT THIS LEGISLATION AND SUPPORT ITS PASSAGE.

SENATE BILL NO. 229 IMPOSES A 5¢/TON TAX ON ALL COAL UTILIZED IN THE GENERATION OF ELECTRICITY IN THE STATE OF KANSAS. IT, ALSO, DEFINES HOW IT WILL BE COLLECTED AND WHAT WILL BE DONE WITH THESE MONIES WHEN COLLECTED.

LADIES AND GENTLEMEN IF YOU WOULD TURN TO PAGE TWO (2) OF THE APPENDIX YOU WILL SEE THAT KANSAS PRODUCED 734,341 TONS OF COAL IN THE YEAR OF 1988. YET, KANSAS BURNED ALMOST 15 MILLION TONS OF COAL IN THE YEAR OF 1988. THAT MEANS 14,300,000 TONS CAME FROM OUT OF STATE.

THIS HAS CAUSED UNEMPLOYMENT IN THE COAL MINES IN THIS STATE AND ALSO CAUSED MINES TO GO OUT OF BUSINESS AND OTHER'S TO CUT BACK ON PRODUCTION BY WORKING ONLY THREE (3) OR FOUR (4) DAYS PER WEEK. WHAT THIS BILL DOES IS TO ALLOW THE STATE OF KANSAS TO COLLECT MONEY ON OUT OF STATE COAL THAT IS BEING USED IN THIS STATE, INSTEAD OF SENDING IT ALL BACK TO OTHER STATES, SO THEY MAY USE IT FOR THEIR SCHOOLS AND ROADS. WE SUPPORT THIS BILL'S PASSAGE.

AGAIN, WE URGE THIS COMMITTEE TO RECOMMEND ADOPTION OF THESE BILL'S SO THAT WE MAY TRY TO SAVE THE COAL INDUSTRY IN THE STATE OF KANSAS.

THANK YOU.

A: 4
3-

Testimony Before

SENATE ASSESSMENT AND TAXATION COMMITTEE

SB 227, SB 228 & SB 229
Kansas Coal Commission Proposals

By TOM TAYLOR
KPL GAS SERVICE
Manager of Governmental Affairs

March 1, 1989

KPL Gas Service supports SB 227 (same concept as SB 269) and SB 228 (same concept as SB 271), which provide a method of encouraging and rewarding those who are able to use Kansas coal, rather than making someone use it, or making them pay a higher price to use it. We believe the "carrot" method is always better than the "stick." SB 227 grants a sales tax exemption for certain equipment used in Kansas coal-fired boiler systems, while SB 228 grants a tax credit for the cost of installing new Kansas coal burning systems.

Next we come to SB 229 (same concept as SB 270), which is an entirely different matter. This bill would levy a 5¢ per ton tax on all coal burned by Kansas electric public utilities to fund a Kansas coal technology fund. This fund would provide grants to state and non-profit institutions to install facilities to burn Kansas coal and to pay for administation of the fund.

KPL Gas Service has spent hundreds of millions of dollars in the past 20 years to build one of the most efficient

-more-electric generating plants in the country, using the most non-polluting fuel available: low-cost and low-sulfur Wyoming coal. Largely because of our efforts to utilize this type of coal, our customers have electric rates about 10 percent below the national average. This is a competitive edge in utility rates that benefits the state and we want to protect it.

We burn approximately 9,000,000 tons of coal a year in our generating plants. At 5¢ a ton, our electric customers would have higher rates amounting to $450,000 a year because of HB 229. Statewide, all utilities burn approximately 15,000,000 tons, so we would be looking at higher electric costs of $750,000 a year for all Kansans. SB 229 would require Kansas electric consumers in every area of the state to subsidize -- through higher rates -- a private industry in one part of the State.

Even though 5¢ a ton sounds like a small amount, these small increments added to utility bills here and there add up quickly and they become an unnecessary expense that will flow through to customers. This measure is promoted as economic development for the coal industry in Southeast Kansas. On the other hand, anything that adds unnecessarily to the cost of electricity is also a negative as far as economic development is concerned. Kansas must have the most competitive electric rates possible. The higher they are, the more business is driven away. We cannot support SB 229 because adding hundreds of thousands of dollars our coal costs adds an unnecessary burden on electric customers and plays a part in taking away our competitive edge.

