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

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PO Box 176
Fergus Falls, MN 56538-0176
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October 30, 2009

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

Re: Cost of Gas Adjustment (COG)
November 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 (44th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (44th Revised Sheet No. 8), showing the November 2009 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $1.8196 per mcf for residential and firm general service customers and $1.8668 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for November 2009, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $1.8668 per mcf since the last COG filing due to an increase in the market price of gas. There has been a decrease in pipeline charges of $0.0472 per mcf due to changes in pipeline capacity and charges. The net effect of these changes is an increase of $1.8196 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
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

NDPSC Volume 2
44th Revised Sheet No. 1.1
Canceling 43rd Revised Sheet No.1.1

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	$7.5461	$8.8201
			Over 10 MCF	1.0540		8.6001
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$4.1088	$5.2479
			Next 2,600 MCF	0.8931		5.0019
			Over 3,000 MCF	0.7411		4.8499
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$4.1088	$5.3479
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 30, 2009 **Effective Date:** November 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
44th Revised Sheet No. 8
Canceling 43rd 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.	2.4425	(2.1352)	0.2343	0.5416	(2.1352)	(0.7419)	(2.8771)
Current Adj.	(0.0472)	1.8668	0.0000	1.8196	1.8668	0.0000	1.8668
Total Adj.	2.3953	(0.2684)	0.2343	2.3612	(0.2684)	(0.7419)	(1.0103)
Total Rate:	$2.4611	$4.8507	$0.2343	$7.5461	$4.8507	($0.7419)	$4.1088

Date Filed: October 30, 2009 **Effective Date:** November 1, 2009

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

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
NOVEMBER 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
TFX Seasonal	3,000		15.1530	5	227,295	0.1452
NOVA - Demand Charge	7,947		12.7090	12	1,211,981	0.7741
Trans Canada - Demand Charge	7,947		11.3830	12	1,085,528	0.6934
BP Canada - Demand Charge	7,947		0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068		12.7090	5	322,046	0.2057
Trans Canada - Seasonal	5,068		11.3830	5	288,445	0.1842
BP Canada - Seasonal	5,068		0.9612	5	24,357	0.0156
BP Canada 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					$3,853,004	2.4611
Estimated Weighted Average Commodity Cost	1,565,565	1/	4.8507		7,594,086	4.8507
Gas Cost Reconciliation Adjustment						0.2343
Total Current Firm Gas Cost					$11,447,090	7.5461
Base Cost of Gas						5.1849
Accumulated Adjustment						$2.3612
Interruptible						
Estimated Weighted Average Commodity Cost						$4.8507
Gas Cost Reconciliation Adjustment						(0.7419)
Total Current Interruptible Gas Cost						4.1088
Base Cost of Gas						5.1191
Accumulated Adjustment						($1.0103)

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

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

Rates Effective November 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	12.7090	Per dk/Mo.
Trans Canada Pipeline Demand Charge	11.3830	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	12.7090	Per dk/Day
Trans Canada - Seasonal	11.3830	Per dk/Mo.
BP Canada - Seasonal	0.9612	Per dk/Mo.
BP Canada Winter Surcharge	3.0417	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	4.8507	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

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

Twenty-Sixth Revised Sheet No. 5B
Superseding
Twenty-Fifth 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	$0.0019	$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.

Issued by: Ron Mucci, Vice President of Regulatory
Issued on: August 28, 2009
Effective on: October 1, 2009

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

	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
RESERVATION RATES	TF12 Base	TF12 Variable	TF5	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/ 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	0.0019	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
November 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 November 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).

Factors contributing to the hike in natural gas prices possibly included weather-related demand for natural gas, rising crude oil prices, and continuing injection demand for natural gas to exploit remaining arbitrage opportunities from storing gas. The Energy Information Administration (EIA) reported storage levels nationwide as of October 23, 2009 were 12.4 percent above the five-year average and 11.0 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 15.

www.eia.doe.gov
Energy Information Administration

October 2009

Short-Term Energy and Winter Fuels Outlook

October 6, 2009 Release

Highlights

- EIA projects average household expenditures for space-heating fuels to be $960 this winter (October 1 to March 31), a decrease of $84, or 8 percent, from last winter. This forecast principally reflects lower fuel prices, although expected slightly milder weather than last winter will also contribute to lower fuel use in many areas. The largest expenditure decreases are in households using natural gas and propane, projected at 12 and 14 percent, respectively. Projected electricity and heating oil expenditures decline by 2 percent (see EIA Short Term and Winter Fuels Outlook slideshow).

