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

105 West Lincoln Avenue
Mailing Address:
P.O. Box 176
Fergus Falls, MN 56538-0176
(218) 736-6935

July 30, 2010

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

Re: Cost of Gas Adjustment (COG)
August 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 (53rd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (53rd Revised Sheet No. 8), showing the August 2010 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.3464 per mcf for residential and firm general service customers and $0.3536 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for August 2010, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.3536 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 $0.0072 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of $0.3464 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, 2010.

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
53rd Revised Sheet No. 1.1
Canceling 52nd 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	$7.6687	$8.9427
			Over 10 MCF	1.0540		8.7227
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.5889	$4.7280
			Next 2,600 MCF	0.8931		4.4820
			Over 3,000 MCF	0.7411		4.3300
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.5889	$4.8280
Transportation Service	5	$3.50 per month	First 400 MCF	$1.1391		$1.1391
			Next 2,600 MCF	0.8931		0.8931
			Over 3,000 MCF	0.7411		0.7411

Date Filed: July 30, 2010 **Effective Date:** August 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
53rd Revised Sheet No. 8
Canceling 52nd 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.	3.4991	(1.0630)	0.3941	2.8302	(1.0630)	(0.1136)	(1.1766)
Current Adj.	0.0072	(0.3536)	0.0000	(0.3464)	(0.3536)	0.0000	(0.3536)
Total Adj.	3.5063	(1.4166)	0.3941	2.4838	(1.4166)	(0.1136)	(1.5302)
Total Rate:	$3.5721	$3.7025	$0.3941	$7.6687	$3.7025	($0.1136)	$3.5889

Date Filed: July 30, 2010 **Effective Date:** August 1, 2010

Issued By: Tamie A. Aberle
Pricing & Tariff Manager

Case No.:

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

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A	7,841		$3.4671	12	$326,226	$0.2329
FT-A - Zone 1-1	500		3.4671	5	8,668	0.0062
FT-A - Zone 1-2	4,500		4.5871	5	103,210	0.0737
FT-A Seasonal	3,000		3.7671	5	56,507	0.0403
TFX Seasonal	3,000		15.1530	5	227,295	0.1623
NOVA - Demand Charge	7,947		16.8984	12	1,611,499	1.1504
Trans Canada - Demand Charge	7,947		16.7280	12	1,595,249	1.1388
BP Canada - Demand Charge	7,947		0.9612	12	91,664	0.0654
NOVA - Seasonal	5,068		16.8984	5	428,205	0.3057
Trans Canada - Seasonal	5,068		16.7280	5	423,888	0.3026
BP Canada - Seasonal	5,068		0.9612	5	24,357	0.0174
BP Canada Winter Surcharge	5,068		3.0417	5	77,077	0.0550
LMS Demand	2,500		1.0000	12	30,000	0.0214
Total Demand Charges					$5,003,845	3.5721
Estimated Weighted Average Commodity Cost	1,400,774	1	3.7025		5,186,366	3.7025
Gas Cost Reconciliation Adjustment						0.3941
Total Current Firm Gas Cost					$10,190,211	7.6687
Base Cost of Gas						5.1849
Accumulated Adjustment						$2.4838
Interruptible						
Estimated Weighted Average Commodity Cost						$3.7025
Gas Cost Reconciliation Adjustment						(0.1136)
Total Current Interruptible Gas Cost						3.5889
Base Cost of Gas						5.1191
Accumulated Adjustment						($1.5302)

1/ Three year normalized average Dk sales.

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

Rates Effective August 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	16.8984	Per dk/Mo.
Trans Canada Pipeline Demand Charge	16.7280	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	16.8984	Per dk/Day
Trans Canada - Seasonal	16.7280	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:	3.7025	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

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

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.

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.

Rate Schedule	Maximum Commodity Rate Per Dekatherm, Per Day	Minimum Commodity Rate Per Dekatherm, Per Day
PAL	$0.1737	$0.0000

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.

Northern Natural Gas Company
FERC Gas Tariff
Fifth Revised Volume No. 1

80 Revised Sheet No. 51
Superseding
79 Revised Sheet No. 51

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.

