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January 30, 2009

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

Re: Cost of Gas Adjustment (COG)  
February 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 (35<sup>th</sup> Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (35<sup>th</sup> Revised Sheet No. 8), showing the February 2009 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$1.2429 per mcf for residential and firm general service customers and \$1.2239 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for February 2009, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$1.2239 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 \$0.0190 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of \$1.2429 per mcf for residential and firm general service customers.

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

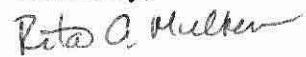
Attachment D shows the calculation of the balancing account since April 30, 2008.

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

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

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

Sincerely,



Rita A. Mulkern  
Regulatory Analysis Manager

Attachments



**Attachment A**

**Attachment A**



# GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

## State of North Dakota Gas Rate Schedule

NDPSC Volume 2  
35th Revised Sheet No. 1.1

### RATE SUMMARY SHEET

Canceling 34th Revised Sheet No.1.1

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	\$6.4590	\$7.7330 7.5130
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	\$3.7203	\$4.8594 4.6134 4.4614
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$3.7203	\$4.9594
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: January 30, 2009

Effective Date: February 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  
35<sup>th</sup> Revised Sheet No. 8  
Canceling 34<sup>th</sup> 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.	2.1467	0.5560	(0.1857)	2.5170	0.5560	(0.7309)	(0.1749)
Current Adj.	(0.0190)	(1.2239)	0.0000	(1.2429)	(1.2239)	0.0000	(1.2239)
Total Adj.	2.1277	(0.6679)	(0.1857)	1.2741	(0.6679)	(0.7309)	(1.3988)
Total Rate:	\$2.1935	\$4.4512	(\$0.1857)	\$6.4590	\$4.4512	(\$0.7309)	\$3.7203

**Date Filed:** January 30, 2009

**Effective Date:** February 1, 2009

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

**Case No.:**

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

<u>Firm</u>	<u>Billing</u> <u>Determinants</u>	<u>Rate</u>	<u>Demand</u> <u>Months</u>	<u>Amount</u>	<u>Amount</u> <u>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	9.9015	12	944,247	0.6031
Trans Canada - Demand Charge	7,947	9.9746	12	951,218	0.6076
ProGas - Demand Charge	7,947	0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068	9.9015	5	250,904	0.1603
Trans Canada - Seasonal	5,068	9.9746	5	252,756	0.1614
ProGas - Seasonal	5,068	0.9612	5	24,357	0.0156
ProGas Winter Surcharge	5,068	3.0049	5	76,144	0.0486
LMS Demand	2,500	1.0000	12	30,000	0.0192
Total Demand Charges				\$3,434,029	2.1935
Estimated Weighted Average Commodity Cost	1,565,565	1/ 4.4512		6,968,643	4.4512
Gas Cost Reconciliation Adjustment					(0.1857)
Total Current Firm Gas Cost				\$10,402,672	6.4590
Base Cost of Gas					5.1849
Accumulated Adjustment					\$1.2741
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$4.4512
Gas Cost Reconciliation Adjustment					(0.7309)
Total Current Interruptible Gas Cost					3.7203
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$1.3988)

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

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

<b>Rates Effective February 1, 2009</b>	\$/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	9.9015	Per dk/Mo.
Trans Canada Pipeline Demand Charge	9.9746	Per dk/Mo.
ProGas - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	9.9015	Per dk/Day
Trans Canada - Seasonal	9.9746	Per dk/Mo.
ProGas - Seasonal	0.9612	Per dk/Mo.
ProGas Winter Surcharge	3.0049	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	4.4512	Per dk

**Base Rate Effective July 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	\$5.1849	Per Mcf

Interruptible:

Commodity	\$5.1191	Per Mcf
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1/ Demand base rate calculation:  $4,768 \times 12 \times \$0.8100 / 707,222$

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. 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