- According to the National Oceanic and Atmospheric Administration's (NOAA) most recent projection of heating degree-days, the Lower-48 States are forecast to be 1 percent warmer this winter compared with last winter and 1 percent milder than the 30-year average (1971-2000). However, heating degree-day projections vary widely between regions. For example, the Midwest, a major market for propane and natural gas, is projected to be about 4 percent warmer than last winter, while the West is projected to be about 4 percent colder.

- EIA expects the price of West Texas Intermediate (WTI) crude oil to average about $70 per barrel this winter (October-March), a $19 increase over last winter. The forecast for average WTI prices rises gradually to about $75 per barrel by December 2010 as U.S. and world economic conditions improve. EIA's forecast assumes U.S. GDP grows by 1.8 percent in 2010 and world oil-consumption-weighted GDP grows by 2.6 percent.

- Energy prices remain volatile, reflecting uncertainty, or risk, in the market. To measure this uncertainty, EIA is tracking futures prices and the market's assessment of the range in which those futures prices might trade (see *STEO Supplement: Energy Price Volatility and Forecast Uncertainty*). The *Outlook* will now report confidence intervals around the New York Mercantile Exchange

(NYMEX) crude oil and natural gas futures prices using a measure of risk derived from the NYMEX options markets known as "implied volatility."

- Natural gas inventories are expected to 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 $3.85 per thousand cubic feet (Mcf) in 2009 to $5.02 in 2010.

Projected Winter Fuel Expenditures by Fuel and Region

The average household winter heating fuel expenditures discussed in this *Outlook* provide a broad guide to changes compared with last winter, but fuel expenditures for individual households are highly dependent on local weather conditions, market size, the size and energy efficiency of individual homes and their heating equipment, and thermostat settings.

Natural Gas. EIA expects households heating primarily with natural gas to spend an average of $105 (12 percent) less this winter. About 52 percent of all households depend on natural gas as their primary heating fuel. The 12-percent decline in natural gas expenditures reflects an 11-percent decrease in prices and a 1-percent decrease in consumption. In the Midwest, where more than 70 percent of all households rely on natural gas, a projected 15-percent decrease in average household expenditures results from an 11-percent decrease in prices and a decline in consumption of 4 percent based on the forecast of warmer weather than last winter.

Heating Oil. EIA expects households heating primarily with heating oil to spend an average of $40 (2 percent) less this winter. About 7 percent of U.S. households depend on heating oil for winter fuel. The Northeast accounts for 80 percent of heating fuel consumption. In that region, the average household is projected to spend 3 percent less ($60) than last winter as a result of a 2-percent decrease in consumption, with regional prices about 1 percent less than last winter. EIA projects residential heating oil prices in the Northeast to average about $2.64 per gallon during the winter season, 2 cents less than last winter. For comparison, prices averaged $3.31 in the winter of 2007-08.

Propane. EIA expects households heating primarily with propane to spend an average of $280 (14 percent) less this winter but that decrease varies broadly by region. EIA expects Midwestern households to see an average reduction in expenditures of 21 percent, and homes in the West 5 percent less this winter. One-half of the difference in the change in fuel bills between the two regions is due to weather with the Midwest about 4 percent warmer and the West about 4 percent colder than

last winter. Propane-heated households represent about 6 percent of total U.S. households.

Electricity. Households heating primarily with electricity can expect to spend an average of $20 (2 percent) less than last winter. The 2-percent decline in electricity expenditures reflects a 2-percent decrease in prices and very little change in consumption. Thirty-five percent of all U.S. households rely on electricity as their primary heating fuel, ranging from 13 percent in the Northeast to 59 percent in the South. The number of households heating with electricity is growing faster, at an estimated annual rate of 2.5 percent, than all the other major heating fuels.

Global Crude Oil and Liquid Fuels

Global Petroleum Overview. Sustained economic growth in China and signs of a turnaround in other Asian countries continue to fuel expectations of a global recovery in world oil consumption. EIA has revised its expectations for world oil consumption upwards by 0.2 million barrels per day (bbl/d) for the remainder of 2009 and for 2010, in large part because of the revision to Asian growth. However, EIA has not revised its WTI oil price projections upward because ample oil supplies remain on the market. Oil inventories remain high and EIA expects oil production by the Organization of the Petroleum Exporting Countries (OPEC) to increase as well.