Issued by: Mary Kay Miller, V.P. Regulatory & Government Affairs
Issued on: February 1, 2010
Effective: April 1, 2010

Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
August 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 August monthly price for the 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).

Despite warm weather over much of the U.S. during the month of July, the continued strong U.S. production and high levels of natural gas in storage were factors leading to the price decline. The Energy Information Administration (EIA) reported storage levels nationwide as of July 16, 2010 were 9.9 percent above the five-year average and 1.8 percent below last year's balance.

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

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 13.

U.S. Energy Information Administration

July 2010

Short-Term Energy Outlook

July 7, 2010 Release

Highlights

- EIA projects that the West Texas Intermediate (WTI) spot price, which ended June near $76 per barrel, will average $79 per barrel over the second half of 2010 and $83 per barrel in 2011. This forecast is unchanged from last month's *Outlook.*

- EIA expects that regular-grade motor gasoline retail prices will average $2.80 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 only slightly ($0.01) from last month's Outlook, but $0.12 per gallon lower than we had forecast in April, when oil prices were significantly higher.

- This *Outlook* includes EIA's revised estimates of reductions in production resulting from the 6-month deepwater drilling moratorium announced by Secretary of the Interior Salazar on May 27. The reductions in crude oil production resulting from the moratorium are estimated to average about 31,000 barrels per day (bbl/d) in the fourth quarter of 2010 (compared with an estimated 26,000 bbl/d in last month's *Outlook*) and about 82,000 bbl/d in 2011 (up from 70,000 bbl/d). EIA will continue to refine its estimated moratorium impacts as additional information becomes available.

- EIA expects the Henry Hub natural gas spot price to average $4.70 per million Btu (MMBtu) this year, a $0.75-per-MMBtu increase over the 2009 average and $0.22 per MMBtu higher than in last month's *Outlook.* Most of the increase in the price forecast occurs in the third quarter of this year, due to projections of increased hurricane activity in the Gulf of Mexico this season, which pushed spot prices higher. EIA expects the Henry Hub spot price to average $5.17 per MMBtu in 2011, up $0.11 per MMBtu from last month's Outlook.

- The annual average residential electricity price changes only moderately over the forecast period, averaging 11.6 cents per kilowatthour (kWh) in 2010, up slightly from 11.5 cents per kWh in 2009, and rising to 12 cents per kWh in 2011.

- Estimated U.S. carbon dioxide (CO_2) emissions from fossil fuels, which declined by 7.0 percent in 2009, are expected to increase by 3.2 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 view of the world oil market is largely unchanged from recent *Outlooks*. EIA forecasts that world oil prices will rise slowly as an expected renewal of global economic growth leads to higher world oil demand and members of the Organization of the Petroleum Exporting Countries (OPEC) continue their support of prices near current levels.

Global Crude Oil and Liquid Fuels Consumption. EIA projects world oil consumption to grow by about 1.5 million bbl/d in both 2010 and 2011, mostly unchanged from last month's *Outlook*. However, estimates for oil consumption in 2009 were revised upwards, with these changes carried through the forecast period. Consequently, the level of forecasted demand in 2010 and 2011 is higher than last month's *Outlook*. Countries outside of the Organization for Economic Cooperation and Development (OECD) represent nearly all of the expected growth in world oil consumption, led by China, Saudi Arabia, and Brazil (World Liquid Fuels Consumption Chart).

Non-OPEC Supply. EIA has revised its forecast of non-OPEC supply upwards from the last *Outlook*, with non-OPEC supply now expected to increase by 0.6 million bbl/d in 2010 and decline by less than 0.1 million bbl/d in 2011. The forecast for oil production in Mexico is more optimistic than last month. Data for the first half of the year have been higher than expected, as recent decline rates at the Cantarell field have fallen and the country has boosted output from other offshore areas. Nonetheless, oil production in Mexico is still expected to fall by 0.1 million bbl/d in 2010 and roughly 0.2 million bbl/d in 2011. Over the forecast period, Brazil, the United States, and Azerbaijan should provide the largest sources of non-OPEC supply growth.

