Approved:_
Date 1-24-01

MINUTES OF THE SENATE UTILITIES COMMITTEE.

The meeting was called to order by Chairperson Senator Stan Clark at 8:30 a.m. on January 22, 2001 in Room 313-S of the Capitol.

All members were present except: Senator Wagle, excused

Committee staff present: Raney Gilliland, Legislative Research
Ann McMorris, Secretary

Conferees appearing before the committee:
David Williams, Production Supervisor, Kansas Corporation Commission
Robert Krehbiel, Kansas Independent Oil & Gas Association
Dick Brewster, BP-Amoco
Robert O. Reid, Colorado Interstate Gas
Bill Eliasan, VP, Gas Strategy, Kansas Gas Service & OK Natural Gas
Jim Borowicz, UtiliCorp United Inc.
James W. Bartling, Mgr. Greeley Gas Company
John Cita, Kansas Corporation Commission

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Others attending: See attached list

This was a joint meeting of the Senate Utilities Committee chaired by Senator Stan Clark, and House Utilities Committee chaired by Rep. Carl Dean Holmes. Chair Holmes opened the meeting and reviewed the purpose and focus for the three joint committee meetings being held this week. Chair Clark referred to three reports with good general and background information on the natural gas industry which are available on the internet from Energy Information Agency which is part of the Department of Energy. All three documents can be accessed under www.eia. Two are statements made by the EIA administrator before the U.S. Senate and the third is a two-year old report entitled Corporate Realignments and Investments.

Presentations on Natural Gas Supply Factors

1. Overview of Kansas Natural Gas Production by David P. Williams, Production Supervisor, Kansas Corporation Commission. (Attachment 1)

2. Robert E. Krehbiel, EVP, Kansas Independent Oil & Gas Association (Attachment 2)

3. Natural Gas: The Price/Supply Relationship by Dick Brewster, BP-Amoco (Attachment 3)

4. Robert O. Reid, Colorado Interstate Gas (Attachment 4)

5. Bill Eliasan, VP, Gas Strategy, Kansas Gas Service & OK Natural Gas (Attachment 5)

6. Jim Borowicz, UtiliCorp United Inc. (Attachment 6)

7. James W. Bartling, Mgr. Greeley Gas Company (Attachment 7)

8. John Cita, Chief Economist, Kansas Corporation Commission (Attachment 8)

No time remained for questions after the presentations.

Next meeting of the joint committees will be on January 23, 2001.

Adjournment.

Respectfully submitted,
Ann McMorris

Attachments - 8

JOINT MEETING
SENATE & HOUSE COMMITTEES ON UTILITIES
GUEST LIST

DATE: January 22, 2001

NAME	REPRESENTING
[illegible]	UtiliCorp United
[illegible] Dawley	UtiliCorp United
Jim Allen	EKOGA
Andy Shaw	Kearney Law Office
[illegible]	Shari Weber
Howard Bartruff	AARP
J. Ted Walters	AARP
Larry D. Carr	AARP
Lee Eisenhauer	PMAK
[illegible]	Taxpayer - Consumer
Ken Peterson	KS Petroleum Council
DENNY KOCH	PNM
Lee Allison	KS Geological Survey
Tim Carr	" "
Scott White	" "
LARRY WILLER	KGS
Brad Dyer	KGS
Rosemary [illegible]	KCC

JOINT MEETING
SENATE & HOUSE COMMITTEES ON UTILITIES
GUEST LIST

DATE: January 22, 2001

NAME	REPRESENTING
Jim Bartling	Greeley Gas Co
Dave Williams	KCC
Robert Krehbiel	KIOGA
Mary Willoughby	Wichita - KNEA
Bruce Snead	City of Manhattan
Bill Curtis	Ks Assoc of School Boards
George Barbee	ENRON
John Federico	Boeing
Ron Gaches	GBBA
Bob Reid	Colorado Interstate Gas
Jack Glaves	P-H - Duke - Oxy & K.M
Bob Alderson	Atmos Energy Corporation
John Cita	KCC
Jeff Wasowski	KCC
Joe White	KCC
Mike Ohrt	Pinegar-Smith
Amy Campbell	Midwest Energy

JOINT MEETING
SENATE & HOUSE COMMITTEES ON UTILITIES
GUEST LIST

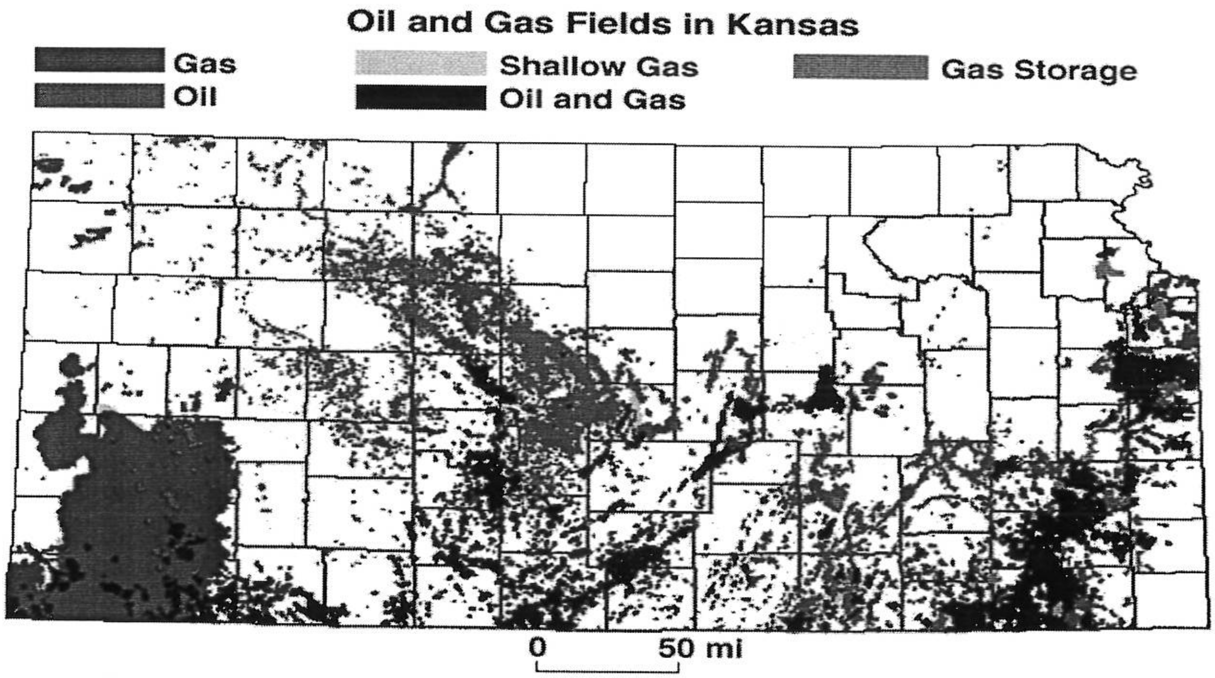
DATE: January 22, 2001

NAME	REPRESENTING
William Eliasen	Ks. Gas Service
Whitney Damron	KS Gas Service
Kerri Spielman	Sen Maj. Ldr's Office
Kelly Kultala	City of Overland Park
Ed O'Malley	Overland Park Chamber of Commerce
Susan Duffy	KCC
Dan [illegible]	WR
James Ludwig	WR

Overview of Kansas Natural Gas Production
David P. Williams - Production Supervisor
Kansas Corporation Commission

Oil and natural gas resources are the most important energy products in Kansas and production of these products has been established in 91 counties throughout the state. These resources are produced from many geologic formations at depths ranging from as shallow as a few feet below surface in Eastern Kansas to deeper horizons of approximately 2000 to 4000 feet in Central and Northwest Kansas. The deepest producing areas are located in Southwestern Kansas, where production depths are common at depths of 4000 feet or more (See Figure - 1).

Figure 1

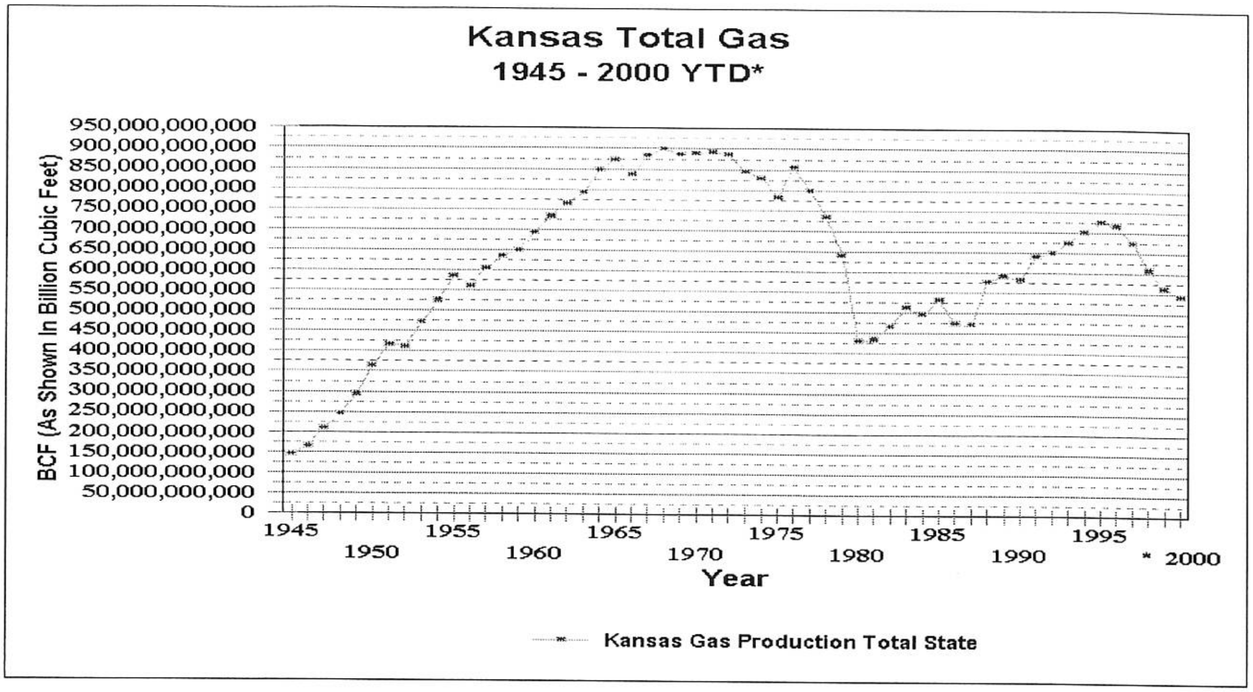


Source: Kansas Geological Survey (KGS).

In 1970, natural gas production peaked at approximately 900 Billion cubic feet . Since 1970 gas production in Kansas has declined by approximately 36%, largely due to the decline in the resource base. It is estimated that by projecting this production forward for the years 2001- 2010, the anticipated rate for the annual Kansas gas decline in production will be in the range of approximately 8% to 10% per year.

This decline is likely to continue until additional new reserves are found (through drilling), or enhanced recovery projects are enacted, or as new innovative technology is advanced that may aid in the lengthening of the proven reserves and/or replace the proven reserves being consumed.

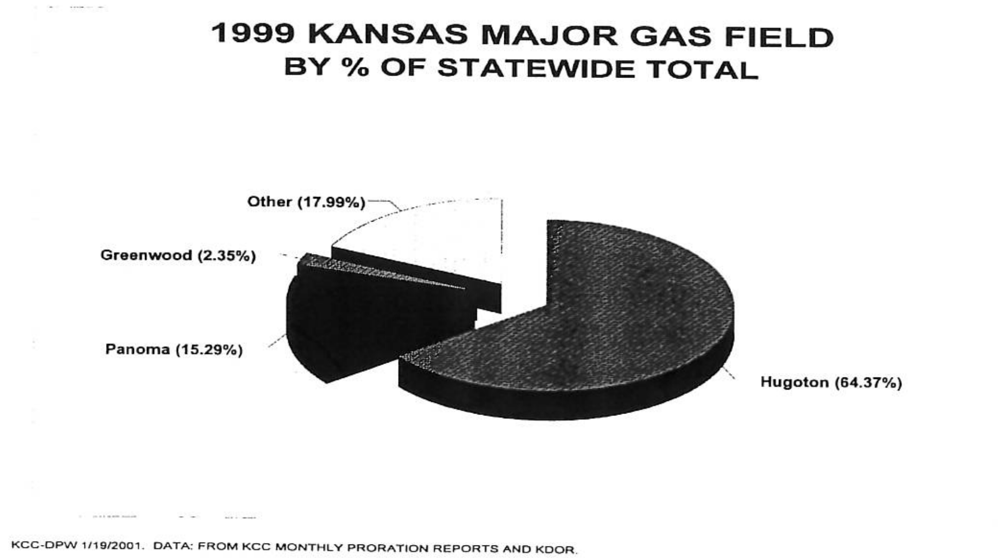
Figure 2



Source: DeGolyer & MacNaughton: Twentieth Century Petroleum Statistics (1999)

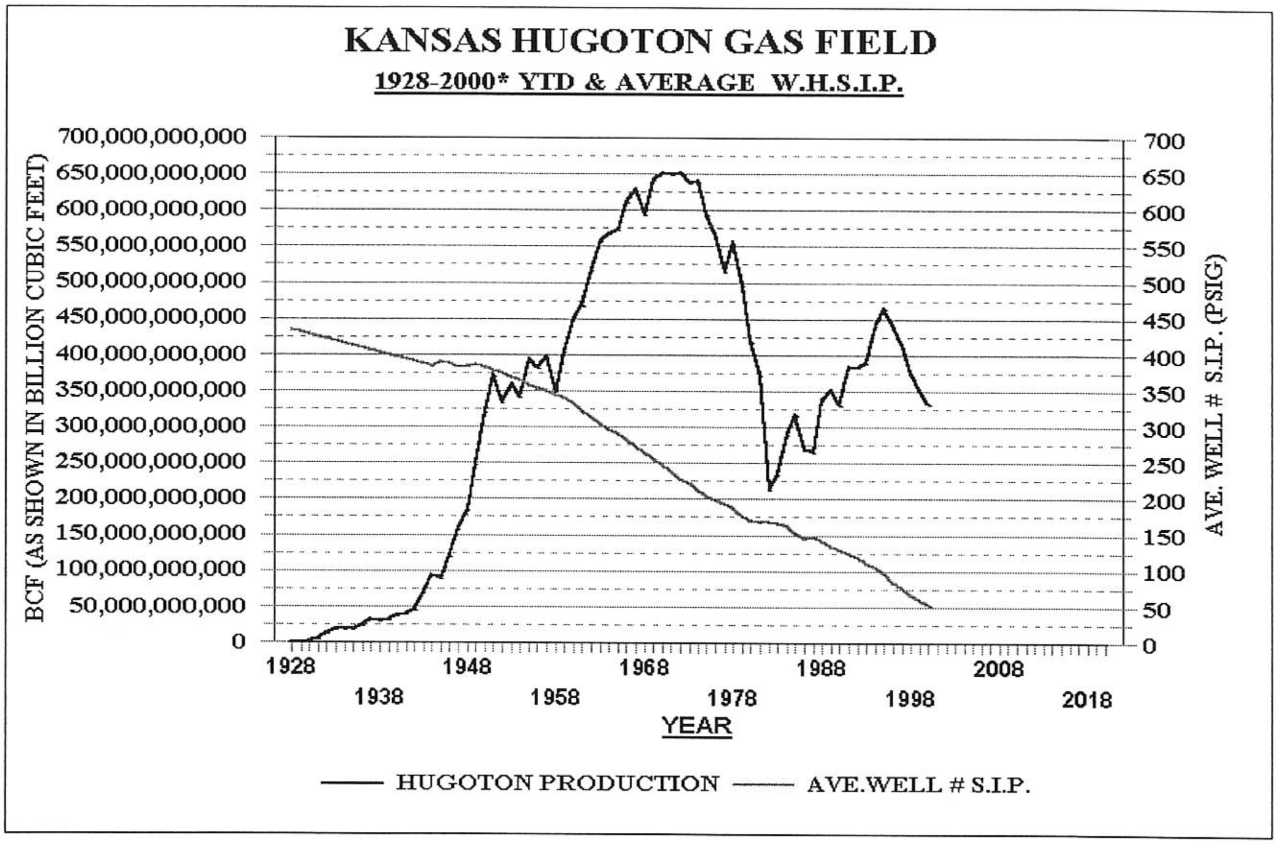
Southwestern Kansas remains the primary natural gas producing region of the state, with approximately 82 % of the total 1999 statewide gas production coming from this area. The majority of this gas production is attributed to three large producing fields: the Hugoton Field (64.4 %); the Panoma Field (15.29%); and the Greenwood Field (2.35 %). The remaining statewide gas production (17.99%) comes from all other fields throughout the state.

Figure 3



In Southwestern Kansas, the Hugoton gas field is known as one of the largest gas fields in North America. The field was discovered in 1922, first produced in 1928, and to date it has produced in excess of 24 Trillion Cubic Feet (Tcf).

Figure 4



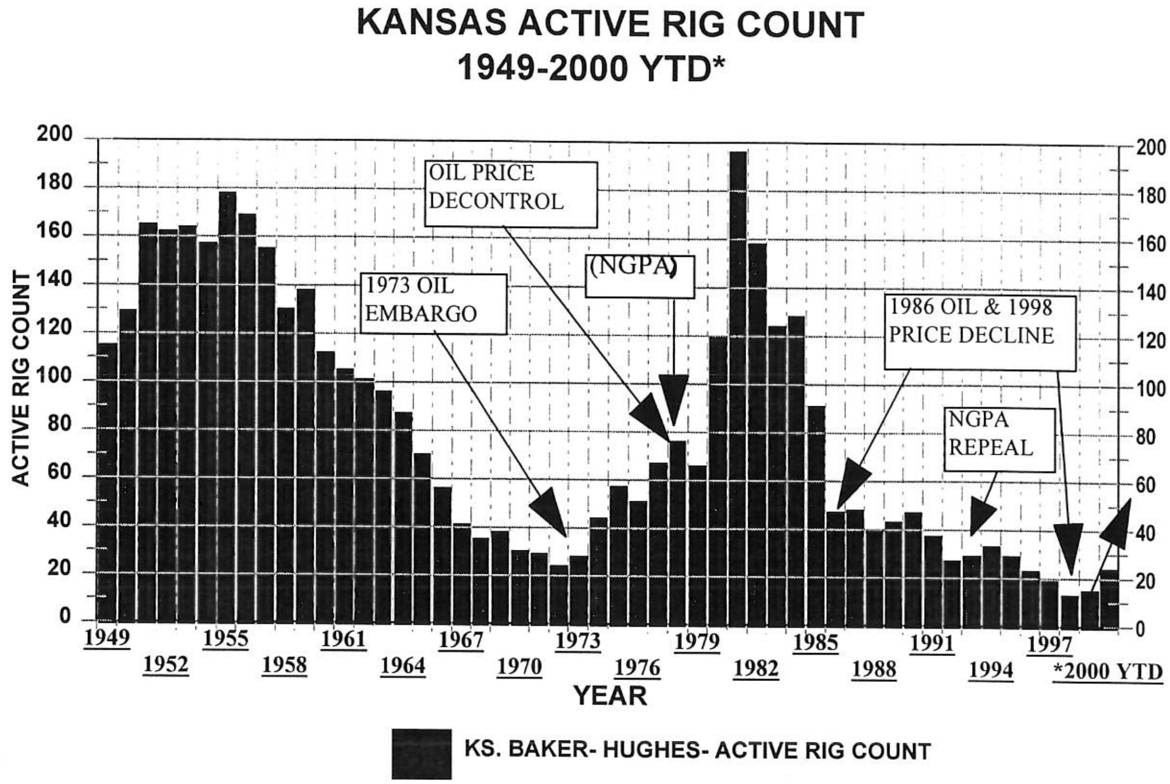
Source: Kansas Corporation Commission (KCC) Proration Data..

The Hugoton field currently produces in excess of 325 Billion cubic feet (Bcf) annually from more than 7450 wells and accounts for more than 64 % of the total statewide gas production. However, this field is in pressure decline with an average well shut-in reservoir pressure of 12 % of the original field-wide reservoir pressure (See Figure 4).

Based on historical average pressure decline rate data the Hugoton field is forecast, for the 2001 through 2010 period, to decline in reservoir pressure at an annual rate of approximately 7 to 10 pounds per square inch gauge (psig). The gas production is forecast to decline annually at a rate of approximately 10 %.

However, increased utilization of well and pipeline technologies, associated with recent Kansas regulatory rule revisions now allow for the optional use of vacuum operations in this field. If utilized successfully, these operational changes may help to extend the life span of the field by lowering the abandonment pressure associated with the wells.

Figure 5



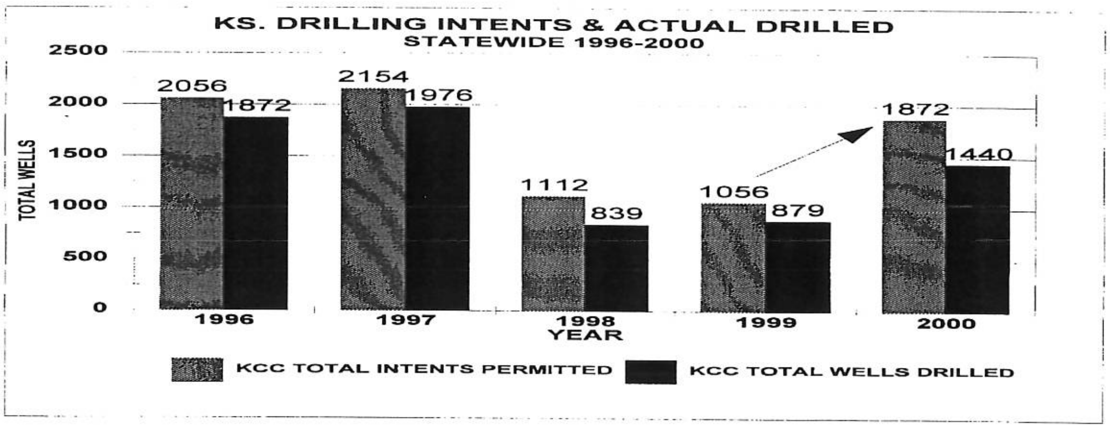
Source: Baker Hughes Rig Count

As shown in Figure 5 drilling activity in Kansas has seen dramatic movement in the number of active rigs over time. This is due in part to the ever changing variables of supply, demand, and technological advances which have effected product price over time.

In 1981, the number of active rigs peaked at just under 200. In contrast in 1998, the active rig count had declined to a total of 15 active rigs . This equates to a decline in active drilling rigs since 1980 of more than 92%.

During calender year 2000 there has been an dramatic increase in the number of active rigs operating in Kansas (up 60% since 1998). Unfortunately, Kansas is now believed to be essentially at "rig capacity" because of limiting constraints of qualified personnel, lack of associated service companies, and the actual infrastructure of rigs that are currently available for drilling.

Figure 6



KCC/DPW 1/19/2001. DATA IS FROM ACTUAL KCC PERMITS APPROVED AND ASSOCIATED SPUD CALLS RECEIVED F

Figure 6 shows that in 2000, Kansas operators increased the number of intent to drill permits as filed with the KCC by more than 77 %. This increase in the number of permitted wells has resulted in more than a 63 % increase in the number of wells that were actual drilled. This is due to the increase in both oil and gas price

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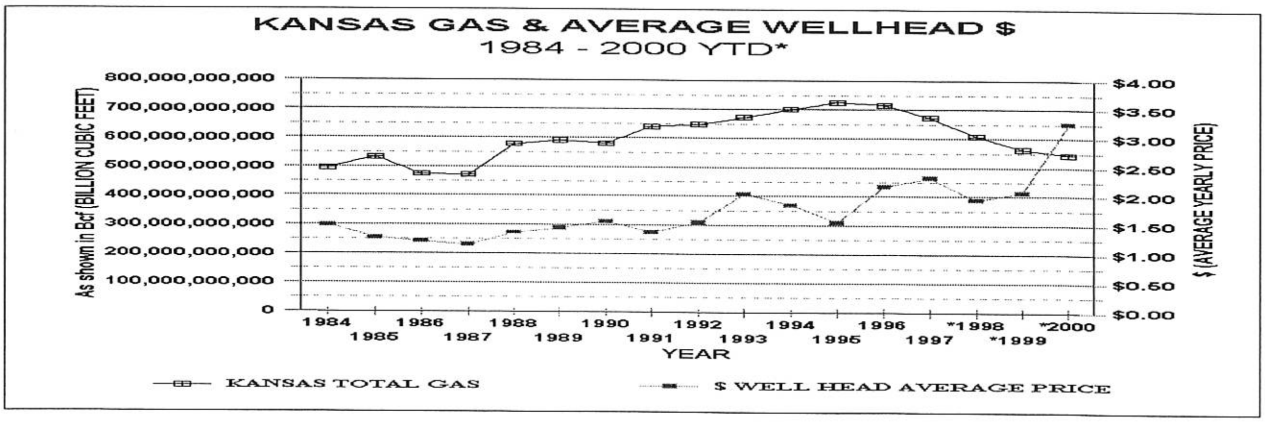
Figure 7.

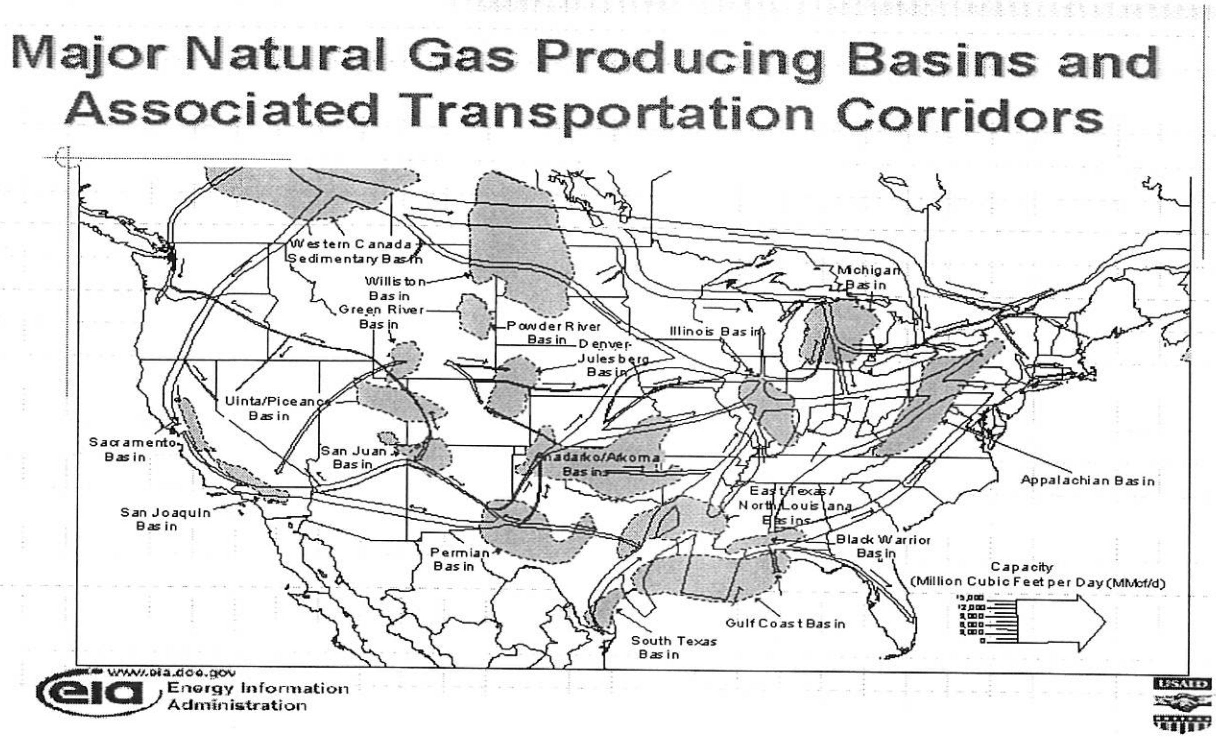


Source: Kansas Department of Revenue (KDOR) & Energy Information Agency (EIA)*1999 Total & **2000 YTD (Through first 9 months subject to revisions).

For the sixteen year period from 1984 -1999, the average well head price for Kansas natural gas had increased by approximately one-third. However, in the first three quarters of 2000, the average well head price has increased by more than 52 % for the same reporting period as one year ago.

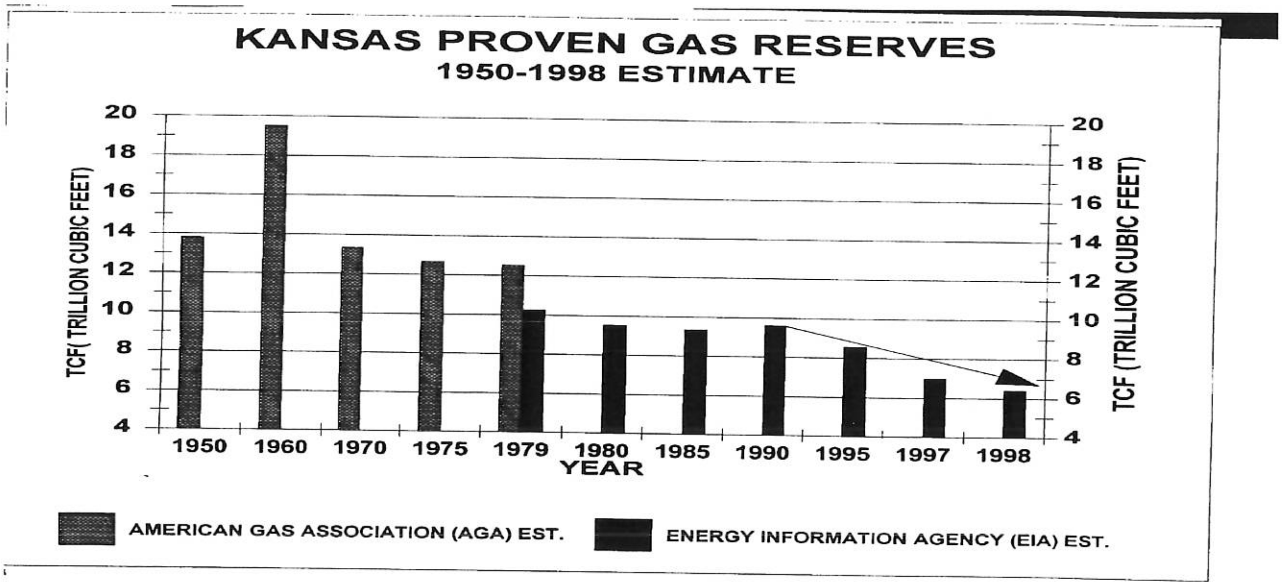
This illustrates that the reported price this year is at a sixteen year high and is predicted to go even higher as spot market prices are approaching the $9-$10 range per thousand cubic of gas (Mcf).

Figure 8



Kansas in centrally located and has been productive for more than a century. The existing gas processing and transportation infrastructure in Kansas is in place and available for any additional gas reserves that may come on line for either interstate or intrastate markets (See: Figure 8).

Figure 9



Source: DeGolyer & MacNaughton "Twentieth Century Petroleum Statistics (1999).

As shown in Figure 9 the Energy Information Agency (EIA), indicates that the Kansas proven gas resource base has continued to decline since 1979 and is now estimated (1998) to be approximately 6.4 trillion cubic feet (Tcf). That represents an approximate decline of 40% in proven reserves since 1979 in Kansas. This decline is likely to continue until additional new reserves are added or as new innovative technologies are advanced that may aid in the lengthening of the proven resource base.

Figure 10

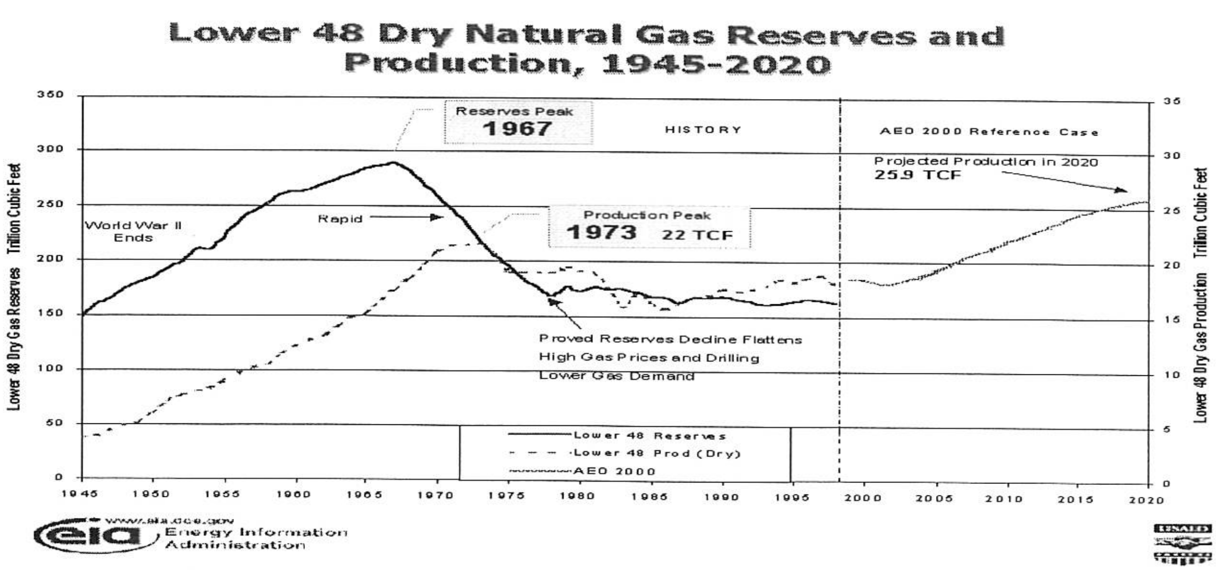


Figure 10 shows production, and reserves for the United States for the period 1945 to present. This graph shows the U.S. proven reserves peaked in 1967 with actual gas production peaking in 1973. EIA estimates that production in 1999 of approximately 18 Tcf will increase in 2020 to approximately 26 Tcf. This represents a 44 % increase in anticipated production over current levels.

