



A Division of MDU Resources Group, Inc.

705 West Fir Ave.
PO Box 176
Fergus Falls, MN 56538-0176
(218) 736-6935

ORIGINAL

April 1, 2009

RECEIVED

APR 02 2009

PUBLIC SERVICE COMMISSION

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

Re: Cost of Gas Adjustment (COG)
April 2009

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and seven (7) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (37th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (37th Revised Sheet No. 8), showing the April 2009 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.5552 per mcf for residential and firm general service customers and \$0.5557 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for April 2009, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.5557 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 \$0.0005 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of \$0.5552 per mcf for residential and firm general service customers.

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

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

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

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

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

Sincerely,

Rita A. Mulkern

Rita A. Mulkern
Regulatory Analysis Manager

Attachments

Attachment A

Attachment A



GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota Gas Rate Schedule

NDPSC Volume 2

37th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 36th Revised Sheet No.1.1

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/MCF
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF \$1.2740 Over 10 MCF 1.0540	\$5.5317	\$6.8057 6.5857
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411	\$2.7057	\$3.8448 3.5988 3.4468
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$2.7057	\$3.9448
Transportation Service	5	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411		\$1.1391 0.8931 0.7411

Date Filed: April 1, 2009

Effective Date: April 1, 2009

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

Case No.:



GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota Gas Rate Schedule

NDPSC Volume 2
37th Revised Sheet No. 8
Canceling 36th 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.	2.2145	(1.1268)	(0.1857)	0.9020	(1.1268)	(0.7309)	(1.8577)
Current Adj.	0.0005	(0.5557)	0.0000	(0.5552)	(0.5557)	0.0000	(0.5557)
Total Adj.	2.2150	(1.6825)	(0.1857)	0.3468	(1.6825)	(0.7309)	(2.4134)
Total Rate:	\$2.2808	\$3.4366	(\$0.1857)	\$5.5317	\$3.4366	(\$0.7309)	\$2.7057

Date Filed: April 1, 2009

Effective Date: April 1, 2009

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

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
APRIL 2009

<u>Firm</u>	<u>Billing</u> <u>Determinants</u>	<u>Rate</u>	<u>Demand</u> <u>Months</u>	<u>Amount</u>	<u>Amount</u> <u>Per dk</u>
FT-A	7,841	\$3.4671	12	\$326,226	\$0.2084
FT-A - Zone 1-1	500	3.4671	5	8,668	0.0055
FT-A - Zone 1-2	4,500	4.5871	5	103,210	0.0659
FT-A Seasonal	3,000	3.7671	5	56,507	0.0361
FT-A Seasonal	1,000	3.7671	4	15,068	0.0096
TFX Seasonal	4,000	15.1530	5	303,060	0.1936
NOVA - Demand Charge	7,947	11.1106	12	1,059,551	0.6768
Trans Canada - Demand Charge	7,947	9.8894	12	943,093	0.6024
ProGas - Demand Charge	7,947	0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068	11.1106	5	281,543	0.1798
Trans Canada - Seasonal	5,068	9.8894	5	250,597	0.1601
ProGas - Seasonal	5,068	0.9612	5	24,357	0.0156
ProGas Winter Surcharge	5,068	3.0417	5	77,077	0.0492
LMS Demand	2,500	1.0000	12	30,000	0.0192
Total Demand Charges				<u>\$3,570,621</u>	<u>2.2808</u>
Estimated Weighted Average Commodity Cost	1,565,565 1/	3.4366		<u>5,380,221</u>	<u>3.4366</u>
Gas Cost Reconciliation Adjustment					<u>(0.1857)</u>
Total Current Firm Gas Cost				<u>\$8,950,842</u>	<u>5.5317</u>
Base Cost of Gas					<u>5.1849</u>
Accumulated Adjustment					<u>\$0.3468</u>
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					<u>\$3.4366</u>
Gas Cost Reconciliation Adjustment					<u>(0.7309)</u>
Total Current Interruptible Gas Cost					<u>2.7057</u>
Base Cost of Gas					<u>5.1191</u>
Accumulated Adjustment					<u>(\$2.4134)</u>

