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

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August 31, 2010

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

Re: Cost of Gas Adjustment (COG)
September 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 (54th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (54th Revised Sheet No. 8), showing the September 2010 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.5689 per mcf for residential and firm general service customers and $0.5557 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for September 2010, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.5557 per mcf since the last COG filing due to a decrease in the market price of gas. There has been a decrease in pipeline charges of $0.0132 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of $0.5689 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,

Tamie A. Aberle
Pricing & Tariff 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
54th Revised Sheet No. 1.1
Canceling 53rd 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	$7.0998	$8.3738
			Over 10 MCF	1.0540		8.1538
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.0332	$4.1723
			Next 2,600 MCF	0.8931		3.9263
			Over 3,000 MCF	0.7411		3.7743
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.0332	$4.2723
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: August 31, 2010

Effective Date: September 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
54th Revised Sheet No. 8
Canceling 53rd 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.	3.5063	(1.4166)	0.3941	2.4838	(1.4166)	(0.1136)	(1.5302)
Current Adj.	(0.0132)	(0.5557)	0.0000	(0.5689)	(0.5557)	0.0000	(0.5557)
Total Adj.	3.4931	(1.9723)	0.3941	1.9149	(1.9723)	(0.1136)	(2.0859)
Total Rate:	$3.5589	$3.1468	$0.3941	$7.0998	$3.1468	($0.1136)	$3.0332

Date Filed: August 31, 2010 **Effective Date:** September 1, 2010

Issued By: Tamie A. Aberle
Pricing & Tariff Manager

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
SEPTEMBER 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		16.8214	12	1,604,156	1.1452
Trans Canada - Demand Charge	7,947		16.6517	12	1,587,973	1.1336
BP Canada - Demand Charge	7,947		0.9612	12	91,664	0.0654
NOVA - Seasonal	5,068		16.8214	5	426,254	0.3043
Trans Canada - Seasonal	5,068		16.6517	5	421,954	0.3012
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					$4,985,341	3.5589
Estimated Weighted Average Commodity Cost	1,400,774	1	3.1468		4,407,956	3.1468
Gas Cost Reconciliation Adjustment						0.3941
Total Current Firm Gas Cost					$9,393,297	7.0998
Base Cost of Gas						5.1849
Accumulated Adjustment						$1.9149
Interruptible						
Estimated Weighted Average Commodity Cost						$3.1468
Gas Cost Reconciliation Adjustment						(0.1136)
Total Current Interruptible Gas Cost						3.0332
Base Cost of Gas						5.1191
Accumulated Adjustment						($2.0859)

1/ Three year normalized average Dk sales.

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

Rates Effective September 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	16.8214	Per dk/Mo.
Trans Canada Pipeline Demand Charge	16.6517	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	16.8214	Per dk/Day
Trans Canada - Seasonal	16.6517	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:	3.1468	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
September 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 September 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).

The domestic supply remaining strong, moderating temperatures midway through the month of August which required less cooling demand and the lack of hurricane activity in the Gulf of Mexico were factors in the projected decrease in natural gas prices. The Energy Information Administration (EIA) reported storage levels nationwide as of August 20, 2010 were 6.2 percent above the five-year average and 6.1 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

August 2010

Short-Term Energy Outlook

August 10, 2010 Release

Highlights

- EIA projects that the West Texas Intermediate (WTI) spot price, which ended July at more than $78 per barrel, will average $81 per barrel in the fourth quarter of 2010 and $84 per barrel in 2011, slightly above the forecasts in last month's *Outlook*.

- EIA expects that regular-grade motor gasoline retail prices, which averaged $2.35 per gallon last year, will average $2.77 per gallon over the second half of 2010, up one cent per gallon from the average for the first half of the year.

- The projected Henry Hub natural gas spot price averages $4.69 per million Btu (MMBtu) this year, a $0.74-per-MMBtu increase over the 2009 average, but virtually unchanged from the forecast in last month's *Outlook*. EIA expects the Henry Hub spot price will average $4.98 per MMBtu in 2011, down $0.19 per MMBtu from last month's *Outlook*.

