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

October 1, 2008

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

Re: Cost of Gas Adjustment (COG)
October 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 (31st Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (31st Revised Sheet No. 8), showing the October 2008 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.8352 per mcf for residential and firm general service customers and $0.7486 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for October 2008, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.7486 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 $0.0866 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of $0.8352 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 October 2008.

Rita A. Mulkern

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

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

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

Attachment A

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
31st Revised Sheet No. 1.1
Canceling 30th Revised Sheet No.1.1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/MCF
Firm Gas Service - General	2	$3.50 per month	First 10 MCF	$1.2740	$9.0369	$10.3109
			Over 10 MCF	1.0540		10.0909
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$5.9615	$7.1006
			Next 2,600 MCF	0.8931		6.8546
			Over 3,000 MCF	0.7411		6.7026
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$5.9615	$7.2006
Transportation Service	5	$3.50 per month	First 400 MCF	$1.1391		$1.1391
			Next 2,600 MCF	0.8931		0.8931
			Over 3,000 MCF	0.7411		0.7411

Date Filed: October 1, 2008

Effective Date: October 1, 2008

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
31st Revised Sheet No. 8
Canceling 30th 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.	2.5510	2.3219	(0.1857)	4.6872	2.3219	(0.7309)	1.5940
Current Adj.	(0.0866)	(0.7486)	0.0000	(0.8352)	(0.7486)	0.0000	(0.7486)
Total Adj.	2.4644	1.5733	(0.1857)	3.8520	1.5733	(0.7309)	0.8424
Total Rate:	$2.5302	$6.6924	($0.1857)	$9.0369	$6.6924	($0.7309)	$5.9615

Date Filed: October 1, 2008 **Effective Date:** October 1, 2008

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

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
OCTOBER 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 Sesaonal	3,000		3.7671	5	56,507	0.0361
TFX Seasonal	4,000		15.1530	5	303,060	0.1936
NOVA - Demand Charge	7,947		10.5374	12	1,004,889	0.6419
Trans Canada - Demand Charge	7,947		13.9161	12	1,327,095	0.8477
ProGas - Demand Charge	7,947		0.8746	12	83,405	0.0533
NOVA - Seasonal	5,068		10.5374	5	267,018	0.1706
Trans Canada - Seasonal	5,068		13.9161	5	352,634	0.2252
ProGas - Seasonal	5,068		0.8746	5	22,162	0.0142
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					$3,961,018	2.5302
Estimated Weighted Average Commodity Cost	1,565,565	1/	6.6924		10,477,387	6.6924
Gas Cost Reconciliation Adjustment						(0.1857)
Total Current Firm Gas Cost					$14,438,405	9.0369
Base Cost of Gas						5.1849
Accumulated Adjustment						$3.8520

Interruptible	
Estimated Weighted Average Commodity Cost	$6.6924
Gas Cost Reconciliation Adjustment	(0.7309)
Total Current Interruptible Gas Cost	5.9615
Base Cost of Gas	5.1191
Accumulated Adjustment	$0.8424

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

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

Rates Effective October 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	10.5374	Per dk/Mo.
Trans Canada Pipeline Demand Charge	13.9161	Per dk/Mo.
ProGas - Demand Charge	0.8746	Per dk/Mo.
NOVA - Seasonal	10.5374	Per dk/Day
Trans Canada - Seasonal	13.9161	Per dk/Mo.
ProGas - Seasonal	0.8746	Per dk/Mo.
ProGas Winter Surcharge	3.0049	
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	6.6924	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

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

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

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

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

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

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

Twenty-Second Revised Sheet No. 5B
Superseding
Twenty-First Revised Sheet No. 5B

STATEMENT OF RATES
(Rates Per Dekatherm)