Global Petroleum Consumption. Global oil consumption declined by 3.2 million bbl/d in the first half of 2009 compared with year-earlier levels. Members of the Organization for Economic Cooperation and Development (OECD) accounted for most of the decline, as non-OECD oil consumption was down by about 0.4 million bbl/d during that period. Preliminary data indicate that oil consumption in the third quarter of 2009 was 1.2 million bbl/d below year-earlier levels. EIA's current macroeconomic outlook assumes that the world economy begins to recover at the end of 2009, 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, which would be the first such growth in five quarters. EIA projects world oil consumption growth of 1.1 million bbl/d in 2010, with almost all of the growth occurring in the non-OECD countries (World Liquid Fuels Consumption Chart).

Non-OPEC Supply. Total non-OPEC supply averaged 50.1 million bbl/d in the first half of 2009, about 0.2 million bbl/d higher than in the first half of 2008. The largest amount of growth came from South America and the former Soviet Union, which was offset in part by a decline in European production. Non-OPEC supply is expected to increase by 0.6 million bbl/d in the second half of 2009 and by 0.2 million bbl/d in 2010, compared with year-earlier levels. Over the forecast period, higher output from

Brazil, the United States, Azerbaijan, Kazakhstan, and Canada should offset 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 first half of 2009, down 2.6 million bbl/d from year-earlier levels. EIA expects OPEC production to rise gradually over the second half of the year in response to an anticipated rebound in demand, unless prices fall sharply from current levels. OPEC is scheduled to meet in Angola on December 22 to reassess the market situation. EIA projects OPEC crude oil production to climb to 29.3 million bbl/d in the second half of 2009, and then average 29.2 million bbl/d in 2010 (World Crude Oil and Liquid Fuels Production Growth Chart).

Global Petroleum Inventories. Based on revised data, OECD commercial oil inventories stood at 2.76 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 higher than average historical levels throughout the forecast period.

Crude Oil Prices. WTI oil prices averaged $69 per barrel in September, about $2 per barrel below the August average, as expectations of an economic recovery and higher oil consumption were weighed down by currently weak demand and high inventories. With prices near $70 per barrel, OPEC agreed to maintain its existing production targets, as expected, at its meeting in September.

Energy prices are volatile, primarily reflecting market participants' adjustments to new information from physical energy markets and/or energy-related financial derivatives. EIA quantifies this uncertainty, or risk, in the market by using "implied volatilities" derived from the NYMEX options markets to construct confidence intervals around the NYMEX crude oil futures prices. Implied volatility is calculated from traded option prices using the Black commodity option pricing model (see *STEO Supplement: Energy Price Volatility and Forecast Uncertainty*). The confidence intervals reflect the range in which those prices are likely to trade.

A confidence level determines the range of prices within the confidence interval. The confidence level represents the probability that the final market price for a particular futures contract, e.g., December 2009 crude oil, will fall somewhere within the lower and upper limits of the range of prices. For example, if a confidence level of 95 percent is specified, then a range of prices can be estimated within which there is a 95-percent probability the delivered price for the commodity in the contract's delivery

month will fall within that range. The higher the specified confidence level, the wider the range between the lower and upper limits.

Confidence intervals tend to be wide, in part because even small imbalances in oil markets can trigger large movements in prices given that both the production and use of oil tend to be relatively insensitive to price changes in the short-run. Increased uncertainty in consumption, production, or many other factors influencing oil prices would tend to induce an increase in implied volatility and a widening of the confidence intervals.

During the 5 days ending October 1, 2009, NYMEX futures market participants were pricing WTI delivered to Cushing, Oklahoma, in December 2009 at an average of $69 per barrel. The 95-percent confidence interval for the December 2009 futures contract is $49 per barrel and $96 per barrel for the lower and upper limits of the confidence interval, respectively; a $47 per barrel range (West Texas Intermediate (WTI) Crude Oil Price Chart). The low and high confidence limits correspond to a 48-percent implied volatility derived from the NYMEX options market. Confidence intervals also tend to widen as markets look further into the future. For example, the 95-percent lower and upper confidence limits for the December 2010 futures contract are $32 per barrel and $168 per barrel, respectively; a $136 per barrel range.

While near-term implied volatilities are now lower, and confidence intervals narrower, than they were at this time last year, the current confidence intervals highlight the fact that there continues to be significant uncertainty in the outlook for oil prices. EIA's crude oil price forecast reflects all available data and our expert judgment, nonetheless there is a substantial likelihood that prices will diverge significantly from the forecast.

