ORIGINAL

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

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

December 1, 2008

RECEIVED

DEC 02 2008

PUBLIC SERVICE COMMISSION

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

Re: Cost of Gas Adjustment (COG)
December 2008

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 (33rd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (33rd Revised Sheet No. 8), showing the December 2008 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $0.1891 per mcf for residential and firm general service customers and $0.4487 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for December 2008, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $0.4487 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 $0.2596 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of $0.1891 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 respectfully requests this filing be accepted as being in full compliance with the filing requirements of this Commission.

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

Sincerely,

Rita A. Mulkern

Rita A. Mulkern
Regulatory Analysis Manager

Attachments

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

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

Dated this 1st day of December 2008.

Rita A. Mulkern

Rita A. Mulkern

Subscribed and sworn to before me this 1st day of December 2008.

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

Sara J. Graf

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

Attachment A

State of North Dakota
Gas Rate Schedule

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/MCF
Firm Gas Service - General	2	$3.50 per month	First 10 MCF	$1.2740	$8.2725	$9.5465
			Over 10 MCF	1.0540		9.3265
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$5.4439	$6.5830
			Next 2,600 MCF	0.8931		6.3370
			Over 3,000 MCF	0.7411		6.1850
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$5.4439	$6.6830
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

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.	2.4772	0.6070	(0.1857)	2.8985	0.6070	(0.7309)	(0.1239)
Current Adj.	(0.2596)	0.4487	0.0000	0.1891	0.4487	0.0000	0.4487
Total Adj.	2.2176	1.0557	(0.1857)	3.0876	1.0557	(0.7309)	0.3248
Total Rate:	$2.2834	$6.1748	($0.1857)	$8.2725	$6.1748	($0.7309)	$5.4439

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
DECEMBER 2008

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A	7,841		$3.4671	12	$326,226	$0.2084
FT-A - Zone 1-1	500		3.4671	5	8,668	0.0055
FT-A - Zone 1-2	4,500		4.5871	5	103,210	0.0659
FT-A Seasonal	3,000		3.7671	5	56,507	0.0361
FT-A Seasonal	1,000		3.7671	4	15,068	0.0096
TFX Seasonal	4,000		15.1530	5	303,060	0.1936
NOVA - Demand Charge	7,947		9.1534	12	872,905	0.5576
Trans Canada - Demand Charge	7,947		12.0895	12	1,152,903	0.7364
ProGas - Demand Charge	7,947		0.7598	12	72,458	0.0463
NOVA - Seasonal	5,068		9.1534	5	231,947	0.1482
Trans Canada - Seasonal	5,068		12.0895	5	306,348	0.1957
ProGas - Seasonal	5,068		0.7598	5	19,253	0.0123
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					$3,574,697	2.2834
Estimated Weighted Average Commodity Cost	1,565,565	1/	6.1748		9,667,051	6.1748
Gas Cost Reconciliation Adjustment						(0.1857)
Total Current Firm Gas Cost					$13,241,748	8.2725
Base Cost of Gas						5.1849
Accumulated Adjustment						$3.0876

Interruptible	
Estimated Weighted Average Commodity Cost	$6.1748
Gas Cost Reconciliation Adjustment	(0.7309)
Total Current Interruptible Gas Cost	5.4439
Base Cost of Gas	5.1191
Accumulated Adjustment	$0.3248

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

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
DECEMBER 2008

Rates Effective December 1, 2008	$/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	9.1534	Per dk/Mo.
Trans Canada Pipeline Demand Charge	12.0895	Per dk/Mo.
ProGas - Demand Charge	0.7598	Per dk/Mo.
NOVA - Seasonal	9.1534	Per dk/Day
Trans Canada - Seasonal	12.0895	Per dk/Mo.
ProGas - Seasonal	0.7598	Per dk/Mo.
ProGas Winter Surcharge	3.0049	
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	6.1748	Per dk

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

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

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

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

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

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

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

STATEMENT OF RATES
(Rates Per Dekatherm)

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

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

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

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

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

RATE SCHEDULE TF

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

COMMODITY RATES 2/
TF12 Base, TF12 Var., TF5 & TFF

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

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

RATE SCHEDULES TFX and LFT

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

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

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

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

**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
December 2008**

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 December monthly price for the AECO Index is expected to increase 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).

