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

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Fergus Falls, MN 56538-0176
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May 28, 2010

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

Re: Cost of Gas Adjustment (COG)
June 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 (51st Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (51st Revised Sheet No. 8), showing the June 2010 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $0.0248 per mcf for residential and firm general service customers and $0.4464 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for June 2010, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.1819 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 $0.0469 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of $0.1350 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 gas cost reconciliation (GCR) adjustment that will apply during the period of June 1, 2010 through May 31, 2011. The total GCR is $0.3941 per mcf for residential and general service customers and a negative $0.1136 per mcf for interruptible customers. The effect of this change is an increase of $0.1598 for residential and general service customers and an increase of $0.6283 for interruptible customers.

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
51st Revised Sheet No. 1.1
Canceling 50th 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	$7.4155	$8.6895
			Over 10 MCF	1.0540		8.4695
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.6293	$4.7684
			Next 2,600 MCF	0.8931		4.5224
			Over 3,000 MCF	0.7411		4.3704
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.6293	$4.8684
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: May 28, 2010 **Effective Date:** June 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
51st Revised Sheet No. 8
Canceling 50th 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.	3.1658	(1.1943)	0.2343	2.2058	(1.1943)	(0.7419)	(1.9362)
Current Adj.	0.0469	(0.1819)	0.1598	0.0248	(0.1819)	0.6283	0.4464
Total Adj.	3.2127	(1.3762)	0.3941	2.2306	(1.3762)	(0.1136)	(1.4898)
Total Rate:	$3.2785	$3.7429	$0.3941	$7.4155	$3.7429	($0.1136)	$3.6293

Date Filed: May 28, 2010 **Effective Date:** June 1, 2010

Issued By: Tamie A. Aberle
Pricing & Tariff Manager

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JUNE 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	17.4182	12	1,661,069	1.0610
Trans Canada - Demand Charge	7,947	17.2751	12	1,647,423	1.0523
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068	17.4182	5	441,377	0.2819
Trans Canada - Seasonal	5,068	17.2751	5	437,751	0.2796
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				$5,132,624	3.2785
Estimated Weighted Average Commodity Cost	1,565,565 1/	3.7429		5,859,753	3.7429
Gas Cost Reconciliation Adjustment					0.3941
Total Current Firm Gas Cost				$10,992,377	7.4155
Base Cost of Gas					5.1849
Accumulated Adjustment					$2.2306
Interruptible					
Estimated Weighted Average Commodity Cost					$3.7429
Gas Cost Reconciliation Adjustment					(0.1136)
Total Current Interruptible Gas Cost					3.6293
Base Cost of Gas					5.1191
Accumulated Adjustment					($1.4898)

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

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

Rates Effective June 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	17.4182	Per dk/Mo.
Trans Canada Pipeline Demand Charge	17.2751	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	17.4182	Per dk/Day
Trans Canada - Seasonal	17.2751	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:	3.7429	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	TF12 Variable	TF5	FIELD-TO-FIELD/MARKET DEMARCATION TFF
Base Tariff Rates 1/				
Summer (Apr-Oct)	5.683	5.683	-0-	5.473
Winter (Nov-Mar)	10.230	13.866	15.153	9.853

COMMODITY RATES 2/ TF12 Base, TF12 Var., TF5 & TFF		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
June 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 June monthly price for the AECO Index is expected to decrease slightly 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).

The seasonal decrease in space heating demand, continued strength in long term domestic supply and storage levels substantially higher than the five year average likely contributed to the expected decrease in the index price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of May 14, 2010 were 16.6 percent above the five-year average and 3.5 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 13.

U.S. Energy Information Administration

May 2010

Short-Term Energy Outlook

May 11, 2010 Release

Highlights

- EIA projects U.S. real gross domestic product (GDP) will grow by 3.0 percent and world real oil-consumption-weighted GDP will increase by 3.6 percent in 2010, both of which are 0.2 percent higher than in the previous *Outlook*. The 2011 forecast for real GDP growth is at 2.9 percent and 3.7 percent for the United States and the world, respectively.

- The more optimistic economic growth forecasts lead to an increase of about $2 per barrel in EIA's projections for West Texas Intermediate (WTI) crude oil spot prices compared with the prior *Outlook*. EIA expects WTI prices to average about $84 per barrel during the second half of this year, rising to $87 by the end of next year.

- To date, energy production, shipments, and prices have not been significantly affected by the oil spill following the April 20 explosion aboard the Deepwater Horizon drilling rig and its subsequent loss in the Gulf of Mexico, 50 miles off the Louisiana coast. EIA and other offices in the Department of Energy are closely monitoring the situation and its effects on the energy sector (see Deepwater Horizon Situation Report).

- EIA forecasts that regular-grade motor gasoline retail prices will average $2.94 per gallon during this summer's driving season (the period between April 1 and September 30), up from $2.44 per gallon last summer. The summer gasoline price forecast is up very slightly ($0.02) from last month.

- EIA expects the Henry Hub natural gas spot price to average $4.48 per million Btu (MMBtu) this year (up $0.04 per MMBtu from last month's forecast), a $0.53-per-MMBtu increase over the 2009 average. EIA expects the Henry Hub spot price to average $5.34 per MMBtu in 2011.

