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

705 West Fir Ave.
PO Box 176
Fergus Falls, MN 56538-0176
(218) 736-6935

November 1, 2011

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

Re: Cost of Gas Adjustment (COG)
November 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 (68th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (68th Revised Sheet No. 8), showing the November 2011 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.5395 per mcf for residential and firm general service customers and a decrease of $0.4060 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for November 2011, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.4060 since the last COG filing. There has been a decrease in pipeline charges of $0.1335 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of $0.5395 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, 2011.

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 Affairs 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
68th Revised Sheet No. 1.1
Canceling 67th 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	$8.0490	$9.3230
			Over 10 MCF	1.0540		9.1030
Firm Gas Service - General Highway 13	2.5	$3.50 per month	First 10 MCF	$2.1740	$8.0490	$10.2230
			Over 10 MCF	1.9540		10.0030
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.4622	$4.6013
			Next 2,600 MCF	0.8931		4.3553
			Over 3,000 MCF	0.7411		4.2033
Interruptible Gas Service - Highway 13	3.5	$3.50 per month	First 400 MCF	$2.0391	$3.4622	$5.5013
			Next 2,600 MCF	1.7931		5.2553
			Over 3,000 MCF	1.6411		5.1033
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.4622	$4.7013
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: November 1, 2011 **Effective Date:** November 1, 2011

Issued By: Tamie A. Aberle
Regulatory Affairs 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
68th Revised Sheet No. 8
Canceling 67th 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.	4.1410	(1.2476)	0.5102	3.4036	(1.2331)	(0.0178)	(1.2509)
Current Adj.	(0.1335)	(0.4060)	0.0000	(0.5395)	(0.4060)	0.0000	(0.4060)
Total Adj.	4.0075	(1.6536)	0.5102	2.8641	(1.6391)	(0.0178)	(1.6569)
Total Rate:	$4.0733	$3.4655	$0.5102	$8.0490	$3.4800	($0.0178)	$3.4622

Date Filed: November 1, 2011 **Effective Date:** November 1, 2011

Issued By: Tamie A. Aberle
Regulatory Affairs Manager

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
NOVEMBER 2011

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A	7,841		$3.4671	12	$326,226	$0.2325
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	0.0736
FT-A Seasonal	2,000		3.7671	5	37,671	0.0268
TFX Seasonal	2,000		15.1530	5	151,530	0.1080
NOVA - Demand Charge	7,947		17.0040	12	1,621,569	1.1557
Trans Canada - Demand Charge	7,947		23.3799	12	2,229,601	1.5891
BP Canada - Demand Charge	7,947		0.9612	12	91,664	0.0653
NOVA - Seasonal	5,068		17.0040	5	430,881	0.3071
Trans Canada - Seasonal	5,068		23.3799	5	592,447	0.4222
BP Canada - Seasonal	5,068		0.9612	5	24,357	0.0174
BP Canada Winter Surcharge	5,068		3.0417	5	77,077	0.0549
LMS Demand 2/						0.0145
Total Demand Charges					$5,694,901	4.0733
Estimated Weighted Average Commodity Cost	1,403,100	1/	3.4655		4,862,443	3.4655
Gas Cost Reconciliation Adjustment						0.5102
Total Current Firm Gas Cost					$10,557,344	8.0490
Base Cost of Gas						5.1849
Accumulated Adjustment						$2.8641

Interruptible	
Estimated Weighted Average Commodity Cost	$3.4655
Gas Cost Reconciliation Adjustment	(0.0178)
LMS Demand 2/	0.0145
Total Current Interruptible Gas Cost	3.4622
Base Cost of Gas	5.1191
Accumulated Adjustment	($1.6569)

1/ Three year normalized average Dk sales.
2/ Amount divided by 2008-2010 average interruptible sales volumes plus 2008-2010 average normalized firm sales volumes.