Figure 11

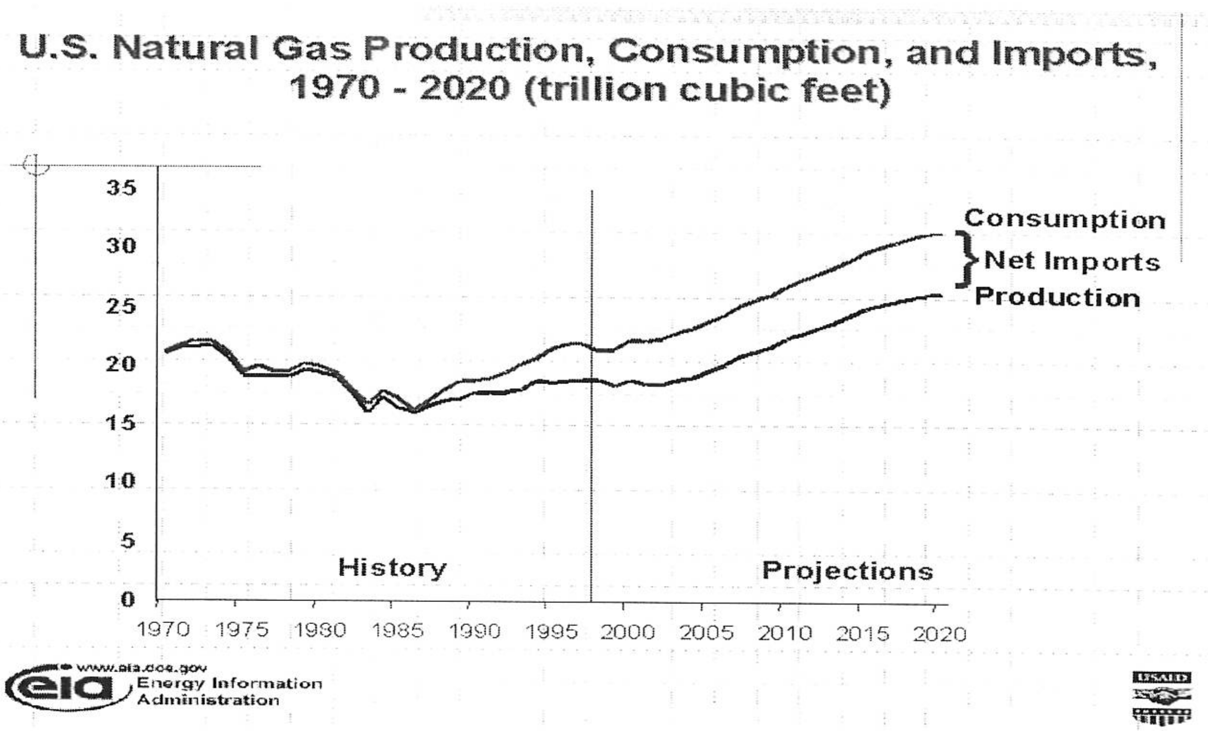
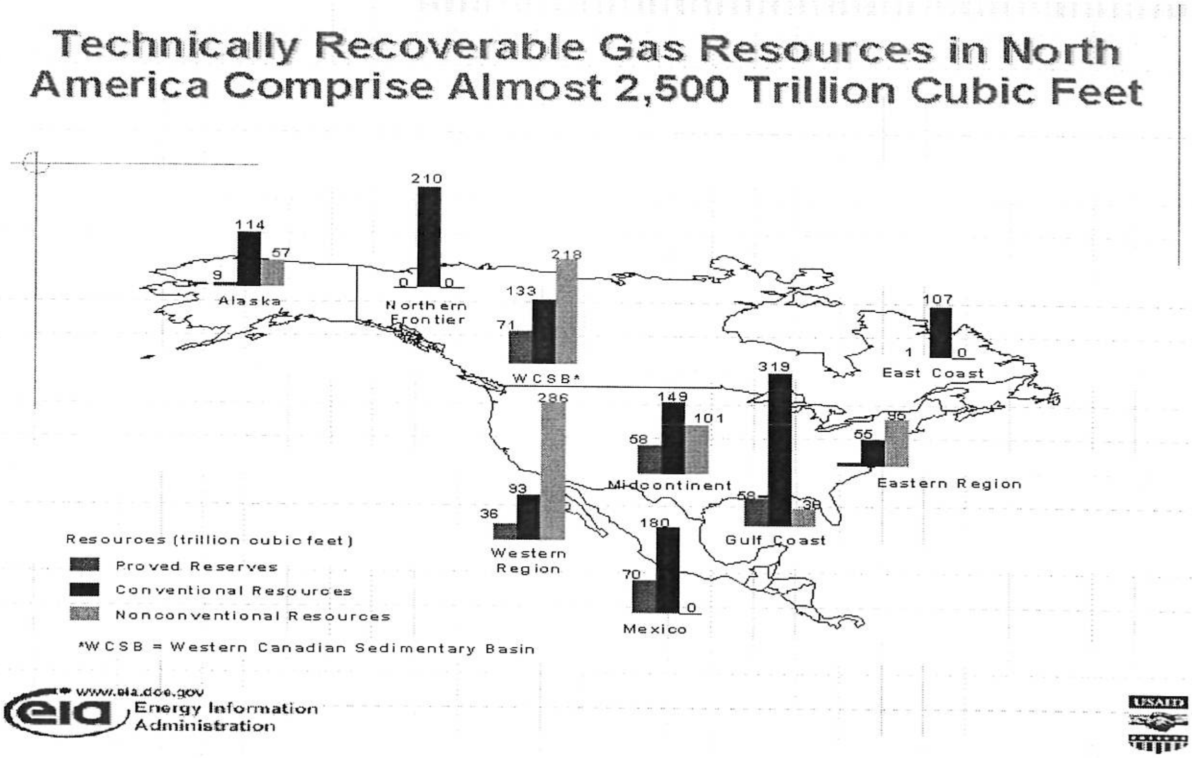


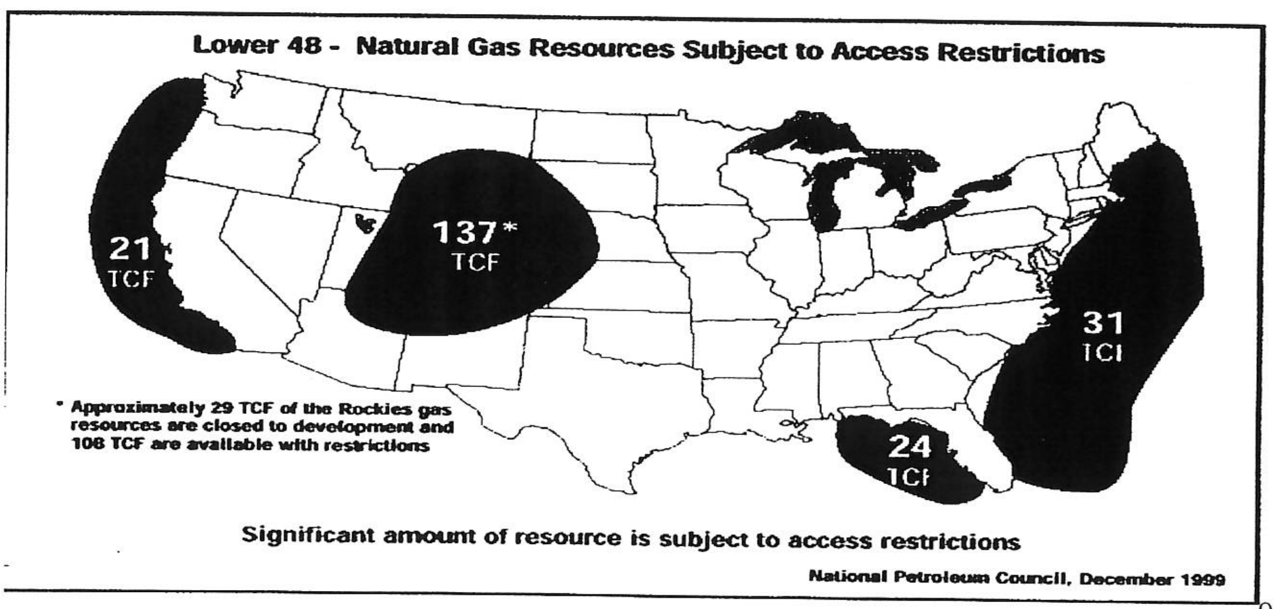
Figure 11 shows the historical and anticipated United States gas production, consumption and imports from 1970 to 2020. This graph shows a widening gap in the forecast of actual production and overall consumption by approximately 15 %.

Figure 12



The Energy Information Agency (EIA) projects that there are additional energy resources located within the Mid-Continent area of the United States (including Kansas). If EIA's estimates, shown in Figure 12, are correct then approximately 58 Trillion cubic feet (Tcf) of proven reserves are located within the Mid-Continent area. In addition 149 Tcf of conventional resources and 101 Tcf of non-conventional resources may be technically recoverable as a source of further energy supply.

Figure 13



In Figure 13 the National Petroleum Council shows areas that may contain additional recoverable gas reserves that are currently under restriction for energy development. Should such lands be developed successfully as shown in this graph the anticipated additionally recoverable gas resource base would increase by approximately 213 Tcf.

STATE OF KANSAS

Monday, January 22,2001

JOINT MEETING OF THE UTILITIES COMMITTEES
OF THE HOUSE AND SENATE

Natural Gas Supply Factors

TESTIMONY OF
Robert E. Krehbiel, Exec. V.P.
Kansas Independent Oil & Gas Association

TESTIMONY

I. Condition of the Exploration and Production Component of the U.S. and Kansas Oil and Gas Industry.

  A. Machinery and Equipment

  B. Personnel

  C. Technology

  ATTACHMENTS A (U.S), B (KANSAS-1982) and C (KANSAS-1998).

II. Current Characteristics of the Kansas Resource Base.

  A. Kansas Geological Survey Open File Report 2000-69-ATTACHMENT D.

  B. Kansas Geological Survey Open File Report 2000-16-ATTACHMENT E.

III. The Wellhead Price of Natural Gas.

  A. The Past-1930 through 1999-ATTACHMENT F.

  B. The Present-2000 previous twelve months-ATTACHMENT G.

  C. The Future-Futures prices through May, 2003-ATTACHMENT H.and N.

  D. Natural Gas Policy Act Ceiling Prices 1978 through 1988-ATTACHMENT I.

IV. The Transportation of Natural Gas

  A. The Pipeline System-ATTACHMENT J.

V. The Cost of Natural Gas.

  A. Producers-Transporters/Affiliates-Consumers-ATTACHMENT K.

  B. Selected National Average Natural Gas Prices-ATTACHMENT L.

  C. Comparison of U.S. Residential Costs to Ks Wellhead Prices-ATTACHMENT M.

VI. How Shortages Occur.

  A. Federal Regulation of Wellhead Price.

    1. 1938 Natural Gas Act.

    2. 1954 State of Wisconsin v. Phillips Petroleum Company.

    3. Opinion 699 and Opinion 699-D.

    4. Natural Gas Policy Act of 1978. (See Attachment I)

  B. Monopoly Power of Purchasers.

VII. Questions posed to Producer Conferees.

QUESTIONS FOR NATURAL GAS PRODUCERS

1. In order to encourage exploration and increase production of natural gas in Kansas, what is the necessary wholesale price?

Answer: Declining production levels of recent years clearly indicate that the $2 to $2.25 wellhead price range is insufficient to induce exploration. The resource base is sufficient to meet current demand if exploration levels had been maintained by reasonable price levels. The last shortage occurred in the late 1970's and the federal government passed the Natural Gas Policy Act of 1978 to encourage production. The price ceiling ascribed to production from new wells in 1978 (See Attachment I) commenced at $2.078 in December, 1978, and was escalated monthly with inflation to $5.093 by December of 1988. This level of wellhead prices fixed over time in federal law provided sufficient price certainty and price incentive to many independent producers to explore for and sell gas in to the interstate market for the first time since the Phillips decision of 1954. In fact it created a gas bubble, so, perhaps this price was too high for that period of time. Today a sustained price in the $3.50 range coupled with confidence in long term prices would, by most independent producer accounts, encourage exploration in Kansas prospective areas. A greater number of economically viable exploration and development prospects come into play as the wellhead price goes up. Short term price spikes such as those being experienced today are unreliable for long term capital decisions. Confidence in future prices is the determinant.

2. a) How long on average does it take your company to develop or produce natural gas from proven reserves and make it available for transport to pipelines?

Answer: If the reserves are truly proven and the project is simply an exploitation project the time line might look something like this: 1 month to propose drilling and obtain necessary approval and permits, 3 to 6 months waiting to obtain a drilling rig, two weeks drilling and testing, 2 weeks waiting on completion tools, 1 week to complete and equip, 2 weeks to lay a small lead lines to tie into an existing gathering system(since this is a proven area the lead line should be less than one mile). This would result in approximately a 6 to 9 month period to bring additional gas volumes on line.

b) What is the process, once a company finds a new gas field, to bring the gas to market?

Answer: The process to bring a new field to market is usually as follows: Geological evaluation of an area, lease acquisition, seismic exploration, financing, drilling, testing, completion, sales and construction of gathering lines to deliver to market. The lead time is approximately two years to get new fields to market.

c) What elements control how fast this gas gets to market? Proximity to markets, quality and quantity of gas affecting ability to market timely, weather, field conditions, ease of construction, and right of way acquisition.

d) Do FERC rules promote or hinder the process of expanding capacity? No opinion.

e) Does the fact that interstate pipelines are cost of service regulated create incentives or disincentives to build out to new fields?

Answer: Interstate pipelines generally do not build out to new fields. In Kansas the producer is generally responsible for laying pipelines to the gatherer of the transmission company and the economic viability of such construction depends in large part on the wellhead price of natural gas. The interstate pipeline companies have not expanded any of their systems to new fields in Kansas for several years to our knowledge.

3. What impact does declining pressure in the Hugoton gas field have on both production and prices?

Answer: Production declines and compression is required. The cost of operation will increase significantly. Prices are more dependent on world supply but the Hugoton Field has been a significant source of supply for many years. The decline in production and deliverability in just the Hugoton field could have a small impact on prices.

4. a) How much natural gas is being exported from Kansas? Is Kansas still a net exporting state.

Answer: According to EIA statistics Kansas produces approximately 550,000,000 MCF per year and consumes approximately 300,000,000 MCF per year. 250,000,000 MCF is exported. Kansas is a net importer of crude oil, producing approximately 34 million barrels per year and consuming approximately 60 million barrels per year.

5. The Kansas Geological Survey, using data from the Energy Information Administration, projects average Kansas well head prices to increase to more than $3.50 per MCF, with Kansas residential prices increasing to more than $7.00 per MCF. In your opinion, what is the explanation for this differential between well-head and burner-tip prices.

Answer: We really don't know but we assume that, in addition to the pipeline transportation costs, it is the services which are provided by the various pipeline affiliates. The affiliates perform services which have been "unbundled"and deregulated. We could not find where, how or if many of these deregulated services are reported.

6. a) In your view, how well is the natural gas market working?

Answer: The current supply shortage indicates that the market has set the wellhead price of natural gas too low to encourage the investment in exploration and production necessary to keep up with growing demand. The resource base appears to be adequate if investment in exploration and production were justified by the market price. Independent producers, who drill 85% of the wells in America, cannot charge a price for their production, so when the market drops their only choice is to cease exploration. Long periods of sustained low wellhead prices will then result in rapid price corrections, such as the fly up we are experiencing today. Does that mean the gas market is not working? If consumers benefitted from a decade and a half of unrealistically low wellhead prices then perhaps it is working. If the consumers did not benefit then that is another issue.

b) Do you think the market is subject to manipulation? Who do you think might manipulate it?

Answer: Natural gas supply shortages have occurred when federal regulation set the price at the wellhead so low as to discourage capital spending for exploration and production. This was the effect of the Phillips decision in1954 which resulted in supply shortages in the interstate markets by the mid 1970's. This was governmental manipulation of the market and the market remains subject to governmental manipulation.

A supply shortage might occur as well if the interstate pipeline purchasers and their affiliates, producing affiliates, gathering affiliates, field services affiliates, marketing affiliates, electric generation affiliates, local distribution affiliates, etc, might somehow achieve a monopoly which would allow them to purchase gas at the wellhead at less than free market determined prices or charge prices for services that exceed free market prices and then pass those costs through to consumers. This concern is often expressed by the agricultural industry, particularly with respect to the beef packing industry. The mergers which have taken place and the deregulation of certain services provided by affiliated entities sets the stage for potential manipulation of market prices both at the wellhead and at the burner tip. We have no particular knowledge in this area and express no opinion.

Independent producers believe, however, that the free market works so long as we are certain it remains free and competitive from wellhead to burner tip.

7. What type of state regulatory changes or state incentives, if any, would help extend the life span of the Hugoton field and other Kansas gas fields?

Answer: Kansas is a mature producing province and as the resource base declines the costs of production increase. The State can reduce the costs of operation by eliminating the sales tax on oil and gas machinery and equipment and labor services applicable to maintaining, reworking and recompleting old wells. The Kansas oil resource base can no longer support the severance tax. Since much natural gas is discovered by independent producers in the search for oil or in association with oil, the severance tax on oil should be repealed to encourage exploration for both oil and gas. To increase production the KCC is reviewing increasing allowables from 25% of absolute open flow or 150 mcf per day, whichever is greater, to 50% of absolute open flow. This should be done and the minimum per day rate should also be increased to 300 or possibly 500 mcf per day as well. Price caps on production enhancements applicable to both crude oil and natural gas should be eliminated.

8. What is currently being done to lower the abandonment pressure associated with wells in the Hugoton field? Is there research that might be considered and should be funded to promote increased well production in the Hugoton Field?

Answer: This question is best answered by the Kansas Geological Survey or the Kansas Corporation Commission.

9. Is your company changing selling practices from short-term contracts or from long-term contracts to short-term contracts?

Answer: Lon g term contracts are not offered at fixed prices. Currently contract prices are tied to a market index price. Some producers may lock in a price using the NYMEX futures market to either provide a floor price for the gas or lock it in for a 12 month or other time period.

10. What happened to the old long-term contracts in the Hugoton field? Were any of them for the life of the field? What is the price of the gas? Have there been any changes to the contracts due to market prices? Are they spot or free market prices?

Answer: The Hugoton is the domain of the major producers and we will defer to their comments.

ATTACHMENTS

1. Attachment A-Charts prepared by the Independent Petroleum Association of America.
2. Attachment B-Extent and Economic Value of the Kansas Oil and Gas Industry-1982.
3. Attachment C-Value of Oil and Gas-Kansas-1998.
4. Attachment D-Kansas Geological Survey-Open File Report 2000-69.
5. Attachment E-Kansas Geological Survey-Open File Report 2000-16.
6. Attachment F-U.S. Wellhead Natural Gas Prices 1930-1999.
7. Attachment G-2000 Henry Hub Natural Gas Prices for previous 12 months.
8. Attachment H-NYMEX FUTURES CLOSING PRICES FOR Henry Hub 11-18-2001.
9. Attachment I-Natural Gas Policy Act Ceiling Prices 12-1978 through 12-1988.
10. Attachment J-Pipeline map reflecting the physical transportation of natural gas.
11. Attachment K-Producers-Transporters/Affiliates-Consumers.
12. Attachment L-Selected National Average Natural Gas Prices.
13. Attachment M-U.S. Residential Cost vs. Kansas Wellhead Price.
14. Attachment N-Futures Contract Specifications-Henry Hub Natural Gas Futures.

ipaa
America's Oil and Gas Producers

State of the U.S. Oil and Natural Gas Industry

EMPLOYMENT: Preliminary employment data for the exploration and production sector of the oil and natural gas as of February 1999, stood at 288,400 employees, compared to 334,700 in the same month last year. In 1998, the U.S. averaged 325,900 employees, compared to 334,600 for 1997. Since the early 1980s, 520,000 jobs relating to the oil and natural gas industry have been lost.

CRUDE OIL IMPORTS: Imports of crude oil and petroleum products in 1998 averaged 10.3 million barrels per day, the highest level ever of imports. This represents a 220,000 b/d increase over 1997 levels of 10.16 MMb/d. Imports have continued to constitute over 53 percent of domestic supply of petroleum products. Five years ago, we depended on imports to supply 45 percent of our needs. Imports of refined products averaged 1.83 MMb/d in 1998 down from 1.93 MMb/d in 1997. Crude oil imports have increased to 8.55 MMb/d in 1998, up from 8.22 MMb/d in 1997. U.S. petroleum imports (crude & products) in January were 10.18 MMb/d; imports in the same month last year were 9.89 MMb/d.

NATURAL GAS IMPORTS: Natural gas imports for 1998 averaged 3.13 Trillion cubic feet (Tcf), a four- percent increase over 1997. They have been rising steadily and rapidly since 1986. Canada continued its role as the major supplier of gas imported into the U.S., supplying the United States with 3.02 Tcf in 1997.

CRUDE OIL PRODUCTION: Crude oil production in 1998 fell to an average 6.24 MMb/d, compared to 6.45 MMb/d in 1997, representing a 209,000 b/d decrease. Crude oil production in the lower 48 states fell to 5.06 MMb/d, while Alaskan production continued its decline to 1.17 MMb/d. U.S. crude oil production in February averaged 5.94 MMb/d, its lowest level in nearly fifty years; compared to 6.38 MMb/d during the same month last year.

NATURAL GAS PRODUCTION: Total dry natural gas production in 1998 averaged 18.97 Tcf, up from 18.90 Tcf for 1997. This was attributed to a significant increase in production in the Gulf of Mexico as well as from Arkansas and Colorado. In 1998, gross withdrawals of natural gas reached an all time high of 24.5 Tcf, topping the 1973 level of 24.0 Bcf. U.S. dry gas production in January was 1.61 Tcf; production in the same month last year was 1.61 Tcf.

ROTARY RIG ACTIVITY: In 1998, the rotary rig count averaged 827 rigs for the United States, a decrease of 116 over one year ago. The rotary rig count has dropped to an all time low of 502 through March 26, 1999. Twenty-two percent of the rigs were drilling for oil, while seventy-eight percent were drilling for gas.

WELL COMPLETIONS: In 1998, total well completions showed a decline of 13 percent to 24,884 over 1997. There were 10,711 gas well completions; 8,720 oil well completions and 5,453 dry holes.

RESERVES: In 1997, crude oil reserves increased 2.4 percent to 22,546 million barrels. Naturals gas liquids 1.9 percent to 7,973 million barrels. Dry natural gas reserves increased 0.4 percent to 167.2 Tcf. The 1997 reserve/production ratios stood at 9.6 for crude oil and 8.8 for natural gas.

Sources: DOE, API, Baker Hughes, BLS

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1. EXPLORATION ACTIVITY

Year	Seismic Crew Count	Exploratory Wells Drilled					Total New-Field Wildcat Wells
		Oil	Gas	Dry	Total	% Dry	
1980	5,915	1,777	2,085	9,008	12,870	70.0	7,332
1981	8,172	2,661	2,522	12,247	17,430	70.3	9,151
1982	7,060	2,481	2,172	11,229	15,882	70.7	7,386
1983	5,681	2,129	1,654	10,062	13,845	72.7	6,057
1984	5,931	2,334	1,588	11,216	15,138	74.1	6,528
1985	4,539	1,724	1,283	9,201	12,208	75.4	5,630
1986	2,355	993	749	5,414	7,156	75.7	3,484
1987	2,113	894	708	5,301	6,903	76.8	3,515
1988	2,161	817	704	4,788	6,350	75.4	3,271
1989	1,587	604	707	4,024	5,336	75.4	2,644
1990	1,493	649	684	3,813	5,146	74.1	2,685
1991	1,251	602	543	3,312	4,457	74.3	2,195
1992	847	504	429	2,541	3,474	73.1	1,762
1993	952	509	554	2,524	3,587	70.4	1,683
1994	1,087	576	740	2,445	3,761	65.0	1,613
1995	1,253	560	578	2,246	3,384	66.4	1,605
1996	1,307	511	590	2,206	3,307	66.7	1,676
1997	1,336	467	536	2,202	3,205	68.7	1,757
1998	1,566	330	546	1,762	2,638	66.8	1,444
1999	1,125	186	636	1,215	2,037	59.6	1,102

2. DRILLING

Year	Rotary Rigs Active	Total Well Completions				Total Footage Drilled (Mill. Ft.)
		Oil	Gas	Dry	Total Excl. Service	
1980	2,912	32,120	17,132	20,234	69,486	311.4
1981	3,970	42,520	19,742	26,972	89,234	406.5
1982	3,105	39,252	18,810	25,827	83,889	375.4
1983	2,229	37,396	14,505	23,837	75,738	316.7
1984	2,429	44,472	14,962	25,549	84,983	368.8
1985	1,980	36,458	12,917	21,431	70,806	316.8
1986	964	18,598	8,055	12,362	39,015	177.6
1987	936	16,441	8,114	11,698	36,253	163.9
1988	936	13,503	8,434	10,291	32,228	154.9
1989	869	10,424	9,493	8,475	28,392	135.0
1990	1,010	12,342	11,006	8,604	31,952	153.8
1991	860	12,044	9,564	7,743	29,351	143.2
1992	722	9,140	8,288	6,279	23,707	121.6
1993	754	9,009	10,169	6,544	25,722	136.9
1994	755	7,446	9,885	5,499	22,830	128.6
1995	723	8,459	8,738	5,374	22,571	122.8
1996	779	9,490	9,787	5,583	24,860	134.8
1997	943	11,698	11,454	6,111	29,263	159.8
1998	827	7,962	11,422	5,141	24,525	138.2
1999	625	5,031	10,213	3,750	18,994	104.6

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3. OPERATORS & PRODUCING WELLS

Year	Drilling Operators of Record	Crude Oil		Natural Gas		Total Producing Wells
		Producing Wells	% of Total	Producing Wells	% of Total	
1980	10,059	543,510	75.6	175,213	24.4	718,723
1981	12,381	557,009	74.6	189,609	25.4	746,618
1982	13,014	580,142	74.0	203,663	26.0	783,805
1983	12,951	603,290	73.8	214,354	26.2	817,644
1984	12,815	620,807	73.3	226,077	26.7	846,884
1985	11,370	646,626	72.5	245,765	27.5	892,391
1986	8,335	628,690	71.5	250,510	28.5	879,200
1987	7,048	620,181	71.0	253,856	29.0	874,037
1988	6,095	623,587	70.9	256,004	29.1	879,591
1989	5,231	606,881	69.9	261,225	30.1	868,106
1990	5,361	602,439	69.2	267,891	30.8	870,330
1991	5,138	610,204	69.1	273,299	30.9	883,503
1992	4,337	594,189	67.9	280,899	32.1	875,088
1993	4,172	583,879	67.1	286,161	32.9	870,040
1994	3,612	581,657	66.9	287,845	33.1	869,502
1995	3,404	574,483	66.1	294,229	33.9	868,712
1996	3,398	574,419	65.4	303,601	34.6	878,020
1997	3,453	573,070	65.4	303,597	34.6	876,667
1998	2,918	562,148	64.5	309,005	35.5	871,153
1999	2,087	554,385	64.4	305,978	35.6	860,363

4. STRIPPER WELLS

Year	Producing Wells		Production		Avg. Output per Well (b/d)	Abandonments	Reserves (Bill. Bbls.)
	Stripper Wells	% U.S. Wells	Thous. b/d	% U.S. Output			
1980	395,176	72.7	1,096	12.7	2.8	6,614	5.2
1981	409,539	73.5	1,168	13.1	2.9	7,215	4.4
1982	416,493	71.8	1,211	14.0	2.9	9,426	4.5
1983	441,501	73.2	1,266	14.6	2.9	11,032	4.6
1984	452,543	72.9	1,266	14.3	2.8	14,170	4.5
1985	458,447	70.9	1,249	14.0	2.7	16,024	4.2
1986	460,429	73.2	1,231	14.0	2.7	19,233	4.0
1987	451,787	72.8	1,224	14.7	2.7	18,241	3.9
1988	454,150	72.8	1,210	14.9	2.7	17,423	3.8
1989	452,589	74.6	1,060	13.9	2.3	16,107	3.7
1990	463,854	77.0	1,050	14.3	2.3	17,235	3.6
1991	462,823	75.8	1,034	13.9	2.2	17,584	3.4
1992	453,277	76.3	1,009	14.7	2.2	16,211	3.3
1993	452,248	77.5	975	14.2	2.2	16,914	3.0
1994	442,500	76.1	931	14.2	2.1	17,896	2.9
1995	433,048	75.4	910	14.0	2.1	16,389	2.8
1996	428,842	74.7	886	15.0	2.1	16,674	2.5
1997	431,552	75.3	884	15.0	2.1	15,037	2.5
1998	419,280	74.6	866	13.9	2.1	13,912	2.4
1999	422,730	76.3	859	13.8	2.0	11,227	2.3

5. NEW RESERVES ADDED

Year	Liquid Hydrocarbons (Mill. Bbls.)			Natural Gas (Tcf)	Crude Oil Reserves Per New Oil Well (Bbls.)	Nat. Gas Reserves Per New Gas Well (MMcf)
	Crude Oil	NGL	Total			
1980	2,970	844	3,814	16.7	92,466	975
1981	2,570	1,081	3,651	21.5	60,442	1,089
1982	1,382	874	2,256	17.3	35,208	920
1983	2,897	1,405	4,302	14.5	77,468	1,000
1984	3,748	518	4,266	14.4	84,278	962
1985	3,022	1,054	4,076	11.9	82,890	921
1986	1,446	959	2,405	13.8	77,750	1,713
1987	3,240	729	3,969	11.7	197,068	1,442
1988	2,380	845	3,225	-2.5	176,257	-296
1989	2,262	288	2,550	16.1	216,999	1,696
1990	2,258	553	2,811	19.5	182,953	1,772
1991	940	634	1,574	14.9	78,047	1,558
1992	1,509	760	2,269	15.4	165,098	1,858
1993	1,551	559	2,110	15.2	172,161	1,495
1994	1,768	739	2,507	19.7	237,443	1,993
1995	2,107	1,020	3,127	19.3	249,084	2,206
1996	1,839	1,274	3,113	20.1	193,783	2,054
1997	2,667	1,013	3,680	19.9	227,988	1,737
1998	479	384	863	15.5	60,191	1,357
1999	2,683	1,278	3,961	22.3	533,294	2,183

6. PROVED RESERVES

As of Dec. 31st	Liquid Hydrocarbons (Mill. Bbls.)			Natural Gas-Dry (Tcf)	Reserve/Production Ratio		
	Crude Oil	NGL	Total Liquid		Crude Oil	Total Liquid	Natural Gas
1980	29,805	6,728	36,533	199.0	10.0	9.9	10.6
1981	29,426	7,068	36,494	201.7	10.0	9.9	10.8
1982	27,858	7,221	35,079	201.5	9.4	9.6	11.5
1983	27,735	7,901	35,636	200.3	9.2	9.5	12.7
1984	28,446	7,643	36,089	197.5	9.4	9.5	11.5
1985	28,416	7,944	36,360	193.4	9.3	9.6	12.1
1986	26,889	8,165	35,054	191.6	9.0	9.4	12.3
1987	27,256	8,147	35,403	187.2	9.5	9.8	11.6
1988	26,825	8,238	35,063	168.0	9.5	9.8	10.1
1989	26,501	7,769	34,270	167.1	10.2	10.3	9.8
1990	26,254	7,586	33,840	169.3	10.5	10.5	9.8
1991	24,682	7,464	32,146	167.1	9.8	9.8	9.7
1992	23,745	7,451	31,196	165.0	9.7	9.7	9.5
1993	22,957	7,222	30,179	162.4	9.8	9.6	9.1
1994	22,457	7,170	29,627	163.8	9.2	11.4	8.7
1995	22,351	7,399	29,750	165.1	9.3	11.5	8.9
1996	22,017	7,823	29,840	166.4	9.3	11.7	8.9
1997	22,546	7,973	30,519	167.2	9.6	12.0	8.8
1998	21,034	7,524	28,558	164.0	9.2	11.7	8.8
1999	21,765	7,906	29,671	167.4	10.1	11.7	9.0

7. PETROLEUM PRODUCTION

Year	Crude Oil	NGL	Total Produc-tion	Average Crude Oil Per Well	% of U.S. Energy Production		
	(Thous. b/d)			(b/d)	Petro-leum	Natural Gas	Total
1980	8,597	1,573	10,170	15.8	28.2	34.2	62.4
1981	8,572	1,609	10,181	15.4	28.2	34.2	62.4
1982	8,649	1,550	10,199	14.9	28.7	32.0	60.7
1983	8,688	1,559	10,247	14.4	30.0	30.6	60.6
1984	8,879	1,630	10,509	14.3	28.6	30.7	59.3
1985	8,971	1,609	10,580	13.9	29.2	29.6	58.8
1986	8,680	1,551	10,231	13.8	28.6	29.0	57.6
1987	8,349	1,595	9,944	13.5	27.2	29.8	57.0
1988	8,151	1,625	9,776	13.1	26.1	30.0	56.1
1989	7,613	1,546	9,159	12.5	24.4	30.3	54.7
1990	7,355	1,559	8,914	12.2	23.0	30.3	53.3
1991	7,417	1,659	9,076	12.2	23.2	30.7	53.9
1992	7,171	1,697	8,868	12.1	22.8	30.9	53.7
1993	6,847	1,736	8,583	11.7	22.1	32.5	54.6
1994	6,662	1,727	8,389	11.5	20.9	32.3	53.2
1995	6,560	1,762	8,322	11.4	20.4	32.0	52.4
1996	6,465	1,830	8,295	11.3	20.0	32.0	52.0
1997	6,452	1,817	8,269	11.3	20.0	32.0	52.0
1998	6,252	1,759	8,011	11.1	19.0	31.0	50.0
1999	5,881	1,850	7,731	10.6	18.0	32.0	50.0

8. PETROLEUM CONSUMPTION

Year	Petroleum Demand (Thous. b/d)			% of U.S. Energy Consumption		Energy/GDP Ratio
	Domestic	Export	Total	Petroleum	Natural Gas	(Thous. Btu Per 1996 $)
1980	17,056	544	17,600	45.0	26.9	15.6
1981	16,058	595	16,653	43.2	26.9	14.8
1982	15,296	815	16,111	42.7	26.1	14.5
1983	15,231	739	15,970	42.6	24.6	13.8
1984	15,726	722	16,448	41.9	25.0	13.7
1985	15,726	781	16,507	41.8	24.1	13.0
1986	16,281	785	17,066	43.3	22.5	12.6
1987	16,665	764	17,429	42.7	23.1	12.6
1988	17,283	815	18,098	42.7	23.1	12.6
1989	17,325	859	18,184	42.0	23.8	12.4
1990	16,988	857	17,845	41.3	23.7	12.2
1991	16,714	1,001	17,715	40.5	24.2	12.2
1992	17,033	950	17,983	40.7	24.4	12.0
1993	17,237	1,003	18,240	40.2	24.7	11.9
1994	17,718	942	18,660	40.4	24.8	11.7
1995	17,725	949	18,674	39.6	25.3	11.6
1996	18,309	981	19,290	39.7	24.9	11.6
1997	18,620	1,003	19,623	40.0	24.8	11.1
1998	18,917	945	19,862	40.5	24.0	10.7
1999	19,519	940	20,459	40.9	23.7	10.5

