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

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PO Box 176
Fergus Falls, MN 56538-0176
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April 1, 2010

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

Re: Cost of Gas Adjustment (COG)
April 2010

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 (49th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (49th Revised Sheet No. 8), showing the April 2010 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $1.1140 per mcf for residential and firm general service customers and a decrease of $1.0268 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for April 2010, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $1.0268 per mcf since the last COG filing. There has been a decrease in pipeline charges of $0.0872 per mcf due to changes in pipeline charges. The net effect of these changes is a decrease of $1.1140 per mcf for residential and firm general service customers.

Attachment C discusses the market conditions of the gas commodity.

Attachment D shows the calculation of the balancing account since April 30, 2009.

Great Plains submitted a check for $600.00 on January 19, 2010 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

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
49th Revised Sheet No. 1.1
Canceling 48th Revised Sheet No.1.1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/MCF
Firm Gas Service - General	2	$3.50 per month	First 10 MCF	$1.2740	$7.2080	$8.4820
			Over 10 MCF	1.0540		8.2620
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.1324	$4.2715
			Next 2,600 MCF	0.8931		4.0255
			Over 3,000 MCF	0.7411		3.8735
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.1324	$4.3715
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: April 1, 2010

Effective Date: April 1, 2010

Issued By: Tamie A. Aberle
Pricing & Tariff Manager

Case No.:

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
49th Revised Sheet No. 8
Canceling 48th 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.	3.1208	(0.2180)	0.2343	3.1371	(0.2180)	(0.7419)	(0.9599)
Current Adj.	(0.0872)	(1.0268)	0.0000	(1.1140)	(1.0268)	0.0000	(1.0268)
Total Adj.	3.0336	(1.2448)	0.2343	2.0231	(1.2448)	(0.7419)	(1.9867)
Total Rate:	$3.0994	$3.8743	$0.2343	$7.2080	$3.8743	($0.7419)	$3.1324

Date Filed: April 1, 2010 **Effective Date:** April 1, 2010

Issued By: Tamie A. Aberle – Pricing & Tariff Manager **Case No.:**

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
APRIL 2010

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
TFX Seasonal	3,000		15.1530	5	227,295	0.1452
NOVA - Demand Charge	7,947		15.9426	12	1,520,350	0.9711
Trans Canada - Demand Charge	7,947		16.4290	12	1,566,735	1.0007
BP Canada - Demand Charge	7,947		0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068		15.9426	5	403,985	0.2580
Trans Canada - Seasonal	5,068		16.4290	5	416,311	0.2659
BP Canada - Seasonal	5,068		0.9612	5	24,357	0.0156
BP Canada 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					$4,852,385	3.0994
Estimated Weighted Average Commodity Cost	1,565,565	1/	3.8743		6,065,468	3.8743
Gas Cost Reconciliation Adjustment						0.2343
Total Current Firm Gas Cost					$10,917,853	7.2080
Base Cost of Gas						5.1849
Accumulated Adjustment						$2.0231
Interruptible						
Estimated Weighted Average Commodity Cost						$3.8743
Gas Cost Reconciliation Adjustment						(0.7419)
Total Current Interruptible Gas Cost						3.1324
Base Cost of Gas						5.1191
Accumulated Adjustment						($1.9867)

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

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
APRIL 2010

Rates Effective April 1, 2010	$/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	15.9426	Per dk/Mo.
Trans Canada Pipeline Demand Charge	16.4290	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	15.9426	Per dk/Day
Trans Canada - Seasonal	16.4290	Per dk/Mo.
BP Canada - Seasonal	0.9612	Per dk/Mo.
BP Canada Winter Surcharge	3.0417	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	3.8743	Per dk

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

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

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

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

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

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

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

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

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

Twenty-Eighth Revised Sheet No. 5B
Superseding
Twenty-Seventh 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	1.02%
Zone 1 - 2	$0.0130	$0.0019	$0.0149	1.38%
Zone 2 - 2	$0.0130	$0.0019	$0.0149	0.36%
Minimum Rate	$0.0130	$0.0019	$0.0149	
IT and AOT				
Zone 1 - 1	$0.1368	$0.0019	$0.1387	1.02%
Zone 1 - 2	$0.1737	$0.0019	$0.1756	1.38%
Zone 2 - 2	$0.0834	$0.0019	$0.0853	0.36%
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: .10% for Zone 1-1, .13% for Zone 1-2, and .03% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted For percentages.