OPEC Supply. The 12 members of OPEC produced an estimated 29.4 million bbl/d of crude oil in the second quarter of 2010. After remaining relatively steady for the past four quarters, EIA expects OPEC crude oil production to rise slightly through 2011 to

accommodate increasing world oil consumption and maintain the organization's market objectives. Even with the increase in crude oil production, OPEC surplus capacity should remain over 5 million bbl/d in 2010 and 2011, versus 4.3 million bbl/d in 2009 and 1.5 million bbl/d in 2008 (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 million bbl/d in 2010 and 0.7 million bbl/d in 2011.

OECD Petroleum Inventories. Commercial oil inventories held in the OECD stood at about 2.7 billion barrels at the end of the first quarter of 2010, equivalent to about 57 days of forward cover, and roughly 67 million barrels more than the 5-year average for the corresponding time of year (Days of Supply of OECD Commercial Stocks Chart). The level of OECD oil inventories is expected to decline through the forecast period, though days-forward-cover should remain high due to falling OECD oil consumption.

Crude Oil Prices. WTI crude oil spot prices averaged $75.34 per barrel in June 2010 ($1.60 per barrel above the prior month's average), close to the $76 per barrel projected in the forecast in last month's *Outlook.* EIA projects WTI prices will average about $79 per barrel over the second half of this year and rise to $84 by the end of next year (West Texas Intermediate Crude Oil Price Chart).

Energy price forecasts are highly uncertain, as history has shown (Energy Price Volatility and Forecast Uncertainty). WTI futures for September 2010 delivery for the 5-day period ending July 1 averaged $77 per barrel, and implied volatility averaged 35 percent. This made the lower and upper limits of the 95-percent confidence interval $60 and $98 per barrel, respectively.

Last year at this time, WTI for September 2009 delivery averaged $70 per barrel, and implied volatility averaged 44 percent, rendering the limits of the 95-percent confidence interval $52 and $95 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. U.S. liquid fuels consumption is beginning to show signs of recovery after having fallen by 810,000 bbl/d in 2009, the fourth consecutive annual decline (U.S. Liquid Fuels Consumption Growth Chart). The year-over-year decline in total liquid fuels consumption slowed to 20,000 bbl/d in the first quarter of 2010. Total consumption for the second quarter, however, rose by 500,000 bbl/d compared with the same period last year. For the year as a whole, projected total liquid fuels consumption grows by 200,000 bbl/d in 2010 and by 170,000 bbl/d in 2011

as all of the major petroleum products register consumption growth in each of those years.

U.S. Liquid Fuels Supply and Imports. Projected domestic crude oil production increases by 75,000 bbl/d in 2010 (U.S. Crude Oil Production Chart). Based on the forecast of a more active hurricane season by the National Oceanic and Atmospheric Administration (NOAA), EIA estimates a median outcome of 26 million barrels of total shut-in crude oil production because of tropical storm activity in the Gulf of Mexico this year (see *2010 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico*).

Reversing a pattern of increases over several years, forecast crude oil production in 2011 falls by 26,000 bbl/d to 5.37 million bbl/d. The lower production forecast includes EIA's estimates of reductions in the output of crude oil from the deepwater Gulf of Mexico of 31,000 bbl/d in the fourth quarter of 2010 and 82,000 bbl/d in 2011 because of the recently imposed 6-month drilling moratorium. The reductions in crude oil production increase from a monthly average of about 10,000 bbl/d in September 2010 to nearly 100,000 bbl/d by December 2011.

Projected ethanol production, which averaged 700,000 bbl/d in 2009, increases to an average of 850,000 bbl/d in 2010 and 880,000 bbl/d in 2011. EIA forecasts that liquid fuel net imports (including both crude oil and refined products), which declined by 1.4 million bbl/d in 2009, will fall by a further 110,000 bbl/d in 2010. In 2011, projected total liquid fuel net imports increase by 80,000 bbl/d.

U.S. Petroleum Product Prices. Projected regular-grade gasoline retail prices rise from an average $2.35 per gallon in 2009 to an average $2.77 per gallon in 2010 and $2.90 per gallon in 2011. Forecast regular-grade pump prices average $2.80 per gallon this summer, an increase of 36 cents from the previous summer. On-highway diesel fuel retail prices, which averaged $2.46 per gallon in 2009, average $2.98 per gallon in 2010 and $3.13 in 2011 in this forecast.