- The annual average residential electricity price changes only moderately over the forecast period, averaging 11.6 cents per kilowatthour (kWh) in 2010, up from 11.5 cents per kWh in 2009, and then rising to 11.9 cents per kWh in 2011.

- Estimated carbon dioxide (CO_2) emissions from fossil fuels, which declined by 7.0 percent in 2009, are expected to increase by 0.6 percent and 1.6 percent in 2010 and 2011, respectively, as economic growth spurs higher energy consumption.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA's assessment of global economic growth, global oil demand, and world oil prices are all slightly higher than in last month's *Outlook.* Expectation of a somewhat more robust global economic recovery supports the updated price forecast, particularly if the Organization of the Petroleum Exporting Countries (OPEC) continues to remain satisfied with its supply targets as global oil consumption continues to grow. The most important downside risk to this forecast is lower-than-expected economic growth.

Global Crude Oil and Liquid Fuels Consumption. EIA projects that world oil consumption will grow by 1.6 million barrels per day (bbl/d) in 2010, slightly higher than in last month's *Outlook,* and also by 1.6 million bbl/d in 2011. This revision for 2010 follows an update of EIA's assumptions for growth in world real oil-consumption-weighted GDP, which is now assumed to rise on average about 3.6 percent per year over the forecast period. The growth in oil consumption is expected to be largely concentrated in the Asia-Pacific and Middle East regions (World Liquid Fuels Consumption Chart).

Non-OPEC Supply. Non-OPEC supply is projected to increase by 660,000 bbl/d in 2010, about 60,000 bbl/d more than in last month's *Outlook.* Nearly all of the revision in 2010 non-OPEC supply growth is due to higher expected production of natural gas liquids and fuel ethanol in the United States. The largest source of growth in 2010 is the United States, followed by Brazil, Azerbaijan, and Kazakhstan. Offsetting projected supply growth in 2010 are further declines in mature basins in Mexico, the United Kingdom, and Norway. EIA expects non-OPEC supplies to fall by 200,000 bbl/d in 2011.

OPEC Supply. EIA projects that OPEC will only gradually increase its crude oil production over the forecast period, largely in line with the decision at its March meeting to leave its production targets unchanged. OPEC crude oil production increases in the forecast by 0.3 and 0.6 million bbl/d in 2010 and 2011, respectively,

primarily in Angola and Nigeria. While EIA expects the increase in Angolan production to come from new capacity additions, higher expected Nigerian production is largely the result of shut-in capacity coming back online. The countries that have the bulk of OPEC 's spare capacity (Saudi Arabia, Kuwait, and the United Arab Emirates) have maintained production at current levels for an extended period and are expected to continue doing so, barring significant changes in the world oil market outlook. Surplus crude oil production capacity does not increase significantly over the forecast period from first-quarter 2010 levels (OPEC Surplus Crude Oil Production Capacity Chart). OPEC production of non-crude petroleum liquids, which are not subject to OPEC production targets, are expected to increase by 0.6 and 0.7 million bbl/d in 2010 and 2011, respectively.

OECD Petroleum Inventories. EIA estimates that commercial oil inventories held in the Organization for Economic Cooperation and Development (OECD) countries stood at 2.70 billion barrels at the end of the first quarter of 2010. This is equivalent to about 58 days of forward cover, and is roughly 95 million barrels more than the 5-year average for the corresponding time of year (Days of Supply of OECD Commercial Stocks Chart). Although OECD oil inventories are still projected to remain at the upper end of the historical range over the forecast period, they are falling as a result of a combination of higher oil consumption and OPEC production restraint.

Crude Oil Prices. WTI crude oil spot prices averaged $84 per barrel in April 2010, about $3 per barrel above the prior month's average and $2 per barrel higher than forecast in last month's *Outlook*. EIA projects WTI prices will average about $84 per barrel over the second half of this year and rise to $87 by the end of next year, an increase of about $2 per barrel from the previous *Outlook* (West Texas Intermediate Crude Oil Price Chart). Energy price forecasts are highly uncertain, as history has shown. Prices for near-term futures options contracts suggest that the market attaches significant likelihood to the movement of prices over a wide range within a relatively short period.

While press reports about the Deepwater Horizon oil spill have arrived continuously since the incident, markets are focusing more on inventories and economic activity than on any potential for spill-related transportation disruptions. Following a 1.5-percentage-point increase in July 2010 implied volatility a few days after the sinking of the drilling rig on April 22, the futures market resumed its downward trajectory in volatility. For the 5 days ending May 7, July 2010 WTI futures contracts were trading at an average of $83.32 per barrel. With implied volatility for the July 2010 contract averaging 33.2 percent for those same 5 days, the lower and upper limits of the 95-percent confidence interval were $67 and $103 per barrel, respectively (see Energy Price Volatility and Forecast Uncertainty)

Last year at this time, WTI for July 2009 delivery averaged $56.35 per barrel and volatility averaged 51.5 percent, translating into a lower and upper limit of $40.26 and $78.88 per barrel for the 95-percent confidence interval.

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). Forecast total petroleum consumption rises by 160,000 bbl/d, or 0.8 percent, in 2010. All of the major petroleum products are expected to register growth except for distillate fuel oil and jet fuel, which remain unchanged. In 2011, projected consumption growth increases by 260,000 bbl/d, or 1.4 percent, with all of the major product categories registering growth. However, even with increases in 2010 and 2011, projected liquid fuels consumption in 2011 is lower than annual consumption from 1999 through 2008.

