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October 30, 2008

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

Re: Cost of Gas Adjustment (COG)
November 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 (32nd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (32nd Revised Sheet No. 8), showing the November 2008 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.9535 per mcf for residential and firm general service customers and \$0.9663 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for November 2008, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.9663 per mcf since the last COG filing due to a decrease in the market price of gas. There has been an increase in pipeline charges of \$0.0128 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of \$0.9535 per mcf for residential and firm general service customers.

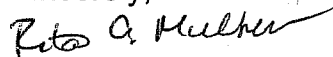
Attachment C explains the reasons for the change in the market price of gas.

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
Regulatory Analysis Manager

Attachments

Attachment A



GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota Gas Rate Schedule

NDPSC Volume 2

32nd Revised Sheet No. 1.1

Canceling 31st Revised Sheet No.1.1

RATE SUMMARY SHEET

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/MCF	
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF	\$1.2740	\$8.0834	\$9.3574
			Over 10 MCF	1.0540		9.1374
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF	\$1.1391	\$4.9952	\$6.1343
			Next 2,600 MCF	0.8931		5.8883
			Over 3,000 MCF	0.7411		5.7363
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF	\$1.2391	\$4.9952	\$6.2343
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 30, 2008

Effective Date: November 1, 2008

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

Case No.:

10/30/08
35



GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota Gas Rate Schedule

NDPSC Volume 2
32nd Revised Sheet No. 8
Canceling 31st 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.	2.4644	1.5733	(0.1857)	3.8520	1.5733	(0.7309)	0.8424
Current Adj.	0.0128	(0.9663)	0.0000	(0.9535)	(0.9663)	0.0000	(0.9663)
Total Adj.	2.4772	0.6070	(0.1857)	2.8985	0.6070	(0.7309)	(0.1239)
Total Rate:	\$2.5430	\$5.7261	(\$0.1857)	\$8.0834	\$5.7261	(\$0.7309)	\$4.9952

Date Filed: October 30, 2008

Effective Date: November 1, 2008

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

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
NOVEMBER 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	10.5800	12	1,008,951	0.6445
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	10.5800	5	268,097	0.1712
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				\$3,981,227	2.5430
Estimated Weighted Average Commodity Cost	1,565,565	1/ 5.7261		8,964,582	5.7261
Gas Cost Reconciliation Adjustment					(0.1857)
Total Current Firm Gas Cost				\$12,945,809	8.0834
Base Cost of Gas					5.1849
Accumulated Adjustment					\$2.8985
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$5.7261
Gas Cost Reconciliation Adjustment					(0.7309)
Total Current Interruptible Gas Cost					4.9952
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$0.1239)

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

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
NOVEMBER 2008**

Attachment B
Page 2 of 7

Rates Effective November 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	10.5800	Per dk/Mo.
Trans Canada Pipeline Demand Charge	13.9161	Per dk/Mo.
ProGas - Demand Charge	0.8746	Per dk/Mo.
NOVA - Seasonal	10.5800	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:	5.7261	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
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1/ Demand base rate calculation: $4,768 \times 12 \times \$0.8100 / 707,222$

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

STATEMENT OF RATES
(Rates Per Dekatherm)

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

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

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

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

Issued by: J. Phill May, Vice President Commercial

Issued on: October 1, 2008

Effective on: November 1, 2008

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

Thirteenth Revised Sheet No. 5C
Superseding
Substitute Twelfth Revised Sheet No. 5C

STATEMENT OF RATES
(Rates Per Dekatherm)

Rate Schedule	Base Tariff Rate	Adjustment Under Section 27 1/	Rate After Current Adjustment
=====	=====	=====	=====
LMS - Monthly Demand Rate	\$1.0000		\$1.0000
LMS - Daily Overrun Rate	\$0.1737		\$0.1737
LMS - Load Management Cost Reconciliation Adjustment		(\$0.0286)	

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

Issued by: J. Phill May, Vice President Commercial
Issued on: February 29, 2008

Effective on: April 1, 2008

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

Attachment B
 Page 6 of 7

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

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

Attachment B
 Page 7 of 7

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

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

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

- 1/ The minimum reservation rate is equal to zero.
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- 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.