- The annual average residential electricity price increases 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 11.9 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 3.4 percent and 0.8 percent in 2010 and 2011, respectively, as economic growth spurs higher energy consumption. However, even with these increases, projected emissions remain below their level in any year from 1999 through 2008.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA's view of the world oil market is largely unchanged from last month's *Outlook*. EIA expects world oil prices will rise slowly as

world oil demand increases because of projected global economic growth, slower growth in non-OPEC oil supply, and continued production restraint by members of the Organization of the Petroleum Exporting Countries (OPEC). A gradual reduction in global oil inventories expected over the forecast period also should lend support to firming oil prices.

Global Crude Oil and Liquid Fuels Consumption. Projected world oil consumption increases by 1.6 million barrels per day (bbl/d) in 2010. Countries outside of the OECD, especially China, Saudi Arabia, and Brazil, represent most of the expected growth in world oil consumption (World Liquid Fuels Consumption Chart). Among the OECD countries, only the United States is expected to show significant increases in oil consumption of about 0.15 million bbl/d in both 2010 and 2011. Projected global oil consumption grows by another 1.5 million bbl/d in 2011.

Non-OPEC Supply. EIA's non-OPEC oil supply forecast was raised by 100,000 bbl/d, with an expected 720,000 bbl/d growth in 2010 primarily from the United States, Brazil and Azerbaijan. Forecast non-OPEC production falls for only the third time over a 15-year period, with a 160,000 bbl/d decline in 2011 led by reduced production from Mexico and the North Sea.

OPEC Supply. EIA expects OPEC crude oil production to rise somewhat through 2011 to accommodate increasing world oil demand and to maintain OPEC market objectives. Projected total OPEC petroleum liquids production increases by 1.0 and 1.2 million bbl/d in 2010 and 2011, respectively, with non-crude petroleum liquids expected to increase by 0.6 million bbl/d in 2010 and by 0.7 million bbl/d in 2011. With the remaining OPEC supply reflecting an increase in crude oil production, OPEC surplus crude oil production capacity should remain about 5 million bbl/d, versus 4.3 million bbl/d in 2009 and 1.5 million in 2008 (OPEC Surplus Crude Oil Production Capacity Chart).

OECD Petroleum Inventories. Commercial oil inventories held by OECD countries stood at an estimated 2.75 billion barrels at the end of the second quarter of 2010, equivalent to about 61 days of forward cover, and about 92 million barrels more than the previous 5-year average for the corresponding time of year (Days of Supply of OECD Commercial Stocks Chart). OECD oil inventories are expected to be relatively flat through the forecast period, although days-forward-cover should remain high.

Crude Oil Prices. WTI crude oil spot prices averaged $76.32 per barrel in July 2010 or about $1 per barrel above the prior month's average, and close to the $77 per barrel projected in last month's *Outlook.* EIA projects WTI prices will average about $80 per

barrel over the second half of this year and rise to $85 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 October 2010 delivery for the 5-day period ending August 5 averaged $82 per barrel, and implied volatility averaged 30 percent. This made the lower and upper limits of the 95-percent confidence interval $67 and $100 per barrel, respectively.

