



A Division of MDU Resources Group, Inc.

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January 31, 2011

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

Re: Cost of Gas Adjustment (COG)
February 2011

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 (59th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (59th Revised Sheet No. 8), showing the February 2011 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.0856 per mcf for residential and firm general service customers and \$0.2039 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for February 2011, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.2039 per mcf since the last COG filing due to an increase in the market price of gas. There has been a decrease in pipeline charges of \$0.1183 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of \$0.0856 per mcf for residential and firm general service customers.

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

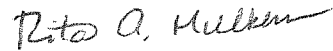
Attachment D shows the calculation of the balancing account since April 30, 2010.

Great Plains submitted a check for \$600.00 on January 10, 2011 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
Regulatory Analysis Manager

Attachments

Attachment A

Attachment A



GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota Gas Rate Schedule

NDPSC Volume 2

59th Revised Sheet No. 1.1

Canceling 58th Revised Sheet No.1.1

RATE SUMMARY SHEET

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/MCF
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF	\$1.2740	\$8.2063	\$9.4803
			Over 10 MCF	1.0540		9.2603
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF	\$1.1391	\$4.0961	\$5.2352
			Next 2,600 MCF	0.8931		4.9892
			Over 3,000 MCF	0.7411		4.8372
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF	\$1.2391	\$4.0961	\$5.3352
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: January 31, 2011

Effective Date: February 1, 2011

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
59th Revised Sheet No. 8
Canceling 58th 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.	3.6695	(1.1278)	0.3941	2.9358	(1.1133)	(0.1136)	(1.2269)
Current Adj.	(0.1183)	0.2039	0.0000	0.0856	0.2039	0.0000	0.2039
Total Adj.	3.5512	(0.9239)	0.3941	3.0214	(0.9094)	(0.1136)	(1.0230)
Total Rate:	\$3.6170	\$4.1952	\$0.3941	\$8.2063	\$4.2097	(\$0.1136)	\$4.0961

Date Filed: January 31, 2011

Effective Date: February 1, 2011

Issued By: Tamie A. Aberle
Pricing & Tariff Manager

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
FEBRUARY 2011**

<u>Firm</u>	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
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	16.9976	12	1,620,959	1.1572
Trans Canada - Demand Charge	7,947	17.2290	12	1,643,026	1.1729
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0654
NOVA - Seasonal	5,068	16.9976	5	430,719	0.3075
Trans Canada - Seasonal	5,068	17.2290	5	436,583	0.3117
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/					0.0145
Total Demand Charges				<u>\$5,046,291</u>	<u>3.6170</u>
Estimated Weighted Average Commodity Cost	1,400,774	1/ 4.1952		<u>5,876,527</u>	4.1952
Gas Cost Reconciliation Adjustment					<u>0.3941</u>
Total Current Firm Gas Cost				<u><u>\$10,922,818</u></u>	<u><u>8.2063</u></u>
Base Cost of Gas					<u>5.1849</u>
Accumulated Adjustment					<u><u>\$3.0214</u></u>
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$4.1952
Gas Cost Reconciliation Adjustment					(0.1136)
LMS Demand 2/					<u>0.0145</u>
Total Current Interruptible Gas Cost					<u>4.0961</u>
Base Cost of Gas					<u>5.1191</u>
Accumulated Adjustment					<u><u>(\$1.0230)</u></u>

1/ Three year normalized average Dk sales.

2/ Amount divided by 2009 interruptibles sales volumes plus three year normalized firm Dk Sales. 2,073,950

	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
LMS Demand	2,500	\$1.0000	12	\$30,000	\$0.0145

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
FEBRUARY 2011**

Rates Effective February 1, 2011	<u>\$/Dk</u>	
FT-A - Zone 1-1	\$3.4671	Per dk/Mo.
FT-A - Zone 1-2	4.5871	Per dk/Mo.
FT-A - Seasonal	3.7671	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
NOVA - Demand Charge	16.9976	Per dk/Mo.
Trans Canada Pipeline Demand Charge	17.2290	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	16.9976	Per dk/Day
Trans Canada - Seasonal	17.2290	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:	4.1952	Per dk

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

Base Rate Calculation

<u>Firm</u>		
Demand 1/	\$0.0658	Per Mcf
Commodity	<u>5.1191</u>	Per Mcf
Total Firm Base Cost	\$5.1849	Per Mcf

<u>Interruptible:</u>		
Commodity	\$5.1191	Per Mcf

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

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

Part 5.0
Statement of Rates
v. 1.0.0

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
<u>Category 1 (Contract Term of Less than 3 Years)</u>	
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
<u>Category 2 (Contract Term of 3 Years to less than 5 Years)</u>	
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
<u>Category 3 (Contract Term of 5 or more Years)</u>	
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

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

Part 5.0
Statement of Rates
v. 1.0.0

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	1.92%
Zone 1-2	\$0.0130	\$0.0019	\$0.0149	2.23%
Zone 2-2	\$0.0130	\$0.0019	\$0.0149	0.31%
Minimum Rate	\$0.0130	\$0.0019	\$0.0149	
IT and AOT				
Zone 1-1	\$0.1368	\$0.0019	\$0.1387	1.92%
Zone 1-2	\$0.1737	\$0.0019	\$0.1756	2.23%
Zone 2-2	\$0.0834	\$0.0019	\$0.0853	0.31%
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: 0.16% for Zone 1-1, 0.18% for Zone 1-2, and 0.02% 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