The price increase can likely be attributed to the seasonal increase in space heating load in the consuming regions of the U.S. The higher than average storage level and strong increase in domestic supply are contributing factors to the projected December 2008 index price approximately ten percent less than the December 2007 price. The Energy Information Administration (EIA) reported storage levels nationwide as of November 14, 2008 were 4.2 percent above the five-year average and 1.4 percent below last year's balance.

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

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

www.eia.doe.gov
Energy Information Administration

November 2008

Short-Term Energy Outlook

November 12, 2008 Release

Highlights

- The current U.S. and global economic downturn has led to a decrease in global energy demand and a rapid and substantial reduction in crude oil and other energy prices. As a result, projections for both energy demand and prices are considerably lower than last month's *Outlook.*

- The monthly average price of West Texas Intermediate (WTI) crude oil fell from over $133 per barrel in July to about $77 per barrel in October, indicative of the abrupt decline in world petroleum demand growth. The annual average WTI price is now projected to be $101.45 per barrel in 2008 and $63.50 in 2009.

- The average U.S. prices for regular-grade gasoline and diesel fuel, at $2.22 and $2.94 per gallon respectively on November 10, were both more than $1.80 per gallon below their highs in mid-July. With a weak economy continuing through most of 2009, along with lower projected crude oil prices, the annual average retail gasoline and diesel prices in 2009 are projected to be $2.37 and $2.73 per gallon, respectively.

- Residential heating oil prices during the current heating season (October though March) are projected to average $2.75 per gallon, a reduction of about 17 percent from the 2007-2008 heating season. Residential propane prices are projected to average $2.22 this winter, a decrease of 10 percent from last winter. Residential natural gas prices are projected to average $13.02 per thousand cubic feet (Mcf), an increase of 2 percent from last winter.

- The impact of the economic downturn on demand is also lowering current and expected natural gas prices. The Henry Hub natural gas spot price is projected to average $9.27 per Mcf in 2008. The projected 2009 annual average Henry Hub price is $6.82 per Mcf compared with $8.17 in the previous *Outlook.*

Economic Outlook

The recent dramatic deterioration in the outlook for economic growth in the United States and the rest of the world has led to a significant reduction in this *Outlook*'s assumptions for world economic growth and projections of energy demand and prices. World real gross domestic product (GDP) growth is projected to slow from about 4 percent in 2006 and 2007 to about 2.5 percent this year and 1.8 percent in 2009. Last month's *Outlook* assumed world GDP would increase by 3.0 percent in 2008 and by 2.8 percent in 2009. Previous lows for world economic growth were 0.3 percent in 1982, 1.7 percent in 1993, and 1.5 percent in 2001.

The year-over-year changes in U.S. real GDP in last month's *Outlook* were 1.8 percent growth in 2008 and 0.8 percent growth in 2009. U.S. real GDP growth in the current *Outlook* has been lowered to 1.3 percent for 2008 and is projected to decline by 1.4 percent in 2009. The 2009 average unemployment rate has been raised from 6.2 percent to 7.9 percent in this forecast. The U.S. manufacturing production index was lowered by 1.1 percent and 7.0 percent for 2008 and 2009, respectively, with the 2009 growth rate of the index falling from a positive 0.5 percent (growth) to negative 5.5 percent (decline).

Global Petroleum

Overview

Rising prices, especially the high oil prices in the first half of 2008, and slowing global economic growth have caused oil demand growth to slow dramatically. The recent announcement by the Organization of the Petroleum Exporting Countries (OPEC) to lower its production target by 1.5 million barrels per day (bbl/d), effective November 1, is aimed at offsetting this lower oil demand and stabilizing prices at or above recent levels. OPEC members plan to meet again in Algeria on December 17 to review market conditions.

Future price levels will primarily depend on the magnitude and duration of the economic downturn as well as OPEC and non-OPEC behavior. Our current expectation of future oil prices assumes that the OPEC production cut may limit, but not reverse, the recent sharp fall in oil prices. We project oil prices to remain relatively flat, averaging $60 to $65 per barrel throughout 2009. The condition of the global economy is expected to remain the most important factor driving world oil prices.