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

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

STATEMENT OF RATES (Rates Per Dekatherm)				
Rate Schedule -----	Base Tariff Rate -----	Adjustment Under Section 19 1/ -----	Rate After Current Adjustment -----	Fuel and Loss Retention Percentages 2/ -----
Commodity Rates				
FT-A - Maximum Rates				
Zone 1 - 1	\$0.0130	\$0.0017	\$0.0147	1.95%
Zone 1 - 2	\$0.0130	\$0.0017	\$0.0147	2.31%
Zone 2 - 2	\$0.0130	\$0.0017	\$0.0147	0.36%
Minimum Rate	\$0.0130	\$0.0017	\$0.0147	
IT and AOT				
Zone 1 - 1	\$0.1368	\$0.0017	\$0.1385	1.95%
Zone 1 - 2	\$0.1737	\$0.0017	\$0.1754	2.31%
Zone 2 - 2	\$0.0834	\$0.0017	\$0.0851	0.36%
Minimum Rate	\$0.0130	\$0.0017	\$0.0147	
1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of \$0.0017 per Dekatherm shall be added to other charges under Company's Rate Schedules.				
2/ Fuel and Losses Retention Percentages shall be applicable to all transportation rate schedules.				
Transportation Fuel and Loss Retention Percentages are inclusive of the following percentages for Gas Lost and Unaccounted For: .26% for Zone 1-1, .31% for Zone 1-2, and .05% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted For percentages.				

Issued by: J. Phill May, Vice President Commercial

Issued on: October 1, 2008

Effective on: November 1, 2008

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

Thirteenth Revised Sheet No. 5C  
Superseding  
Substitute Twelfth 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		(\$0.0286)	

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

Issued by: J. Phill May, Vice President Commercial

Issued on: February 29, 2008

Effective on: April 1, 2008

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

Attachment B  
 Page 6 of 7

FIELD-TO-  
 FIELD/MARKET  
 DEMARCATION

MARKET-TO-MARKET

RESERVATION RATES

TF12 Base Variable TF5

TF6

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
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.

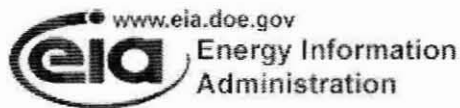
**Great Plains Natural Gas Co.  
Market Conditions for Wahpeton's Natural Gas  
February 2009**

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 February monthly price for the AECO Index is expected to decrease from the previous month. The AECO Index is based on the weighted average one month spot price at AECO-C and Nova Inventory Transfer (N.I.T.) as reported by Natural Gas Exchange (NGX).

Likely key factors contributing to the decline of natural gas prices include a lower level of industrial demand for natural gas, as a result of the ongoing economic downturn, and relatively low crude oil prices. The Energy Information Administration (EIA) reported storage levels nationwide as of January 23, 2009 were 1.2 percent above the five-year average and 1.5 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.



January 2009

## Short-Term Energy Outlook

January 13, 2009 Release

### *Highlights*

- This edition of the *Short-Term Energy Outlook* is the first to include monthly forecasts through December 2010.
- The energy forecast is sensitive to economic conditions. In this forecast, U.S. real gross domestic product (GDP) is expected to decline by 2 percent in 2009, leading to decreases in domestic energy consumption for all major fuels. Economic recovery is projected to begin in 2010, with 2 percent year-over-year growth in GDP.
- In the past 6 months, the monthly average price of West Texas Intermediate (WTI) crude oil has fallen from \$133 per barrel in July to \$41 in December. WTI prices are projected to average \$43 per barrel in 2009 and \$55 in 2010.
- Average monthly U.S. prices for regular gasoline and diesel fuel were \$1.69 and \$2.45 per gallon, respectively, in December 2008, more than \$2.25 per gallon below their monthly peaks last July. Economic contraction in 2009 and lower projected crude oil prices are expected to reduce annual average retail gasoline and diesel fuel prices in 2009 to \$1.87 and \$2.27 per gallon, respectively.
- Residential heating oil prices during the current (2008-09) heating season are projected to average \$2.48 per gallon, a reduction of 25 percent from the 2007-2008 heating season. Residential propane prices are projected to average \$2.14 this winter, a decrease of 13 percent from last winter. Residential natural gas prices are projected to average \$12.17 per thousand cubic feet (Mcf), a decrease of 4 percent from last winter.
- The U.S. economic downturn is also contributing to lower natural gas prices. The Henry Hub natural gas spot price is projected to decline from an average of \$9.13 per Mcf in 2008 to \$5.78 per Mcf in 2009, but then increase in 2010 to an average of \$6.63 per Mcf.