U.S. Crude Oil and Liquid Fuels

U.S. Petroleum Consumption. EIA forecasts total consumption of liquid fuels and other petroleum products decreasing by about 730,000 bbl/d (3.7 percent) in 2009 compared with 2008 (U.S. Petroleum Products Consumption Growth Chart). During the first half of the year, consumption declined by almost 1.25 million bbl/d (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 210,000 bbl/d (1.1 percent) in the second half of 2009 as economic recovery begins to take hold. Monthly average motor gasoline consumption since June has shown year-over-year increases for the first time since September 2007 and continues to grow over year-ago levels throughout the forecast. The modest economic recovery projected for 2010

contributes to a 320,000-bbl/d (1.7 percent) increase in total liquid fuels consumption, led by an increase of 110,000 bbl/d (3.0 percent) in distillate consumption.

U.S. Petroleum Supply. EIA projects total U.S. crude oil production to average 5.27 million bbl/d in 2009 and increase to an average of 5.34 million bbl/d in 2010 (U.S. Crude Oil Production Chart). The last year U.S. crude oil production increased was 1991. Crude oil production from the 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. Distillate and Propane Inventories. As of September 30, the start of the winter heating season, total distillate fuel inventories were an estimated 170 million barrels, up about 43 million barrels from the previous year and 38 million barrels above the end-of-September average of the last 5 years. Total distillate inventories at the end of March 2010 are projected to be 132 million barrels, about 12 million barrels above the previous 5-year average.

U.S. propane inventories were an estimated 73 million barrels at the end of September, about 14 million barrels above last year's level and 8 million barrels above the end-of-September average over the last 5 years. Projected propane inventories will end the winter season at about 32 million barrels, 2 million barrels above the average of the last 5 years. Lower natural gas production over the coming months because of very high natural gas inventories in both the United States and Canada could reduce natural gas liquids and propane production and lead to lower-than-projected propane inventories next year.

U.S. Petroleum Product Prices. EIA expects the monthly average regular-grade gasoline retail price to fall from $2.62 per gallon in August to an average of $2.44 per gallon for the last 3 months of the year. Higher projected crude oil prices in 2010 (refiner average cost of crude oil about $12 per barrel, or 29 cents per gallon, higher than the 2009 average) lead to an expected increase in regular-grade gasoline prices to an average of $2.65 per gallon next year. Projected diesel fuel retail prices, which averaged $2.63 per gallon in August and September, will average $2.60 during the fourth quarter of 2009 in the forecast, as the winter heating fuel season begins.

Natural Gas

U.S. Natural Gas Consumption. Total natural gas consumption is projected to decline by 2.0 percent in 2009 and 0.2 percent in 2010 (Total U.S. Natural Gas Consumption Growth Chart). Weak economic conditions continue to hamper the industrial sector, where the most recent data show natural gas consumption is down by 12.4 percent

through July compared with the same period last year. With lower consumption in the residential and commercial sectors as well, natural gas use in the electric power sector continues to serve as the only demand outlet for increased natural gas supplies. EIA data indicate that electric-power-sector natural gas consumption increased by 0.4 percent in 2009 through July, compared with the same period in 2008, despite a 5.3-percent decline in total electricity generation over the same period. Sustained low natural gas prices are expected to prolong the preferred use of natural gas in place of coal for electricity generation in some regions until space-heating demand picks up this winter.

EIA expects natural gas consumption growth in the commercial and industrial sectors in 2010 to be offset by a decline in the electric power sector. In addition to the assumption of fewer cooling degree-days next year, higher relative natural gas prices and the start-up of new coal-fired generating capacity are all expected to contribute to a reduction in natural-gas-fired electric generation in 2010.

U.S. Natural Gas Production and Imports. EIA expects total U.S. marketed natural gas production to increase by 1.5 percent in 2009 and decline by 3.8 percent in 2010. Marketed natural gas production in the Lower-48 States rose by 2.9 percent this year through July, compared with the same interval in 2008, despite a more than 40-percent decline in the working rig count since the start of the year. While production has remained stronger than expected through much of this year, EIA expects the pullback in drilling to lead to a 3.6-percent decline in Lower-48 production from the first half to the second half of 2009. In addition to the natural rate of decline from producing wells, the current forecast assumes some additional production curtailments as natural gas inventories begin to swell toward capacity limits this month. Although the working rig count has begun to increase slightly in recent weeks, EIA expects domestic natural gas production to continue to fall, with marketed production during the first half of 2010 to average about 1.8 billion cubic feet (Bcf) per day lower than the second half of 2009. However, economic recovery and increasing demand next year are expected to push prices up and provide the incentive for increasing production later next year.