Natural Gas

U.S. Natural Gas Consumption. EIA projects total natural gas consumption will average 64.7 billion cubic feet per day (Bcf/d) and 64.8 Bcf/d in 2010 and 2011, respectively (Total U.S. Natural Gas Consumption Growth Chart). Estimated year-over-year consumption growth averaged 2.8 Bcf/d (4.3 percent) in the first half of 2010, with significant increases in the electric power and industrial sectors. This growth is expected to continue at a slower pace in the second half of the year with an increase of 1.5 Bcf/d (2.6 percent). EIA's projected natural-gas-weighted industrial

production index (a measure of industrial activity in natural-gas-intensive industries) increases by 7.5 percent in 2010, leading to a 1.0 Bcf/d (5.9-percent) increase in natural gas consumption in the industrial sector.

Projected natural gas consumption is virtually flat in 2011. The projected 2.7 percent increase in the natural-gas-weighted industrial production index and NOAA forecast of slightly colder weather next year (1.4 percent increase in heating degree-days) contribute to consumption growth in the residential, commercial, and industrial sectors in 2011. However, this growth is offset by a decline in natural gas consumption in the electric power sector because of the forecast increase in natural gas prices relative to coal prices next year.

U.S. Natural Gas Production and Imports. EIA expects total marketed natural gas production of 61.3 Bcf/d in 2010, an increase of 1.3 Bcf/d over 2009 levels. EIA projects a continuing decline in Gulf of Mexico production, which is offset by gains in onshore production. Forecast marketed production declines by 0.4 Bcf/d to 60.9 Bcf/d in 2011.

Federal Gulf of Mexico natural gas production falls by about 10 percent in both 2010 and 2011 as a result of hurricane outages, the announced offshore drilling moratorium, and the decline in active drilling rigs over the last 4 years. The estimated median outcome for hurricane outages from June through November is a cumulative 166 Bcf this year, compared with 19 Bcf in 2009 (*2010 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico*). The offshore drilling moratorium is projected to reduce Gulf of Mexico production by an average of 0.05 Bcf/d for the last 6 months of 2010 and 0.25 Bcf/d for 2011.

Projected lower-48 onshore production increases by 2 Bcf/d (3.8 percent) in 2010 and 0.2 Bcf/d (0.3 percent) in 2011. According to Baker-Hughes, natural gas rig counts have climbed from under 670 in July 2009 to about 950 in April this year and have remained relatively stable since then.

Forecasted imports of liquefied natural gas (LNG) average 1.37 Bcf/d in 2010, a downward revision of about 0.14 Bcf/d from last month. Projected imports increase to 1.52 Bcf/d in 2011. While imports are expected to grow, higher prices in European and Asian markets will likely divert LNG cargoes from the United States. EIA also forecasts gross pipeline imports of 8.8 Bcf/d in 2010, a decrease of about 2.9 percent from 2009. EIA expects gross pipeline imports of 8.2 Bcf/d in 2011.

U.S. Natural Gas Inventories. On June 25, 2010, working natural gas in storage was 2,684 Bcf (U.S. Working Natural Gas in Storage Chart). This is 27 Bcf below last year's level and 287 Bcf higher than the 5-year (2005-2009) average. EIA expects working gas

inventories this year to remain very near last year's levels, reaching 3,810 Bcf at the end of October 2010.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $4.80 per MMBtu in June, $0.66 per MMBtu higher than the average spot price in May (Henry Hub Natural Gas Price Chart). The forecast price for the second half of 2010 averages $4.68 per MM Btu, $0.32 per MMBtu higher than last month's *Outlook*. The risk of hurricane outages and the projected reduction in drilling activity combine to strengthen prices through the year. A small decline in U.S. production alongside increased consumption leads to higher prices in 2011; the projected Henry Hub spot price averages $5.17 per MMBtu.