## *Global Petroleum*

**Overview.** The downward trend in oil prices continued in December as the worsening global economy weakened oil demand and the second Organization of Petroleum Exporting Countries (OPEC) agreement for substantial production cuts within a month has failed, thus far, to support substantially higher prices. The outlook for supply and demand fundamentals indicates a fairly loose oil market balance over the next 2 years. The global economic downturn points to declining oil consumption in 2009, while additional production capacity from both OPEC and non-OPEC nations should boost surplus production capacity, reducing the likelihood of a renewed strong upward pressure on prices. Global real GDP growth (weighted according to shares of world oil consumption) is assumed to be 0.6 percent in 2009 and 3.0 percent in 2010. These projections compare with 4.6 percent real GDP growth in 2007 and 3.2 percent in 2008. The oil price path going forward will be driven mainly by the depth and duration of the global economic downturn, the pace and timing of the recovery, and actual OPEC production.

**Consumption.** World oil consumption continues to be revised downward in response to the global economic downturn. Global consumption is estimated to have been largely unchanged in 2008 and is projected to fall by 800,000 barrels per day (bbl/d) in 2009. Total world oil consumption is expected to record a modest rebound in 2010, rising by 880,000 bbl/d from year-earlier levels, on the assumption of the beginning of an expected recovery in global economic growth. Oil consumption growth is concentrated in countries outside of the Organization for Economic Cooperation and Development (OECD), particularly China, the Middle East, and Latin America. However, projected declines in oil consumption in OECD countries more than offset any non-OECD oil consumption growth in 2009 ([World Oil Consumption](#)). If the world economic recovery happens sooner or is stronger than EIA now anticipates, oil consumption could decline at a slower rate or potentially increase at a faster rate than expected, putting upward pressure on oil prices.

**Non-OPEC Supply.** Non-OPEC supply is projected to rise modestly over the next 2 years. After falling by 340,000 bbl/d in 2008 because of project delays and disruptions in Central Asia and the Gulf of Mexico, non-OPEC supply is projected to grow by about 180,000 bbl/d in 2009 and 90,000 bbl/d in 2010. These projections assume that unexpected delays to new non-OPEC supply that have occurred in the past will continue through the forecast period. Supply growth in countries such as the United States, Brazil, and Azerbaijan is expected to more than compensate for continued declines in many non-OPEC nations, particularly Mexico, the North Sea, and Russia. The global economic slowdown and falling oil prices bring additional risk to the usual

uncertainties concerning non-OPEC supply growth, such as unexpected disruptions, project delays, and underestimation of decline rates. Lower oil prices bring into doubt the viability of some high-cost non-OPEC projects, especially those utilizing nonconventional technology or those seeking to exploit frontier oil basins. The credit crunch associated with the global economic crisis can also make it difficult to acquire financing for new projects or even finance the investment required to prevent accelerated declines at producing fields. If conditions in global financial markets lead to delayed investment in existing and new oil fields, then even a short-lived economic downturn could have longer-term ramifications for world oil supply. This would heighten the risk of a return to a tight supply situation once the world economy and oil demand growth recover.

***OPEC Supply.*** OPEC's December announcement that it would cut crude oil production again, following its earlier cut in November, has not yet led to a substantial increase in oil prices. Together, the two announced cuts imply a new overall target for production (excluding Iraq) of 24.845 million bbl/d, 4.2 million bbl/d below actual September production. However, the market is not presently convinced that OPEC members will willingly curtail output enough to lead to much higher prices. Adherence to the announced cuts will be challenging, as several individual countries are motivated to maintain production at higher levels to generate revenue needed to finance their government programs amid falling prices. The lack of transparency in the new agreement, highlighted by the failure to publicize individual country production cuts, is one indicator of the reluctance of countries to cut production consistent with the group's new overall production target. OPEC plans to meet again on March 15 in Vienna to evaluate the effectiveness of its recent actions.

