

September 1, 2009

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

Re: Cost of Gas Adjustment (COG)
September 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 (42nd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (42nd Revised Sheet No. 8), showing the September 2009 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.4258 per mcf for residential and firm general service customers and \$0.3523 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for September 2009, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.3523 per mcf since the last COG filing due to a decrease in the market price of gas. There has been a decrease in pipeline charges of \$0.0735 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of \$0.4258 per mcf for residential and firm general service customers.

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

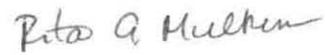
Attachment D shows the calculation of the balancing account since April 30, 2009.

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

42nd Revised Sheet No. 1.1

Canceling 41st Revised Sheet No.1.1

RATE SUMMARY SHEET

Page 1 of 1

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 Over 10 MCF 1.0540	\$5.3135	\$6.5875 6.3675
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411	\$1.8895	\$3.0286 2.7826 2.6306
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$1.8895	\$3.1286
Transportation Service	5	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411		\$1.1391 0.8931 0.7411

Date Filed: September 1, 2009

Effective Date: September 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
 42nd Revised Sheet No. 8
 Canceling 41st 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.	2.4555	(2.1354)	0.2343	0.5544	(2.1354)	(0.7419)	(2.8773)
Current Adj.	(0.0735)	(0.3523)	0.0000	(0.4258)	(0.3523)	0.0000	(0.3523)
Total Adj.	2.3820	(2.4877)	0.2343	0.1286	(2.4877)	(0.7419)	(3.2296)
Total Rate:	\$2.4478	\$2.6314	\$0.2343	\$5.3135	\$2.6314	(\$0.7419)	\$1.8895

Date Filed: September 1, 2009

Effective Date: September 1, 2009

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

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
SEPTEMBER 2009**

<u>Firm</u>	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
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	12.1928	12	1,162,754	0.7427
Trans Canada - Demand Charge	7,947	10.9730	12	1,046,429	0.6684
ProGas - Demand Charge	7,947	0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068	12.1928	5	308,966	0.1974
Trans Canada - Seasonal	5,068	10.9730	5	278,056	0.1776
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				<u>\$3,832,042</u>	<u>2.4478</u>
Estimated Weighted Average Commodity Cost	1,565,565	1/ 2.6314		<u>4,119,628</u>	<u>2.6314</u>
Gas Cost Reconciliation Adjustment					<u>0.2343</u>
Total Current Firm Gas Cost				<u><u>\$7,951,670</u></u>	<u><u>5.3135</u></u>
Base Cost of Gas					<u>5.1849</u>
Accumulated Adjustment					<u><u>\$0.1286</u></u>
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$2.6314
Gas Cost Reconciliation Adjustment					(0.7419)
Total Current Interruptible Gas Cost					<u>1.8895</u>
Base Cost of Gas					<u>5.1191</u>
Accumulated Adjustment					<u><u>(\$3.2296)</u></u>

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

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
SEPTEMBER 2009**

Rates Effective September 1, 2009	<u>\$/Dk</u>	
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	12.1928	Per dk/Mo.
Trans Canada Pipeline Demand Charge	10.9730	Per dk/Mo.
ProGas - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	12.1928	Per dk/Day
Trans Canada - Seasonal	10.9730	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:	2.6314	Per dk
Base Rate Effective September 1, 1981		
Demand Charge	\$0.8100	Per Mcf/Mo.
Commodity Charge	5.1191	Per Mcf
Base Rate Calculation		
<u>Firm</u>		
Demand 1/	\$0.0658	Per Mcf
Commodity	5.1191	Per Mcf
Total Firm Base Cost	<u>\$5.1849</u>	Per Mcf
<u>Interruptible:</u>		
Commodity	\$5.1191	Per Mcf

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

STATEMENT OF RATES
 (Rates Per Dekatherm)

Attachment B
 Page 3 of 7

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
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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. Nepl, 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)

Attachment B
 Page 4 of 7

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	0.64%
Zone 1 - 2	\$0.0130	\$0.0017	\$0.0147	0.89%
Zone 2 - 2	\$0.0130	\$0.0017	\$0.0147	0.25%
Minimum Rate	\$0.0130	\$0.0017	\$0.0147	
IT and AOT				
Zone 1 - 1	\$0.1368	\$0.0017	\$0.1385	0.64%
Zone 1 - 2	\$0.1737	\$0.0017	\$0.1754	0.89%
Zone 2 - 2	\$0.0834	\$0.0017	\$0.0851	0.25%
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: .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.