Uncertainty over future natural gas prices is lower this year compared with last year at this time. Natural gas futures for September 2010 delivery for the 5-day period ending July 1 averaged $4.77 per MMBtu, and the average implied volatility over the same period was 53 percent. This produced lower and upper bounds for the 95-percent confidence interval of $3.16 and $7.18 per MMBtu, respectively. At this time last year the natural gas September 2009 futures contract averaged $4.00 per MMBtu and implied volatility averaged almost 76 percent. This rendered the lower and upper limits of the 95-percent confidence interval at $2.25 and $7.14 per MMBtu.

Electricity

U.S. Electricity Consumption. This summer has started out much warmer than last summer, resulting in more demand for air conditioning. Cooling degree-days during June were 28 percent higher than in June 2009 (U.S. Summer Cooling Degree Days). EIA estimates the total consumption of electricity across all sectors during the first half of this year increased by 3.8 percent from the first half of 2009. Consumption is expected to show similar year-over-year growth of 3.5 percent during the second half of 2010. Growth in electricity consumption should return to a more typical rate of 1.1 percent in 2011 (U.S. Total Electricity Consumption Chart).

U.S. Electric Power Sector Generation. Snowmelt runoff projections earlier this spring pointed to low levels of hydropower generation during the summer. However, heavy rainfall in the Pacific Northwest during May and June has pushed generation by hydroelectric plants much higher than normal. An increase in EIA's expectation for overall electricity consumption offsets higher expected natural gas fuel costs, keeping growth in natural gas generation at 5.6 percent during 2010, unchanged from last month's *Outlook*. The level of natural gas generation is expected to stay relatively flat in 2011.

U.S. Electricity Retail Prices. EIA estimates that residential retail electricity prices during the first half of 2010 were about the same as in the first half of 2009. However, rising fuel costs for natural gas and coal generation are likely to push up retail prices later this year, causing prices over the entire year to grow by about 0.8 percent. Increased fuel costs should push residential prices higher by about 2.7 percent during 2011 (U.S. Residential Electricity Prices Chart).

Coal

U.S. Coal Consumption. EIA projects that coal consumption in the electric power sector will increase by 4.6 percent in 2010. Continued electricity demand growth in 2011 combined with minimal growth in nuclear and natural-gas-fired generation results in an additional 2.4-percent increase in electric-power-sector coal consumption next year (U.S. Coal Consumption Growth Chart).

U.S. Coal Supply. Projected coal production falls by 0.4 percent in 2010 despite increases in domestic consumption and lower imports. The balance between supply and consumption is satisfied through significant reductions in both producer (14 percent) and end-user (11 percent) inventories (U.S. Electric Power Sector Coal Stocks Chart). EIA projects a 3.6-percent increase in coal production in 2011 to meet continued growth in coal consumption (U.S. Annual Coal Production Chart).

U.S. Coal Trade. U.S. coal imports and exports fell by 34 percent and 28 percent in 2009, respectively. EIA projects imports to decline another 15 percent in 2010 as increased domestic consumption is met by draws on U.S. coal inventories. Forecast coal exports, on the other hand, grow by 25 percent in 2010, driven in part by rising demand for metallurgical coal in China and other Southeast Asian countries. Metallurgical coal is an essential component of the steelmaking process, and currently constitutes a larger share of the U.S. coal export market than steam coal (burned in thermal electric power plants). From January through April 2010, the United States exported 19.6 million tons of metallurgical coal, 95 percent higher than the comparable period in 2009.

Projected coal imports grow by 35 percent in 2011, but the annual tonnage (26 million short tons) remains significantly below the 2005-through-2008 average of 34 million short tons. Forecast coal exports in 2011 are relatively unchanged from 2010 levels.