	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
LMS Demand	2,500	$1.0000	12	$30,000	$0.0145

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
NOVEMBER 2011

Rates Effective November 1, 2011	$/Dk	
FT-A - Zone 1-1	$3.4671	Per dk/Mo.
FT-A - Zone 1-2	4.5871	Per dk/Mo.
FT-A - Seasonal	3.7671	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
NOVA - Demand Charge	17.0040	Per dk/Mo.
Trans Canada Pipeline Demand Charge	23.3799	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	17.0040	Per dk/Day
Trans Canada - Seasonal	23.3799	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:	3.4655	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	$0.0018	$0.0148	1.47%
Zone 1-2	$0.0130	$0.0018	$0.0148	1.98%
Zone 2-2	$0.0130	$0.0018	$0.0148	0.51%
Minimum Rate	$0.0130	$0.0018	$0.0148	
IT and AOT				
Zone 1-1	$0.1368	$0.0018	$0.1386	1.47%
Zone 1-2	$0.1737	$0.0018	$0.1755	1.98%
Zone 2-2	$0.0834	$0.0018	$0.0852	0.51%
Minimum Rate	$0.0130	$0.0018	$0.0148	

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of $0.0018 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: 0.17% for Zone 1-1, 0.22 % for Zone 1-2, and 0.05% 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		$0.0265	

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

Third Revised Sheet No. 50
Superseding
Second Revised Sheet No. 50

RATE SCHEDULE TF

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

COMMODITY RATES 2/ TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0382	0.0213			0.0175	0.0000	0.0382	0.0213
Field	Market	0.0382	0.0213	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0294	0.0108

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 $0.0018 and the Market Area Electric Compression charge of $0.0005 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

Third Revised Sheet No. 51
Superseding
Second 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	0.0382	0.0213			0.0175	0.0000	0.0382	0.0213
Field	Market	0.0382	0.0213	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0294	0.0108

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	0.0018	0.0018	0.0018	0.0018
MOPS Transmission	1.5337	0.0000	0.0018	0.0018	0.0018	0.0018
Tivoli - Downstream	0.6827	0.0000	0.0018	0.0018	0.0018	0.0018
Other Gulf Coast	4.8169	0.0000	0.0018	0.0018	0.0018	0.0018

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 $0.0018 and the Market Area Electric Compression charge of $0.0005 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 $0.0018.

RATE SCHEDULES TF, TFX, LFT, GST, TI, & FDD

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.85%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.20% 4/ 5/
FDD Storage Fuel	1.21%

	Electric Compression
COMMODITY RATES:	1/
Market Area	$0.0005
Field Area	$0.0000

1/ Northern will adjust its Fuel percentages and electric compression commodity rates in accordance with Sections 53A and 53B, respectively, of the General Terms and Conditions of this Tariff.

2/ Fuel shall be determined by Mileage Indicator Districts (MIDS) for the Field Area.

3/ Fuel charged in the Field and Market Areas for a pooling transaction or for processing plant transactions will not exceed the fuel charged on a unified Field-to-Market transaction having the same initial Field receipt point and ultimate Market delivery point, i.e., the total fuel collected for transactions that go into and out of pooling points or processing plants in either the Field Area or the Market Area will be no greater than the fuel collected on the total path between the original receipt point and the ultimate delivery point, subject to the shipper(s) providing Northern the requisite information.

4/ The Unaccounted For percentage utilizes the most recent twelve-month period ending December 31, 2010.

5/ Sheet No. 54A identifies the specific transportation transactions exempt from fuel and unaccounted-for retention charges.

6/ The Out-of-Balance Fuel Percentage for deliveries in MIDS 1-7 shall be the applicable Section 1 Mainline Fuel percentage, and for deliveries in MIDS 8-16B shall be the applicable Section 2 Mainline Fuel percentage.

In the event facilities have been abandoned, Northern shall have the right to file to reduce the applicable MID fuel percentage(s) on a common basis for all transactions affected by the abandonment to reflect the reduction in use for the remainder of the PRA period. In the event such abandoned facilities (gas compressors) have been replaced with electric compressors installed after October 1, 1998, and Northern reduces the applicable MID fuel percentages, Northern has the right to file to increase the applicable electric compression commodity rate.

