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

705 West Fir Ave.
PO Box 176
Fergus Falls, MN 56538-0176
(218) 736-6935

ORIGINAL

October 1, 2009

RECEIVED
OCT 0 2 2009
PUBLIC SERVICE COMMISSION

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

Re: Cost of Gas Adjustment (COG)
October 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 (43rd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (43rd Revised Sheet No. 8), showing the October 2009 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $0.4130 per mcf for residential and firm general service customers and $0.3525 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for October 2009, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $0.3525 per mcf since the last COG filing due to an increase in the market price of gas. There has been an increase in pipeline charges of $0.0605 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of $0.4130 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, 2009.

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

Attachment A

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

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	$5.7265	$7.0005
			Over 10 MCF	1.0540		6.7805
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$2.2420	$3.3811
			Next 2,600 MCF	0.8931		3.1351
			Over 3,000 MCF	0.7411		2.9831
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$2.2420	$3.4811
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

Date Filed: **October 1, 2009**

Effective Date: **October 1, 2009**

Issued By: Donald R. Ball
Vice President - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
43rd Revised Sheet No. 8
Canceling 42nd 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.	2.3820	(2.4877)	0.2343	0.1286	(2.4877)	(0.7419)	(3.2296)
Current Adj.	0.0605	0.3525	0.0000	0.4130	0.3525	0.0000	0.3525
Total Adj.	2.4425	(2.1352)	0.2343	0.5416	(2.1352)	(0.7419)	(2.8771)
Total Rate:	$2.5083	$2.9839	$0.2343	$5.7265	$2.9839	($0.7419)	$2.2420

Date Filed: October 1, 2009 **Effective Date:** October 1, 2009

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

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
OCTOBER 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	12.6338	12	1,204,810	0.7696
Trans Canada - Demand Charge	7,947	11.3155	12	1,079,091	0.6893
ProGas - Demand Charge	7,947	0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068	12.6338	5	320,140	0.2045
Trans Canada - Seasonal	5,068	11.3155	5	286,735	0.1832
ProGas - Seasonal	5,068	0.9612	5	24,357	0.0156
ProGas Winter Surcharge	5,068	3.0417	5	77,077	0.0492
LMS Demand	2,500	1.0000	12	30,000	0.0192
Total Demand Charges				$3,926,613	2.5083
Estimated Weighted Average Commodity Cost	1,565,565 1/	2.9839		4,671,489	2.9839
Gas Cost Reconciliation Adjustment					0.2343
Total Current Firm Gas Cost				$8,598,102	5.7265
Base Cost of Gas					5.1849
Accumulated Adjustment					$0.5416

Interruptible	
Estimated Weighted Average Commodity Cost	$2.9839
Gas Cost Reconciliation Adjustment	(0.7419)
Total Current Interruptible Gas Cost	2.2420
Base Cost of Gas	5.1191
Accumulated Adjustment	($2.8771)

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

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

Rates Effective October 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	12.6338	Per dk/Mo.
Trans Canada Pipeline Demand Charge	11.3155	Per dk/Mo.
ProGas - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	12.6338	Per dk/Day
Trans Canada - Seasonal	11.3155	Per dk/Mo.
ProGas - Seasonal	0.9612	Per dk/Mo.
ProGas Winter Surcharge	3.0417	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	2.9839	Per dk

Base Rate Effective September 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

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

Twelfth Revised Sheet No. 5
Superseding
Eleventh Revised Sheet No. 5

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

Issued by: Raymond D. Neppl, Vice President
Issued on: November 29, 2005 Effective on: January 1, 2006
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP02-132-002, issued November 8, 2002, 01 FERC ¶ 61,170

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	$0.0019	$0.0149	0.64%
Zone 1 - 2	$0.0130	$0.0019	$0.0149	0.89%
Zone 2 - 2	$0.0130	$0.0019	$0.0149	0.25%
Minimum Rate	$0.0130	$0.0019	$0.0149	
IT and AOT				
Zone 1 - 1	$0.1368	$0.0019	$0.1387	0.64%
Zone 1 - 2	$0.1737	$0.0019	$0.1756	0.89%
Zone 2 - 2	$0.0834	$0.0019	$0.0853	0.25%
Minimum Rate	$0.0130	$0.0019	$0.0149	

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of $0.0019 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: .05% for Zone 1-1, .07% for Zone 1-2, and .02% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted For percentages.