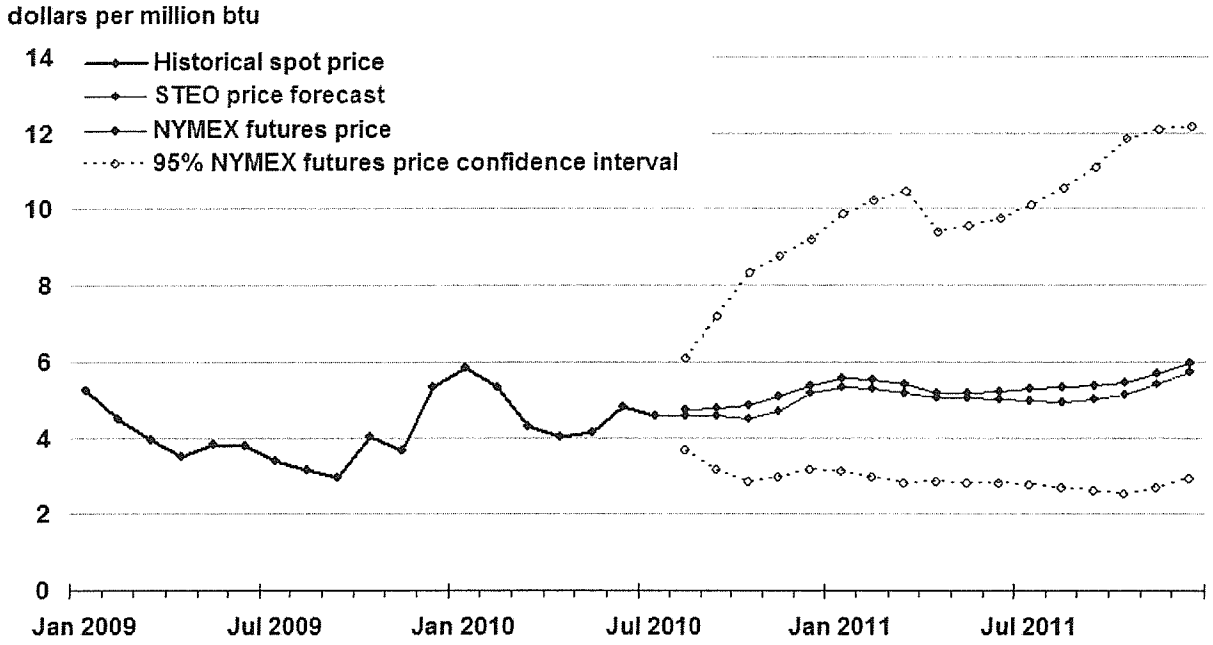
U.S. Coal Prices. EIA estimates that the 2009 delivered electric-power-sector coal price increased by about 7 percent despite decreases in spot coal prices, lower prices for other fossil fuels, and declines in coal-fired electricity generation. This higher cost of delivered coal reflects the impacts of longer-term power-sector coal contracts

initiated during a period of high prices and rising transportation costs. The projected electric-power-sector delivered coal price increases slightly (by 1.4 percent) to average $2.24 per MMBtu in 2010, and then declines to an average of $2.19 per MMBtu in 2011.

U.S. Carbon Dioxide Emissions

Forecast economic growth combined with increased use of coal and natural gas in the electric power sector contribute to increases in fossil-fuel CO_2 emissions of 3.2 percent in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). Increased demand for petroleum in the transportation sector (motor gasoline, diesel fuel and jet fuel), combined with continued electric-power-sector coal demand growth, contribute to the projected 1.6-percent increase in fossil-fuel CO_2 emissions in 2011. However, even with increases in 2010 and 2011, projected CO_2 emissions are lower than annual emissions were from 1999 through 2008.