Estimates for the first quarter of 2010 indicate a 70,000 bbl/d decrease in total consumption compared with the same period last year, primarily because of very mild weather in the Northeast and lower distillate fuel consumption. Weekly data for April suggest stabilization and even a modest turnaround in motor gasoline consumption as well as in the distillate and jet fuel markets. Total consumption for the second quarter of 2010 is projected to be up by 360,000 barrels per day from the same period last year.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production averaged 5.32 million bbl/d in 2009, up 370,000 bbl/d from 2008 (U.S. Crude Oil Production Chart). Projected growth in domestic output is more moderate in 2010, increasing by about 190,000 bbl/d. The primary contributors to the production growth in 2009 and 2010 are the Thunder Horse, Tahiti, Shenzi, and Atlantis offshore fields in the Federal Gulf of Mexico (GOM). The Deepwater Horizon accident has not affected our projections as this was an exploratory well and was not expected to be online by 2011.

Forecast total crude oil production in 2011 falls by 16,000 bbl/d, with declines in the Federal GOM and Alaska more than offsetting growth in lower-48 output. Several new GOM hubs and fields are scheduled to begin production this year, such as the Great White field in the Perdido Spar and the Petrobras floating production storage and offloading (FPSO) vessel operating in the Chinook and Cascade fields. Despite this new production, projected GOM production declines by 41,000 bbl/d in 2011 because of declining output from existing wells. Offsetting the projected drop in GOM production and the 42,000 bbl/d decline in Alaskan production is an increase in production from lower-48 non-GOM fields of 66,000 bbl/d in 2011.

Projected ethanol production, which averaged 700,000 bbl/d in 2009, increases to an average of 840,000 bbl/d in 2010, and to 850,000 bbl/d in 2011. Ethanol blending is expected to exceed the requirements under the Renewable Fuels Standard both this year and next, rising from an estimated 7.0 percent of the gasoline pool in 2008 to an average of 9.5 percent in 2011. Higher ethanol production rates than projected may occur as plants idled by the economic downturn return to operation, but total production may still be constrained by ethanol blending limits and infrastructure.

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 $2.86 per gallon in 2010 and $2.98 per gallon in 2011. On-highway diesel fuel retail prices, which averaged $2.46 per gallon in 2009, average $3.05 per gallon in 2010 and $3.20 in 2011 in this forecast.

Deepwater Horizon Oil Spill

On April 20, 2010, an explosion occurred aboard the Deepwater Horizon mobile offshore drilling unit (MODU) located 52 miles southeast of Venice, Louisiana. The MODU was drilling an exploratory well and was not producing oil at the time of the incident. However, the oil spill still has the potential to affect energy supplies, infrastructure, and prices in the region. About 30 percent of the total crude oil and 12 percent of the total natural gas produced in the United States comes from Gulf Coast waters. The Gulf Coast is also a major refining center, representing about half of the refining capacity in the United States. Nearly two-thirds of the crude oil processed by Gulf Coast refineries is imported by tanker.

This *Outlook* does not assume any significant disruptions to energy supply due to the spill. The current relatively high level of on-shore crude oil and product stocks and the availability of the Strategic Petroleum Reserve can buffer the impact of any short-term crude oil supply disruptions. To date, however, there has been no impact on energy transportation and only very small impacts on production. On May 2, according to the Minerals Management Service, two natural gas production platforms producing approximately 6.2 million cubic feet per day (less than 0.1 percent of daily gas production in the Gulf of Mexico) were shut down due to the oil slick.

Natural Gas

U.S. Natural Gas Consumption. EIA expects total natural gas consumption to increase by 3.0 percent to 64.4 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). Consumption growth in 2010 is led by the industrial and electric power sectors. Despite higher natural gas prices in the first quarter of 2010 compared with the same period in 2009, natural gas accounted for a slightly higher share of generation in the electric power sector. This gain in the natural gas share of electric-power-sector generation is expected to continue through this year. In the industrial sector, EIA's natural-gas-weighted industrial production index (a measure of industrial activity in natural-gas-intensive industries) showed a year-over-year increase of 6.8 percent during the first quarter of 2010 and is forecast to rise by 5 percent on average for the entire year.

EIA's expectation of continued growth in industrial output in 2011 leads to a projected 1.3 percent increase in industrial natural gas consumption next year. However, the forecast of higher natural gas prices restrains natural gas use in the electric power sector next year. In addition, the assumption of a 2.2 percent decline in first- quarter heating degree days next year, and the resulting decline in space heating demand, reduces residential and commercial sector consumption next year.

U.S. Natural Gas Production and Imports. EIA expects total marketed natural gas production to increase by 0.8 Bcf/d (1.3 percent) to 60.7 Bcf/d in 2010 and to decline by 0.3 Bcf/d (0.5 percent) in 2011. This production forecast is lower than last month's *Outlook* by 0.1 and 0.3 Bcf/d in 2010 and 2011, respectively. The recent revisions to EIA's historical natural gas production data and balancing item (the difference between total monthly consumption and total production) for 2009 and January 2010 of about 0.5 Bcf/d on average are primarily reflected in a smaller (less negative) balancing item in this forecast.