Rate Schedule	Base Tariff Rate	Adjustment Under Section 19 1/	Rate After Current Adjustment	Fuel and Loss Retention Percentages 2/
Commodity Rates				
FT-A - Maximum Rates				
Zone 1 - 1	$0.0130	$0.0019	$0.0149	1.16%
Zone 1 - 2	$0.0130	$0.0019	$0.0149	1.57%
Zone 2 - 2	$0.0130	$0.0019	$0.0149	0.41%
Minimum Rate	$0.0130	$0.0019	$0.0149	
IT and AOT				
Zone 1 - 1	$0.1368	$0.0019	$0.1387	1.16%
Zone 1 - 2	$0.1737	$0.0019	$0.1756	1.57%
Zone 2 - 2	$0.0834	$0.0019	$0.0853	0.41%
Minimum Rate	$0.0130	$0.0019	$0.0149	

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of $0.0019 per Dekatherm shall be added to other charges under Company's Rate Schedules.

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

Transportation Fuel and Loss Retention Percentages are inclusive of the following percentages for Gas Lost and Unaccounted For: .09% for Zone 1-1, .10% for Zone 1-2, and .01% 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: February 29, 2008
Effective on: April 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

Attachment B
Page 6 of 7

RATE SCHEDULE TF

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

COMMODITY RATES 2/ TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0379	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.

Attachment B
Page 7 of 7

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
October 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 October monthly price for the AECO Index decreased 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).

Lower prices for crude oil, as well as lower natural gas demand and a strong year over year increase in domestic natural gas production, contributed to lower prices. The Energy Information Administration (EIA) reported storage levels nationwide as of September 19, 2008 were 1.2 percent above the five-year average and 5.1 percent below last years balance.

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

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

www.eia.doe.gov
Energy Information Administration

September 2008

Short-Term Energy Outlook

September 9, 2008 Release

Highlights

- The monthly average price of West Texas Intermediate (WTI) crude oil decreased from over $133 per barrel in June and July to about $117 per barrel in August, reflecting expectations of a slowdown in world petroleum demand growth. WTI, which averaged $72 per barrel in 2007, is projected to average $116 per barrel in 2008. Projected stronger growth in world petroleum demand is expected to increase the annual average WTI price to $126 per barrel in 2009.

- The weekly price of regular-grade gasoline, which peaked at $4.11 per gallon on July 14, averaged $3.65 per gallon on September 8. Annual average retail gasoline and diesel prices in 2008 are projected to be $3.61 and $4.09 per gallon, respectively, compared with $2.81 for gasoline and $2.88 for diesel in 2007. Following the expected increase in the annual average crude oil price, gasoline and diesel prices are projected to average $3.88 and $4.26 per gallon, respectively, in 2009.

- The Henry Hub natural gas spot price averaged $7.17 per thousand cubic feet (Mcf) in 2007 and is expected to average about $9.70 per Mcf in 2008 and $8.55 per Mcf in 2009.

- Residential heating oil prices during the upcoming heating season (October though March) are projected to average $4.13 per gallon, an increase of about 25 percent over last heating season. Residential natural gas prices over the same period are projected to average $14.93 per Mcf compared with $12.72 per Mcf during the last heating season, an increase of about 17 percent.

- Heating fuel expenditures for the average household using oil as its primary heating fuel are expected to increase by $585 (30 percent) over last winter. The corresponding average expenditure increases for households heated with natural gas and propane are $162 (19 percent) and $217 (13 percent), respectively.

Global Petroleum

Overview. Sluggish Organization for Economic Cooperation and Development (OECD) consumption and prospects for increased supplies from producers outside of the Organization of the Petroleum Exporting Countries (OPEC) in the coming year have weakened market conditions. Lower demand for OPEC oil and a rebound in global surplus production capacity is expected to provide the market with a potential cushion against supply disappointments over the near term. Sentiment that a slowdown in the global economy will dampen world oil consumption growth appears to be overshadowing supply concerns stemming from geopolitical events and the absence of normal inventory build in the OECD countries through mid-2008. The disruption of Caspian export flows in August, continued tensions between Russia and Georgia, and Hurricane Gustav all failed to raise prices.