I do not want to end up on a negative note. The goal of providing economic development for southeast Kansas and providing jobs there is obviously a worthy goal. Equally worthy are the efforts to turn Kansas coal into a better product by making it cleaner and less polluting. Since economic development is good for the State, we would propose that the coal technology fund be paid for either from the general fund or from lottery gaming revenues that have been designated for economic development.

KPL Gas Service supports economic development. We serve Southeast Kansas and our employees live and work there. We are vitally interested in the well being of Southeast Kansas, therefore, we support attempts of the State to help the coal industry. That's why we have supported the Coal Commission, and donated money to help fund the Commission's study. But, we cannot support adding an unnecessary increase to electric consumers bills.

TESTIMONY

Before the Senate Assessment & Taxation Committee

S.B. 229

Wednesday, March 1, 1989

By Conni L. McGinness
Director, Legislative Relations
Kansas Electric Cooperatives, Inc.

Attachment 5
Senate Assessment and Taxation
Wednesday, March 1, 1989

TESTIMONY

May it please the Committee, my name is Conni McGinness, and I am Director of Legislative Relations for Kansas Electric Cooperatives, Inc. (KEC). KEC is the statewide service organization representing 34 rural electric cooperatives, which in turn have a membership of over 160,000 consumers. I am speaking here today on behalf of KEC and its member-systems in opposition to S.B. 229.

All of the electric cooperatives would be affected by this legislation, but particularly Sunflower Electric Cooperative in Western Kansas. This legislation would, in effect, cause the farmers in the western one-third of the state, through their electric bills, to fund an industry's development in Southeastern Kansas. This concept seems unfair.

We do not oppose the encouragement of burning Kansas coal, as proposed in S.B. 227 and S.B. 228, but to impose a new tax on only a particular segment (utilities that burn coal) of an industry does not seem equitable.

For example, this bill would increase a consumer's utility bill if she happens to be on the lines of a utility who operates a coal-fired electric generator located in the state of Kansas. But her neighbor, who may be served by a utility which does not have a coal-fired generation facility in Kansas, does not have to pay. Besides the obvious possible inequities, this bill also gives a competitive edge to utilities that do not have coal generating plants in Kansas when you look at bottom-line utility bills. For these reasons, we urge you to vote against S.B. 229.

Thank you for allowing me to testify today. I would be willing to answer any questions you may have.

TESTIMONY

Before the Senate Assessment & Taxation Committee

S.B. 229

Wednesday, March 1, 1989

By Conni L. McGinness
Director, Legislative Relations
Kansas Electric Cooperatives, Inc.

TESTIMONY

May it please the Committee, my name is Conni McGinness, and I am Director of Legislative Relations for Kansas Electric Cooperatives, Inc. (KEC). KEC is the statewide service organization representing 34 rural electric cooperatives, which in turn have a membership of over 160,000 consumers. I am speaking here today on behalf of KEC and its member-systems in opposition to S.B. 229.

All of the electric cooperatives would be affected by this legislation, but particularly Sunflower Electric Cooperative in Western Kansas. This legislation would, in effect, cause the farmers in the western one-third of the state, through their electric bills, to fund an industry's development in Southeastern Kansas. This concept seems unfair.

We do not oppose the encouragement of burning Kansas coal, as proposed in S.B. 227 and S.B. 228, but to impose a new tax on only a particular segment (utilities that burn coal) of an industry does not seem equitable.

For example, this bill would increase a consumer's utility bill if she happens to be on the lines of a utility who operates a coal-fired electric generator located in the state of Kansas. But her neighbor, who may be served by a utility which does not have a coal-fired generation facility in Kansas, does not have to pay. Besides the obvious possible inequities, this bill also gives a competitive edge to utilities that do not have coal generating plants in Kansas when you look at bottom-line utility bills. For these reasons, we urge you to vote against S.B. 229.

Thank you for allowing me to testify today. I would be willing to answer any questions you may have.

WRITTEN STATEMENT OF SUNFLOWER ELECTRIC COOPERATIVE, INC.

REGARDING HEARING ON SENATE BILL No. 229

Presented to the

SENATE COMMITTEE ON ASSESSMENT AND TAXATION

SENATOR DAN THIESSEN, CHAIRMAN

BY

JERRY C. KEMPF

DIRECTOR OF EXTERNAL AFFAIRS

Dated: March 1, 1989

Attachment 6
Senate Assessment and Taxation
Wednesday, March 1, 1989

Mr. Chairman and members of the committee, my name is Jerry C. Kempf. I am Director of External Affairs for Sunflower Electric Cooperative, Inc. (Sunflower). Sunflower is a generation and transmission cooperative located in Hays, Kansas. We serve the western one-third of the state. I have enclosed a brochure to more fully inform each of you about Sunflower.