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

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

Rates Effective April 1, 2009

	<u>\$/Dk</u>	
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	11.1106	Per dk/Mo.
Trans Canada Pipeline Demand Charge	9.8894	Per dk/Mo.
ProGas - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	11.1106	Per dk/Day
Trans Canada - Seasonal	9.8894	Per dk/Mo.
ProGas - Seasonal	0.9612	Per dk/Mo.
ProGas Winter Surcharge	3.0417	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	3.4366	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	<u>\$5.1849</u>	Per Mcf

Interruptible:

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

STATEMENT OF RATES
 (Rates Per Dekatherm)

Attachment B
 Page 3 of 7

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

STATEMENT OF RATES
 (Rates Per Dekatherm)

Attachment B
 Page 4 of 7

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	0.64%
Zone 1 - 2	\$0.0130	\$0.0017	\$0.0147	0.89%
Zone 2 - 2	\$0.0130	\$0.0017	\$0.0147	0.25%
Minimum Rate	\$0.0130	\$0.0017	\$0.0147	
IT and AOT				
Zone 1 - 1	\$0.1369	\$0.0017	\$0.1385	0.64%
Zone 1 - 2	\$0.1737	\$0.0017	\$0.1754	0.89%
Zone 2 - 2	\$0.0834	\$0.0017	\$0.0851	0.25%
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: .05% for Zone 1-1, .07% for Zone 1-2, and .02% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted For percentages.

STATEMENT OF RATES
 (Rates Per Dekatherm)

Attachment B
 Page 5 of 7

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		\$0.0090	

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.

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

Attachment B
 Page 6 of 7

FIELD-TO-
 FIELD/MARKET
 DEMARCATION

MARKET-TO-MARKET

RESERVATION RATES	TF12		TF5	TFF
	Base	Variable		
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/		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
TF12 Base, TF12 Var., TF5 & TFF		Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Receipt Point	Delivery Point								
Market	Market	0.0379	0.0210			0.0175	0.0000	0.0379	0.0210
Field	Market	0.0379	0.0210	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0293	0.0107

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

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

Attachment B
 Page 7 of 7

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

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

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

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

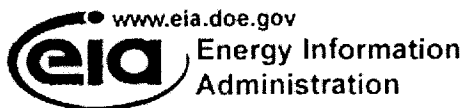
**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
April 2009**

The principal gas sources of natural gas for Wahpeton, North Dakota are from the large Western Canadian Sedimentary Basin (WCSB). The pricing point for much of this gas is the Alberta Energy Company (AECO-C), one of the largest and most liquid volume points in North America. The April 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 lower level of industrial demand for natural gas as a result of the ongoing economic downturn, the imminent end of winter and corresponding reduction in demand related to space heating and the high level of gas in storage contributed to the anticipated reduction of the natural gas price. The Energy Information Administration (EIA) reported storage levels nationwide as of March 20, 2009 were 20.4 percent above the five-year average and 29.0 percent above last year's balance.

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

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



March 2009

Short-Term Energy Outlook

March 10, 2009 Release

Highlights

- The global economic contraction continues to depress energy demand.
- The annual price of West Texas Intermediate (WTI) crude oil averaged \$100 per barrel in 2008. The global economic slowdown is projected to cut these prices by more than half, to average \$42 per barrel in 2009 and \$53 in 2010--forecasts slightly lower than last month's *Outlook*.
- Gasoline prices have been slowly increasing over the last 2 months while crude oil prices have stabilized and refiner margins have recovered from their recent near-historic lows. After averaging \$1.69 per gallon in December 2008, the lowest monthly average since February 2004, the retail gasoline price in February rose to \$1.92 per gallon. Retail gasoline prices are projected to average \$1.96 per gallon in 2009 and \$2.18 per gallon in 2010.
- The U.S. economic downturn is the principal cause for the decline in domestic natural gas consumption, particularly in the industrial sector--where it is projected to fall by 6 percent in 2009--which in turn has led to lower natural gas prices. The Henry Hub natural gas spot price is projected to decline from an average of \$9.13 per thousand cubic feet (Mcf) in 2008 to about \$4.70 per Mcf in 2009, but then increase in 2010 to an average of almost \$5.90 per Mcf.

