GREAT PLAINS
NATURAL GAS CO.
A Division of MDU Resources Group, Inc.

105 West Lincoln Avenue
Mailing Address:
P.O. Box 176
Fergus Falls, MN 56538-0176
(218) 736-6935

March 2, 2009

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Cost of Gas Adjustment (COG)
March 2009

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and seven (7) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (36th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (36th Revised Sheet No. 8), showing the March 2009 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.3721 per mcf for residential and firm general service customers and \$0.4589 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for March 2009, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.4589 per mcf since the last COG filing due to a decrease in the market price of gas. There has been an increase in pipeline charges of \$0.0868 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of \$0.3721 per mcf for residential and firm general service customers.

Attachment C explains the reasons for the change in the market price of gas.

Attachment D shows the calculation of the balancing account since April 30, 2008.

Great Plains submitted a check for \$600.00 on December 30, 2008 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment covers the \$50.00 filing fee associated with this month's COG filing.

Great Plains respectfully requests this filing be accepted as being in full compliance with the filing requirements of this Commission.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Rita A. Mulkern

Rita A. Mulkern
Regulatory Analysis Manager

Attachments

STATE OF NORTH DAKOTA)
: ss.
COUNTY OF BURLEIGH)

Rita A. Mulkern, being first duly sworn, deposes and says; that she is the Regulatory Analysis Manager of Great Plains Natural Gas Co., the Applicant herein; that she has read the foregoing Application, knows the contents thereof, and that the same is true and correct to the best of her knowledge, information and belief.

Dated this 2nd day of March 2009.

Rita A. Mulkern

Rita A. Mulkern

Subscribed and sworn to before me this 2nd day of March 2009.

SARA J GRAF
Notary Public
State of North Dakota
My Commission Expires September 18, 2013

Sara J. Graf

Sara J. Graf, Notary Public
Burleigh County, North Dakota
My Commission Expires: 09/18/2013

Attachment A

Attachment A

State of North Dakota
Gas Rate Schedule

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/MCF
Firm Gas Service - General	2	$3.50 per month	First 10 MCF	$1.2740	$6.0869	$7.3609
			Over 10 MCF	1.0540		7.1409
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.2614	$4.4005
			Next 2,600 MCF	0.8931		4.1545
			Over 3,000 MCF	0.7411		4.0025
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.2614	$4.5005
Transportation Service	5	$3.50 per month	First 400 MCF	$1.1391		$1.1391
			Next 2,600 MCF	0.8931		0.8931
			Over 3,000 MCF	0.7411		0.7411

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
36th Revised Sheet No. 8
Canceling 35th Revised Sheet No. 8

COST OF GAS

Summary:	Firm				Interruptible		
	Est. Wtd. Demand Costs	Average Commodity	GCR Adj.	Est. Wtd. Total Firm	Average Commodity	GCR Adj.	Total Int.
Base Rate	$0.0658	$5.1191	$0.0000	$5.1849	$5.1191	$0.0000	$5.1191
Accumulated Adj.	2.1277	(0.6679)	(0.1857)	1.2741	(0.6679)	(0.7309)	(1.3988)
Current Adj.	0.0868	(0.4589)	0.0000	(0.3721)	(0.4589)	0.0000	(0.4589)
Total Adj.	2.2145	(1.1268)	(0.1857)	0.9020	(1.1268)	(0.7309)	(1.8577)
Total Rate:	$2.2803	$3.9923	($0.1857)	$6.0869	$3.9923	($0.7309)	$3.2614

Date Filed: March 2, 2009 **Effective Date:** March 1, 2009

Issued By: Donald R. Ball
Vice President – Regulatory Affairs **Case No.:**

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MARCH 2009

Firm	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
FT-A	7,841	$3.4671	12	$326,226	$0.2084
FT-A - Zone 1-1	500	3.4671	5	8,668	0.0055
FT-A - Zone 1-2	4,500	4.5871	5	103,210	0.0659
FT-A Seasonal	3,000	3.7671	5	56,507	0.0361
FT-A Seasonal	1,000	3.7671	4	15,068	0.0096
TFX Seasonal	4,000	15.1530	5	303,060	0.1936
NOVA - Demand Charge	7,947	11.1116	12	1,059,647	0.6768
Trans Canada - Demand Charge	7,947	9.8894	12	943,093	0.6024
ProGas - Demand Charge	7,947	0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068	11.1116	5	281,568	0.1799
Trans Canada - Seasonal	5,068	9.8894	5	250,597	0.1601
ProGas - Seasonal	5,068	0.9612	5	24,357	0.0156
ProGas Winter Surcharge	5,068	3.0049	5	76,144	0.0486
LMS Demand	2,500	1.0000	12	30,000	0.0192
Total Demand Charges				$3,569,809	2.2803
Estimated Weighted Average Commodity Cost	1,565,565 1/	3.9923		6,250,205	3.9923
Gas Cost Reconciliation Adjustment					(0.1857)
Total Current Firm Gas Cost				$9,820,014	6.0869
Base Cost of Gas					5.1849
Accumulated Adjustment					$0.9020

Interruptible	
Estimated Weighted Average Commodity Cost	$3.9923
Gas Cost Reconciliation Adjustment	(0.7309)
Total Current Interruptible Gas Cost	3.2614
Base Cost of Gas	5.1191
Accumulated Adjustment	($1.8577)

1/ Authorized in MN Docket No. G004/GR-04-1487 plus Wahpeton volumes.