The future price path will be influenced by the pace of world gross domestic product (GDP) growth and OPEC behavior. OPEC met on September 9 in Vienna to review market conditions. EIA expects that OPEC will continue to assess market conditions in the months ahead, and will lower crude oil production over the next few quarters in order to prevent a sharp decline in prices. The main upside price risk is that the slowdown in global oil demand growth is temporary and that demand will recover. Important downside price risks include weaker demand growth due to the lagged impact of higher oil prices, weaker economic activity than anticipated, or the absence of a substantial reduction in OPEC crude oil production.

Consumption. After rising by about 370,000 barrels per day (bbl/d) during the first half of 2008, global oil consumption is projected to rise by about 970,000 bbl/d in the second half of 2008 and by 920,000 bbl/d in all of 2009 compared with year-earlier levels. Sluggish growth in consumption during the first half of 2008 was driven in large part by a 930,000-bbl/d decline in U.S. consumption. Declines in U.S. oil consumption are not expected to be as large in the second half of this year due to both relatively weak consumption in the second half of last year and the price declines over the past several months. The global oil consumption growth projections for the third and fourth quarters of 2008 represent a 130,000-bbl/d downward revision from last month's *Outlook*, mainly reflecting weaker demand in OECD countries.

Reports indicate that China plans to halt imports of selected products in September to draw down stocks built up before the Olympics. Moderation in China's demand, however, is expected to be temporary, as sustained economic growth is expected to support oil consumption growth. Over both years, lower OECD consumption is expected to be more than offset by continued non-OECD consumption growth, led by China, the Middle East, Latin America, and India (World Oil Consumption).

Non-OPEC Supply. The non-OPEC oil supply situation is expected to improve through the end of next year. If new projects come online as now anticipated, total non-OPEC supply is projected to rise by about 300,000 bbl/d in the second half of 2008 and by about 900,000 bbl/d in 2009 compared with year-earlier levels. This compares with a 280,000-bbl/d decline in non-OPEC supply recorded during the first half of 2008. Non-OPEC supply growth through 2009 is expected to be led by the United States, Brazil, and Azerbaijan (Non-OPEC Oil Production Growth). The combination of possible additional delays in key projects, heightened risks to Caspian export flows, potential impacts from hurricanes over the next few months, and the risk of weaker production trends in Russia, Mexico, and the North Sea could dampen non-OPEC supply growth, leading to both higher demand for OPEC oil and higher prices than currently projected.

OPEC Supply. OPEC crude oil production is expected to increase to 32.9 million bbl/d during the third quarter of 2008, up from 32.3 million bbl/d in the second quarter. The forecast assumes that Saudi Arabia will maintain its July 9.7-million-bbl/d production level in August and September, representing a 400,000-bbl/d rise from second quarter levels. Amid weaker market conditions and declining prices, OPEC met in Vienna on September 9 to review market conditions and consider revising its production strategy.

OPEC crude oil production is projected to drop back to about 32.8 million bbl/d in the fourth quarter of 2008 and continue to decline to an average of 32.1 million bbl/d in 2009, keeping OECD inventories near 5-year average levels measured in days of forward consumption. Lower crude oil production, combined with planned increases in OPEC total liquids production capacity, suggests OPEC surplus crude production capacity could increase from 1.2 million bbl/d currently to about 3 million bbl/d by the end of next year (OPEC Surplus Oil Production Capacity).

Inventories. Revised data indicate OECD commercial inventories during the second quarter of 2008 declined by 120,000 bbl/d, well below the average build of 910,000 bbl/d during this time of year. At the end of the second quarter, estimated OECD commercial inventories stood at 2.56 billion barrels, equal to about 53 days of forward consumption, which is close to normal levels (Days of Supply of OECD Commercial Stocks). OECD commercial inventories are projected to rise by 90,000 bbl/d in the third quarter compared with the average seasonal build of 450,000 bbl/d, which, due to falling OECD consumption, would leave OECD commercial inventories at near-normal levels in terms of days of supply at the end of the third quarter.

