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

ORIGINAL

RECEIVED

JUL 03 2008

PUBLIC SERVICE COMMISSION

July 2, 2008

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

Re: Purchased Gas Cost Adjustment (PGA)
July 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 Purchased Gas Cost Adjustment (PGA) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (28th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Purchased Gas Adjustment Tariff (28th Revised Sheet No. 8), showing the July 2008 cost of gas and the resulting Purchased Gas Cost Adjustment. The net effect of this filing is an increase of $2.3504 per mcf for residential and firm general service customers and $2.2764 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for July 2008, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $2.2764 per mcf since the last PGA filing due to an increase in the market price of gas. There has been an increase in pipeline charges of $0.0740 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of $2.3504 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 2nd day of July 2008.

Rita A. Mulkern

Rita A. Mulkern

Subscribed and sworn to before me this 2nd day of July 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

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

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	$14.4251	$15.6991
			Over 10 MCF	1.0540		15.4791
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$11.2731	$12.4122
			Next 2,600 MCF	0.8931		12.1662
			Over 3,000 MCF	0.7411		12.0142
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$11.2731	$12.5122
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: July 2, 2008

Effective Date: July 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
28th Revised Sheet No. 8
Canceling 27th 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.	2.4670	4.6085	(0.1857)	6.8898	4.6085	(0.7309)	3.8776
Current Adj.	0.0740	2.2764	0.0000	2.3504	2.2764	0.0000	2.2764
Total Adj.	2.5410	6.8849	(0.1857)	9.2402	6.8849	(0.7309)	6.1540
Total Rate:	$2.6068	$12.0040	($0.1857)	$14.4251	$12.0040	($0.7309)	$11.2731

Date Filed: July 2, 2008 **Effective Date:** July 1, 2008

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

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JULY 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	10.9308	12	1,042,405	0.6658
Trans Canada - Demand Charge	7,947	14.4821	12	1,381,071	0.8822
ProGas - Demand Charge	7,947	0.9104	12	86,819	0.0555
NOVA - Seasonal	5,068	10.9308	5	276,986	0.1769
Trans Canada - Seasonal	5,068	14.4821	5	366,976	0.2344
ProGas - Seasonal	5,068	0.9104	5	23,070	0.0147
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				$4,081,142	2.6068
Estimated Weighted Average Commodity Cost	1,565,565 1/	12.0040		18,793,042	12.0040
Gas Cost Reconciliation Adjustment					(0.1857)
Total Current Firm Gas Cost				$22,874,184	14.4251
Base Cost of Gas					5.1849
Accumulated Adjustment					$9.2402

Interruptible	
Estimated Weighted Average Commodity Cost	$12.0040
Gas Cost Reconciliation Adjustment	(0.7309)
Total Current Interruptible Gas Cost	11.2731
Base Cost of Gas	5.1191
Accumulated Adjustment	$6.1540

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

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

Rates Effective July 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	10.9308	Per dk/Mo.
Trans Canada Pipeline Demand Charge	14.4821	Per dk/Mo.
ProGas - Demand Charge	0.9104	Per dk/Mo.
NOVA - Seasonal	10.9308	Per dk/Day
Trans Canada - Seasonal	14.4821	Per dk/Mo.
ProGas - Seasonal	0.9104	Per dk/Mo.
ProGas Winter Surcharge	3.0049	
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	12.0040	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

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

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.

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	0.0381	0.0212			0.0175	0.0000	0.0381	0.0212
Field	Market	0.0381	0.0212	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0295	0.0109

1/ The minimum reservation rate is equal to zero.
2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs.
3/ Maximum and Minimum rates include ACA of \$0.0019 and the Market Area Electric Compression charge of \$0.0003 where applicable.
4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
5/ Where Applicable, Field Area Electric Compression charge of \$0.0000 and ACA will be added to the mileage based rates.