Issued by:
Issued on: February 26, 2010

Effective on: April 1, 2010

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

Fifteenth Revised Sheet No. 5C
Superseding
Fourteenth 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		$0.0453	

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:
Issued on: February 26, 2010

Effective on: April 1, 2010

RATE SCHEDULE TF

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

COMMODITY RATES 2/ TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0384	0.0215			0.0175	0.0000	0.0384	0.0215
Field	Market	0.0384	0.0215	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 $0.0006 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	0.0384	0.0215			0.0175	0.0000	0.0384	0.0215
Field	Market	0.0384	0.0215	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0295	0.0109

GULF COAST	Reservation 1/ Maximum	Reservation 1/ Minimum	Commodity 6/ Maximum	Commodity 6/ Minimum	Out-of-Balance 6/ Maximum	Out-of-Balance 6/ Minimum
MOPS Gathering	1.0514	0.0000	0.0019	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 $0.0006 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
April 2010

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 estimated price for the April AECO Index is expected to decrease from the previous month index. 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).

Seasonal warmer temperatures throughout most of the lower 48 States and continued strength in natural gas production likely contributed to declining natural gas prices. The Energy Information Administration (EIA) reported storage levels nationwide as of March 19, 2010 were 8.0 percent above the five-year average and 1.7 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 12.

U.S. Energy Information Administration

March 2010

Short-Term Energy Outlook

March 9, 2010 Release

Highlights

- Although spot crude oil prices continue to fluctuate on a daily basis, EIA's projections for West Texas Intermediate (WTI) crude oil spot prices have remained relatively stable over the last 4 *Outlooks*. EIA expects WTI prices to average above $80 per barrel this spring, rising to an average of about $82 per barrel by the end of the year and to $85 per barrel by the end of 2011.

- Projected economic growth this year is higher in this forecast, with U.S. real gross domestic product (GDP) growing by 2.8 percent and world oil-consumption-weighted real GDP growing by 3.4 percent, compared with 2.3 percent and 2.7 percent growth, respectively, in last month's *Outlook*. The 2011 forecast for real GDP growth is relatively unchanged at 2.6 percent and 3.5 percent for the United States and the world, respectively.

- EIA forecasts that the annual average regular grade retail gasoline price will increase from $2.35 per gallon in 2009 to $2.84 in 2010 and to $2.96 in 2011 because of the projected rising crude oil prices. Average U.S. pump prices likely will exceed $3 per gallon at times during the forthcoming spring and summer driving season. Projected annual average retail diesel fuel prices are $2.96 and $3.14 per gallon, respectively, in 2010 and 2011.

- EIA expects this year's annual average natural gas Henry Hub spot price to be $5.17 per million Btu (MMBtu), a $1.22-per-MMBtu increase over the 2009 average. EIA projects price increases to continue in 2011, averaging $5.65 per MMBtu for the year. Projected working gas inventories end the first quarter of 2010 at about 1,550 billion cubic feet (Bcf) compared with 1,644 Bcf in the previous *Outlook* because of colder-than-normal weather in February. Natural-gas-weighted heating degree-days were nearly 11 percent above the 30-year norm last month.

- The annual average residential electricity price changes only slightly over the forecast period, averaging 11.5 cents per kilowatthour (kWh) in both 2009 and 2010, and then rising to 11.6 cents per kWh in 2011.

- Carbon dioxide (CO_2) emissions from fossil fuels, which declined by 6.4 percent in 2009, increase by 1.5 percent and 1.2 percent in 2010 and 2011, respectively, in the forecast as economic growth fuels higher energy consumption.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA's more optimistic updated expectation for global economic growth during 2010 drives the 2010 forecast for oil consumption growth upwards to 1.5 million barrels per day (bbl/d) from 1.2 million bbl/d in last month's *Outlook*. This increased growth in 2010 oil consumption supports a firming of crude oil prices at above $80 per barrel this summer and accommodates a further drawdown of commercial oil inventories. While EIA has also reduced its projections for surplus production capacity in the Organization of the Petroleum Exporting Countries (OPEC), surplus capacity remains ample, dampening the likelihood of a large upward swing in prices.