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

First Revised Sheet No. 50
Superseding
Original Sheet No. 50

RATE SCHEDULE TF

RESERVATION RATES		MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
		TF12 Base	TF12 Variable	TF5	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/		Market Area 3/		Field Mileage 5/		Carlton Surcharge 4/		Out-of Balance 3/		
TF12 Base, TF12 Var., TF5 & TFF	Receipt Point	Maximum	Minimum	Rate per 100 miles	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
	Market	0.0384	0.0215				0.0175	0.0000	0.0384	0.0215
	Field	0.0384	0.0215	0.0122	0.0040		0.0175	0.0000		
	Market			0.0122	0.0040					
	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. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
- 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
Sixth Revised Volume No. 1

First Revised Sheet No. 51
Superseding
Original Sheet No. 51

RATE SCHEDULES TFX and LFT

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

COMMODITY RATES 2/ TFX and LFT		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0384	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/		Commodity 6/		Out-of-Balance 6/	
		Maximum	Minimum	Maximum	Minimum	Maximum	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. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
- 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.

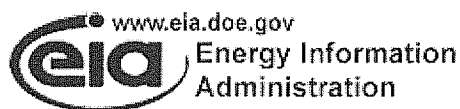
**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
February 2011**

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 February monthly price for the AECO Index is expected to increase 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).

Below normal temperatures over a large portion of the U.S. during the month of January and the corresponding increase in consumption to meet heating demand is the reason for the anticipated increase in the index price. The year over year comparison indicates the anticipated February AECO price will be approximately 20 percent less than the previous year. The Energy Information Administration (EIA) reported storage levels nationwide as of January 21, 2011 were 1.2 percent above the five-year average and 0.4 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 15.



January 2011

Short-Term Energy Outlook

January 11, 2011 Release

Highlights

- This edition of the *Short-Term Energy Outlook* is the first to include forecasts (monthly, quarterly and annual) through December 2012.
- EIA expects the price of West Texas Intermediate (WTI) crude oil to average about \$93 per barrel in 2011, \$14 higher than the average price last year. For 2012, EIA expects WTI prices to continue to rise, with a forecast average price of \$99 per barrel in the fourth quarter 2012. EIA's forecast assumes U.S. real gross domestic product (GDP) grows 2.2 percent in 2011 and 2.9 percent in 2012, while world real GDP (weighted by oil consumption) grows by 3.3 percent and 3.7 percent in 2011 and 2012, respectively.
- EIA expects regular-grade motor gasoline retail prices to average \$3.17 per gallon this year, 39 cents per gallon higher than last year and 3.29 per gallon in 2012, with prices forecast to average about 5 cents per gallon higher in each year during the April through September peak driving season. There is regional variation in the forecast, with average expected prices on the West Coast about 25 cents per gallon above the national average during the April through September period. There is also significant uncertainty surrounding the forecast, with the current market prices of futures and options contracts for gasoline suggesting more than a 25 percent probability that the national average retail price for regular gasoline could exceed \$3.50 per gallon in the June through September period in 2011 and an 8 to 10 percent probability that it could exceed \$4.00 per gallon in August and September 2011.
- Natural gas working inventories ended 2010 at 3.1 trillion cubic feet (Tcf), about 1 percent below the 2009 record-setting end-of-December level. Inventories are expected to remain at or near record-high levels through most of 2011. The projected Henry Hub natural gas spot price averages \$4.02 per million Btu (MMBtu) for 2011, \$0.37 per MMBtu lower than the 2010 average.

EIA expects the natural gas market to begin to tighten in 2012, with the Henry Hub spot price increasing to an average \$4.50 per MMBtu.

- EIA expects average household expenditures for space-heating fuels to total \$990 this winter, about \$22 higher than last year. EIA projects higher expenditures for heating oil and propane, flat expenditures for natural gas, but lower expenditures for electricity. A forecast of milder weather than last winter in the South and the West leads to lower fuel consumption in those areas.
- EIA projects that U.S. carbon dioxide (CO₂) emissions from fossil fuels, which increased by 3.8 percent in 2010, will decline by 0.6 percent in 2011. EIA expects that CO₂ emissions will increase by 2.4 percent in 2012 as consumption grows for all the fossil fuels. Projected fossil-fuel CO₂ emissions in 2012 remain below the levels seen in any year from 2000 through 2008.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA expects a continued tightening of world oil markets over the next 2 years. World oil consumption grows by an annual average of 1.5 million barrels per day (bbl/d) through 2012 while the growth in supply from non-Organization of the Petroleum Exporting Countries (non-OPEC) countries averages less than 0.1 million bbl/d each year. Consequently, EIA expects the market will rely on both inventories and significant increases in production of crude oil and non-crude liquids in OPEC member countries to meet world demand growth. While on-shore commercial oil inventories in the Organization for Economic Cooperation and Development (OECD) countries remained high last year, floating oil storage fell sharply in 2010, and EIA expects OECD oil inventories will decline over the forecast period.

There are many significant uncertainties that could push oil prices higher or lower than expected. Should OPEC not increase production as global consumption recovers, oil prices could be significantly higher than the central forecast. The rate of economic recovery, both domestically and globally, also remains uncertain due to a variety of factors including fiscal issues facing national and sub-national governments, China's efforts to address concerns regarding its growth and inflation rates, and unforeseen production issues.