RATE SCHEDULES TFX and LFT

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

COMMODITY RATES 2/ TFX and LFT		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0381	0.0212			0.0175	0.0000	0.0381	0.0212
Field	Market	0.0381	0.0212	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0295	0.0109

	Reservation 1/		Commodity 6/		Out-of-Balance 6/	
GULF COAST	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
MOPS Gathering	1.0514	0.0000	0.0019	0.0019	0.0019	0.0019
MOPS Transmission	1.5337	0.0000	0.0019	0.0019	0.0019	0.0019
Tivoli - Downstream	0.6827	0.0000	0.0019	0.0019	0.0019	0.0019
Other Gulf Coast	4.8169	0.0000	0.0019	0.0019	0.0019	0.0019

1/ The minimum reservation rate is equal to zero.
2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs.
3/ Maximum and Minimum rates include ACA of $0.0019 and the Market Area Electric Compression charge of $0.0003 where applicable.
4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
5/ Where applicable, Field Area Compression charge of $0.0000 and ACA will be added to the mileage based rates.
6/ Maximum and Minimum rates include ACA of $0.0019.

Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
July 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 July monthly price for the AECO Index increased 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).

Increases in demand from electric generators meeting air-conditioning demand have already occurred in the Southwest and part of the East Coast in June and are expected to expand as the summer proceeds. This, along with the continued record high prices of crude oil and the storage level slightly below the five year average, all likely contributed to the increase in the commodity price of natural gas. The amount of imported LNG is less than half of last year's level, putting additional pressure on storage injections and natural gas prices. The Energy Information Administration (EIA) reported storage levels nationwide as of June 20, 2008 were 15.8 percent below last years balance and 2.7 percent below the five-year average.

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 10.

www.eia.doe.gov
Energy Information Administration

June 2008

Short-Term Energy Outlook

June 10, 2008 Release

Highlights

- West Texas Intermediate (WTI) crude oil prices were on a rollercoaster ride upwards over the last month, increasing from $113 to $133 per barrel over the first 3 weeks on May, then falling back to $122 on June 4 before surging to over $138 by June 6. Supply uncertainties in several oil exporting regions, coupled with healthy demand growth in the emerging market countries, continued to pressure oil markets. The overall picture of strong demand and tight supply is expected to continue. WTI prices, which averaged $72 per barrel in 2007, are projected to average $122 per barrel in 2008 and $126 per barrel in 2009.

- Regular-grade gasoline is expected to average $3.78 per gallon in 2008, or 97 cents above the 2007 average price. The U.S. average regular gasoline price, currently over $4 per gallon, is projected to peak at $4.15 per gallon in August. Retail diesel fuel prices are projected to average $4.32 per gallon in both 2008 and 2009, an increase of $1.44 per gallon over the 2007 average.

- World oil consumption is projected to grow by 1 million barrels per day (bbl/d) in 2008. U.S. consumption of liquid fuels and other petroleum is expected to decline by about 290,000 bbl/d in 2008 because of higher petroleum product prices and slower economic growth. Adjusting for increased ethanol use, U.S. petroleum consumption is projected to fall by 440,000 bbl/d in 2008.

- The Henry Hub natural gas spot price averaged $7.17 per thousand cubic feet (Mcf) in 2007 and is expected to average about $11 per Mcf in both 2008 and 2009.

- Based on the current Atlantic hurricane season outlook from the National Oceanic and Atmospheric Administration (NOAA), EIA estimates expected production shut-ins on the U.S. Gulf Coast during the upcoming hurricane season (June through November) of about 11 million barrels for crude oil and 78 billion cubic feet (Bcf) for natural gas (*The 2008 Outlook for Hurricane*

Production Outages in the Gulf of Mexico). Actual shut-ins may differ significantly from this estimate depending on the number, track, and strength of hurricanes as the season progresses.

Global Petroleum

The combination of rising consumption, further downward revisions in the supply outlook for countries outside of the Organization of the Petroleum Exporting Countries (OPEC), and low surplus production capacity reinforce the perception that supply is having a difficult time keeping up with demand growth, accounting for much of the upward trend in oil prices. Consumption in countries outside of the Organization for Economic Cooperation and Development (OECD) continues to grow rapidly, offsetting weaker consumption in OECD countries, especially the United States. Declining production in a number of non-OPEC nations, including Mexico, United Kingdom, and Norway, is largely offsetting increases in other countries. Slow growth in non-OPEC supply is coinciding with disruptions in supplies from some OPEC countries, such as Nigeria. Ongoing geopolitical concerns in several producing countries, including Venezuela and Iran, have contributed to oil price volatility.