Last year at this time, WTI for October 2009 delivery averaged $73 per barrel, and implied volatility averaged 46 percent, with the limits of the 95-percent confidence interval at $54 and $99 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Projected total liquid fuels consumption grows by 140,000 bbl/d (0.7 percent) in 2010 and 170,000 bbl/d (0.9 percent) in 2011 as all of the major petroleum products register consumption growth (U.S. Liquid Fuels Consumption Growth Chart). This reverses the trend of falling consumption over the last 4 years. A year-over-year decline in total liquid fuels consumption averaging 40,000 bbl/d in the first quarter of 2010 was followed by a year-over-year rise in consumption averaging 380,000 bbl/d in the second quarter of 2010, led by increases in motor gasoline and distillate fuel oil consumption. During 2010 as a whole, gasoline and distillate fuel are projected to increase by 0.3 percent and 1.4 percent, respectively. Projected gasoline consumption growth increases to 0.8 percent in 2011 while distillate fuel consumption growth falls slightly to 1.2 percent. Jet fuel consumption grows more slowly, at an average annual rate of about 0.5 percent through 2011, resulting from the drop in air carrier capacity over the last 2 years. Airlines are expected to remain reluctant to expand capacity in the immediate future, relying on increases in utilization rates as air passenger and freight transport recovers from the recession.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production, which increased by 370,000 bbl/d in 2009, is projected to increase by 110,000 bbl/d in 2010 (U.S. Crude Oil Production Chart), led by a 120,000 bbl/d increase in output from the federal Gulf of Mexico (GOM). Crude oil production shut in by hurricanes during June and July averaged 70,000 bbl/d, slightly higher than EIA's original forecast of 50,000 bbl/d for these 2 months. Forecast total domestic crude oil production rises by 30,000 bbl/d to 5.46 million bbl/d in 2011, including a projected 120,000 bbl/d decline in GOM output next year, mostly reflecting EIA's estimates of an average reduction in

crude oil output of about 82,000 bbl/d in 2011 due to the current 6-month moratorium on deepwater drilling.

Projected ethanol production, which averaged 710,000 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 fell from 57 percent to 51 percent of total U.S. consumption between 2008 and 2009, averages 50 percent of total consumption in 2010 and 2011.

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 $2.92 per gallon in 2011. Forecast regular-grade pump prices will average $2.80 per gallon this summer, an increase of 36 cents from last summer. On-highway diesel fuel retail prices, which averaged $2.46 per gallon in 2009, average $2.97 per gallon in 2010 and $3.14 in 2011 in this forecast.

Natural Gas

U.S. Natural Gas Consumption. EIA expects total natural gas consumption will increase by 3.8 percent from 2009 levels to 64.9 billion cubic feet per day (Bcf/d) in 2010 and then remain flat in 2011 (Total U.S. Natural Gas Consumption Growth Chart). Growth in the use of natural gas in both the power generation and industrial sectors accounts for the bulk of the increase in consumption in 2010 over 2009. Use of natural gas for power generation is expected to grow by more than 1 Bcf/d to 20 Bcf/d in 2010, despite a year-over-year increase in natural gas prices. Although the use of natural gas for electric power generation has been on a generally upward trend over the last several years, it is expected to decline slightly in 2011.

EIA estimates natural gas consumption in the electric power sector during the month of July at 29.1 Bcf/d, an upward revision from 27.6 Bcf/d in last month's *Outlook*, and 15 percent higher than last July's 25.2 Bcf/d. The revision accounts for greater air-conditioning demand resulting from a very warm July, which was 36 percent warmer than last year as measured by population-weighted cooling degree-days.

Projected natural gas consumption in the industrial sector also grows significantly in 2010, increasing by almost 7 percent, from 16.8 Bcf/d in 2009 to 17.9 Bcf/d in 2010. Forecast industrial-sector consumption growth slows to 1 percent in 2011 as the projected growth in the natural-gas-weighted industrial production index slows from 7.9 percent in 2010 to 2.3 percent in 2011. Residential and commercial consumption is projected to remain relatively flat over the forecast.

U.S. Natural Gas Production and Imports. EIA expects total marketed natural gas production will increase by 1.1 Bcf/d (1.9 percent) to 61.1 Bcf/d in 2010. Projected production declines gradually in 2011, falling by 0.8 Bcf/d (1.4 percent) as relatively low prices depress drilling activity.

Natural gas production shut in because of hurricanes during June and July was less than EIA had originally projected. The original forecast called for outages totaling 20 Bcf compared with actual outages from Hurricanes Alex and Bonnie in June and July of 8 Bcf. Nevertheless, the next 3 months are typically the height of the hurricane season and additional outages are likely. Based on the May NOAA hurricane forecast, shut-in production from August to October is projected to total 146 Bcf. The offshore drilling moratorium is projected to reduce Gulf of Mexico production by 10 Bcf over the last 6 months of 2010 and 92 Bcf during 2011.