Although the working natural gas rig count has declined in recent weeks, the resurgent trend in drilling activity from last year's low contributes to the outlook for production growth in 2010. With a forecast of lower prices throughout the remainder of 2010 relative to the first quarter, EIA expects some continuation of the recent reduction in drilling activity. The lagged effect of sustained lower drilling in the forecast contributes to a slight decline in production during 2011.

Liquefied natural gas (LNG) imports have fallen in recent weeks as maintenance, feed-gas shortages, and startup delays reduce the amount of previously expected global LNG supply. Higher prices in other LNG-consuming countries in Europe and

Asia continue to attract cargoes away from U.S. ports. However, EIA continues to expect that new LNG supply trains coming on-stream in Qatar, Yemen, and Peru will more than satisfy global demand and contribute to a 0.4 Bcf/d increase in U.S. LNG imports during 2010. This increase does not offset a projected 0.7 Bcf/d decline in pipeline imports during 2010. The majority of U.S. pipeline imports come from Canada, where natural gas production has been in recent decline as a result of lower drilling activity.

U.S. Natural Gas Inventories. On April 30, 2010, working natural gas in storage was 1,995 Bcf (U.S. Working Natural Gas in Storage Chart), 315 Bcf above the previous 5-year average (2005–2009) and 97 Bcf above the level during the corresponding week last year. The estimated storage injection in April of 335 Bcf was 88 Bcf above April 2009 and 134 Bcf above the previous 5-year average for the month. EIA expects working gas inventories at the end of October 2010 to be about 3,800 Bcf, slightly below the level reached at the end of the injection season (October 31) last year. Although EIA does not expect inventories to eclipse last year's record 3,837 Bcf reached in late November, sufficient storage capacity remains above 3,800 Bcf to absorb additional volumes if available.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $4.03 per MMBtu in April, $0.26 per MMBtu lower than the average spot price in March (Henry Hub Natural Gas Price Chart). Resilient production and mild weather in March and April have combined to keep near-term prices low. However, the forecast for sustained low natural gas prices this summer will likely contribute to a decline in natural gas drilling activity over the next several months. As a result, the current 2011 forecast of higher prices comes as production begins to decline later this year. The Henry Hub spot price forecast averages $4.48 per MMBtu in 2010 and $5.34 per MMBtu in 2011.

Natural gas options markets were fairly stable in April, with implied volatilities finishing the month close to where they started. July 2010 natural gas futures prices averaged $4.11 per MMBtu for the 5 days ending May 7, roughly where they started the month. Implied volatility averaged 46.1 percent for the same five-day period, rendering the lower and upper limits of the 95-percent confidence interval at $2.95 and $5.70 per MMBtu, respectively.

A year earlier, natural gas delivered to the Henry Hub in July 2009 was trading at $3.90 per MMBtu and implied volatility averaged about 66 percent. The lower and upper limits for the 95-percent confidence interval were $2.42 and $6.28 per MMBtu.

Electricity

U.S. Electricity Consumption. Retail sales of electricity to the industrial sector during the first quarter of 2010 are estimated to have grown by 2.7 percent since the same period last year, which would be the first year-over-year gain in industrial electricity sales since the beginning of 2008. Total consumption of electricity across all sectors is projected to grow by 2.7 percent during 2010 and by 1.3 percent next year (U.S. Total Electricity Consumption Chart).

U.S. Electric Power Sector Generation. EIA has increased its projected growth in natural gas generation in the electric power sector to 3.8 percent during 2010 from 2.0 percent in the last *Outlook*. This increase is primarily a result of delivered coal prices that remain near record levels. In addition, low runoff levels in the Pacific Northwest likely will drive down the share of electricity generated from hydropower, thereby boosting natural gas generation in that region. Also, the American Wind Energy Association reports that wind power capacity additions during the first quarter of this year were the lowest since the beginning of 2007. Thus, EIA has lowered its expectations for growth in wind generation to 17 percent during 2010, compared to an increase of 28 percent last year. Electricity generation from natural gas falls by 1 percent in 2011 as higher natural gas prices results in a small reduction in the baseload generation share.

U.S. Electricity Retail Prices. Generation fuel costs remain high, especially for coal-fired generation. Residential electricity prices in most areas of the country already reflect these higher fuel costs. However, the Middle Atlantic Census region will likely experience strong price increases this year after relatively flat growth last year (U.S. Residential Electricity Prices Chart). Nationwide, EIA projects residential prices to grow by 0.3 percent this year and 2.8 percent in 2011.

Coal

U.S. Coal Consumption. Forecast electricity demand growth contributes to the projected 3.9-percent growth in coal consumption in the electric power sector in 2010. Forecast coal consumption in the electric power sector in 2011 grows by an additional 2.9 percent to 1 billion short tons (U.S. Coal Consumption Growth Chart).

U.S. Coal Supply. EIA estimates that 2009 coal production fell by nearly 8.5 percent in response to lower U.S. coal consumption, fewer exports, and higher coal inventories. Production declines by an additional 3.0 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 both producer and end-user

inventories. EIA projects a 5.4-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).