The market remains concerned that the cushion of surplus production capacity of less than 2 million bbl/d (almost all located in Saudi Arabia) and/or stocks is insufficient to protect against possible changes in supply or consumption, especially as we enter the summer hurricane season. The absence of a Saudi commitment to add capacity beyond its current goal of 12.5 million bbl/d adds to the uncertainty about the adequacy of future supply capacity growth.

Consumption. Preliminary data indicate global oil consumption rose by about 630,000 bbl/d during the first quarter of 2008 compared with year-earlier levels, much lower than the 1.0-million-bbl/d growth expected in the previous *Outlook*. Most of this downward revision occurred in the OECD countries. With this revision, OECD consumption during the first quarter is estimated to have fallen by 460,000 bbl/d from year-earlier levels, with the declines concentrated in the United States. Consumption in the other OECD regions was flat during the first quarter, with European consumption increasing relative to year-earlier levels only because warmer-than-normal weather led to unseasonably low consumption in first quarter of 2007. OECD consumption is projected to decrease by 240,000 bbl/d in 2008 and increase slightly in 2009.

In contrast, consumption in the non-OECD countries is projected to grow by 1.2 million bbl/d in 2008, led by China, India, and the Middle East (World Oil Consumption). Continued economic growth, fuel subsidies, and increased oil-fired power generation are supporting increases in non-OECD oil consumption. Efforts to ease subsidies in some non-OECD Asian nations such as India and Indonesia could eventually lead to higher prices in those countries and lower overall non-OECD consumption growth. However, China represents the single largest source of world oil consumption growth in our forecast, and that country has not yet begun to remove price subsidies.

Non-OPEC Supply. Non-OPEC supply growth remains weak despite 6 years of rising prices. Non-OPEC production is expected to rise by 310,000 bbl/d in 2008, down sharply from last month's *Outlook*. Actual production data from Russia, Norway, and Mexico, along with lowered expectations for Brazil, are the principal reasons for the downward revision. Non-OPEC supply during the first quarter of the year was 240,000 bbl/d lower than the first quarter of 2007, and the second quarter of 2008 is expected to be 200,000 bbl/d lower than last year. As a result, virtually all of the growth in non-OPEC supply is expected in the second half of the year, with an expected year-over-year increase of 820,000 bbl/d, driven by growth in Brazil and Azerbaijan (Non-OPEC Oil Production Growth). EIA has also revised its estimates of non-OPEC supply growth downwards in 2009 to 1.1 million bbl/d, slightly below expected consumption growth for the year. Given recent history, EIA believes that the pace and timing of non-OPEC supply growth will continue to be subject to possible delays in key projects and accelerating production declines in some older fields. As a result, net production gains could be less than the current forecast, leading to a higher price path.

OPEC Supply. OPEC crude oil production is projected to average 36.9 million bbl/d in the second quarter, 140,000 bbl/d higher than first quarter levels. Over the quarter, lower production in Nigeria, due to security problems and a workers strike, was offset by higher Iraqi and Saudi production. Saudi Arabia reportedly increased output in mid-May by 300,000 bbl/d, with production expected to reach 9.4 million bbl/d in June. At these production levels, global surplus production capacity, virtually all of which is in Saudi Arabia, should be about 1.4 million bbl/d in June (OPEC Surplus Oil Production Capacity). OPEC crude oil production is expected to increase during the third quarter of 2008, although this is dependent upon how the security situation in Iraq and Nigeria evolves. Iraq plans to raise exports from the north by about 100,000 bbl/d in June if security conditions permit.

Inventories. OECD commercial inventories fell in the first quarter of 2008 by about 430,000 bbl/d, in line with the 5-year average decline during that part of the year. At the end of the first quarter, OECD commercial inventories stood at 2.54 billion barrels, 18 million barrels above the 5-year average and equal to 53 days of forward consumption. However, OECD stock additions during the second quarter are projected to be far below the average 5-year build, with OECD commercial inventories staying at or below their 5-year average for the remainder of the year (Days of Supply of OECD Commercial Stocks).