Global Crude Oil and Liquid Fuels Consumption. World oil consumption grew by an estimated 2.2 million bbl/d in 2010, to 86.6 million bbl/d. This growth more than offset the losses of the previous 2 years and surpassed the 2007 level of 86.3 million bbl/d

reached prior to the economic downturn. EIA expects average global consumption growth over the next 2 years to return to rates seen before the onset of the global downturn in 2008. Forecast global consumption growth averages 1.4 million bbl/d in 2011 and 1.6 million bbl/d in 2012, compared with an average of 1.3 million bbl/d per year from 2000 through 2007. From 2000 through 2007 the non-OECD countries as a group accounted for about three-fourths of total world consumption growth. The non-OECD countries are expected to account for all of the world's growth over the next 2 years, with the largest contributions coming from China, the Middle East, and Brazil (World Liquid Fuels Consumption Chart). Among the OECD regions, EIA expects that only North America will show oil consumption growth over the next 2 years, but it will be offset by continued declines in OECD Europe and Asia.

Non-OPEC Supply. EIA expects non-OPEC crude oil and liquid fuels production to rise by 160,000 bbl/d in 2011 and a further 20,000 bbl/d in 2012. Increases in non-OPEC oil production will be concentrated in a few countries, particularly in China, Brazil, and Canada, where EIA expects each to show annual average production growth of 120,000 to 150,000 bbl/d in 2011 and 2012. Ghana became a new non-OPEC oil producer with the startup of the Jubilee field in December of 2010. Other non-OPEC production is expected to decline. EIA expects Mexico's production will fall by about 200,000 bbl/d in 2011, followed by another production decline of 80,000 bbl/d in 2012. Similarly, the United Kingdom is expected to see production declines of an average 120,000 bbl/d in both 2011 and 2012 since oil production and the discovery of new reserves have not kept pace with the maturation of existing fields.

OPEC Supply. OPEC is not scheduled to meet again until June 2011 to discuss its production targets. Nonetheless, EIA expects that OPEC members' crude oil production will continue to rise over the next 2 years to accommodate increasing world oil consumption, especially with non-OPEC supplies expected to show limited growth. Projected OPEC crude oil production increases by 0.5 and 1.1 million bbl/d in 2011 and 2012, respectively. OPEC non-crude petroleum liquids, which are not subject to production targets, increase by 0.7 million bbl/d in 2011 and by 0.4 million bbl/d in 2012. EIA expects OPEC surplus production capacity will fall from about 4.7 million bbl/d at the end of 2010 to 4.3 million bbl/d at the end of 2012 (OPEC Surplus Crude Oil Production Capacity Chart).

OECD Petroleum Inventories. EIA estimates commercial oil inventories held in the OECD ended 2010 at 2.71 billion barrels, equivalent to about 58 days of forward-cover, and roughly 75 million barrels more than the 5-year average for the corresponding time of year. Projected OECD oil inventories decline over the forecast with days of forward-cover falling from current high levels to closer to the 5-year average by the end of 2012 (Days of Supply of OECD Commercial Stocks Chart).

Crude Oil Prices. WTI crude oil spot prices averaged over \$89 per barrel in December, about \$5 per barrel higher than the November average, as expectations of higher oil demand, combined with unusually cold weather in both Europe and the U.S. Northeast, lifted prices. EIA has raised the first-quarter 2011 WTI spot price forecast by over \$7 per barrel from the last month's *Outlook*, to about \$92 per barrel. WTI spot prices rise to an average \$99 per barrel in the fourth quarter of 2012. Projected WTI spot prices average \$93 per barrel in 2011 and \$98 per barrel in 2012.

Energy price forecasts are uncertain ([Energy Price Volatility and Forecast Uncertainty](#)). WTI futures for March 2011 delivery for the 5-day period ending January 6 averaged \$91 per barrel, and implied volatility averaged 28 percent. This makes the lower and upper limits of the 95-percent confidence interval \$76 per barrel and \$109 per barrel, respectively, for WTI delivered in March 2011. Last year at this time, WTI for March 2010 delivery averaged \$82 per barrel and implied volatility averaged 40 percent, with the limits of the 95-percent confidence interval at \$66 per barrel and \$102 per barrel. Based on futures and options prices over the first week in January, the probability that the monthly average price of WTI crude oil will exceed \$100 per barrel in December 2011 is about 36 percent. Conversely, the probability that the monthly average December 2011 WTI price will fall below \$80 per barrel is about 31 percent.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Preliminary data indicate that total consumption of petroleum and non-petroleum liquid fuels increased by 350,000 bbl/d (1.9 percent) in 2010 ([U.S. Liquid Fuels Consumption Growth Chart](#)). The major sources of consumption growth were distillate fuel oil (diesel fuel and heating oil), which grew by 130,000 bbl/d (3.7 percent), and motor gasoline, which increased by 60,000 bbl/d (0.7 percent). Reflecting the ongoing economic recovery, projected total U.S. liquid fuels consumption in 2011 increases by 160,000 bbl/d (0.8 percent) in 2011 and a further 170,000 bbl/d (0.9 percent), to 19.4 million bbl/d, in 2012. Motor gasoline and distillate fuel account for much of the growth in consumption over the next 2 years.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production, which increased by 150,000 bbl/d in 2010 to 5.51 million bbl/d, declines by 20,000 bbl/d in 2011 and by a further 130,000 bbl/d in 2012 ([U.S. Crude Oil Production Chart](#)). The 2011 forecast includes declines of 50,000 bbl/d in Alaska and 220,000 bbl/d in Federal Gulf of Mexico (GOM) production, which are almost offset by a projected 250,000-bbl/d increase in lower-48 non-GOM production. In 2012, lower-48 non-GOM output increases by 70,000 bbl/d, Alaskan production declines by 20,000 bbl/d, and GOM output decreases by 180,000 bbl/d.