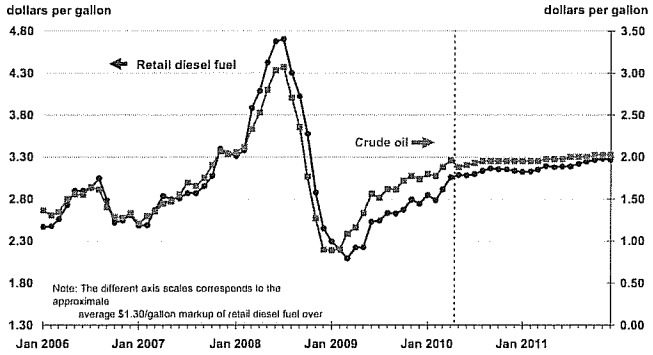
U.S. Coal Trade. U.S. coal imports fell by more than one third in 2009, and the slightly more than 22 million short tons imported was the smallest amount received since 2002. Imports decline further in 2010 (by 4 percent) as increased consumption is satisfied by draws on coal inventories. Projected increases in coal consumption will lead to imports growing by 19 percent in 2011.

U.S. Coal Prices. EIA estimates that the 2009 delivered electric-power-sector coal price increased by about 7 percent 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 increases slightly (0.7 percent) to average $2.22 per MMBtu in 2010, and then declines to an average $2.18 per MMBtu in 2011.

U.S. Carbon Dioxide Emissions

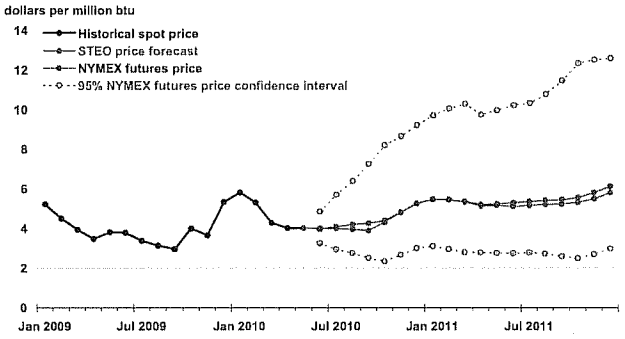
Forecast continued economic growth combined with increased use of coal in the electric power sector contribute to expected increases in CO_2 emissions from fossil fuels of 0.6 percent and 1.6 percent in 2010 and 2011, respectively (U.S. Carbon Dioxide Emissions Growth Chart). However, even with increases 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, May

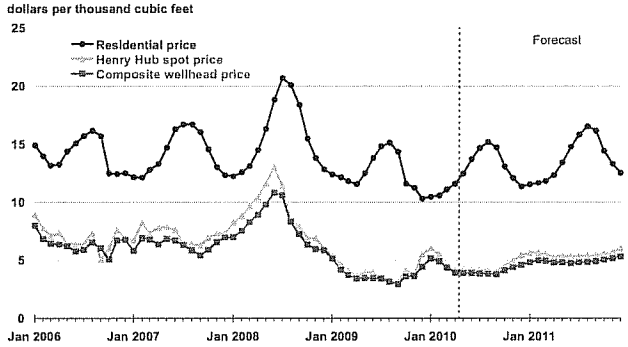
Henry Hub Natural Gas Price



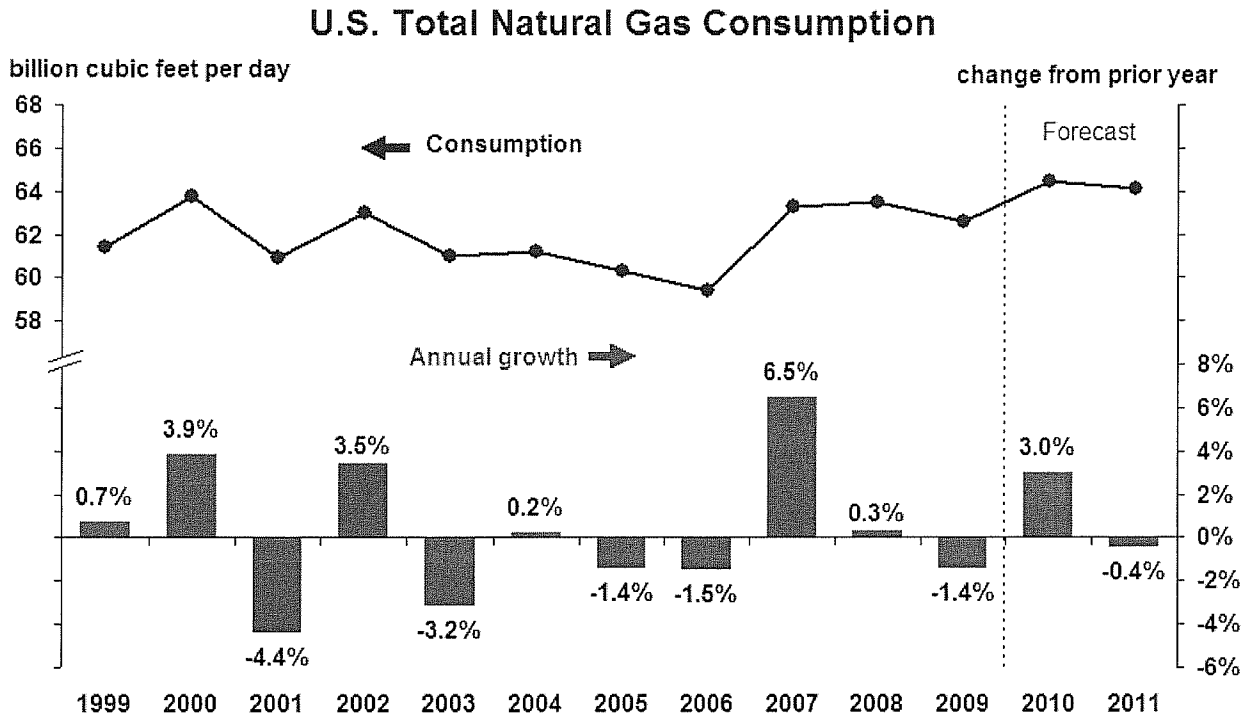
Note: Confidence interval derived from options market information from 5 trading days ending May 7, 2010
Intervals not calculated for months with sparse trading in "close-to-the-money" options contracts