Global Crude Oil and Liquid Fuels

Overview. Following the sharp price decline that occurred during the second half of 2008, the global oil market has remained relatively stable since the beginning of the year. This situation is expected to continue through most of 2009, until economic recovery in the United States and elsewhere leads to a rebound in oil demand growth.

The future direction of world oil prices in the short-term will largely depend upon the timing and pace of the recovery of the global economy. Our macroeconomic forecasts

are derived from the IHS Global Insight macroeconomic model. If economic growth in the United States and overseas rebounds sooner than expected, oil demand could experience stronger-than-expected growth and outpace production increases, leading to rising prices. However, any upward movement in oil prices will be muted by the relatively high levels of commercial inventories in the Organization for Economic Cooperation and Development (OECD) and surplus production capacity among members of the Organization of the Petroleum Exporting Countries (OPEC). OPEC is scheduled to meet March 15 to assess the market situation and determine its future oil production targets.

U.S. real gross domestic product (GDP) is expected to decline by 2.8 percent in 2009, leading to a reduction in domestic energy consumption for all major fuels. An economic rebound is projected to begin in 2010, with a 1.9-percent year-over-year growth in U.S. real GDP.

Consumption. Average annual world oil consumption is projected to decline by almost 1.4 million barrels per day (bbl/d) in 2009, with consumption in the OECD falling by 1.6 million bbl/d. This expected decline in global consumption growth is roughly 200,000 bbl/d larger than in last month's *Outlook*, reflecting lower expectations of global economic activity in 2009. World GDP growth (oil-consumption weighted) is assumed to decline by 0.8 percent in 2009 followed by growth of 2.6 percent in 2010, compared with last month's assumption of a 0.1-percent decline and 3-percent growth.

EIA's projection for 2009 global oil consumption is now 3 million bbl/d lower than it was in the September 2008 *Outlook*. World oil consumption is expected to rebound in 2010, growing by 900,000 bbl/d, in response to an economic recovery which is projected to begin at the end of 2009. However, this revised projection for 2010 is 300,000 bbl/d lower than in last month's forecast due to the projected slower pace of recovery in the global economy (World Liquid Fuels Consumption).

Non-OPEC Supply. Non-OPEC supply is expected to remain fairly flat over the next 2 years, following a decline of 300,000 bbl/d in 2008. This contrasts with an average annual growth of 570,000 bbl/d from 2000 through 2007. The largest sources of growth over the forecast period are the United States, Brazil, and Azerbaijan, offset by large declines in production in Mexico, the North Sea, and Russia (Non-OPEC Crude Oil and Liquid Fuels Production Growth). Considerable downside risks remain, as additional project delays, declines in drilling activity, and more rapid decline rates than assumed could result from the financial crisis and the current price environment.

OPEC Supply. Press and industry reports indicate that OPEC countries have trimmed production significantly over the past several months. Estimated OPEC crude oil production fell by 1.1 million bbl/d during the fourth quarter of 2008, reaching 30.6 million bbl/d. OPEC crude oil production is expected to fall by an additional 2 million bbl/d in the first quarter of 2009 to 28.6 million bbl/d, the lowest level for the first quarter since 2003. OPEC crude oil production in 2009 is expected to average 28.9 million bbl/d, then rise to 29.8 million bbl/d in 2010. In addition, EIA expects that OPEC production of non-crude liquids will grow by 410,000 bbl/d in 2009 and by 740,000 bbl/d in 2010. This is lower than last month's forecast due to a re-estimation of the impact of falling crude oil production upon the growth of production in associated non-crude liquids.