STATEMENT OF RATES
 (Rates Per Dekatherm)

Attachment B
 Page 5 of 7

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.

R A T E S C H E D U L E T F

Attachment B
 Page 6 of 7

RESERVATION RATES	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
	TF12		TF5	TFF
	TF12 Base	Variable		
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.

R A T E S C H E D U L E S T F X a n d L F T

Attachment B
 Page 7 of 7

RESERVATION RATES		MARKET-TO-MARKET		FIELD-TO-FIELD		Apr-Oct		Nov-Mar	
		Apr-Oct	Nov-Mar	Apr-Oct	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/		Commodity 6/		Out-of-Balance 6/	
		Maximum	Minimum	Maximum	Minimum	Maximum	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.

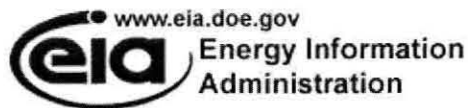
**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
September 2009**

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 September monthly price for the AECO Index is expected to decrease 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 decline in natural gas prices likely included moderate cooling demand for natural gas and continued strength in domestic production capacity, specifically in unconventional gas. The AECO index price for September 2009 is expected to be approximately 60 percent less than the September 2008 price of \$6.95. The Energy Information Administration (EIA) reported storage levels nationwide as of August 21, 2009 were 18.1 percent above the five-year average and 18.8 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 13.



August 2009

Short-Term Energy Outlook

August 11, 2009 Release

Highlights

- Crude oil prices continue to be very volatile. The West Texas Intermediate (WTI) crude oil spot price fell from \$71.47 on June 29 to \$59.62 on July 14 and then increased to \$71.59 by August 3. EIA expects the price of WTI crude oil to stay roughly flat at an average of \$70 per barrel in the fourth quarter of 2009, an increase of about \$27 compared with the average for the first quarter of the year. The WTI spot price is projected to rise slowly as economic conditions improve, to an average of about \$72 per barrel in 2010.
- U.S average prices for regular-grade gasoline, which reached an earlier summer peak of \$2.69 per gallon in EIA's June 22 weekly survey, fell by more than 20 cents per gallon in 4 weeks following the drop in crude oil prices but are now bouncing back as the recent rebound in crude oil prices is passed through to retail markets. Gasoline prices will be strongly influenced by any changes in crude oil prices and, based on recent price volatility, could approach the June 22 peak later this summer. EIA expects the annual average regular-grade gasoline retail price in 2009 to be \$2.34 per gallon. Higher projected crude oil prices next year are expected to increase the average price to \$2.66 per gallon in 2010. Annual average diesel fuel retail prices are expected to be \$2.46 and \$2.84 per gallon in 2009 and 2010, respectively.
- EIA expects the monthly average Henry Hub natural gas spot price to stay below \$4 per thousand cubic feet (Mcf) until late in the year as natural gas inventories are projected to set a new record high at the end of this year's injection season (October 31). The Henry Hub price is projected to increase from an average of \$3.92 per Mcf in 2009 to an average of \$5.48 per Mcf in 2010.
- Carbon dioxide (CO₂) emissions from fossil fuels, which fell by 3.2 percent in 2008, are projected to decline by 5 percent this year. Lower CO₂ emissions from coal account for more than one-half of the decline. Economic recovery next

year and modest growth in energy consumption are expected to lead to a 0.7-percent increase in CO₂ emissions.

Global Petroleum

Global Petroleum Overview. The oil market continues to be defined by the tension between optimism over the perceived recovery of the global economy on the one hand and persistently weak global consumption of crude oil and other liquid fuels on the other. There are indications that oil consumption could be recovering outside of the Organization for Economic Cooperation and Development (OECD). However, this has been somewhat offset by an erosion of compliance with production cuts announced by the Organization of the Petroleum Exporting Countries (OPEC). The rising level of global oil inventories when combined with weak current consumption indicates overall weakness in the oil market. For example, U.S. commercial crude oil and petroleum product stocks have increased for 5 straight quarters for the first time since 1979-1980, and they are projected to increase again in the third quarter of this year. As a result, the future level of oil prices will largely depend upon the timing and pace of the global economic recovery and the resultant impact on global oil consumption that would tend to erode surplus stocks.