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

Natural Gas Prices



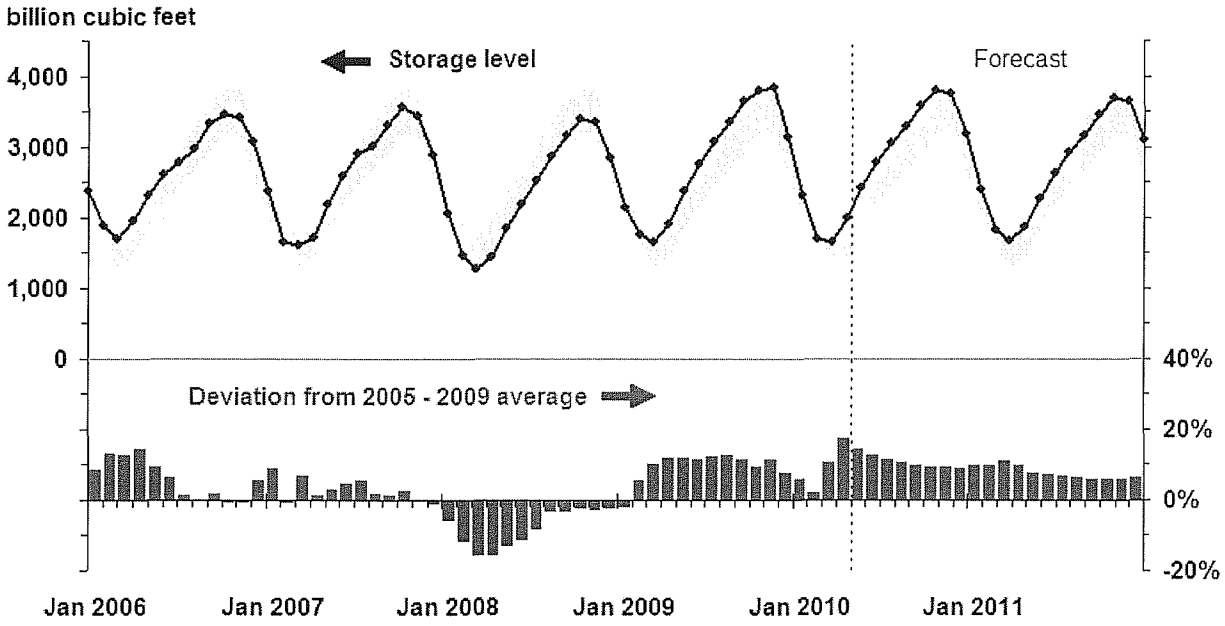
Source: Short-Term Energy Outlook, May 2010; Reuters News



U.S. Energy Information Administration

Source: Short-Term Energy Outlook, May 2010

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

U.S. Energy Information Administration

Source: Short-Term Energy Outlook, May 2010

GREAT PLAINS NATURAL GAS CO.
GAS COST RECONCILIATION ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
FIRM
TO BE EFFECTIVE JUNE 1, 2010 THROUGH MAY 31, 2011

(Over)/under recovered gas costs @ April 30, 2010:			$114,988
Less projected recovery from rates already established:			
	Volume	Rate	Amount
May	11,000	$0.2343	$2,577
Additional recovery required			$112,411
Projected sales volumes (mcf)			
June 2010		6,500	
July		6,000	
August		6,300	
September		9,200	
October		18,300	
November		32,100	
December		46,100	
January 2011		52,300	
February		41,800	
March		35,300	
April		20,500	
May		10,800	
Total			285,200
Total gas cost reconciliation adjustment to be effective June 1, 2010 through May 31, 2011			$0.3941

GREAT PLAINS NATURAL GAS CO.
GAS COST RECONCILIATION ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE
TO BE EFFECTIVE JUNE 1, 2010 THROUGH MAY 31, 2011

(Over)/under recovered gas costs @ April 30, 2010:			($30,590)
Less projected recovery from rates already established:			
	Volume	Rate	Amount
May	11,900	($0.7419)	($8,829)
Additional recovery required			($21,761)
Projected sales volumes (mcf)			
June 2010		15,400	
July		10,900	
August		7,400	
September		9,800	
October		9,200	
November		16,600	
December		18,000	
January 2011		22,100	
February		25,300	
March		20,500	
April		19,900	
May		16,500	
Total			191,600
Total gas cost reconciliation adjustment to be effective June 1, 2010 through May 31, 2011			($0.1136)