9. PETROLEUM SUPPLY

Year	Imports: Crude Oil	Imports: Refined Products	Imports: Total (excl. SPR)	Other Supply	Total Supply	Imports as % of Demand
	(Thous. b/d)					
1980	5,263	1,646	6,909	616	17,695	40.5
1981	4,396	1,599	5,996	391	16,568	37.3
1982	3,488	1,625	5,113	478	15,790	33.4
1983	3,329	1,722	5,051	503	15,801	33.2
1984	3,426	2,011	5,437	587	16,533	34.6
1985	3,201	1,866	5,067	640	16,287	32.2
1986	4,178	2,045	6,224	763	17,218	38.2
1987	4,674	2,004	6,678	768	17,390	40.1
1988	5,107	2,295	7,402	840	18,018	42.8
1989	5,843	2,217	8,061	865	18,085	46.5
1990	5,894	2,123	8,018	1,004	17,936	47.2
1991	5,782	1,844	7,627	1,046	17,749	45.6
1992	6,083	1,805	7,888	1,114	17,870	46.3
1993	6,787	1,833	8,620	1,152	18,355	50.0
1994	7,063	1,933	8,996	1,291	18,676	50.8
1995	7,230	1,605	8,835	1,517	18,674	49.8
1996	7,508	1,971	9,479	1,516	19,290	51.8
1997	8,225	1,936	10,161	1,193	19,623	54.6
1998	8,706	2,002	10,708	1,143	19,862	56.6
1999	8,731	2,121	10,852	1,876	20,459	55.6

10. PETROLEUM IMPORTS BY ORIGIN

Year	OPEC Sources: Thous. b/d	OPEC Sources: % Total Imports	Arab OPEC: Thous. b/d	Arab OPEC: % Total Imports	Persian Gulf: Thous. b/d	Persian Gulf: % Total Imports	Total: Thous. b/d (incl. SPR)
1980	4,300	62.2	2,007	29.0	1,519	22.0	6,909
1981	3,323	55.4	1,530	25.5	1,219	20.3	5,996
1982	2,146	42.0	866	16.9	696	13.6	5,113
1983	1,832	36.3	682	13.5	442	8.8	5,051
1984	2,049	37.7	829	15.2	506	9.3	5,437
1985	1,830	36.1	498	9.8	311	6.1	5,067
1986	2,837	45.6	1,183	19.0	912	14.7	6,224
1987	3,060	45.8	1,372	20.2	1,077	16.1	6,678
1988	3,520	47.6	1,841	24.9	1,541	20.8	7,402
1989	4,140	51.4	2,130	26.4	1,861	23.1	8,061
1990	4,296	53.6	2,244	28.0	1,966	24.5	8,018
1991	4,092	53.7	2,098	27.5	1,845	24.2	7,627
1992	4,092	51.9	1,984	25.2	1,778	22.5	7,888
1993	4,273	49.6	2,002	23.2	1,782	20.7	8,620
1994	4,247	47.2	1,971	21.9	1,728	19.2	8,996
1995	4,002	45.3	1,807	20.5	1,573	17.8	8,835
1996	4,211	44.4	1,860	19.6	1,604	16.9	9,479
1997	4,569	45.0	2,040	20.1	1,755	17.3	10,162
1998	4,905	45.8	2,426	22.7	2,136	19.9	10,708
1999	4,953	45.6	2,723	25.1	2,464	22.7	10,852

11. NATURAL GAS

Year	Marketed Production (Wet)	Dry Gas Production	Imports	Exports	Total Supply	Consumption
	(Bcf)					
1980	20,180	19,403	985	49	21,875	19,877
1981	19,956	19,181	904	59	21,691	19,404
1982	18,582	17,820	933	52	20,525	18,001
1983	16,884	16,094	918	55	18,712	16,835
1984	18,304	17,466	843	55	20,300	17,951
1985	17,270	16,454	950	55	19,499	17,281
1986	16,859	16,059	750	61	18,266	16,221
1987	17,433	16,621	993	54	19,176	17,211
1988	17,918	17,103	1,294	74	20,315	18,030
1989	18,095	17,311	1,382	107	21,435	18,801
1990	18,594	17,810	1,532	86	21,302	18,716
1991	18,532	17,698	1,773	129	21,836	19,035
1992	18,712	17,840	2,138	216	22,360	19,544
1993	18,982	18,095	2,350	140	23,253	20,279
1994	19,710	18,821	2,624	162	23,666	20,708
1995	19,506	18,599	2,841	154	24,301	21,581
1996	19,751	18,793	2,937	153	25,031	21,967
1997	19,866	18,902	2,994	157	24,916	21,959
1998	19,646	18,708	3,152	159	24,326	21,262
1999	19,611	18,660	3,586	163	24,079	21,361

12. NATURAL GAS PRICES

Year	Wellhead: Current $	Wellhead: Current 1999	City Gate	End Use: Residential	End Use: Commercial	End Use: Industrial	End Use: Utilities
	($/Mcf)						
1980	1.59	2.90	N/A	3.68	3.39	2.56	2.27
1981	1.98	3.31	N/A	4.29	4.00	3.14	2.89
1982	2.46	3.88	N/A	5.17	4.82	3.87	3.48
1983	2.59	3.92	N/A	6.06	5.59	4.18	3.58
1984	2.66	3.88	3.95	6.12	5.55	4.22	3.70
1985	2.51	3.55	3.75	6.12	5.50	3.95	3.55
1986	1.94	2.69	3.22	5.83	5.08	3.23	2.43
1987	1.67	2.25	2.87	5.54	4.77	2.94	2.32
1988	1.69	2.20	2.92	5.47	4.63	2.95	2.34
1989	1.69	2.12	3.01	5.64	4.74	2.96	2.43
1990	1.71	2.06	3.03	5.80	4.83	2.93	2.38
1991	1.64	1.91	2.90	5.82	4.81	2.69	2.18
1992	1.74	1.99	3.01	5.89	4.88	2.84	2.36
1993	2.04	2.27	3.21	6.16	5.22	3.07	2.61
1994	1.85	2.02	3.07	6.41	5.44	3.05	2.28
1995	1.55	1.65	2.78	6.06	5.05	2.71	2.02
1996	2.17	2.27	3.34	6.34	5.40	3.42	2.69
1997	2.32	2.38	3.66	6.94	5.80	3.59	2.78
1998	1.94	1.97	3.07	6.82	5.48	3.14	2.40
1999	2.08	2.08	3.11	6.62	5.27	3.04	2.62

13. OIL & COMPOSITE PRICES

Year	Crude Wellhead		Refiner Acquisition Cost			Oil/Gas Composite	
	Current $	Constant 1999 $	U.S.	Import	Composite	Current $	Constant 1999 $
	($/Bbl.)						
1980	21.59	39.42	24.23	33.89	28.07	14.52	26.51
1981	31.77	53.08	34.33	37.05	35.24	20.36	34.01
1982	28.52	44.93	31.22	33.55	31.87	20.57	32.41
1983	26.19	39.64	28.87	29.30	28.99	20.13	30.47
1984	25.88	37.77	28.53	28.88	28.63	19.99	29.18
1985	24.09	34.09	26.66	26.99	26.75	18.88	26.72
1986	12.51	17.33	14.82	14.00	14.55	11.50	15.93
1987	15.40	20.73	17.76	18.13	17.90	12.12	16.31
1988	12.58	16.38	14.74	14.56	14.67	10.76	14.01
1989	15.86	19.89	17.87	18.08	17.97	12.18	15.27
1990	20.03	24.17	22.59	21.76	22.22	13.96	16.85
1991	16.54	19.31	19.33	18.70	19.06	12.24	14.29
1992	15.99	18.27	18.63	18.20	18.43	12.23	13.98
1993	14.25	15.86	16.67	16.14	16.41	12.36	13.75
1994	13.19	14.38	15.67	15.51	15.59	11.27	12.28
1995	14.62	15.60	17.33	17.14	17.23	10.86	11.59
1996	18.46	19.34	20.77	20.64	20.71	14.36	15.05
1997	17.23	17.71	19.61	18.53	19.04	14.36	14.76
1998	10.87	11.03	13.18	12.04	12.52	10.63	10.79
1999	15.56	15.56	17.82	17.25	17.47	12.84	12.84

14. PETROLEUM PRODUCT PRICES

Year	Wholesale Prices						Retail Gasoline	
	Gasoline	Kerosene	Distillate	Resid. Fuel	Average 4 Products		Excl. Taxes	Incl. Taxes
	($/Gal.)					($/Bbl.)	($/Gal.)	
1980	0.87	0.80	0.78	0.44	0.73	30.56	1.08	1.19
1981	1.02	1.01	0.97	0.61	0.89	37.28	1.20	1.33
1982	0.95	0.97	0.92	0.58	0.83	34.97	1.12	1.26
1983	0.87	0.85	0.80	0.57	0.77	32.31	1.03	1.22
1984	0.81	0.85	0.80	0.59	0.74	31.29	1.00	1.21
1985	0.81	0.82	0.77	0.56	0.73	30.69	0.95	1.16
1986	0.48	0.50	0.45	0.36	0.44	18.47	0.70	0.92
1987	0.53	0.57	0.52	0.45	0.51	21.37	0.72	0.95
1988	0.50	0.51	0.46	0.39	0.46	19.41	0.71	0.95
1989	0.59	0.61	0.56	0.41	0.53	22.38	0.77	1.01
1990	0.72	0.73	0.68	0.51	0.65	27.38	0.88	1.14
1991	0.64	0.65	0.60	0.41	0.57	23.78	0.84	1.15
1992	0.61	0.63	0.58	0.42	0.55	23.02	0.78	1.11
1993	0.55	0.60	0.55	0.40	0.51	21.35	0.77	1.11
1994	0.53	0.58	0.53	0.43	0.50	21.04	0.74	1.11
1995	0.56	0.58	0.54	0.47	0.53	22.33	0.77	1.14
1996	0.63	0.73	0.70	0.58	0.66	27.72	0.85	1.23
1997	0.66	0.66	0.62	0.54	0.62	26.12	0.83	1.22
1998	N/A	N/A	N/A	N/A	N/A	N/A	0.66	1.06
1999	N/A	N/A	N/A	N/A	N/A	N/A	0.76	1.16

15. WELLHEAD REVENUES & TAXES

Year	Wellhead Revenues (Mill. $)					Severance and Production Taxes Paid (Mill. $)
	Crude Oil	% of Total	Natural Gas	% of Total	Total	
1980	67,747	67.9	32,086	32.1	99,834	3,865
1981	99,401	71.6	39,513	28.4	138,914	6,418
1982	90,034	66.3	45,712	33.7	135,746	7,464
1983	83,052	65.5	43,730	34.5	126,781	7,265
1984	83,873	63.3	48,689	36.7	132,561	7,192
1985	78,881	64.5	43,348	35.5	122,228	7,002
1986	39,634	54.8	32,706	45.2	72,341	5,360
1987	46,930	61.7	29,113	38.3	76,043	3,998
1988	37,427	55.3	30,281	44.7	67,708	4,002
1989	44,071	59.0	30,581	41.0	74,651	3,821
1990	53,772	62.8	31,796	37.2	85,568	4,621
1991	44,777	59.6	30,392	40.4	75,170	4,625
1992	41,852	56.2	32,559	43.8	74,411	4,083
1993	35,613	47.9	38,723	52.1	74,336	4,153
1994	32,073	46.8	36,464	53.2	68,537	3,404
1995	35,006	53.7	30,234	46.3	65,240	3,177
1996	43,561	50.4	42,860	49.6	86,420	3,271
1997	40,576	46.8	46,089	53.2	86,665	3,781
1998	24,805	39.4	38,113	60.6	62,918	2,719
1999	33,401	45.0	40,791	55.0	74,191	2,373

16. FINANCIAL STATISTICS

Year	Rate of Return %		Exploration & Development Outlays (Mill. $)			Wages ($/Hour)	
	Oil & Gas	All Mfg.	Larger Firms	Independents	Total	Oil & Gas	All Mfg.
1980	21.7	12.2	26,235	14,175	40,410	9.70	7.27
1981	17.8	12.9	31,992	23,698	55,690	10.78	7.99
1982	12.5	9.7	30,330	23,387	53,717	11.81	8.50
1983	12.4	12.3	24,201	22,047	46,248	12.38	8.84
1984	11.0	13.9	25,698	22,356	48,054	12.77	9.18
1985	10.3	11.0	23,097	20,538	43,635	13.31	9.52
1986	3.7	11.1	12,168	11,754	23,922	13.75	9.73
1987	6.2	14.7	10,555	9,208	19,763	14.02	9.91
1988	15.0	16.6	13,198	10,759	23,957	14.47	10.18
1989	11.6	14.9	11,557	9,795	21,352	12.29	10.49
1990	12.6	12.0	11,316	9,642	20,958	12.72	10.83
1991	9.7	7.9	10,599	10,863	21,462	13.52	11.18
1992	N/A	N/A	N/A	N/A	N/A	13.97	11.46
1993	N/A	N/A	N/A	N/A	N/A	14.13	11.74
1994	N/A	N/A	N/A	N/A	N/A	14.10	12.06
1995	N/A	N/A	N/A	N/A	N/A	14.52	12.37
1996	N/A	N/A	N/A	N/A	N/A	14.87	12.77
1997	N/A	N/A	N/A	N/A	N/A	15.66	13.17
1998	N/A	N/A	N/A	N/A	N/A	16.83	13.49
1999	N/A	N/A	N/A	N/A	N/A	16.86	13.91

17. DRILLING COSTS & INDICES

Year	Drilling Costs Total (Mill. $)	Per Well ($)	Per Ft. ($)	Producer Price Index	Crude Price Index	Oil Machinery Index
				1982=100		
1980	22,800	367,682	77.03	88.0	75.9	76.3
1981	36,666	453,691	94.30	96.1	109.6	91.1
1982	39,428	514,378	108.73	100.0	100.0	100.0
1983	25,105	371,721	83.34	101.6	92.9	97.4
1984	25,206	326,463	71.90	103.7	91.3	96.6
1985	23,697	349,399	75.35	104.7	84.5	96.8
1986	13,552	364,577	76.88	103.2	46.9	94.3
1987	9,239	279,615	58.71	105.4	55.5	93.3
1988	10,550	354,713	70.23	108.0	46.2	97.0
1989	9,669	362,243	75.08	113.6	56.3	99.1
1990	10,937	383,596	76.07	119.2	71.0	102.4
1991	11,461	421,453	82.64	121.7	61.9	108.6
1992	8,556	382,607	70.27	123.2	58.0	107.8
1993	9,824	426,793	75.30	124.7	51.4	108.2
1994	9,676	483,237	79.49	125.5	47.1	110.8
1995	10,539	513,415	87.23	127.9	51.1	114.1
1996	10,919	496,105	88.92	131.3	62.6	117.8
1997	16,042	603,918	107.83	131.8	57.5	122.8
1998	17,586	778,480	133.64	130.7	35.7	125.9
1999	N/A	N/A	N/A	133.0	50.3	126.5

18. OIL & GAS EMPLOYMENT

Year	Extraction	Refining	Transpor-tation	Wholesale	Retail	Total Industry
	(Thous.)					
1980	559.7	167.0	189.3	223.9	560.8	1,700.7
1981	692.1	185.1	195.8	231.5	562.2	1,866.7
1982	708.3	175.8	198.2	222.6	559.0	1,863.9
1983	597.8	169.2	193.6	210.9	556.2	1,727.7
1984	606.5	162.2	192.3	208.3	574.7	1,744.0
1985	582.9	152.5	193.5	205.9	588.5	1,723.3
1986	450.5	140.7	185.6	200.5	596.0	1,573.3
1987	401.8	133.5	183.8	197.9	608.0	1,525.0
1988	400.3	120.8	182.6	203.2	625.4	1,532.3
1989	381.0	117.3	181.8	206.9	641.4	1,528.4
1990	394.7	117.8	183.2	195.6	647.1	1,538.4
1991	392.9	121.5	185.4	185.6	626.4	1,511.8
1992	352.6	119.2	182.6	172.7	615.7	1,442.8
1993	349.8	112.2	179.4	162.8	617.2	1,421.4
1994	336.5	108.9	176.4	161.1	633.9	1,416.8
1995	320.1	104.5	168.6	158.8	648.9	1,400.9
1996	322.0	100.2	161.5	155.5	668.9	1,408.1
1997	339.0	98.0	155.6	154.9	675.9	1,423.4
1998	339.2	96.0	150.3	155.0	689.4	1,429.9
1999	293.1	92.1	145.0	153.5	701.5	1,385.2

19. GENERAL ECONOMIC DATA

Year	Cost of Oil Imports	Gross Domestic Product Current $	Constant 1996 $	Price Deflator	Consumer Price Index	Industrial Production Index
	(Bill. $)			1996=100	1982-84=100	1992=100
1980	78.6	2,545.6	4,872.3	57.4	82.4	79.7
1981	76.7	3,131.4	4,993.9	62.7	90.9	81.0
1982	60.5	3,259.2	4,900.3	66.5	96.5	76.7
1983	53.2	3,535.0	5,105.6	69.2	99.6	79.5
1984	56.9	3,932.8	5,402.8	71.8	103.9	86.6
1985	50.5	4,213.0	5,689.8	74.0	107.6	88.0
1986	35.1	4,452.9	5,885.7	75.7	109.7	89.0
1987	42.3	4,742.5	6,092.6	77.8	113.7	93.2
1988	38.8	5,108.3	6,349.0	80.5	118.4	97.4
1989	49.7	5,489.1	6,568.7	83.6	124.0	99.1
1990	61.6	5,803.3	6,683.5	86.8	130.8	98.9
1991	51.4	5,986.2	6,669.1	89.8	136.3	97.0
1992	51.2	6,319.0	6,891.1	91.7	140.4	100.0
1993	51.0	6,642.3	7,054.2	94.2	144.6	103.4
1994	50.8	7,054.3	7,337.8	96.1	148.3	109.1
1995	54.4	7,400.6	7,537.8	98.2	152.5	114.3
1996	72.0	7,813.2	7,813.2	100.0	157.0	119.4
1997	71.2	8,318.4	8,159.5	101.9	160.6	127.0
1998	50.3	8,790.2	8,515.6	103.2	163.1	132.4
1999	67.2	9,299.2	8,875.7	104.8	166.7	137.0

PEAK YEAR MILESTONES

Operators of Record	1982	12,955	
Seismic Crew Count	1981	8,172	
Rotary Rigs Active	1981	3,970	
Exploratory Wells Drilled	1981	17,430	
Oil Wells Drilled	1984	44,472	
Gas Wells Drilled	1981	19,742	
Dry Holes Drilled	1981	26,972	
Total Wells Drilled	1981	89,234	
Producing Oil Wells	1985	646,626	
Producing Gas Wells	1998	309,005	
Drilling Costs	1982	$39.4	Bill.
Crude Oil Production	1970	9,637	Thous. b/d
Stripper Well Production	1961	1,622	Thous. b/d
Petroleum Imports	1999	10,852	Thous. b/d
Petroleum Demand	1999	19,519	Thous. b/d
Natural Gas Production	1973	22,648	Bcf
Natural Gas Consumption	1972	22,049	Bcf
Natural Gas Imports	1999	3,547	Bcf
Oil Wellhead Price	1981	$31.77	per Bbl.
Gas Wellhead Price	1984	$2.66	per Mcf
Total Industry Employment	1981	1.9	Mill.

SOURCES:

1. Seismic Crews: IHS Energy Group: Wells: American Petroleum Institute (API)
2. Rotary Rigs: Baker Hughes; Wells and Footage: API (estimated completion basis)
3. Operators: IHS Energy Group; Producing Wells: *World Oil*
4. Stripper Wells: Interstate Oil & Gas Compact Commision (IOGCC)

5.-6. Energy Information Administration (EIA); API; American Gas Association

7.-13. EIA and IPAA

14. Wholesale Prices: IPAA; Retail Gasoline Prices: *Oil & Gas Journal*
15. Wellhead Value: EIA; Taxes: IPAA
16. Rate of Return: API (20 Largest Companies) and Standard and Poor's Compustat; Wages: Bureau of Labor Statistics; Other Data: API
17. Drilling Costs: *Joint Association Survey;* Oil Field Wage Index: IPAA; Other Indices: Dept. of Commerce
18. Bureau of Labor Statistics
19. Department of Commerce

NOTES:

A. Crude oil production and imports include lease condensate. Other petroleum supply includes refinery processing gain and other hydrocarbons.

B. Producing wells and reserves are shown as of December 31st each year.

C. Alaskan natural gas reserves incurred a significant downward revision in 1988.

D. Imports for the Strategic Petroleum Reserve are included only in Table #10, "Imports by Origin."

E. Marketed natural gas (wet) includes natural gas liquids. Total natural gas supply includes withdrawals from storage and supplemental gaseous fuels.

F. Gasoline wholesale prices are for unleaded fuel after 1981. Retail prices are for unleaded fuel after 1984.

G. All GDP statistics are in 1996 "chain weighted" dollars, unless noted otherwise.

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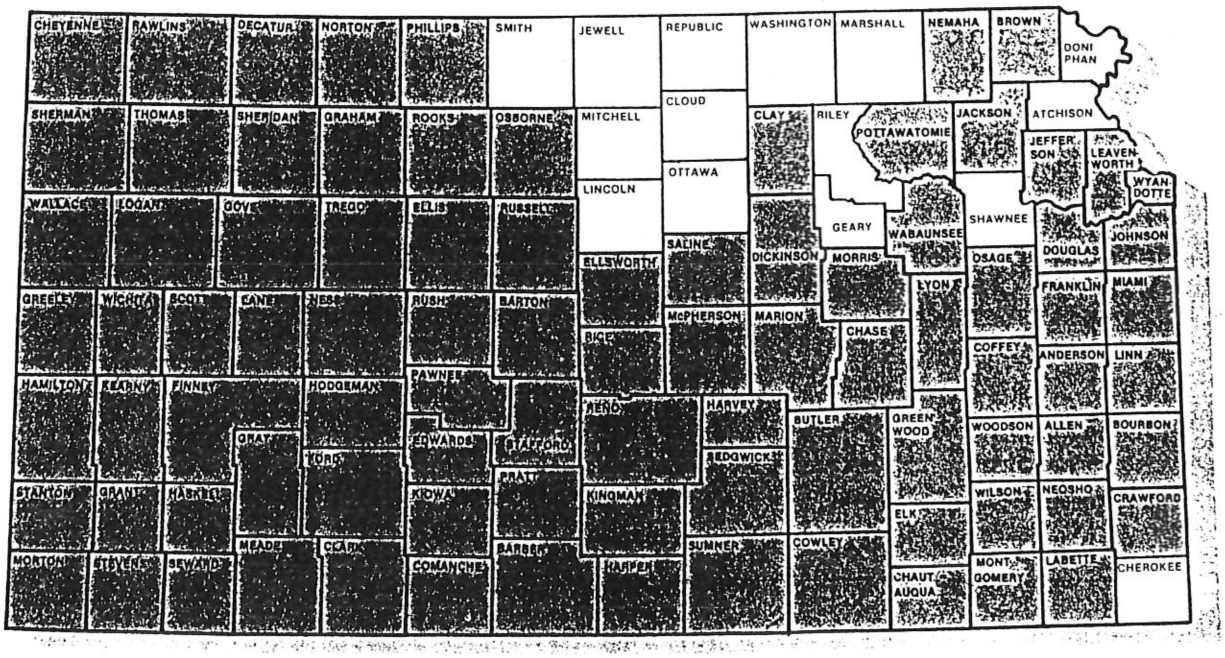
KANSAS



Counties with crude oil and/or natural gas production

EXTENT AND ECONOMIC VALUE OF OIL AND GAS INDUSTRY

1.	Number of counties	105
2.	Number of counties with crude oil and/or gas production	90
3.	Total land area (acres)	52,343,680
4.	Area proved productive of crude oil and/or gas (acres)	7,600,000
5.	Estimated nonproductive area leased Jan. 1, 1983 (acres)	9,400,000
6.	Percent of total land area productive or leased	32.5%
7.	Wellhead value of crude oil produced all time to Jan. 1, 1983 (thous.)	$20,974,133
8.	Average field price of crude oil per barrel in 1982	$30.79
9.	Wellhead value of crude oil produced in 1982 (thous.)	$2,171,465
10.	Wellhead value of natural gas produced in 1982 (thous.)	$645,655
11.	Total wellhead value of oil and gas in 1982 (thous.)	$2,817,120
12.	Percent of petroleum value to total all minerals	78.6%
13.	Principal mineral products in order of value: 1st ... Crude oil; 2nd ... Natural gas; 3rd ... Portland cement	
14.	Number of employees engaged in oil and gas production	17,108
15.	First year of crude oil production	1889
	First year of natural gas production	1882
16.	First recorded production of: Crude oil (barrels) ..... in 1889	500
	Natural gas (Mcf) ..... in 1906	69,323
17.	Geophysical activity — crew months worked in 1982	98

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ATTACHMENT "B"

KANSAS

PRODUCTION AND RESERVES

18. Year of peak crude oil production 1956
19. Crude oil produced in peak year (barrels) 124,204,000
20. Percent of crude oil produced by stripper wells 68.3%
21. Number of producing wells at end of 1982: Crude oil 46,189
    Gas and gas distillate 11,254
    Total 57,443
22. Average daily production of crude oil per well at end of 1982 4.2 b/d
23. Percent of wells on artificial lift ... 97.6%
24. Average production (barrels per day):

	Crude Oil	NGL	Total Petroleum Liquids
1979	156,151	87,397*	243,548
1980	164,347	78,500*	242,847
1981	180,301	76,500*	256,801
1982	193,219	75,000*	268,219

*Estimated

25. Production and new reserves found in 1982:

	Crude Oil (million bbls.)	NGL (million bbls.)	Total Petroleum Liquids (million bbls.)	Natural Gas (billion cu. ft.)
New reserves found	70	−93	−23	144
Estimated production	63	14	77	459
Net change in reserves	7	−107	−100	−315

26. Production and new reserves found all time to Dec. 31, 1982:

	Crude Oil (million bbls.)	NGL (million bbls.)	Total Petroleum Liquids (million bbls.)	Natural Gas (billion cu. ft.)
Total reserves found	5,454	982	6,436	37,701
Total production	5,076	680	5,756	27,573
Proved reserves, Dec. 31, 1982	378	302	680	10,128

EXPLORATION AND DEVELOPMENT

27. Rotary drilling rigs active in 1982 (average) 157
28. Deepest producing well drilled to Jan. 1, 1983 (feet)... Natural gas 6,774
29. Deepest well drilled to Jan. 1, 1983 (feet) .... Dry hole 8,713
30. Wells and footage drilled in 1982:

	Number	Percent
Wildcat Wells		
Oil wells	358	17.0
Gas wells	81	3.8
Dry holes	1,671	79.2
Total wells	2,110	100.0
Average depth per well (feet)		3,770
Total footage		7,954,245
Development Wells		
Oil wells	3,750	53.1
Gas wells	729	10.3
Dry holes	2,354	33.4
Service wells	223	3.2
Total wells	7,056	100.0
Average depth per well (feet)		3,057
Total footage		21,567,448
Total Wells		
Oil wells	4,108	44.8
Gas wells	810	8.8
Dry holes	4,025	43.9
Service wells	223	2.5
Total wells	9,166	100.0
Average depth per well (feet)		3,221
Total footage		29,521,693

31. Total wells drilled all time to Jan. 1, 1983 (excluding service wells):

	Number	Percent
Oil wells	109,070	51.6
Gas wells	20,735	9.8
Dry holes	81,714	38.6
Total wells	211,519	100.0

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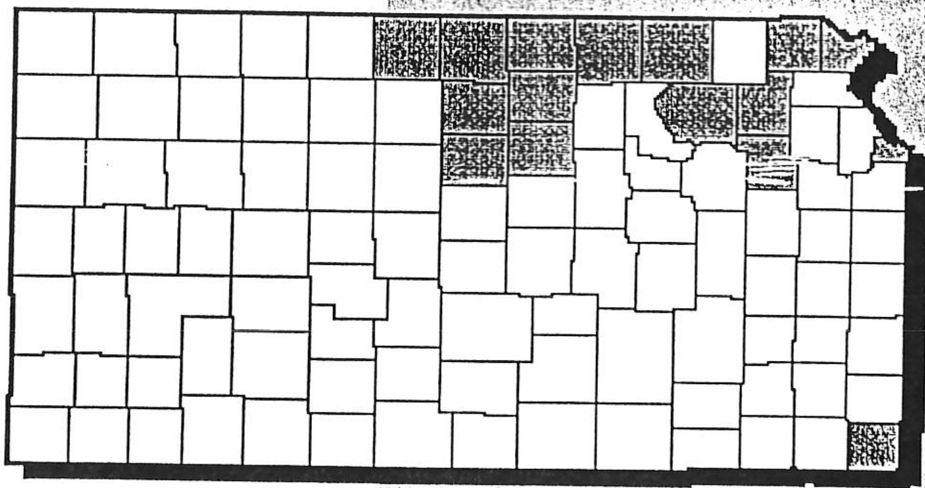
Kansas

ATTACHMENT "C"



☐ Counties with oil and/or gas production

Background Information

Counties

Number of counties	105
With oil and/or gas production	89

,rst year of production

Crude oil	1889
Natural gas	1882

Year and amount of peak production

Crude oil — 124,204 thous. bbls.	1956
Natural gas — 899,955 MMcf	1970

Deepest producing well (ft.)

Crude oil	7,400
Natural gas	6,774

Year and depth of deepest well drilled (ft.)

1984	11,300

Cumulative number of total wells drilled
as of 12/31/98 (excluding service wells)

Oil wells	128,056	50%
Gas wells	27,881	11%
Dry holes	101,284	39%
Total	**257,221**	**100%**

Cumulative crude oil wellhead value $39,483,553
as of 12/31/98 (thous. $)

Cumulative production & new reserves
duction as of 12/31/98, reserves as of 12/31/96

	Crude Oil	NGL (mill. bbls)	Total	Natural Gas (Bcf)
Reserves	6,100	1,308	7,408	43,188
Production	5,862	1,037	6,899	36,199

Value of Oil and Gas

Average wellhead price
(1998)

Crude oil ($/bbl.)	$12.19
Natural gas ($Mcf)	$1.96

Wellhead value of production
(1998, in thous. $)

Crude oil	$433,245
Natural gas	$1,124,099
Total	$1,557,344

Average natural gas price
(1998, $/Mcf)

Residential consumers	$6.00
Commercial consumers	$4.98
Industrial consumers	$3.17
Electric utilities	$2.14
City Gate	$2.96

Severance taxes paid $51,686
(1998, in thous. $)

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KANSAS 1998

1998 Industry Statistics

Number of wells drilled

	Exploratory	Development	Total
Oil	15	194	209
Gas	15	285	300
Dry	135	216	351
Service	--	26	26
Total	165	721	886

Total footage drilled
(thous. ft.)

	Exploratory	Development	Total
Oil	75.0	710.4	785.4
Gas	78.6	963.1	1,041.7
Dry	592.8	787.3	1,380.1
Service	--	49.1	49.1
Total	746.3	2,509.9	3,256.3

(Note: Totals may not add due to rounding.)

New-field wildcats drilled	118
Footage (thous. ft.)	524.8
Average rotary rigs active	13

State-wide rank

	Crude Oil	Natural Gas
Wells drilled	5th	9th
Production	10th	8th
Reserves (1997)	10th	8th

Number of producing wells
(12/31/98)

Crude oil	41,520
Flowing	0
Artificial lift	41,520
Natural gas	17,786
Total	59,306

Average production

	thous. bbls.	thous. b/d
Crude oil	35,541	97
NGL (est.)	29,113	80
Total	64,654	177

Natural gas marketed production (MMcf) 573,520

Average output per producing well

Crude oil (bbls.)	856
Natural gas (Mcf)	45,346

Average number of employees

Oil and natural gas extraction	5,953
Refining	1,453
Transportation	2,904
Wholesale	4,225
Retail	8,393
Total petroleum industry	22,928

Compiled by IPAA December 1999

1997 Latest Available Data

Petroleum reserves
as of 12/31/97 (mill. bbls.)

	Crude Oil	NGL	Total
New reserves	10	-42	-32
Production	38	25	63
Net annual change	-28	-67	-95
Proved reserves	238	271	509

Natural gas reserves
as of 12/31/97 (Bcf)

	Associated Dissolved	Non-Associated	Dry Gas
New reserves	-18	-139	-76
Production	13	647	629
Net annual change	-31	-786	-705
Proved reserves	51	7,277	6,989

Cost of drilling and equipping wells

	Cost/ft. ($)	Cost/ well ($)	Total Cost (thous. $)
Oil	43.84	136,985	74,383
Gas	52.10	178,337	87,385
Dry	22.91	87,005	48,375
Total	38.30	132,249	210,143

Stripper wells

Producing stripper wells	40,504
Stripper well abandonments	1,765
Crude oil production in bbls.	30,675,301
Crude oil production b/d	83,812
Percentage of oil production	77.0%

Stripper oil reserves
as of 1/1/98 (thous. bbls.)

Primary	72,873
Secondary	65,933
Total	138,806

Federal Onshore Mineral Lease Royalties

Oil	$648,379
Gas	$5,002,033
Total Royalties	$5,860,379

Federal Onshore and Indian Oil and Gas Leases

Number of leases	450
Acres leased	123,734

For more information please contact: Information Services Department, Independent Petroleum Association of America, 1101 16th Street, N.W., Washington, D.C. 20036, 202-857-4722, FAX: 202-857-4799

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Natural Gas

Natural gas accounts for approximately two-thirds of Kansas' current energy production. Annual gas production peaked in 1970 at 900 billion cubic feet (bcf) and consumption peaked two years later at 600 bcf (Figure 21). Kansas is one of the top gas-producing states and remains a net exporter of natural gas primarily to the upper midwestern states. In the current year, Kansas should produce approximately 250 bcf more gas than it consumes. Gas production in Kansas is concentrated in southwest Kansas. The fields in this area of the state, including the Hugoton Field, produced 90% of the gas in Kansas (Figure 22). In 1999, gas production of 566 bcf in Kansas was valued at $1.174 billion at the wellhead. Production in 2000 is estimated at over 550 bcf and valued at approximately $2.052 billion. The increased value is attributed to significantly higher average wellhead prices during 2000 (Figure 23).