Liquid fuel net imports (including both crude oil and refined products) fell from 57 percent of total U.S. consumption in 2008 to 49.4 percent in 2010, primarily because of the decline in consumption during the recession and rising exports. EIA forecasts that liquid fuel net imports will average 9.6 million bbl/d in 2011 and 9.9 million bbl/d in 2012, about 50 percent and 51 percent of total consumption, respectively.

EIA expects slow growth in fuel ethanol production over the next 2 years. EIA projects that ethanol production will increase by 6 percent (50,000 bbl/d) in 2011, reflecting the startup of several new plants and the restart of some plants that were idled during the recession. EIA projects that ethanol production growth will slow to 1 percent in 2012. Forecast ethanol blending into gasoline exceeds the conventional biofuels component of the Renewable Fuels Standard (RFS) in both 2011 and 2012.

U.S. Petroleum Product Prices. Projected regular-grade gasoline retail prices rise from an average of \$2.78 per gallon in 2010 to \$3.17 per gallon in 2011 and \$3.29 per gallon in 2012. On-highway diesel fuel retail prices, which averaged \$2.99 per gallon in 2010, average \$3.40 per gallon and \$3.52 per gallon in 2011 and 2012, respectively. Rising crude oil prices are the primary reason for higher retail prices, but higher gasoline and distillate refining margins are also expected to contribute to higher retail prices.

The projected monthly average regular gasoline price peaks this year at \$3.27 per gallon in July. New York Harbor RBOB (Reformulated Blendstock for Oxygenate Blending) futures contracts for July 2011 delivery for the 5-day period ending January 6 averaged \$2.52 per gallon and implied volatility averaged 29 percent. The probability the RBOB futures price will exceed \$2.80 per gallon (and the retail price exceed \$3.50 per gallon) in July 2011 is about 26 percent. The probability the RBOB futures price will exceed \$3.30 per gallon (and the retail price exceed \$4.00 per gallon) in July 2011 is about 7 percent.

Natural Gas

U.S. Natural Gas Consumption. EIA expects total natural gas consumption to decline by 0.9 percent in 2011. Projected residential and commercial consumption fall by about 2.7 percent in 2011 partly because of the forecast of 1.3 percent fewer heating degree-days during the winter months this year compared with last year, but also because of recent changes in the way EIA collects and reports natural gas consumption data (see *Changes in Natural Gas Monthly Consumption Data Collection and the Short-Term Energy Outlook*). Forecast natural gas consumption in the electric power sector falls by 1.0 percent in 2011 because of the forecast return to near-normal summer weather compared with the very warm summer last year. Forecast cooling

degree-days fall by 16 percent, from 1,468 in 2010 to 1,234 in 2011. Only industrial sector natural gas consumption rises in 2011, by 1.1 percent, because of the 1.2 percent increase in the natural-gas-weighted industrial production index.

Total natural gas consumption grows by 1.6 percent in 2012 to 66.5 billion cubic feet per day (Bcf/d). While projected commercial and residential consumption decline by a slight 0.2 percent from 2011 to 2012, the electric power and industrial sectors drive growth with projected increases of 3.6 and 1.6 percent, respectively.

U.S. Natural Gas Production and Imports. Total marketed natural gas production increased significantly in 2010, by an estimated 2.4 Bcf/d, or 4.1 percent. Declines in production of 0.07 Bcf/d and 0.46 Bcf/d in Alaska and the GOM, respectively, were offset by a 2.9 Bcf/d increase in lower-48 onshore production. EIA expects average total production to fall by 0.3 percent in 2011. The latest EIA data for monthly natural gas production, which are for October 2010, showed a slight decline in the lower-48 states from the previous month. EIA expects this gradual decline to continue throughout 2011 because of a falling drilling rig count in response to lower prices. The number of rigs drilling for natural gas reported by Baker Hughes Inc. increased from a low of 665 in July 2009 to 973 in April 2010. Over the following 6 months the natural gas rig count stayed relatively unchanged, but in the last several weeks the rig count has fallen and ended December 2010 at 919 rigs, a level not seen since February 2010. The large price difference between petroleum liquids and natural gas on an energy-equivalent basis contributes to an expected shift towards drilling for liquids.

The December 2010 *Natural Gas Monthly* contains extensive revisions to estimated production in 2008, 2009, and much of 2010. These changes have reduced the annualized balancing items for those years. EIA's forecast has been updated to reflect these new estimates. EIA has adjusted the forecast for natural gas production in last month's *Outlook* downward by about 0.5 Bcf/d to reflect the revised estimates.

The projected decline in production in 2011 and increase in natural gas consumption in 2012 contribute to a strengthening of natural gas prices late in this year and next. As natural gas prices begin to rise, forecast production rebounds in 2012, growing by 2.2 percent. Projected total marketed production averages 64.2 Bcf/d in December 2012 compared with 62.3 Bcf/d and 60.6 Bcf/d in December 2010 and December 2011, respectively.