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

Fourteenth Revised Sheet No. 5C
Superseding
Thirteenth Revised Sheet No. 5C

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		$0.0080	

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.

Issued by: J. Phill May, Vice President Commercial
Issued on: February 20, 2009 Effective on: April 1, 2009

RATE SCHEDULE TF

RESERVATION RATES	MARKET-TO-MARKET TF12 Base	MARKET-TO-MARKET TF12 Variable	MARKET-TO-MARKET 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	0.0381	0.0212			0.0175	0.0000	0.0381	0.0212
Field	Market	0.0381	0.0212	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0295	0.0109

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 $0.0019 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

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	0.0381	0.0212			0.0175	0.0000	0.0381	0.0212
Field	Market	0.0381	0.0212	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0295	0.0109

GULF COAST	Reservation 1/		Commodity 6/		Out-of-Balance 6/	
	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
MOPS Gathering	1.0514	0.0000	0.0019	0.0019	0.0019	0.0019
MOPS Transmission	1.5337	0.0000	0.0019	0.0019	0.0019	0.0019
Tivoli - Downstream	0.6827	0.0000	0.0019	0.0019	0.0019	0.0019
Other Gulf Coast	4.8169	0.0000	0.0019	0.0019	0.0019	0.0019

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 $0.0019 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 $0.0019.

Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
October 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 October monthly price for the AECO Index is expected to increase from the previous month index. 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).

Reports from the U.S. Department of Commerce showing improved retail sales and a report from the Federal Reserve showing improved levels of industrial production likely were factors in the improved outlook. The AECO index price for October 2009 is expected to be approximately 50 percent less than the October 2008 price of $5.88. The Energy Information Administration (EIA) reported storage levels nationwide as of September 18, 2009 were 16.0 percent above the five-year average and 16.9 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

September 2009

Short-Term Energy Outlook

September 9, 2009 Release

Highlights

- Volatility persists for crude oil spot prices, although over narrower ranges than seen earlier this year and last year. EIA expects the price of West Texas Intermediate (WTI) crude oil to average about $70 per barrel in the fourth quarter of 2009, a $27-increase over the first quarter of the year. The forecast for average WTI prices rises gradually to about $75 per barrel by December 2010 as world economic conditions improve.

- EIA expects the monthly average regular-grade gasoline retail price to fall from $2.62 per gallon in August and September to an average of $2.56 per gallon over the fourth quarter of 2009. Higher crude oil prices next year contribute to an increase in the annual average gasoline retail price from $2.34 per gallon in 2009 to $2.70 in 2010. Projected annual average diesel fuel retail prices are $2.47 and $2.88 per gallon in 2009 and 2010, respectively.

- EIA projects the monthly Henry Hub natural gas spot price to average $2.32 per thousand cubic feet (Mcf) in October, the lowest monthly average spot price since September 2001. Natural gas inventories likely will set a new record high at the end of this year's injection season (October 31) reaching more than 3.8 trillion cubic feet (Tcf). The projected Henry Hub annual average spot price increases from $3.65 per Mcf in 2009 to $4.78 in 2010. However, upward price pressure next year is limited by the sensitivity of natural gas use in the electric power sector to higher natural gas prices and continued expansion of U.S. natural gas production from shale formations.

- EIA expects electricity retail prices to show year-over-year declines next year for the first time since early 2003 because of lower fossil fuel costs for generation. The projected annual average 2010 residential electricity price of 11.4 cents per kilowatthour is about 2 percent lower than the 2009 average.