Economic conditions and government policies have affected Kansas gas production (e.g., the Energy Petroleum Allocation Act of 1973, the Energy Policy and Conservation Act of 1975, the Power plant and Industrial Fuel Use Act of 1978, and the Price and Allocation Decontrol in 1981). The dramatic decrease in gas production during the 1970's from 900 BCF per year to less than 450 BCF per year appears to be related to market distortions resulting from federal government policies (Figure 21). Subsequent decontrol in 1981 of prices, allocations, and uses of fuels, and the 1986 Kansas Corporation Commission's (KCC) modified spacing rules in the Hugoton Field contributed to a second production peak of just over 700 bcf in 1996 (Figures 15, 21). Production has declined since 1996, but appears to have stabilized at approximately 500 bcf. The production decline is attributed to decreased average reservoir pressure in the Hugoton area from over 400 pounds per square inch (psi) to under 60 psi today[15]. As reservoir pressures continue to decline, intelligent energy policies, significant investment capital, and new technologies must be developed to assure continued production.

Kansas gas production is dominated by the large fields of southwest Kansas (e.g., Hugoton, Panoma, Byerly, Bradshaw, and Greenwood). However, stripper gas production in Kansas is significant. Stripper gas production would generally be anything less than 90 thousand cubic feet per day (MCFPD). In Kansas, 63% of the 17,146 producing gas wells averaged less than 90 MCFPD and produced 24.1% of the gas[16]. As with oil, stripper gas production is sensitive to changes in the wellhead oil price and well operating costs (e.g., electricity, taxes, and wages).

In 1999, 1,015 different operators reported natural gas production. The average Kansas independent produced just less than 550,000 mcf of gas in 1999. The top ten producing

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[15] Personal Communication from David P. Williams, Kansas Corporation Commission. The 1999 average well head shut-in pressure for the field was 52.5 psig. The original estimated reservoir pressure for the entire Hugoton Field (Chase Group) was 435 psig.

[16] Producing well numbers are for 1999 Kansas Geological Survey Open-File Report 2000-16, 1999 Kansas Oil and Gas Production: An Examination of the Importance of Stripper Production. http://www.kgs.ukans.edu/PRS/publication/2000/ofr2000-16/index.html

companies produced approximately 78% of the gas in 1999. Seven of the top ten producing companies are independents. Kansas' gas production is a mix of the largest integrated companies (e.g., Exxon-Mobil and BP-America) and independent companies (e.g., Anadarko and Helmrich & Payne).[17]

The seasonal nature of natural gas production has changed significantly after the mid-1990's. Prior the mid-1990's natural gas displayed a seasonal pattern with peak production during the winter heating season (Figure 23). This variation in production was also reflected in seasonal price fluctuations. With the construction of underground gas storage, the development of futures markets, and the increased use of natural gas in electric power generation, seasonal variations in production and price have disappeared. As a result, during the summer there is no longer a cheap and plentiful supply of natural gas to power irrigation pumps in southwest Kansas.

Forecast - Demands on natural gas for electric power generation are absorbing all the excess natural gas supply during warm months, gas that traditionally was put into storage for use as a home heating fuel during the winter. As a result entered the winter of 2000-01 with very low natural gas storage levels and extremely high prices (Figures 23, 24).

The last few winters have had above-normal temperatures, masking the increased demand for natural gas resulting from the strong economic growth and the increased electrification. The winter of 1999-2000 had 3,404 Heating Degree Days (HDD). The normal winter is 3,958 HDD. As this winter appears more seasonable, wellhead prices are exceeding $9-10/MCF for periods of time. As storage levels approach historically low levels, the ability of underground natural gas storage facilities to meet peak demand will be significantly degraded[18]. By using natural gas to solve an electric supply problem, we have creating a gas supply problem.

Agriculture in western Kansas depends on natural gas to run irrigation pumps and is particularly vulnerable to high gas prices. Utility companies have a percentage of winter demand covered by longer-term contracts for natural gas. This will partially buffer utilities (and residential consumers) from short-term price increases or at least delay the onset of them. Agricultural interests generally do not have such contracts, buying gas on the spot market. Farmers could be hit with an immediate doubling or tripling of energy costs to irrigate fields. Also, the highest prices may coincide with the end of the heating season and the onset of irrigation as storage levels reach their lowest levels (i.e., April-May-June, Figure 20). Similar negative impacts could be felt in the chemicals industry (e.g., ammonia production).

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[17] In 1999, the top ten natural gas producing companies are in descending order: 1) Exxon Mobil; 2) BP America; 3) Oxy USA, Inc.; 4) Anadarko Petroleum Co., 5) Pioneer (Mesa); 6) Helmrich & Payne Co., 7) Chesapeake; 8) Kansas Natural Gas Co.; 9) Osborn Heirs Co.; 10) Texaco.

[18] Storage deliverability is a function of remaining working gas levels. As working gas volumes decline, the maximum rate that gas can be delivered declines. Working gas levels below 700 bcf can result in late season deliverability below demand requirements. See: J. A. Dieter and David A. Pursell, Underground Natural Gas Storage, Simmons and Company International Energy Industry Research Paper, June 28, 2000. http://www.simmonsco-intl.com/research

If we limp out of the winter 2000-01 with less than 500 Bcf of gas in storage, we will barely get storage back to even half-full before newly installed summer gas-fired electricity plants are cranked up. If summer weather is hot, particularly in the population areas of the eastern U.S., gas storage withdrawals may occur in the summer. If this does not happen in summer 2001, it will almost certainly occur a year later. Once gas withdrawals begin in the summer, the U.S. has one winter left before our storage system runs dry. These demand-side pressures begin to raise questions such as:

- How can enough gas be produced to meet demand at affordable prices?
- Can we increase gas production fast enough to keep up with a demand increasing from 21 trillion cubic feet (tcf) in 1999 to 30 tcf in 2020 or sooner?[19]

The recent low price for natural gas over the last few years has depressed exploration and development efforts in the U.S. and Kansas. In addition, restrictive or prohibited access to federal lands has limited access to many prospective areas for new gas discoveries[20]. With the recent price increases, industrial activity and gas production have increased. However, the U.S. and Kansas industry has been decimated. It will take significant time, increased investment capital, and application of advanced technologies to increase natural gas production. Present rig activity in the U.S. and Kansas needs to increase approximately six-fold in order to sufficiently increase natural gas supply to catch up with the rapidly increasing demand[21]. It will require significant effort and cooperation to increase Kansas rig activity from 25 to 150 along with all the related geologic, geophysical, and engineering activity.

Last year (1999) the value of natural gas production at the wellhead in Kansas was $1.034 billion. This year, we project that figure will reach $2.052 billion. This will certainly have a positive impact on state tax revenues. Severance tax revenues will probably double to over $100 million. Additional Kansas ad valorum and income tax revenues from increased economic activity will be even greater.

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[19] Statement on oil and gas supply and demand by Department of Energy EIA Administrator Jay Hawkes before the Subcommittee on Energy and Power of the Commerce Committee, U.S. House of Representatives on May 24, 2000. http://www.eia.doe.gov/neic/speeches/hrtest524/TestimonyMay242000Final.htm.

[20] 1999, Meeting the Challenges of the Nation's Growing Natural Gas Demand, Report from the National Petroleum Council. Available at http://www.npc.org/.

[21] *Outlook for Natural Gas: Is a Train Wreck Pending?* Presentation by Matthew R. Simmons at U.S. Department Of Energy, Strategic Initiatives Workshop, December 6 - 9, 2000 available at: http://www.simmonsco-intl.com/research/default.asp?viewnews=true&newstype=1#Industry_group_speeches.

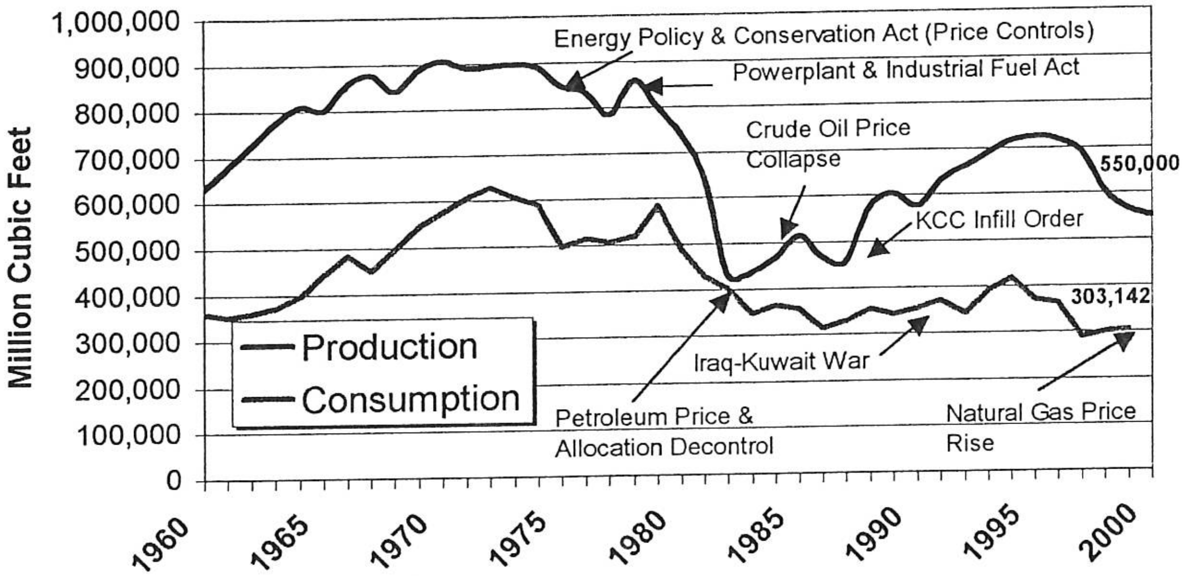

Figure 21 - Kansas natural gas production and consumption, 1960-2000, with major national and international events that affected both production and consumption.

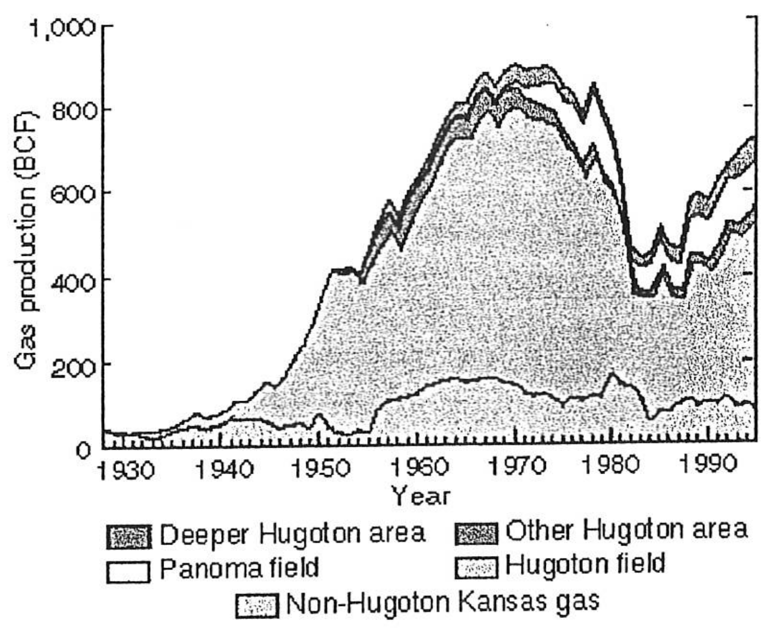

Figure 22 - Gas production in Kansas showing the importance of production from gas fields in the Hugoton area. (BCF = billion cubic feet of gas). Chart from Kansas Geological Survey, Public Information Circular 5, http://www.kgs.ukans.edu/Publications/pic5/pic5_1.html.

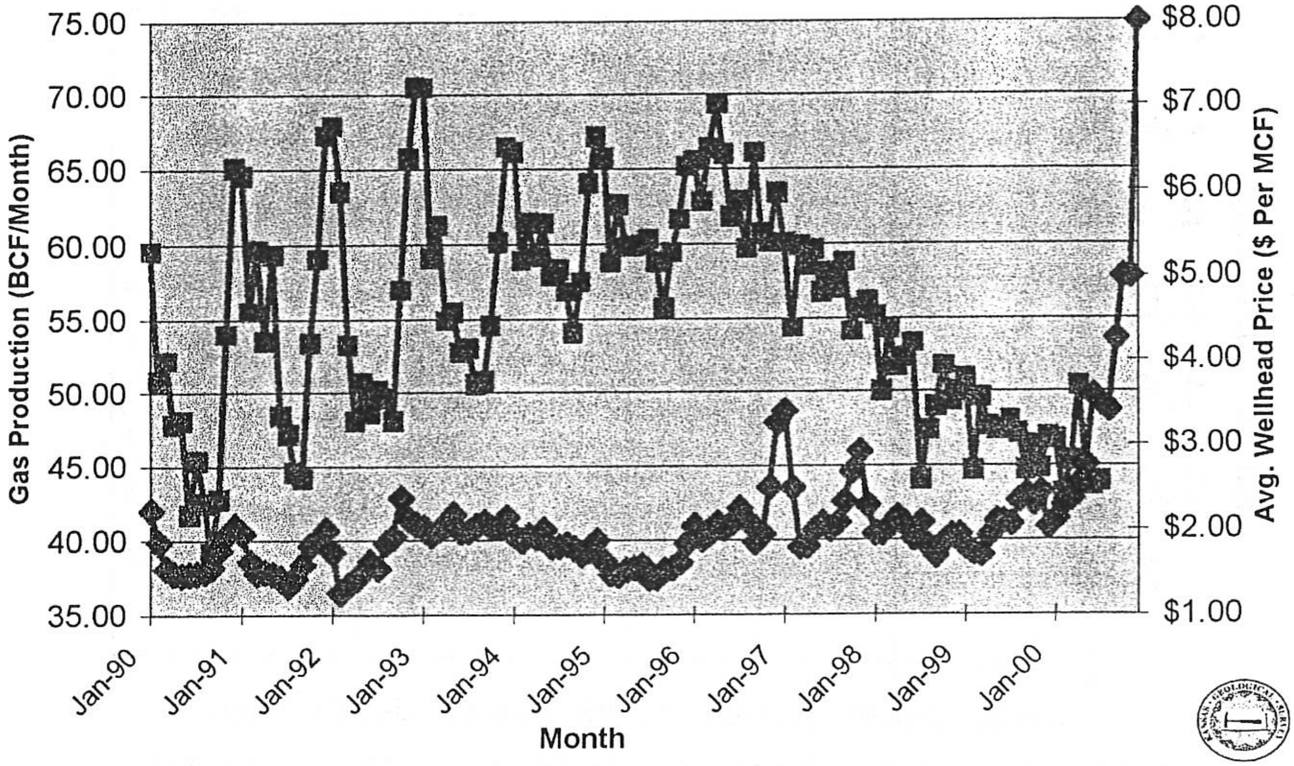

Figure 23 - Monthly Kansas natural gas production and average monthly wellhead price 1990-2000. Kansas production shows significant changes in production patterns. The seasonal production pattern of the first part of the decade disappeared. The steady decline from early 1997 is attributed to declining pressures in the major gas fields of southwest Kansas. However, the decline has slowed and monthly production may be increasing during 2000. Production is through August 2000 and prices are the average daily-posted wellhead price through December 2000.

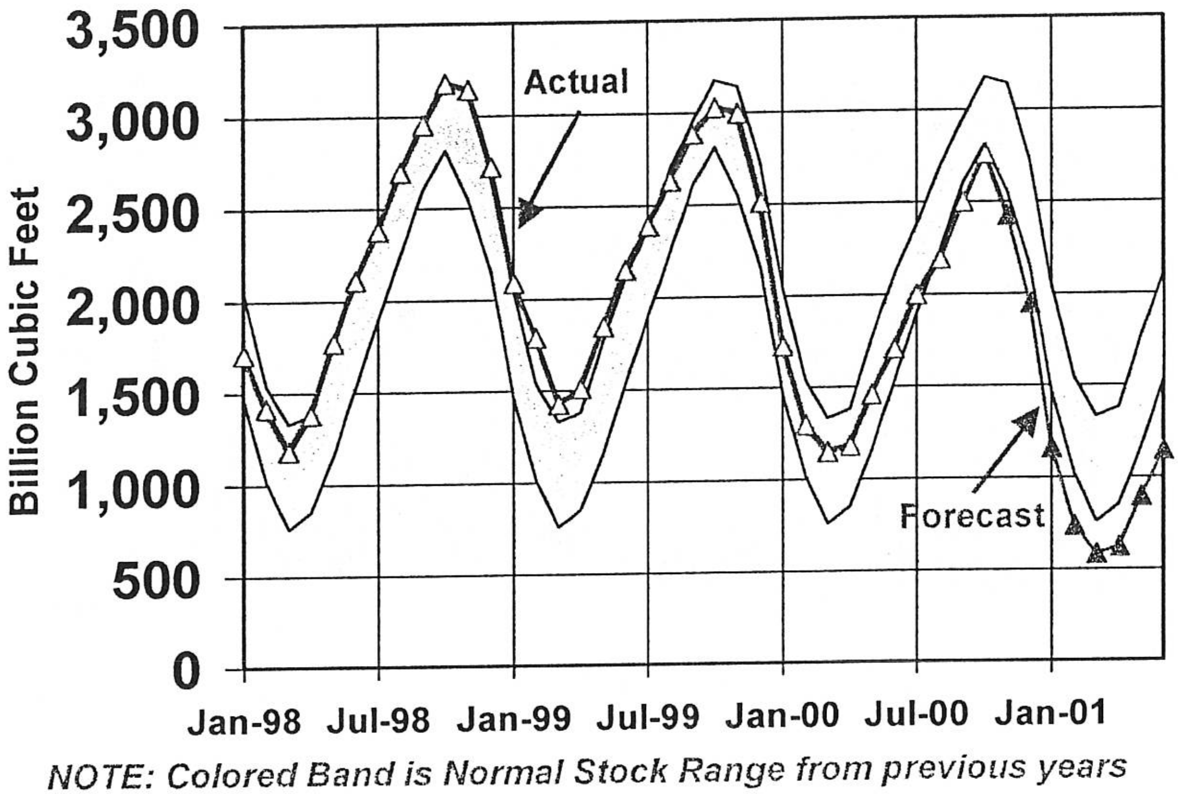

Figure 24 - Monthly U.S. natural gas stocks from January 1998 with forecast until June 2001. Sources: U.S. Department of Energy and American Gas Association. Stocks through 12/22/00 total 1,938 bcf. Forecasted projections follow average monthly storage changes for previous year. Kansas along with the rest of the U.S. could face spot shortages during the spring of 2001.

Results: Gas Production

Gas production in the first five months of 1999 was reported from 15,468 leases with 17,146 wells (Table 2a). Total production was 218.7 billion cubic feet. This is an average monthly production of 43.7 billion cubic feet. Average daily per well production would be 85 MCF. The reported 1999 gas production represents a 8% decline compared to the first five months of 1998, and reflects production declines in the gas fields of southwest Kansas.

The number of gas wells grouped by production rate shows that 63% of the gas wells in Kansas average less than 90 MCFPD (Table 2a). Approximately 10,772 wells producing 24.1% of the state's gas would be considered as stripper production.

Table 2a -- Kansas Gas Production from January through May 1999

	Producing Leases			Producing Wells			Gas Production		
MCFPD/Well	Number	% of Total	Cum %	Number	% of Total	Cum %	MCF	% of Total	Cum %
0.1-40	5210	33.7%	33.7%	6780	39.5%	39.5%	14,949,983	6.8%	6.8%
40.01-60	1786	11.5%	45.2%	1833	10.7%	50.2%	13,742,572	6.3%	13.1%
60.1-90	2123	13.7%	59.0%	2159	12.6%	62.8%	24,011,095	11.0%	24.1%
90.01-120	1854	12.0%	70.9%	1867	10.9%	73.7%	29,408,431	13.4%	37.5%
120.01-150	1365	8.8%	79.8%	1367	8.0%	81.7%	27,732,643	12.7%	50.2%
150.1-300	2747	17.8%	97.5%	2755	16.1%	97.8%	82,913,492	37.9%	88.1%
300.1-450	281	1.8%	99.3%	283	1.7%	99.4%	14,913,812	6.8%	94.9%
450.1-600	56	0.4%	99.7%	56	0.3%	99.7%	4,310,961	2.0%	96.9%
600.01	46	0.3%	100.0%	46	0.3%	100.0%	6,753,745	3.1%	100.0%
Totals	15,468	100.0%		17,146	100.0%		218,736,734	100.0%	

Data Source: Kansas Department of Revenue

References Cited

Carr, Timothy R. and Paul M. Gerlach, 1997, Kansas oil and gas production: An examination of the importance of stripper production: Kansas Geological Survey Open-File Report 97-64, 4p.

Carr, Timothy R. and Paul M. Gerlach, 1998, Kansas oil and gas production: An examination of the importance of stripper production: Kansas Geological Survey Open-File Report 98-50, 5p.

April 2000
URL: http://www.kgs.ukans.edu/PRS/publication/2000/ofr2000-16/index.html

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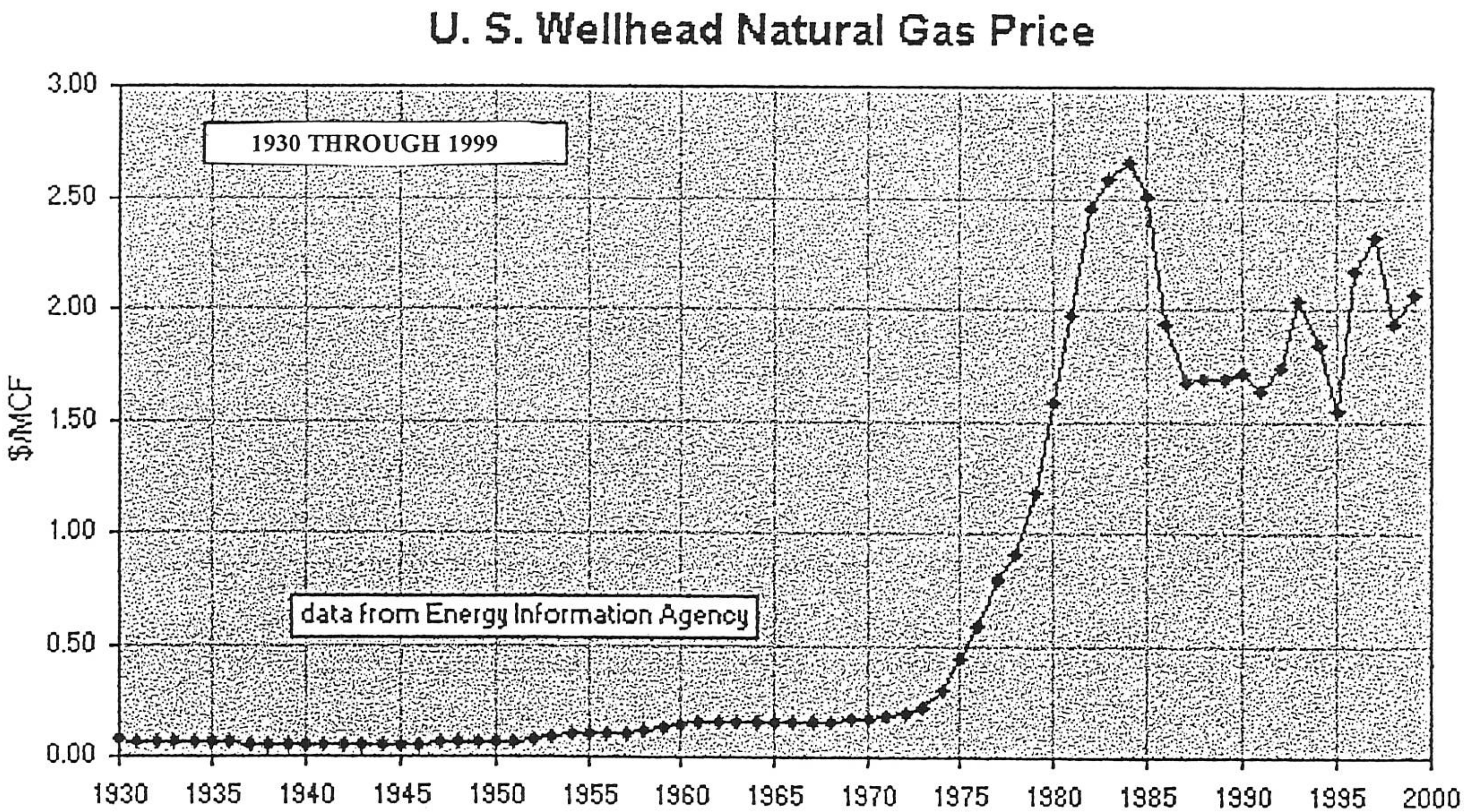

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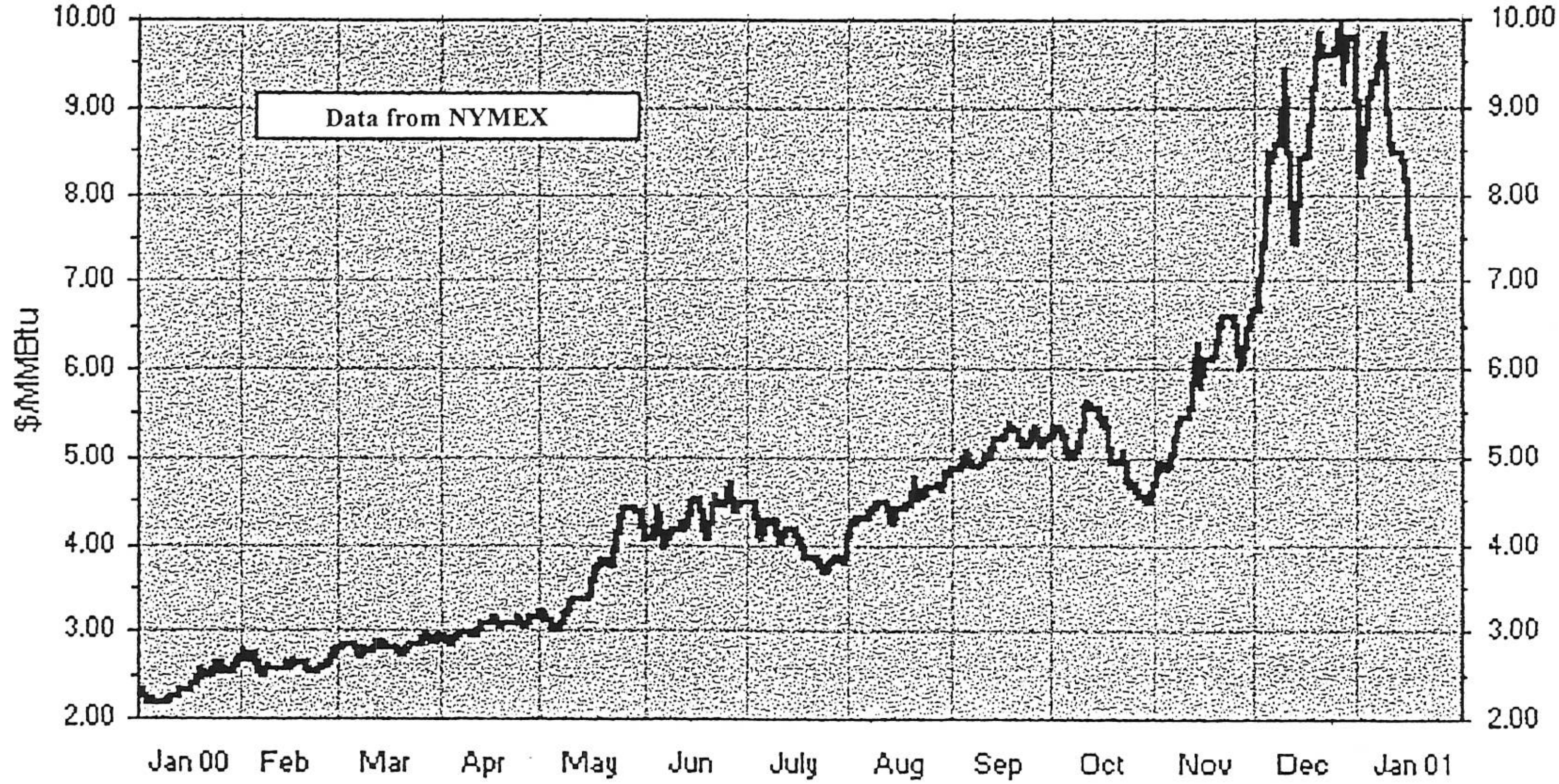
PREVIOUS 12 MONTHS-NYMEX HENRY HUB NATURAL GAS PRICE



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Options Contract Prices

CONTRACT	LAST	OPEN	HIGH	LOW	MOST RECENT SETTLE	CHG	OPEN INTEREST	PREVIOUS DAY'S TOTAL VOLUME	LAST UPDATED
FEB 2001	N/A	7.720	7.900	6.800	6.909*	-1.194	34935	0	1/18/01 07:38:2
MAR 2001	N/A	7.400	7.580	6.550	6.654*	-1.114	46643	0	1/18/01 07:38:2
APR 2001	N/A	6.100	6.200	5.500	5.670*	-0.680	22436	0	1/18/01 07:38:2
MAY 2001	N/A	5.720	5.800	5.350	5.470	-0.465	24360	6470	1/18/01 07:38:2
JUN 2001	N/A	5.720	5.780	5.350	5.465	-0.455	18770	1623	1/18/01 07:38:2
JUL 2001	N/A	5.730	5.800	5.400	5.480	-0.445	13810	1120	1/18/01 07:38:2
AUG 2001	N/A	5.730	5.800	5.400	5.495	-0.435	13992	1994	1/18/01 07:38:2
SEP 2001	N/A	5.710	5.760	5.370	5.470	-0.425	13699	4609	1/18/01 07:38:2
OCT 2001	N/A	5.700	5.760	5.400	5.470	-0.428	21897	732	1/18/01 07:38:2
NOV 2001	N/A	5.770	5.830	5.450	5.583	-0.423	8916	271	1/18/01 07:38:2
DEC 2001	N/A	6.030	6.030	5.680	5.743	-0.415	12947	741	1/18/01 07:38:2
JAN 2002	N/A	6.050	6.050	5.700	5.773*	-0.402	9357	0	1/18/01 07:38:1
FEB 2002	N/A	5.740	5.740	5.460	5.538	-0.402	4644	693	1/18/01 07:38:2
MAR 2002	N/A	5.470	5.470	5.200	5.238	-0.387	14483	2411	1/18/01 07:38:2
APR 2002	N/A	4.610	4.610	4.610	4.548	-0.317	15024	206	1/18/01 07:38:2
MAY 2002	N/A	4.775	4.775	4.705	4.428*	-0.347	8995	0	1/18/01 07:38:2
JUN 2002	N/A	4.680	4.770	4.680	4.428*	-0.342	5561	0	1/18/01 07:38:2
JUL 2002	N/A	4.750	4.750	4.710	4.433*	-0.342	3865	0	1/18/01 07:38:2
AUG 2002	N/A	4.570	4.570	4.570	4.433	-0.292	14636	383	1/18/01 07:38:2
SEP 2002	N/A	4.770	4.770	4.720	4.428*	-0.347	7491	0	1/18/01 07:38:2
OCT 2002	N/A	4.785	4.785	4.730	4.463*	-0.342	5602	0	1/18/01 07:38:2
NOV 2002	N/A	4.700	4.700	4.700	4.568	-0.292	3196	148	1/18/01 07:38:2
DEC 2002	N/A	4.760	4.760	4.760	4.668	-0.292	3531	870	1/18/01 07:38:2
JAN 2003	N/A	4.710	4.710	4.710	4.707	-0.292	5497	109	1/18/01 07:38:2
MAR 2003	N/A	4.520	4.520	4.520	4.282	-0.292	9291	37	1/18/01 07:38:2
APR 2003	N/A	4.310	4.310	4.310	3.979*	-0.342	4202	0	1/18/01 07:38:2
MAY 2003	N/A	4.200	4.200	4.200	3.904*	-0.342	3805	0	1/18/01 07:38:2

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N/A: Not Available

+ Previous settlement price available through settlement page.

* No recent trade activity. Data from date contract last traded.