RATE SCHEDULES FDD, PDD, IDD & SMS

Rate Schedule FDD		
Maximum Reservation Fee	1.7140	1/
Maximum Capacity Fee	0.3567	1/
Injection Charge - Firm	0.0149	
Withdrawal Charge - Firm	0.0149	
Annual Rollover Fee	0.3567	1/
Rate Schedule PDD		
Maximum Capacity Fee	0.3567	1/
Maximum Monthly Inventory Charge	0.0887	1/
Injection Charge	0.0149	
Withdrawal Charge	0.0149	
Annual Rollover Fee	0.3567	1/
Rate Schedule IDD		
Maximum Monthly Inventory Charge	0.0887	1/
Injection Charge	0.0149	
Withdrawal Charge	0.0149	
Annual Rollover Fee	0.3567	1/
Rate Schedule SMS		
Reservation Fee	2.1800	
Commodity Rate	0.0208	

1/ Minimum Rate is zero.

Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
November 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 November 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 transition into the winter heating season and mild temperatures across much of the US during this period resulted in continued strong injections into storage. Near record levels of gas in storage and strong domestic supply likely contributed to decrease in the price of the monthly index. The Energy Information Administration (EIA) reported storage levels nationwide as of October 21, 2011 were 4.4 percent above the five-year average and 0.7 percent below last year's record 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 16.

Independent Statistics & Analysis
U.S. Energy Information Administration

October 2011

Short-Term Energy and Winter Fuels Outlook

October 12, 2011 Release

Highlights

- EIA projects average household heating expenditures for natural gas, propane, and heating oil will increase by 3 percent, 7 percent, and 8 percent, respectively, this winter (October 1 to March 31) compared with last winter, while electricity heating expenditures fall by less than 1 percent. Average expenditures for households that heat with oil are forecast to be higher than in any previous winter.

- This forecast reflects higher prices for natural gas, propane, and heating oil, and slightly milder weather than last winter in much of the Nation contributing to lower consumption in many areas (see EIA Short Term Energy and Winter Fuels Outlook slideshow).

- According to the National Oceanic and Atmospheric Administration's (NOAA) most recent projection of heating degree-days, the lower-48 States are forecast to be 2 percent warmer during the October through March winter heating season compared with last winter. However, heating degree-day projections vary widely among regions, with the West projected to be about 3 percent colder than last winter, and the South projected to be about 5 percent warmer.

- Forecast U.S. real gross domestic product (GDP) grows by 1.5 percent this year and by 1.8 percent next year, slightly lower than in last month's *Outlook*. World oil-consumption-weighted real GDP grows by 3.0 percent and 3.5 percent in 2011 and 2012, respectively, compared with 3.1 percent and 3.8 percent in the last *Outlook*. EIA expects the U.S. average refiner acquisition cost of crude oil to average $99 per barrel in 2011 and $98 per barrel in 2012, compared with $100 per barrel and $103 per barrel, respectively, in the previous *Outlook*.

- Natural gas working inventories ended September 2011 at 3.4 trillion cubic feet (Tcf), about 2.6 percent, or 91 billion cubic feet (Bcf), below the 2010 end-of-September level. EIA expects that working natural gas inventories will approach last year's high levels by the end the injection season. The projected

Henry Hub natural gas spot price averages $4.15 per million British thermal units (MMBtu) in 2011, $0.24 per MMBtu lower than the 2010 average. EIA expects the rate of growth in domestic natural gas production to slow in 2012, with the Henry Hub spot price averaging $4.32 per MMBtu.

Projected Winter Fuel Expenditures by Fuel and Region

The average household winter heating fuel expenditures discussed in this *Outlook* provide a broad guide to changes compared with last winter, but fuel expenditures for individual households are highly dependent on local weather conditions, market size, the size and energy efficiency of individual homes and their heating equipment, and thermostat settings (see Winter Fuels Outlook table).

Natural Gas. EIA expects households heating with natural gas to spend an average of $19 (3 percent) more this winter than last winter. About one-half of U.S. households utilize natural gas as their primary heating fuel. The increase in natural gas expenditures represents a 4-percent increase in prices and a 1-percent decrease in consumption. In the Midwest, where 71 percent of households use natural gas as the primary heating fuel, average household expenditures are expected to be unchanged from last winter. The projected changes in residential natural gas prices this winter range from a 2 percent decline in the West to a 10 percent increase in the South. Price changes vary across regions because of a number of factors such as regional changes in production and pipeline supply capacity and differences in regulatory constraints in passing price changes through to customers.