U.S. Petroleum

Production. In 2008, total domestic crude oil output is projected to average 5.1 million bbl/d, the same as in 2006 and 2007 (U.S. Crude Oil Production). Production growth in the lower-48 and Federal Gulf of Mexico regions is expected to offset declines in Alaskan production. In 2009, total production is projected to average 5.3 million bbl/d, up 210,000 bbl/d from 2008. Federal Gulf of Mexico output is expected to rise 270,000 bbl/d due mostly to the Thunder Horse platform coming on-stream in late 2008 and the Tahiti platform beginning production in 2009, but declines are projected for Alaska and the lower-48 States. This projection includes an estimated expectation of hurricane-induced outage of about 11 million barrels for the offshore region in 2008 (see *Hurricane Outlook*). Fuel ethanol production is projected to increase from an annual average of 420,000 bbl/d in 2007, to 580,000 bbl/d in 2008 and 640,000 bbl/d in 2009.

Consumption. Total petroleum consumption of liquid fuels and other petroleum products averaged 20.7 million bbl/d in 2007, similar to 2006 (U.S. Petroleum Products Consumption Growth). Based on prospects for a weak economy and record high crude oil and product prices extending into next year, consumption is projected to shrink by 290,000 bbl/d in 2008, a sharper drop than the nearly 200,000 bbl/d projected in the previous *Outlook*. In 2009, total consumption is projected to rise by 140,000 bbl/d, somewhat less than the nearly 200,000 bbl/d increase projected in the previous *Outlook*.

Prices. WTI crude oil prices, which averaged $72 per barrel in 2007 (Crude Oil Prices), are projected to average $122 per barrel in 2008, up about $12 per barrel from the projection in last month's *Outlook*; and $126 per barrel in 2009, up more than $20 per barrel from the previous *Outlook*.

EIA projects that regular-grade motor gasoline retail prices, which averaged $2.81 per gallon in 2007, will average $3.78 per gallon this year, up more than 25 cents from last month's *Outlook*. Gasoline prices are expected to continue to rise from $3.98 per gallon on June 2 to a monthly average price peak of $4.15 per gallon in August. This forecast reflects a sizable narrowing of refiner gasoline margins from those of last year because of weakness in gasoline demand and growth in ethanol supply. In 2009, regular-grade gasoline retail prices are projected to average $3.92 per gallon, 48 cents higher than projected in the previous *Outlook*.

Diesel fuel retail prices in 2008 and 2009 are projected to average $4.32 per gallon, up from $2.88 per gallon last year. This reflects strength in diesel demand, particularly in emerging markets, that has significantly increased the margins between diesel prices and crude oil costs from those of last year. Diesel fuel prices are projected to remain near the June 2 price of $4.71 per gallon over the next few months as refiner margins begin to weaken slightly, offsetting the projected rise in crude oil costs.

Natural Gas

Consumption. Total natural gas consumption is expected to increase by 2.2 percent in 2008 and by 0.9 percent in 2009 (Total U.S. Natural Gas Consumption Growth). Year-over-year increases in the residential, commercial, and electric power sectors have been largely weather-driven. In 2009, residential and commercial sector consumption is expected to be decline slightly while natural gas consumption for electricity generation is expected to increase by 2.5 percent. Growth in the industrial sector, which increased by 4.8 percent in the first quarter of 2008 compared with the corresponding period last year, seems to be tied to export strength and some resurgence in natural-gas-intensive industries, such as fertilizers. In annual terms, natural gas consumption in the industrial sector is expected to increase by 1.3 percent in 2008 and 0.4 percent in 2009.

Production and Imports. Total U.S. marketed natural gas production is expected to increase by 6 percent in 2008 and by 1.5 percent in 2009. This projection includes an estimated expected hurricane-induced outage of about 78 Bcf for the offshore region in 2008 (see *Hurricane Outlook*). High rig counts in the lower-48 onshore region, particularly in unconventional reserve basins, are expected to lead to an increase in onshore production of 7.4 percent in 2008. In annual terms, marketed natural gas production in 2009 from the Federal Gulf of Mexico is projected to increase by 2.6 percent while the lower-48 onshore region is expected to increase by 1.4 percent.