Consumption. World oil consumption is projected to increase by almost 100,000 bbl/d in 2008 and to remain virtually flat in 2009. In both years, growth in countries outside of the Organization for Economic Cooperation and Development (OECD)— especially China, Latin America, and oil-exporters in the Middle East—offset projected sharp declines in oil consumption in OECD countries (World Oil Consumption). Between 2007 and 2009, non-OECD oil consumption is projected to rise by 2.3 million bbl/d compared with a decline of 2.2 million bbl/d in the OECD. We expect economic growth in non-OECD countries not to fall as precipitously as in the OECD countries, with the non-OECD countries maintaining modest oil demand growth.

Non-OPEC Supply. Non-OPEC supply is expected to decline in 2008, but growth should return in 2009 because of projects currently near completion. EIA expects non-OPEC supply to fall by 280,000 bbl/d in 2008. A combination of factors contributed to the decline in 2008, including project delays and large supply disruptions in Central Asia and the Gulf of Mexico. EIA projects that non-OPEC supply will grow by 500,000 bbl/d in 2009, with the largest sources of growth coming from the United States, Azerbaijan, and Brazil. In the United States, production of petroleum and other liquids is expected to rise by 450,000 bbl/d in 2009 because of the start-up of several offshore crude oil production platforms, recovery from hurricane-induced shut-ins, and continuing growth in fuel ethanol production.

Non-OPEC supply growth is at continual risk to unexpected disruptions or project delays, but the global economic slowdown brings additional difficulties as well. Lower oil prices bring into doubt the viability of some high-cost non-OPEC projects. If problems 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 thereby oil demand growth) recovers.

OPEC Supply. OPEC decided at its October meeting to cut its crude oil production targets by 1.5 million bbl/d in response to the global economic slowdown, weakening oil demand, falling oil prices, and in anticipation of rising non-OPEC supplies. The extent of actual OPEC compliance to its new production target is uncertain. This *Outlook* assumes that the recent sharp decline in oil prices will lead to compliance that is above historical levels. EIA projects that OPEC crude oil production will fall from 32.3 million bbl/d in October 2008 to 31.3 million bbl/d in the first quarter of 2009, where it will remain relatively stable through the end of 2009. This represents a decline of 1 million bbl/d from October 2008 production levels, or about 70 percent of the announced cut. Last month's assessment already had a 600,000-bbl/d reduction in OPEC crude production over this period, so the new estimate represents an additional 400,000-bbl/d cut from last month's *Outlook*.

Lower crude oil production, combined with planned increases in OPEC production capacity, suggests OPEC surplus production capacity could increase from 1.6 million bbl/d in the second quarter of 2008 to nearly 4 million bbl/d by the end of next year (OPEC Surplus Oil Production Capacity). Although it is possible that weak market conditions could delay some of these capacity expansion plans, EIA expects OPEC surplus production capacity to rise above 3 million bbl/d next year for the first time since 2003, which would provide Saudi decision makers with a cushion large enough to provide a capability to dampen the impact of future disruptions or geopolitical uncertainties on oil prices.

Inventories. Revised data indicate that OECD commercial inventories rose by 400,000 bbl/d in the second quarter of 2008, or at about half of the historic level of inventory build rate during this time of year. OECD commercial inventories stood at 2.6 billion barrels at mid-year, or 56 days of forward consumption cover. On the basis of days of forward cover, OECD commercial inventories are well above historic levels, and EIA projects that they will remain there through the end of 2009 (Days of Supply of OECD Commercial Stocks).

U.S. Petroleum

Consumption. Consumption of all petroleum products is projected to decline substantially in 2008, driven down by the increase in prices and by a weakening economy during the second half of the year. Total domestic petroleum consumption is projected to average 19.6 million bbl/d in 2008, down 1.1 million bbl/d, or 5.4 percent, from the 2007 average (U.S. Petroleum Products Consumption Growth). This marks the first time since 1980 that annual total petroleum consumption is expected to decline by more than 1 million bbl/d. In 2008, motor gasoline consumption is projected to decline by 280,000 bbl/d, or 3 percent, and distillate fuel consumption is projected to decline by 250,000 bbl/d, or 6 percent. In 2009, total petroleum product consumption is projected to sink by a further 250,000 bbl/d, or 1.3 percent. This decline is more than twice that projected in the previous *Outlook.*

Production. In 2008, domestic crude oil production is projected to average 4.9 million bbl/d, down 120,000 bbl/d from 2007 levels. This is primarily due to the loss of production in the Federal Gulf of Mexico caused by Hurricanes Ike and Gustav (U.S. Crude Oil Production). Domestic crude oil production has been steadily declining since the 1970s, and the 2008 projection for crude oil production falls below 5 million bbl/d for the first time since 1946. However, domestic production is projected to increase in 2009 by 400,000 bbl/d to an average of 5.3 million bbl/d. Contributing to the increase in output are the Gulf of Mexico Thunder Horse platform, which is expected to come on stream later this year, and the Tahiti platform, expected to come on stream late in 2009.