EIA expects gross pipeline imports of 8.6 Bcf/d in 2011 and 8.2 Bcf/d in 2012, year-over-year decreases of 4.3 and 4.4 percent, respectively. Canadian gas will become less competitive as new U.S. pipelines and increased lower-48 production with lower transport costs displace imports. Projected liquefied natural gas (LNG) imports

average 1.1 Bcf/d in 2011, a 4.7-percent decrease from 2010 levels. Imports in 2012 grow modestly to 1.2 Bcf/d. High domestic production, high inventories, and low U.S. prices relative to European and Asian markets should continue to discourage LNG imports into North America.

U.S. Natural Gas Inventories. On January 6, 2011, working natural gas in storage stood at 3,097 Bcf, slightly below last year's level at this time ([U.S. Working Natural Gas in Storage Chart](#)). At the end of the winter heating season (March 31, 2011), EIA expects about 1,774 Bcf of working natural gas will remain in storage, a record high and well above last year's level of 1,662 Bcf. The forecast higher inventory is primarily the result of both the current high natural gas production rates and about 4 percent fewer heating degree-days during the first quarter 2011 compared with the same period last year. EIA expects record high inventories to continue through most of 2011, with falling production to bring inventories back into their historical range next year.

U.S. Natural Gas Prices. The Henry Hub spot price averaged \$4.25 per MMBtu during December, an increase of about 54 cents from November's price of \$3.71 per MMBtu ([Henry Hub Natural Gas Price Chart](#)). EIA expects the higher forecast production during the first half of 2011 compared with the same period last year, combined with a decline in consumption, to moderate natural gas spot prices. The projected spot price falls to a low of \$3.73 per MMBtu in June then rises to \$4.61 in December, averaging \$4.02 per MMBtu for all of 2011, which is \$0.37 per MMBtu lower than the 2010 average and \$0.31 per MMBtu lower than in last month's *Outlook*. In 2012, the spot price rises to an average of \$4.50 per MMBtu.

Uncertainty over future natural gas prices is slightly lower this year compared with last year at this time. Natural gas futures for March 2011 delivery (for the 5-day period ending January 6) averaged \$4.39 per MMBtu, and the average implied volatility over the same period was 43 percent. This produced lower and upper bounds for the 95-percent confidence interval for March 2011 contracts of \$3.21 per MMBtu and \$6.02 per MMBtu, respectively. At this time last year, the natural gas March 2010 futures contract averaged \$5.73 per MMBtu and implied volatility averaged 57 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.88 per MMBtu and \$8.47 per MMBtu.

Electricity

U.S. Electricity Consumption. EIA expects total U.S. consumption of electricity to fall slightly during 2011 and then grow by 2.6 percent in 2012 ([U.S. Total Electricity Consumption Chart](#)). EIA estimates that retail sales of electricity to the residential

sector rose by 6.1 percent in 2010 as a result of a relatively cold winter in the Southeast and a very warm summer east of the Rocky Mountains. Based on the forecast return to more normal temperatures, residential electricity sales fall by 2.1 percent during 2011. Forecast growth in manufacturing output should lead to increases in industrial sector electricity sales of 1.5 percent this year and 2.2 percent in 2012.

U.S. Electricity Generation. Projected total electricity generation decreases by 0.3 percent in 2011, following a 4.0 percent increase in 2010. A forecast 6.0-percent increase in conventional hydropower generation during 2011 (due to an assumed return to near-normal precipitation levels) and a 13-percent increase in generation from other renewable sources, mostly wind, lead to a 2.4-percent reduction in coal-fired generation and a 1.0-percent decline in natural gas generation. During 2012, EIA expects a 2.6-percent increase in total electric power sector generation, which will be fueled primarily by increased generation from coal, natural gas, and non-hydropower renewables ([U.S. Electric Power Sector Generation Growth Chart](#)).

U.S. Electricity Retail Prices. EIA expects the U.S. retail price for electricity distributed to the residential sector during 2010 to average 11.6 cents per kilowatt-hour, about the same level as in 2009. EIA expects the U.S. residential price to increase only slightly over the forecast period--by 0.6 percent in 2011 and by 1.0 percent in 2012 ([U.S. Residential Electricity Prices Chart](#)).

Coal

U.S. Coal Consumption. EIA estimates that coal consumption in the electric power sector grew by nearly 5.0 percent in 2010, primarily the result of higher electricity consumption because of the very warm summer. EIA projects that coal consumption in the electric power sector will decrease by 1.1 percent in 2011 as increases in generation from hydropower and other renewable energy sources back out coal. In 2012, projected electricity generation increases by 2.7 percent and coal consumption in the electric power sector grows by 3.6 percent ([U.S. Coal Consumption Growth Chart](#)).

U.S. Coal Supply. Coal production for the first 6 months of 2010 fell by 2.5 percent despite a 5.5-percent increase in U.S. coal consumption. A drawdown in stocks, particularly in the electric power sector, met the demand increase ([U.S. Electric Power Sector Coal Stocks Chart](#)). Estimated coal production increases in the second half of 2010 contribute to 2010 annual growth of 1.0 percent. EIA projects coal production in 2011 will remain relatively flat as coal consumption shows little change ([U.S. Annual Coal Production Chart](#)). The projected increase in coal consumption in 2012 leads to a forecast 4.1 percent increase in coal production.