EIA forecasts gross pipeline imports of 9.05 Bcf/d in 2010, an increase of about 0.1 percent from 2009. EIA expects gross pipeline imports of 8.95 Bcf/d in 2011. Forecasted imports of liquefied natural gas (LNG) average 1.35 Bcf/d in 2010 and 1.42 in 2011. Higher LNG prices in European and Asian markets could divert the growing world supply of LNG away from the United States.

U.S. Natural Gas Inventories. On July 30, 2010, working natural gas in storage was 2,948 Bcf (U.S. Working Natural Gas in Storage Chart), 221 Bcf above the 5-year average and 132 Bcf below the level during the corresponding week last year. EIA expects inventories at the end of October to total 3,752 Bcf, slightly below the record level reached at the end of the injection season last year.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $4.63 per MMBtu in July, $0.17 per MMBtu lower than the average spot price in June (Henry Hub Natural Gas Price Chart). The forecast price for the second half of 2010 averages $4.66 per MMBtu, about the same as last month's *Outlook*. A small decline in U.S. production and increased consumption are projected to lead to higher prices in 2011, when the projected Henry Hub spot price averages $4.98 per MMBtu.

Uncertainty over future natural gas prices is lower this year compared with last year at this time. Natural gas futures for October 2010 delivery for the 5-day period ending August 5 averaged $4.74 per MMBtu, and the average implied volatility over the same period was 51 percent. This produced lower and upper bounds for the 95-percent confidence interval of $3.26 and $6.89 per MMBtu, respectively. At this time last year the natural gas October 2009 futures contract averaged $4.16 per MMBtu and implied volatility averaged 80 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $2.32 and $7.47 per MMBtu.

Electricity

U.S. Electricity Consumption. Temperatures during this year's summer season continue to be well above normal in sharp contrast to the mild summer of 2009. Weather has been particularly hot in the Northeast during June and July. Total cooling degree-days during the last 2 months were 54 percent higher than normal in the Mid-Atlantic region and 73 percent higher than normal in New England (U.S. Summer Cooling Degree Days). EIA projects that total consumption of electricity will grow by 4 percent during 2010. Growth is expected to slow to a rate of 0.4 percent in 2011 as summer temperatures are assumed to return to more normal levels (U.S. Total Electricity Consumption Chart).

U.S. Electric Power Sector Generation. The increased need for peaking generation this summer has boosted EIA's projection of growth in natural gas generation to 6 percent in 2010, compared with 5.6 percent in last month's *Outlook.* The level of natural gas generation is expected to fall by 0.7 percent in 2011. According to the American Wind Energy Association, wind power capacity additions slowed considerably during the first half of 2010. EIA forecasts wind capacity to increase by 4.3 gigawatts during 2010, about half the annual increase during the last 2 years. Capacity is forecasted to increase by 6.5 gigawatts in 2011 as the continuing production tax credit and the improved economy spur new additions.

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 are likely to push up retail prices later this year, causing prices over the entire year to grow by about 0.6 percent. Increased fuel costs are expected to push residential prices higher by about 2.9 percent during 2011 (U.S. Residential Electricity Prices Chart).

Coal

U.S. Coal Consumption. Electric-power-sector coal consumption for the first half of 2010 was 4.8 percent higher than the comparable period in 2009, and EIA expects that consumption growth will continue. Projected coal consumption in the electric power sector increases by 5.3 percent in 2010. Despite an expected 0.4 percent increase in electricity consumption in 2011, fossil-fuel-fired electricity generation is projected to decline, primarily because of forecasted increases in hydroelectric and wind generation, and electric-power-sector coal consumption is forecasted remain relatively flat (U.S. Coal Consumption Growth Chart).

U.S. Coal Supply. Drawdowns in both producer (14 percent) and end-user (12 percent) inventories (U.S. Electric Power Sector Coal Stocks Chart) will cause projected coal production to fall by 0.2 percent in 2010. EIA projects a modest 1.8-percent increase in coal production in 2011 (U.S. Annual Coal Production Chart).