Global Petroleum Consumption. World oil consumption has dropped sharply since the middle of 2008 in response to the global economic downturn and higher prices. Preliminary data indicate that global oil consumption declined by 3.1 million barrels per day (bbl/d) in the first half of 2009 compared with year-earlier levels. OECD countries accounted for 2.8 million bbl/d of the overall decline, while non-OECD consumption recorded a decline of only 300,000 bbl/d. The current macroeconomic outlook assumes that the world economy begins to recover slightly at the end of this year, led by Asia. As a result, EIA expects world oil consumption to grow year-over-year in the fourth quarter of 2009, the first such growth in five quarters. Overall, global oil consumption is projected to decline by 1.7 million bbl/d in 2009, then rise by 940,000 bbl/d in 2010 (World Liquid Fuels Consumption Chart).

Non-OPEC Supply. Total non-OPEC crude oil and other liquid fuels supply is expected to rise by 410,000 bbl/d in 2009 and by 160,000 bbl/d in 2010. Over the forecast period, higher output from Brazil, the United States, and the former Soviet Union is expected to offset falling production in Mexico and the North Sea (Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart). There is some indication that the chronic delays that have plagued non-OPEC projects have begun to ease. However, many projects are still moving forward at a slower pace to either defer necessary investment decisions or take advantage of further reductions in procurement costs.

OPEC Supply. OPEC crude oil production is estimated at 28.7 million bbl/d in the second quarter of 2009, mostly unchanged from first quarter levels, but down 3 million bbl/d from the peak in the third quarter of 2008. The combination of higher prices and OPEC's historical tendency for weaker compliance with production targets over time suggests that OPEC crude oil production could rise over the remainder of the year, unless prices fall sharply from current levels. Rising global oil inventories and increasing tanker activity would seem to indicate that this past trend is continuing. OPEC is scheduled to meet on September 9 to review market conditions and to consider its production policy.

Global Petroleum Inventories. Based on preliminary data, OECD commercial oil inventories stood at 2.75 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 above average levels throughout the forecast period. Industry reports indicate that crude oil and refined products held in floating storage, which are not included in the OECD stock totals, have recently increased to 140 million barrels in response to weakness in global oil consumption and higher levels of contango in the market (i.e., relatively high future prices compared with current prices).

Crude Oil Prices. EIA projects WTI crude oil prices, which averaged \$100 per barrel in 2008, to average \$60 per barrel in 2009 before recovering to an average of about \$72 per barrel in 2010 (Crude Oil Prices Chart). This projection is unchanged from last month's *Outlook*. As always, energy price movements are highly uncertain as seen over the last month in the swing in the WTI crude oil spot price from \$71.47 on June 29 to \$59.62 on July 14 and back up to \$71.59 by August 3. Another measure of how the market reflects this uncertainty is the sizable participation in near-term options on crude oil futures contracts at strike prices that are significantly different from current futures market prices. This reflects the tendency for crude oil prices to fluctuate within a wide range in a relatively short period.

U.S. Crude Oil and Liquid Fuels

U.S. Petroleum Consumption. EIA projects total U.S. consumption of liquid fuels and other petroleum products to decrease by 790,000 bbl/d (4.1 percent) in 2009 (U.S. Petroleum Products Consumption Growth Chart). This includes projected declines of 320,000 bbl/d (8.2 percent) in distillate fuel consumption and 150,000 bbl/d (9.8 percent) in jet fuel consumption. Motor gasoline consumption is projected to decline slightly in 2009 as the positive impact of the significant price decline compared with last summer offsets some of the negative impact of the economic downturn. The

modest economic recovery projected for 2010 is expected to contribute to a 280,000-bbl/d (1.5 percent) increase in total liquid fuels consumption, led by increases of 110,000 bbl/d (3.2 percent) in distillate consumption, 50,000 bbl/d (0.6 percent) in motor gasoline consumption, and 60,000 bbl/d (2.6 percent) in other oils consumption.

U.S. Petroleum Supply. Total U.S. crude oil production averaged 4.95 million bbl/d in 2008, down from 5.06 million bbl/d in 2007 (U.S. Crude Oil Production Chart). U.S. production is expected to increase to an average of 5.22 million bbl/d in 2009 and 5.25 million bbl/d in 2010. Oil production from the Thunder Horse, Tahiti, Shenzi, and Atlantis Federal offshore fields is expected to account for about 14 percent of lower-48 crude oil production by the fourth quarter of 2010.