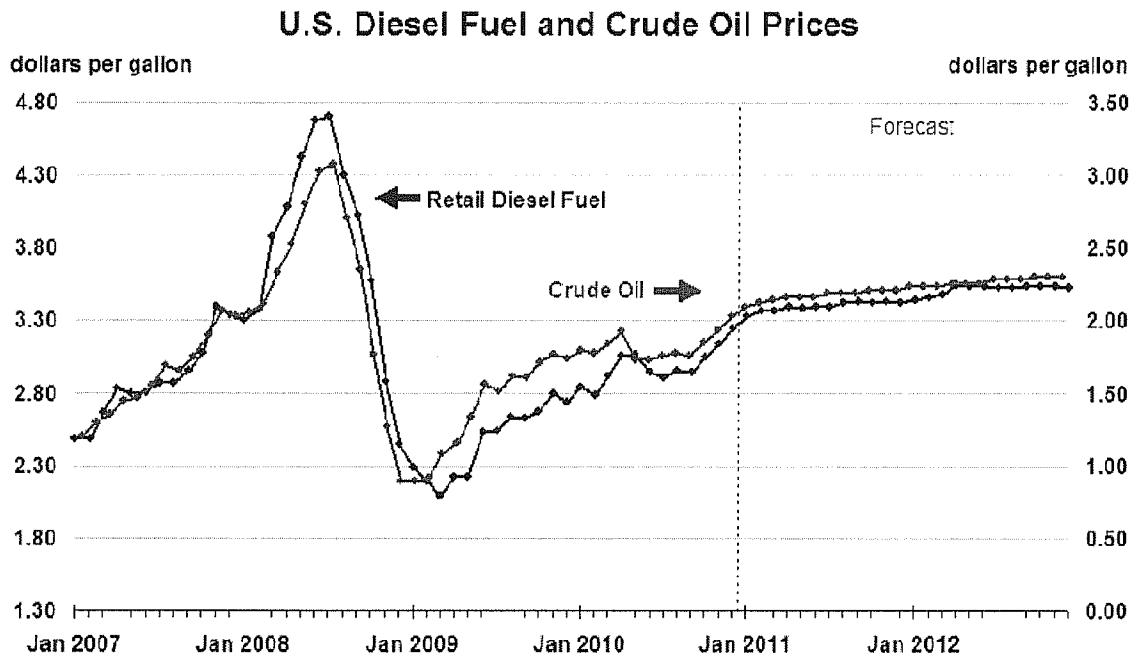
U.S. Coal Trade. Strong global demand for coal, particularly metallurgical coal used to produce steel, has resulted in sharp increases in U.S. coal exports in 2010 to an average 7.3 percent of production. Metallurgical coal exports nearly doubled in the first half of 2010 compared with the first half of 2009, and metallurgical coal's share of total coal exports has grown from 52 percent in 2008 to about 70 percent in 2010. Metallurgical coal exports to Asia and Europe accounted for nearly 90 percent of the increase, with significant increases to China, the Netherlands, Turkey, Japan and South Korea. EIA expects total U.S. coal exports to stay near current levels in 2011 and 2012 as other major coal-exporting countries increase their supply to the global coal market.

U.S. Coal Prices. Coal prices have been rising relatively steadily over the last 10 years reflecting longer-term power sector coal contracts initiated during a period of high energy prices, rising transportation costs, increased consumption, and increases in spot coal prices. However, EIA expects that the power sector coal price will show little change over 2011 and 2012 as coal competes with natural gas for market share in the power sector. The projected power sector delivered coal price, which averaged \$2.26 per MMBtu in 2010, averages \$2.24 per MMBtu in both 2011 and 2012.

U.S. Carbon Dioxide Emissions

EIA estimates fossil-fuel CO₂ emissions increased by 3.8 percent in 2010 ([U.S. Carbon Dioxide Emissions Growth Chart](#)). Coal- and natural gas-related CO₂ emissions rose as a result of increased usage of both fuels for electricity generation and higher consumption of natural gas in the industrial sector.

Projected declines in fossil fuel consumption in the electric power sector in 2011 more than offset increased consumption of petroleum in the transportation sector (i.e., motor gasoline, diesel fuel, and jet fuel). Consequently, forecast fossil-fuel CO₂ emissions fall by 0.6 percent in 2011. The forecast resumption of growth in electricity generation and improvement in economic growth in 2012 contribute to a 2.4-percent increase in fossil-fuel CO₂ emissions. Projected fossil-fuel CO₂ emissions in 2012 remain below the levels seen since 1999 and 4.4 percent below 2005 emissions.