Global Crude Oil and Liquid Fuels Consumption. As noted above, the upward adjustment of 0.3 million bbl/d in the 2010 forecast for global liquid fuels consumption growth in this *Outlook* is largely due to expectations for greater economic growth (World Liquid Fuels Consumption Chart). Most of the increased economic growth in 2010 is expected in the Asia-Pacific and Middle East regions, thus largely outside of the countries in the Organization for Economic Cooperation and Development (OECD). EIA's expectations for both economic and oil consumption growth in 2011 remain about the same as in the previous *Outlook*.

Non-OPEC Supply. Non-OPEC supply increased by 590,000 bbl/d in 2009, the largest annual increase since 2004. Non-OPEC supply is projected to increase by 550,000 bbl/d in 2010 before declining slightly in 2011, as declining production in mature areas more than offsets any new production growth. The largest source of supply growth in 2010 is the United States, followed by Brazil, Azerbaijan, and Kazakhstan. Further declines in mature fields in Mexico, the United Kingdom, and Norway are expected in 2010.

OPEC Supply. The forecast assumes that OPEC does not change its target production levels at its scheduled meeting in mid-March. Given expected oil demand growth in 2010, oil prices should continue to firm despite expected increases in both non-OPEC and OPEC production this year. EIA projects that OPEC production of crude oil and

non-crude petroleum liquids, the latter of which are not subject to OPEC production targets, will increase by about 0.4 and 0.6 million bbl/d each year, respectively, about the same as in the previous *Outlook*. Overall, EIA also projects a slight decrease in OPEC surplus crude oil production capacity from the previous *Outlook* (OPEC Surplus Crude Oil Production Capacity Chart).

OECD Petroleum Inventories. EIA has revised its estimate of OECD commercial oil inventories at the end of 2009 downwards to 2.67 billion barrels, equivalent to about 57 days of forward cover and about 63 million barrels more than the 5-year average for the corresponding time of year (Days of Supply of OECD Commercial Stocks Chart). OECD oil inventories are still projected to remain at the upper end of the historical range over the forecast period.

Crude Oil Prices. WTI crude oil spot prices averaged $76.39 per barrel in February 2010, almost $2 per barrel lower than the prior month's average and very near the $76 per barrel forecast in last month's *Outlook*. Last month, the WTI spot price reached a low of $71.15 on February 5 and peaked at $80.04 on February 22. EIA expects WTI prices to average above $80 per barrel this spring, rising to an average of about $82 per barrel by the end of the year and to $85 per barrel by the end of 2011 (West Texas Intermediate Crude Oil Price Chart).

Following a slight increase in expected WTI price volatility early in February, implied volatility trended lower through the rest of the month, continuing a trend begun in the fourth quarter of 2009. Over the 5-day period ending March 4, May 2010 WTI futures averaged $80.21 per barrel. Over the same 5-day period, the lower and upper limits for the 95-percent confidence interval for May 2010 futures were $65 and $99 per barrel, respectively, based on the May 2010 implied volatility, calculated from New York Mercantile Exchange (NYMEX) near-the-money options on WTI futures (see Energy Price Volatility and Forecast Uncertainty).

One year ago, WTI delivered into Cushing, Oklahoma, in May 2009 averaged about $45 per barrel and implied volatility, at 74 percent, was more than twice the rate now trading in the options markets. The 95-percent confidence interval for May 2009 WTI futures thus had lower and upper limits of $28 and $75 per barrel, respectively.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. U.S. liquid fuels consumption declined by 810,000 bbl/d (4.2 percent) to 18.7 million bbl/d in 2009, the fourth consecutive annual decline (U.S. Liquid Fuels Consumption Growth Chart). Motor gasoline was the only major petroleum product whose annual consumption did not decline. Distillate fuel

consumption declined by 310,000 bbl/d (8.0 percent) in 2009, led by a sharp economy-related decline in transportation usage.

The economic recovery contributes to projected growth in total liquid fuels consumption of 200,000 bbl/d in 2010 and 210,000 bbl/d in 2011. Nevertheless, expected U.S. consumption in 2011 is lower than total consumption was in 1999 and is 1.7 million bbl/d lower than the highest level of annual consumption reached in 2005.