The combination of lower oil demand, rising natural gas liquids production, and increases in crude oil production capacity over the next 2 years will result in an OPEC surplus production capacity averaging 4 to 5 million bbl/d over the period. Higher surplus production capacity should mitigate the impacts of actual or perceived supply disruptions and reduce the likelihood of sharp price increases. There remains a risk, however, that financial constraints and prospects of weak demand could lead OPEC members to further delay expansion programs, reducing future surplus capacity and setting the stage for higher prices once the economic recovery is underway.

Inventories. Revised data indicate that OECD commercial inventories stood at 2.7 billion barrels at the end of 2008, equivalent to 52 days of forward cover, which is above recent end-of-year average levels (Days of Supply of OECD Commercial Stocks). Measured as days of forward cover, OECD commercial inventories are projected to remain in the upper end of the historic range through the end of 2010.

U.S. Crude Oil and Liquid Fuels

Consumption. Total consumption of liquid fuels in 2008 declined by almost 1.3 million bbl/d, or 6.1 percent, from that of 2007 (U.S. Liquid Fuels Consumption Growth). The major factors contributing to the fall in consumption were a rapid rise in retail prices to record levels during the first half of 2008 and a deteriorating economy in the second half of the year. Total liquid fuels consumption for 2009 is projected to fall by a further 420,000 bbl/d, or 2.2 percent, because of continued economic weakness. The expected economic recovery in 2010 is projected to boost total liquid fuels consumption by 210,000 bbl/d, or 1.1 percent, with all of the major fuels registering increases in consumption.

Production. Domestic crude oil production in 2009 is projected to increase by about 400,000 bbl/d from 2008 levels to an average of 5.36 million bbl/d (U.S. Crude Oil

Production). This would be the first increase in production since 1991. Output is projected to rise by a further 150,000 bbl/d in 2010. Contributing to the increases in output are the Gulf of Mexico Thunder Horse platform, which is producing now, and the Tahiti platform, which is expected to come on stream later this year.

Prices. Under current economic and world crude oil supply assumptions, WTI prices are expected to average \$42 per barrel in 2009 and \$53 per barrel in 2010 (Crude Oil Prices). A stronger economic recovery, lower non-OPEC production because of the current low oil prices and financial market constraints, or more aggressive action to cut production by OPEC countries could lead to a faster and stronger rise in oil prices.

Regular-grade gasoline prices, which averaged \$3.26 per gallon in 2008, are projected to average \$1.96 per gallon in 2009 and \$2.18 per gallon in 2010. The monthly average price is expected to peak slightly over \$2 per gallon this year, although it remains possible that weekly prices could rise significantly higher at some point this spring or summer. Because of lower motor gasoline consumption, refining margins for gasoline are expected to remain depressed for much of 2009 but are expected to increase slightly in 2010 as consumption begins to recover.

On-highway diesel fuel retail prices are projected to average \$2.19 per gallon in 2009 and \$2.51 in 2010. The expected continuing decline in diesel fuel consumption in the United States this year as well as the growing weakness in distillate fuel usage outside the United States are projected to result in a narrowing of refining margins for distillate throughout the forecast period. Because of the global weakness in industrial output, it is possible that we will see diesel prices fall below gasoline prices this summer.

Natural Gas

Consumption. Total natural gas consumption is projected to decline by 1.3 percent in 2009 and then increase by 0.4 percent in 2010 (Total U.S. Natural Gas Consumption Growth). The outlook for continued economic weakness in 2009 is expected to take its greatest toll on industrial sector natural gas consumption, which is expected to decline by about 6 percent this year, more than offsetting the small projected increases in other end-use sectors. Lower natural gas delivered prices compared with coal in some markets, particularly in the Southeast, are expected to cause some electric power generators to switch some generation from coal to natural gas. Natural gas consumption by the electric power sector is projected to grow by 0.4 percent in 2009.