Global Petroleum

Global Petroleum Overview. WTI oil prices hovered in the $67-to-$74-per-barrel range in August as expectations of an economic recovery and higher oil consumption in the future were weighed against weak current demand and high inventories. As long as oil prices remain in their current range, EIA expects the Organization of the Petroleum Exporting Countries (OPEC) to maintain its existing production targets.

Global Petroleum Consumption. Preliminary data indicate that global oil consumption declined by 3 million barrels per day (bbl/d) in the second quarter of 2009 compared with year-earlier levels. Members of the Organization for Economic Cooperation and Development (OECD) accounted for most of the decline; total non-OECD consumption was virtually unchanged. The current macroeconomic outlook assumes that the world economy begins to recover at the end of this year, led by non-OECD Asia. As a result, EIA expects world oil consumption to grow in the fourth quarter of 2009 compared with year-earlier levels, the first such growth in 5 quarters. Projected world oil consumption grows by 0.9 million bbl/d in 2010, with relatively strong growth in non-OECD countries being partially offset by a slight decline in OECD consumption (World Liquid Fuels Consumption Chart).

Non-OPEC Supply. Total non-OPEC supply averaged 50.1 million bbl/d in the second quarter of 2009, about 0.3 million bbl/d higher than in the second quarter of 2008. The largest amount of growth came from Central and South America (0.3 million bbl/d) and the Former Soviet Union (0.3 million bbl/d), which was offset by a 0.3 million bbl/d decline in Europe. Over the forecast period, higher output from Brazil, the United States, Azerbaijan, Kazakhstan, and Canada offsets falling production in Mexico and the North Sea (Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart).

OPEC Supply. OPEC crude oil production was 28.7 million bbl/d in the second quarter of 2009, similar to first quarter levels, but down 3 million bbl/d from peak production in the third quarter of 2008. The combination of higher prices and OPEC's historical tendency for weaker compliance with production targets over time (see *This Week in Petroleum*, August 12, 2009) suggests that OPEC crude oil production could rise over the remainder of the year, unless prices fall sharply from current levels. Projected OPEC crude oil production climbs to 29.3 million bbl/d in the second half of 2009, then averages 28.9 million bbl/d in 2010.

Global Petroleum Inventories. Based on preliminary data, OECD commercial oil inventories stood at 2.74 billion barrels at the end of the second quarter of 2009. At 61 days of forward cover, OECD commercial inventories were well above average levels for that time of year (Days of Supply of OECD Commercial Stocks Chart). EIA expects OECD oil inventories to remain at above-average levels throughout the forecast period because of weakness in global oil consumption and continuing contango in the futures market, i.e., relatively high future prices compared with current prices.

Crude Oil Prices. Equity-market and exchange-rate expectations continue to be cited by market analysts as proximate causes of oil-price behavior, in addition to changing expectations of global oil consumption growth. EIA projects that WTI crude oil prices will average $69 per barrel in the second half of 2009, $19 per barrel lower than in the second half of 2008 (Crude Oil Prices Chart). This projection is largely unchanged from last month's *Outlook* and reflects the view that an expected economic upturn will restore oil demand growth and gradually work off the surplus oil inventories. Although a consensus seems to be forming that the global economic downturn may have bottomed out, there still remains considerable uncertainty regarding the timing and pattern of any economic recovery.

U.S. Crude Oil and Liquid Fuels

U.S. Petroleum Consumption. EIA forecasts total consumption of liquid fuels and other petroleum products to decrease by about 800,000 bbl/d (4 percent) in 2009 (U.S. Petroleum Products Consumption Growth Chart) compared with 2008. During the first half of the year, consumption declined by almost 1.25 million barrels per day (6.3 percent) from the same period last year, one of the steepest declines on record. The year-over-year projected decline in petroleum consumption slows to 300,000 barrels per day (1.6 percent) in the second half of 2009 as economic recovery begins to take hold. Monthly average motor gasoline consumption in June showed an increase over the same month from the prior year for the first time since September 2007 and continues to grow over year-ago levels through the forecast. The modest economic recovery projected for 2010 contributes to a 260,000-bbl/d (1.4 percent) increase in total liquid fuels consumption, led by increases of 110,000 bbl/d (2.9 percent) in distillate consumption, 60,000 bbl/d (0.6 percent) in motor gasoline consumption, and 10,000 bbl/d (0.7 percent) in jet fuel consumption.