U.S. Coal Trade. U.S. coal gross imports and gross exports fell by 34 percent and 28 percent in 2009, respectively. Forecast coal exports grow by 25 percent in 2010, driven in part by rising demand for metallurgical coal in China and other Asian countries. Metallurgical coal currently constitutes a larger share of the U.S. coal export market than steam coal. From January through March 2010, the United States exported 3.1 million short tons of metallurgical coal to China, India, Japan, and South Korea, which was 276 percent higher than in the first quarter of 2009. Forecast coal exports in 2011 are relatively unchanged from 2010 levels.

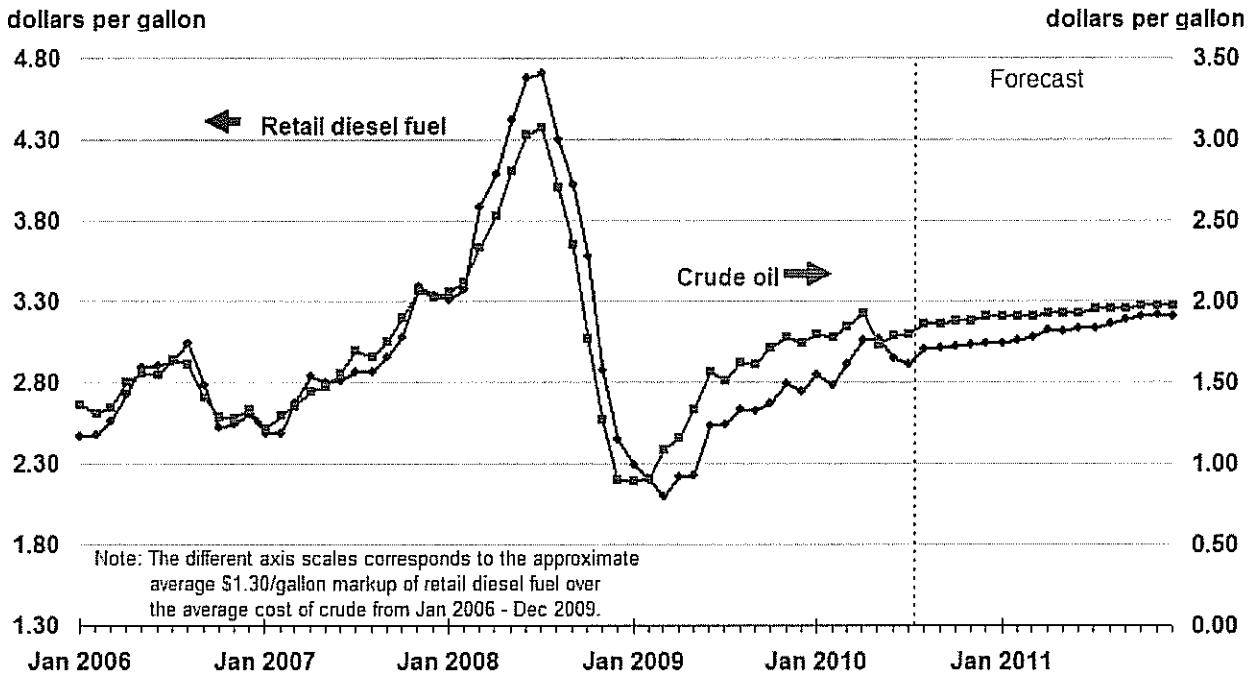
EIA projects coal imports to decline another 15 percent in 2010 as increased consumption is met by draws on domestic inventories. Projected coal imports grow by 35 percent in 2011, but the annual tonnage (26 million short tons) remains significantly below the 2005-through-2008 average of 34 million short tons.

U.S. Coal Prices. The 2009 delivered electric-power-sector coal price increased by 6.7 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 by 1.7 percent to average $2.25 per MMBtu in 2010, and then declines to an average of $2.20 per MMBtu in 2011.