EIA projects that total OPEC crude oil production (including Iraq) will fall by more than 2 million bbl/d, from 31.4 million bbl/d in September 2008 to 29.3 million bbl/d in the first quarter of 2009, implying a compliance rate of a little more than 50 percent. Because of Indonesia's exit from OPEC, EIA has revised its historic and forecasted values for OPEC oil production to be consistent with the current membership. OPEC crude oil production is expected to average 30.0 million bbl/d in 2009 and 30.7 million bbl/d in 2010. In addition, EIA expects that OPEC production of non-crude liquids will rise substantially next year, growing by 600,000 bbl/d in 2009 and by 850,000 bbl/d in 2010. The combination of lower demand for OPEC crude oil and the capacity expansions expected in several OPEC countries means that surplus production capacity could increase to roughly 4.0 million bbl/d in 2009 and 4.7 million bbl/d by the end of 2010, compared with the 1 to 2 million bbl/d of surplus capacity available over the past several years (OPEC Surplus Oil Production Capacity).

**Inventories.** Revised data indicate that OECD commercial inventories rose by 330,000 bbl/d in the third quarter of 2008, lower than historic rates for inventory builds during that time of year. OECD commercial inventories stood at 2.63 billion barrels at the end of the third quarter, equivalent to 57 days of forward consumption cover. On the basis of days of forward cover, OECD commercial inventories are well above average historic levels, and EIA projects that they will remain there through the end of 2010 (Days of Supply of OECD Commercial Stocks). The combination of substantial surplus capacity and above-average inventories should dampen price pressure over the period. In any event, a sustained rebound in prices is not likely until the economic recovery causes a sustained rebound in demand for OPEC crude oil.

### ***U.S. Petroleum***

**Consumption.** The increase in prices to record levels in 2008 and the weakening economy drove total petroleum products consumption down by about 1.2 million bbl/d, or 5.7 percent, from the 2007 average (U.S. Petroleum Products Consumption Growth). Motor gasoline consumption declined by slightly more than 300,000 bbl/d, or 3.3 percent. Despite the cold weather that gripped much of the Nation in December, distillate fuel consumption in 2008 declined by 5.3 percent from the year before. In 2009, total petroleum products consumption is projected to fall by nearly 400,000 bbl/d, or 2 percent, due to continued economic weakness. Consumption for both motor gasoline and distillate fuel are forecasted to decline by about 100,000 bbl/d each. The expected economic recovery in 2010 is projected to boost total petroleum products consumption by 150,000 bbl/d, or 0.8 percent, and both motor gasoline and distillate consumption are each projected to rise by about 50,000 bbl/d.

**Production.** In 2008, domestic crude oil production averaged 4.9 million bbl/d, down by 140,000 bbl/d from 2007 (U.S. Crude Oil Production). However, in 2009, domestic output is projected to increase by over 300,000 bbl/d to an average of 5.25 million bbl/d. This would be the first increase in production since 1991. Output is projected to rise by a further 50,000 bbl/d in 2010. Contributing to the increases in output are the Gulf of Mexico Thunder Horse platform, which is coming on stream now, and the Tahiti platform, expected to come on stream late in 2009.

**Prices.** Having fallen from record highs to below \$40 per barrel, WTI prices averaged near \$100 per barrel in 2008. Under current economic assumptions and assuming no major crude oil supply disruptions, WTI prices are expected to average \$43.25 per barrel in 2009 and \$54.50 per barrel in 2010 (Crude Oil Prices).

Regular-grade gasoline prices averaged \$1.68 per gallon on January 5, down substantially from their July 14 peak of \$4.11 per gallon. These prices are projected to

average \$1.87 per gallon in 2009 and \$2.18 per gallon in 2010. Because of lower motor gasoline consumption, the difference between the retail gasoline price and the cost of crude oil is expected to remain narrow for much of 2009 but is expected to increase slightly in 2010.