U.S. Petroleum Supply. EIA projects total U.S. crude oil production to average 5.24 million barrels per day in 2009 and increase to an average of 5.30 million bbl/d in 2010 (U.S. Crude Oil Production Chart). Crude oil production from the new Thunder Horse, Tahiti, Shenzi, and Atlantis Federal offshore fields accounts for about 14 percent of Lower-48 crude oil production in the fourth quarter of 2010.

U.S. Petroleum Product Prices. EIA expects the monthly average regular-grade gasoline retail price to fall from $2.62 per gallon in August and September to an average $2.56 per gallon over the last 3 months of the year. Higher projected crude oil prices in 2010 (about $12 per barrel, or 29 cents per gallon, higher than the 2009 average) increase regular-grade gasoline prices to an average of $2.70 per gallon next year. Projected diesel fuel retail prices, which averaged $2.63 per gallon in August, increase over the next few months to average $2.74 during the fourth quarter of 2009 as the winter heating fuel season begins.

Natural Gas

U.S. Consumption. EIA projects that total natural gas consumption will likely decline by 2.4 percent in 2009 and remain flat in 2010 (Total U.S. Natural Gas Consumption Growth Chart). Despite low relative prices for much of the year, industrial natural gas consumption declined by 12 percent in the first 6 months of 2009 compared with the same period last year. EIA expects this year-over-year consumption decline will continue through the second half of the year for industrial users, although the trend will be less pronounced. Conversely, EIA expects natural gas use in the electric power sector will increase by 4.3 percent on a year-over-year basis during the second half of 2009 as natural gas continues to compete with coal for a share of the baseload power supply at current prices.

EIA expects natural gas consumption will increase slightly in the commercial and industrial sectors in 2010 as a result of improved economic conditions and low prices. Consumption remains relatively flat in the residential and electric power sectors next year. The anticipated addition of new coal-fired generating capacity and rising natural gas prices limits the potential for significant increases beyond the forecast 2009 level in natural gas consumption by electric generators.

U.S. Production and Imports. EIA expects total U.S. marketed natural gas production to increase by 0.9 percent in 2009 and fall by 3.5 percent in 2010. Despite a 20-percent drop in prices and a 45-percent drop in working natural gas drilling rigs since the start of the year, total natural gas production increased slightly from January to June 2009. This current production trend reflects significant improvements in horizontal drilling technology and robust productivity from shale gas discoveries in Louisiana, Oklahoma, Arkansas, and Pennsylvania. While lower prices have caused a reduction in drilling activity by all rig types, according to data compiled by Smith International, working horizontal rigs have fallen by only 27 percent since the start of the year compared with a 65-percent decrease among vertically-directed rigs. Working horizontal drilling rigs now represent more than half of the active natural gas drilling fleet.

As U.S. natural gas inventories swell to record-high levels, some curtailment of production is expected. The sustained reduction in drilling activity and production curtailments are projected to result in a 5.7-percent decline in marketed production from the Lower-48 non-Gulf of Mexico (GOM) between the first and second half of the year. The projected 1.3-percent increase in Federal GOM production during the second half of 2009 over the first half results from the addition of new producing wells and continued recovery from damage sustained during last year's hurricane season.

Projected U.S. liquefied natural gas (LNG) imports increase to about 460 billion cubic feet (Bcf) in 2009 from 350 Bcf in 2008 and rise to about 660 Bcf in 2010. Maintenance to existing LNG supply facilities and delays to new liquefaction projects, in addition to higher world oil prices during the second half of 2009, contribute to the 43-Bcf downward revision in the 2009 LNG import forecast from last month's *Outlook*.