The pace and extent of economic recovery in 2010 are the primary factors influencing the natural gas consumption forecast next year, particularly for industrial users.

Based on the current economic assumptions for 2010, slight growth in the industrial sector and 2-percent growth in the electric power sector are balanced by declines in the residential and commercial sectors because of projected milder winter temperatures.

Production and Imports. Total U.S. marketed natural gas production is expected to remain flat in 2009 and then fall by 0.8 percent in 2010. Baker-Hughes reports 916 natural gas rigs working in the United States as of March 6, 2009, a decline of 43 percent from August 2008. Consequently, the robust growth in natural gas production in the Lower-48 region (excluding the Gulf of Mexico) over the last few years is expected to end as production reaches about 53 billion cubic feet per day (Bcf/d) in early 2009, then declines during the second half of 2009. The extent of the production decline later this year is highly uncertain and subject to fluctuations in demand and prices over the period. Rig activity is expected to recover in 2010 as the economy improves and prices increase. However, annual average production is still projected to be lower next year because of the decline in new wells drilled this year.

U.S. imports of liquefied natural gas (LNG) are expected to increase slightly in 2009 to 380 Bcf. New LNG supply capacity in Qatar, Indonesia, and Yemen could supply a significantly greater volume of LNG imports this year. However, delays to this new supply capacity as well as uncertainty about the weakness of natural gas demand in other LNG-consuming countries contribute to doubts about much higher LNG imports might be this year. LNG imports in 2010 are projected to be about 460 billion cubic feet (Bcf) as global supply projects ramp up. Pipeline imports are expected to decline by 9.4 percent in 2009 as Canadian drilling activity subsides, fields age, and a growing portion of available supply is dedicated to oil sands development.

Inventories. On February 27, 2009, working natural gas in storage was 1,793 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 218 Bcf above the 5-year average (2003–2007) and 270 Bcf above the level during the corresponding week last year. Storage inventories at the end of March 2009 are expected at about 1.6 trillion cubic feet (Tcf), roughly 200 Bcf above the previous 5-year average for that time.

Prices. The Henry Hub spot price averaged \$4.65 per Mcf in February, \$0.75 per Mcf below the average spot price in January. Prices continue to reflect demand reductions brought about by the current economic downturn. As the year progresses, it is expected that average spot prices will remain near \$4 per Mcf. If prices fall further than currently forecast, natural gas will become increasingly competitive with coal for base load power generation in some regions. On the supply side, the current drilling pullback could contribute to higher-than-expected prices if the economy begins to

recover earlier than expected and production is slow to react. The Henry Hub spot price is expected to average \$4.67 per Mcf in 2009 and \$5.87 per Mcf in 2010.

Electricity

Consumption. An expected decline of 6.4 percent in industrial electricity sales during 2009 leads to a projected decline in total electricity consumption of 1.7 percent this year (U.S. Total Electricity Consumption). Total electricity consumption is expected to grow by 1.2 percent in 2010 as a slowly improving economic climate contributes to a recovery in the sales of electricity.

Prices. Despite the recent drop in generation fuel costs, some electric utilities have proposed slight rate increases in response to higher costs of securing credit for purchases of fuel and wholesale power, while other retail electricity distributors, especially in the West South Central region, have been able to pass the declining fuel costs on to customers through lower rates. Residential electricity prices are projected to rise at annual rates of about 1.1 percent in 2009 and 1.8 percent in 2010 (U.S. Residential Electricity Prices).

Generation. Below-average snowpack in the Pacific region is expected to contribute to a 4.3-percent decline in U.S. hydropower generation in the electric power sector during 2009. Some of the drop in hydropower and coal-fired generation is expected to be picked up by natural-gas-fired generation, which is expected to increase by 1.2 percent in 2009.