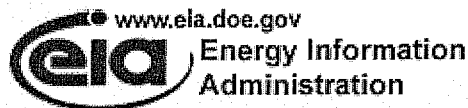
**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
November 2008**

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

The continued decline in crude oil prices, strong year over year increase in domestic U.S. natural gas production and higher than normal storage injections contributed to lower prices. The Energy Information Administration (EIA) reported storage levels nationwide as of October 24, 2008 were 2.9 percent above the five-year average and 2.8 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 13.



October 2008

Short-Term Energy and Winter Fuels Outlook

October 7, 2008 Release

Highlights

- Average household expenditures for all space-heating fuels are projected to be \$1,137 this winter (October 1 to March 31), a 15-percent increase over the estimated \$986 spent last winter. The largest increases will be in households using heating oil and natural gas. The projected increases primarily reflect higher prices, although colder weather than last winter will also contribute to higher fuel use in many areas.
- Strong global demand and low surplus production capacity contributed to the run-up to record crude oil prices in July. The current slowdown in economic growth is contributing to the recent decline in oil demand and the sharp decline in prices since July. Nonetheless, oil markets are expected to remain relatively tight because of sluggish production growth. Absent a major worldwide economic downturn that significantly impacts global demand, West Texas Intermediate (WTI) crude oil prices are projected to average about \$112 per barrel in both 2008 and 2009.
- According to the National Oceanic Atmospheric Administration's (NOAA) most recent projection of heating degree-days, the Lower-48 States are forecast to be 2.4 percent colder this winter compared with last winter, but 1.7 percent warmer than the 30-year average (1971 to 2000). However, regional heating degree-day projections vary widely; for example, the West North Central region is projected to be almost 5 percent warmer than last winter.
- During September, Hurricanes Gustav and Ike shut in a total of 32 million barrels of crude oil and 165 billion cubic feet (Bcf) of natural gas production in the Federal Gulf of Mexico. Recovery is ongoing and expected to continue at least through October.

Projected Winter Fuel Expenditures by Fuel and Region

The average household winter heating fuel expenditures discussed in this *Outlook* provide a broad guide to changes from last winter, but fuel expenditures for individual households are highly dependent on local weather conditions, market size, the size and energy efficiency of individual homes and their heating equipment, and thermostat settings.

Natural Gas. Households heating primarily with natural gas are expected to spend an average of \$155 (18 percent) more this winter. Nationwide, about 52 percent of all households depend on natural gas as their primary heating fuel. The increase in natural gas expenditures reflects the combined effects of a 17-percent increase in price and 1-percent increase in consumption. In the Midwest, where 72 percent of all households rely on natural gas, a projected 17-percent increase in average household expenditures results from a 19-percent increase in prices and a decline in consumption of 2 percent due to the forecast of slightly warmer weather than last winter.

Heating Oil. Households heating primarily with heating oil can expect to pay an average of \$449 (23 percent) more this winter. Only 7 percent of U.S. households depend on heating oil for winter fuel and most of these households are in the Northeast, where 31 percent of households use heating oil as their primary space heating fuel. In that region, the average household is projected to pay 24 percent more than last winter as a result of an 18-percent increase in prices and a 5-percent increase in consumption. Residential heating oil prices in the Northeast are projected to average about \$3.90 per gallon during the winter season compared with \$3.31 per gallon last winter. The projected increase is consistent with higher crude oil prices and projections of lower distillate inventories than last year going into the heating season.

Propane. Households heating primarily with propane can expect to pay an average of \$188 (11 percent) more this winter. Propane-heated households, which represent about 6 percent of total U.S. households, are projected to see an average increase of 11 percent in propane expenditures this winter, but that increase varies widely by region. Western households are expected to see an average increase in expenditures of 5 percent, while Southern homes are expected to spend 16 percent more this winter.

Electricity. Households heating primarily with electricity can expect to pay an average of \$89 (10 percent) more. Thirty-five percent of all U.S. households rely on electricity as their primary heating fuel, ranging from 12 percent in the Northeast to 59 percent in the South. On average, electricity expenditures during the winter are projected to rise by 10 percent because of increased consumption and prices.

Households in the South are projected to pay 13 percent more this winter on electricity bills.

Global Petroleum

Overview. Higher oil production in Saudi Arabia during summer 2008 combined with the demand response to extremely high prices and recent credit market problems that point to a lower trajectory for the world economy and oil consumption growth are currently reinforcing the sentiment of a loosening in the global oil balance. As a result, the recent supply disruptions in the Gulf of Mexico have not resulted in the kind of price increases that would have been expected had they occurred earlier in the year.