U.S. Inventories. On August 28, 2009, working natural gas in storage was 3,323 Bcf (U.S. Working Natural Gas in Storage Chart). Current inventories are now 501 Bcf above the 5-year average (2004–2008) and 489 Bcf above the level during the corresponding week last year. While weekly stocks could exceed reported end-of-month levels, EIA now expects working natural gas inventories to reach 3,840 Bcf at the end of the 2009 injection season (October 31). This would be 275 Bcf above the previous record of 3,565 Bcf reported for the end of October 2007. The working gas inventory forecast assumes weekly storage injections will average about 57 Bcf over the next 9 weeks, compared with average storage injections of about 60 Bcf per week over this period during the previous 5 years.

U.S. Prices. The Henry Hub spot price averaged $3.23 per Mcf in August, $0.25 per Mcf below the average spot price in July. Prices continue to be pushed lower as robust production adds to already high inventories. As electric power demand for air conditioning wanes, a continuation of recent natural gas supply trends could cause spot natural gas prices to fall below current projections before cooler temperatures induce higher demand for space heating. In the projections, prices rise modestly in 2010, reflecting increased economic activity and lower production levels as a result of the current drilling pullback. However, it will take some time to work off current inventory levels and enhanced production capabilities should limit significant increases in prices throughout the forecast period. On an annual basis, the projected Henry Hub spot price averages $3.65 Mcf in 2009 and $4.78 Mcf in 2010.

Electricity

U.S. Electricity Consumption. Total U.S. electricity consumption fell by 4.4 percent during the first half of the year compared with the same period in 2008, primarily because of the effect of the economic downturn on industrial electricity sales. The expected year-over-year decline in total consumption during the second half of 2009 is smaller, a 2.3-percent decline, as residential sales begin to recover (U.S. Total Electricity Consumption Chart).

U.S. Electricity Generation. While generation from coal fell by 12 percent in the first half of the year compared with the same period in 2008, natural gas generation has risen by 3 percent. Lower coal prices relative to natural gas prices next year and the planned addition of up to 10 gigawatts of coal capacity during 2009 and 2010 could mitigate or reverse the fuel-switching trend.

U.S. Retail Electricity Prices. EIA significantly lowered its electricity retail price projections through 2010 from last month's *Outlook* due to the dramatic decline in natural gas fuel costs for power generation (U.S. Residential Electricity Prices Chart). Although retail residential prices during the first half of this year are up by 5 percent from the same period last year, EIA expects prices during the second half will show little change from the second half of last year. The projected annual average 2010 residential electricity price of 11.4 cents per kilowatthour is about 2 percent lower than the 2009 price.

Coal

U.S. Coal Consumption. Electric-power-sector coal consumption fell by 11 percent in the first half of this year. The decline resulted from lower total electricity generation combined with increases in generation from natural gas, nuclear, hydropower, and wind. Coal is expected to regain a larger share of the baseload generation mix beginning in 2010, as natural gas prices begin to rise. Projected coal consumption in the electric power sector increases by almost 2 percent in 2010 but remains below the 1-billion short-ton level for the second consecutive year. Coal consumed for steam (retail and general industry) and coke production declined by 15 percent in the first quarter of 2009 compared with the first quarter of last year. In the forecast, lower consumption of coal in both sectors continues for the remainder of the year, followed by a combined increase in coal consumed by these sectors of more than 5 percent in 2010 (U.S. Coal Consumption Growth Chart).