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MARCH 2009

Rates Effective March 1, 2009	$/Dk	
FT-A - Zone 1-1	$3.4671	Per dk/Mo.
FT-A - Zone 1-2	4.5871	Per dk/Mo.
FT-A - Seasonal	3.7671	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
NOVA - Demand Charge	11.1116	Per dk/Mo.
Trans Canada Pipeline Demand Charge	9.8894	Per dk/Mo.
ProGas - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	11.1116	Per dk/Day
Trans Canada - Seasonal	9.8894	Per dk/Mo.
ProGas - Seasonal	0.9612	Per dk/Mo.
ProGas Winter Surcharge	3.0049	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	3.9923	Per dk

Base Rate Effective July 1, 1981		
Demand Charge	$0.8100	Per Mcf/Mo.
Commodity Charge	5.1191	Per Mcf

Base Rate Calculation		
Firm		
Demand 1/	$0.0658	Per Mcf
Commodity	5.1191	Per Mcf
Total Firm Base Cost	$5.1849	Per Mcf
Interruptible:		
Commodity	$5.1191	Per Mcf

1/ Demand base rate calculation: 4,768 X 12 X $0.8100 / 707,222

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
Category 1 (Contract Term of less than 3 Years)	
Monthly Reservation Rates	
FT-A	
Zone 1 - 1 Maximum Rate	$3.7671
Zone 1 - 1 Minimum Rate	$0.0000
Zone 1 - 2 Maximum Rate	$4.8871
Zone 1 - 2 Minimum Rate	$0.0000
Zone 2 - 2 Maximum Rate	$2.1400
Zone 2 - 2 Minimum Rate	$0.0000
Category 2 (Contract Term of 3 Years to less than 5 Years)	
Monthly Reservation Rates	
FT-A	
Zone 1 - 1 Maximum Rate	$3.6171
Zone 1 - 1 Minimum Rate	$0.0000
Zone 1 - 2 Maximum Rate	$4.7371
Zone 1 - 2 Minimum Rate	$0.0000
Zone 2 - 2 Maximum Rate	$1.9900
Zone 2 - 2 Minimum Rate	$0.0000
Category 3 (Contract Term of 5 or more Years)	
Monthly Reservation Rates	
FT-A	
Zone 1 - 1 Maximum Rate	$3.4671
Zone 1 - 1 Minimum Rate	$0.0000
Zone 1 - 2 Maximum Rate	$4.5871
Zone 1 - 2 Minimum Rate	$0.0000
Zone 2 - 2 Maximum Rate	$1.8400
Zone 2 - 2 Minimum Rate	$0.0000

Viking Gas Transmission Company
FERC Gas Tariff
First Revised Volume No. 1

Twenty-Fourth Revised Sheet No. 5B
Superseding
Twenty-Third Revised Sheet No. 5B

STATEMENT OF RATES
(Rates Per Dekatherm)

Rate Schedule	Base Tariff Rate	Adjustment Under Section 19 1/	Rate After Current Adjustment	Fuel and Loss Retention Percentages 2/
Commodity Rates				
FT-A - Maximum Rates				
Zone 1 - 1	$0.0130	$0.0017	$0.0147	1.95%
Zone 1 - 2	$0.0130	$0.0017	$0.0147	2.31%
Zone 2 - 2	$0.0130	$0.0017	$0.0147	0.36%
Minimum Rate	$0.0130	$0.0017	$0.0147	
IT and AOT				
Zone 1 - 1	$0.1368	$0.0017	$0.1385	1.95%
Zone 1 - 2	$0.1737	$0.0017	$0.1754	2.31%
Zone 2 - 2	$0.0834	$0.0017	$0.0851	0.36%
Minimum Rate	$0.0130	$0.0017	$0.0147	

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of $0.0017 per Dekatherm shall be added to other charges under Company's Rate Schedules.

2/ Fuel and Losses Retention Percentages shall be applicable to all transportation rate schedules.

Transportation Fuel and Loss Retention Percentages are inclusive of the following percentages for Gas Lost and Unaccounted For: .26% for Zone 1-1, .31% for Zone 1-2, and .05% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted For percentages.

STATEMENT OF RATES
(Rates Per Dekatherm)

Rate Schedule	Base Tariff Rate	Adjustment Under Section 27 1/	Rate After Current Adjustment
LMS - Monthly Demand Rate	$1.0000		$1.0000
LMS - Daily Overrun Rate	$0.1737		$0.1737
LMS - Load Management Cost Reconciliation Adjustment		($0.0286)	

1/ Pursuant to Section 27 of the General Terms and Conditions of this Tariff, a mechanism is established to reconcile through surcharges or credits to the Rate Schedule LMS rate, as appropriate, differences between the cost to maintain Company's line pack gas and the amounts Company receives or pays for such gas arising out of the purchase and sale of such gas.