However, unless the global economy is weaker than anticipated, EIA expects that the call on Organization of the Petroleum Exporting Countries' (OPEC) crude oil will exceed OPEC crude oil production over the next 6 months. This market balance and the relatively low level of Organization for Economic Cooperation and Development (OECD) commercial oil inventories suggest some upward pressure on prices. However, if non-OPEC oil production increases as expected during 2009, oil price pressures would then moderate.

Consumption. Global oil consumption is projected to rise by about 300,000 barrels per day (bbl/d) in 2008 and by almost 800,000 bbl/d in 2009 compared with year-earlier levels. Growth for 2008 is nearly 350,000 bbl/d lower than last month's projection, reflecting the deteriorating global economic outlook. Solid growth in non-OECD countries, especially China, Latin America, and oil-exporting countries in the Middle East, is partly offset by sharp declines in U.S. oil consumption as well as lower oil consumption in many other OECD countries (World Oil Consumption). In 2008, non-OECD consumption is expected to rise by 1.4 million bbl/d, while OECD consumption is expected to fall by 1.1 million bbl/d. China's oil consumption remained high in August 2008 as imports for crude and oil products climbed 12 percent and 32 percent, respectively, from year-earlier levels according to Chinese government data. These trends are similar for 2009, although the decline in OECD consumption in 2009 is expected to be about half of the amount seen in 2008. The level of Chinese demand growth following the Olympics will have an important impact on non-OECD consumption growth and will depend on the domestic economy as well as the level of exports to other countries.

Non-OPEC Supply. Non-OPEC supply had been expected to increase in the second half of the year after declining by almost 300,000 bbl/d during the first half of 2008 compared with year-earlier levels. However, a series of supply disruptions,

especially the closure of the Baku-Tbilisi-Ceyhan oil pipeline and the impacts of Hurricanes Gustav and Ike upon the U.S. Gulf of Mexico, led to a revision in this *Outlook*. As a result, non-OPEC supply is expected to decline by about 115,000 bbl/d during the second half of 2008, compared with the year-earlier level, and consequently non-OPEC supply growth in 2008 is now expected to be negative for the first time since 2005. The 2009 growth in non-OPEC supply of 730,000 bbl/d is expected to largely meet the anticipated increase in global consumption, barring delays in new projects and unanticipated disruptions. The United States, Azerbaijan, and Brazil represent the bulk of non-OPEC supply growth in 2009, although some of the growth in two of these countries simply represents a return to normal production conditions (Non-OPEC Oil Production Growth).

OPEC Supply. OPEC crude oil production is expected to average 32.7 million bbl/d during the third quarter of 2008, up 1.7 million bbl/d from year-earlier levels. The forecast assumes production in Saudi Arabia of 9.6 million bbl/d in the third quarter, representing a 900,000-bbl/d rise from year-earlier levels. OPEC's call for greater compliance with quotas at its September meeting, suggests about a 500,000-bbl/d cut in output, but this outcome is uncertain. Given that the bulk of OPEC above-target output has been coming from Saudi Arabia, the group's decision to scale back production will depend on Saudi Arabia's willingness to cut. Taking into account uncertainties about Saudi actions, this *Outlook* assumes that OPEC crude oil production declines to 32.4 million bbl/d in the fourth quarter of 2008 and falls through 2009 to an average of 31.6 million bbl/d for that year. Lower crude oil production, combined with planned increases in OPEC total liquids production capacity, suggests OPEC surplus crude production capacity could increase from 1.5 million bbl/d in the second quarter of 2008 to over 3 million bbl/d by the end of next year (OPEC Surplus Oil Production Capacity).

Inventories. Revised data indicate that OECD commercial inventories held steady during the second quarter of 2008, well below the average build of 900,000 bbl/d during this time of year. At the end of the second quarter, estimated OECD commercial inventories stood at 2.56 billion barrels, 35 million barrels below the 5-year average (Days of Supply of OECD Commercial Stocks). OECD commercial inventories are projected to rise by about 280,000 bbl/d in the third quarter compared with the average seasonal build of about 400,000 bbl/d. EIA expects OECD commercial inventories to remain below 5-year average levels throughout the forecast period.