Coal

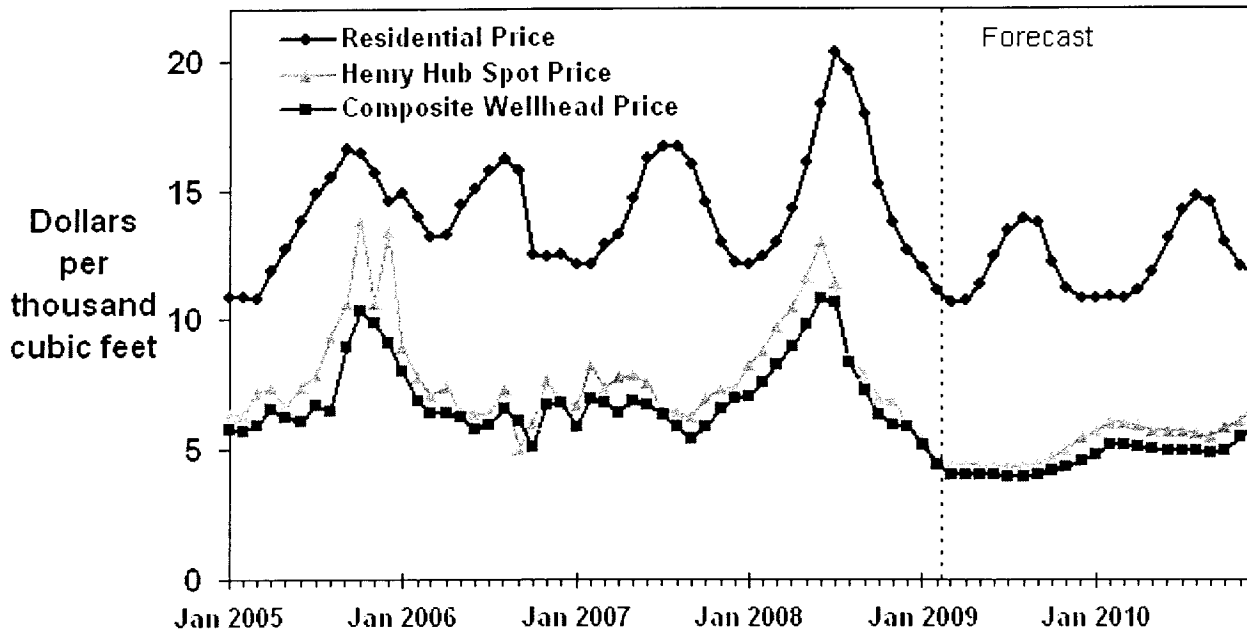
Consumption. The projected decline in electricity consumption and projected increases from some other generation sources is expected to lead to a 1.7-percent decline in coal consumption for electricity generation. An expected increase in electricity consumption of 1.2 percent in 2010 will lead to a 0.4-percent increase in coal consumption for electricity generation (U.S. Coal Consumption Growth).

Production. A significant increase in coal exports in 2008 contributed to a 2.1-percent increase in coal production. Production is expected to fall by 4.9 percent in 2009 as lower total domestic coal consumption is combined with declines in exports and an increase in imports. Production is projected to increase by 1.8 percent in 2010 as domestic consumption and exports increase with an improving economy (U.S. Annual Coal Production).