Attachment B
Page 6 of 7

RATE SCHEDULE TF

RESERVATION RATES	MARKET-TO-MARKET TF12 Base	TF12 Variable	TF5	FIELD-TO-FIELD/MARKET DEMARCATION TFF
Base Tariff Rates 1/				
Summer (Apr-Oct)	5.683	5.683	-0-	5.473
Winter (Nov-Mar)	10.230	13.866	15.153	9.853

COMMODITY RATES 2/ TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0379	0.0210			0.0175	0.0000	0.0379	0.0210
Field	Market	0.0379	0.0210	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0293	0.0107

1/ The minimum reservation rate is equal to zero.
2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs.
3/ Maximum and Minimum rates include ACA of $0.0017 and the Market Area Electric Compression charge of $0.0003 where applicable.
4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
5/ Where Applicable, Field Area Electric Compression charge of $0.0000 and ACA will be added to the mileage based rates.

RATE SCHEDULES TFX and LFT

Attachment B
Page 7 of 7

RESERVATION RATES	MARKET-TO-MARKET Apr-Oct	MARKET-TO-MARKET Nov-Mar	FIELD-TO-FIELD Apr-Oct	FIELD-TO-FIELD Nov-Mar
Base Tariff Rates 1/	$5.683	$15.153	$5.473	$9.853

COMMODITY RATES 2/ TFX and LFT		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0379	0.0210			0.0175	0.0000	0.0379	0.0210
Field	Market	0.0379	0.0210	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0293	0.0107

GULF COAST	Reservation 1/ Maximum	Reservation 1/ Minimum	Commodity 6/ Maximum	Commodity 6/ Minimum	Out-of-Balance 6/ Maximum	Out-of-Balance 6/ Minimum
MOPS Gathering	1.0514	0.0000	0.0017	0.0017	0.0017	0.0017
MOPS Transmission	1.5337	0.0000	0.0017	0.0017	0.0017	0.0017
Tivoli - Downstream	0.6827	0.0000	0.0017	0.0017	0.0017	0.0017
Other Gulf Coast	4.8169	0.0000	0.0017	0.0017	0.0017	0.0017

1/ The minimum reservation rate is equal to zero.
2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs.
3/ Maximum and Minimum rates include ACA of $0.0017 and the Market Area Electric Compression charge of $0.0003 where applicable.
4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
5/ Where applicable, Field Area Compression charge of $0.0000 and ACA will be added to the mileage based rates.
6/ Maximum and Minimum rates include ACA of $0.0017.

Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
March 2009

The principal gas sources of natural gas for Wahpeton, North Dakota are from the large Western Canadian Sedimentary Basin (WCSB). The pricing point for much of this gas is the Alberta Energy Company (AECO-C), one of the largest and most liquid volume points in North America. The March monthly price for the AECO Index is expected to decrease from the previous month. The AECO Index is based on the weighted average one month spot price at AECO-C and Nova Inventory Transfer (N.I.T.) as reported by Natural Gas Exchange (NGX).

In addition to increased onshore natural gas production this year and relatively high levels of working gas in storage, key factors contributing to natural gas prices include a lower level of industrial demand for natural gas as a result of the ongoing economic downturn and relatively low crude oil prices. Moderating temperatures, easing heating demand, also likely contributed to the price decline. The Energy Information Administration (EIA) reported storage levels nationwide as of January 23, 2009 were 11.7 percent above the five-year average and 14.0 percent above last year's balance.

The Department of Energy's (DOE) Energy Information Administration (EIA) provides various publications on energy issues. The information is available on the DOE website: http://www.eia.doe.gov.

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 11.

www.eia.doe.gov
Energy Information Administration

February 2009

Short-Term Energy Outlook

February 10, 2009 Release

Highlights

- U.S. real gross domestic product (GDP) is expected to decline by 2.7 percent in 2009, triggering decreases in domestic energy consumption for all major fuels. Economic recovery is projected to begin in 2010, with 2.2 percent year-over-year growth in GDP. Accompanying the projected economic recovery should be a mild rebound in energy consumption for all the major fuels in 2010.

- Over the past 6 months, the monthly average price of West Texas Intermediate (WTI) crude oil fell from $133 per barrel in July to $41 in December and January. WTI prices are projected to average $43 per barrel in 2009 and $55 in 2010, unchanged from last month's *Outlook.*

- The U.S. price for regular gasoline averaged $1.69 per gallon in December 2008, the lowest monthly average since February 2004 and down nearly $2.40 per gallon from the monthly peak seen last July. Gasoline prices have been slowly increasing over the last 6 weeks as crude oil prices have stabilized and refiner margins have recovered from their recent near-historic lows. Retail gasoline prices are projected to average $1.95 per gallon in 2009 and $2.19 per gallon in 2010.

- The U.S. economic downturn is also contributing to a decline in natural gas consumption, particularly in the industrial sector, which has led to lower natural gas prices. The Henry Hub natural gas spot price is projected to decline from an average of $9.13 per thousand cubic feet (Mcf) in 2008 to about $5 per Mcf in 2009, but then increase in 2010 to an average of almost $6 per Mcf.