EIA projects gasoline consumption will begin to show modest, but consistent, increases over the previous year, growing by 60,000 bbl/d in 2010 and 70,000 bbl/d in 2011. Projected distillate fuel consumption begins showing year-over-year growth this month, with an increase in average annual consumption of 20,000 bbl/d and 90,000 bbl/d in 2010 and 2011, respectively. However, this forecast for recovery in distillate fuel consumption remains highly uncertain because of the continuing observed weak diesel fuel demand.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production averaged 5.32 million bbl/d in 2009, up about 370,000 bbl/d from 2008 (U.S. Crude Oil Production Chart). Projected growth in domestic crude oil production is more moderate in 2010, increasing by about 210,000 bbl/d. Production growth in 2011 slows sharply to 20,000 bbl/d, as substantial declines in the Federal Gulf of Mexico and Alaska almost offset gains in lower-48 on-shore production.

Ethanol production continues to grow to meet the volume requirements of the Renewable Fuel Standard. Ethanol production, which averaged 700,000 bbl/d in 2009, increases to an average of 800,000 bbl/d in 2010 and 850,000 bbl/d in 2011 in the forecast.

The decline in liquid fuels consumption in 2009 along with growth in domestic crude oil and ethanol production led to a 1.4-million-bbl/d drop in total liquid fuel net imports (including both crude oil and refined products). EIA forecasts that total liquid fuel net imports will fall by 150,000 bbl/d in 2010 and then rise by 100,000 bbl/d in 2011.

U.S. Petroleum Product Prices. Regular-grade gasoline prices averaged $2.35 per gallon in 2009, increasing from an average of $1.79 per gallon in January 2009 to $2.61 per gallon in December. EIA expects these prices will average $2.84 per gallon in 2010 and $2.96 per gallon in 2011. Average regular-grade pump prices likely will exceed $3 per gallon at times during the upcoming spring and summer and will easily pass that benchmark in high-cost regions, such as the West Coast. Due to forecast growth in

motor gasoline consumption, the difference between the average gasoline retail price and the average cost of crude oil increases slightly in both 2010 and 2011.

On-highway diesel fuel retail prices, which averaged $2.46 per gallon in 2009, average $2.96 per gallon in 2010 and $3.14 in 2011 in this forecast. As with motor gasoline, the forecast recovery in the consumption of diesel fuel in the United States, as well as growth in distillate fuel usage outside the United States, slowly strengthens refining margins for distillate throughout the forecast period.

Natural Gas

U.S. Natural Gas Consumption. EIA expects total natural gas consumption to increase by 0.7 percent to 62.9 billion cubic feet per day (Bcf/d) in 2010 and decline by 0.4 percent in 2011 (Total U.S. Natural Gas Consumption Growth Chart). Cold weather drives this year's natural gas consumption increases. Total natural-gas-weighted heating degree-days during the first 2 months of this year were 5.5 percent above the 30-year normal level and the highest for the period since 2004.

The combination of frigid temperatures and electric space heating in the Southeast contributed not only to increases in residential and commercial sector natural gas consumption but also to very strong natural gas consumption in the electric power sector. Even with the assumption of near-normal weather in March, EIA expects first-quarter natural gas use in the electric power sector to increase by about 3 percent above the same period last year and about 17 percent above the previous 5-year average. This increase in first quarter 2010 electric power sector consumption has all but eliminated the projected 1.3-percent year-over-year decline in natural gas consumption for this sector in last month's *Outlook*.

The 2011 outlook for a small decline in total natural gas consumption reflects the projected return to near-normal weather, which is expected to reduce consumption in the residential, commercial, and electric power sectors. Continued economic recovery contributes to a projected 2.1-percent increase in natural gas consumption in the industrial sector.

U.S. Natural Gas Production and Imports. EIA expects total marketed natural gas production to decline by 2.7 percent to 58.7 Bcf/d in 2010 and increase by 1.1 percent in 2011. The number of working natural gas rigs has been increasing this year in response to higher prices in both the spot and forward markets. According to Smith International, natural gas rigs have increased by more than 17 percent, or by nearly 140, since the start of this year. There are currently almost 570 working horizontal rigs, a new record. EIA still anticipates a decline in 2010 production because of the lag

time arising from low drilling rates last year and steep decline rates associated with newly- drilled wells. However, continued recovery of drilling rig activity, increasing drilling efficiency, and the potential for higher production rates from shale gas wells could lead to higher-than-expected production this year and next.