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 2/	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) 3/	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 2008	(39,169)	0	1,480	(37,689)	48,707	0.2343	11,412	(49,101)	168,279
February	(54,257)	0	1,119	(53,138)	45,646	0.2343	10,695	(63,833)	104,447
March	(4,038)	0	653	(3,385)	36,916	0.2343	8,650	(12,035)	92,412
April	27,134	0	564	27,698	21,863	0.2343	5,122	22,577	114,988
	$88,611	$0	$11,777	$100,388	260,207		$51,341	$49,047	
Balance @ April 30, 2010									**$114,988**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Total net additions less total adjustment amount.
3/ 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 2/	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) 3/	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 2008	(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)
March	987	0	(413)	574	19,857	(0.7419)	(14,732)	15,306	(48,827)
April	6,335	0	(318)	6,017	16,471	(0.7419)	(12,220)	18,237	(30,590)
	($54,808)	$0	($7,455)	($62,263)	191,562		($141,864)	$79,601	
Balance @ April 30, 2010									**($30,590)**

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

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
FIRM

	1/	2/	3/	Total
May 2009				
Cost of Gas - Actual	$5.75370	$5.40660	$5.75370	
Cost of Gas - Recovered	5.19010	5.71740	5.71740	
(Over) Under recovery per dk	$0.56360	($0.31080)	$0.03630	
dk billed	5,365	15,976	(4,519)	16,822
(Over) Under recovery	$3,024	($4,965)	($164)	($2,105)
June 2009				
Cost of Gas - Actual	$9.45500	$5.75370	$9.45500	
Cost of Gas - Recovered	5.64380	5.19010	5.19010	
(Over) Under recovery per dk	$3.81120	$0.56360	$4.26490	
dk billed	3,010	3,528	2,569	9,107
(Over) Under recovery	$11,472	$1,988	$10,955	$24,415
July 2009				
Cost of Gas - Actual	$12.03200	$9.45500	$12.03200	
Cost of Gas - Recovered	5.84870	5.64380	5.64380	
(Over) Under recovery per dk	$6.18330	$3.81120	$6.38820	
dk billed	2,388	525	3,534	6,447
(Over) Under recovery	$14,766	$2,001	$22,577	$39,344
August 2009				
Cost of Gas - Actual	$12.43850	$12.03200	$12.43850	
Cost of Gas - Recovered	5.50500	5.84870	5.84870	
(Over) Under recovery per dk	$6.93350	$6.18330	$6.58980	
dk billed	2,318	465	3,160	5,943
(Over) Under recovery	$16,072	$2,875	$20,824	$39,771
September 2009				
Cost of Gas - Actual	$12.46600	$12.43850	$12.46600	
Cost of Gas - Recovered	5.07920	5.50500	5.50500	
(Over) Under recovery per dk	$7.38680	$6.93350	$6.96100	
dk billed	2,199	4,777 4/	(1,201)	5,775
(Over) Under recovery	$16,243	($10,048)	($8,360)	($2,165)
October 2009				
Cost of Gas - Actual	$4.79250	$12.46600	$4.79250	
Cost of Gas - Recovered	5.49220	5.07920	5.07920	
(Over) Under recovery per dk	($0.69970)	$7.38680	($0.28670)	
dk billed	5,735	5,304	496	11,535
(Over) Under recovery	($4,013)	$39,177	($142)	$35,022

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
FIRM

	1/	2/	3/	Total
November 2009				
Cost of Gas - Actual	$8.62610	$4.79250	$8.62610	
Cost of Gas - Recovered	7.31180	5.49220	5.49220	
(Over) Under recovery per dk	$1.31430	($0.69970)	$3.13390	
dk billed	6,355	12,798	(120)	19,033
(Over) Under recovery	$8,352	($8,956)	($376)	($980)
December 2009				
Cost of Gas - Actual	$6.71380	$8.62610	$6.71380	
Cost of Gas - Recovered	7.18640	7.31180	7.31180	
(Over) Under recovery per dk	($0.47260)	$1.31430	($0.59800)	
dk billed	12,660	22,713	(2,960)	32,413
(Over) Under recovery	($5,983)	$29,852	$1,770	$25,639
January 2010				
Cost of Gas - Actual	$7.17410	$6.71380	$7.17410	
Cost of Gas - Recovered	8.59770	7.18640	7.18640	
(Over) Under recovery per dk	($1.42360)	($0.47260)	($0.01230)	
dk billed	16,552	33,043	(888)	48,707
(Over) Under recovery	($23,563)	($15,617)	$11	($39,169)
February 2010				
Cost of Gas - Actual	$8.40320	$7.17410	$8.40320	
Cost of Gas - Recovered	8.61360	8.59770	8.59770	
(Over) Under recovery per dk	($0.21040)	($1.42360)	($0.19450)	
dk billed	14,330	36,735	(5,419)	45,646
(Over) Under recovery	($3,015)	($52,296)	$1,054	($54,257)
March 2010				
Cost of Gas - Actual	$9.13110	$8.40320	$9.13110	
Cost of Gas - Recovered	8.08770	8.61360	8.61360	
(Over) Under recovery per dk	$1.04340	($0.21040)	$0.51750	
dk billed	12,009	40,470	(15,563)	36,916
(Over) Under recovery	$12,531	($8,515)	($8,054)	($4,038)
April 2010				
Cost of Gas - Actual	$9.46680	$9.13110	$9.46680	
Cost of Gas - Recovered	6.97370	8.08770	8.08770	
(Over) Under recovery per dk	$2.49310	$1.04340	$1.37910	
dk billed	6,599	30,884	(15,620)	21,863
(Over) Under recovery	$16,452	$32,224	($21,542)	$27,134

1/ Consumed in current month.
2/ Consumed in prior month.
3/ True-up of prior month volumes.
4/ Includes annual volume true-up.