Last week the National Oceanic and Atmospheric Administration (NOAA) lowered its outlook for an above-average hurricane season from a 25-percent chance in their May outlook to a 10-percent chance in their 2009 Atlantic Hurricane Season Outlook Update. This revision, combined with no reported shut-in production during June and July, reduces EIA's original seasonal estimates of crude oil and natural gas production outages (The 2009 Outlook for Hurricane Production Outages in the Gulf of Mexico) by about one-half. However, significant uncertainty always remains as any one storm can cause widespread disruptions and damage (see EIA, *This Week in Petroleum*, July 29, 2009 and August 5, 2009).

U.S. Petroleum Product Prices. Regular-grade motor gasoline retail prices, which averaged \$3.26 per gallon in 2008, are expected to average \$2.34 per gallon this year. Higher projected crude oil prices in 2010 (about 30 cents per gallon on average), along with slightly higher refining margins, are expected to boost average motor gasoline prices to \$2.66 per gallon next year. Diesel fuel retail prices, which averaged \$3.80 per gallon in 2008, are projected to average \$2.46 per gallon in 2009 and \$2.84 in 2010.

Natural Gas

Natural Gas Consumption. EIA projects total U.S. natural gas consumption will decline by 2.6 percent in 2009 and increase by 0.5 percent in 2010 (Total U.S. Natural Gas Consumption Growth). Despite some recent signs of economic stability, the severe contraction during the first half of the year contributed to an estimated 3.8-percent decline in daily average natural gas consumption compared with consumption during the first half of 2008. The decline in natural gas use during this period was driven principally by a drop in industrial activity, reflected in the 17-percent year-over-year decline in the natural-gas-weighted industrial production index during the first half of the year. Natural gas prices have declined to the point where they now compete against coal for a share of the baseload generation in the

electric power sector. Consequently, natural gas consumption in the electric power sector is expected to increase by 2 percent in 2009. The assumption of improved economic conditions in 2010 is the primary factor leading to projected demand increases in the residential, commercial, and industrial sectors next year. However, the expectation of higher natural gas prices and lower coal prices in 2010 likely will lead to a slight reduction in natural gas consumption in the electric power sector.

Natural Gas Supply. We expect total U.S. marketed natural gas production to stay flat in 2009 and decrease by 2.8 percent in 2010. The outlook for production is conditioned on the current low price environment that has brought about a significant pullback in drilling activities. According to Baker-Hughes, total working natural gas rigs have now declined by 58 percent since September 2008. Data for March through May 2009 suggest that the decline in drilling has begun to reduce marketed production in the lower-48 non-Gulf of Mexico (GOM) region. While the monthly average rate of decline was about 0.3 billion cubic feet per day (Bcf/d) during those 3 months, production is expected to decrease at a faster pace through the remainder of 2009 with some curtailments from existing production expected. Federal GOM production is expected to increase by 3.3 percent in 2009 in part because recovery from damage sustained during last year's hurricane season and the lower expected incidence of hurricane activity this year (NOAA, [2009 Atlantic Hurricane Season Outlook Update](#)). Although drilling activity is expected to pick up early next year, the lagged affect of reduced drilling this year is expected to lead to lower production in all regions outside Alaska. Alaska natural gas production is expected to remain near current levels through the forecast.

We expect U.S. liquefied natural gas (LNG) imports to increase to about 500 billion cubic feet (Bcf) in 2009, up from 352 Bcf in 2008, and rise to about 740 Bcf in 2010. While increasing over 2008 levels, U.S. LNG import growth this year has been constrained because of increased LNG demand in Europe and delays and maintenance to new and existing LNG liquefaction capacity. With limited natural gas storage availability, recent data suggest that European inventory levels are now nearing capacity. As a result, LNG shipments may be redirected to U.S. ports in the coming months as prices in the European market become less attractive to LNG suppliers. A similar scenario may also occur in Canada, with natural gas pipeline imports increasing in the months ahead as Canadian storage facilities are topped off. An increase in U.S. natural gas imports would likely be balanced by larger-than-expected declines in domestic natural gas production.