EIA expects U.S. net imports to be slightly higher in 2010 as a projected decline in pipeline imports is offset by lower exports and higher imports of liquefied natural gas (LNG). While cold weather across the northern hemisphere has helped absorb some of the new LNG supply that has recently come on-stream, U.S. LNG imports are forecast to increase by nearly 0.8 Bcf/d over last year in the first quarter 2010. For 2010 as a whole, U.S. LNG imports are forecast to increase by about 45 percent (or 0.56 Bcf/d). As global LNG demand and import capacity expand next year, EIA expects U.S. LNG imports to show little year-over-year growth in 2011.

U.S. Natural Gas Inventories. On February 26, 2010, working natural gas in storage was 1,737 Bcf (U.S. Working Natural Gas in Storage Chart), 21 Bcf above the previous 5-year average (2005–2009) and 71 Bcf below the level during the corresponding week last year. Persistent cold weather so far this year has taken a toll on inventories. The estimated total inventory withdrawal in January and February is 1,406 Bcf. The 5-year average withdrawal for these 2 months is 1,159 Bcf. EIA now expects working natural gas inventories to finish the first quarter of 2010 at around 1,549 Bcf, or about 3.5 percent above the previous 5-year average. In addition, resilient domestic production and higher U.S. LNG imports contribute to a projected end-of-October 2010 inventory that remains above the previous 5-year average.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $5.32 per MMBtu in February, $0.51 per MMBtu lower than the average spot price in January and $0.14 per MMBtu lower than the forecast for February in last month's Outlook (Henry Hub Natural Gas Price Chart). Historically, colder-than-normal weather and correspondingly high demand has contributed to large storage withdrawals and elevated prices during the winter. For example, similar natural-gas-weighted heating degree-days and working natural gas storage withdrawals were recorded in January and February of this year and in 2003. While the cold weather in 2003 contributed to a 63-percent increase in the monthly average spot price from December 2002 to February 2003, the monthly average spot price in February 2010 was virtually unchanged from the average price in December 2009.

Much of the subdued price action this winter is attributable to the level of, as opposed to the change in, working inventories. By the end of February 2003, working stocks stood at 851 Bcf compared with an estimated 1,729 Bcf this February. Prices may strengthen slightly in the coming months as demand to rebuild natural gas in storage

from risk-averse local distribution companies begins. However, the potential for higher domestic production, increasing LNG supply, and limited consumption growth all reduce the possibility of sustained high prices as inventories are replenished over the next several months. The Henry Hub spot price forecast averages $5.17 per MMBtu in 2010 and $5.65 per MMBtu in 2011.

Volatility in the April and May 2010 futures and options markets trended lower over the last month. For the 5-day period ended March 4, May futures averaged $4.77 per MMBtu, while the lower and upper limits of the 95-percent confidence interval calculated based on the implied volatility calculated from near-the-money options were $3.57 and $6.39 per MMBtu, respectively. A year earlier, natural gas delivered to the Henry Hub in May 2009 was trading at $4.30 per MMBtu, with lower and upper limit for the 95-percent confidence interval calculated based on implied volatility of $2.80 and $6.60 per MMBtu, respectively.

Electricity

U.S. Electricity Consumption. EIA's assumption of 5.5 percent growth in manufacturing output during 2010 translates to an expected growth in electricity sales to the industrial sector of about 1 percent. EIA forecasts electricity sales to the residential sector to grow by 3.5 percent during 2010 since summer temperatures this year are expected to return to their normal levels after a relatively cool summer last year. Total consumption of electricity across all sectors is expected to grow by 2.0 percent during 2010 and by 1.5 percent next year (U.S. Total Electricity Consumption Chart).

U.S. Electricity Generation. Natural gas generation during January and February was estimated to be about 10 percent higher than the same months last year because of the cold weather experienced in the South. This higher-than-expected level of natural gas generation during the early part of this year will pull up the projected 2010 annual growth rate to 0.6 percent, in contrast to the relatively flat growth projected in last month's *Outlook*.

U.S. Electricity Retail Prices. The estimated average U.S. residential electricity price during 2009 was about 11.5 cents per kWh. EIA projects U.S. residential electricity prices will be about the same in 2010, followed by an increase of 1.4 percent in 2011 resulting primarily from higher natural gas generation fuel costs (U.S. Residential Electricity Prices Chart).