U.S. Petroleum

Consumption. Total U.S. petroleum and other liquids consumption is projected to decline by 610,000 bbl/d, or about 3 percent, in 2008 based on prospects for a weaker economy and high crude oil and product prices continuing into 2009 (U.S. Petroleum Products Consumption Growth). Preliminary July and August 2008 weekly survey data indicate that year-over-year declines in total consumption, which began in August 2007, have narrowed since earlier this year. During the first 6 months of 2008, total petroleum consumption fell by an average of 930,000 bbl/d compared with consumption during the same period in 2007. During July and August, the year-over-year declines averaged 660,000 bbl/d. For the rest of the year (September though December), the year-to-year decline in consumption is projected to narrow to an average of about 130,000 bbl/d.

Supply. In 2008, total domestic crude oil output is projected to average 5.13 million bbl/d, up slightly from the 2007 average of 5.06 million bbl/d (U.S. Crude Oil Production). Production growth in the lower-48 region is expected to more than offset declines in Alaskan output. This projection includes an assumption of hurricane-induced outages of about 14.5 million barrels for the offshore region in 2008 (see *Hurricane Outlook*). In 2009, total crude oil production is projected to increase to 5.42 million bbl/d, mostly because of the Thunder Horse and Tahiti platforms coming on-stream in late 2008 and 2009, respectively. Fuel ethanol production is projected to increase from an annual average of 430,000 bbl/d in 2007 to 590,000 bbl/d in 2008 and to 660,000 bbl/d in 2009. Because of declining petroleum consumption and growing ethanol production, total net imports of petroleum are expected to fall by 740,000 bbl/d in 2008 and by a further 460,000 bbl/d in 2009.

Prices. WTI crude oil prices, which averaged $72 per barrel in 2007 (Crude Oil Prices), are projected to average $116 per barrel in 2008 and $126 per barrel in 2009. Regular-grade motor gasoline retail prices, which averaged $2.81 per gallon in 2007, are projected to rise to an average of $3.61 per gallon this year and $3.88 per gallon in 2009. This forecast projects continuing weak gasoline margins because of the decline in gasoline consumption and growth in ethanol use. Diesel fuel retail prices in 2008 are projected to average $4.09 per gallon, up from $2.88 per gallon in 2007, and increase to an average of $4.26 per gallon in 2009. Diesel prices reflect continuing strength in demand, particularly in emerging global markets, which has significantly increased the margins between diesel prices and crude oil costs from their 2007 level.

Natural Gas

Consumption. Total natural gas consumption is expected to increase by 2.7 percent in 2008 and by 2.2 percent in 2009 (Total U.S. Natural Gas Consumption Growth). Consumption growth is expected in all sectors during the forecast period, led by the residential and commercial sectors in 2008 and electric power in 2009. Despite higher prices through the first half of 2008, natural gas consumption in the industrial sector increased by 3.7 percent compared with the corresponding period in 2007. Consumption in the industrial sector is expected to increase by 1.6 percent in 2008 and by 1.4 percent in 2009. However, fragile domestic economic conditions add significant uncertainty to the forecast.

Production and Imports. Total U.S. marketed natural gas production is expected to increase by 7.8 percent in 2008 and by 3.8 percent in 2009. Strong year-over-year production growth has been led by the development of onshore fields, particularly in Texas and Wyoming, where production increased by 16 and 12 percent, respectively, during the first 6 months of 2008 relative to year-ago levels. The increase in lower-48 production excluding the Federal Gulf of Mexico (GOM) has more than offset the year-over-year decline of almost 3 percent during the first half of 2008 in Federal GOM production. Federal GOM production in 2008 is projected to be slightly lower than in 2007, followed by a 4.3 percent increase in 2009. Production in the lower-48 non-Gulf region is expected to increase by 9.5 percent in 2008 and by 3.8 percent in 2009, though the projection of supply growth next year remains subject to expectations about natural gas prices.