Henry Hub Natural Gas Price



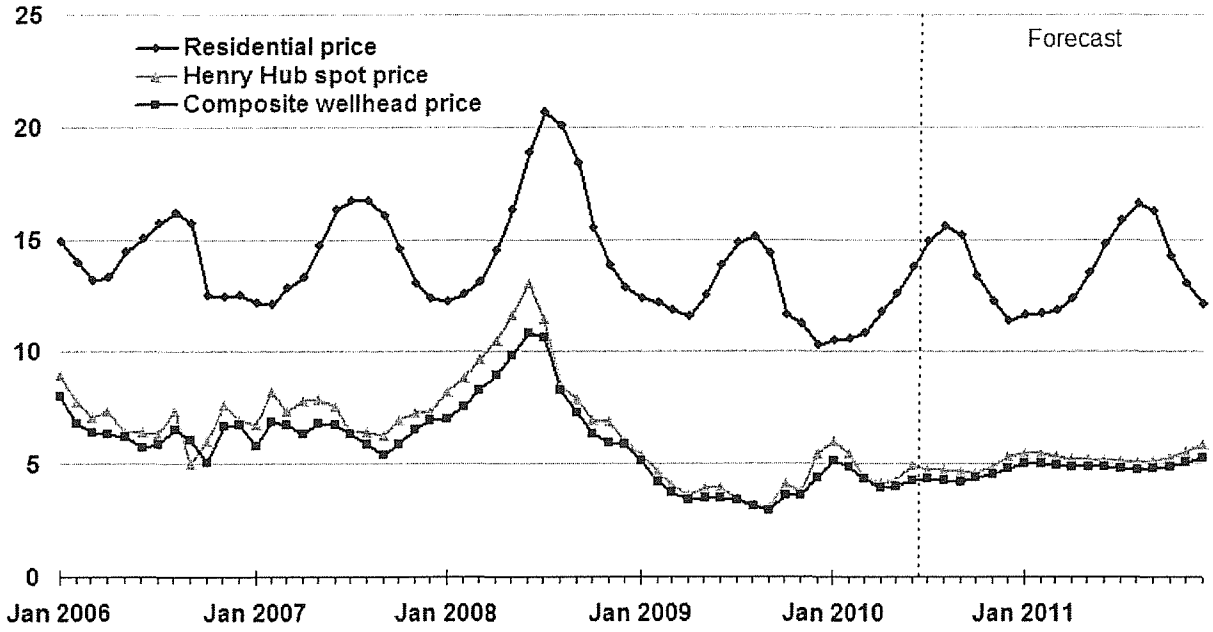
Note: Confidence interval derived from options market information for the 5 trading days ending July 1, 2010
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