U.S. Petroleum

Consumption. Consumption of all petroleum products has fallen in 2008, driven down by the increase in prices and the weakening economy. Motor gasoline and distillate fuel lead the way with projected average declines of about 200,000 bbl/d for each fuel compared with last year. The declines in consumption are expected to continue in 2009 but at a much lower rate. Total domestic petroleum consumption is projected to average 19.8 million bbl/d in 2008, down 830,000 bbl/d from the 2007 average (U.S. Petroleum Products Consumption Growth), followed by a further 100,000-bbl/d decline in 2009.

Production. In 2008, domestic crude oil production is projected to average just below 5.0 million bbl/d, down from 2007 levels due to the loss of production in the Gulf of Mexico caused by Hurricanes Ike and Gustav (U.S. Crude Oil Production). Domestic crude production has been steadily declining since the 1970s and the 2008 projection for crude oil production falls under 5 million bbl/d for the first time since 1946. However, domestic production is projected to increase in 2009 by 330,000 bbl/d to an average of 5.3 million bbl/d. Contributing to the increases in output are the Thunderhorse platform, which is expected to come on stream later this year, and the Tahiti platform, expected to come on stream late in 2009.

Prices. Oil markets are expected to remain tight over the next 6 months because of sluggish production growth, which will help push WTI crude oil prices to \$120 per barrel by April 2009, before declining to \$106 per barrel by year's end. WTI prices are projected to average \$112 per barrel in both 2008 and 2009 (Crude Oil Prices). Further deterioration in actual or expected global economic growth as a fallout of the current financial crisis may lead to weaker oil prices.

Gasoline

Inventories. Motor gasoline inventories during the summer were tight and became even tighter as a result of Hurricanes Gustav and Ike. On September 30, total gasoline inventories were estimated at 180 million barrels, 23 million barrels below the 5-year average and the lowest since August 1967 (Motor Gasoline Inventories). Continued weakness in motor gasoline markets and growth in domestic fuel ethanol production is expected to allow inventories to recover. By the beginning of the second quarter next year, total gasoline inventories are expected to reach 205 million barrels, about 4 million barrels below the previous 5-year average.

Prices. Regular grade gasoline prices are projected to average \$3.56 per gallon in both 2008 and 2009, following movements in projected crude oil prices. 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 interval.

Distillate

Inventories. Refinery shut-ins caused by Hurricanes Gustav and Ike also pulled distillate (diesel fuel and heating oil) inventories down to relatively low levels (Distillate Fuel Inventories). As of September 30, the start of the winter heating season, distillate fuel inventories were an estimated 122 million barrels, down 12 million barrels from the previous year and 11 million barrels below the average of the last 5 years. Total distillate inventories at the end of March 2009 are projected to be 104 million barrels, about 6 million barrels below the previous 5-year average but still within the low end of the normal range.

Prices. The increases in heating oil and diesel fuel prices this year have outpaced the rise in crude oil prices because of the continuing stronger growth in global distillate demand relative to other petroleum products. Residential heating oil retail prices this winter are projected to average \$3.89 per gallon, an increase of 58 cents per gallon over last winter, compared with a projected 38-cents-per-gallon increase in the price of WTI crude oil. Although oil prices are expected to be up slightly on average next year, the on-highway diesel fuel retail prices are projected to average \$3.91 per gallon in 2009, down from a projected \$4.01 per gallon in 2008, reflecting a weakening of the very high wholesale distillate-crude oil price margins seen this past summer.

Propane

Inventories. As of September 30, U.S. propane inventories were an estimated 59 million barrels, slightly above last year's level but 7 million barrels below the average over the last 5 years. These inventories are projected to end the winter season at about 28 million barrels, near the average of the last 5 years. This projection assumes that, because of high prices and a slow economy, the combination of propane production increases and reduced petrochemical consumption will offset the reduced availability of waterborne supplies, which have been diverted to fast-growth areas such as Asia and the Middle East.

Prices. Spot propane prices are strongly influenced by both crude oil and natural gas prices. Retail propane prices are projected to average \$2.60 per gallon in 2008 and \$2.65 per gallon in 2009. However, with current low inventories, propane markets are likely to remain relatively tight this winter, with the potential for additional upward

pressure on residential propane prices if the United States experiences colder-than-expected weather.