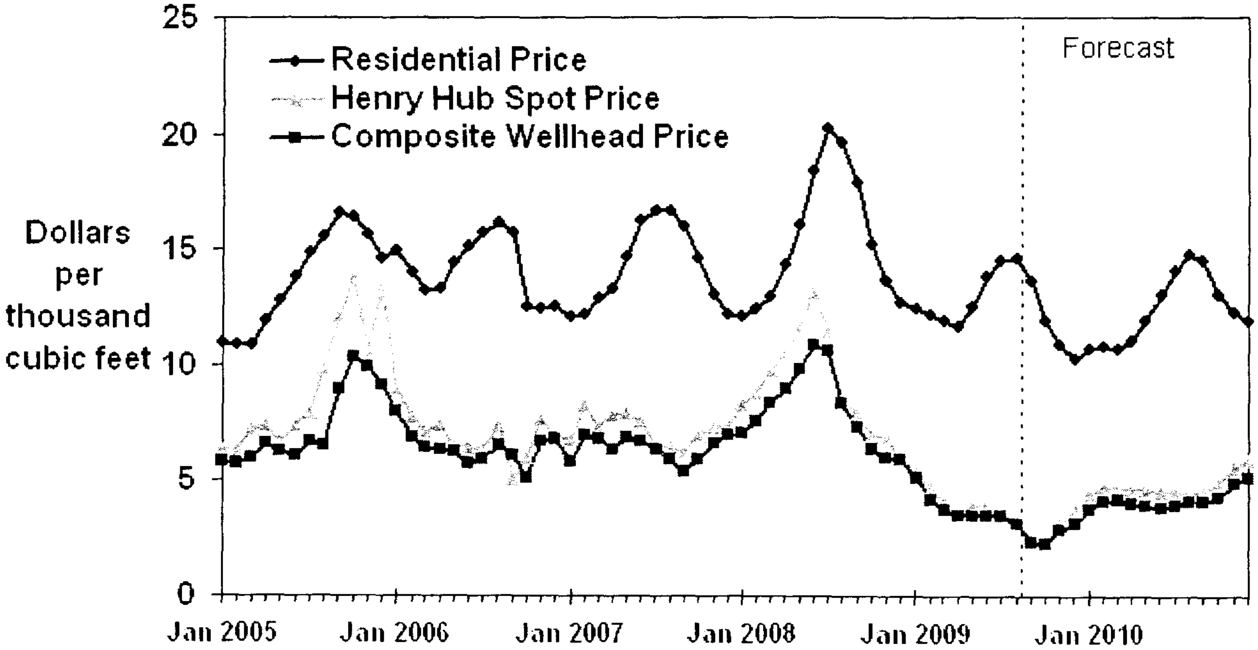
U.S. Coal Supply. Coal production for the first 6 months of 2009 fell by more than 5 percent in response to lower U.S. coal consumption, fewer exports, and higher coal inventories; these conditions persist in the forecast for the remainder of 2009. Projected production declines by 1.4 percent in 2010, despite increases in domestic consumption and exports. Reductions in coal inventories and increased imports offset the increase in U.S. coal consumption (U.S. Annual Coal Production Chart).