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ATTACHMENT "H"

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CHAPTER 30

CURRENT TABLES OF MAXIMUM LAWFUL PRICES*

TABLE I—NATURAL GAS CEILING PRICES

[Other than NGPA §§ 104 and 106(a)]

Subpart of part 271	NGPA section	Category of gas	Maximum lawful price per MMBtu for deliveries in									
			Dec. 1978	Jan. 1979	Feb. 1979	Mar. 1979	Apr. 1979	May 1979	June 1979	July 1979	Aug. 1979	Sept. 1979
B	102	New natural gas, certain OCS gas	$2.078	$2.096	$2.116	$2.136	$2.156	$2.177	$2.198	$2.220	$2.244	$2.268
C	103	New, onshore production wells	1.969	1.980	1.993	2.006	2.019	2.033	2.047	2.062	2.079	2.096
F	105(b)(1)(B)	Alternative maximum lawful price for certain intrastate rollover gas [1]	1.121	1.128	1.136	1.144	1.152	1.160	1.168	1.176	1.186	1.195
G	107(c)(1)	High-cost gas (deep gas) [2]	2.078	2.096	2.116	2.136	2.156	2.177	2.198	2.220	2.244	2.268
	107(c)(5)	Gas produced from tight formations [3]								4.124	4.158	4.192
H	108	Stripper gas	2.224	2.243	2.264	2.285	2.306	2.329	2.352	2.375	2.400	2.426
I	109	Not otherwise covered	1.630	1.639	1.650	1.661	1.672	1.684	1.696	1.708	1.722	1.738

TABLE I—NATURAL GAS CEILING PRICES—CONTINUED

[Other than NGPA §§ 104 and 106(a)]

Subpart of part 271	NGPA section	Category of gas	Maximum lawful price per MMBtu for deliveries in									
			Oct. 1979	Nov. 1979	Dec. 1979	Jan. 1980	Feb. 1980	Mar. 1980	Apr. 1980	May 1980	June 1980	July 1980
B	102	New natural gas, certain OCS gas	2.292	2.314	2.336	2.358	2.381	2.404	2.429	2.453	2.478	2.504
C	103	New, onshore production wells	2.113	2.128	2.143	2.158	2.173	2.188	2.204	2.221	2.238	2.255
F	105(b)(1)(B)	Alternative maximum lawful price for certain intrastate rollover gas [1]	1.206	1.213	1.221	1.229	1.238	1.247	1.256	1.266	1.276	1.286
G	107(c)(1)	High-cost gas (deep gas) [2]	2.292									
	107(c)(5)	Gas produced from tight formations [3]	4.226	4.256	4.286	4.316	4.346	4.376	4.408	4.442	4.476	4.510
H	108	Stripper gas	2.452	2.475	2.499	2.523	2.548	2.573	2.598	2.625	2.652	2.680
I	109	Not otherwise covered	1.750	1.762	1.774	1.786	1.799	1.812	1.825	1.839	1.853	1.867

TABLE I—NATURAL GAS CEILING PRICES—CONTINUED

[Other than NGPA §§ 104 and 106(a)]

Subpart of part 271	NGPA section	Category of gas	Maximum lawful price per MMBtu for deliveries in								
			Aug. 1980	Sept. 1980	Oct. 1980	Nov. 1980	Dec. 1980	Jan. 1981	Feb. 1981	Mar. 1981	Apr. 1981
B	102	New natural gas, certain OCS gas	2.532	2.560	2.588	2.614	2.640	2.667	2.696	2.729	2.761
C	103	New, onshore production wells	2.274	2.293	2.312	2.329	2.346	2.363	2.384	2.408	2.428
F	105(b)(1)(B)	Alternative maximum lawful price for certain intrastate rollover gas [1]	1.297	1.308	1.319	1.329	1.339	1.349	1.361	1.373	1.385
G	107(c)(5)	Gas produced from tight formations [3]	4.548	4.586	4.624	4.658	4.692	4.726	4.768	4.812	4.858
H	108	Stripper gas	2.710	2.740	2.770	2.798	2.826	2.855	2.888	2.922	2.956
I	109	Not otherwise covered	1.883	1.899	1.916	1.929	1.943	1.957	1.978	1.993	2.011

TABLE I—NATURAL GAS CEILING PRICES—CONTINUED

[Other than NGPA §§ 104 and 106(a)]

Subpart of part 271	NGPA section	Category of gas	Maximum lawful price per MMBtu for deliveries in						
			May 1981	June 1981	July 1981	Aug. 1981	Sept. 1981	Oct. 1981	Nov. 1981
B	102	New natural gas, certain OCS gas	2.787	2.813	2.840	2.863	2.888	2.909	2.940
C	103	New, onshore production wells	2.444	2.460	2.478	2.488	2.501	2.514	2.533
F	105(b)(1)(B)	Alternative maximum lawful price for certain intrastate rollover gas [1]	1.394	1.403	1.412	1.419	1.426	1.433	1.444
G	107(c)(5)	Gas produced from tight formations [3]	4.888	4.920	4.952	4.976	5.002	5.028	5.066
H	108	Stripper gas	2.984	3.012	3.041	3.066	3.091	3.116	3.149
I	109	Not otherwise covered	2.024	2.037	2.050	2.060	2.070	2.080	2.096

* A discussion of these tables, along with other pricing information, begins on page 35. A schedule for deregulation of natural gas prices appears at page 34.

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ATTACHMENT "I"

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TABLE I—NATURAL GAS CEILING PRICES—CONTINUED

[Other than NGPA §§ 104 and 106(a)]

Subpart of part 271	NGPA section	Category of gas	Maximum lawful price per MMBtu for deliveries in: Dec. 1981	Jan. 1982	Feb. 1982	Mar. 1982	Apr. 1982	May 1982	June 1982	July 1982
B	102	New natural gas, certain OCS gas	2.971	3.003	3.033	3.063	3.093	3.112	3.132	3.152
C	103	New, onshore production wells	2.552	2.572	2.590	2.608	2.626	2.634	2.642	2.650
F	106(b)(1)(B)	Alternative maximum lawful price for certain intrastate rollover gas [1]	1.455	1.466	1.476	1.486	1.496	1.501	1.506	1.511
G	107(c)(5)	Gas produced from tight formations	5.104	5.144	5.180	5.216	5.252	5.268	5.264	5.300
H	108	Stripper gas	3.183	3.217	3.249	3.281	3.314	3.335	3.356	3.377
I	109	Not otherwise covered	2.112	2.128	2.143	2.158	2.173	2.180	2.187	2.194

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[1] Section 271.602(a) provides that for certain gas sold under an intrastate rollover contract the maximum lawful price is the higher of the price paid under the expired contract, adjusted for inflation or an alternative Maximum Lawful Price specified in this Table. This alternative Maximum Lawful Price for each month appears in this row of Table I.

[2] Commencing November 1, 1979, the price of natural gas finally determined to be eligible as deep high-cost-gas under section 107(c)(1) of the NGPA is deregulated. (*See*, Part 272 of the Commission's Regulations.) Prior to that date, the maximum lawful price applicable to deep high-cost gas was the price specified in Subpart B of Part 271.

[3] The maximum lawful price for tight formation gas is the lesser of the negotiated contract price or 200% of the price specified in Subpart C of Part 271. The maximum lawful price for tight formation gas applies on or after July 16, 1979. (*See*, § 271.703 and § 271.204.)

TABLE I.—NATURAL GAS CEILING PRICES (OTHER THAN NGPA SECS. 104 AND 106 (A))

[Maximum lawful price per MMBtu for deliveries]

Subpart of Part 271	NGPA section	Category of gas	August 1982	September 1982	October 1982	November 1982	December 1982	January 1983
B	102	New Natural gas, certain OCS gas	3.176	3.200	3.224	$3.249	$3.274	$3.299
C	103	New, onshore production wells	2.662	2.674	2.686	2.698	2.710	2.722
F	106(b)(1)(B)	Alternative maximum lawful price for certain intrastate rollover gas	1.518	1.525	1.532	1.539	1.546	1.553
G	107(c)(5)	Gas produced from tight formations	5.324	5.348	5.372	5.396	5.420	5.444
H	108	Stripper gas	3.403	3.429	3.455	3.481	3.508	3.535
I	109	Not otherwise covered	2.204	2.214	2.224	2.234	2.244	2.254

[Reprinted from 47 FR 32935, July 30, 1982]

TABLE I
Natural Gas Ceiling Prices (Continued)
[Other than NGPA §§ 104 and 106(a)]

1983

Subpart of part 271	NGPA section	Category of gas	Maximum lawful price per MMBtu for deliveries in: Jan. 1983	Feb. 1983	Mar. 1983	Apr. 1983	May 1983	June 1983	July 1983	Aug. 1983	Sept. 1983	Oct. 1983	Nov 1983	Dec 1983
B	102	New natural gas, certain OCS gas	$3 299	$3 321	$3.344	$3 367	$3 394	$3 421	$3 448	$3.472	$3 496	$3.520	$3.542	$3 564
C	103	New, onshore production wells	2 722	2.732	2 742	2.752	2 765	2 778	2 792	2 803	2.814	2.825	2 833	2 841
F	106(b)(1)(B)	Alternative maximum lawful price for certain intrastate rollover gas[1]	1 553	1 559	1 565	1 571	1 579	1 587	1 595	1.601	1.607	1.613	1 618	1 623
G	107(c)(5)	Gas produced from tight formations[2]	5 444	5 464	5 484	5.504	5 530	5 556	5.584	5 606	5.628	5.650	5.666	5 682
H	108	Stripper gas	3 535	3 559	3.583	3 607	3 636	3.665	3.694	3 720	3.746	3 772	3.795	3 818
I	109	Not otherwise covered	2 254	2 262	2 270	2.278	2 289	2 300	2 311	2.320	2 329	2.338	2.345	2 352

1984

Subpart of part 271	NGPA section	Category of gas	Maximum lawful price per MMBtu for deliveries in: Jan. 1984	Feb. 1984	Mar 1984	Apr 1984	May 1984	June 1984	July 1984	Aug 1984	Sept 1984	Oct 1984	Nov. 1984	Dec 1984
B	102	New natural gas, certain OCS gas	$3 586	$3 609	$3 632	$3.656	$3 680	$3 705	$3 730	$3 752	$3 774	$3 797	$3 821	$3.845
C	103	New, onshore production wells	2 849	2 859	2 869	2 879	2.889	2 899	2 909	2.917	2 925	2 933	2.942	2 951
F	106(b)(1)(B)	Alternative maximum lawful price for certain intrastate rollover gas[1]	1 628	1 633	1 638	1 643	1 649	1 655	1 661	1 666	1.671	1.676	1 681	1 686
G	107(c)(5)	Gas produced from tight formations[2]	5 698	5 718	5.738	5 758	5 778	5 705	5 818	5 834	5 850	5.866	5 884	5 [illegible]02
H	108	Stripper gas	3 841	3 866	3 891	3.916	3 942	3 968	3 994	4.018	4 042	4.066	4.092	4 118
I	109	Not otherwise covered	2 359	2 367	2 375	2 383	2 391	2.399	2 407	2.414	2 421	2.428	2 436	2 444

[1] Section 271 602(a) provides that for certain gas sold under an intrastate rollover contract the maximum lawful price is the higher of the price paid under the expired contract, adjusted for inflation or an alternative Maximum Lawful Price specified in this Table. This alternative Maximum Lawful Price for each month appears in this row of Table I

[2] The maximum lawful price for tight formation gas is the lesser of the negotiated contract price or 200% of the price specified in subpart C of Part 271. The maximum lawful price for tight formation gas applies on or after July 16, 1979. (See §271 703 and §271 704.)

TABLE I
Natural Gas Ceiling Prices (Continued)
[Other than NGPA §§ 104 and 106(a)]

1985

Subpart of part 271	NGPA section	Category of gas	Jan. 1985	Feb 1985	Mar. 1985	Apr. 1985	May 1985	June 1985	July 1985	Aug. 1985	Sept. 1985	Oct. 1985	Nov. 1985	Dec. 1985
			Maximum lawful price per MMBtu for deliveries in											
B	102	New natural gas, certain OCS gas[4]	$3.869	$3.890	$3.911	$3.932	$3.962	$3.992	$4.022	$4 045	$4.068	$4.091	$4.118	$4.141
C	103(b)(1)	New, onshore production wells[5]	2.960	2.966	2.972	2 978	2.991	3 004	3.017	3.024	3.031	3.038	3.047	3 058
	103(b)(2)	New onshore production wells[5]	3.415	3 428	3.442	3.455	3.477	3.498	3.520	3.535	3.550	3.565	3.582	3.599
E	105(b)(3)	Intrastate existing contracts	3.869	3.887	3.905	3.923	3 950	3.977	4.004	4.023	4.043	4.063	4.084	4.105
F	106(b)(1)(B)	Alternative maximum lawful price for certain intrastate rollover gas[1]	1.691	1.695	1.699	1.703	1.711	1.719	1.727	1.731	1.735	1.739	1.744	1.749
G	107(c)(5)	Gas produced from tight formations[3]	5.920	5 932	5.944	5.956	5 982	6.008	6.034	6.048	6.062	6.076	6.094	6.112
H	108	Stripper gas	4 144	4.166	4 188	4.210	4.242	4.274	4.306	4 330	4.354	4.379	4.405	4.432
I	109	Not otherwise covered	2.452	2 457	2.462	2.467	2.478	2.489	2.500	2.506	2.512	2.518	2.525	2.532

1986

Subpart of part 271	NGPA section	Category of gas	Jan. 1986	Feb. 1986	Mar. 1986	Apr. 1986	May 1986	June 1986	July 1986	Aug. 1986	Sept. 1986	Oct. 1986	Nov. 1986	Dec. 1986
			Maximum lawful price per MMBtu for deliveries in											
B	102	New natural gas, certain OCS gas[4]	$4.166	$4.191	$4.216	$4.241	$4.264	$4.287	$4.310	$4.332	$4 354	$4.376	$4.403	$4.431
C	103(b)(1)	New, onshore production wells[5]	3 065	3.074	3.083	3.092	3.099	3.106	3.113	3.119	3.125	3.131	3.141	3.151
	103(b)(2)	New onshore production wells[5]	3.616	3.633	3.650	3 667	3.682	3.697	3.712	3.726	3.740	3.754	3.772	3.791
E	105(b)(3)	Intrastate existing contracts	4.127	4.149	4.171	4.193	4 212	4.232	4.252	4.270	4.288	4.306	4.330	4.354
F	106(b)(1)(B)	Alternative maximum lawful price for certain intrastate rollover gas[1]	1.754	1.759	1.764	1.769	1.773	1.777	1.781	1.784	1.787	1.790	1.796	1.802
G	107(c)(5)	Gas produced from tight formations[3]	6.130	6.148	6.166	6.184	6.198	6.212	6.226	6.238	6.250	6.262	6.282	6.302
H	108	Stripper gas	4.459	4 486	4.513	4.540	4.565	4 590	4.615	4.639	4.663	4.687	4.716	4 746
I	109	Not otherwise covered	2.539	2.546	2.553	2.560	2.566	2.572	2.578	2.583	2.588	2.593	2.601	2 609

[1] Section 271.602(a) provides that for certain gas sold under an intrastate rollover contract the maximum lawful price is the higher of the price paid under the expired contract, adjusted for inflation or an alternative Maximum Lawful Price specified in this Table. This alternative Maximum Lawful Price for each month appears in this row of Table I.

[3] The maximum lawful price for light formation gas is the lesser of the negotiated contract price or 200% of the price specified in subpart C of Part 271. The maximum lawful price for light formation gas applies on or after July 16, 1979. (See §271.703 and §271.704).

[4] Commencing January 1, 1985, the price of natural gas finally determined to be new natural gas under sec. 102(c) is deregulated. (See Part 272 of the Commission's Regulations.)

[5] Commencing January 1, 1985, the price of some natural gas finally determined to be natural gas produced from a new, onshore production well under sec. 103 is deregulated. (See Part 272 of the Commission's regulations.)

TABLE I
Natural Gas Ceiling Prices (Continued)
[Other than NGPA §§ 104 and 106(a)]
1987

Subpart of part 271	NGPA section	Category of gas	Maximum lawful price per MMBtu for deliveries in											
			Jan. 1987	Feb. 1987	Mar. 1987	Apr. 1987	May 1987	June 1987	July 1987	Aug. 1987	Sept. 1987	Oct. 1987	Nov. 1987	Dec. 1987
B	102	New natural gas, certain OCS gas[4]	$4.459	$4.478	$4.497	$4.516	$4.544	$4.572	$4.600	$4.630	$4.660	$4.690	$4.715	$4.740
C	103(b)(1)	New, onshore production wells[5]	3.161	3.164	3.167	3.170	3.180	3.190	3.200	3.210	3.220	3.231	3.238	3.245
	103(b)(2)	New onshore production wells[5]	3.810	3.821	3.832	3.843	3.862	3.881	—	—	—	—	—	—
E	105(b)(3)	Intrastate existing contracts	4.378	4.393	4.408	4.423	4.447	4.471	4.495	4.520	4.546	4.572	4.593	4.614
F	106(b)(1)(B)	Alternative maximum lawful price for certain intrastate rollover gas[1]	1.808	1.810	1.812	1.814	1.819	1.825	1.831	1.837	1.843	1.849	1.853	1.857
G	107(c)(5)	Gas produced from tight formations[2]	6.322	6.328	6.334	6.340	6.360	6.380	6.400	6.420	6.440	6.462	6.476	6.490
H	108	Stripper gas	4.776	4.796	4.816	4.836	4.868	4.896	4.926	4.958	4.990	5.022	5.049	5.076
I	109	Not otherwise covered	2.617	2.620	2.623	2.626	2.634	2.642	2.650	2.659	2.668	2.677	2.683	2.689

1988

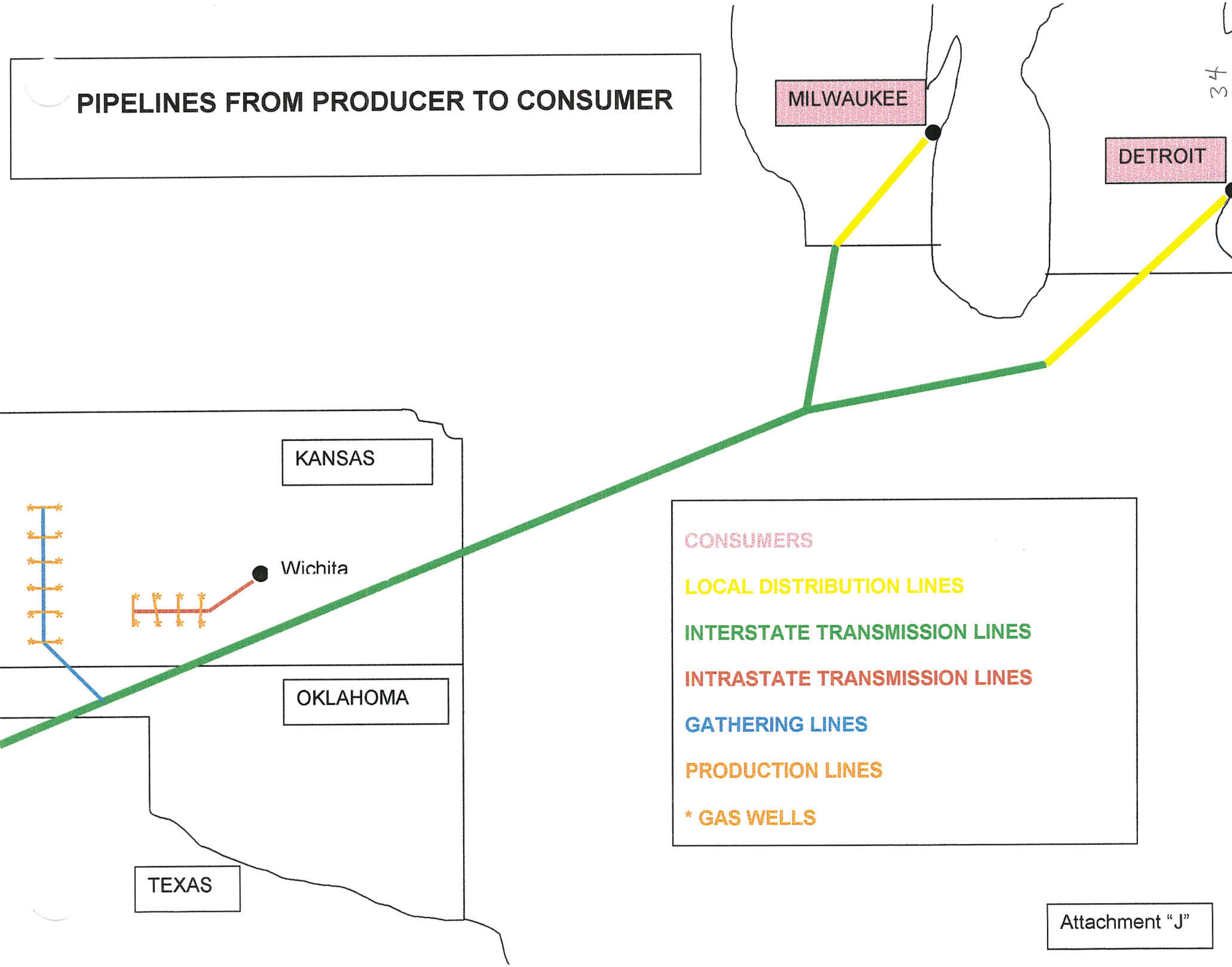
Subpart of part 271	NGPA section	Category of gas	Maximum lawful price per MMBtu for deliveries in											
			Jan. 1988	Feb. 1988	Mar. 1988	Apr. 1988	May 1988	June 1988	July 1988	Aug. 1988	Sept. 1988	Oct. 1988	Nov. 1988	Dec. 1988
B	102	New natural gas, certain OCS gas[4]	$4.765	$4.792	$4.819	$4.846	$4.872	$4.898	$4.924	$4.957	$4.990	$5.023	$5.058	$5.093
C	103(b)(1)	New, onshore production wells[5]	3.252	3.260	3.268	3.276	3.283	3.290	3.297	3.309	3.321	3.333	3.345	3.358
E	105(b)(3)	Intrastate existing contracts	4.635	4.657	4.679	4.701	4.722	4.743	4.765	4.793	4.821	4.849	4.879	4.909
F	106(b)(1)(B)	Alternative maximum lawful price for certain intrastate rollover gas[1]	1.861	1.865	1.869	1.873	1.877	1.881	1.885	1.892	1.899	1.906	1.913	1.920
G	107(c)(5)	Gas produced from tight formations[2]	6.504	6.520	6.536	6.552	6.566	6.580	6.594	6.618	6.642	6.666	6.690	6.716
H	108	Stripper gas	5.103	5.131	5.160	5.189	5.217	5.245	5.273	5.308	5.343	5.379	5.416	5.453
I	109	Not otherwise covered	2.695	2.701	2.707	2.713	2.719	2.725	2.731	2.741	2.751	2.761	2.771	2.781

[1] Section 271.602(a) provides that for certain gas sold under an intrastate rollover contract the maximum lawful price is the higher of the price paid under the expired contract, adjusted for inflation or an alternative Maximum Lawful Price specified in this Table. This alternative Maximum Lawful Price for each month appears in this row of Table I.

[2] The maximum lawful price for tight formation gas is the lesser of the negotiated contract price or 200% of the price specified in subpart C of Part 271. The maximum lawful price for tight formation gas applies on or after July 16, 1979. (See §271.703 and §271.704).

[4] Commencing January 1, 1985, the price of natural gas finally determined to be new natural gas under sec. 102(c) is deregulated. (See Part 272 of the Commission's Regulations.)

[5] Commencing January 1, 1985, the price of some natural gas finally determined to be natural gas produced from a new, onshore production well under sec. 103 is deregulated. (See Part 272 of the Commission's regulations.)



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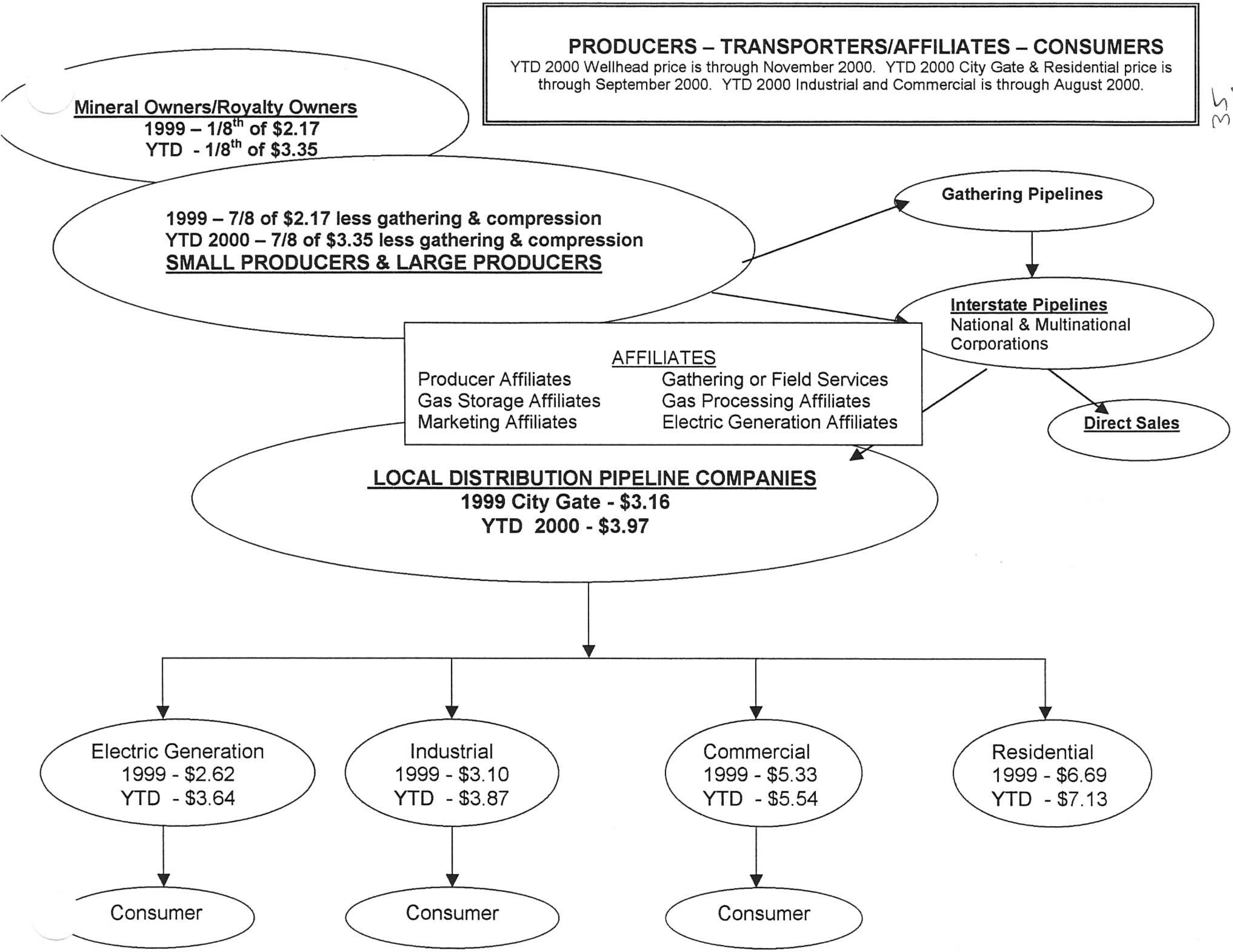

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ATTACHMENT "K"

Table 4

Table 4. Selected National Average Natural Gas Prices, 1994-2000

(Dollars per Thousand Cubic Feet)

Year and Month	Wellhead Price[a]	City Gate Price	Delivered to Consumers: Residential Price	Commercial: Price	Commercial: % of Total[b]	Industrial: Price	Industrial: % of Total[b]	Electric Utilities Price
1994 Annual Average	**1.85**	**3.07**	**6.41**	**5.44**	**79.3**	**3.05**	**25.5**	**2.28**
1995 Annual Average	**1.55**	**2.78**	**6.06**	**5.05**	**76.7**	**2.71**	**24.5**	**2.02**
1996 Annual Average	**2.17**	**3.34**	**6.34**	**5.40**	**77.6**	**3.42**	**19.4**	**2.69**
1997 Annual Average	**2.32**	**3.66**	**6.94**	**5.80**	**70.8**	**3.59**	**18.1**	**2.78**
1998								
January	1.95	3.08	6.41	5.65	73.2	3.67	16.8	2.64
February	1.95	3.08	6.41	5.59	72.9	3.58	16.7	2.51
March	2.05	3.06	6.29	5.40	73.6	3.40	17.3	2.53
April	2.15	3.23	6.81	5.64	67.7	3.28	15.8	2.59
May	2.04	3.12	7.70	5.73	62.6	3.14	14.9	2.47
June	1.90	2.98	8.51	5.51	62.9	2.97	15.1	2.40
July	2.08	3.31	8.53	5.64	56.0	3.04	13.1	2.50
August	1.81	3.01	9.25	5.46	53.3	2.75	13.8	2.21
September	1.69	2.78	8.96	5.49	57.0	2.65	14.2	2.15
October	1.85	2.99	7.60	5.31	59.2	2.75	14.8	2.22
November	1.93	2.99	6.58	5.22	64.5	2.95	15.7	2.37
December	1.94	3.10	6.34	5.23	68.3	2.92	17.2	2.22
Annual Average	**1.94**	**3.07**	**6.82**	**5.48**	**67.0**	**3.14**	**16.1**	**2.40**
1999								
January	[R]1.84	[R]2.87	[R]6.00	[R]5.19	[R]73.1	[R]3.29	[R]16.9	2.32
February	[R]1.75	2.93	[R]6.29	[R]5.28	[R]69.7	[R]2.92	[R]16.8	2.26
March	[R]1.68	[R]2.69	[R]6.06	[R]4.97	[R]69.3	[R]2.95	[R]17.4	2.15
April	[R]1.86	[R]2.94	[R]6.44	[R]5.32	[R]65.4	[R]3.00	[R]16.6	2.29
May	[R]2.16	[R]3.41	[R]7.30	[R]5.34	[R]61.1	[R]2.86	[R]16.0	2.57
June	[R]2.12	[R]3.28	[R]8.20	[R]5.29	[R]61.1	[R]2.81	[R]15.8	2.53
July	[R]2.18	[R]3.23	[R]8.83	[R]5.44	[R]58.2	[R]2.86	[R]15.7	2.58
August	[R]2.49	[R]3.53	[R]9.14	[R]5.46	[R]56.6	[R]2.99	[R]18.8	2.86
September	[R]2.61	[R]3.72	[R]8.63	[R]5.55	[R]60.0	[R]3.41	[R]17.5	2.98
October	[R]2.50	[R]3.31	[R]7.56	[R]5.46	[R]61.7	[R]3.20	[R]17.5	2.83
November	[R]2.67	[R]3.76	[R]7.15	[R]5.72	[R]63.0	[R]3.51	[R]17.7	3.01
December	[R]2.20	[R]3.24	[R]6.51	[R]5.56	[R]67.6	[R]3.05	[R]21.3	2.68
Annual Average	**[R]2.17**	**[R]3.16**	**[R]6.69**	**[R]5.33**	**[R]66.2**	**[R]3.10**	**[R]18.8**	**2.62**
2000								
January	[E]2.12	3.33	6.24	[R]5.49	[R]66.8	[R]3.48	[R]17.1	2.74
February	[E]2.30	3.50	[R]6.40	[R]5.61	[R]68.0	3.67	16.6	2.95
March	[E]2.36	3.57	[R]6.78	[R]5.31	64.2	3.54	15.8	2.99
April	[E]2.55	3.72	[R]7.01	[R]5.61	[R]64.3	[R]3.63	15.5	3.22
May	[E]2.90	4.00	[R]7.88	[R]5.28	[R]63.6	[R]3.73	[R]14.6	3.61
June	[E]3.73	5.21	[R]9.12	[R]5.74	[R]61.0	[R]4.31	[R]15.4	4.46
July	[E]3.70	5.13	[R]9.92	[R]5.74	[R]59.3	[R]4.45	[R]15.9	4.36
August	[E]3.67	4.03	10.12	5.95	56.8	4.21	15.1	NA
September	[E]4.26	NA	NA	NA	NA	NA	NA	NA
October	[E]4.61	NA	NA	NA	NA	NA	NA	NA
*								
2000 YTD[c]	**[E]3.22**	**3.84**	**7.02**	**5.54**	**64.3**	**3.87**	**15.8**	**3.64**
1999 YTD[c]	**2.12**	**3.01**	**6.54**	**5.23**	**67.0**	**2.97**	**16.8**	**2.43**
1998 YTD[c]	**1.95**	**3.10**	**6.82**	**5.57**	**68.4**	**3.26**	**15.5**	**2.50**

[a] See Appendix A, Explanatory Note 8, for discussion of wellhead prices.

[b] Percentage of total deliveries represented by onsystem sales, see Figure 6. See Table 25 for breakdown by State.

[c] Year-to-date price represents months for which price information is available in the current year.

[R] Revised Data.

[E] Estimated Data.

[NA] Not Available.

Notes: Data for 1994 through 1999 are final. All other data are preliminary unless otherwise indicated. Geographic coverage is the 50 States and the District of Columbia. In 1996, consumption of natural gas for agricultural use was classified as industrial use. In 1995 and earlier years, agricultural use was classified as commercial use. See Explanatory Note 5 for further explanation.

Sources: 1994-1999: Energy Information Administration (EIA) *Natural Gas Annual 1999.* January 2000 through current month: EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers," Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," and EIA estimates. See Appendix A, Explanatory Note 8 for estimation procedures and revision policy.