Heating Oil. EIA expects households heating primarily with heating oil to spend an average of about $193 (8 percent) more this winter than last winter as a result of a 10-percent increase in prices and a 1-percent decrease in consumption. About 6 percent of U.S. households depend on heating oil for winter fuel; however, the Northeast accounts for about 80 percent of these households. EIA projects residential heating oil prices to average $3.71 per gallon during the winter season, 33 cents per gallon more than last winter, and the highest average winter price on record (although lower than the record heating oil prices realized during the summer of 2008 when crude oil and all petroleum product prices hit their peak).

Propane. About 5 percent of total U.S. households heat with propane. EIA expects households heating primarily with propane to spend more this winter, but that increase varies across regions. EIA expects that households in the Midwest will see an average increase in winter propane expenditures of 4 percent, as projected residential propane prices increase by 5 percent from last winter and consumption falls by about

1 percent. Households in the Northeast may see a larger increase in propane prices with expenditures rising by 9 percent.

Electricity. Households heating primarily with electricity can expect to spend an average of $6 (1 percent) less this winter. Projected household electricity expenditures are lower this winter because the decline in consumption more than offsets a 1-percent increase in prices. About 37 percent of all U.S. households rely on electricity as their primary heating fuel, ranging from 14 percent in the Northeast to 62 percent in the South. The number of households heating with electricity is expected to increase by 1.7 percent from last winter. About 80 percent of the increase occurs in the South, where electric heat pumps are popular.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. The expected pace of global oil consumption growth for 2011 is slightly lower in this month's *Outlook,* while projected total supply in 2011 is higher, resulting in some easing of oil market tightness. Despite this easing, EIA continues to expect markets to rely on inventories to meet some consumption growth in 2011 and 2012. Oil consumption growth from countries outside of the Organization for Economic Cooperation and Development (OECD) is projected to outpace the growth in supply from producers that are not members of the Organization of the Petroleum Exporting Countries (OPEC), implying a need for OPEC producers to increase their output to balance the market in 2011 and 2012.

Oil prices continue to face upward price pressure due to supply uncertainty and downward price pressure because of lowering expectations of economic growth. Upside uncertainty to the crude oil price outlook remains as a result of ongoing unrest in oil-producing regions. Heightened turmoil in Syria, which produced an average 400 thousand bbl/d in 2010, and the potential for more sanctions on the country's energy sector is one source of risk to non-OPEC supply. At the same time, downside demand risks predominate, as fears persist about the rate of global economic recovery, contagion effects of the debt crisis in the European Union, and other fiscal issues facing national governments. On the supply side, there may be downward price pressure if Libya is able to ramp up oil production and exports sooner than anticipated.

Global Crude Oil and Liquid Fuels Consumption. EIA expects that world crude oil and liquid fuels consumption will continue growing from its record-high level of 87.1 million barrels per day (bbl/d) in 2010 and reach 88.4 million bbl/d on 2011 and 89.8 million bbl/d in 2012 (World Liquid Fuels Consumption Chart). Consumption in

OECD countries is projected to decline in both 2011 and 2012, while China and other emerging economies account for all projected oil consumption growth through 2012.

Non-OPEC Supply. EIA projects that non-OPEC liquid fuels production will grow by 0.49 million bbl/d in 2011 and 0.85 million bbl/d to an average of 53.1 million bbl/d in 2012 (Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart). The largest sources of expected growth in non-OPEC oil production over the forecast period are Brazil, Canada, China, Colombia, Kazakhstan, and the United States, with average annual growth in each country of over 100 thousand bbl/d. In contrast, Russian, Mexican, and North Sea production will be lower by the end of the forecast period.