Global Petroleum

Overview. The worsening global economy and a weak oil consumption outlook are keeping the world oil market well supplied, despite two downward revisions in production targets by the Organization of the Petroleum Exporting Countries (OPEC) within the past few months. Lower global oil demand and rising surplus production capacity through at least mid-year 2009 reduce the possibility for a strong and sustained rebound in oil prices over that period. OPEC is scheduled to meet in Vienna on March 15, which could lead to another production cut to mitigate some of the slack in the world oil market. However, near-month oil prices will likely be driven primarily by the global economy. Global real gross domestic product (GDP, weighted according to shares of world oil consumption) is assumed to decline by 0.1 percent in 2009 and rise by 3.0 percent in 2010, versus last month's assessment of 0.6-percent growth in real GDP in 2009 and 3.0-percent growth in 2010.

Consumption. World oil consumption is projected to fall by 1.2 million barrels per day (bbl/d) in 2009, representing an additional decline of 400,000 bbl/d from last month's *Outlook*. World oil consumption is expected to rebound in 2010, growing by more than 1.2 million bbl/d, due to an expected recovery in the global economy. Oil consumption growth over the next 2 years is concentrated in countries outside of the Organization for Economic Cooperation and Development (OECD), particularly China, the Middle East, and Latin America, offsetting projected declines in OECD oil consumption (World Oil Consumption). If the world economy recovers sooner than EIA now anticipates, oil consumption could be higher than expected, putting upward pressure on oil prices.

Non-OPEC Supply. Non-OPEC oil supply is expected to grow by 150,000 bbl/d in 2009 and 130,000 bbl/d in 2010. The expected growth in non-OPEC supply over the next 2 years comes in stark contrast to the 330,000-bbl/d decline seen in 2008, which was the result of longer-than-expected delays in key projects, larger-than-expected decline rates in mature basins, and supply disruptions in the Gulf of Mexico and Central Asia. The largest sources of growth over the forecast period are the United States, Brazil, and Azerbaijan, offset by large declines in production in Mexico, the North Sea, and Russia. The expected decline in Russian output in 2009 (-160,000 bbl/d) is especially noteworthy. Russian oil production grew by 3 million bbl/d from 2000 through 2007, representing 75 percent of total non-OPEC oil production growth over that period.

There are downside risks to the outlook for non-OPEC supply, as additional project delays are certainly possible given the financial crisis and the current price environment. Sustained lower oil prices bring into doubt the viability of some high-cost non-OPEC projects, especially those utilizing nonconventional technology or those seeking to exploit frontier oil basins. The credit crunch associated with the global economic crisis can also make it difficult to acquire financing for new projects or even to finance the investment required to prevent accelerated declines at producing fields. EIA's forecast reflects an attempt to account for some of these potential delays.

OPEC Supply. OPEC producers are cutting crude production targets in response to lower prices and eroding consumption. Estimated OPEC crude oil production fell by 1 million bbl/d during the fourth quarter of 2008, reaching 30.7 million bbl/d. OPEC crude oil production is expected to fall by an additional 1.6 million bbl/d in the first quarter of 2009 to 29.1 million bbl/d, the lowest level in 5 years, largely resulting from lower production in Saudi Arabia. The decline of 2.6 million bbl/d over this period represents nearly two-thirds of the 4.2-million-bbl/d cut in OPEC's production target announced at its December meeting. For the year, OPEC crude oil production is expected to average 29.4 million bbl/d, then rise to 30.1 million bbl/d in 2010. In addition, EIA expects that OPEC production of non-crude liquids will rise substantially next year, growing by 660,000 bbl/d in 2009 and by 870,000 bbl/d in 2010, due to increasing condensate and natural gas production.

The combination of lower demand for OPEC crude oil, increasing production of non-crude liquids, and the capacity expansions expected in several OPEC countries means that surplus production capacity could increase dramatically over the next 2 years. OPEC surplus production capacity could average 4.3 million bbl/d in 2009, eventually exceeding 5 million bbl/d by the end of 2010. By comparison, OPEC surplus production capacity ranged from 1 to 2 million bbl/d over the past 5 years (OPEC Surplus Oil Production Capacity). The lack of surplus production capacity was a crucial factor during the run-up in oil prices through the first half of 2008. If OPEC does hold 4 to 5 million bbl/d of surplus production capacity over the next 2 years, this could act to cushion the world oil market and help mitigate the price effect of perceived or actual supply disruptions.

Inventories. Preliminary data indicate that OECD commercial inventories stood at 2.58 billion barrels at the end of 2008, equivalent to 52 days of forward cover (Days of Supply of OECD Commercial Stocks), above average levels for that time of year. Measured as days of forward cover, OECD commercial inventories are projected to remain above average levels through the end of 2010. High crude inventories in some markets, along with a growing use of floating storage, are signs that the oil market is well supplied. Along with ample OPEC surplus production capacity, high commercial inventories should help mitigate any strong upward price pressures.