* November 4.62

2000 YTD 3.35

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ATTACHMENT "L"

Selected National Average Natural Gas Prices, 1994-2000
(Dollars per Thousand Cubic feet)

Year and Month	Wellhead Pricea/	City Gate Price	Delivered to Consumers: Residential Price	Delivered to Consumers: Electric Utilities Price
1994 Annual Average.	1.85	3.07	6.41	2.28
1995 Annual Average.	1.55	2.78	6.06	2.02
1996 Annual Average.	2.17	3.34	6.34	2.69
1997 Annual Average.	2.32	3.66	6.94	2.78
1998				
January...........	1.95	3.08	6.41	2.64
February..........	1.95	3.08	6.41	2.51
March.............	2.05	3.06	6.29	2.53
April.............	2.15	3.23	6.81	2.59
May...............	2.04	3.12	7.70	2.47
June..............	1.90	2.98	8.51	2.40
July..............	2.08	3.31	8.53	2.50
August............	1.81	3.01	9.25	2.21
September.........	1.69	2.78	8.96	2.15
October...........	1.85	2.99	7.60	2.22
November..........	1.93	2.99	6.58	2.37
December..........	1.94	3.10	6.34	2.22
Annual Average..	1.94	3.07	6.82	2.40
1999				
January...........	RE/1.80	2.87	6.00	2.32
February..........	RE/1.73	2.93	6.29	2.26
March.............	RE/1.70	2.69	6.06	2.15
April.............	RE/1.93	2.94	6.44	2.29
May...............	RE/2.10	3.41	7.30	2.57
June..............	RE/2.09	3.28	8.20	2.53
July..............	RE/2.07	3.23	8.83	2.58
August............	RE/2.34	3.53	9.14	2.86
September.........	RE/2.42	3.72	8.63	2.98
October...........	RE/2.31	3.31	7.56	2.83
November..........	RE/2.44	3.76	7.15	3.01
December..........	RE/2.03	3.24	6.51	2.68
Annual Average..	RE/2.08	3.16	6.69	2.62
2000				
January...........	E/2.12	3.33	6.24	2.74
February..........	E/2.30	3.50	6.40	2.95
March.............	E/2.36	3.57	6.78	2.99
April.............	E/2.55	3.72	7.01	3.22
May...............	E/2.90	4.00	7.88	3.61
June..............	E/3.73	5.21	9.12	4.46
July..............	E/3.70	5.13	9.92	4.36
August............	E/3.67	4.03	10.12	4.30 + 1.68
September.........	E/4.26 +2.18	5.71 +2.55	9,78 + 3.09	NA
October...........	E/4.61	NA	NA	NA
November..........	E/4.62	NA	NA	NA
2000 YTD...........	E/3.35 +1.27	3.97 +.81	7.13 + .44	3.76 +1.14
1999 YTD...........	E/2.08	3.06	6.62	2.51
1998 YTD...........	1.95	3.08	6.90	2.44

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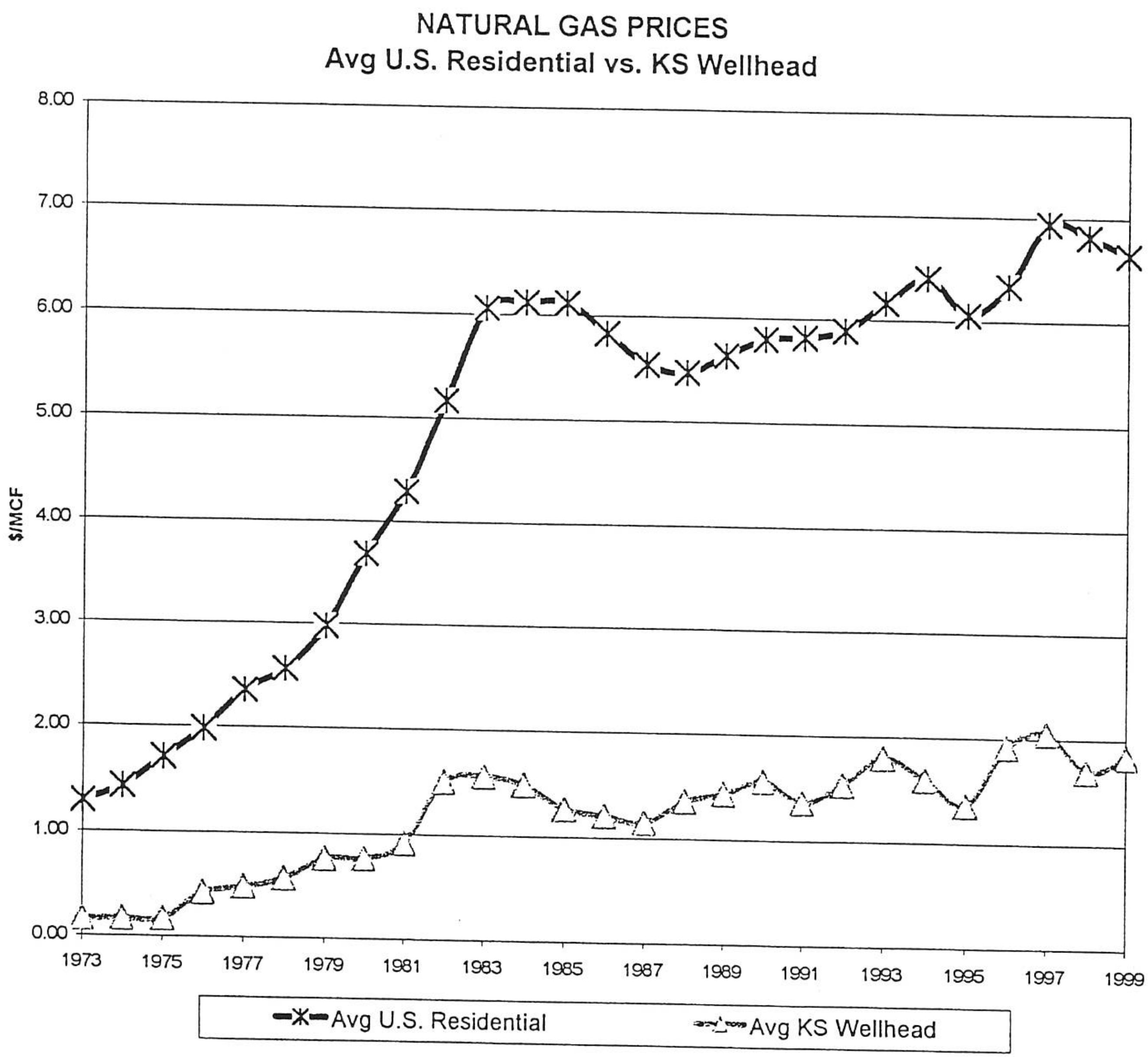

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Henry Hub Natural Gas

Trading Unit

Futures: 10,000 million British thermal units (MMBtu).

Options: One NYMEX Division natural gas futures contract.

Trading Hours

Futures and Options: Open outcry trading is conducted from 9:30 A.M. - 3:10 P.M. After-hours trading in futures and options is conducted via the NYMEX ACCESS® electronic trading system from 7 P.M. to 9 A.M. on Sundays and 4 P.M. to 9 A.M., Mondays through Thursdays. All times are New York time.

Trading Months

Futures: 36 consecutive months commencing with the next calendar month (for example, on October 3, 2000, trading occurs in all months from November 2000 through October 2003), plus a long-dated contract, initially listed 36 months out.

Options: 12 consecutive months, plus 15, 18, 21, 24, 27, 30, 33, and 36 months on a June-December cycle.

Price Quotation

Futures and Options: Dollars and cents per MMBtu, for example, $2.035 per MMBtu.

Minimum Price Fluctuation

Futures and Options: $0.001 (0.1 ¢) per MMBtu ($10 per contract).

ATTACHMENT "N"

Maximum Daily Price Fluctuation

Futures: Initial limits of $0.30 (30¢) per MMBtu are in place in all but the first two months and rise to $0.60 (60¢) per MMBtu if the previous day's settlement price in any back month is at the $0.30 (30¢) limit. In the event of a $0.75 (75¢) per MMBtu move in either of the first two contract months, limits on all months become $0.75 (75¢) per MMBtu in all months from the limit in place in the direction of the move following a one-hour trading halt.

Options: No price limits.

Last Trading Day

Futures: Trading terminates three business days prior to the first calendar day of the delivery month.

Options: Trading terminates at the close of business on the business day immediately preceding the expiration of the underlying futures contract.

Exercise of Options

By a clearing member to the Exchange clearinghouse not later than 5:30 P.M. or 45 minutes after the underlying futures settlement price is posted, whichever is later, on any day up to and including the options expiration.

Option Strike Prices

Twenty strike prices in increments of $0.05 (5¢) per MMBtu above and below the at-the-money strike price in all months, plus an additional twenty strike prices in increments of $0.05 per MMBtu above the at-the-money price will be offered in the first three nearby months, and the next ten strike prices in increments of $0.25 (25¢) per MMBtu above the highest and below the lowest existing strike prices in all months for a total of at least 81 strike prices in the first three nearby months and a total of at least 61 strike prices for four months and beyond. The at-the-money strike price is nearest to the previous day's close of the underlying futures contract. Strike price boundaries are adjusted according to futures price movements.

Delivery Location

Sabine Pipe Line Co.'s Henry Hub in Louisiana. Seller is responsible for the movement of the gas through the Hub; the buyer, from the Hub. The Hub fee will be paid by seller.

Delivery Period

Delivery shall take place no earlier than the first calendar day of the delivery month and shall be completed no later than the last calendar day of the delivery month. All deliveries shall be made at as uniform as possible an hourly and daily rate of flow over the course of the delivery month.

Alternate Delivery Procedure (ADP)

An alternate delivery procedure is available to buyers and sellers who have been matched by the Exchange subsequent to the termination of trading in under terms different from those prescribed in the contract specifications, they may proceed on that basis after submitting a notice of their intention to the Exchange.

Exchange of Futures For, or in Connection with, Physicals (EFP)

The commercial buyer or seller may exchange a futures position for a physical position of equal quantity by submitting a notice to the Exchange. EFPs may be used to either initiate or liquidate a futures position.

Quality Specifications

Pipeline specifications in effect at time of delivery.

Position Limits

7,000 contracts for all months combined, but not to exceed 1,000 in the last three days of trading in the spot month or 5,000 in any one month.

Exchange of Futures For, Or In Connection With, Physicals (EFP)

The commercial buyer or seller may exchange a futures position for a physical position of equal quantity by submitting a notice to the Exchange. EFPs may be used to either initiate or liquidate a futures position.

Trading Symbols -
Futures: NG

Options: ON

TOP

3

Comments to:

The Kansas Senate/House Joint Committee on Utilities

on

Natural Gas: The Price/Supply Relationship

January 22, 2001
Topeka, Kansas

Submitted by:

Dick Brewster
bp

Mr. Chairman, Members of the Committee, for the record, my name is Dick Brewster, and I am Director of Government Affairs for bp. We appreciate the chance to confer with you today and try to respond to your concerns about the natural gas price and supply relationship.

I've handed out a presentation that I hope will be helpful to you. It outlines the supply/demand dynamics, the industry's response, reviews the natural gas marketplace as a balancing mechanism, and reviews BP's role in the North American supply solution.

Last week, Chairman Holmes emailed a list of questions he thought we should keep in mind as we prepared for this hearing. As I go through my comments today, I'll try to respond to a number of those questions.

Let me call your attention to page 21 of the presentation. BP supplies about 6% of the total supply to the U.S. market, and we are North America's largest single gas producer. The top 5 producers produce less than 20% of the gas used in the U. S. And there are some 8,000 gas producers in the U.S. I mention this because one of Chairman Holmes' questions was whether the natural gas market is subject to manipulation, and if so, who might be positioned to manipulate it. With this many players, each holding a small percentage of the total supply, market manipulation would not be possible.

In that same question, Chairman Holmes asked how well we think the natural gas market is working. It would seem self-serving for me to simply say its working well and stop there. We are all aware of the significant hardships on many individuals and families resulting from the current high gas prices. But if the market is supposed to make sure there are adequate supplies of gas, to respond to demand, the market is working well. I hope the rest of my presentation will demonstrate that conclusion.

Please look at page 4 of the presentation. This slide shows U.S and Canadian gas consumption and the growth rate of gas demand. Note that natural gas sales in North American in 1999 were some $340 billion. The graphs on page 5 will tell you where the greatest demand increase comes from – power generation, now and in the next two decades. Page 6 shows the big reason increased demand in this sector. Natural gas is simply the cleanest fuel available for power generation.

Slide 7 indicates that even without the development of new technology and excluding natural gas from Alaska, there are domestic gas reserves sufficient to last 55 to 75 years. Around 85% of gas consumed in the U.S. is produced domestically. Around 13.6% is imported from Canada, and the rest is imported LNG (Liquefied Natural Gas). The graph on page 8 shows the gas supply sources for North America. Alaska is not included. We believe the supply capacity is there, but acknowledge the significant challenges that face the industry.

The resources are there, according to what we've reviewed. So, why are prices spiking to sharply now, and why are we hearing that it's the result of supply concerns?

Page 9 of the material I provided begins to explain the situation. Historic low price levels through most of 1998 and '99 caused fewer new wells to be drilled, many marginal wells shut in, much of the needed skilled workforce was lost, service operations closed down and fewer drill rigs were produced or maintained. Demand kept rising, but the supply side remained depressed.

Now the industry is responding. But new gas cannot be brought into the marketplace overnight. Page 11 shows gas drilling rig activity is up dramatically. BP's rig counts are increasing and in two years will be close to double our 1999 level. Chairman Holmes asked how long it takes to get production to market. There is no single answer. In a developed area like Hugoton, incremental reserves are into the marketplace as soon as they are developed. New areas may takes months, or even years to get to the marketplace. We believe FERC regulation of interstate pipelines is not a hindrance to marketing gas, and overall is beneficial.

Page 12 shows the historic relationship between growth in production and drilling activity. That rig count is dramatically up in the past few months and indicates production rates will start to rise significantly as well. To maintain and increase our production in the Hugoton field, we are working to apply new technology to our operations. While the Hugoton has had a 15% decline rate the past several years, we've held our production flat for the past 14 months. This fact speaks to another of the Chairman's questions asks what is being done to prolong the life of wells in Hugoton in the face of declining pressure. We are optimizing our operations, using different types of compressors, and taking other steps, spending around $14 million this year to maintain and increase our production in Kansas.

The Chairman asked what impact declining pressure in the Hugoton field has on production and prices. As I have just indicated, declining pressure typically means declining production, though we are working to overcome these typical consequences.

Declining pressure has no impact on prices. Prices are determined on the commodities exchange. Natural gas is bought and sold as a commodity, just like wheat and corn. Producers can no more control he price of gas than farmers can control the price of wheat.

Page 14 shows natural gas storage and its fluctuations recently. Storage was at the low end going into the winter. The unprecedented cold has meant early seasonal draw down. The next page shows that low storage levels are projected going into next winter, too. But higher prices have driven some demand out of the market, alleviating at least some of the pressure.

The graph on page 17 indicates that, historically, consumer prices have not been as volatile as wellhead prices have been. The red line indicates the wellhead price, while the blue bars represent the residential consumer prices. Competition has saved gas consumers money, some $600 billion in the last 15 years. See page 19.

The balance of the slides show what BP is doing to respond. Let me point to the information on page 22. We plan to increase our total supply in excess of the current market growth rates. We'll be spending some $1.8 billion a year.

The industry is responding. It will take time to increase supplies and storage so that prices can stabilize. The volatile wellhead prices are probably short term, and are the result of an unprecedented tight supply slamming suddenly into a wall of unprecedented high demand.

Chairman Holmes asked some questions which I've not yet specifically addressed:

I will defer to others to provide specific information on how much gas is being exported from Kansas today. Kansas remains a net gas exporting state because of the Hugoton field, North America's largest. The export position, of course, is dependent on continued Hugoton production.

The Chairman noted the differential between wellhead prices and burner tip prices. The full explanation of that difference must come from representatives of the pipelines and utilities. I can only say that these services are provided in an excellent way and the cost is regulated at the Federal and state level.

We were asked about the old long-term contracts in Hugoton. I can speak for BP alone, of course, and will note that we settled all these issues in 1994. Current delivery contracts are for different periods of time, of course. These contracts often contain provisions that allow the price to move according to market conditions.

What type of incentives might be provided to extend the life of the Hugoton and other Kansas gas fields? At our request, the Senate Utilities Committee introduced a bill last week, Senate Bill 51. This measure improves the incentives provided by existing law for investment in certain new wells, and certain production enhancement projects.

As I have said, BP will be spending close to $2 billion a year in developing new gas and improving existing production. The industry will have to spend close to $40 billion a year. To attract some of that investment to Kansas, you can help reduce costs, and we believe this bill can help. There are bills to exempt the high cost equipment we must use from the sales tax, as other manufacturing equipment and machinery is exempt. In short, Kansas must become an economically attractive state in which to invest.

Finally, the Chairman asks, "Who benefits?" We believe we all benefit. Natural gas is a clean and abundant source of energy for the growing U.S. economy. The market place is the best way to maintain the balance of supply and demand and stable prices. It will take huge investments in natural gas to maintain adequate supplies.

Unlike the price regulatory schemes of the past, we are not faced with closing schools and businesses. We are not forced to prioritize gas use. The market handles these things, as it should. I know prices are high today. But the current market works, and in the long term will allow adequate energy supplies for the U.S.

Mr. Chairman, members of the Committee, I will be happy to answer any questions, and appreciate the chance to offer information to you.

Dick Brewster
bp

3-5

4

North American Outlook for Natural Gas

Presentation to Kansas House & Senate Utility Committees

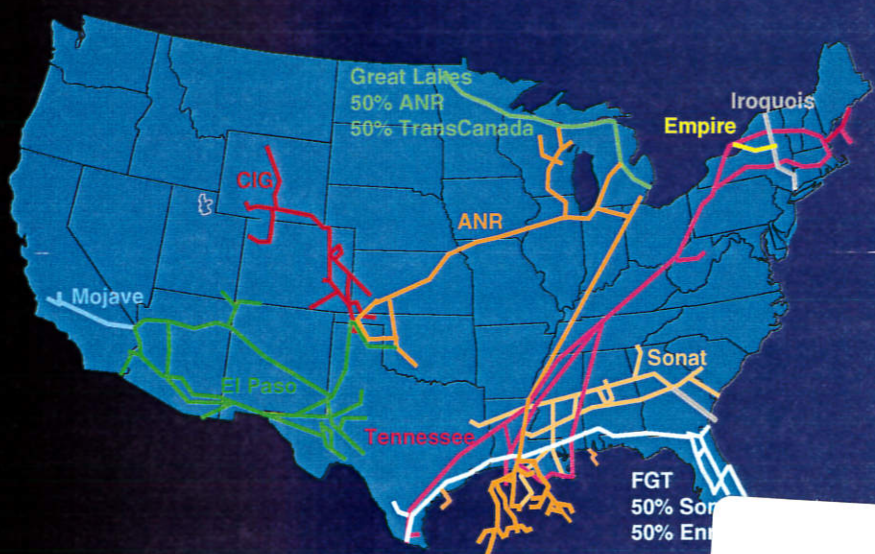
Robert O. Reid

Senior Vice President, ANR/CIG

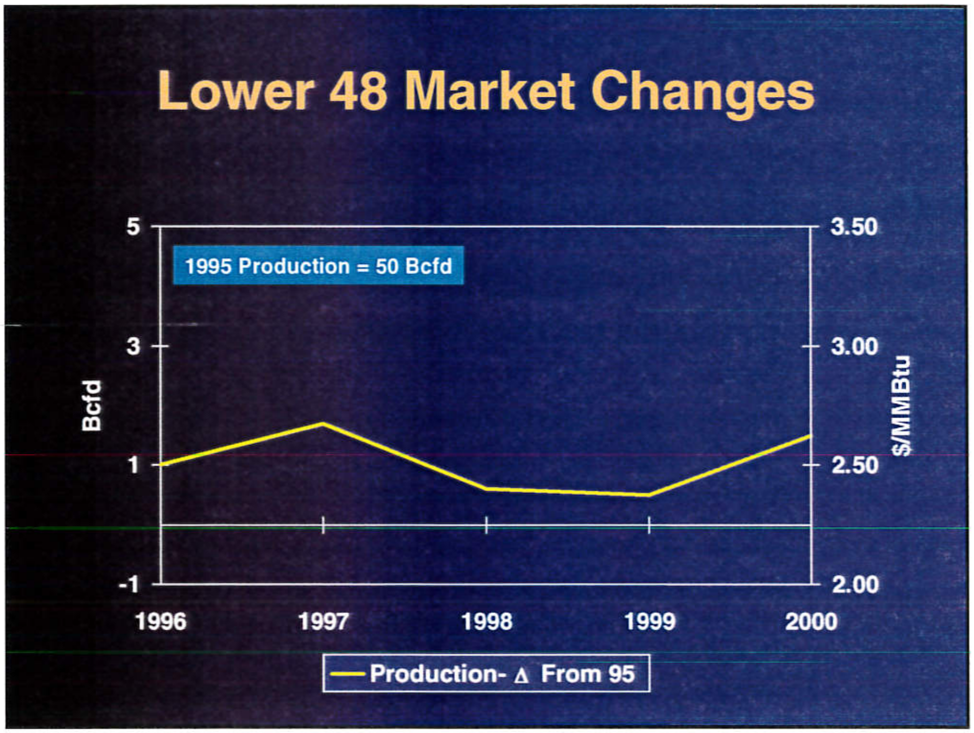
January 22, 2001

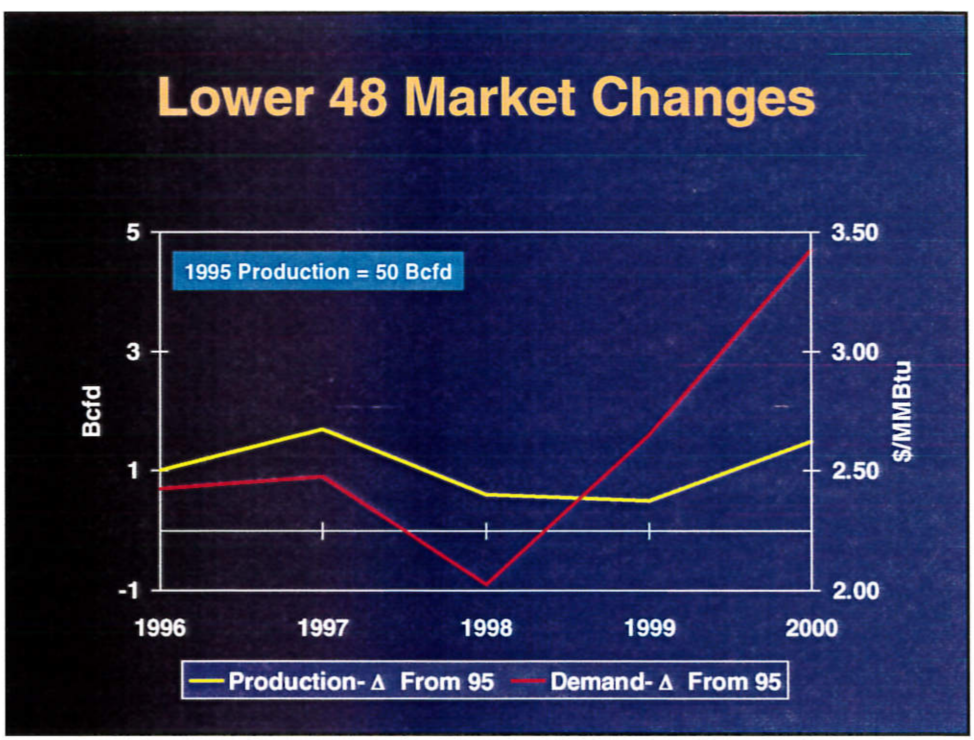
El Paso/Coastal

Natural Gas Transmission System



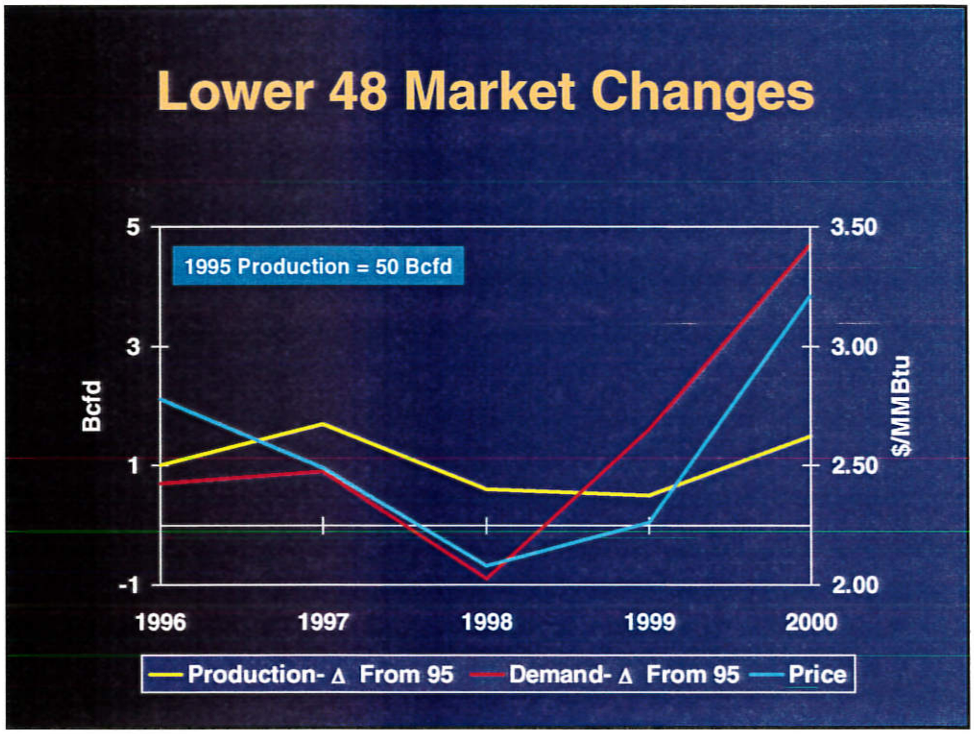
Senate Utilities Committee
January 22, 2001
Attachment 4-1

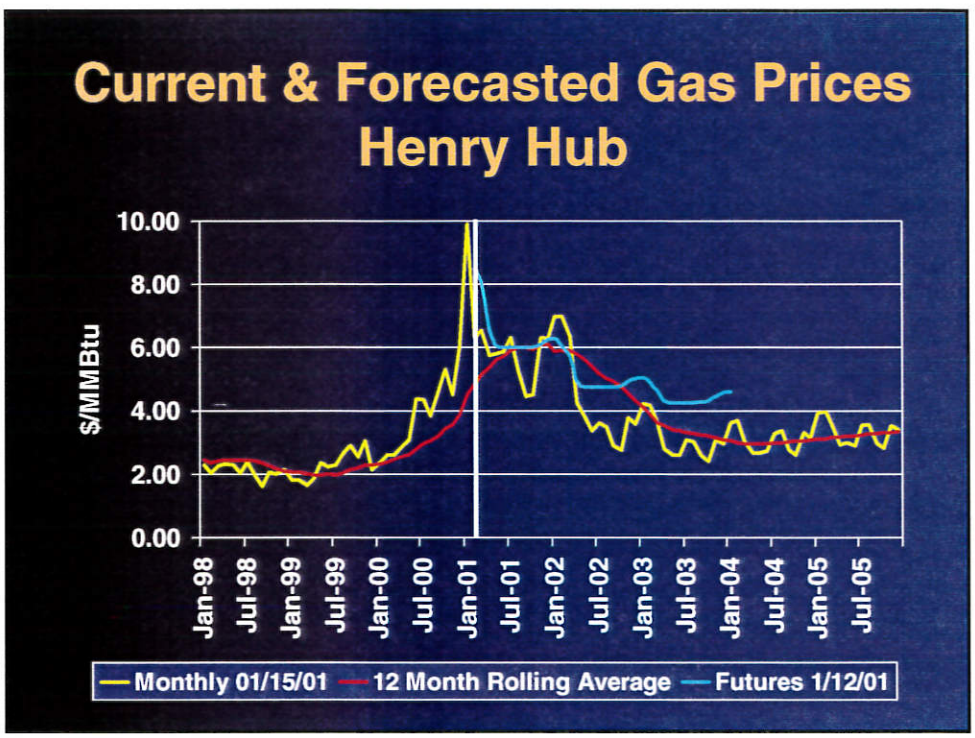




4-2

Confidential





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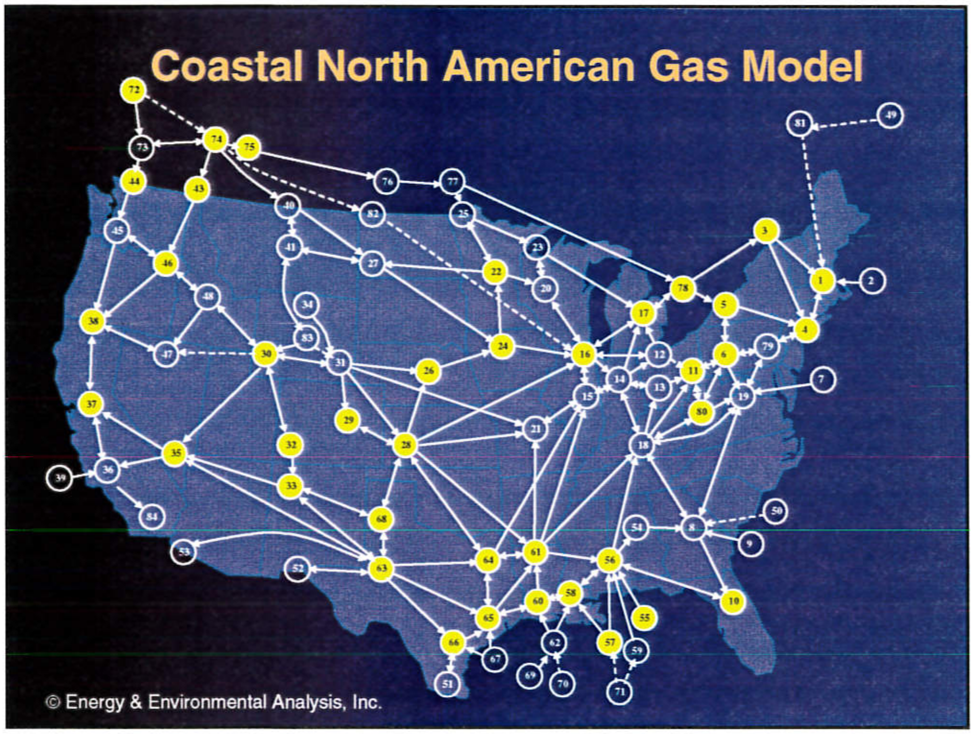
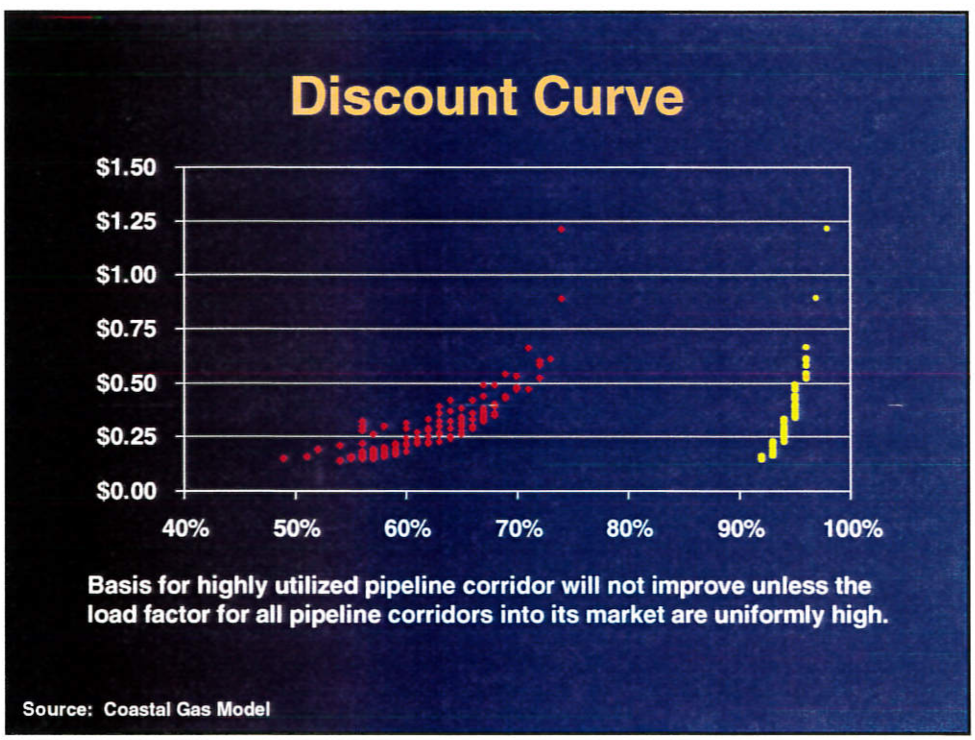
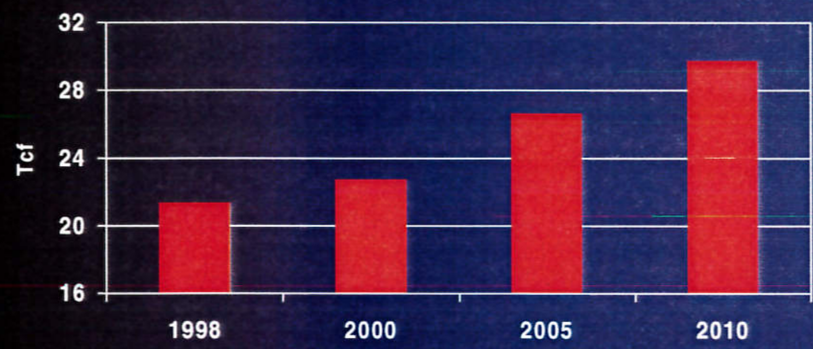




4-4

Confidential

U.S. Gas Demand



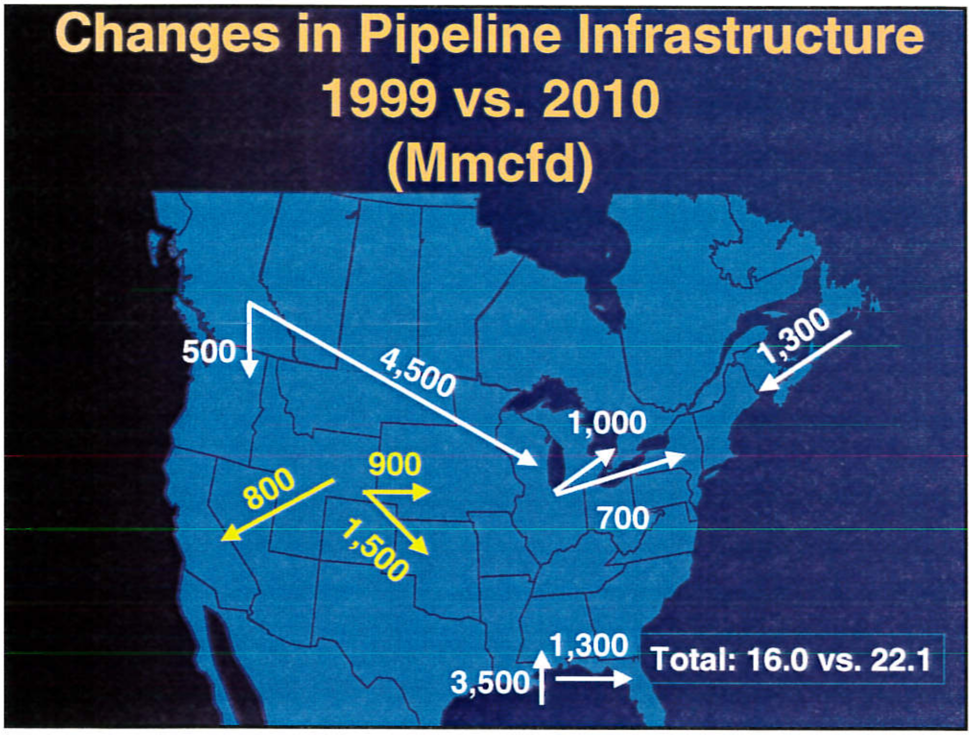
Gas demand is forecasted to grow from 21.4 Tcf in 1998 to 29.2 Tcf in 2010 representing an annual growth rate of 2.7%. From 1986-1998 the Annual Growth Rate was 2.3%.