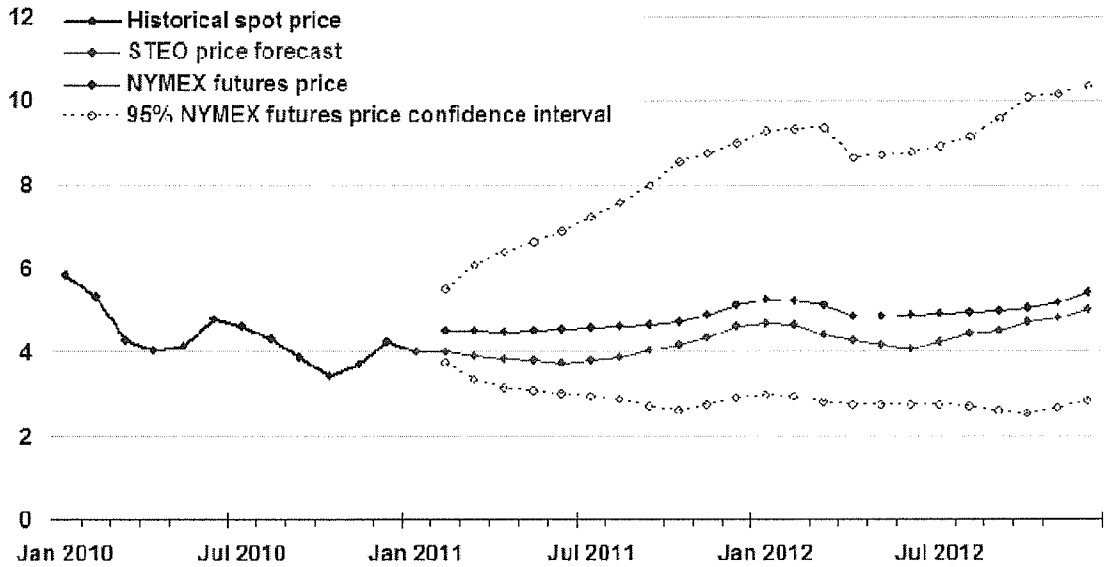
Crude oil price is refiner average acquisition cost. Retail prices include State and Federal taxes.

Source: Short-Term Energy Outlook, January 2011



Henry Hub Natural Gas Price

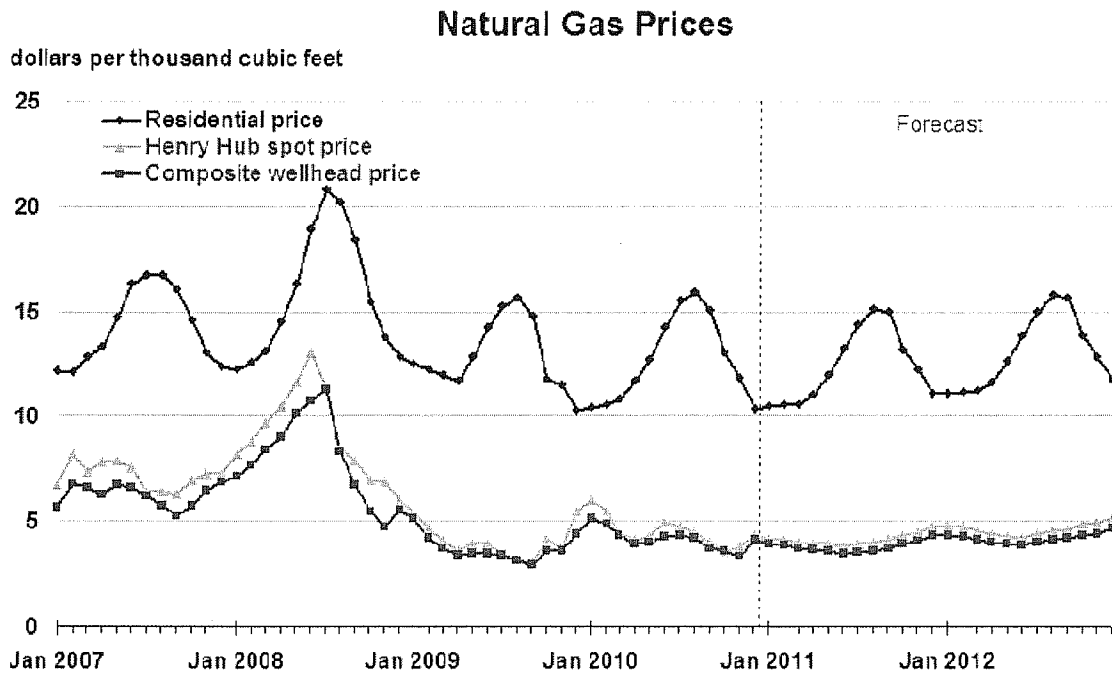
dollars per million btu



*Note: Confidence interval derived from options market information for 5 trading days ending January 6, 2011
Intervals not calculated for months with sparse trading in "near-the-money" options contracts*