Natural Gas Inventories. On July 31, 2009, working natural gas in storage was 3,089 Bcf ([U.S. Working Natural Gas in Storage](#)). Current inventories are now 496 Bcf above the 5-year average (2004–2008) and 580 Bcf above the level during the corresponding

week last year. Total working natural gas stocks eclipsed 3,000 Bcf during the week ending July 24, 2009. This is the earliest day on record that inventories have exceeded 3,000 Bcf during the injection season (April through October), a mark previously set when stocks reached 3,005 during the week ending August 31, 2007. We now expect working natural gas stocks to reach 3,800 Bcf at the end of October, 235 Bcf above the previous record of 3,565 Bcf reported at the end of October 2007.

Natural Gas Prices. The Henry Hub spot price averaged \$3.50 per Mcf in July, \$0.41 per Mcf below the average spot price in June. Prices remain low as the drop in drilling activity thus far has failed to bring about the production decline necessary to slow the natural gas inventory build. Resilient production, high storage levels, and the potential for increases in both LNG and pipeline natural gas imports suggest that prices may fall below current projections before space-heating demand picks up this winter and economic conditions improve. We expect the Henry Hub spot price to increase from an average \$3.92 per Mcf in 2009 to \$5.48 per Mcf in 2010 because of the current decline in drilling activity and projected growth in consumption next year. However, sustained cutbacks in drilling activity or stronger demand than expected could lead to even higher prices. However, improvements in drilling technology and procedures are expected to limit price increases over the forecast period.

Electricity

Electricity Consumption. Total retail sales of electricity are projected to decline by 2.7 percent throughout the United States during 2009. Sales in the industrial sector are projected to decrease by about 10 percent this year due to the weak economy. The decline in the West South Central region is projected to be smaller than in other regions since hot summer weather has boosted residential electricity sales. Total electricity consumption is expected to rise by 0.8 percent in 2010 ([U.S. Total Electricity Consumption Chart](#)).

Electricity Prices. Residential electricity prices rose by about 7.5 percent during the first 5 months of 2009 as high generation fuel costs from last year were passed through to retail consumers. Lower generation fuel costs this year are expected to be passed through to retail consumers later this year, keeping the annual average growth in prices at around 4.2 percent in 2009 and 2.6 percent in 2010 ([U.S. Residential Electricity Prices Chart](#)).

Coal

U.S. Coal Consumption. Our projected electric-power-sector consumption of about 975 million short tons of coal in 2009 would be the first time since 2002 that annual

consumption falls below the billion-short-ton level. The 6.4-percent decline in coal consumption in the electric power sector is the result of lower total electricity generation combined with projected increases in generation from natural gas, hydroelectric, and wind. Coal consumption in the electric power sector is expected to increase by 1.3 percent in 2010 but remain below the billion-short-ton level. Coal regains a larger share of the baseload generation mix in 2010 in the forecast as rising natural gas prices hinder growth in natural-gas-fired generation. Coal consumption for both steam and coke production is projected to decline significantly in 2009; steam coal consumption by retail and general industry declines by 15 percent while coal consumption at coke plants declines by 42 percent ([U.S. Coal Consumption Growth Chart](#)).

U.S. Coal Supply. Coal production is expected to fall by nearly 8 percent in 2009 in response to lower domestic coal consumption, fewer exports, and higher coal inventories. Production is projected to decrease slightly (0.4 percent) in 2010 despite increases in domestic consumption and exports. Reductions in coal inventories and increased imports are projected to offset the increase in domestic coal consumption ([U.S. Annual Coal Production Chart](#)).

U.S. Coal Prices. Despite declines in electricity demand, decreases in spot coal prices, and lower costs for other fossil fuels, EIA expects the average delivered electric-power-sector coal price to increase from an average of \$2.07 per million Btu in 2008 to \$2.21 per million Btu in 2009. A significant portion of power-sector coal contracts were entered into during a period of high prices for all fuels. We expect the average delivered power-sector coal price to decline to \$2.03 per million Btu in 2010 as expiring high-priced contracts are replaced.

Carbon Dioxide Emissions

This *Outlook* introduces a short-term forecast of CO₂ emissions from the consumption of the three fossil fuels: coal, natural gas, and petroleum. The economic downturn, combined with natural gas displacing some coal as a source of electricity generation, is projected to lead to a 5-percent decline in fossil-fuel-based CO₂ emissions in 2009. We expect an improving economy to increase CO₂ emissions from fossil fuels by 0.7 percent in 2010.