U.S. Petroleum

Consumption. Total petroleum products consumption in 2008 declined by almost 1.2 million bbl/d, or 5.8 percent, from the 2007 average, the largest annual decline since

1980 (U.S. Petroleum Products Consumption Growth). The major factors behind the fall in consumption were a rapid rise in retail prices to record levels during the first half of 2008 followed by a weakening economy in the second half. Motor gasoline consumption in 2008 declined by 320,000 bbl/d, or 3.4 percent. Despite the cold weather that gripped much of the Lower-48 States in December, distillate fuel consumption in 2008 fell by 5.4 percent from the previous year as a result of precipitous declines in transportation consumption of diesel fuel. Major reductions in airline capacity during the fourth quarter contributed to the 100,000-bbl/d, or 6.2-percent, drop in jet fuel consumption. Total petroleum products consumption in 2009 is projected to fall by a further 460,000 bbl/d, or 2.4 percent, because of continued economic weakness. Consumption of both motor gasoline and distillate fuel are projected to decline by about 100,000 bbl/d each. Jet fuel is forecast to fall by a further 60,000 bbl/d. The expected economic recovery in 2010 is projected to boost total petroleum products consumption by 220,000 bbl/d, or 1.1 percent.

Production. In 2008, domestic crude oil production averaged 4.95 million bbl/d, down by 110,000 bbl/d from 2007 (U.S. Crude Oil Production). However, in 2009, domestic output is projected to increase by about 400,000 bbl/d to an average of 5.35 million bbl/d. This would be the first increase in production since 1991. Output is projected to rise by a further 130,000 bbl/d in 2010. Contributing to the increases in output are the Gulf of Mexico Thunder Horse platform, which is coming on stream now, and the Tahiti platform, expected to come on stream later this year.

Prices. WTI prices averaged almost $100 per barrel in 2008, with daily spot prices ranging from almost $150 per barrel in early July to about $30 per barrel towards the end of the year. Under current economic and world crude oil supply assumptions, WTI prices are expected to average $43 per barrel in 2009 and $55 per barrel in 2010 (Crude Oil Prices). The possibility of a milder recession or faster economic recovery, lower non-OPEC production because of the current low oil prices and financial market constraints, and more aggressive action to lower production by OPEC countries could lead to a faster and stronger recovery in oil prices.

Regular-grade gasoline prices are projected to average $1.95 per gallon in 2009 and $2.19 per gallon in 2010. Because of lower motor gasoline consumption, refining margins for gasoline are expected to remain low for much of 2009 but are expected to increase slightly in 2010 as consumption begins to recover.

On-highway diesel fuel retail prices, which averaged $3.79 per gallon in 2008, are projected to average $2.28 per gallon in 2009 and $2.55 in 2010. The expected continuation of the decline in diesel fuel consumption in the United States this year as well as a slowing of the growth in distillate fuel usage outside the United States are projected to result in a narrowing of refining margins for distillate throughout the forecast.

Natural Gas

Consumption. Total natural gas consumption is projected to decline by 1.3 percent in 2009 and then increase by 0.6 percent in 2010 (Total U.S. Natural Gas Consumption Growth). The expectation of limited weather-driven consumption growth in the residential and commercial sectors in 2009 is outweighed by the implications of continued economic weakness in the industrial and electric power sectors. Consumption in the industrial and electric power sectors is expected to decline by 5.1 and 1.0 percent, respectively, in 2009. Consumption growth in 2010 remains largely dependent upon the timing and pace of economic recovery. Based on current assumptions, 2.2-percent growth in the electric power sector combined with slight growth in the residential and industrial sectors are all expected to contribute to 2010 consumption growth.

Production and Imports. Total U.S. marketed natural gas production is expected to rise slightly in 2009 and fall by 1.1 percent in 2010. The dramatic decline in drilling activity, as total working natural gas rigs have declined by more than 31 percent since August 2008, is expected to contribute to lower production during the second half of 2009. Despite the cutback in drilling activity, the current outlook suggests that some production curtailments may be necessary during the latter part of 2009 in order to balance the market. Nevertheless, this year's marketed production from the Lower-48 non-Gulf of Mexico (GOM) is expected to increase by 1.1 percent due to the low operating cost of wells currently in use and the lagged effect of aggressive drilling programs during the latter part of 2008. In contrast, the natural decline in production from existing fields and long-term decline in drilling activity are expected to lead to a 6.4-percent decrease in production in the Federal GOM this year. In 2010, annual production is projected to decline relative to 2009 in the Federal GOM and Lower-48 non-GOM by 6.3 and 0.6 percent, respectively.

U.S. imports of liquefied natural gas (LNG) are expected to reach about 369 billion cubic feet (Bcf) in 2009, a slight increase over the volume received in 2008. Shipments of LNG to the United States this year will be affected by the timing of supply additions in Russia, Norway, Qatar, and Yemen and the status of global natural gas inventories in LNG-consuming regions. In 2010, U.S. LNG imports are projected to be about 463 Bcf.

Inventories. On January 30, 2009, working natural gas in storage was 2,179 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 17 Bcf above the 5-

year average (2004–2008) and 60 Bcf above the level during the corresponding week last year. Storage inventories are expected to finish the 2009 withdrawal season (March 31, 2009) at about 1.5 trillion cubic feet (Tcf), roughly 100 Bcf above the previous 5-year average for that time. This fall, inventories are expected to approach the previous high of 3,565 Bcf recorded at the end of October 2007.