Natural Gas

Consumption. Total natural gas consumption is expected to increase by 2.4 percent in 2008 and by 1.9 percent in 2009 (Total U.S. Natural Gas Consumption Growth). Despite slower expected growth in 2009, consumption is expected to increase in all sectors during the forecast period. This winter, total residential consumption of natural gas in the United States is expected to increase by 3.5 percent year-over-year based on the projected 2.4-percent increase in heating degree-days. In addition to weather, worsening economic conditions add significant uncertainty to the forecast, particularly for the industrial sector. In annual terms, consumption in the industrial sector is expected to increase by 1.0 percent in 2008 and 1.1 percent in 2009.

Production and Imports. Total U.S. marketed natural gas production is expected to increase by 6.7 percent in 2008 and by 4.2 percent in 2009. Domestic production continues to be led by the development of fields in the Lower-48 non-Gulf of Mexico region, which is expected to increase production by 9.7 percent in 2008. Recent hurricane damage resulted in estimated production shut-ins of about 165 Bcf in the Federal Gulf of Mexico in September, with at least an additional 16 Bcf in the onshore and State waters areas of Louisiana. While the length of the hurricane recovery process is unknown, marketed natural gas production from the Federal Gulf of Mexico is projected to decline by 9.1 percent in 2008. In 2009, Federal Gulf of Mexico and Lower-48 non-Gulf of Mexico growth are expected to be 8.1 and 3.8 percent, respectively.

U.S. imports of liquefied natural gas (LNG) remain below year-ago levels with third-quarter imported cargoes less than half of what they were last year. Demand growth in Europe and Asia combined with limited global supply increases to date continue to weigh on the market. LNG imports to the United States are no longer expected to increase during the remainder of 2008, and import growth in 2009 remains vulnerable to additional delays in new capacity and unexpected maintenance on existing capacity. For the year, LNG imports are expected to total about 350 Bcf and about 450 Bcf in 2009 as more global LNG capacity is expected to be brought online.

Inventories. On September 26, 2008, working natural gas in storage was 3,110 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 50 Bcf above the 5-year average (2003–2007) and 137 Bcf below the level during the corresponding week last year.

Prices. The Henry Hub spot price averaged \$7.88 per thousand cubic feet (Mcf) in September, \$0.62 per Mcf below the average spot price in August. Despite hurricane damage to supply infrastructure in the Federal Gulf of Mexico, the recent decline in prices was the result of demand loss associated with these same hurricanes, moderate temperatures, lower oil prices, and uncertainties about future economic growth. This winter, however, natural gas expenditures for U.S. households are expected to increase by about 18 percent compared with last winter. The increase in end-use prices is the result of the particularly high spot prices that were recorded earlier this year as a portion of the inventories for the upcoming heating season were being built. Beyond the winter, continued growth in on-shore production is expected to bring prices down. On an annual basis, the Henry Hub spot price is expected to average about \$9.67 per Mcf in 2008 and \$8.17 per Mcf in 2009, compared with \$7.17 per Mcf in 2007.

Electricity

Consumption. After a relatively warm June and July, cooling degree-days during August in most regions of the United States were lower than normal (U.S. Summer Cooling Degree-Days). Summer residential electricity consumption this year was approximately the same as it was in the summer of 2007. For the entire year, total electricity consumption is expected to grow by about 1 percent (U.S. Total Electricity Consumption). Growth in consumption during 2009 is expected to remain relatively low, primarily as a result of the projected slow growth in economic activity.

Prices. The delivered cost of fuel continues to affect power generators. During 2008, the cost of natural gas and coal for electric utilities is projected to be 36 percent higher and 12 percent higher, respectively, than last year. As electricity providers continue to pass along these increased costs, U.S. residential electricity prices are expected to grow by 6.2 percent this year and 9.4 percent in 2009 (U.S. Residential Electricity Prices). Price increases are expected to be especially pronounced in the Middle and South Atlantic regions.