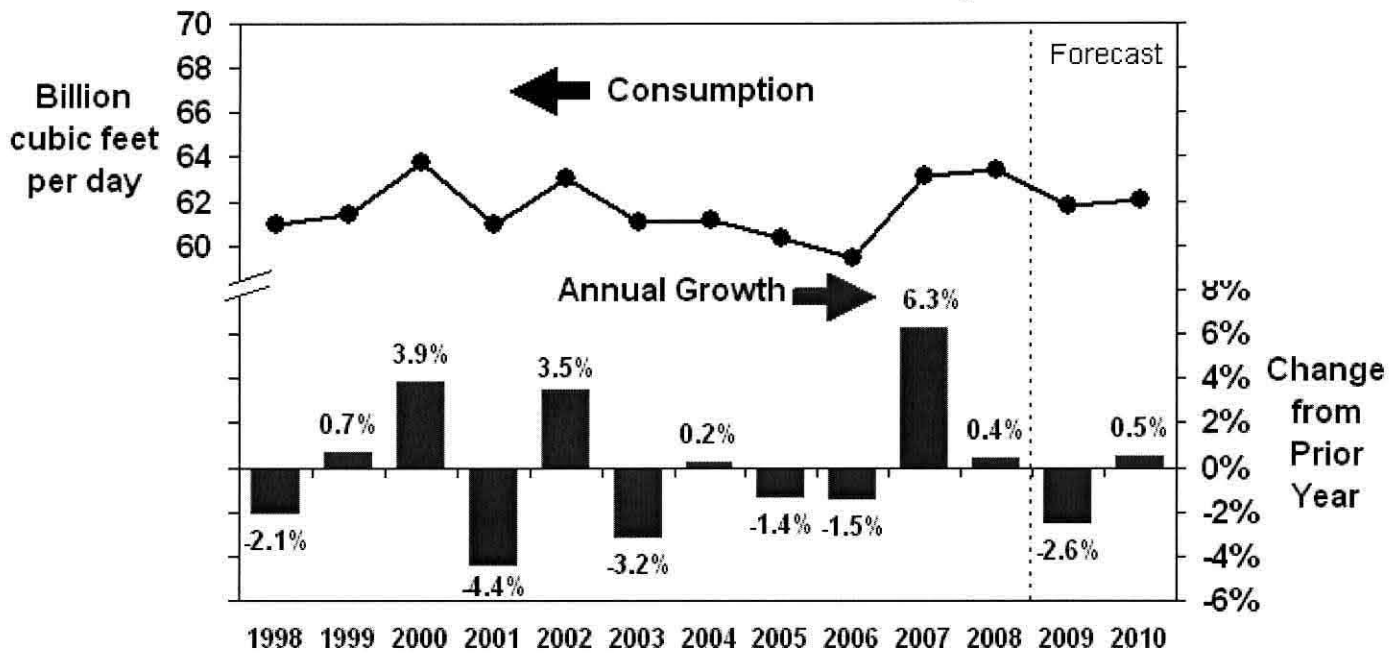
Petroleum CO₂ Emissions. Petroleum CO₂ emissions are expected to decline by 4 percent in 2009, primarily due to declines in transportation sector consumption. Although we expect little change in CO₂ emissions from motor gasoline during 2009, CO₂ emissions from other transportation petroleum fuels, particularly jet fuel (a 9.8-percent decline in consumption), distillate fuel oil (an 8.2-percent decline), and

residual fuel oil (a 6.3- percent decline), are expected to fall significantly. CO₂ emissions from petroleum in 2010 are projected to increase by 0.6 percent, which is lower than the 1.5-percent increase in total petroleum consumption primarily because of the continued growth in the biofuel share of the transportation fuel markets.