Prices. As a result of world-wide economic stagnation, oil markets are expected to remain weak throughout the forecast. WTI prices are projected to average $101 per barrel in 2008. Under the current economic assumptions and assuming no major crude oil supply disruptions, WTI prices are expected to average $63.50 per barrel in 2009 (Crude Oil Prices). This is down from $112 per barrel average projected for 2009 in last month's *Outlook*. Further deterioration in actual or expected global economic growth as a fallout of the current financial crisis may lead to even lower oil prices.

Regular grade gasoline prices averaged $2.22 per gallon on November 10, down substantially from their July 14 peak of $4.11 per gallon. They are projected to average $2.37 per gallon in 2009, almost $1.20 per gallon below that projected in the previous *Outlook*. Because of the continued weakness in motor gasoline consumption, the difference between the price of gasoline and the cost of crude is expected to remain low throughout the forecast.

Residential heating oil retail prices this winter are projected to average $2.75 per gallon, a decrease of 56 cents from last winter's average. On-highway diesel fuel retail prices are projected to average $2.73 per gallon in 2009, down $1.08 from the 2008 average, compared with a 90-cent-per-gallon decline in the price of WTI crude oil. This narrowing of margins reflects a projected slowing of the growth in distillate fuel usage outside the United States and a weakening of refining margins during the economic slowdown.

Spot propane prices are strongly influenced by both crude oil and natural gas prices. Residential retail propane prices are projected to average $2.22 this winter (down from $2.68 in the previous *Outlook*), a decrease of about 10 percent from the 2007-2008 winter heating season. However, with current low inventories, propane markets are likely to remain relatively tight this winter, with the potential for upward pressure on residential propane prices if colder-than-expected weather occurs.

Natural Gas

Consumption. Total natural gas consumption is expected to increase by 1.1 percent in 2008 and fall by 0.2 percent in 2009 (Total U.S. Natural Gas Consumption Growth). Consumption in 2008 is projected to be higher in every sector except for electric power, led by 4.1- and 3.2-percent growth in the residential and commercial sectors, respectively. While very slight growth is expected in the residential and commercial sectors in 2009, the contracting economy is expected to cause a 2.2-percent decline in industrial sector consumption next year. The weakness in global economic growth could limit U.S. exports of natural-gas-intensive products and further reduce natural gas consumption by industrial consumers.

Production and Imports. Total U.S. marketed natural gas production is expected to increase by 6 percent in 2008 and by 2 percent in 2009. Production activity from unconventional fields in the States of Texas, Wyoming, and Oklahoma is expected to increase supply from the Lower-48 non-GOM by almost 10 percent this year. While continued onshore production growth is expected in 2009, lower average prices and poor economic conditions are expected to limit the expansion of supplies to 1.9 percent. For 2008, Federal GOM production is now expected to decline by 14.8 percent as repairs to supply infrastructure continue, while 2009 growth of 2.7 percent reflects the expectation of further recovery and less shut-in production during the 2009 hurricane season.

Strong global demand, supply constraints, and lower relative U.S. natural gas prices have all contributed to the decline in U.S. imports of liquefied natural gas (LNG), which are expected to fall from 770 billion cubic feet (Bcf) in 2007 to 350 Bcf in 2008, a reduction of 55 percent. LNG imports are expected to total about 410 Bcf in 2009. The limited natural gas storage facilities in LNG-consuming nations outside of the United States could lead to higher U.S. LNG import growth in 2009, particular during the storage injection season (April to September) as more global LNG capacity is brought online.

Inventories. On October 31, 2008, working natural gas in storage was 3,405 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 78 Bcf above the 5-year average (2003–2007) and 130 Bcf below the level during the corresponding week last year.