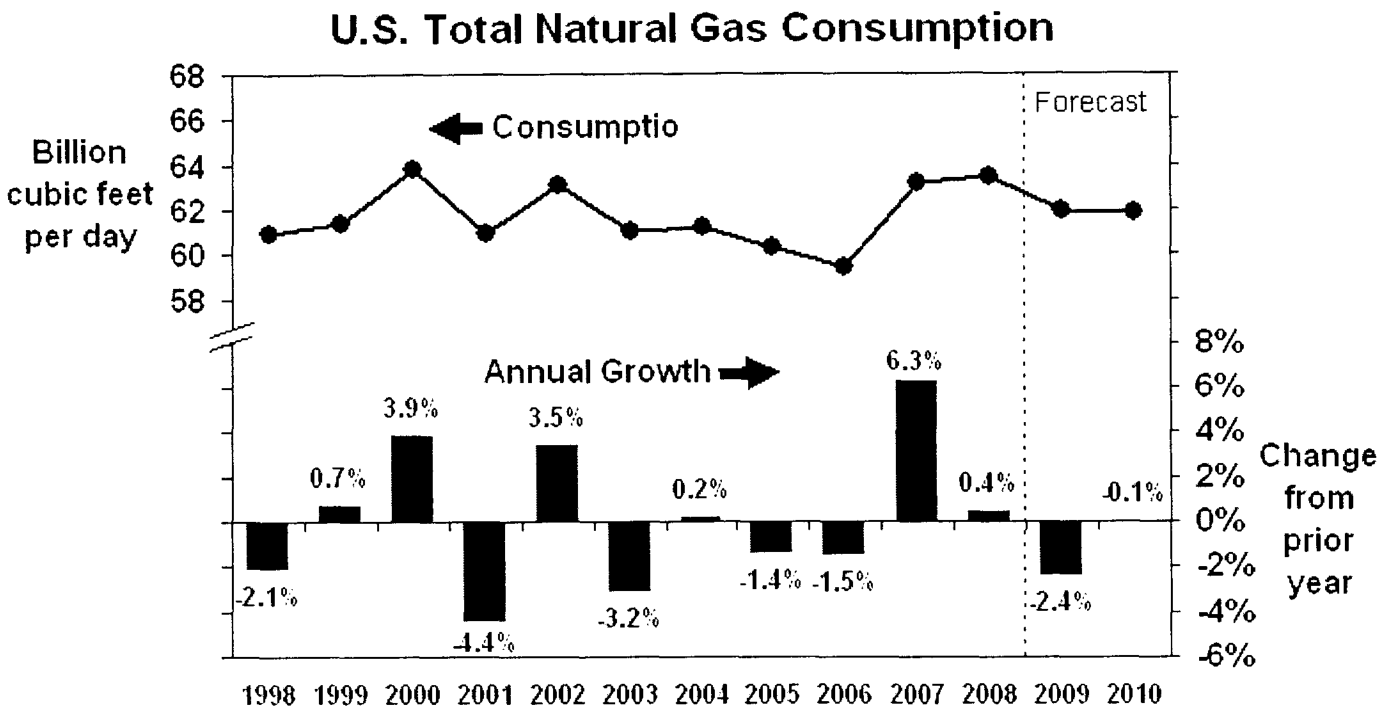
U.S. Coal Prices. The monthly average delivered electric-power-sector coal price reached a record high of $2.29 per million Btu in March 2009. The delivered cost of coal to the electric power sector had continued to rise, despite decreases in spot coal prices, lower prices for other fossil fuels, and declines in demand for coal for electricity generation, because a significant portion of power-sector coal contracts was entered into during a period of high prices for all fuels. The projected average power-sector coal price of $2.18 per million Btu for September 2009 represents the first decline in price from the same month of the prior year since 2002. Projected power-sector coal prices fall over the forecast to about $1.95 per million Btu in December 2010.