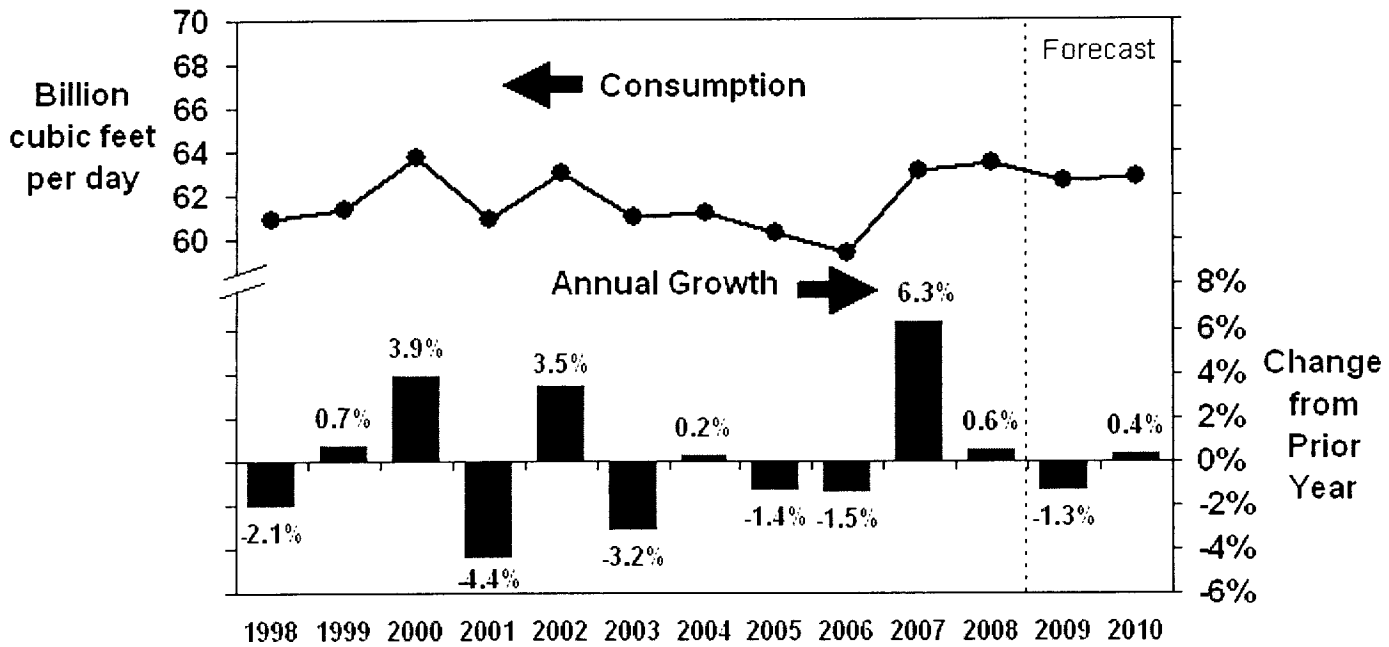
Exports. Reductions in global coal demand, coupled with the return to normal supply conditions in other major coal-producing and exporting countries, are expected to reduce U.S. coal exports by about 10 million short tons, an 11.8-percent decrease, in 2009. The improving global economy is expected to spur global coal demand in 2010, leading to a projected 12-percent increase in exports.

Prices. The average delivered coal price to the electric power sector is estimated to have increased by about 17 percent in 2008. Declines in electricity demand and lower transportation costs should result in average delivered coal prices falling by 1 percent in 2009 and remaining flat in 2010. Delivered coal prices tend to move more slowly than spot prices because of the nature of existing long-term coal supply contracts.