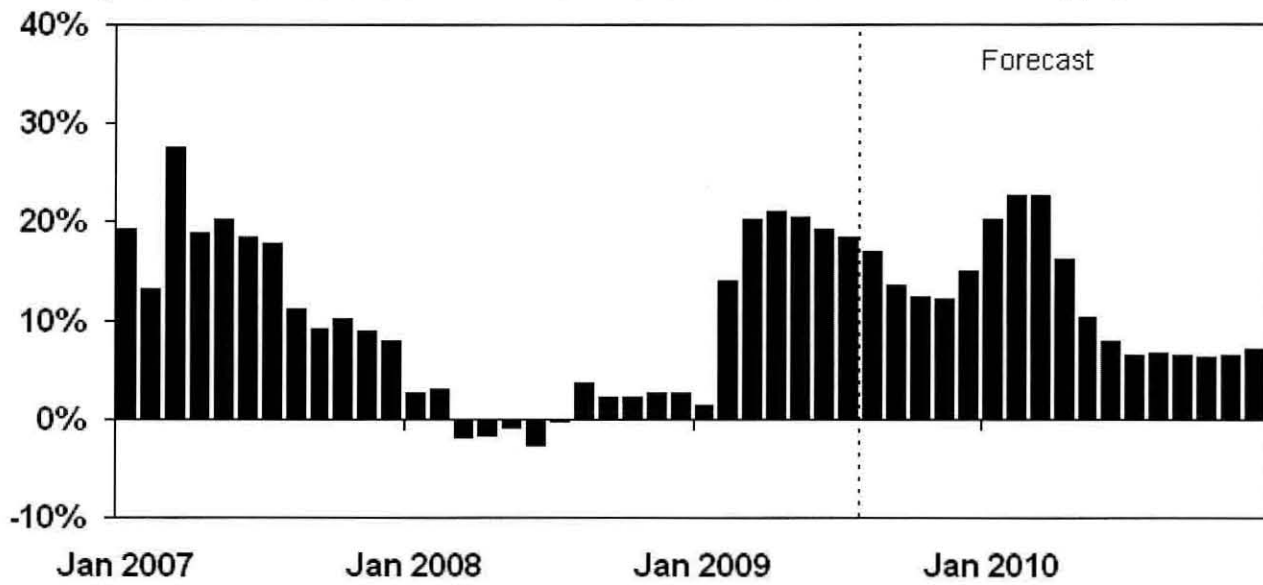
Coal CO₂ Emissions. Fuel switching in the electric power sector and declines in industrial use are projected to lead to a 7.9-percent decline in coal-based CO₂ emissions for 2009. Increases in coal consumption, primarily in the electric power sector, are expected to lead to a 1.1-percent increase in coal CO₂ emissions in 2010.

Natural Gas CO₂ Emissions. Natural gas-based CO₂ emissions are projected to decline by 2.3 percent in 2009 despite significant consumption increases in the electric power sector. Natural gas consumption is expected to decline in 2009 for all other major sectors. CO₂ emissions from natural gas are expected to grow slightly in 2010 as natural gas consumption increases by 0.5 percent.