Prices. The Henry Hub spot price averaged $6.94 per Mcf in October, $0.94 per Mcf below the average spot price in September. The slowing economy, continued growth in domestic natural gas production, and the significant decline in oil prices have led to a dramatic shift in expectations for natural gas prices over the forecast. Still, household heating expenditures this winter are expected to be slightly higher than last year due to the pass-through of some higher-priced natural gas that was put in storage earlier in the year to meet winter demand. Beyond the winter, the weak economy and continued growth in onshore natural gas production are expected to keep prices relatively low. On an annual basis, the Henry Hub spot price, which averaged $7.17 per Mcf in 2007, is expected to average $9.25 per Mcf in 2008 and $6.82 per Mcf in 2009, $1.35 per Mcf lower than the forecast 2009 price in last month's *Outlook*.

Electricity

Consumption. The latter half of this summer was much cooler than the same period last year (U.S. Summer Cooling Degree-Days), especially in the upper Midwest and Northeast regions. As a result, residential electricity consumption is expected to fall 0.5 percent this year. The economic slowdown will impact consumption in all sectors during 2009, particularly the industrial sector, which is now expected to decline by 2.5 percent next year in contrast to the 0.2-percent decline projected in last month's *Outlook* (U.S. Total Electricity Consumption).

Prices. The recent drop in power generation fuel costs has caused some utilities to reconsider the steep price increases announced this past summer. However, fuel costs still remain high, and it is unlikely that electricity rates for most customers will fall significantly in the near term. U.S. residential electricity prices are expected to increase by about 6.5 percent in both 2008 and 2009 (U.S. Residential Electricity Prices).