On-highway diesel fuel retail prices, which averaged \$3.79 per gallon in 2008, are projected to average \$2.27 per gallon in 2009 and \$2.54 in 2010. The projected continuation of the decline in the consumption of diesel fuel in the United States as well as a slowing of the growth in distillate fuel usage outside the United States are expected to result in a weakening of refining margins for distillate throughout the forecast.

### *Natural Gas*

**Consumption.** Total natural gas consumption is estimated to have increased by 0.7 percent in 2008, primarily driven by a 5.8-percent increase in heating degree-days year-over-year. Natural gas consumption is projected to decline by 1.0 percent in 2009 and then increase by 0.7 percent in 2010 (Total U.S. Natural Gas Consumption Growth). The demand outlook for 2009 is largely driven by expectations of continued economic weakness. The slight consumption growth projected in the residential sector is expected to be more than offset by consumption declines in the commercial, industrial, and electric power sectors this year. With the natural-gas-weighted industrial production index projected to fall by 6.6 percent in 2009, industrial sector natural gas consumption is expected to decline by 3.0 percent. Consumption growth in 2010 is expected to be limited to the electric power sector, with all other sectors expected to decline slightly.

**Production and Imports.** Total U.S. marketed natural gas production is estimated to have increased by 5.9 percent in 2008 led by the development of unconventional reserves in the Lower-48 States. Total marketed production is expected to increase by 0.7 percent in 2009, and then decline by 0.9 percent in 2010. Producers have already begun to react to lower prices and the outlook for lower consumption as evidenced by the recent pullback in drilling activity. The number of rigs drilling for natural gas in the Lower-48 onshore region has fallen from about 1,540 in August 2008 to under 1,200 at the beginning of January 2009. Despite the cutback in drilling activity, the current outlook suggests that some production curtailments may be necessary during the latter part of 2009 in order to balance the market. Nevertheless, in 2009, Lower-48 production outside of the Gulf of Mexico (GOM) region is expected to increase by 1.0 percent. Although drilling activity is expected to begin recovery in 2010, production is projected to decline relative to 2009 by 4.7 percent in the Federal GOM and by 0.4 percent in the Lower-48 non-GOM.

U.S. imports of liquefied natural gas (LNG) are estimated to have totaled about 350 billion cubic feet (Bcf) in 2008. Shipments of LNG to the United States are currently expected to rise to about 420 Bcf in 2009. However, limits to natural gas storage capacity outside the United States could unexpectedly boost U.S. imports of LNG during the summer months if global demand for natural gas does not increase as expected. U.S. LNG imports in 2010 are projected to reach a little more than 500 Bcf.

*Inventories.* On January 2, 2009, working natural gas in storage was 2,830 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 87 Bcf above the 5-year average (2004-2008), and 31 Bcf above the level during the corresponding week last year. Storage inventories are expected to finish the 2009 winter season (March 31, 2009) at over 1.5 trillion cubic feet (Tcf), about 270 Bcf above the corresponding period last year, but below the 1.7 Tcf mark recorded in 2006. The expected supply overhang throughout the 2009 injection season (April 1 to October 31) is projected to send the resulting working gas inventories near the previous high reported on November 2, 2007.

*Prices.* The Henry Hub spot price averaged \$9.13 per Mcf in 2008 but ended the year averaging \$5.99 per Mcf in December. Weak natural gas demand associated with poor economic conditions together with strong domestic production growth contributed to the recent decrease in prices that is expected to persist in 2009. On an annual basis, the Henry Hub spot price is expected to average \$5.78 per Mcf in 2009 and \$6.63 per Mcf in 2010. As consumption reacts to worsening economic factors, natural gas prices may need to fall further than currently forecast in order to restrain production activities and balance the market during the second half of 2009, particularly as inventory nears storage capacity. Prices are expected to begin to increase in 2010 as the economy improves.