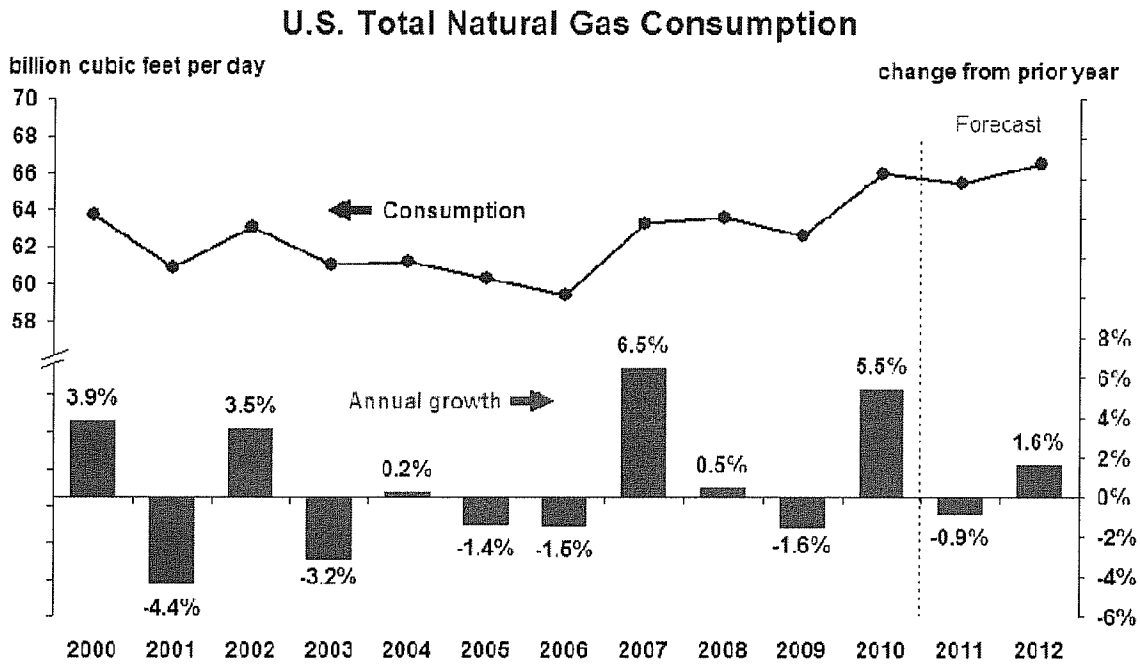
Source: Short-Term Energy Outlook, January 2011





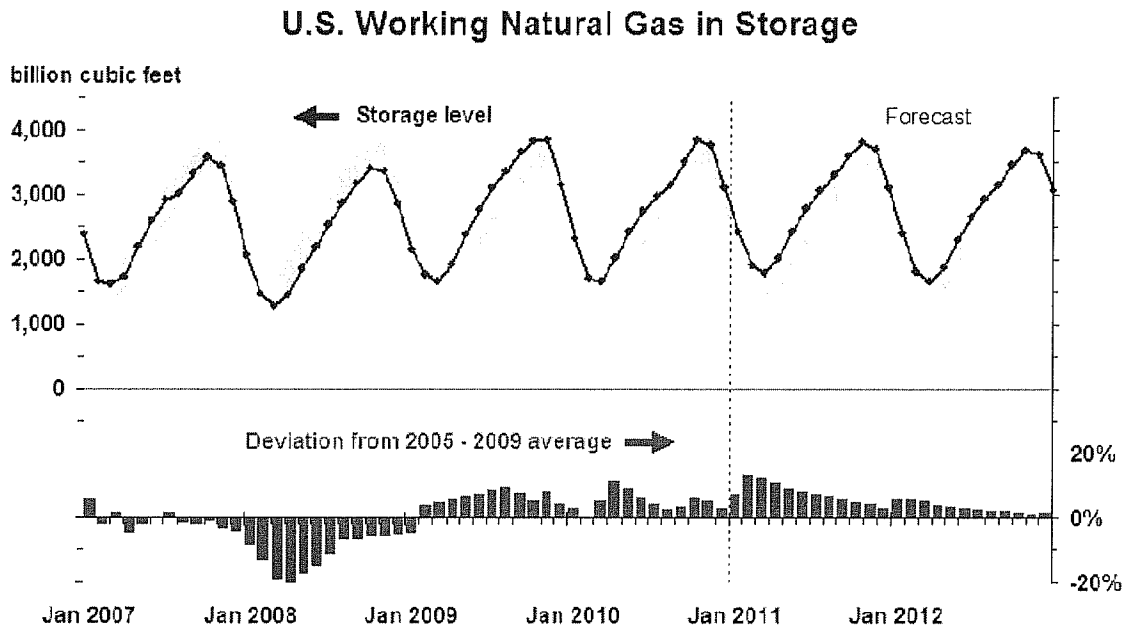
Source: Short-Term Energy Outlook, January 2011





Source: Short-Term Energy Outlook, January 2011





Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2006 - Dec. 2010

Source: Short-Term Energy Outlook, January 2011



**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									<u>\$114,988</u>
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
August	86,747	0	1,115	87,862	5,953	0.3941	2,347	85,515	257,000
September	92,220	0	1,725	93,945	6,368	0.3941	2,509	91,436	348,436
October	34,666	0	2,373	37,039	8,070	0.3941	3,181	33,858	382,294
November	23,805	0	2,602	26,407	17,808	0.3941	7,018	19,389	401,683
December	(6,120)	0	2,728	(3,392)	38,100	0.3941	15,015	(18,407)	383,276
Balance @ December 31, 2010									<u>\$383,276</u>

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**

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ April 30, 2010									<u>(\$30,590)</u>
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)
August	(1,507)	0	(224)	(1,731)	9,466	(0.1136)	(1,075)	(656)	(32,299)
September	422	0	(230)	192	13,953	(0.1136)	(1,585)	1,777	(30,522)
October	4,873	0	(219)	4,654	26,958	(0.1136)	(3,062)	7,716	(22,806)
November	4,335	0	(170)	4,165	36,122	(0.1136)	(4,104)	8,269	(14,537)
December	6,272	0	(119)	6,153	29,056	(0.1136)	(3,301)	9,454	(5,083)
Balance @ December 31, 2010									<u>(\$5,083)</u>

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).