U.S. liquefied natural gas (LNG) imports increase to about 471 Bcf in 2009, from 352 Bcf in 2008, and rise to about 660 Bcf in 2010. Higher LNG import levels may occur on a temporary basis as cargoes are redirected from Europe, where storage is reaching capacity and prices have declined. EIA expects that the startup of several large LNG supply projects in 2010 will lead to an increase in U.S. LNG imports, although previous supply additions abroad have been slowed by construction delays and feedgas shortages that contribute to EIA's present uncertainty about the future of current projects.

U.S. Natural Gas Inventories. On September 25, 2009, working natural gas in storage was 3,589 billion cubic feet (U.S. Working Natural Gas in Storage Chart). Current inventories are now 481 Bcf above the 5-year average (2004–2008) and 491 Bcf above the level during the corresponding week last year. Working natural gas stocks are now expected to reach 3,850 Bcf at the end of the 2009 injection season (October 31), about 40 Bcf below the sum of historical non-coincident demonstrated peak working gas storage volumes at individual active natural gas storage sites, a conservative measure of capacity that may understate the amount that could actually be stored. (See *Estimates of Peak Underground Working Gas Storage Capacity in the United States, 2009 Update*). The projected working gas inventory is about 285 Bcf above the previous record of 3,565 Bcf reported for the end of October 2007.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $3.06 per Mcf in September, $0.17 per Mcf below the average spot price in August. Spot prices fell early in September then moved higher as pipeline maintenance reduced available supply and natural-gas-fired electric generators increased demand. A slight tightening of the year-over-year supply and demand balance was evident in the weekly storage injections, which averaged 67 Bcf this September compared with 72 Bcf last September. EIA expects prices to remain low through October then begin to increase as space-heating demand picks up this winter and economic conditions improve. Prices are expected to increase in 2010 but, even with a projected winter storage withdrawal greater than the 5-year average, end-of-March inventories still will be the highest recorded since March of 1991. Furthermore, lower breakeven costs for domestic production and growing global LNG supply should limit sustained price increases throughout the forecast period. EIA expects the Henry Hub spot price to average $3.85 per Mcf in 2009 and $5.02 per Mcf in 2010.

For the 5 days ending October 1, 2009, natural gas futures on the NYMEX were trading at $5.59 per MMBtu for gas delivered to Henry Hub, Louisiana, during December 2009 (approximately equal to $5.76 per Mcf assuming a natural gas heat content of 1,030 Btu per Mcf). The 95-percent confidence interval around this price has a lower limit of $3.70 and an upper limit of $8.50, a difference of $4.80 per MMBtu, which corresponds to a 56-percent implied volatility (Henry Hub Natural Gas Price Chart).

Last year at this time, NYMEX natural gas to be delivered to Henry Hub in December 2008 was trading at $7.80 per MMBtu. The lower and upper limits of the 95-percent confidence interval were $5.40 and $11.40, respectively. This $6.00-per-MMBtu range corresponded to an implied volatility of 51 percent. The current implied volatility is

slightly higher than last year, but because the natural gas price is almost $2 per MMBtu lower, the price range of the 95-percent confidence interval is smaller.

Forecast Henry Hub natural gas spot prices in this *Outlook* are about $1 per MMBtu lower than the NYMEX futures prices. While considerable uncertainty in the market persists, this difference reflects EIA's expectation that a significant volume of natural gas production remains economic at prices below the current NYMEX 2010 futures prices. Furthermore, EIA expects that natural gas demand in the electric power sector, which served as a crucial outlet for high natural gas supplies this year, will be limited in 2010 as prices move slightly higher and new coal-fired electric generation capacity becomes available.

Electricity

U.S. Electricity Consumption. During the first half of 2009, the largest declines in residential electricity sales occurred in the western United States, while industrial sales declined most dramatically in the eastern United States. The rate of decline in electricity consumption is expected to slow during the second half of 2009, especially in the southwestern United States, where warm temperatures increased summer air conditioning usage. EIA projects total U.S. electricity consumption will decline by 3.3 percent in 2009 and then grow by 1.3 percent in 2010 as the improving economy leads to slowly recovering industrial sector electricity sales (U.S. Total Electricity Consumption Chart).