U.S. imports of liquefied natural gas (LNG) have been severely hampered by global LNG demand growth and higher relative prices in the Asia-Pacific region and Europe. For 2008, LNG imports are expected to total about 350 billion cubic feet (Bcf), a decline of more than 50 percent, or 420 Bcf, from 2007, and then to total about 450 Bcf in 2009 as new global LNG supply is added to the market.

Inventories. On August 29, 2008, working natural gas in storage was 2,847 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 102 Bcf above the 5-year average (2003–2007) and 148 Bcf below the level during the corresponding week last year.

Prices. The Henry Hub spot price averaged $8.49 per Mcf in August, $2.96 per Mcf below the average spot price in July. Mild temperatures, increasing production, and lower oil prices all contributed to the price decline. Cooling degree-days in August were 4 percent below normal and 14 percent below the 5-year average. In the near term, potential hurricane disruptions present the greatest uncertainty in the price

forecast. September has historically been the peak month for hurricane activity, and EIA's current *Outlook* assumptions include shut-in production of 65 Bcf for the remainder of the season attributable to Gulf Coast storms. Nevertheless, continued growth in onshore production is expected to limit any large and sustained increases in the natural gas spot price. On an annual basis, the Henry Hub spot price is expected to average about $9.71 per Mcf in 2008 and $8.55 per Mcf in 2009, a decline of $0.33 and $0.46 per Mcf, respectively, from the previous forecast.

Electricity

Consumption. As noted above, August 2008 was much cooler than in recent years (U.S. Summer Cooling Degree-Days), with particularly mild temperatures in the Midwest region. The projected growth in electricity consumption during 2008 has been lowered from last month's *Outlook* to 0.8 percent (U.S. Total Electricity Consumption).

Prices. Some utilities increased electricity rates beginning in July and more increases are expected in the upcoming months. Average U.S. residential electricity prices are projected to increase by 5.7 percent in 2008 and by 9.5 percent in 2009 (U.S. Residential Electricity Prices).

Coal

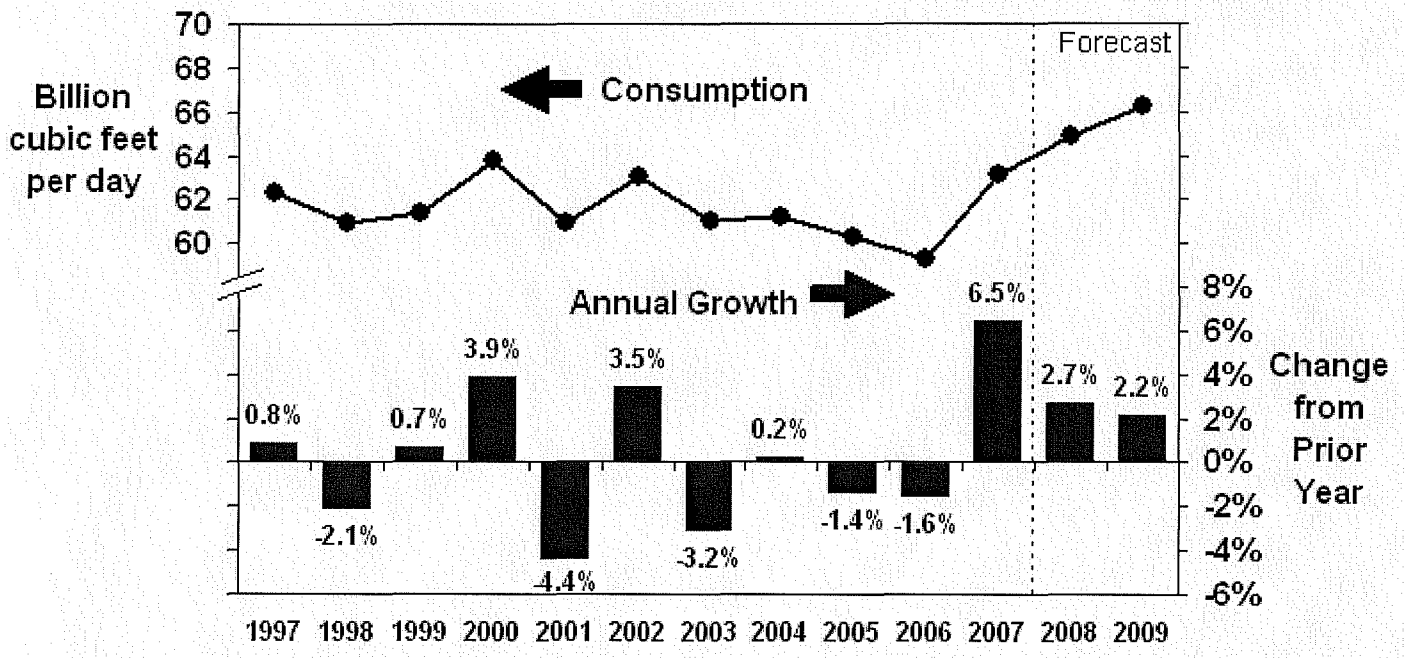
Consumption. Electric-power-sector coal consumption grew by 1.9 percent in 2007. Although first-quarter 2008 electric-power-sector coal consumption grew by about 2 percent compared with first-quarter 2007, slow growth in total electricity consumption is expected to limit growth in the sector to just 0.7 percent in 2008. In 2009, a small increase in electricity consumption, combined with projected increases from other generation sources (nuclear, natural gas, hydroelectric, and wind), will lead to a very slight decline in electric-power-sector coal consumption (U.S. Coal Consumption Growth).