Liquefied natural gas (LNG) imports remain substantially below last year. LNG supplies continue to flow to the higher-priced markets of Asia-Pacific and Europe. LNG imports to the United States this year are expected to total about 530 Bcf, a decline of about 240 Bcf from the 2007 total. In 2009, LNG imports are expected to reach about 850 Bcf as new liquefaction capacity increases world supply.

Inventories. On May 30, 2008, working natural gas in storage was 1,806 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 1 Bcf below the 5-year average (2003-2007) and 326 Bcf below the level during the corresponding week last year.

Prices. The Henry Hub spot price averaged $11.65 per Mcf in May, $1.16 per Mcf above the average spot price in April. High oil prices, low LNG imports, consumption growth, and a year-over-year decline in working inventories of 326 Bcf have all contributed to the recent strength in spot prices. These conditions are expected to continue and keep pressure on natural gas prices. On an annual basis, the Henry Hub spot price is expected to average a little over $11 per Mcf in 2008 and in 2009, an average increase of about $1.35 per Mcf from last month's forecast.

Electricity

Consumption. Three of the five warmest summers since 1975 in terms of cooling degree-days occurred in 2005, 2006, and 2007 (U.S. Summer Cooling Degree Days). NOAA projects temperatures this summer will fall back to near-normal levels, thus limiting annual growth in electricity consumption to 0.6 percent for 2008. Consumption is expected to grow at a higher rate of 1.6 percent in 2009 (U.S. Total Electricity Consumption).

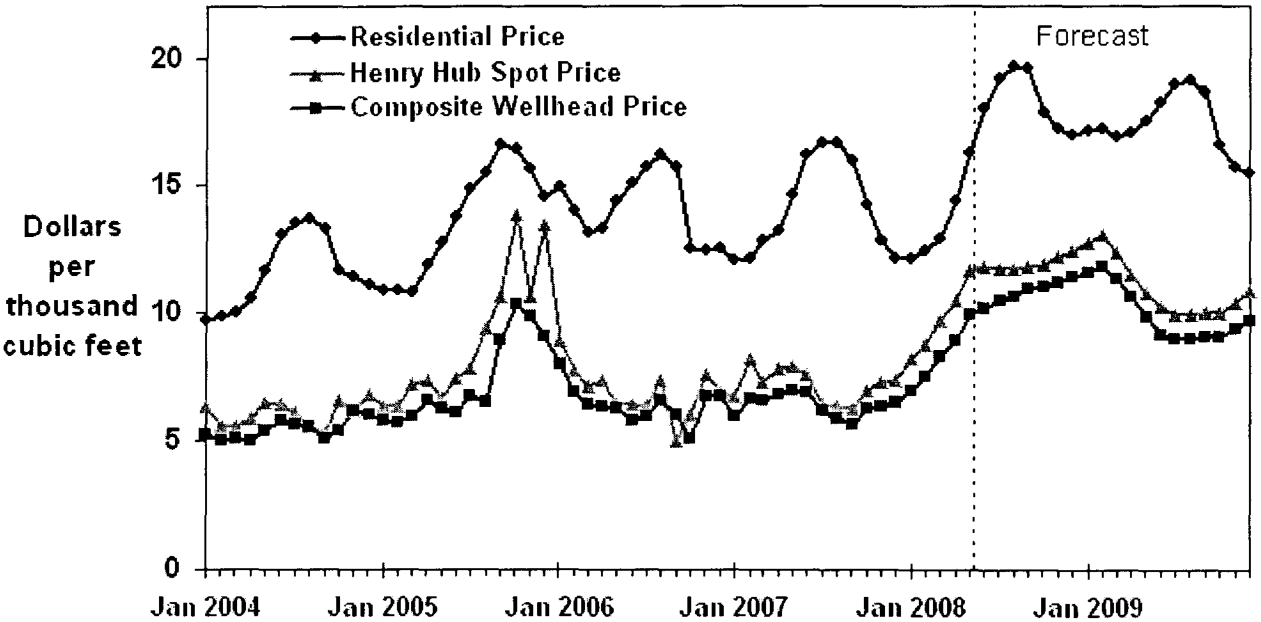
Prices. The cost of most fuels used in generating electricity has risen significantly since the beginning of the year. How soon these higher generation costs are passed through to consumers depends on a number of factors such as the terms of utilities' fuel purchase contracts and the regulatory structure within a given State. Average U.S. residential electricity prices are expected to increase by about 3.7 percent in 2008 and by 3.6 percent in 2009 (U.S. Residential Electricity Prices).