U.S. Electricity Generation. According to the September *Electric Power Monthly*, more than 50 percent of the decline in coal generation during the first half of 2009 occurred in the Appalachian States, where spot coal prices spiked late last year. Conversely, natural gas generation in those same States was up by 80 percent during the first half of 2009, compared with the same period last year. EIA expects this fuel-switching trend to reverse during 2010, with generation from U.S. coal-fired plants increasing by 1.8 percent while natural gas generation falls by 1.3 percent. This reversal is mainly the result of a number of coal-fired plants expected to begin generation in 2010.

U.S. Electricity Retail Prices. Although increased capital construction costs for generation and transmission upgrades have resulted in higher residential electricity rates over the past year, recent steep declines in utilities' cost of fuel for power generation and the cost of purchased power are likely to push those rates lower by about 1.6 percent in 2010 (U.S. Residential Electricity Prices Chart).

Coal

U.S. Coal Consumption. Coal consumption in the electric power sector fell by 11 percent in the first half of this year compared to the first half of last year, the result of lower total electricity generation combined with increases in generation from natural gas, nuclear, hydropower, and wind. Lower electric power sector coal consumption is expected to continue for the remainder of the year with the total annual decline projected at more than 9 percent. Coal is expected to regain a larger share of the baseload generation mix beginning in 2010, as demand for electricity grows and natural gas prices rise at the same time new coal-fired plants come online. Projected coal consumption in the electric power sector increases by more than 2 percent in 2010 but it remains below 1 billion short-tons for the second consecutive year. Coal consumed for steam (retail and general industry) and coke production declined by 21 percent in the first half of 2009 compared with the first half of last year. In the forecast, lower consumption of coal in both sectors continues for the remainder of the year, followed by an increase of 5 percent in the coke sector. EIA projects 4 percent growth in 2010 for coal use in the retail and general industry sector (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 and increase in the forecast for the remainder of 2009. Projected production declines by 2.3 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. Despite decreases in spot coal prices, lower prices for other fossil fuels, and declines in demand for coal for electricity generation, the monthly average delivered electric-power-sector coal price reached a record high of $2.29 per MMBtu in March 2009. The delivered cost of coal to the electric power sector had continued to rise because a significant portion of power-sector coal contracts were initiated during a period of high prices for all fuels. Projected power-sector coal prices fall over the forecast, averaging about $2.20 per MMBtu for 2009 and just over $2.00 per MMBtu in 2010.