### *Electricity*

*Consumption.* Total electricity consumption is projected to decline by 0.5 percent in 2009 (U.S. Total Electricity Consumption), with an expected 3.6-percent decline in electricity sales to the industrial sector during due to economic conditions partially offset by slight growth in residential electricity sales. Total electricity consumption is expected to rebound in 2010 by 1.5 percent, driven by growth in the commercial and residential sectors.

*Prices.* A number of utilities that increased electricity rates last summer have begun reducing prices in response to fuel costs which have fallen from last year's peak levels.

Other utilities are pursuing slight increases to cover the cost of upgrades to generation and transmission facilities. Overall, U.S. residential electricity prices are forecast to grow by 2.3 percent in 2009 and by 2.0 percent in 2010 ([U.S. Residential Electricity Prices](#)).

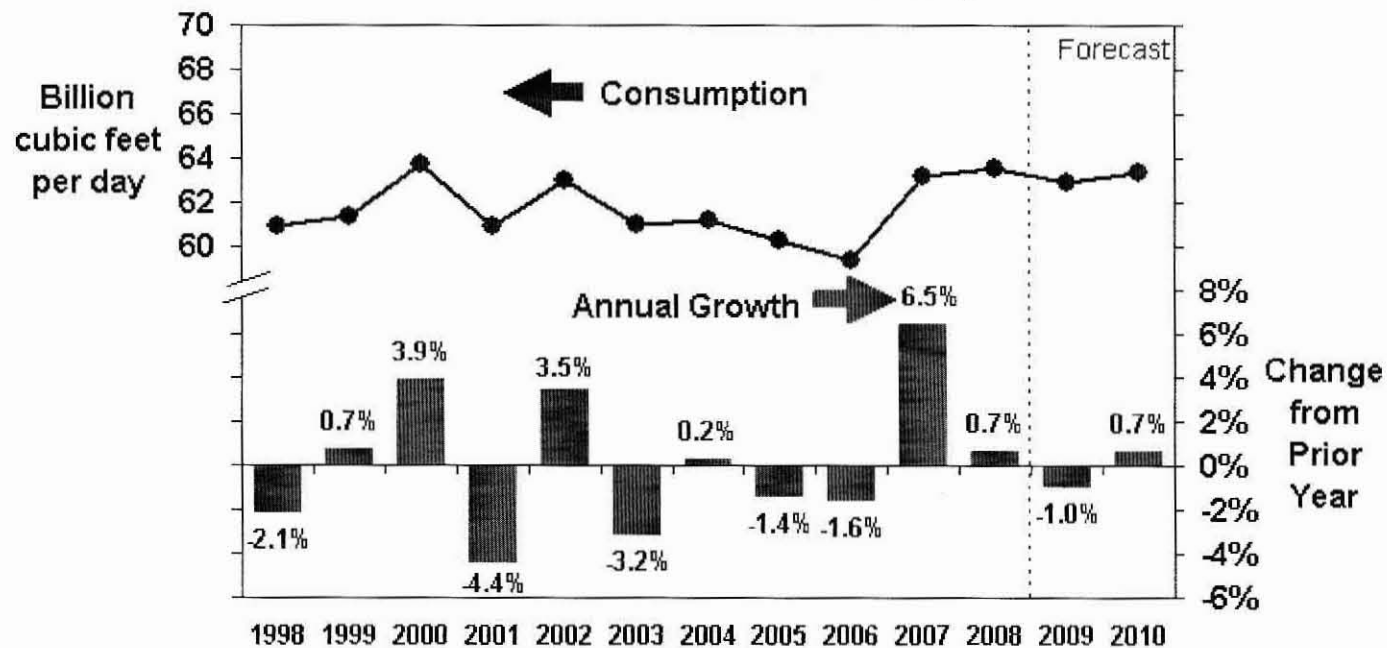
## *Coal*

**Consumption.** The projected decline in electricity consumption, combined with projected increases from other generation sources (nuclear, petroleum, and wind) will lead to a 0.7-percent decline in electric-power-sector coal consumption, which accounts for more than 90 percent of total coal consumption. An expected increase in electricity consumption in 2010 of 1.5 percent will lead to a 1.9-percent increase in electric-power-sector coal consumption. Consumption growth in the coke plant sector is estimated to have been flat in 2008 but is expected to fall by 8.2 percent in 2009 and by 5 percent in 2010 due to the economic slowdown. Retail and other industrial sector coal consumption is expected to decline by 9.0 percent in 2009 but increase by 0.7 percent in 2010 as economic conditions improve ([U.S. Coal Consumption Growth](#)).

**Production.** A significant increase in coal exports in 2008 contributed to a 2.8-percent increase in coal production. Production is expected to fall in 2009 by 4.0 percent as lower total domestic coal consumption is combined with declines in exports and a small increase in imports. Production is projected to increase by 2.4 percent in 2010 as domestic consumption and exports increase with an improving economy ([U.S. Annual Coal Production](#)).

**Exports.** Reductions in global coal demand, coupled with the return to normal supply conditions in major coal-producing and exporting countries that experienced disruptions during 2008, are expected to reduce U.S. coal exports, which grew by nearly 40 percent in 2008, by 10 million short tons in 2009, a 12-percent decrease. The improving global economy in 2010 will spur global coal demand and this will lead to a projected 12-percent increase in exports.