Coal

U.S. Coal Consumption. Anticipated increases in electricity demand and higher natural gas prices will contribute to modest growth in coal-fired generation in 2010 and 2011. Forecast coal consumption in the electric power sector increases by about 3 percent in 2010, though staying under 1 billion short tons. EIA projects coal consumption in the electric power sector will increase by 1.6 percent in 2011, but remain below the 1-billion-short-ton level for the third consecutive year (U.S. Coal Consumption Growth Chart).

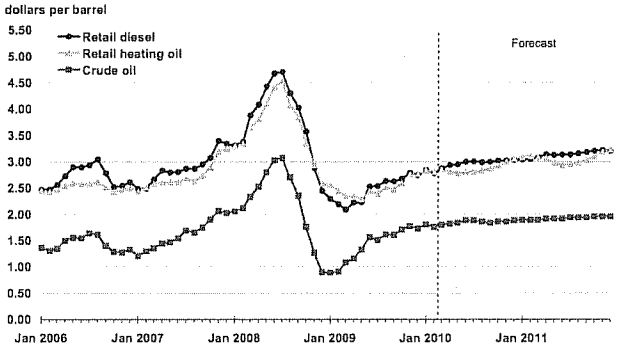
U.S. Coal Supply. EIA estimates that 2009 coal production fell by nearly 8 percent in response to lower U.S. coal consumption, fewer exports, and higher coal inventories. Production declines by an additional 7 percent in 2010 in this forecast despite increases in domestic consumption and exports. The balance between production and consumption is satisfied through significant reductions in end-user (secondary) inventories. EIA projects a 7-percent increase in coal production in 2011 to meet continued growth in coal consumption and exports as existing inventories are reduced (U.S. Annual Coal Production Chart).

U.S. Coal Prices. EIA estimates that the 2009 delivered electric-power-sector coal price increased by nearly 7 percent in 2009 despite decreases in spot coal prices, lower prices for other fossil fuels, and declines in coal-fired electricity generation. This higher cost of delivered coal reflects the impact of longer-term power-sector coal contracts that were initiated during a period of high prices for all fuels. The projected electric-power-sector delivered coal price falls by almost 6 percent to average $2.08 per MMBtu in 2010 and declines by an additional 2.4 percent in 2011.

U.S. Carbon Dioxide Emissions

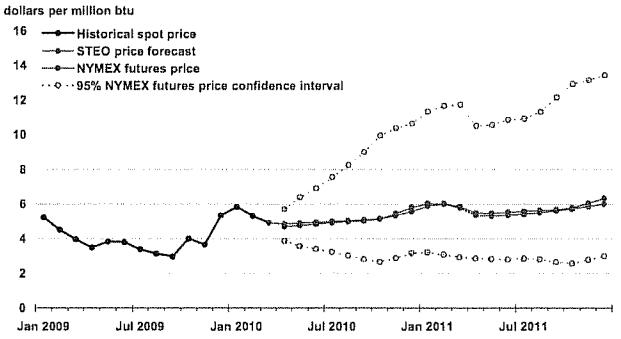
Projected improvements in the economy contribute to an expected 1.5-percent increase in CO_2 emissions in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). Increased use of coal in the electric power sector and continued economic growth, combined with the expansion of transportation-related petroleum consumption, lead to a 1.2-percent increase in CO_2 emissions in 2011. However, even with increases in 2010 and 2011, projected CO_2 emissions in 2011 are lower than annual emissions from 1999 through 2008.

U.S. Diesel Fuel and Crude Oil Prices



Source: Short-Term Energy Outlook, March 2010

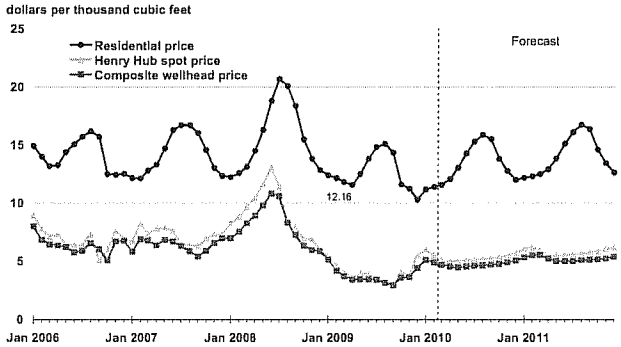
Henry Hub Natural Gas Price



Note: Confidence interval derived from options market information from 5 trading days ending March 4, 2010
Intervals not calculated for months with sparse trading in "close-to-the-money" options contracts