U.S. Carbon Dioxide Emissions

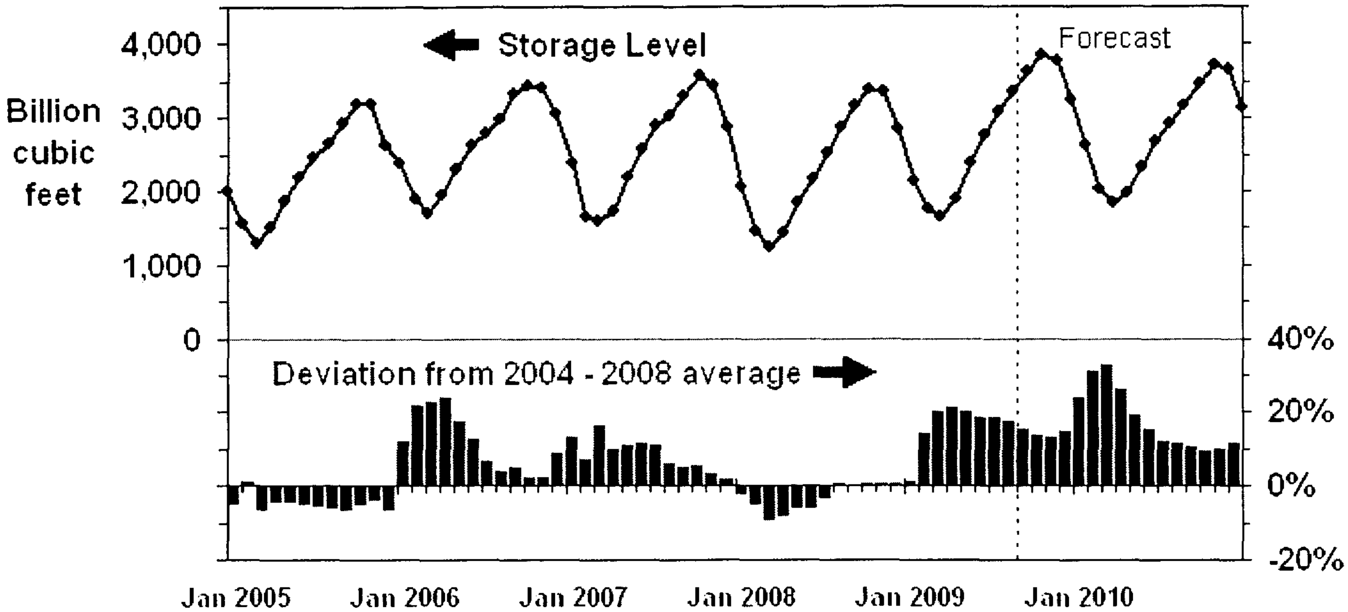
Projected carbon dioxide (CO_2) emissions from fossil fuels fall by 6.0 percent in 2009 because of the weak economic conditions and declines in the consumption of most fossil fuels (U.S. Carbon Dioxide Emissions Growth Chart). Coal leads the drop in 2009 CO_2 emissions, falling by nearly 10 percent because of fuel switching from coal to natural gas in the electric power sector. The projected recovery in the economy contributes to an expected 0.9-percent increase in CO_2 emissions in 2010.

Natural Gas Prices




U.S. Total Natural Gas Consumption
68
66
64
62
60
58
Billion cubic feet per day
Consumptio
Forecast
Annual Growth
8%
6%
4%
2%
0%
-2%
-4%
-6%
Change from prior year
-2.1%
0.7%
3.9%
-4.4%
3.5%
-3.2%
0.2%
-1.4%
-1.5%
6.3%
0.4%
-2.4%
-0.1%
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010

U.S. Working Natural Gas in Storage



NOTE: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2004 - Dec. 2008

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, 2009									**$65,941**
May	($2,105)	$0	$671	($1,434)	16,822	($0.1857)	($3,124)	$1,690	67,631
June	24,415	0	690	25,105	9,107	0.2343	(427) 2/	25,532	93,163
July	39,344	0	629	39,973	6,447	0.2343	1,511	38,462	131,625
August	39,771	0	902	40,673	5,943	0.2343	1,392	39,281	170,906
Balance @ August 31, 2009.									**$170,906**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 6,097.5 dk @ ($0.1857) and 3,009.9 dk @ $0.2343.

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, 2009									**($110,191)**
May	($5,411)	$0	($1,024)	($6,435)	15,426	($0.7309)	($11,275)	$4,840	(105,351)
June	(2,099)	0	(967)	(3,066)	10,879	(0.7419)	(7,985) 2/	4,919	(100,432)
July	(3,038)	0	(592)	(3,630)	7,435	(0.7419)	(5,516)	1,886	(98,546)
August	(4,584)	0	(581)	(5,165)	9,775	(0.7419)	(7,252)	2,087	(96,459)
Balance @ August 31, 2009.									**($96,459)**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 7,849.5 dk @ ($0.7309) and 3,029.9 dk @ ($0.7419).