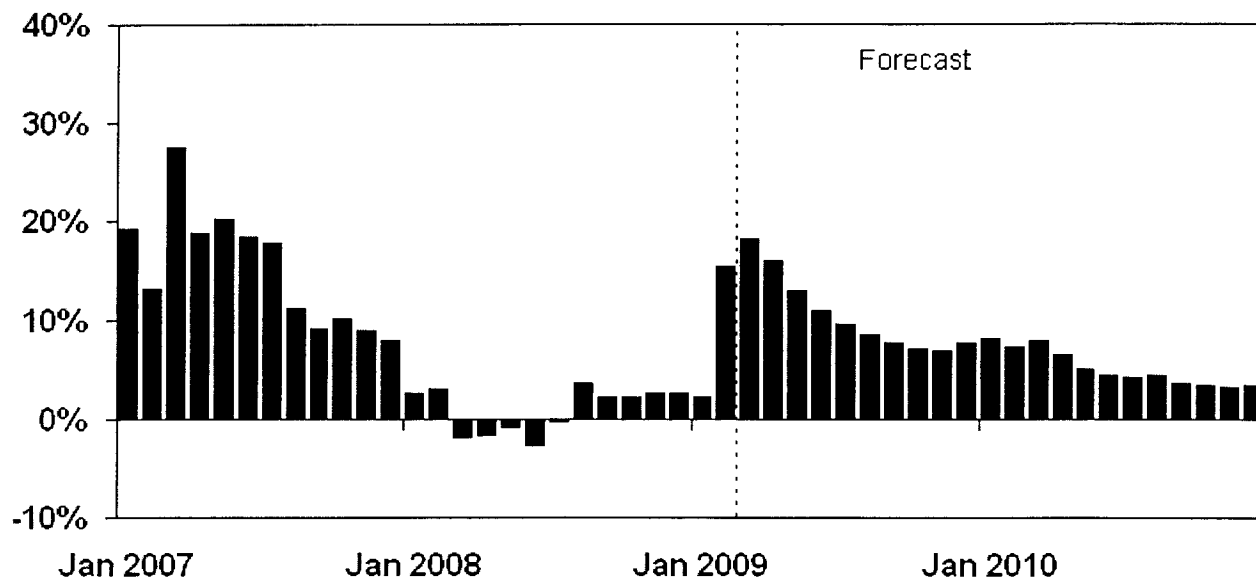
Natural Gas Prices



U.S. Total Natural Gas Consumption



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**

	(Over) Under Recovery	Refunds & Other	Interest 1/ Interest 2/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2008									(\$46,836)
May	(\$7,154)	\$0	(\$671)	(\$7,825)	17,007	\$0.7009	\$11,920	(\$19,745)	(66,581)
June	25,399	0	(868)	24,531	9,026	(0.1857)	(1,676)	26,207	(40,374)
July	12,556	0	(565)	11,991	6,909	(0.1857)	(1,283)	13,274	(27,100)
August	47,784	0	(408)	47,376	5,577	(0.1857)	(1,036)	48,412	21,312
September	26,255	0	135	26,390	6,028	(0.1857)	(1,119)	27,509	48,821
October	13,043	0	440	13,483	8,294	(0.1857)	(1,540)	15,023	63,844
November	16,133	0	605	16,738	18,404	(0.1857)	(3,418)	20,156	84,000
December	(4,149)	(2,340)	829	(5,660)	34,013	(0.1857)	(6,316)	656	84,656
January 2008	(35,023)	0	840	(34,183)	55,308	(0.1857)	(10,271)	(23,912)	60,744
February	(17,882)	0	587	(17,295)	44,492	(0.1857)	(8,262)	(9,033)	51,711
Balance @ February 28, 2009									\$51,711

- 1/ Interest calculated at 13.3%, the authorized rate of return.
2/ December 2008 Northern Natural Gas refund.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/ Interest 2/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
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)
October	(6,575)	0	(1,707)	(8,282)	12,016	(0.7309)	(8,782)	500	(165,804)
November	4,717	0	(1,689)	3,028	19,205	(0.7309)	(14,037)	17,065	(148,739)
December	(1,569)	(3) 2/	(1,492)	(3,064)	12,982	(0.7309)	(9,489)	6,425	(142,314)
January 2008	339	0	(1,410)	(1,071)	10,874	(0.7309)	(7,948)	6,877	(135,437)
February	553	0	(1,325)	(772)	10,203	(0.7309)	(7,457)	6,685	(128,752)
Balance @ February 28, 2009									<u>(\$128,752)</u>

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

2/ December 2008 Northern Natural Gas refund.