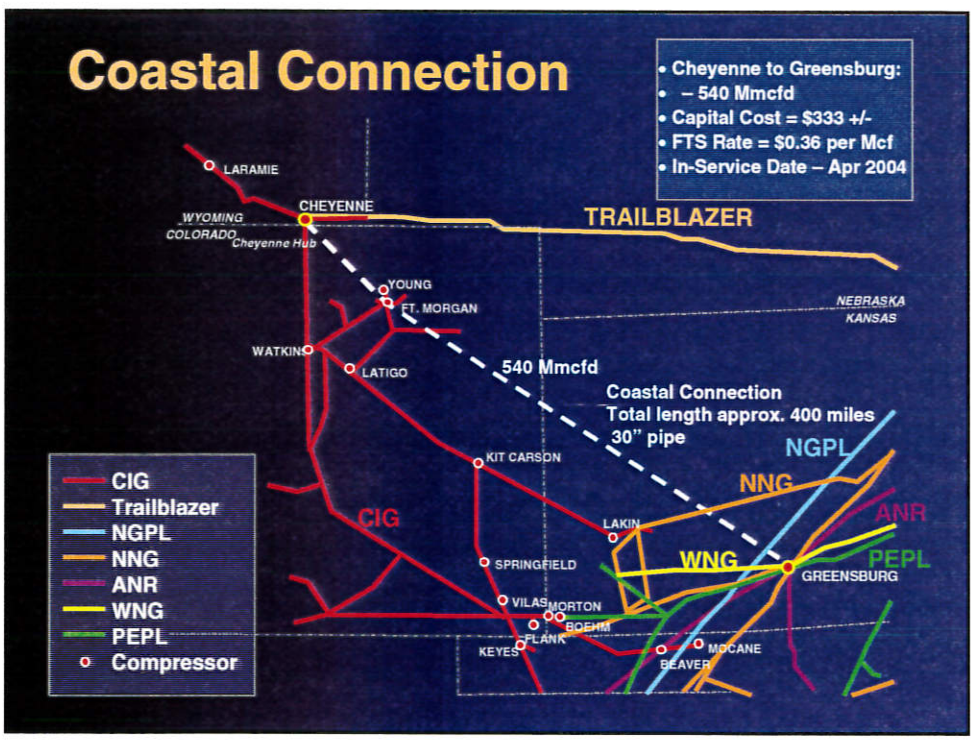
Projected Growth in Gas Demand by Sector
(Tcf)

	2000	2010	Change	% Change	Annual % Change
Residential	4.8	5.5	0.7	14.6	1.4
Commercial	3.1	3.7	0.6	19.4	1.8
Industrial/Other	10.6	12.3	1.7	16.0	1.5
Power Gen	3.8	7.7	3.9	102.6	7.3
Total	22.3	29.2	6.9	30.9	2.7

4-5

Confidential

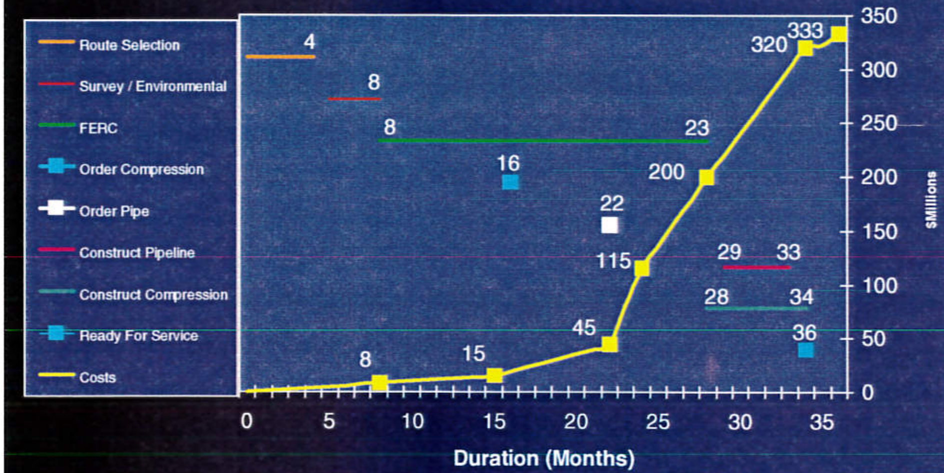




4-6

Confidential

Coastal Connection Schedule / Cost Commitment



Colorado Interstate Gas Company

A SUBSIDIARY OF THE COASTAL CORPORATION

4-7

Confidential

HIGH GAS PRICES

- Grave Situation

  1. High prices – customer hardship

  2. Underlying problem – inadequate national deliverability (supply)

- Components of Gas Bill (Jan 2001, Average Customer)

  1. Cost of Gas (COG or PGA), 80%

  2. Delivery Charge, 16%

  3. Taxes, 4%

- Delivery Charge

  1. Portion retained by Kansas Gas Service for operating the system, maintain pipe and facilities and new construction

  2. Established by KCC last Rate Case 1995

  3. Weather Normalization Adjustment – delivery charge normalized so that during periods of high gas sales the charge is reduced, and low gas sales the charge is increased

- COG

  1. Monthly calculation of costs for gas delivered to Kansas Gas Service

  2. Two components:

     A. Transportation/Storage from upstream pipelines, 22% of total

     B. Gas costs, 58% of total paid

- Transportation/Storage

    1. Eight pipelines, Williams Gas Pipeline the largest
    2. Minimal change in these costs
    3. Rates set by the FERC
    4. Kansas Gas Service aggressively litigates rate cases
    5. Release Capacity
    6. Role of Storage

        A. Primarily peak day deliverability

        B. Also price management

- Gas Costs

    1. The only variable in the customer bills
    2. Market price of gas is measured by indexes, both monthly and daily
    3. Index price for Jan 2001 is $9.98 (Jan 2000 was $2.25)
    4. Small differences in regions (basis)
    5. Price of gas fluctuates uniformly across nation
    6. NYMEX Futures – separate but related to gas price – indicative of future

- Gas Purchasing

    1. Generally three types of purchases

        A. Long Term – reliable, either index or fixed price, less common

        B. Seasonal – specific needs, index, reservation charge

        C. Short Term (Spot) – either daily or monthly, index

2. Past several years a buyer's market – tendency away from long term

3. Purchase from producers or marketers

4. Marketers perform important functions:

    A. Aggregation of supply

    B. Combine gas with optionality

    C. Diverse sources of supply, transportation, etc.

    D. Economies of scale

- Kansas Gas Service's Gas Supply

    1. Long Term, 66%

        A. 20 year contracts

        B. Reliability

        C. Majority index, some fixed price

        D. Advantageous this year

    2. Seasonal, 16%

        A. Revised annually to accommodate changes

        B. Reliability

        C. Bid out to least cost supplier

    3. Short Term, 18%

        A. Adjusted for daily and monthly conditions

        B. Least cost supplier

        C. During periods of high demand this may not be available

- Gas Cost Management Tools

    1. Long term supply
    2. Hedging
    3. Sale of release capacity and storage space
    4. Shifting purchases to locations with favorable pricing (Pony Express)
    5. Storage

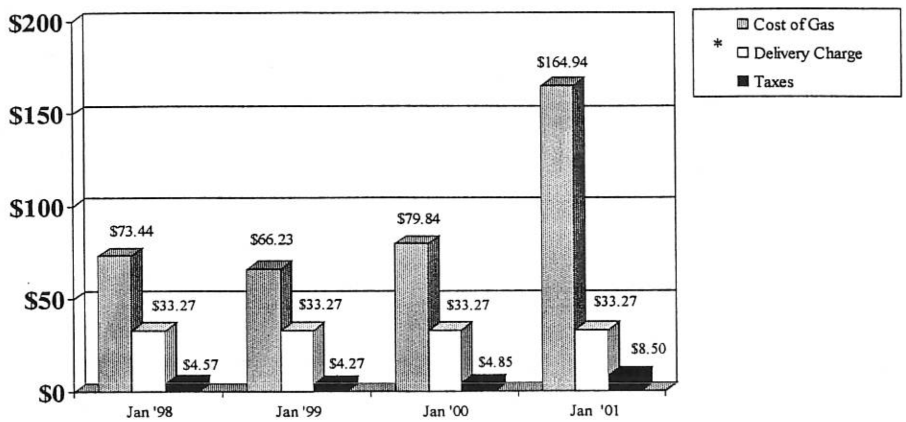
- Other Programs To Manage How Customers Cope With High Costs

    1. Average Payment Plan
    2. WeatherWise Program
    3. Low Income assistance programs
    4. Ad Valorem refunds
    5. Project Deserve

- Summary

    1. Due to recent moderate weather the nation's storage reserve will be adequate
    2. Prices for the remainder of this winter are coming down
    3. Over the next 18 months prices will remain high as supply catches up to demand
    4. Best cure for high prices is high prices

Average Bill - Residential Customer

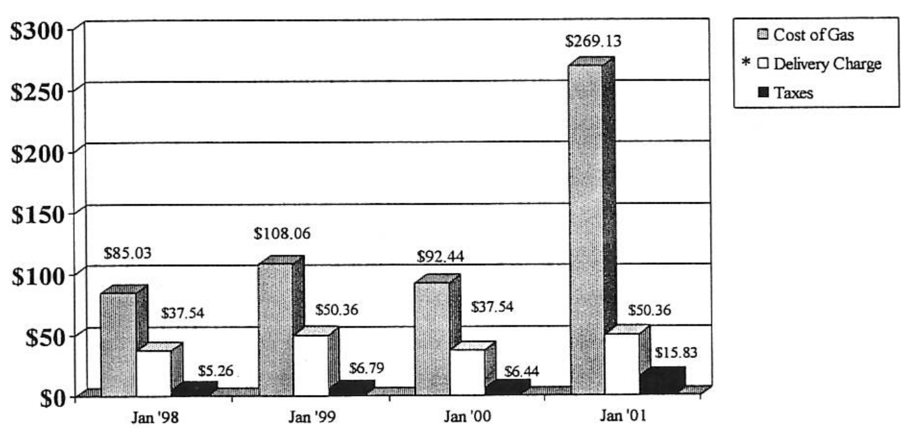


	Jan '98	Jan '99	Jan '00	Jan '01
	19 Mcf COG -$3.865	19 Mcf COG -$3.406	19 Mcf COG -$4.202	19 Mcf COG -$8.681
Bill Total	111.28	103.77	117.96	206.71

*Delivery Charge includes the Customer and Energy Charges as shown on the bill.

KANSAS GAS SERVICE
A DIVISION OF ONEOK

Actual Bill - Residential Customer



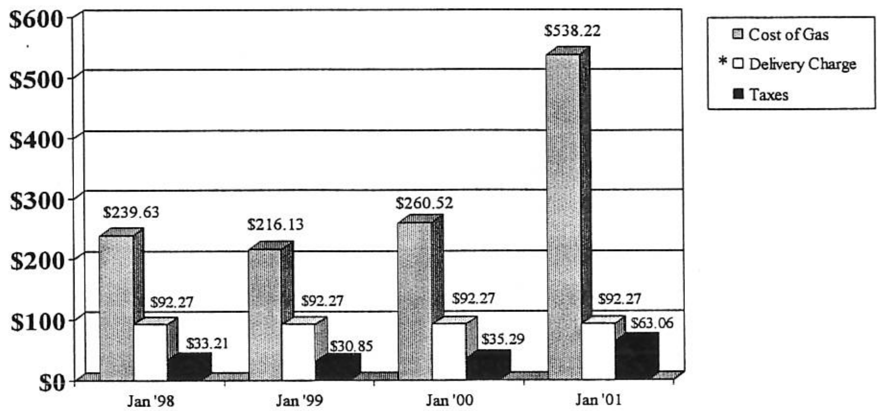
	Jan '98	Jan '99	Jan '00	Jan '01
	22 Mcf COG -$3.865	31 Mcf COG -$3.406	22 Mcf COG -$4.202	31 Mcf COG -$8.681
Bill Total	$127.83	$165.21	136.42	$335.32

*Delivery Charge includes the Customer and Energy Charges as shown on the bill.

KANSAS GAS SERVICE
A DIVISION OF ONEOK

5-5

Average Bill- Commercial Customer

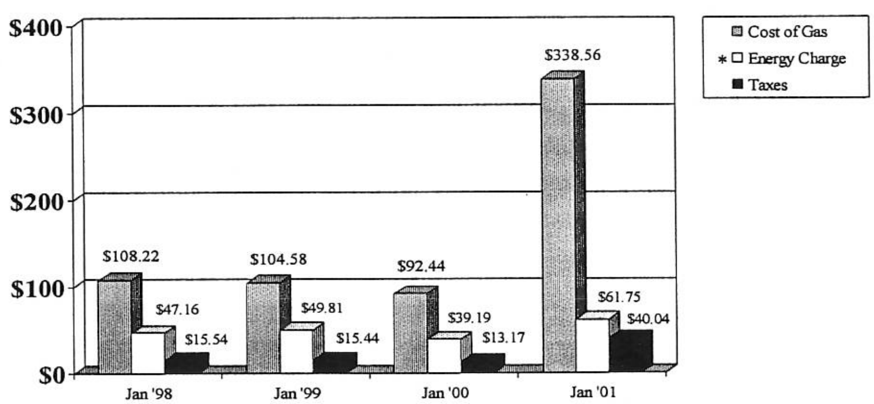


	Jan '98	Jan '99	Jan '00	Jan '01
	62 Mcf COG -$3.865	62 Mcf COG -$3.406	62 Mcf COG -$4.202	62 Mcf COG -$8.681
Bill Total	$365.11	$339.25	$338.08	$693.55

KANSAS GAS SERVICE
A DIVISION OF ONEOK

*Delivery Charge includes the Customer and Energy Charges as shown on the bill.

Actual Bill - Commercial Customer



	Jan '98	Jan '99	Jan '00	Jan '01
	28 Mcf COG -$3.865	30 Mcf COG -$3.406	22 Mcf COG -$4.202	39 Mcf COG -$8.681
Bill Total	$170.92	$169.83	$144.80	$440.35

KANSAS GAS SERVICE
A DIVISION OF ONEOK

*Delivery Charge includes the Customer and Energy Charges as shown on the bill.

5-6

UTILICORP UNITE

Senate Utilities Committee
January 22, 2001
Attachment 6-1

Market Analysis

From

A Trader's View

6-2

Basic Concept:

•The natural gas market is an auction.

•Buyers bidding against other buyers cause prices to go up.

•Sellers selling against other sellers cause prices to go down.

Price: What does it mean?

At an auction, price represents what the last buyer was willing to pay for the last molecule purchased when the market is moving up.

It also represents what the last seller was willing to sell the last molecule for when the market is moving down.

Price, then, represents the value of the marginal unit.

9-7

Marginal Unit – Theoretical Model

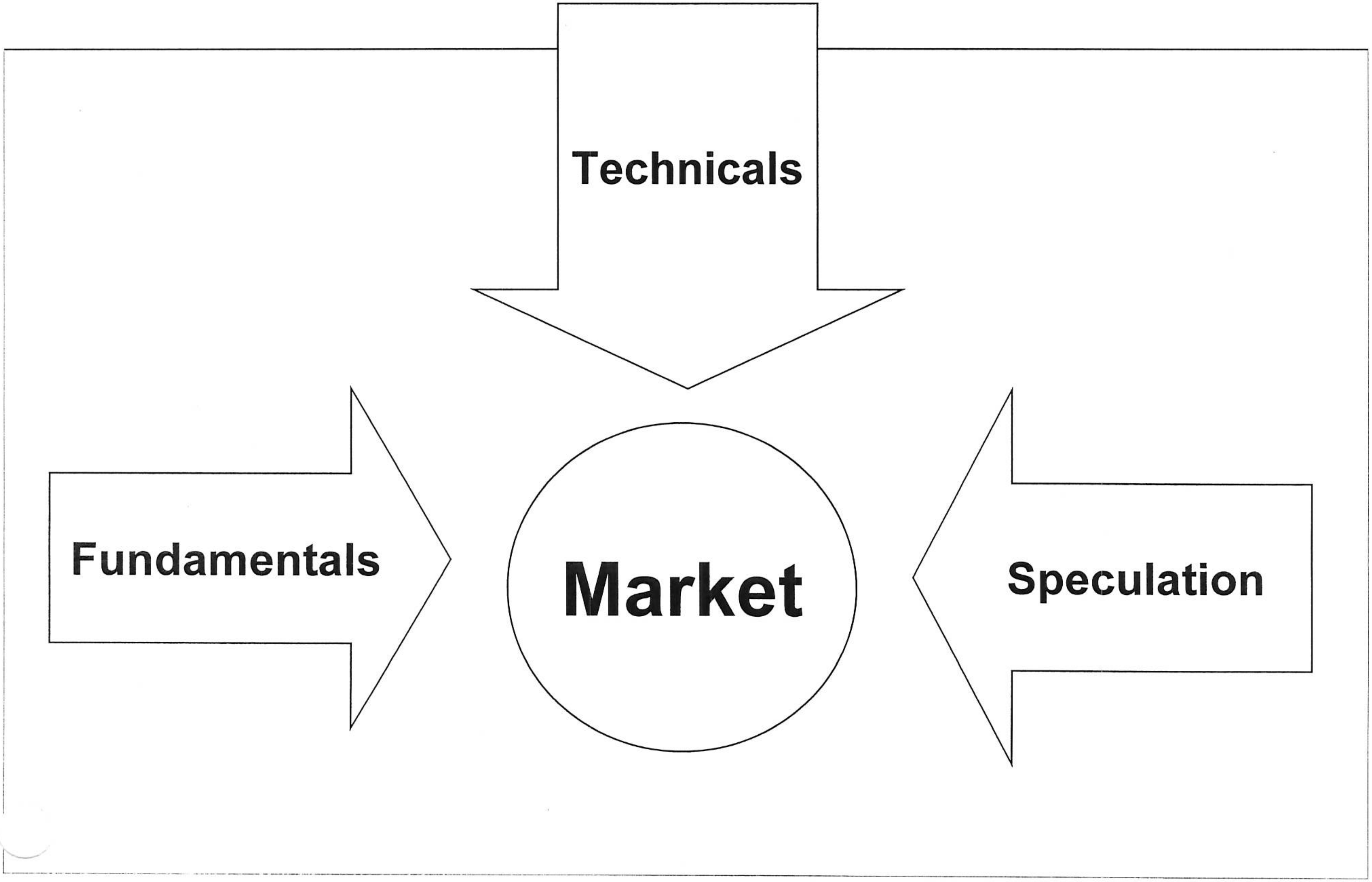
Supply Pools	Estimated Production Volume	If The Estimated Cost of Production	Estimated Cumulative Production Volume	What IF Demand Equals	Minimum Market Price
Canadian Gas	10 Bcfd	$1.25	10 Bcfd	8 Bcfd	$1.26
Rockies	8 Bcfd	$1.50	18 Bcfd	16 Bcfd	$1.51
Mid Continent	12 Bcfd	$1.75	30 Bcfd	28 Bcfd	$1.76
Permian	14 Bcfd	$2.00	44 Bcfd	40 Bcfd	$2.01
Gulf Coast	16 Bcfd	$2.25	60 Bcfd	60 Bcfd	$2.26
Storage		$4.00		61 Bcfd	$4.01
Storage				70 Bcfd	?

- Do not forget, the market is an auction.

- If production represents 60 Bcfd, then when demand equals 70 Bcfd, the marginal unit can equal $9.98 or what the last buyer is willing to pay.

What affects buyers and sellers in their decision-making process?

6-7



8-9

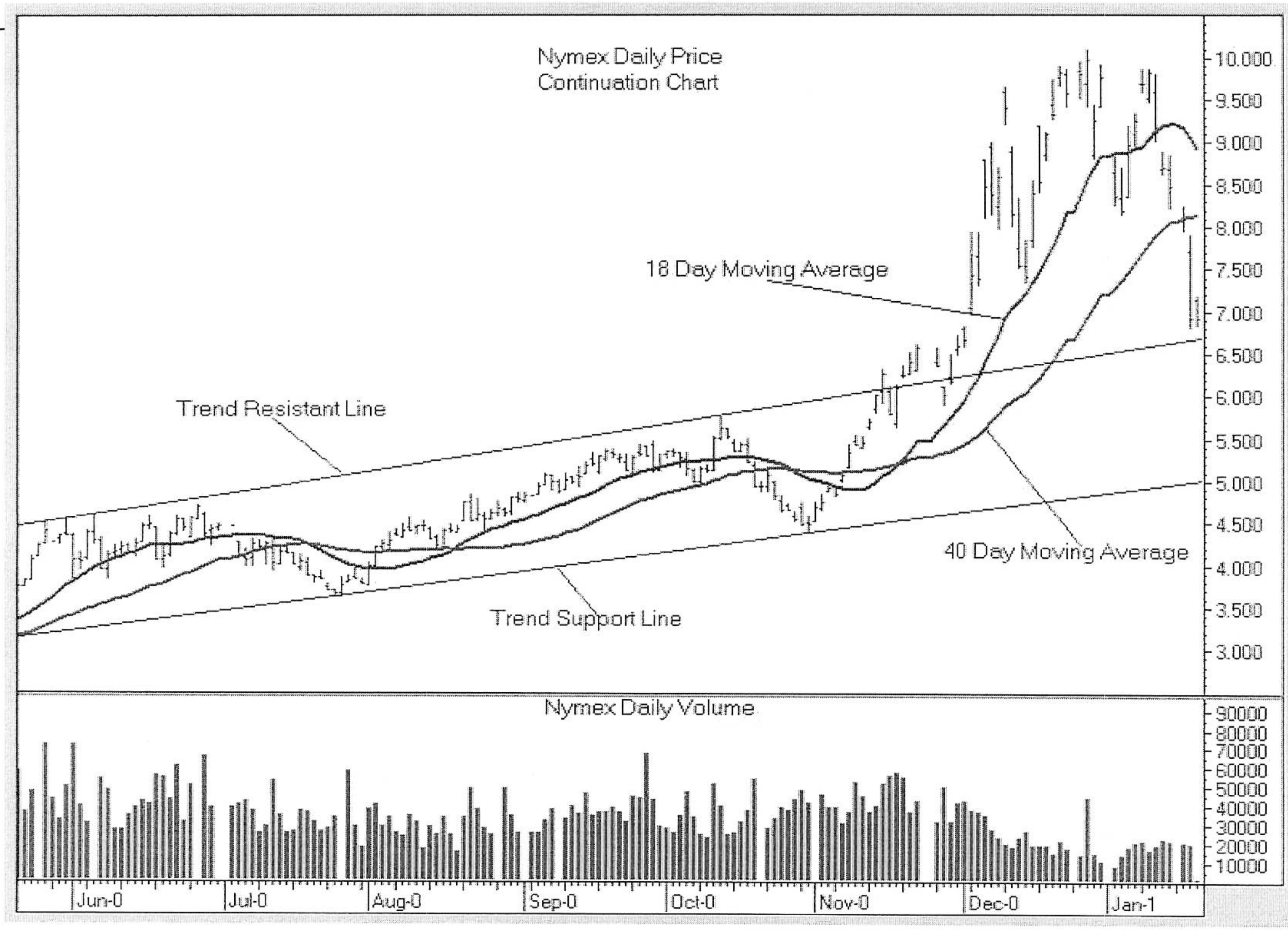
Fundamentals:

- Weather
  - Short Term
  - Seasonal
  - Hurricanes
- Storage Inventory:
- Supply & Demand Forecasts
- Drilling Activity

Generally fundamentals are longer-term influences.

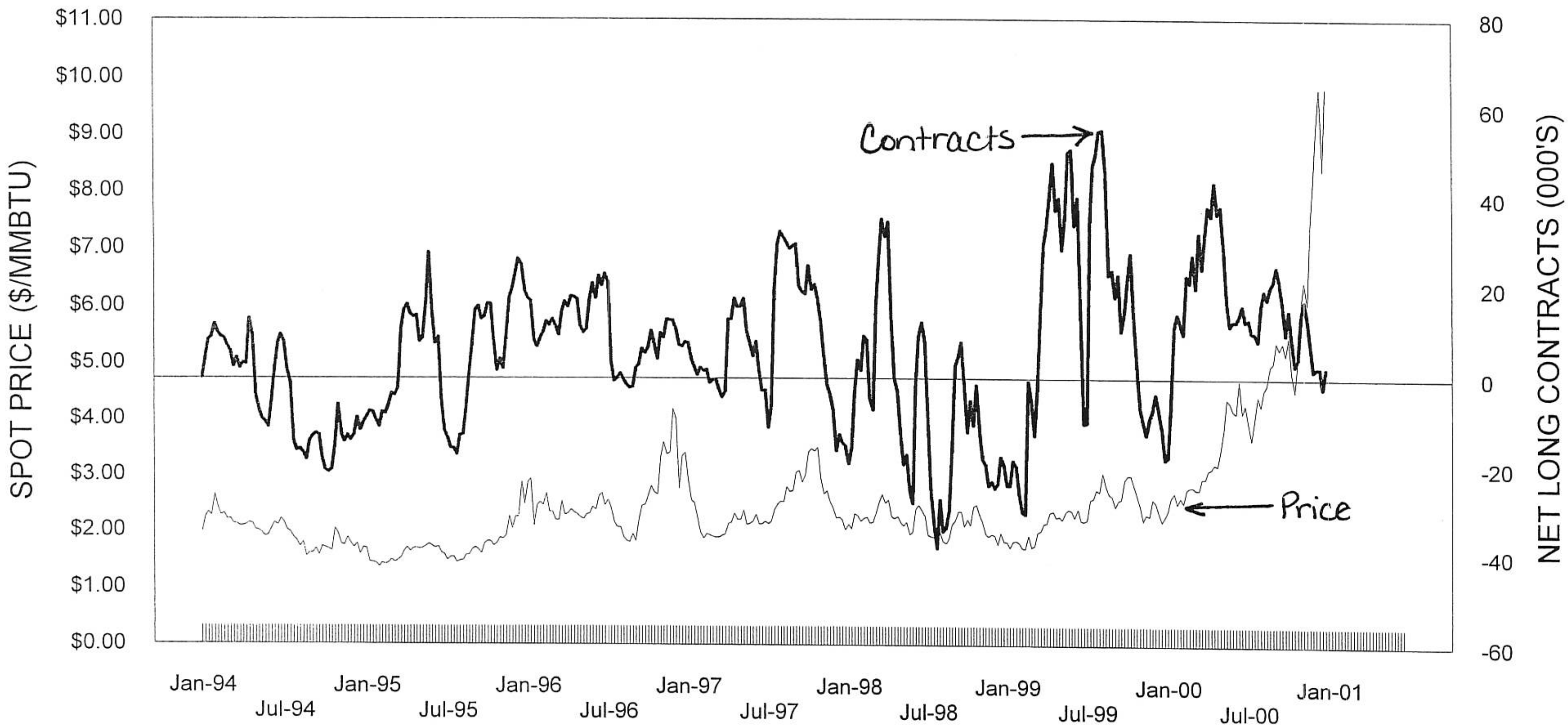
6-9

Technicals:



NATURAL GAS NON-COMMERCIAL (LARGE SPEC) TRADERS

OPEN INTEREST AND SPOT CONTRACT PRICE



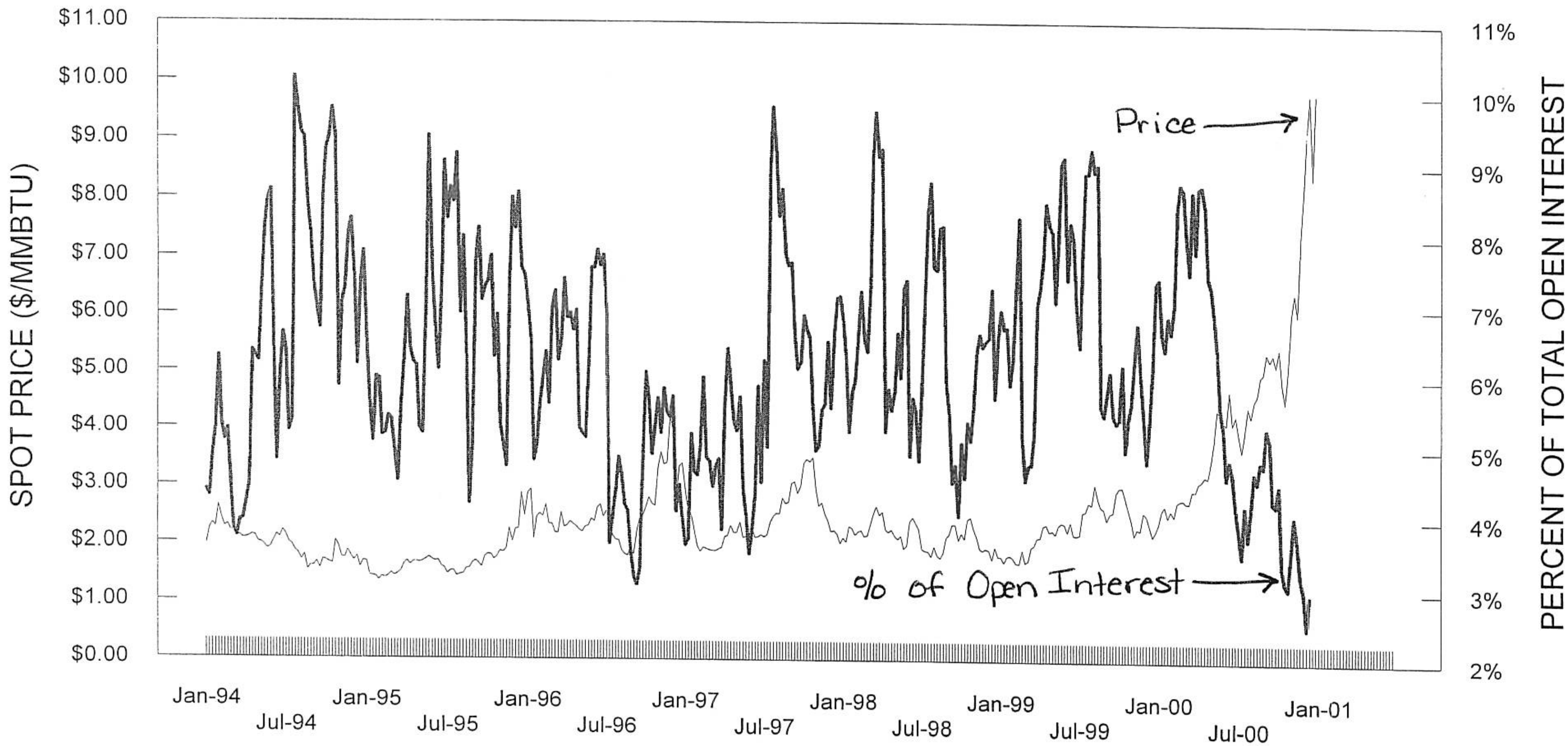
SOURCE: CFTC & NYMEX

6-10

6-11

NATURAL GAS NON-COMMERCIAL (LARGE SPEC) TRADERS

PARTICIPATION IN TOTAL OPEN INTEREST AND SPOT CONTRACT PRICE



SOURCE: CFTC & NYMEX

6-12

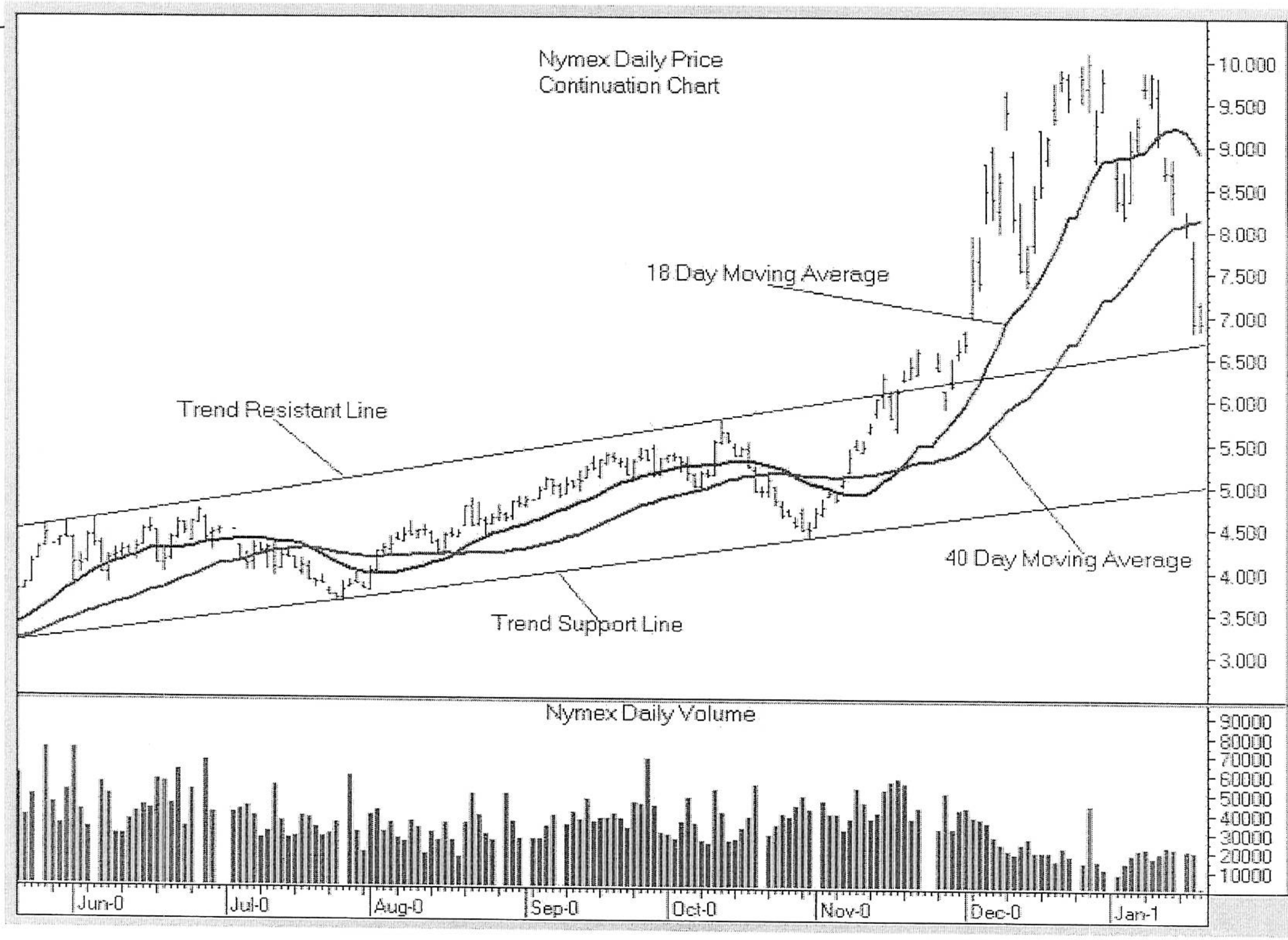
Demand is the problem!