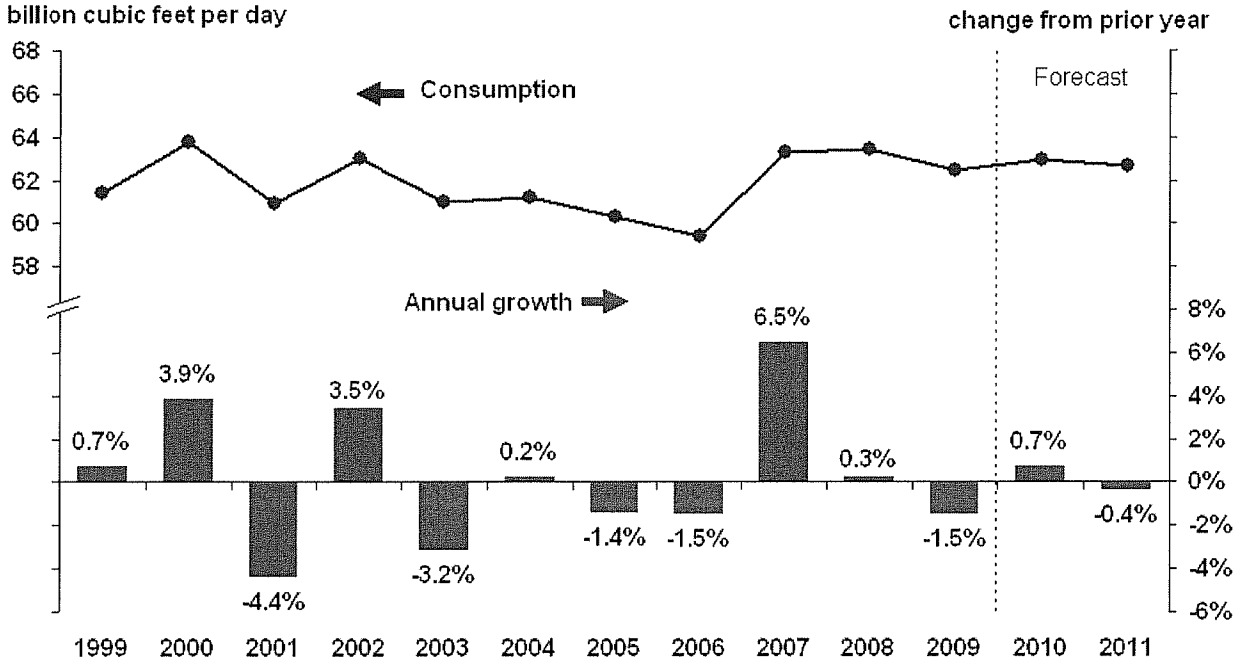
Source: Short-Term Energy Outlook, March 2010; Reuters News Service; and CME Group