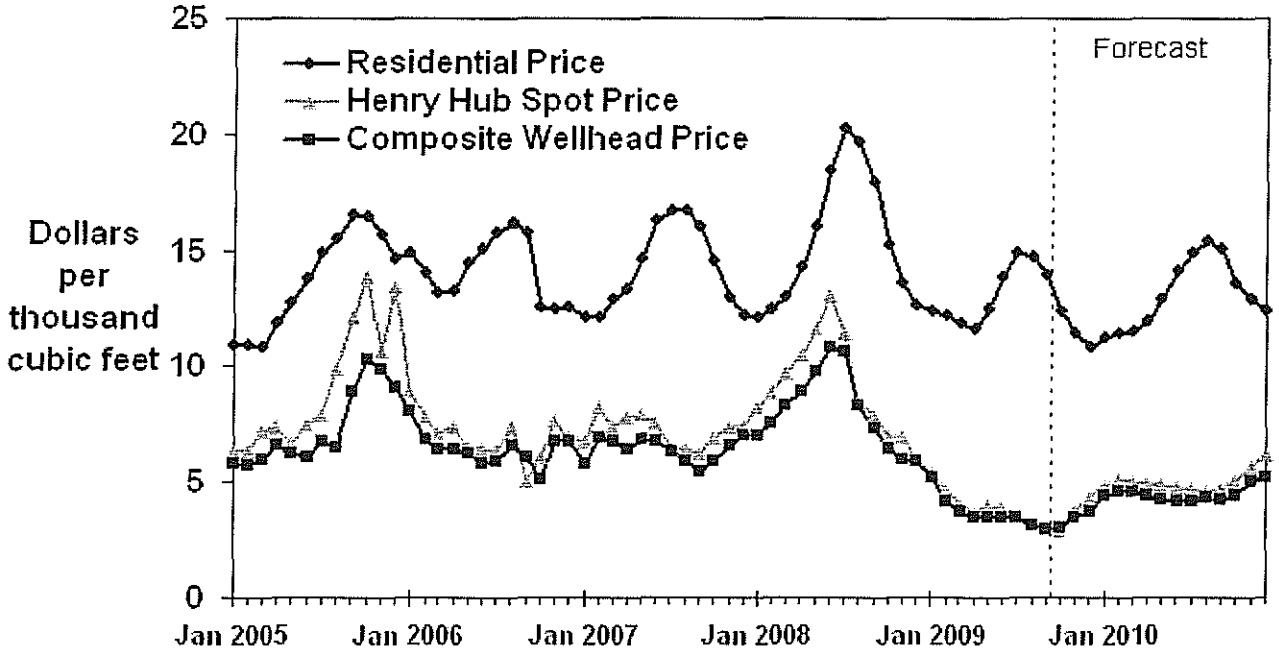
U.S. Carbon Dioxide Emissions

Projected carbon dioxide (CO_2) emissions from fossil fuels fall by 5.9 percent in 2009. Coal leads the drop in 2009 CO_2 emissions, falling by 10.1 percent. Changes in energy consumption in the industrial sector, a result of the weak economy, and changes in

electricity generation sources are the primary factors for the decline in CO_2 emissions (U.S. Carbon Dioxide Emissions Growth Chart). The projected recovery in the economy contributes to an expected 1.1-percent increase in CO_2 emissions in 2010.

A convergence of several factors has contributed to the projected decline in CO_2 emissions in 2009 (see *STEO Supplement: Understanding the Decline in CO2 Emissions in 2009*). EIA estimates that the combined effects of the decline in consumption of coal and natural gas in the industrial, commercial, and residential sectors, the substitution of natural gas for coal in the electric power sector, and the forecast increase in non-CO_2 emitting electricity generation (hydroelectric, nuclear, wind, solar, wood and wood waste) reduce CO_2 emissions by 242 million metric tons, or 70 percent of the total projected 2009 decline. The projected reduction in petroleum consumption accounts for the remaining 30 percent of the decline in CO_2 emissions. CO_2 emissions from petroleum are expected to fall by 102 million metric tons in 2009, with over two-thirds of the decline attributable to economy-related reductions in consumption of jet fuel and distillate fuel oil, including both diesel fuel and home heating oil. Reduced petroleum consumption in the industrial sector also contributes to the overall reduction in petroleum use.

Natural Gas Prices



Short-Term Energy Outlook, October 2009

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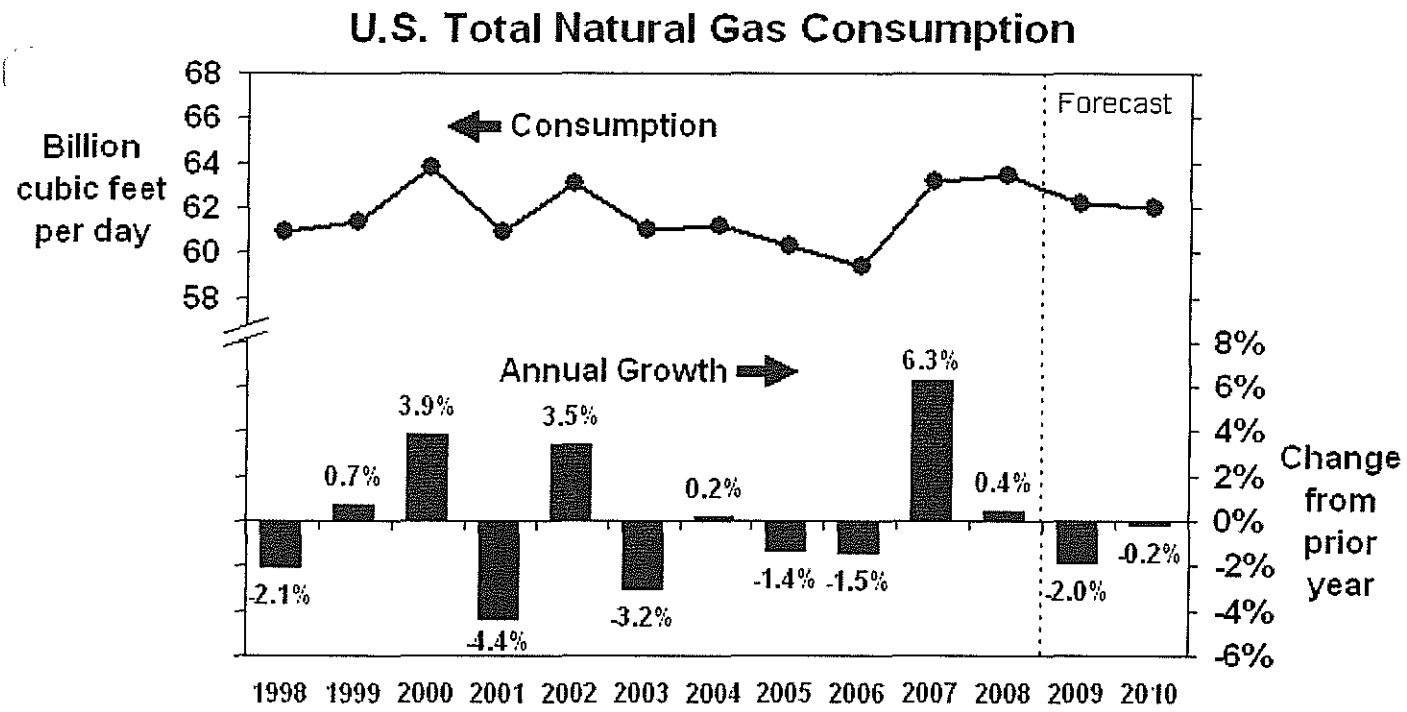