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE

	1/	2/	3/	Total
May 2009				
Cost of Gas - Actual	$2.46860	$3.35310	$2.46860	
Cost of Gas - Recovered	2.93340	3.43660	3.43660	
(Over) Under recovery per dk	($0.46480)	($0.08350)	($0.96800)	
dk billed	6,371	7,140	1,915	15,426
(Over) Under recovery	($2,961)	($596)	($1,854)	($5,411)
June 2009				
Cost of Gas - Actual	$2.89130	$2.46860	$2.89130	
Cost of Gas - Recovered	3.23530	2.93340	2.93340	
(Over) Under recovery per dk	($0.34400)	($0.46480)	($0.04210)	
dk billed	3,030	1,718	6,131	10,879
(Over) Under recovery	($1,042)	($799)	($258)	($2,099)
July 2009				
Cost of Gas - Actual	$2.89020	$2.89130	$2.89020	
Cost of Gas - Recovered	3.43660	3.23530	3.23530	
(Over) Under recovery per dk	($0.54640)	($0.34400)	($0.34510)	
dk billed	2,349	364	4,722	7,435
(Over) Under recovery	($1,283)	($125)	($1,630)	($3,038)
August 2009				
Cost of Gas - Actual	$2.81640	$2.89020	$2.81640	
Cost of Gas - Recovered	2.98370	3.43660	3.43660	
(Over) Under recovery per dk	($0.16730)	($0.54640)	($0.62020)	
dk billed	3,186	475	6,114	9,775
(Over) Under recovery	($533)	($260)	($3,791)	($4,584)
September 2009				
Cost of Gas - Actual	$1.98310	$2.81640	$1.98310	
Cost of Gas - Recovered	2.63140	2.98370	2.98370	
(Over) Under recovery per dk	($0.64830)	($0.16730)	($1.00060)	
dk billed	2,925	5,276 4/	1,029	9,230
(Over) Under recovery	($1,896)	($11,679)	($1,030)	($14,605)
October 2009				
Cost of Gas - Actual	$2.42920	$1.98310	$2.42920	
Cost of Gas - Recovered	2.98390	2.63140	2.63140	
(Over) Under recovery per dk	($0.55470)	($0.64830)	($0.20220)	
dk billed	11,857	5,542	(847)	16,552
(Over) Under recovery	($6,577)	($3,593)	$171	($9,999)

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE

	1/	2/	3/	Total
November 2009				
Cost of Gas - Actual	$4.78910	$2.42920	$4.78910	
Cost of Gas - Recovered	4.85070	2.98390	2.98390	
(Over) Under recovery per dk	($0.06160)	($0.55470)	$1.80520	
dk billed	11,817	10,876	(4,689)	18,004
(Over) Under recovery	($728)	($6,033)	($8,464)	($15,225)
December 2009				
Cost of Gas - Actual	$4.72260	$4.78910	$4.72260	
Cost of Gas - Recovered	4.66940	4.85070	4.85070	
(Over) Under recovery per dk	$0.05320	($0.06160)	($0.12810)	
dk billed	9,833	10,508	1,794	22,135
(Over) Under recovery	$523	($647)	($230)	($354)
January 2010				
Cost of Gas - Actual	$5.38450	$4.72260	$5.38450	
Cost of Gas - Recovered	5.45520	4.66940	4.66940	
(Over) Under recovery per dk	($0.07070)	$0.05320	$0.71510	
dk billed	7,996	25,712	(8,423)	25,285
(Over) Under recovery	($565)	$1,368	($6,023)	($5,220)
February 2010				
Cost of Gas - Actual	$5.42750	$5.38450	$5.42750	
Cost of Gas - Recovered	5.45520	5.45520	5.45520	
(Over) Under recovery per dk	($0.02770)	($0.07070)	($0.02770)	
dk billed	4,798	23,878	(8,163)	20,513
(Over) Under recovery	($133)	($1,688)	$226	($1,595)
March 2010				
Cost of Gas - Actual	$5.08670	$5.42750	$5.08670	
Cost of Gas - Recovered	4.90110	5.45520	5.45520	
(Over) Under recovery per dk	$0.18560	($0.02770)	($0.36850)	
dk billed	6,281	14,157	(581)	19,857
(Over) Under recovery	$1,165	($392)	$214	$987
April 2010				
Cost of Gas - Actual	$4.19460	$5.08670	$4.19460	
Cost of Gas - Recovered	3.87430	4.90110	4.90110	
(Over) Under recovery per dk	$0.32030	$0.18560	($0.70650)	
dk billed	8,128	10,790	(2,447)	16,471
(Over) Under recovery	$2,603	$2,003	$1,729	$6,335

1/ Consumed in current month.
2/ Consumed in prior month.
3/ True-up of prior month volumes.
4/ Includes annual volume true-up.