Natural Gas Prices



Source: Short-Term Energy Outlook, March 2010; Reuters News Service

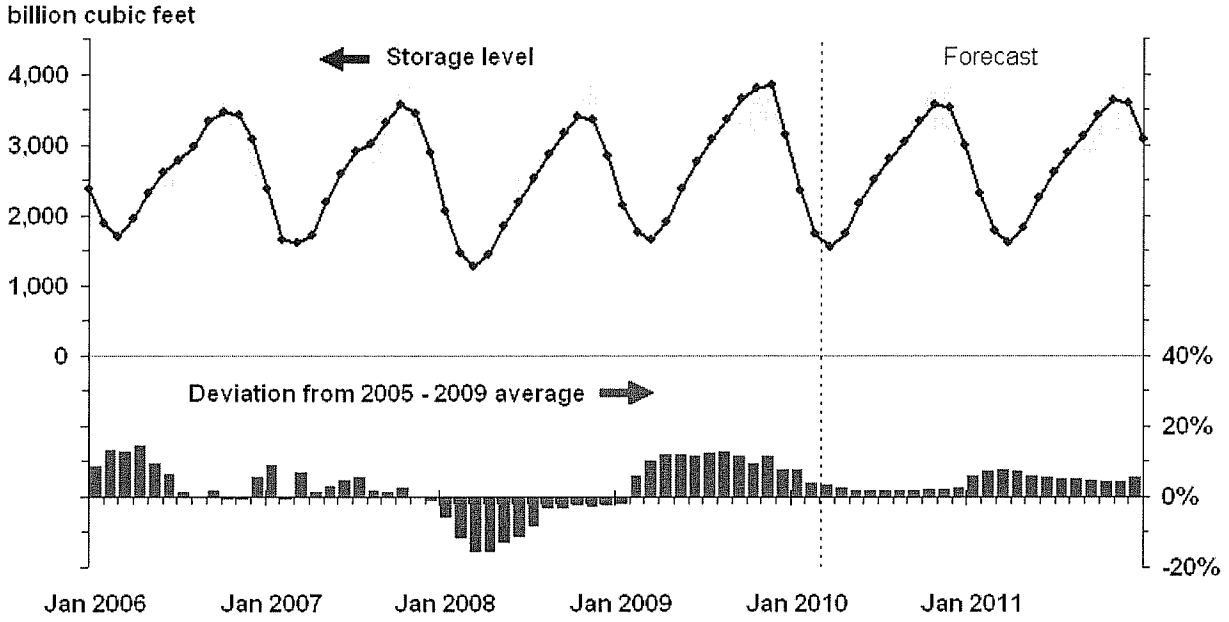
U.S. Total Natural Gas Consumption



Source: Short-Term Energy Outlook, March 2010

U.S. Energy Information Administration

U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2005 - Dec. 2009

Source: Short-Term Energy Outlook, March 2010

U.S. Energy Information Administration

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, 2009									**$65,941**
May	($2,105)	$0	$671	($1,434)	16,822	($0.1857)	($3,124)	$1,690	67,631
June	24,415	0	690	25,105	9,107	0.2343	(427) 2/	25,532	93,163
July	39,344	0	629	39,973	6,447	0.2343	1,511	38,462	131,625
August	39,771	0	902	40,673	5,943	0.2343	1,392	39,281	170,906
September	(2,165)	0	1,179	(986)	5,775	0.2343	1,353	(2,339)	168,567
October	35,022	0	1,154	36,176	11,535	0.2343	2,703	33,473	202,040
November	(980)	0	1,387	407	19,033	0.2343	4,459	(4,052)	197,988
December	25,639	0	1,349	26,988	32,413	0.2343	7,595	19,393	217,381
January 2010	(39,169)	0	1,480	(37,689)	48,707	0.2343	11,412	(49,101)	168,280
February	(54,257)	0	1,119	(53,138)	45,646	0.2343	10,695	(63,833)	104,447
Balance @ February 28, 2010									**$104,447**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 6,097.5 dk @ ($0.1857) and 3,009.9 dk @ $0.2343.

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, 2009									**($110,191)**
May	($5,411)	$0	($1,024)	($6,435)	15,426	($0.7309)	($11,275)	$4,840	(105,351)
June	(2,099)	0	(967)	(3,066)	10,879	(0.7419)	(7,985) 2/	4,919	(100,432)
July	(3,038)	0	(592)	(3,630)	7,435	(0.7419)	(5,516)	1,886	(98,546)
August	(4,584)	0	(581)	(5,165)	9,775	(0.7419)	(7,252)	2,087	(96,459)
September	(14,605)	0	(571)	(15,176)	9,230	(0.7419)	(6,848)	(8,328)	(104,787)
October	(9,999)	0	(634)	(10,633)	16,552	(0.7419)	(12,280)	1,647	(103,140)
November	(15,225)	0	(633)	(15,858)	18,004	(0.7419)	(13,357)	(2,501)	(105,641)
December	(354)	0	(663)	(1,017)	22,135	(0.7419)	(16,422)	15,405	(90,236)
January 2010	(5,220)	0	(567)	(5,787)	25,285	(0.7419)	(18,759)	12,972	(77,264)
February	(1,595)	0	(492)	(2,087)	20,513	(0.7419)	(15,218)	13,131	(64,133)
Balance @ February 28, 2010									**($64,133)**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 7,849.5 dk @ ($0.7309) and 3,029.9 dk @ ($0.7419).