Production and Inventories. U.S. coal production (U.S. Annual Coal Production) fell by 1.4 percent in 2007. Growth in both domestic consumption and particularly in exports is expected to contribute to a 2.9-percent increase in coal production in 2008. Secondary (consumer-held) coal stocks, which grew to 159 million short tons in 2007, are expected to remain stable in 2008 and grow by an average of 2.8 percent in 2009.

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 45-percent increase in U.S. coal exports in 2008. Coal exports are projected to be 86.5 million short tons in 2009.

U.S. Total Natural Gas Consumption



Short-Term Energy Outlook, September 2008

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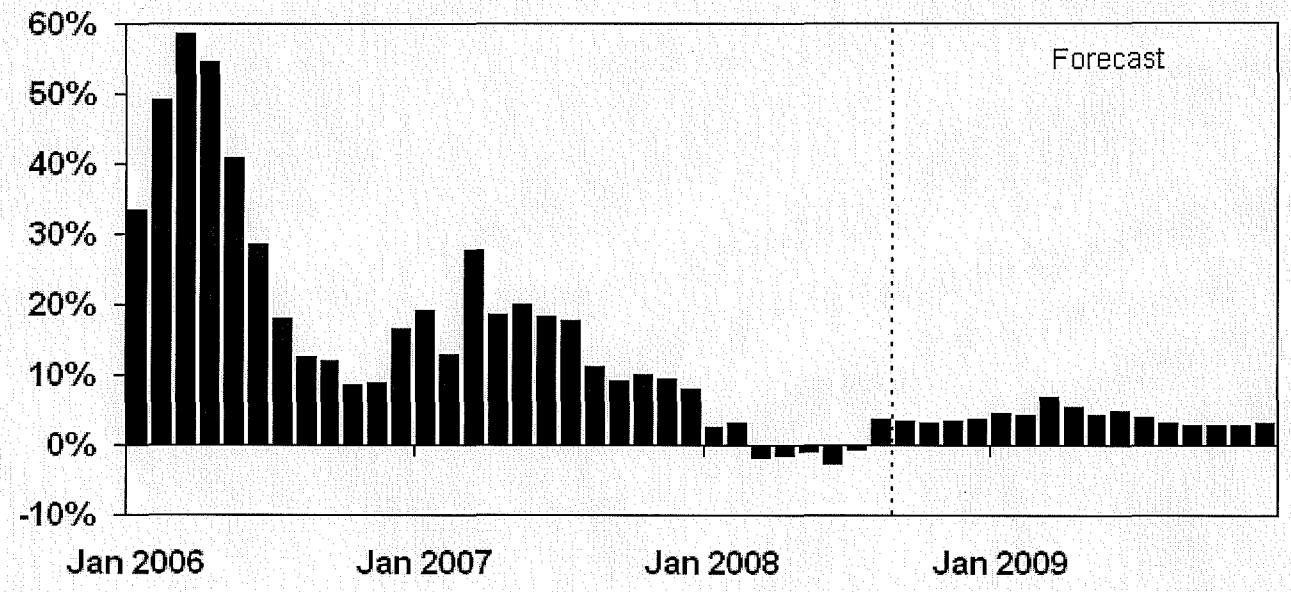
U.S. Working Natural Gas in Storage
(Percent Difference from Previous 5-Year Average)