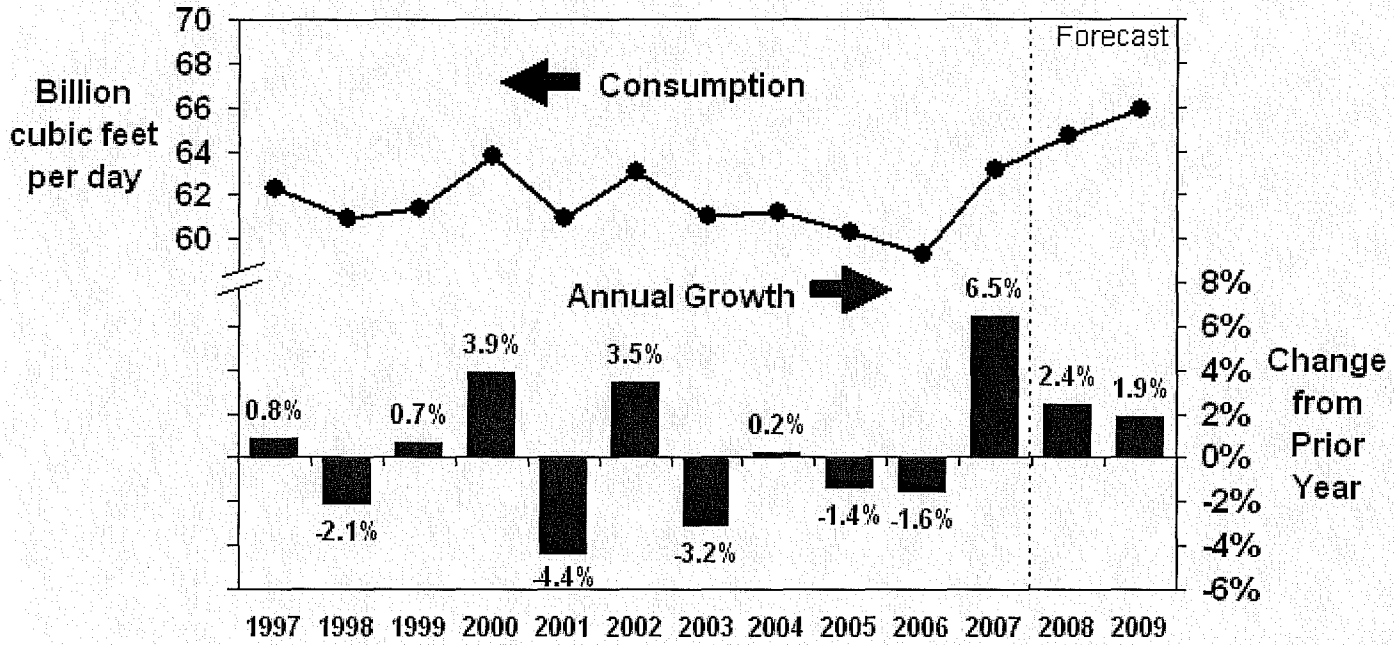
Coal

Consumption. Electric-power-sector coal consumption is projected to grow by about 1.2 percent in 2008. Slow growth in electricity consumption, combined with projected increases in electricity generation from other sources (nuclear, natural gas, and wind), will lead to a slight decline (0.9 percent) in electric-power-sector coal consumption in 2009 (U.S. Coal Consumption Growth).

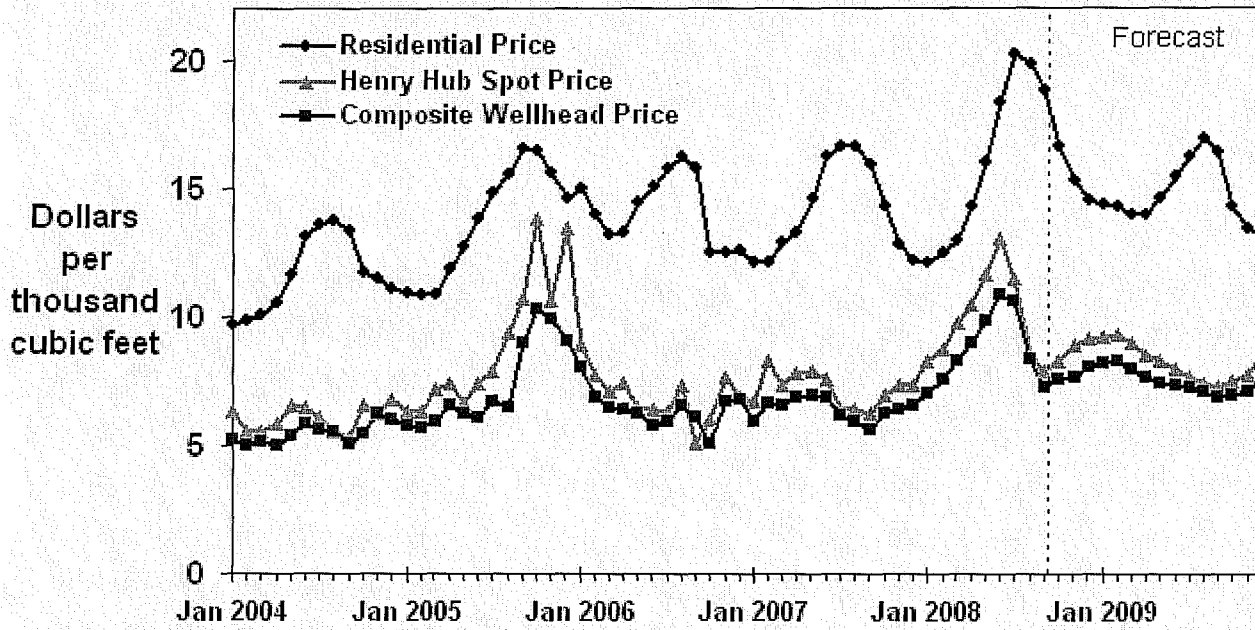
Production and Inventories. Growth in domestic coal consumption and particularly in exports is expected to contribute to a 3-percent increase in coal production in 2008 (U.S. Annual Coal Production). In 2009 coal production will remain relatively unchanged as increases in coal exports are offset by decreases in domestic consumption and producer-held stocks. Secondary (consumer-held) coal stocks, which grew to almost 160 million short tons in 2007, are expected to remain stable in 2008 and grow by an average of 2.3 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. Continued robust worldwide demand for coal is projected to lead to an overall 43-percent increase in U.S. coal exports in 2008. Coal exports are projected to grow 2.4 percent to 86.5 million short tons in 2009.