I am here today to testify in opposition to Senate Bill 229 (SB 229). SB 229 would "impose upon all electric public utilities" in the state of Kansas a new tax on coal in the amount of $.05 per ton. The tax proceeds would be used to fund clean coal technology projects, installation of facilities by universities and other non-profit institutions which burn Kansas coal and fund administration.

Sunflower burned 900,000 tons of coal in l988 and anticipates burning 1,000,000 tons in l989. The new tax would cost Sunflower an additional $50,000 based on 1989 projected coal usage. The impact to our customers is about $1 per meter. As important, this is not the only new tax or fee that is being considered by the Kansas legislature. The proposed state water plan and creation of the petroleum storage tank release trust fund or two other issues that would impose considerable costs on the electric utility industry in Kansas.

Sunflower is not opposed to paying its fair share of the costs of governance. In 1988 we paid $838,330 state fees and taxes and $5,794,672 in local fees and taxes.

The Sunday, February 26 edition of the Wichita Eagle-Beacon devoted four sections to the subject of economic development. Articles discussed how "Kansas could claim a share of the growth in the national economy", legislative economic development initiatives, the successes in urban areas and the dilemma facing rural Kansas. Increasing utility costs will not help out the economic development picture in Kansas. More specifically, rural Kansas will be hurt the most by increases in electric utility costs. We serve areas that have custumer density of just over one meter per mile of line. Consequently, existing high cost of service conditions will be further impacted.

The federal government has authorized a clean coal technology (CCT) program with multi-billion dollar funding. Utilization of CCT funds would do substantially more in making the coal in southeast Kansas more competitive and desirable to burn. Almost any project, whether KCCT, CCT or jointly funded will need an electric utility to participate. Adding cost will do little to further this goal.

In 1986, the Kansas coal industry produced 1,486,000 tons of coal. This was 0.2% of

In 1986, the Kansas coal industry produced 1,486,000 tons of coal. This was 0.2% of the national total of 890,315,000. The peak year of production occurred in 1918 when 7,562,000 tons of Kansas coal was produced. Coal production nationally has been sluggish over the last decade. However, the National Coal Association states that increases in production and decreases in mining cost will result in record high production over the next few years. It is estimated that proven recoverable coal reserves in the United States exceed 225 billion tons. A study done for the Kansas Coal Commission indicates that Kansas may have between 400 and 600 million strippable reserves. However, these reserves contain mostly high sulfur coal.

Considering the size of the Kansas coal reserves, the nature of the reserves and the federal assault on combustion technology, any long term program needs to be carefully thought out. We do not think that SB 229 shows this balance but is an attempt at a quick fix to a serious problem.

Mr. Chairman and members of the committee, we ask that you vote against SB 229. It taxes an already weak industry, does little to promote the use of Kansas coal and unfairly penalizes the rural Kansas electric consumer.

SENATE ASSESSMENT & TAXATION COMMITTEE
TESTIMONY KANSAS GAS AND ELECTRIC COMPANY
SENATE BILL 229
March 1, 1989

Senate Bill 229 proposes to levy an additional tax on utilities to fund projects intended to increase the use of Kansas coal.

While the intent of providing increasing coal usage is laudable, these points should be considered:

1. By increasing the cost of coal, there is incentive for utilities to use other fuels like nuclear, gas or oil. In short, a coal tax is ultimately counter-productive to the purpose of the proposal. With federal legislation about Clean Air being considered, it seems likely that extra costs soon will be imposed on this fuel whether or not Kansas enacts a tax and thus the new local burden simply will further reduce coal's economic advantage.

2. Increasing the cost of fuel will add to the price of electricity. This complicates the goal of providing reasonably-priced energy service to citizens of the state as demonstrated by earlier elimination of sales taxes from residential utility service.

3. The burn tax is in addition to the severance tax on coal. The annual severance tax bill has been as high as $700,000 for Kansas coal used at LaCygne Station owned by our company and Kansas City Power and Light.

Since the benefits of increased coal mining in Kansas do not accrue directly to citizens who use electricity produced in coal-burning power plants but to all Kansans, it would seem more equitable to pay the cost of these proposals from the general fund.

Attachment 7
Senate Assessment and Taxation
Wednesday, March 1, 1989