Prices. The Henry Hub spot price averaged $5.40 per Mcf in January, $0.60 per Mcf below the average December spot price. For all of 2008, the Henry Hub spot price averaged $9.13 per Mcf. Despite colder-than-normal weather last month, prices continued downward in response to the ongoing drop in natural gas demand. Natural gas prices in 2009 are expected to be largely driven by the extent of the supply response to the persistence of sluggish consumption in light of the current economic downturn. Prices are expected to remain weak as inventories build toward capacity this fall. A warmer summer or faster economic recovery than anticipated could push consumption and prices higher than expected. Prices are projected to recover in 2010 as economic growth contributes to an increase in demand. The Henry Hub spot price is expected to average $5.01 per Mcf in 2009 and $5.93 per Mcf in 2010.

Electricity

Consumption. Total electricity consumption is projected to decline by 0.8 percent in 2009 (U.S. Total Electricity Consumption), including an expected decline of nearly 5 percent in industrial sector electricity sales. Total electricity consumption is expected to grow by 1.3 percent in 2010 as economic recovery boosts sales of electricity to the residential and commercial sectors.

Prices. Residential electricity prices, which increased by an estimated 6.5 percent last year, are projected to rise at lower-than-normal annual rates of about 2 percent in 2009 and 2010 (U.S. Residential Electricity Prices). Industrial electricity prices are expected to increase by just 1 percent in 2009 after having grown by 10 percent last year.

Coal

Consumption. Coal consumption in the electric-power-sector grew by 1.3 percent during the first half of 2008, but a significant decline in the second half of 2008 caused annual electric-power-sector coal consumption to fall by 0.5 percent in 2008. The economic slowdown in 2009 will lead to a decline in electricity consumption, and this factor combined with projected increases from other generation sources (nuclear, petroleum, and wind) will lead to a 1.2-percent decline in electric-power-sector coal consumption. An expected increase in electricity consumption of 1.3 percent in 2010 will lead to a 1.8-percent increase in electric-power-sector coal consumption.

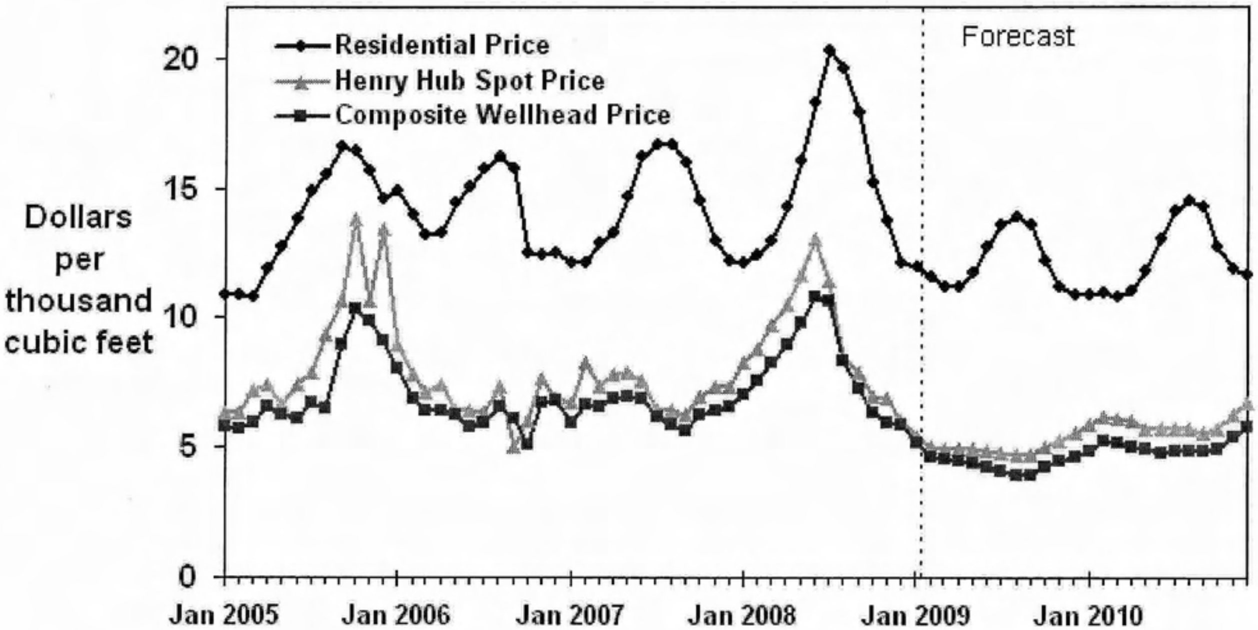
Consumption growth in the coke plant sector is estimated to have been flat in 2008 but is expected to fall by 11 percent in 2009 and by 5.7 percent in 2010 due to the economic slowdown. Retail and other industrial sector coal consumption is estimated to have declined by 2.2 percent in 2008 and is expected to decline by an additional 13.8 percent in 2009. Retail and other industrial sector coal consumption growth is projected to be 3.5 percent in 2010 (U.S. Coal Consumption Growth).