U.S. Energy Information Administration

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

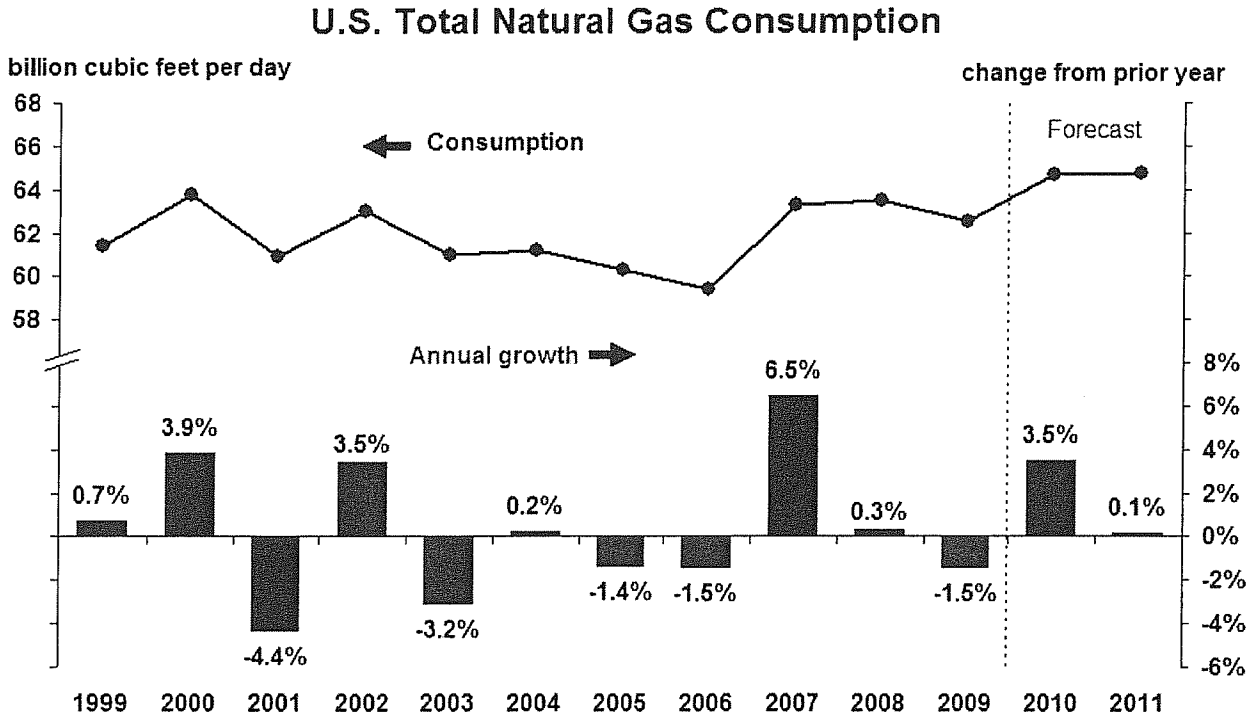
Natural Gas Prices

dollars per thousand cubic feet



U.S. Energy Information Administration

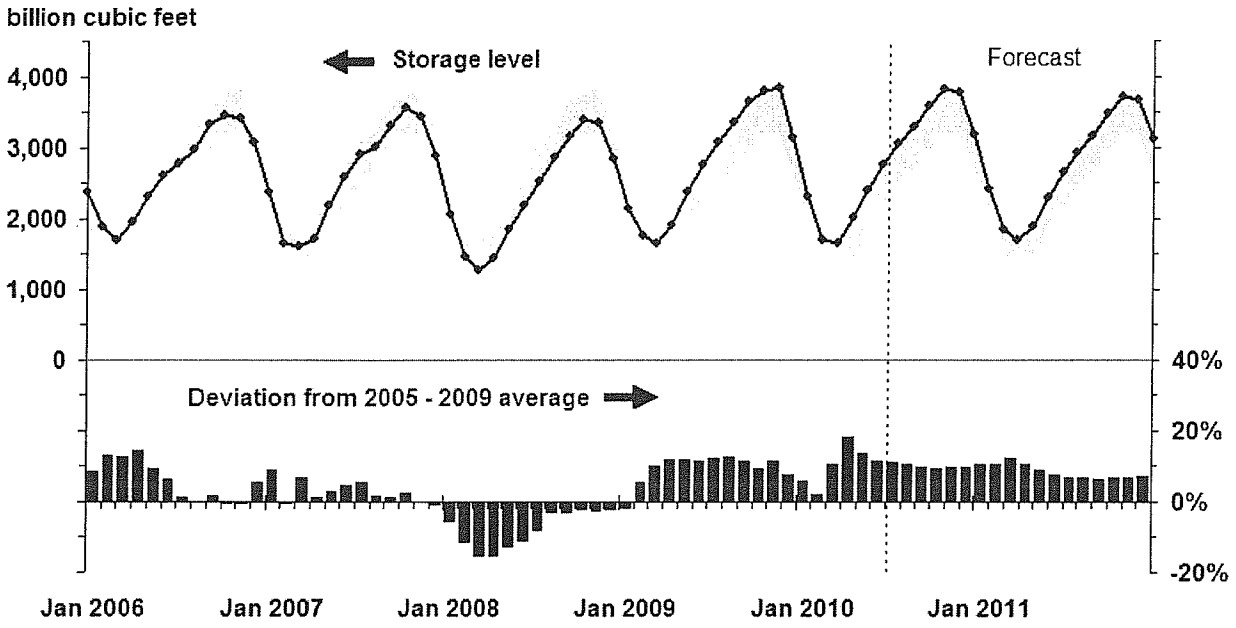
Source: Short-Term Energy Outlook, July 2010; Reuters News Service



U.S. Energy Information Administration

Source: Short-Term Energy Outlook, July 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, July 2010

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, 2010									**$114,988**
May	$29,734	$0	$723	$30,457	12,466	$0.2343	$2,921	$27,536	142,524
June	11,277	0	917	12,194	8,311	0.3941	2,356 2/	9,838	152,362
Balance @ May 31, 2010									**$152,362**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 5,750.5 dk @ ($0.2343) and 2,560.2 dk @ $0.3941.

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, 2010									**($30,590)**
May	$576	$0	($199)	$377	10,944	($0.7419)	($8,120)	$8,497	(22,093)
June	(8,617)	0	(146)	(8,763)	11,808	(0.1136)	(6,678) 2/	(2,085)	(24,178)
Balance @ May 31, 2010									**($24,178)**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 8,493.0 dk @ ($0.7419) and 3,315.3 dk @ $0.1136.