OPEC Supply. EIA expects OPEC crude oil production to decline by 30 thousand bbl/d in 2011. This is in sharp contrast to the last *Outlook*, in which EIA expected total OPEC crude oil production to decline by 360 thousand bbl/d. The significant change in this *Outlook* for 2011 is largely due to increased production in Saudi Arabia, which rose to 9.9 million bbl/d in the third quarter of this year, compared with 9.1 million bbl/d in the second quarter. EIA maintains its assumption that about one-half of Libya's pre-disruption production will resume by the end of 2012, contributing to the overall growth in OPEC crude oil output of 270 thousand bbl/d in 2012. EIA expects that OPEC surplus crude oil production capacity fell from 4.0 million bbl/d in the fourth quarter of 2010 to 2.8 million bbl/d in the fourth quarter of 2011, but will increase to 3.5 million bbl/d by the end of 2012 as Libyan production capacity comes back on line (OPEC Surplus Crude Oil Production Capacity Chart). Forecast OPEC non-crude liquids production, which is not subject to production targets, is expected to increase by 450 thousand bbl/d in both 2011 and 2012.

OECD Petroleum Inventories. EIA expects that OECD commercial inventories will decline in both 2011 and 2012. Days of supply (total inventories divided by average daily consumption) fall slightly but remain relatively high at 58 days during the fourth quarter of 2010, 57 days during the fourth quarter 2011, and 56 days during the fourth quarter 2012 (Days of Supply of OECD Commercial Stocks Chart).

Crude Oil Prices. West Texas Intermediate (WTI) crude oil spot prices fell from an average of $97 per barrel in July to $86 per barrel in August and September (West Texas Intermediate Crude Oil Price Chart). The WTI spot price began October below $80 per barrel. EIA revised the projected oil price paths downward from last month's *Outlook*. EIA expects that the U.S. refiner average crude oil acquisition cost will average about $99 per barrel in 2011 and $98 per barrel in 2012 compared with $100 per barrel and $103 per barrel for 2011 and 2012, respectively, in last month's *Outlook*.

The significant price discount for WTI relative to other U.S. and world crude oils is expected to continue until transportation bottlenecks restricting the movement of crude oil out of the mid-continent region are relieved. Consequently, the projected average U.S. refiner acquisition cost of crude oil, which averaged almost $2.70 per barrel below WTI in 2010, averages about $7 per barrel above WTI in 2011 and $10 per barrel above WTI in 2012.

Energy price forecasts are highly uncertain (Market Prices and Uncertainty Report). WTI futures for December 2011 delivery over the 5-day period ending October 6 averaged $79 per barrel and implied volatility averaged 51 percent, establishing the lower and upper limits of a 95-percent confidence interval for the market's expectations of monthly average WTI prices in December of $57 per barrel and $110 per barrel, respectively. Last year at this time, WTI for December 2010 delivery averaged $83 per barrel and implied volatility averaged 30 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $68 per barrel and $101 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total consumption of liquid fuels in 2010 grew by about 410 thousand bbl/d, or 2.2 percent, the highest rate of growth since 2004 (U.S. Liquid Fuels Consumption Growth Chart). In contrast, projected total U.S. liquid fuels consumption in 2011 falls by 230 thousand bbl/d (1.2 percent), revised downward from the previous *Outlook's* 170 thousand bbl/d (0.9 percent) decline as the 2011 U.S. real GDP growth forecast has been lowered for the seventh consecutive month. Motor gasoline consumption accounts for much of the projected decline for the year.

EIA expects total liquid fuels consumption to increase by 90 thousand bbl/d (0.5 percent) to 19.1 million bbl/d in 2012. Projected motor gasoline consumption rises by 40 thousand bbl/d (0.5 percent) as highway travel increases modestly, and distillate fuel consumption increases by 30 thousand bbl/d (0.7 percent) as growth in industrial activity and non-petroleum imports continues to slow as a result of continuing weak economic growth.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production, which increased by 110 thousand bbl/d in 2010 to 5.5 million bbl/d, increases by a further 180 thousand bbl/d in 2011 and by 70 thousand bbl/d in 2012 (U.S. Crude Oil Production Chart), driven by increased oil-directed drilling activity, particularly in unconventional shale formations.