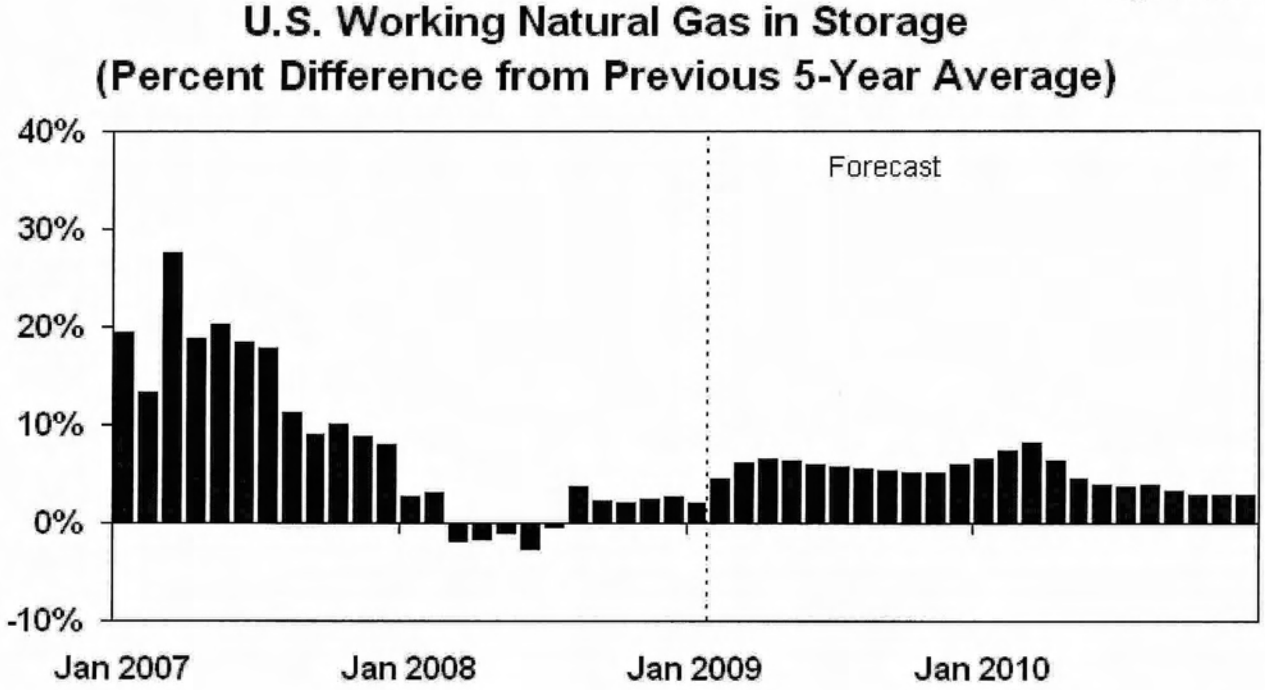
Production. A significant increase in coal exports in 2008 contributed to a 2.1-percent increase in coal production. Production is expected to fall by 4.4 percent in 2009 as lower total domestic coal consumption is combined with declines in exports and an increase in imports. Production is projected to increase by 2.5 percent in 2010 as domestic consumption and exports increase with an improving economy (U.S. Annual Coal Production).

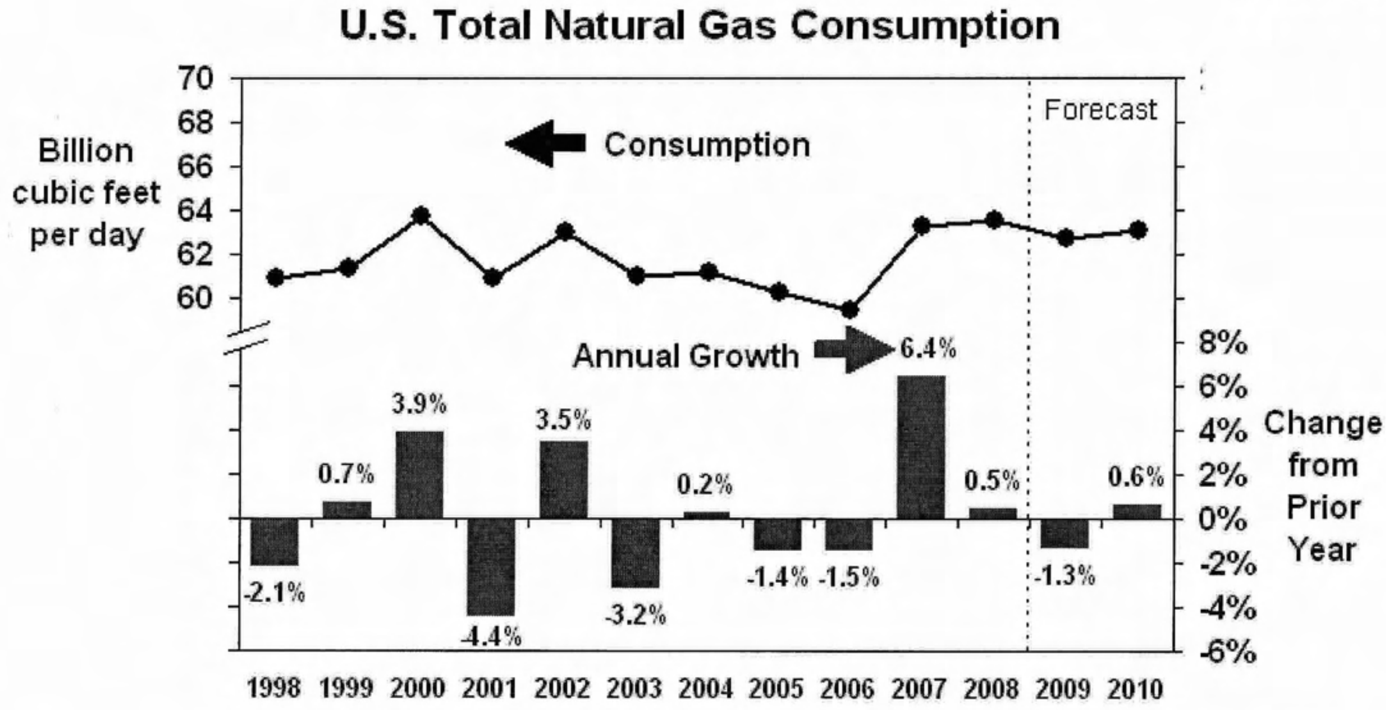
Exports. Strong global demand for coal and supply disruptions in several key coal-exporting countries (Australia, South Africa, and China), spurred a 38-percent increase in U.S. coal exports in 2008. Reductions in global coal demand, coupled with the return to normal supply conditions in other major coal-producing and exporting countries, are expected to reduce U.S. coal exports by about 10 million short tons, a 11.7-percent decrease, in 2009. The improving global economy will spur global coal demand in 2010 and this will lead to a projected 12-percent increase in exports.