Demand inelasticity is the bomb!

UtiliCorp United

6-13

Technicals:



6-14

Going Forward

•Strong demand is expected to continue.

•High levels of volatility will be a key factor with these market conditions.

6-15

Recommendations

- Diversify supply portfolio using fixed prices to offset the high levels of expected volatility.

- Use call options for a portion of the portfolio to offset further supply shortfalls that may occur as we get closer to winter.

COMMENTS OF
JAMES W. BARTLING, MANAGER PUBLIC AFFAIRS
GREELEY GAS COMPANY
BEFORE THE JOINT MEETING OF THE
SENATE UTILITIES COMMITTEE
AND
HOUSE UTILITIES COMMITTEE
JANUARY 22, 2001

Chairman Clark, Chairman Holmes, Vice-Chairman Emler, Vice-Chairman Sloan, and Members of both the Senate and House Utilities Committees:

I appreciate the opportunity to speak before the joint Senate / House Utilities Committees to address specific questions that this joint Committee has asked. Let me first start by telling you a little about myself and the company that I represent.

My name is Jim Bartling and I am Manager of Public Affairs for Greeley Gas Company, an operating company of Atmos Energy Corporation. Greeley serves approximately 117,000 customers in 114 communities within 31 counties in the State of Kansas. We are a local distribution company with operations regulated by the Kansas Corporation Commission (KCC).

The first question this Committee asked to be addressed concerns the costs of gathering and marketing affiliation and the impact that they have on the average residential gas bill: Greeley purchases natural gas delivered by an interstate pipeline. The cost of gathering is usually included in the commodity portion of the three cost components (transmission and storage, commodity, and distribution). Most gas is priced as it enters into the interstate pipeline. The gathering cost relates to what it costs to move the gas from the well in the field to the interstate pipeline. In western Kansas, Greeley also owns its own gathering system. The gathering costs in that instance are included in the distribution portion of the three cost components. Marketing affiliation has no impact on the average residential customer's bill.

Within this first question you also asked if Greeley Gas Company can do anything to lower its operational costs. Greeley Gas is always looking for ways to be more efficient while at the same time maintaining a high level of service to our customers.

New technology continues to provide new opportunities for our operation and we will continue to evaluate each one, but making sure that the safety of our customers remains our paramount concern.

Your second question concerns Greeley's gas purchasing practices: Greeley has a gas supply department at Atmos Energy Corporation's corporate headquarters that is responsible for securing transportation capacity on the intrastate and interstate pipelines. The gas supply department also secures storage capacity off of the interstate pipeline.

It is important to point out that storage plays a significant role in Greeley's, as well as other local distribution company's (LDC's), purchasing practices. It is doubtful if the existing transmission lines coming across Kansas would be large enough to meet the eastern Kansas customers' daily needs on a very cold day if it were not for the old gas fields in eastern Kansas that have been converted to storage fields. Greeley and other utilities put gas in storage during the summer to take care of about 20% of their winter peak demand. The other 80% comes from flowing gas on the interstate pipeline.

In addition to securing transportation and storage capacity, the gas supply department determines how much gas it is going to need for the five winter months, assuming a "normal" winter. (Normal as defined by a 30-year average number of degree days reported by the National Oceanic and Atmospheric Administration for this five month period – currently 4,323 for Olathe 3-E., compared to an annual degree day count of 5,029.) The gas supply department then goes out and purchases the amount of gas that it has calculated that it will need. The price of that gas is determined each month, based upon what other buyers on the specific pipeline are paying.

If usage during the month is higher than expected, the gas company goes out and purchases additional gas on a daily basis at the daily rate being paid by other buyers on the pipeline. The prices paid by other buyers are reflected on a daily or monthly index that is published and reflected on the Internet.

During the summer months the gas supply department is buying its summer needs but it is also buying gas to be placed into storage in preparation for next winter. The price of gas in storage is priced when it is placed into storage, not when it comes out.

The second part of this question concerned whether Greeley purchased most of its gas through a bidding process or Request for Proposal (RFP): Greeley currently operates under an agreement with the KCC Staff that was approved by the KCC a few years ago. Under that agreement Greeley submits its RFP to the Staff for comment. Greeley then submits its RFP to qualified suppliers, and then provides the KCC Staff with an analysis of the bids received and an explanation for the bid that was accepted by Greeley.

Most of the gas sold by Greeley is referred to as its "monthly base gas." This is the amount of gas that customers would use in a normal heating month. When the weather is colder than normal or demand is greater for other reasons, Greeley buys additional gas on a daily basis.

The last part to this question concerns whether or not Greeley was considering longer-term contracts: Because of price volatility, Greeley has not elected to enter into long term contracts for the last several years. Although we do have some long-term contracts with local producers located close to Greeley's system, these local production gas wells provide a very small percentage of our gas needs.

As to whether there are any constraints in our effort to market natural gas, I am not aware of any.

Your fourth question concerns whether or not we have sufficient storage capacity for this winter and for the future, and whether or not we foresee any constraints in storage capacity this winter or in the future: We feel that we have sufficient storage capacity from the interstate pipelines. We are able to supplement the pipeline storage capacity with our own storage facilities in southeast Kansas. Greeley has sufficient storage capacity to supplement the flowing gas that it receives from the interstate pipeline to meet its peak day demand. As to whether we see future constraints, it should be noted that because new gas-fired electric generation plants are scheduled to come on line, there is more competition now for gas supply during the spring and summer months, which may drive up the cost of gas that Greeley and other utilities would purchase to place in storage for next winter.

Changes that we would like to see the FERC consider to promote expanded pipeline capacity: I don't know of any that would be necessary. Greeley retains representation for its customers before FERC and monitors actions taken by FERC that might have an impact on its customers.

Your next question concerns Greeley's experience with transportation customers where, because their marketer has failed to deliver promised gas, a customer has returned as a sales customer: Greeley has approximately 100 transportation customers in Kansas that are transporting gas to serve approximately 220 meters. Almost 100 meters were being supplied by Mountain Energy when they announced that they were not going to be able to fulfill their commitments. Greeley worked with these customers to help many of them find alternate suppliers. Two of these customers indicated that they were not satisfied with their savings while transporting and requested to come back as firm sales customers and were allowed to do so.

One of the things that Greeley does to protect our small volume transporters (those with insufficient annual volumes to qualify for interruptible status – 220,000 Ccf per year) is to make sure that the assignment of pipeline capacity that the customer takes with them when they start transporting, comes back to Greeley if that marketer goes into bankruptcy or does not honor its contract with the customer. This means that if the customer wants to come back as a sales customer, Greeley automatically gets the capacity on the interstate pipeline back from the marketer which it needed to supply gas to that customer.

There are some situations in which the customer insists on taking complete control of that capacity. In that case, we make sure that the customer understands that by taking that capacity, the customer runs the risk that the interstate pipeline capacity held by Greeley may not be there if that customer wants to come back as a sales customer. In those situations Greeley explains to the customer that it might be in the customer's best interest to maintain the capacity in its name instead of assigning it to a marketer.

Is the Cold Weather Rule Working? The cold weather rule has been in place for over 15 years. Greeley thinks that some changes are needed and are discussing those changes with the other LDC's in hopes of presenting something to the KCC this spring or summer for its consideration.

Surcharge on customers' bills for long term assistance programs: Greeley does not believe that it is appropriate to use utility rates to charge all of its customers a surcharge to collect funds to be used to assist their neighbors. Some of our customers may not be willing to pay to provide such assistance. Greeley supports assisting customers in this area, but believes that such assistance should be provided on a voluntary basis through personal and corporate donations to existing organizations that provide such assistance.

Your final question dealt with providing a portion of the ad valorem tax refund moneys for assistance programs: Early last week Greeley filed with the KCC to refund a portion of the ad valorem tax refund to low income customers to help them pay their gas bills this winter. That application is currently pending before the KCC. Late last week additional discussion on this issue was held and it was decided to amend the current filing to include all of the ad valorem tax refund for low-income customers rather than just a portion. That filing will be done this week.

This concludes my responses to the joint Committee's questions. I will be happy to answer any other questions.

Presentation of John Cita
Chief Economist, Kansas State Corporation Commission
January 22, 2001
to
Kansas Senate and House Utility Committees
Honorable Stan Clark and Carl Holmes, Chairmen

Natural Gas Price Forecast: An Expectation of Prices to Come

As a member of the Commission's Natural Gas Price Task Force I was asked to develop forecasts to provide some indication of what the price of natural gas may be in the near future. Today I offer the joint Utilities Committee an updated version of those forecasts. Using the market data that was available on January 18, 2001, I have developed forecasts for the calendar year 2001, 2002 and 2003. If you will turn to my first graph, you can see the forecast prices I have developed. Those prices represent the average annual gas price forecasts for the average residential consumer in Kansas. I would point out that those prices are not burner-tip prices. That is, they do not represent the consumer's final price of gas, to emphasize, they are essentially gas only prices. To get a burner-tip price forecast you would add approximately $4.00 to those prices. Lastly, in making these forecasts, I assume weather conditions will be close to normal. If next summer is warmer than normal and/or next winter is colder than normal, these forecast prices are very likely to be too low.

As you can see, I am forecasting a price of $6.72 for this calendar year, $4.86 for next year, and $4.25 for the calendar year 2003. I should also note, there is a significant amount of price volatility in today's gas market. The price can swing as much as $0.70 in a day. That volatility is likely to continue into the future. That suggests that any gas price forecast will be subject to a large margin of error.

To put those forecast prices into context, I offer the same price information but for the historical years 1998, 1999 and last year. In 1998, the average annual price of gas for the average residential customer was $2.02, $2.08 in 1999, and $3.62 in 2000.

Household Budget Implications

Based on these forecasts, it does not appear that there will be any price relief until 2002 and beyond. It appears unlikely that Kansas consumers will experience during the next three years prices as low as they were in 1998/1999. In contrasting the 1999 price with the price forecast for 2001, the average Kansan will spend $4.64 more for a unit of gas (MMBtu). If the average residential customer in Kansas consumers 100 MMBtu of gas in a normal year, the implication of that price increase is clear. Between 1999 and 2001, the average residential gas customer will spend approximate $500 more on its annual gas bill. Of course, most of that increase will hit during the four major winter months, November through February.

Annual budget changes (calendar year basis) for the average residential consumer:

1998 to 1999:	$6.00
1999 to 2000:	$154.00
2000 to 2001f:	$310.00 [assuming future weather is normal]
2001f to 2002f:	$(186.00) [assuming future weather is normal]

The Annual Gas Bill as a Proportion of Household Income

I thought it might be worthwhile to track what proportion of annual income the typical Kansan spends on his annual gas bill. By comparing the annual gas bill to household income we can obtain some sense of the relative burden of the annual gas bill. If you will turn to the next graph, entitled Annual Gas Bill as a Percent of Real Household Income, you can see that the average Kansas household spends approximately 1 percent of its annual income to cover its natural gas expenses. There are a few items that may be worth noting:

- since 1980, the proportion has declined slightly
- the proportion reached a maximum of 1.49% in 1983
- based on the 2001 forecast price (of $6.72), the proportion reaches 1.25%

However, the gas industry was undergoing a significant structural change in the early 1980s with the deregulation of the wellhead market. During the early 1980, wellhead prices increased significantly as a result of deregulation and the occurrence of a significant gas shortage at that time. Therefore, it is probably more representative to show this ratio over the post-deregulation period. If you will turn to the next graph, I show the same analysis but for the time period since

1985. Again there are a couple items that may be worth noting:

- in the post-deregulation era, the relative gas bill burden forecast for 2001(based on a forecast price of $6.72) will be as large as ever
- the relative gas bill burden forecast for 2002(based on a forecast price of $4.86) is just under 1%

This analysis suggests that the average household in Kansas can probably weather the current high prices. It also suggests that, about a year from now, the relative burden of the household gas bill will return to the its historical trend line for the average household. That is not to suggest that consumers in any way like higher prices, obviously consumers do not like higher gas bills. But, against a backdrop of a larger (real) income, the average household is more able to pay higher prices for all commodities, including natural gas.

<u>What About Households on Fixed Incomes or With Incomes that Lag Behind the Average?</u>

As usual, price increases hit fixed income households the hardest. Those families whose incomes rise slower than average are the next hardest hit - probably the working poor. The need to provide any possible relief to fixed income and working-poor families is likely to be sustained for the next 12 to 18 months.

<u>Why the current high prices?</u>

1. *Winter 2000/2001Storage:*

On November 1, 2000, storage facilities - nationally - were not full to capacity. Consequently, that set the stage for the market being nervous about having enough gas to get through the winter. *Why were the gas storage facilities not full as planned?* Perhaps the primary reason is the *increased competition* during the summer (particularly summer 2000) between injecting gas into storage and burning gas to generate electricity. In general, this increased competition implies: 1) the price of gas will be higher during the summer, creating a likelihood that higher prices will linger into the winter months and 2) there is an increased risk that storage facilities will not get filled to capacity by the start of winter, consequently, the gas market is likely to be more jittery during the winter months, meaning price spikes are more likely.

2. *The Weather:*

Record cold temperatures over nearly the entire nation were sustained for an extended period. This translated to a significant increase in demand for gas and, by mid-December, a fear that there may not be enough gas in total (flowing plus storage) to get through the winter. Consumers went from experiencing a record warm winter (Dec,Jan,Feb) to a record cold early winter (Nov,Dec)

3. *The Growth of Field Production has Lagged the Growth in Demand for Gas:*

Lagging wellhead prices failed to provide an incentive to *develop new sources* of supply sufficient to keep up with existing and new (summer) demand. Consequently, the supply of field gas is probably lagging behind current demand. Since 1990, real wellhead prices have been below the historical trend for wellhead price. That suggests the price incentive for developing new supplies has probably been deficient.

Natural Gas Price Forecasts

Price: average annual gas price (per MMBtu) for typical Kansas household
Time period: Calendar years 2001, 2002, 2003
Pipeline: WNG (KS, TX, OK) Index
Forecast Date: January 18, 2001

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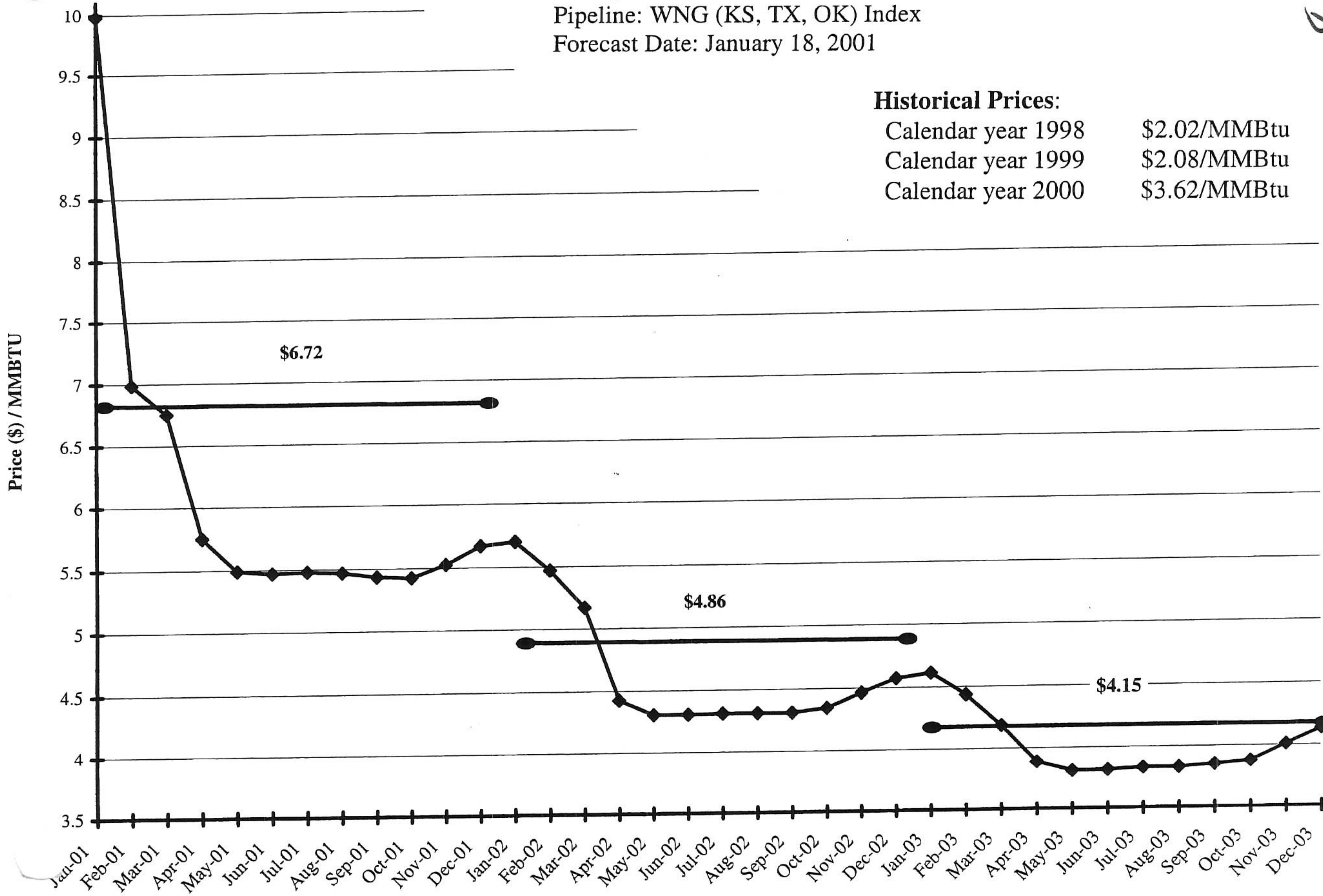
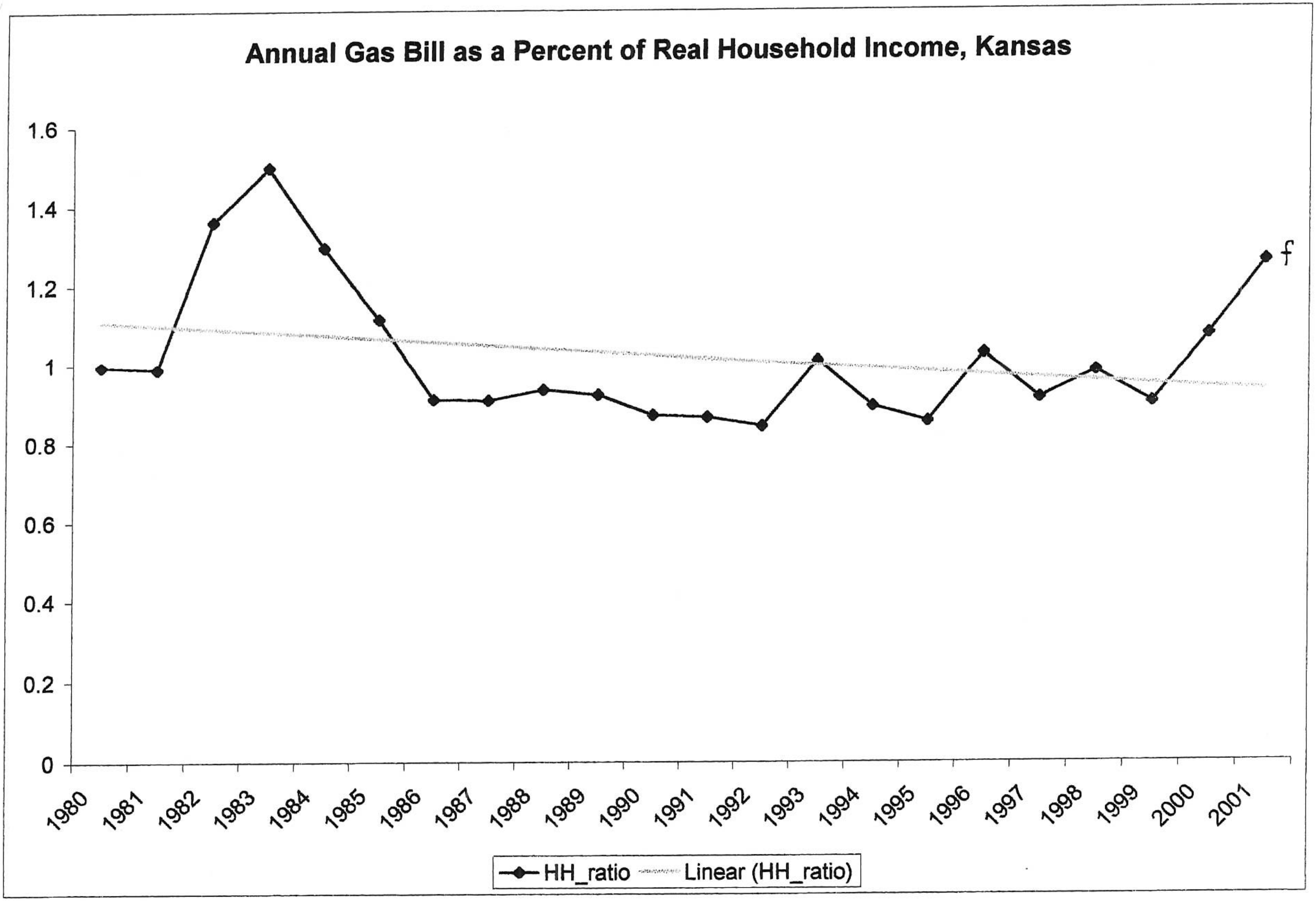
Historical Prices:

Calendar year 1998	$2.02/MMBtu
Calendar year 1999	$2.08/MMBtu
Calendar year 2000	$3.62/MMBtu





Annual Gas Bill as a Percent of Real Household Income, Kansas
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
1980
1981
1982
1983
1984
1985
1986
1987
1988
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1992
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2000
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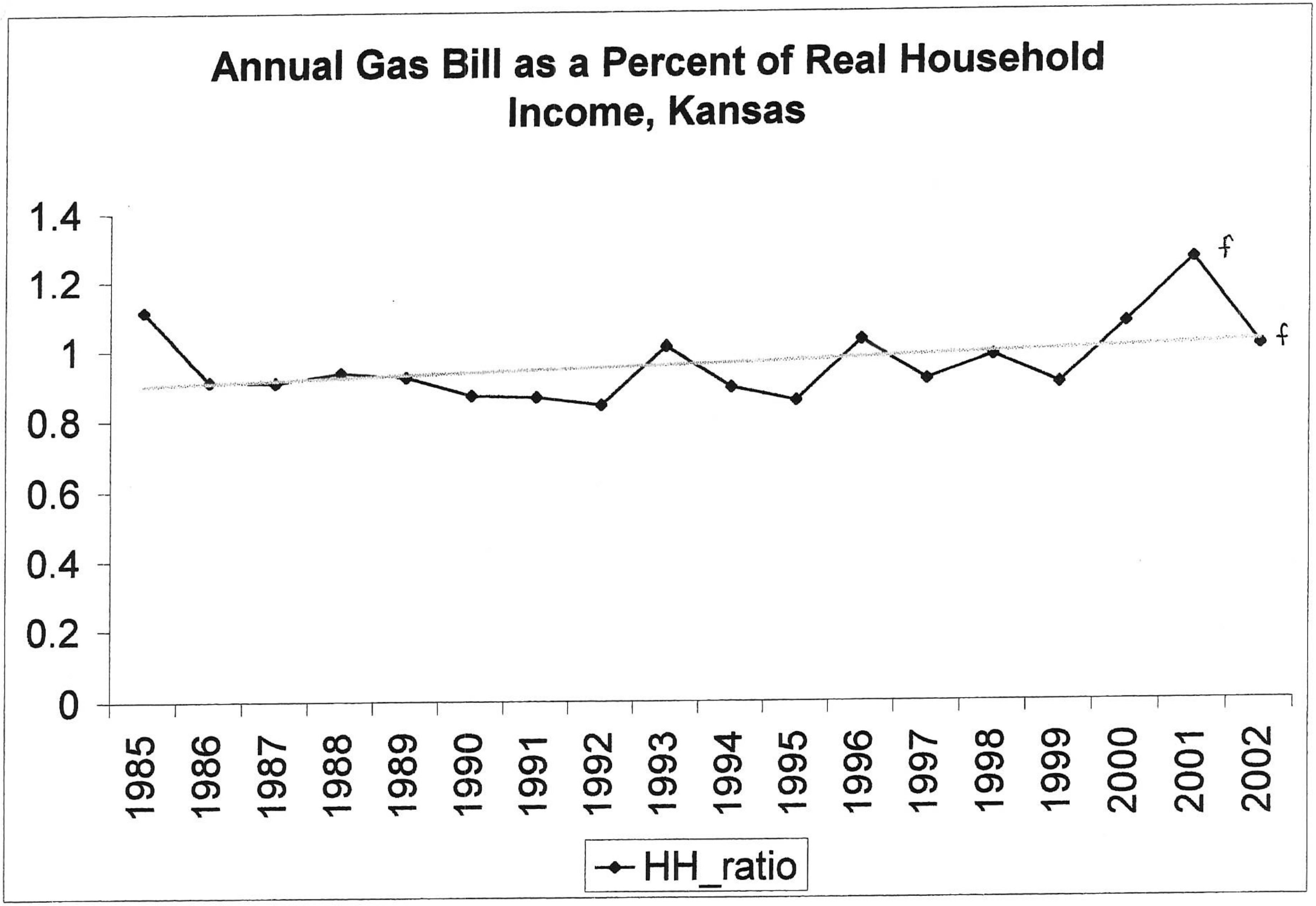

Annual Gas Bill as a Percent of Real Household Income, Kansas
1.4
1.2
1
0.8
0.6
0.4
0.2
0
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
f
f
HH_ratio

8-7

8

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January 19, 2001

WHY HAVE NATURAL GAS PRICES INCREASED?

Below is a brief explanation of the reasons for increased natural gas prices. This explanation was prepared in cooperation with staff of the Kansas Corporation Commission and the Citizens Utility Ratepayer Board.

The Rule of Supply and Demand

Under the Natural Gas Policy Act of 1978, the federal government deregulated the price of natural gas as a commodity. Natural gas prices are subject to the laws of supply and demand and, therefore, are strictly determined in the marketplace. There has been an increasing demand for natural gas while supply levels have remained flat. This situation is reflected in the current market price of natural gas which has more than tripled since a year ago: approximately $2.25 last January compared with $9.98 this January.

The United States' natural gas market consists of two large regional markets, one east and the other west of the Rockies. Within each of those markets, prices tend to be highly integrated. That integration is due, in part, to the expansive network of interstate pipelines that serves those market areas. Natural gas spot market prices can fluctuate dramatically from one day (or even hour) to the next in response to purchasers' concerns about cold weather and gas storage. Therefore, natural gas prices in Kansas are affected by market conditions throughout the eastern two-thirds of the United States. For instance, cold weather in the larger metropolitan areas, such as Chicago and Detroit, will affect the price Kansans pay for natural gas.

Demand for Natural Gas

A combination of increased use of natural gas for generation of electricity coupled with below-average temperatures throughout Kansas and the United States this winter has resulted in greater demand for natural gas and correspondingly higher prices.

Electric Generation. There has been an increase in natural gas use for electricity generation as new gas-fired power plants have come on line. More power plants have been needed to accommodate increased electric demand attributable in large part to the expanded use of communications technologies, such as computers. Construction of new gas-fired generating units may be driven by the uncertainty of future market conditions. Increasing wholesale electric competition and the prospect of retail wheeling in Kansas and other states have caused investors to minimize initial costs by installing peaking type units (which are designed to produce electricity during periods of greatest customer demand)

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rather than base load generating plants (which are designed to produce electricity at all times). Examples of base load generating plants in Kansas are Western Resources' Jeffrey and the Sunflower Electric Cooperative's Holcomb generating plants which use coal and Kansas Gas and Electric's and Kansas City Power and Light's Wolf Creek Generating Station, which uses nuclear power. The majority of recently announced and constructed peaking plants are either combustion turbine or combined cycle units which are fueled by natural gas. Peaking plants require less initial investment and construction lead time than base load generating plants. Consequently, greater use of natural gas for generation of electricity results in greater competition between burning gas during the summer and putting gas into storage to be burned during the winter. That increased competition can reduce the availability of natural gas to place in storage for heating during the winter if the supply of natural gas remains stagnant.

Weather. The weather has been much colder this winter than last winter. The temperature for the combined months of November and December was among the coldest ever recorded in Kansas history. The cold spell that has affected Kansas also has affected most of the country, driving demand, and therefore prices, up relative to supply.

Supply of Natural Gas

Several factors affect the supply of natural gas: production and drilling, capacity constraints on pipelines, and storage. As previously noted, the supply of natural gas has been fairly stagnant. It is projected to go up but not in time to affect prices during this winter's heating season.

Production and Drilling. Until 1999, prices of natural gas were low and there was little incentive for investments to be made in natural gas exploration and development. However, as prices have increased, investments in drilling operations have correspondingly increased. The Energy Information Administration (EIA) noted that gas rigs in operation in the United States hit a record of 879 on December 29, 2000, compared to a low of 362 rigs in the third week of April 1999. There is an estimated time lag of at least 6 to 18 months between the time of initial drilling and when additional gas supplies reach the market. With respect to Kansas natural gas production, there has been a significant increase in the number of rigs operating in Kansas (24 in 2000, compared to 15 in 1998). However, Kansas is considered to be at "rig capacity" because of the current limiting constraints of qualified personnel, lack of associated service companies, and the number of rigs that are currently available for drilling.

Capacity Constraints on Pipelines. Natural gas from the United States and Canada is transported through gathering lines to interstate pipelines and then transported to local distribution companies and consumers throughout the United States. The EIA noted in a report dated October 2000 that there appeared to be adequate available capacity on the natural gas pipeline grid throughout the country as the winter season was approaching. This projection assumed normal operations would be maintained on the national pipeline system during an average heating season. However, as previously noted, this winter has been very cold and capacity constraints and bottleneck problems could arise as demand exceeds capabilities.

Even if disruptions occur, however, the EIA observed that the pipeline network is sufficiently resilient, at least in the short term, to handle major disruptions. In California, for example, supplies were limited for several months due to an explosion in August 2000, which disrupted service on the El Paso Natural Gas Company system in southern California. Gas prices in southern California soared temporarily but a combination of market adjustments averted widespread shortages.

In Kansas, by contrast, gas delivery is not expected to be hampered by the natural gas pipeline infrastructure. Colorado Interstate Gas Company and Williams Gas-Pipeline Central each plan to develop new pipeline routes from supply interconnections with affiliated and other interstate systems in southwestern Kansas. Both projects are expected to be completed in 2003. These links should serve the growing local natural gas market and provide alternative interstate routes to the Midwestern marketplace.

Storage. Domestic gas production and imported gas are more than sufficient to meet consumer needs during the summer. The portion of supply that is not needed during the summer is placed into storage facilities and is withdrawn in the winter for the heating season. Natural gas storage accounts on average for approximately 20 percent of the natural gas consumed during the winter season, which runs from November 1 through March 31. Stored gas is intended to fill in the gap between winter demand and winter supply (flowing natural gas to end users). The EIA noted that working or easily accessible gas in storage is estimated to have been below 1,800 billion cubic feet at the end of December. This storage level is 20 percent below the previous five-year average level. This is the lowest level since recordkeeping began. The reasons for low storage volumes are: (1) there was more competition for gas due to increased power loads during the 2000 cooling season; and (2) the cost of gas was higher than usual in early summer; therefore, storage users were reluctant to purchase gas at that price and put it into storage. They feared a downward price adjustment after they had paid a higher price for the gas. Storage levels are expected to be adequate this heating season; nevertheless, perceptions of tight supply in the national market have driven up prices in Kansas and elsewhere. The EIA reported that despite adequate storage volumes for this heating season, the gas supply system in this country could be severely challenged if summer demand in 2001 is as strong as currently expected.

Conclusion

Nobody knows exactly when prices will go down. The EIA noted that the current situation is the result of short-term supply imbalances that will even out over the long term, moving the market toward a long-run equilibrium. Rising production levels and a cooler summer should drive prices down.

KCC Fact Sheet

John Wine, Chair
Cynthia L. Claus, Commissioner
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January 2001

Overview of natural gas costs and bill components

Thank you for the opportunity to provide information about the high gas costs Kansans are now experiencing. The reason for this is that the wholesale cost of the gas purchased by utilities has increased significantly. The actual cost of the gas purchased by a utility from its supplier is reflected on the billing statement as a Purchased Gas Adjustment (PGA) or as a Cost of Gas (COG). As part of its regulatory duties the Commission reviews and monitors the purchasing practices of natural gas public utilities to ensure only the actual cost the utility pays for the gas is passed on to the customer through the PGA or COG which goes up or down with the market forces.

Unfortunately, the state of Kansas can do little, if anything, to protect consumers from these increases. This is because the federal government has deregulated natural gas as a commodity. Consequently, the market forces of supply and demand dictate what a utility has to pay for its gas supplies. As is reflected on monthly billings, the PGA or COG fluctuates on a monthly basis, reflecting the actual cost of gas.

Natural gas prices have hit all-time record high levels. Primary reasons for the increase in costs are: the demand for natural gas to fuel electric power plants, couples with an increase in electric consumption, in addition to lower gas prices in the past few years resulting in decreased gas exploration and production resulting in lower than normal volumes of gas reserves in storage.

Explained below are the three components of a rate

Cost of Gas: There are two elements that constitute the cost of gas. The first is the PGA, which is the actual monthly cost of gas (this will fluctuate on a monthly basis). The second is the cost of transporting the gas to the local distribution company's facilities. Generally, this is over the facilities of an interstate pipeline whose rates are established by the Federal Energy Regulatory Commission (FERC). They remain constant until the FERC grants them a rate increase. The Commission has no jurisdiction over these costs.

Customer Charge: Reflects the operating and maintenance costs of meters, service lines, pressure regulation devices, meter reading, and billing. These are costs incurred by the utility to serve a customer regardless of a customers usage. This charge is approved by the Commission.

Energy Charge: or Base Rate Includes all other costs of doing business. These costs consist of salaries, supplies and materials, depreciation on facilities, interest on debt and return on investment. This rate is approved by the Commission.

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