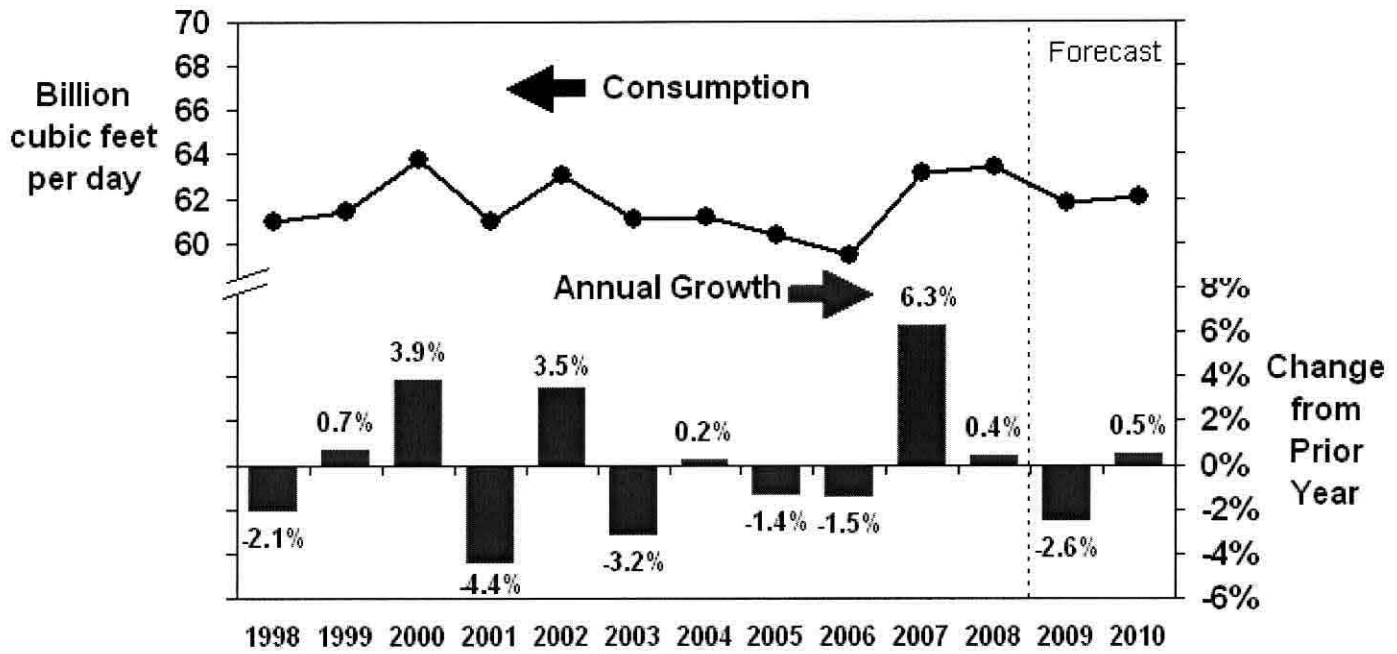
U.S. Total Natural Gas Consumption



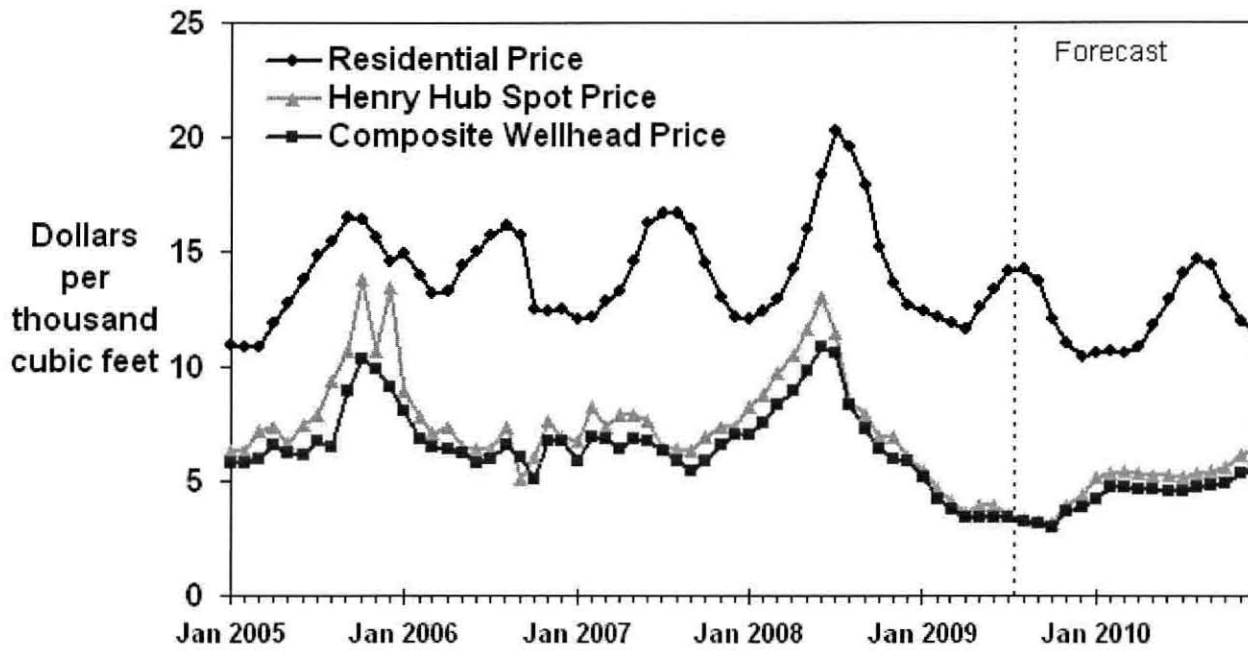
U.S. Working Natural Gas in Storage (Percent Difference from Previous 5-Year Average)



U.S. Total Natural Gas Consumption



Natural Gas Prices



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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ April 30, 2009									<u>\$65,941</u>
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
Balance @ July 31, 2009.									<u>\$131,625</u>

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**

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ April 30, 2009									<u>(\$110,191)</u>
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)
Balance @ July 31, 2009.									<u>(\$98,546)</u>

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).