U.S. Carbon Dioxide Emissions

Forecast economic growth combined with increased use of coal and natural gas is expected to contribute to increases in fossil-fuel CO_2 emissions of 3.4 percent in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). Projected coal-related CO_2 emissions increase by 6.0 percent in 2010 primarily a result of increased electricity sector coal usage. Higher natural gas consumption in the industrial and electric power sectors is expected to lead to a 3.9-percent increase in CO_2 emissions from natural gas. Demand for petroleum in the transportation sector (motor gasoline, diesel fuel and jet fuel) combined with continued industrial sector fossil fuel demand growth contribute to the projected 0.8-percent increase in fossil-fuel CO_2 emissions in 2011. However, even with these increases, projected CO_2 emissions in 2010 and 2011 remain below their level in any year from 1999 through 2008.

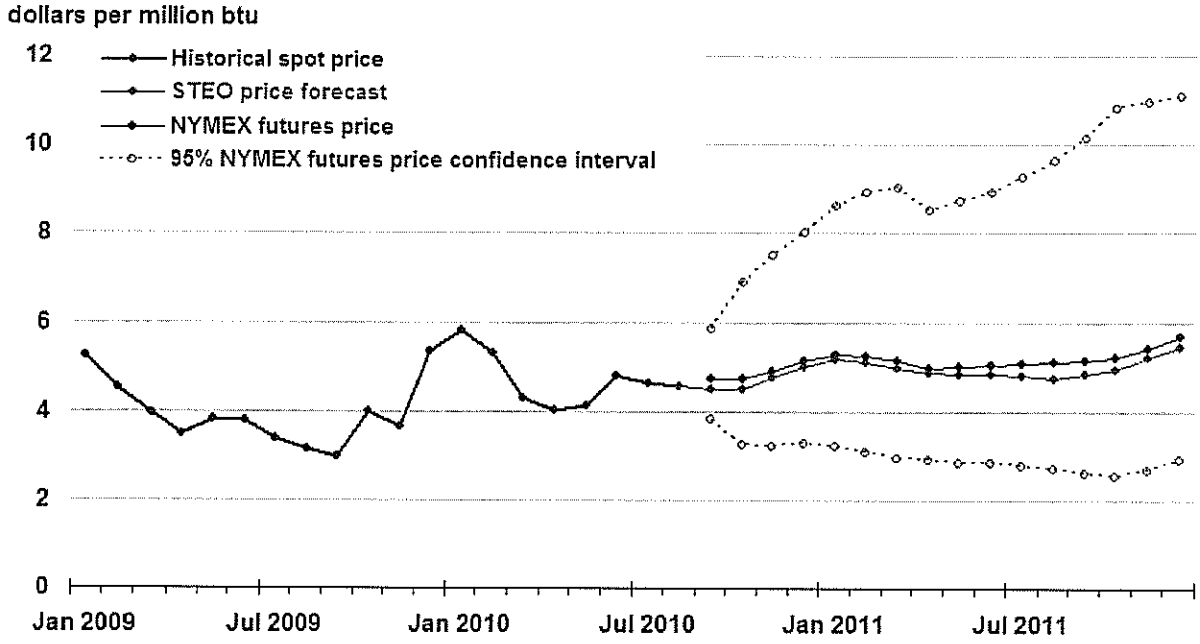
U.S. Diesel Fuel and Crude Oil Prices



U.S. Energy Information Administration

Source: Short-Term Energy Outlook, August 2010

Henry Hub Natural Gas Price

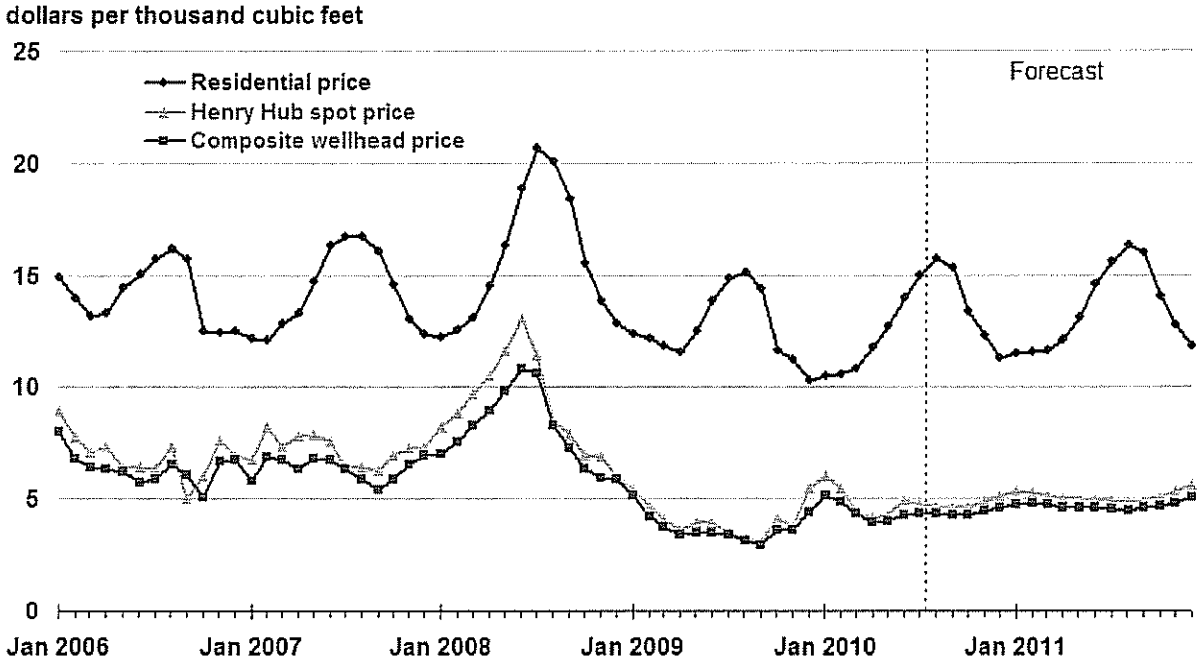


Note: Confidence interval derived from options market information for the 5 trading days ending August 5, 2010
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