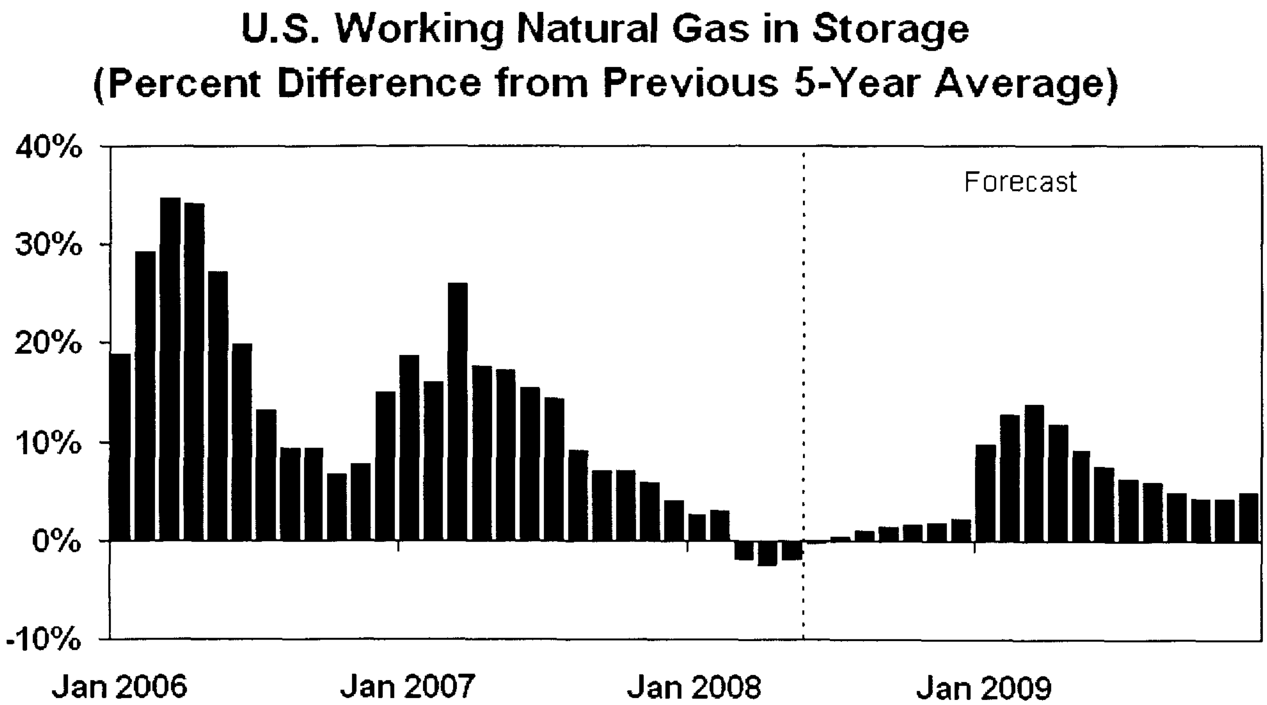
Coal

Consumption. Electric-power-sector coal consumption grew by 1.9 percent in 2007. Slow growth in total electricity consumption is expected to limit growth in electric-power-sector coal consumption to 0.9 percent in 2008. Projected increases from other generation sources (nuclear, natural gas, hydroelectric, and wind) in 2009 will continue to dampen electric-power-sector coal consumption growth, projected to be 0.6 percent in 2009 (U.S. Coal Consumption Growth).