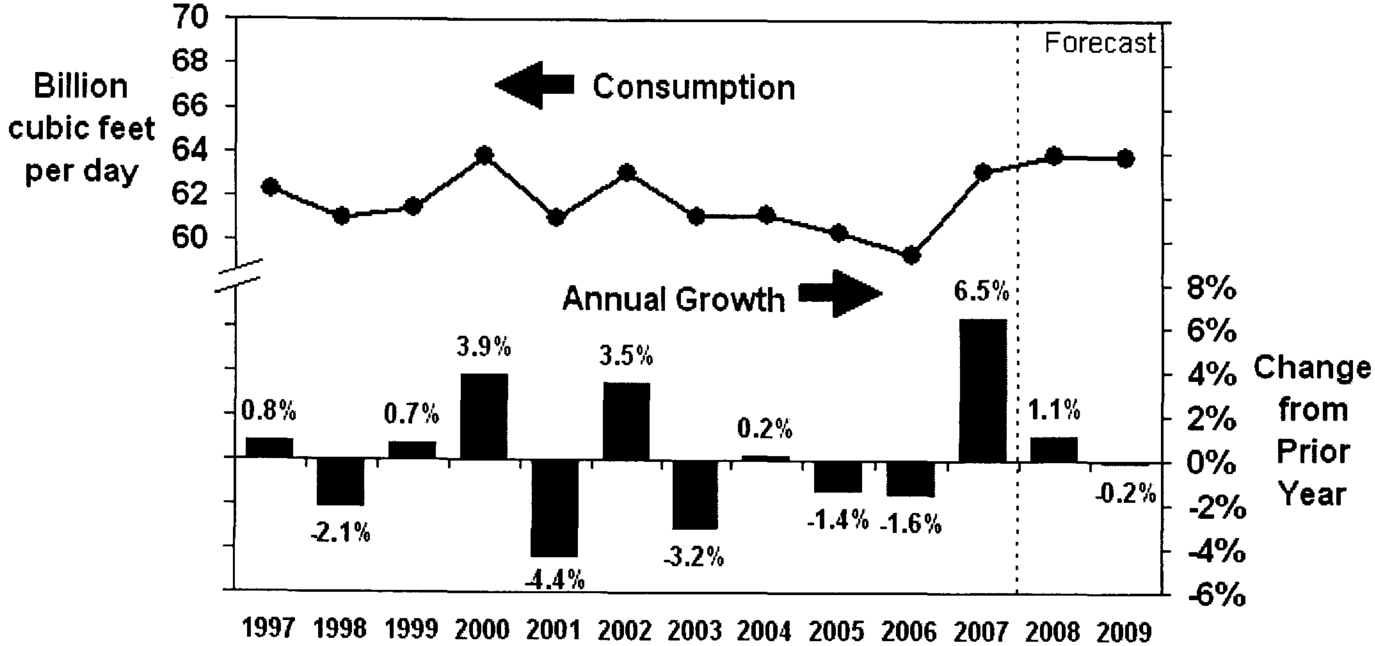
Coal

Consumption. Although electric-power-sector coal consumption for the first half of 2008 grew by 1.3 percent, slow growth in summer electricity consumption is expected to keep annual growth flat in 2008. In 2009, weak economic growth, which will constrain growth in electricity consumption, coupled with projected increases from other generation sources (nuclear, natural gas, petroleum, and wind), will lead to a 0.4-percent decline in electric-power-sector coal consumption (U.S. Coal Consumption Growth).

Production. Growth in both domestic consumption and exports is expected to contribute to a 2.1-percent increase in coal production in 2008. Production is expected to decline by only 0.5 percent in 2009 as lower domestic consumption is nearly offset by continued export growth (U.S. Annual Coal Production).

Exports. In the first half of 2008, U.S. coal exports increased by 13 million short tons, or 50 percent, over first-half 2007 shipments. Strong global demand for coal, combined with supply disruptions in several key coal-exporting countries (Australia, South Africa, and China), were the primary factors behind the increase in U.S. coal exports. Although the supply disruptions have ended, continued robust worldwide demand for coal is projected to lead to an overall 40-percent increase in U.S. coal exports in 2008. Coal exports are projected to be 86.5 million short tons, a 5.5-percent increase, in 2009.