Prices. Despite record increases (some well over 100 percent) in spot prices for several types of coal, the average delivered coal price to the electric power sector is estimated to have increased by 16 percent in 2008. Although the rise in spot prices did contribute to the increase in the cost of coal delivered to the electric power, the rise in transportation costs was the primary reason for the cost increase. Declines in electricity demand and lower transportation costs should see the delivered coal price remain flat in 2009. The delivered coal price to the electric power sector is projected to increase by 1.3 percent in 2010 to $2.09 per million British thermal units.

Natural Gas Prices




U.S. Working Natural Gas in Storage
(Percent Difference from Previous 5-Year Average)
40%
30%
20%
10%
0%
-10%
Forecast
Jan 2007
Jan 2008
Jan 2009
Jan 2010


U.S. Total Natural Gas Consumption
Billion cubic feet per day
70
68
66
64
62
60
Forecast
Consumption
Annual Growth
6.4%
3.9%
3.5%
0.7%
0.2%
0.5%
0.6%
-2.1%
-4.4%
-3.2%
-1.4%
-1.5%
-1.3%
8%
6%
4%
2%
0%
-2%
-4%
-6%
Change from Prior Year
1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010

GREAT PLAINS NATURAL GAS CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
APPLICABLE TO NORTH DAKOTA
FIRM

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2008									**($46,836)**
May	($7,154)	$0	($671)	($7,825)	17,007	$0.7009	$11,920	($19,745)	(66,581)
June	25,399	0	(868)	24,531	9,026	(0.1857)	(1,676)	26,207	(40,374)
July	12,556	0	(565)	11,991	6,909	(0.1857)	(1,283)	13,274	(27,100)
August	47,784	0	(408)	47,376	5,577	(0.1857)	(1,036)	48,412	21,312
September	26,255	0	135	26,390	6,028	(0.1857)	(1,119)	27,509	48,821
October	13,043	0	440	13,483	8,294	(0.1857)	(1,540)	15,023	63,844
November	16,133	0	605	16,738	18,404	(0.1857)	(3,418)	20,156	84,000
December	(4,149)	(2,340) 2/	829	(5,660)	34,013	(0.1857)	(6,316)	656	84,656
January 2008	(35,023)	0	840	(34,183)	55,308	(0.1857)	(10,271)	(23,912)	60,744
Balance @ January 31, 2009.									**$60,744**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ December 2008 Northern Natural Gas refund.

GREAT PLAINS NATURAL GAS CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2008									**($111,189)**
May	($7,255)	$0	($1,155)	($8,410)	8,115	$0.1814	$1,472	($9,882)	(121,071)
June	(7,516)	0	(1,252)	(8,768)	7,134	(0.7309)	(5,214)	(3,554)	(124,625)
July	(44,216)	0	(1,282)	(45,498)	11,473	(0.7309)	(8,386)	(37,112)	(161,737)
August	(2,975)	0	(1,685)	(4,660)	8,162	(0.7309)	(5,966)	1,306	(160,432)
September	(10,606)	0	(1,655)	(12,261)	8,741	(0.7309)	(6,389)	(5,872)	(166,304)
October	(6,575)	0	(1,707)	(8,282)	12,016	(0.7309)	(8,782)	500	(165,804)
November	4,717	0	(1,689)	3,028	19,205	(0.7309)	(14,037)	17,065	(148,739)
December	(1,569)	(3) 2/	(1,492)	(3,064)	12,982	(0.7309)	(9,489)	6,425	(142,314)
January 2008	339		(1,410)	(1,071)	10,874	(0.7309)	(7,948)	6,877	(135,437)
Balance @ January 31, 2009.									**($135,437)**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ December 2008 Northern Natural Gas refund.