U.S. Energy Information Administration

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

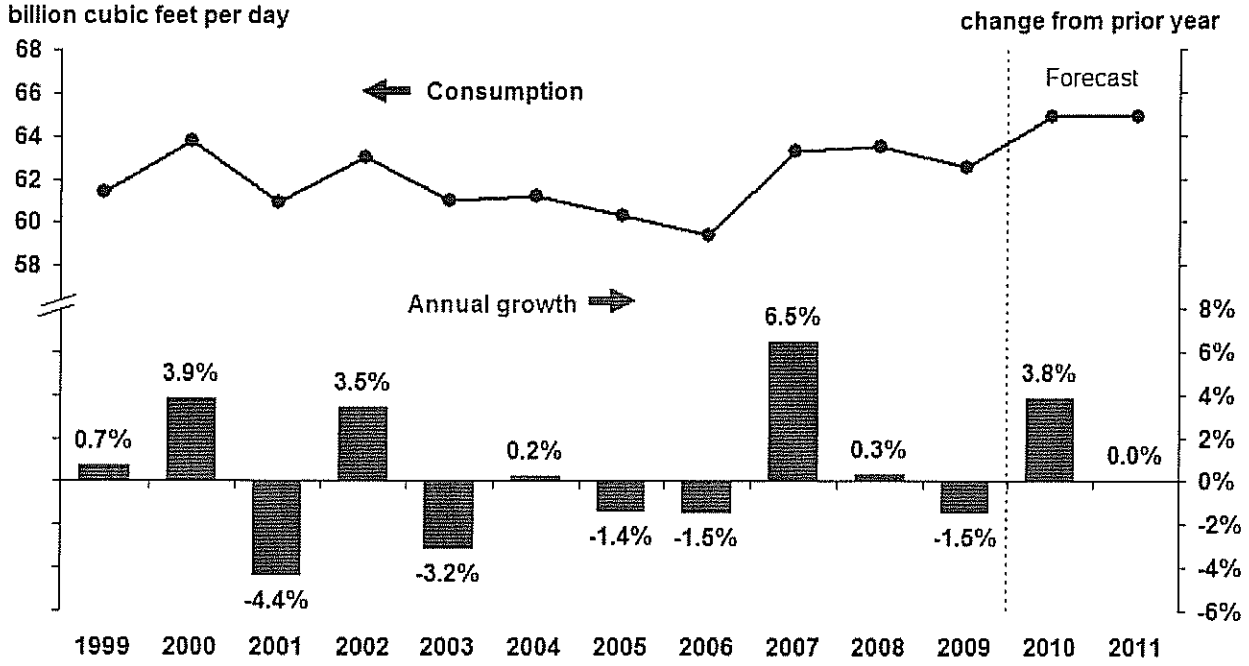
Natural Gas Prices



U.S. Energy Information Administration

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

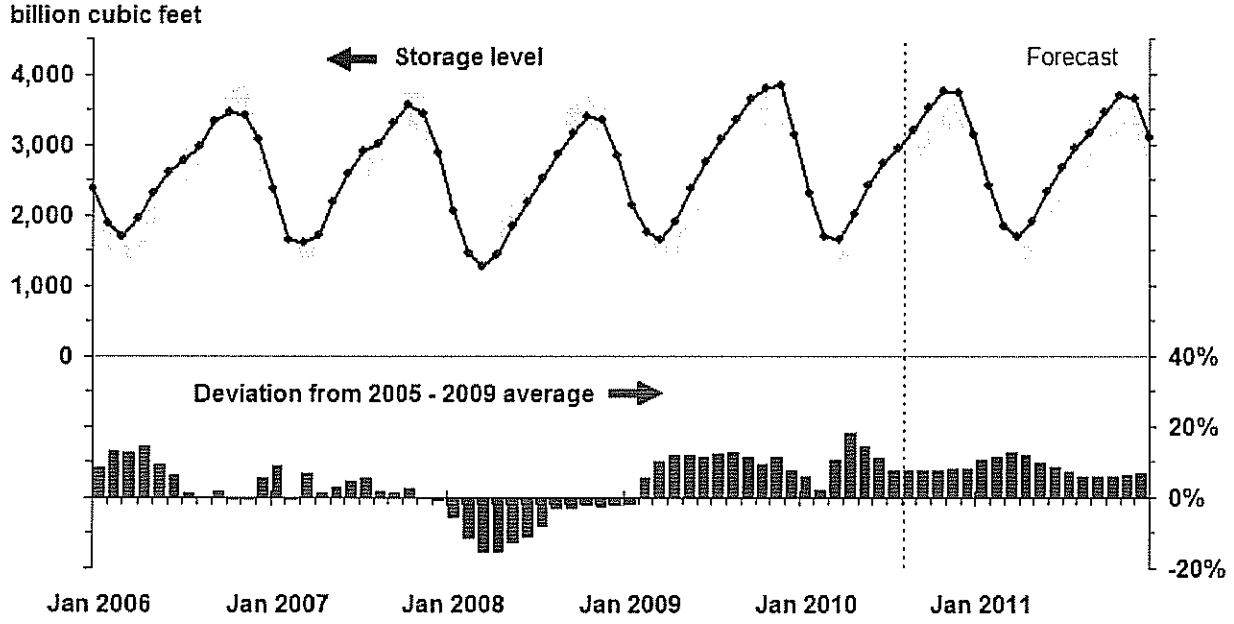
U.S. Total Natural Gas Consumption



U.S. Energy Information Administration

Source: Short-Term Energy Outlook, August 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

Source: Short-Term Energy Outlook, August 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, 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
July	20,585	0	982	21,567	6,200	0.3941	2,444	19,123	171,485
Balance @ July 31, 2010									**$171,485**

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)
July	(8,501)	0	(169)	(8,670)	10,612	(0.1136)	(1,205)	(7,465)	(31,643)
Balance @ July 31, 2010									**($31,643)**

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.