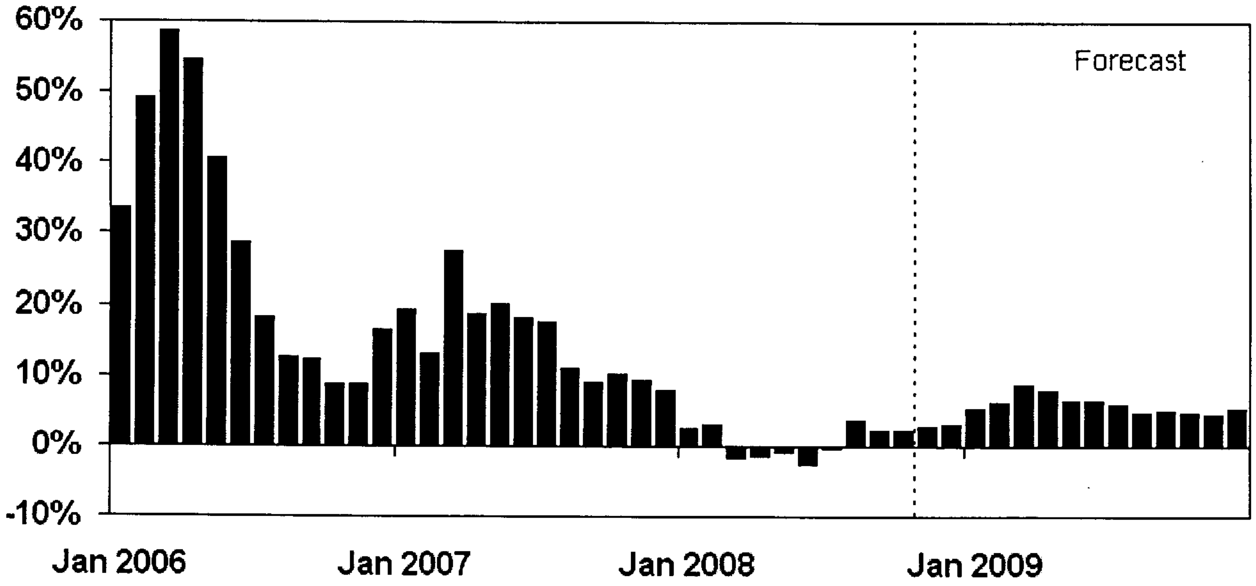
U.S. Total Natural Gas Consumption



Short-Term Energy Outlook, November 2008

www.eia.doe.gov

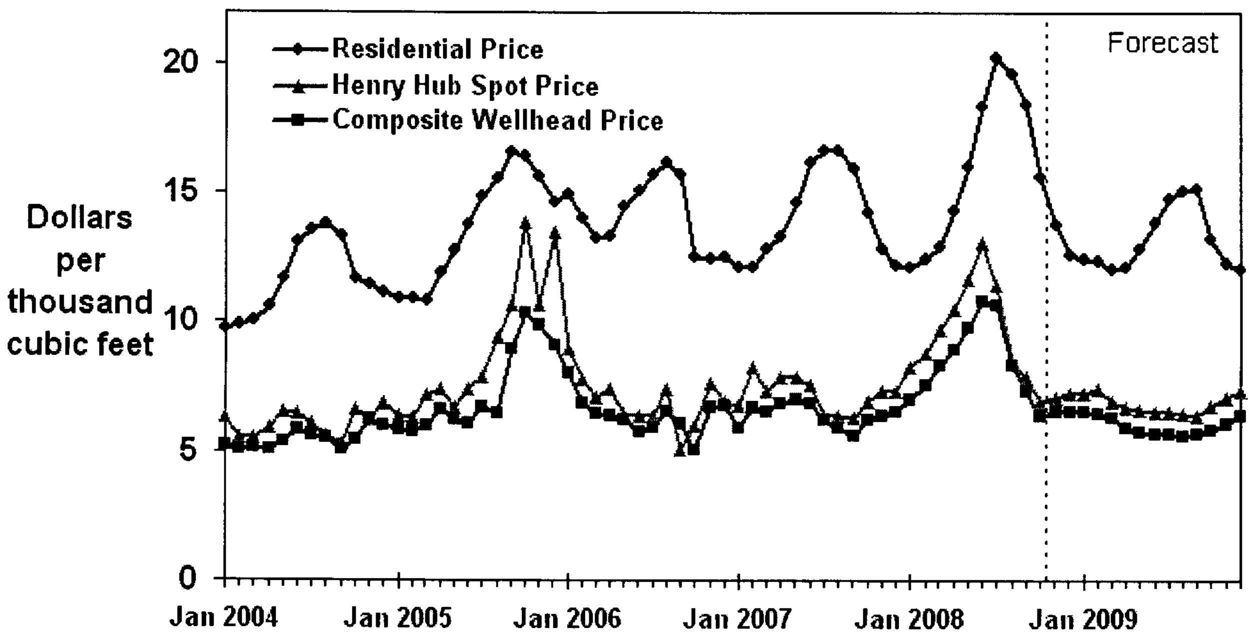
U.S. Working Natural Gas in Storage
(Percent Difference from Previous 5-Year Average)



Short-Term Energy Outlook, November 2008

www.eia.doe.gov

Natural Gas Prices



Short-Term Energy Outlook, November 2008

www.eia.doe.gov

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2008									**($46,836)**
May	($7,154)	$0	($671)	($7,825)	17,007	$0.7009	$11,920	($19,745)	(66,581)
June	25,399	0	(868)	24,531	9,026	(0.1857)	(1,676)	26,207	(40,374)
July	12,556	0	(565)	11,991	6,909	(0.1857)	(1,283)	13,274	(27,100)
August	47,784	0	(408)	47,376	5,577	(0.1857)	(1,036)	48,412	21,312
September	26,255	0	135	26,390	6,028	(0.1857)	(1,119)	27,509	48,821
October	13,043	0	440	13,483	8,294	(0.1857)	(1,540)	15,023	63,844
Balance @ October 31, 2008									**$63,844**

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2008									**($111,189)**
May	($7,255)	$0	($1,155)	($8,410)	8,115	$0.1814	$1,472	($9,882)	(121,071)
June	(7,516)	0	(1,252)	(8,768)	7,134	(0.7309)	(5,214)	(3,554)	(124,625)
July	(44,216)	0	(1,282)	(45,498)	11,473	(0.7309)	(8,386)	(37,112)	(161,737)
August	(2,975)	0	(1,685)	(4,660)	8,162	(0.7309)	(5,966)	1,306	(160,432)
September	(10,606)	0	(1,655)	(12,261)	8,741	(0.7309)	(6,389)	(5,872)	(166,304)
October	(6,575)	0	(1,707)	(8,282)	12,016	(0.7309)	(8,782)	500	(165,804)
Balance @ October 31, 2008									**($165,804)**