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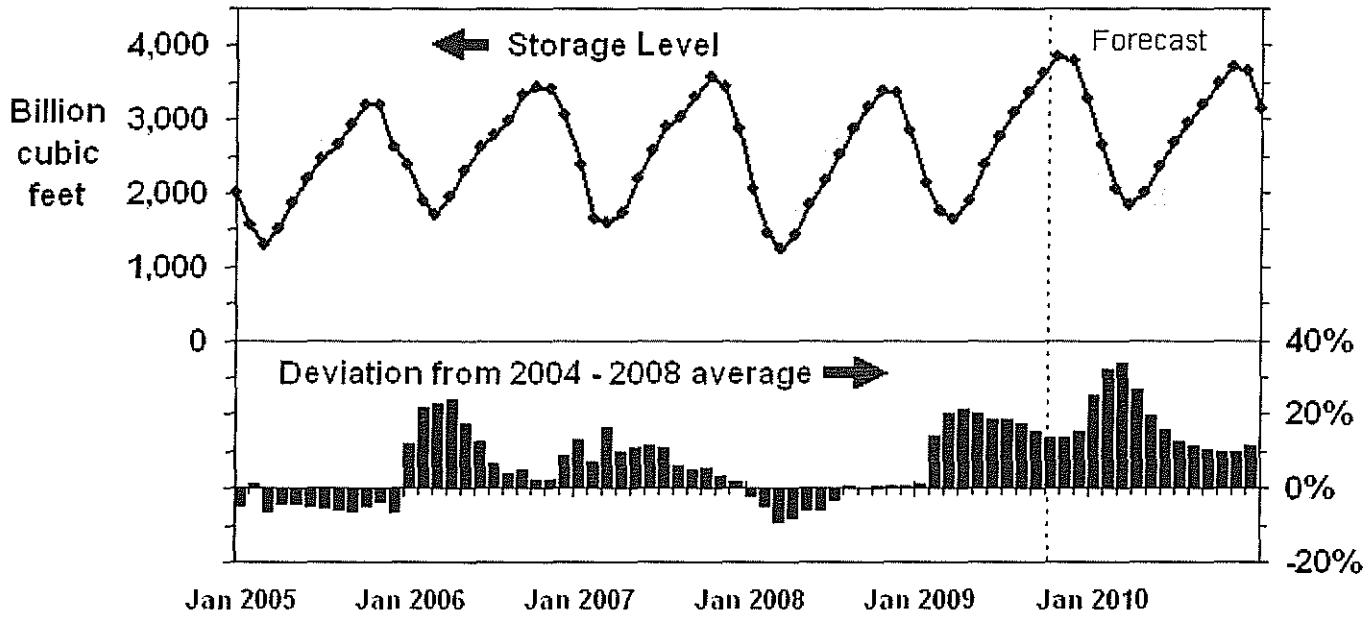
U.S. Working Natural Gas in Storage



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

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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
September	(2,165)	0	1,179	(986)	5,775	0.2343	1,353	(2,339)	168,567
Balance @ September 30, 2009.									**$168,567**

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)
September	(14,605)	0	(571)	(15,176)	9,230	(0.7419)	(6,848)	(8,328)	(104,787)
Balance @ September 30, 2009.									**($104,787)**

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).