The rapid growth in U.S. ethanol production since the mid-2000s is projected to slow with total production averaging 900 thousand bbl/d in 2011 and 910 thousand bbl/d in 2012. Assuming ethanol net exports average roughly 40 thousand bbl/d next year, EIA expects that 870 thousand bbl/d of ethanol will be blended into gasoline in 2012, which is sufficient to meet the requirements of the renewable fuels standard (RFS). The expiration of the Federal motor fuels excise tax credit for ethanol blending is expected to have little effect on ethanol blending levels, as ethanol producers do not currently appear to be capturing much of the value of the credit.

Liquid fuel net imports (including both crude oil and refined products) fell from 57 percent of total U.S. consumption in 2008 to 49 percent in 2010 because of rising domestic production and the decline in consumption during the economic downturn. EIA forecasts that liquid fuel net imports' share of total consumption will decline further to 46 percent in 2011 before rising slightly to 47 percent in 2012.

U.S. Crude Oil and Petroleum Product Inventories. Commercial crude oil inventory levels ended September 2011 at an estimated 336 million barrels, 26 million barrels below last year but 7 million barrels higher than the previous 5-year average for that month. Commercial crude oil stocks are gradually drawn down to 317 million barrels by the end of 2012, close to their 5-year average.

Total motor gasoline stocks at the end of September 2011 were an estimated 214 million barrels, down 5 million barrels from last year but 6 million barrels above the previous 5-year average for that month. Distillate fuel oil stocks ended September 2011 at an estimated 157 million barrels, down 10 million barrels from the same time last year but 7 million barrels above the previous 5-year average. Projected total motor gasoline and distillate inventories average about 3 million barrels and 8 million barrels higher, respectively, than their previous 5-year averages at the end of 2012. The Northeast Home Heating Oil Reserve, which was emptied earlier this year because of the move to low-sulfur heating oil in several northeast States next year, is expected to be restocked with 650,000 barrels this month and 350,000 barrels next month.

U.S. Petroleum Product Prices. EIA forecasts that the annual average regular-grade gasoline retail price, which averaged $2.78 per gallon in 2010, will increase to an average of $3.52 per gallon in 2011, and average $3.43 per gallon in 2012. The increase in retail prices in 2011 reflects not only the higher cost of crude oil but also changes in the average U.S. refinery gasoline margin (the difference between refinery wholesale gasoline prices and the average cost of crude oil). The average U.S. refinery gasoline margin increases from $0.34 per gallon in 2010, to $0.51 per gallon in 2011, then declines to $0.43 per gallon in 2012.

EIA expects that on-highway diesel fuel retail prices, which averaged $2.99 per gallon in 2010, will average $3.80 per gallon in 2011, and $3.73 per gallon in 2012. Projected U.S. refinery diesel fuel margins increase from an average of $0.39 per gallon in 2010 to $0.64 per gallon in 2011, then fall to an average of $0.56 per gallon in 2012.

Natural Gas

U.S. Natural Gas Consumption. Projected natural gas consumption increases by an average 1.2 billion cubic feet per day (Bcf/d) in 2011 and 0.5 Bcf/d in 2012, with growth in the electric power and industrial sectors driving the increases. Projected natural gas consumption for electricity generation increases by 0.36 Bcf/d and 0.37 Bcf/d in 2011 and 2012, respectively. EIA expects consumption in the industrial sector to rise from 18.1 Bcf/d to 18.5 Bcf/d in 2011 and 18.6 Bcf/d in 2012, as the projected natural-gas-weighted industrial production index also continues to rise but at a slowing rate.

Natural gas consumption for the third quarter of 2011 averaged an estimated 57.9 Bcf/d, with consumption in the electric power sector making up almost half of the total. There were an estimated 942 cooling degree-days for the third quarter 2011, about 22 percent more than the 30-year normal, and above the 930 cooling degree-days for the record-breaking heat of the third quarter of 2010.

U.S. Natural Gas Production and Imports. EIA expects marketed natural gas production to average 66.0 Bcf/d in 2011, a 4.2 Bcf/d (6.7 percent) increase over 2010. The entirety of this growth is coming from increases in onshore production in the lower 48 States, which will more than offset a steep year-over-year decline of over 0.9 Bcf/d (15 percent) in the Federal Gulf of Mexico (GOM) and a small decline in Alaska. EIA expects that overall production will continue to grow in 2012, but at a slower pace, increasing 1.4 Bcf/d (2.1 percent) to an average of 67.4 Bcf/d.