U.S. Total Natural Gas Consumption



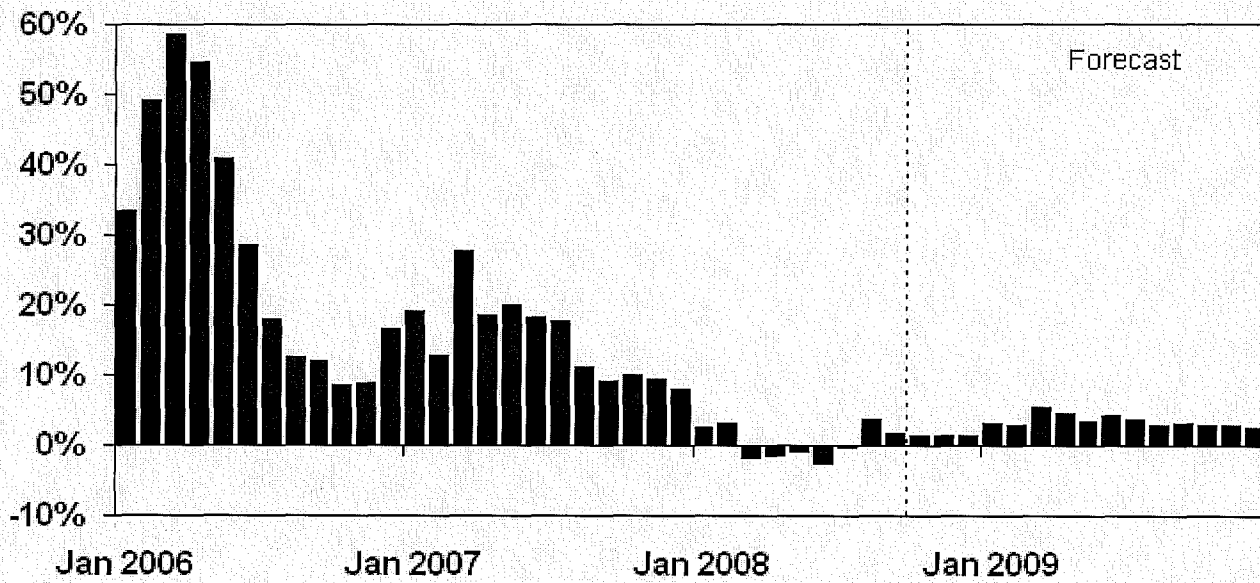
Natural Gas Prices



Short-Term Energy Outlook, October 2008



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



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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ April 30, 2008									<u>(\$46,836)</u>
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
Balance @ September 30, 2008									<u>\$48,821</u>

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ April 30, 2008									<u>(\$111,189)</u>
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)
Balance @ September 30, 2008									<u>(\$166,304)</u>