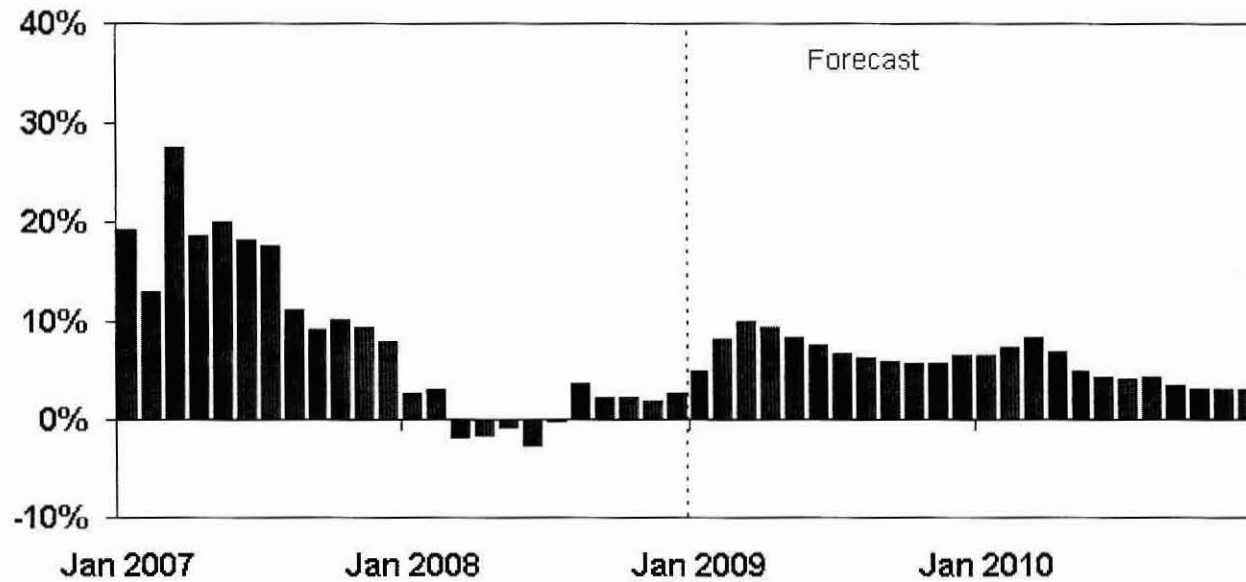
## U.S. Total Natural Gas Consumption



Short-Term Energy Outlook, January 2009



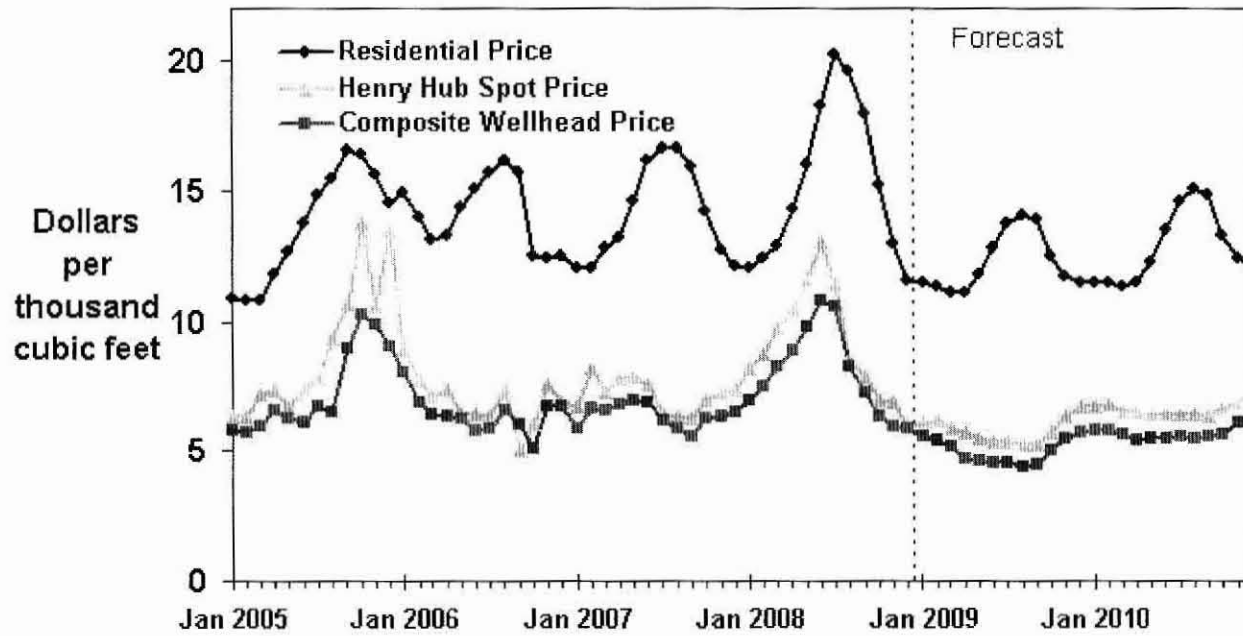
## U.S. Working Natural Gas in Storage (Percent Difference from Previous 5-Year Average)



Short-Term Energy Outlook, January 2009



## Natural Gas Prices



Short-Term Energy Outlook, January 2009



**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 &amp; 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>
<b>Balance @ April 30, 2008</b>									<b><u>(\$46,836)</u></b>
May	(\$7,154)	\$0	(\$671)	(\$7,825)	17,007	\$0.7009	\$11,920	(\$19,745)	(66,581)
June	25,399	0	(868)	24,531	9,026	(0.1857)	(1,676)	26,207	(40,374)
July	12,556	0	(565)	11,991	6,909	(0.1857)	(1,283)	13,274	(27,100)
August	47,784	0	(408)	47,376	5,577	(0.1857)	(1,036)	48,412	21,312
September	26,255	0	135	26,390	6,028	(0.1857)	(1,119)	27,509	48,821
October	13,043	0	440	13,483	8,294	(0.1857)	(1,540)	15,023	63,844
November	16,133	0	605	16,738	18,404	(0.1857)	(3,418)	20,156	84,000
December	(4,149)	(2,340) 2/	829	(5,660)	34,013	(0.1857)	(6,316)	656	84,656
<b>Balance @ December 31, 2008</b>									<b><u>\$84,656</u></b>

1/ Interest calculated at 13.3%, the authorized rate of return.

2/ December 2008 Northern Natural Gas refund.

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

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

1/ Interest calculated at 13.3%, the authorized rate of return.

2/ December 2008 Northern Natural Gas refund.