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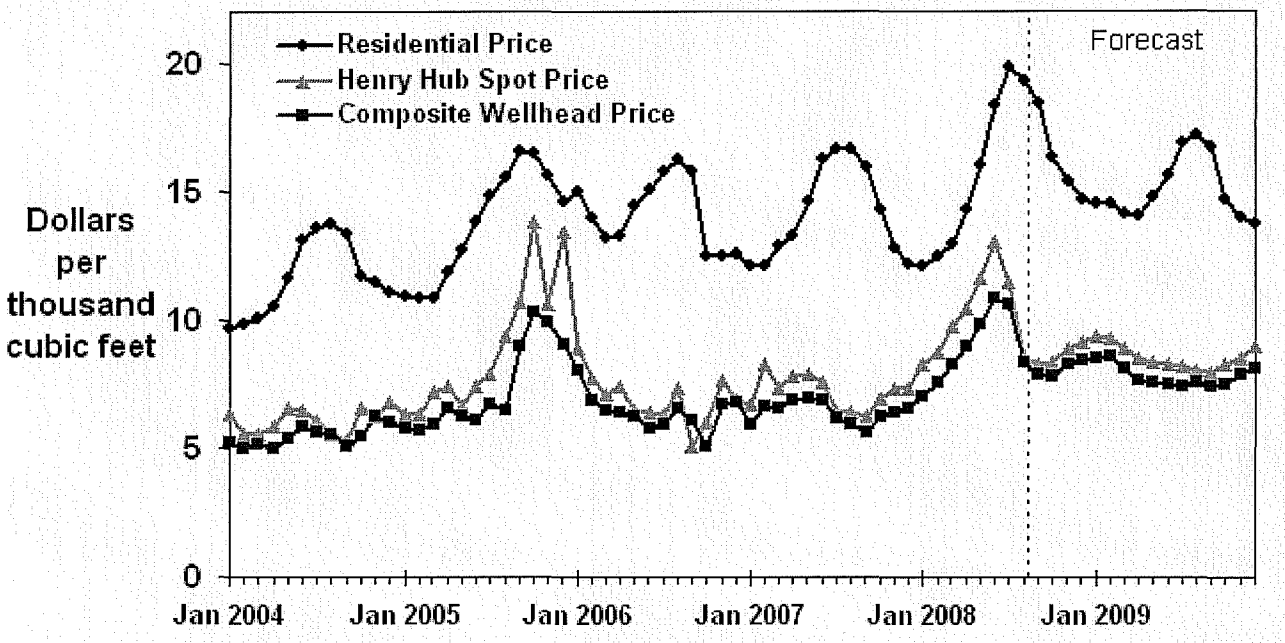
Natural Gas Prices



Short-Term Energy Outlook, September 2008

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 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
Balance @ August 31, 2008									**$21,312**

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)
Balance @ August 31, 2008									**($160,431)**

Attachment D
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