Production and Inventories. U.S. coal production (U.S. Coal Production) is estimated to have fallen by 1.5 percent in 2007. Growth in domestic consumption and exports will contribute to a 2.9-percent increase in coal production in 2008. Secondary (consumer-held) coal stocks are estimated to have grown by 5.5 percent in 2007 to 159 million short tons. Coal consumers are expected to continue to build stocks in 2008, growing by an average of 6.2 percent. Primary stocks, held by coal producers/distributors, are projected to decline by more than 6 million short tons between the end of 2007 and the end of 2009.

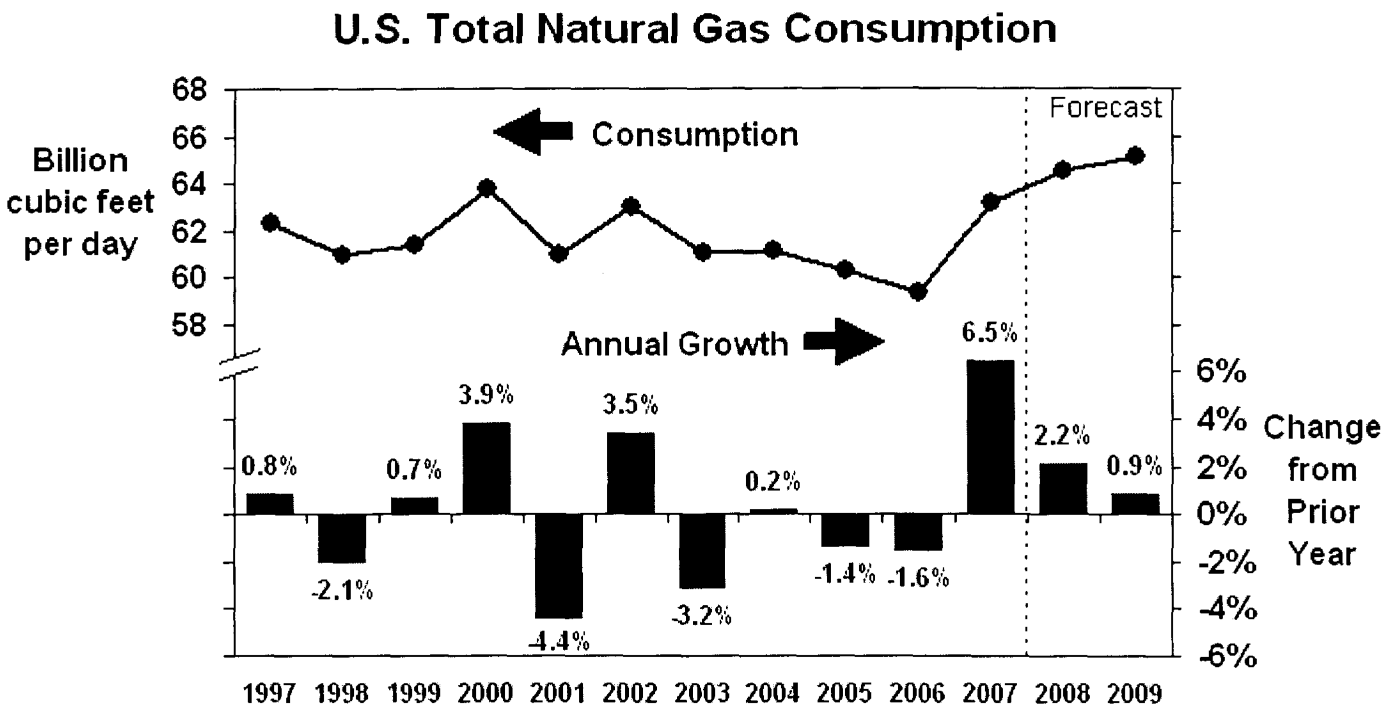
Natural Gas Prices





Short-Term Energy Outlook, June 2008

www.eia.doe.gov



Short-Term Energy Outlook, June 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)
Balance @ May 31, 2008									**($66,581)**

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)
Balance @ May 31, 2008									**($121,070)**