Drilling activity has been resilient despite lower natural gas spot and futures prices. According to Baker Hughes, the September 30 rig count was 923 active drilling rigs targeting natural gas, up from this year's low of 866 on May 20. If drilling continues to increase, production could grow more than expected in 2012.

Growing domestic natural gas production has reduced reliance on natural gas imports and contributed to increased exports. EIA expects that pipeline gross imports of natural gas will fall by 4.8 percent to 8.6 Bcf/d during 2011 and by another 3.1 percent to 8.4 Bcf/d in 2012. Projected U.S. imports of liquefied natural gas (LNG) fall from 1.2 Bcf/d in 2010 to 0.9 Bcf/d in 2011 and to 0.7 Bcf/d in 2012. Pipeline gross exports to

Mexico and Canada are expected to average 4.1 Bcf/d in 2011 and 4.2 Bcf/d in 2012, compared with 3.1 Bcf/d in 2010.

U.S. Natural Gas Inventories. On September 30, 2011, working natural gas in storage stood at 3,409 Bcf, 91 Bcf below the 2010 end-of-September level (U.S. Working Natural Gas in Storage Chart). EIA expects that inventories, though currently lower than last year, will come close to last year's levels towards the end of the 2011 injection season, reaching 3.77 Tcf at the end of October 2011.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $3.90 per MMBtu in September 2011, 15 cents lower than the August 2011 average (Henry Hub Natural Gas Price Chart). EIA expects that Henry Hub spot prices will fall further in October, before rising above $4 per MMBtu in December. This month's *Outlook* lowers the 2011 forecast by 5 cents to $4.15 per MMBtu, 24 cents less than the 2010 average. Although the average 2011 spot natural gas price is lower than the 2010 average, the forecast price over the winter 2011-12 is higher than last winter's average. Last year the Henry Hub spot price hit a low of $3.43 per million Btu in October 2010. EIA expects this winter's heating season will start out with an average Henry Hub spot price of $3.78 per million Btu in October 2011. EIA expects the Henry Hub price in 2012 to average $4.32 per MMBtu.

Natural gas futures prices for December 2011 delivery (for the 5-day period ending October 6, 2011) averaged $3.93 per MMBtu, and the average implied volatility was 34 percent (Market Prices and Uncertainty Report). The lower and upper bounds for the 95-percent confidence interval for December 2011 contracts are $3.13 per MMBtu and $4.93 per MMBtu. At this time last year, the December 2010 natural gas futures contract averaged $4.07 per MMBtu and implied volatility averaged 39 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $3.09 per MMBtu and $5.37 per MMBtu.

Coal

U.S. Coal Consumption. EIA expects that coal consumption for electricity generation will decline by 19 million short tons (MMst) (1.9 percent) in 2011, as the growth in total electricity generation of 0.6 percent is satisfied by increases in generation from natural gas (1.2 percent) and hydropower (23 percent). Projected increases in generation from natural gas and nuclear, combined with lower electricity consumption, contribute to an additional 3.9 percent decline in electric power sector coal consumption in 2012.

U.S. Coal Supply. EIA forecasts that coal production will fall by 1.5 percent in 2011 despite a significant increase in coal exports. Coal production in the Western region is projected to decline, while production in the Appalachian and Interior regions increases slightly. EIA expects coal production to decline by nearly 24 MMst (2.2 percent) in 2012 as domestic consumption and exports fall (U.S. Annual Coal Production Chart) and inventories at electric power plants decline (U.S. Electric Power Sector Coal Stocks Chart).

U.S. Coal Trade. U.S. coal exports rose by about 35 percent during the first half of 2011 compared with 2010. Exports of 54 MMst during the first half of 2011 were the highest since 1982. EIA expects U.S. coal exports to remain elevated over the second half of 2011, reaching an annual total of 99 MMst. Forecast U.S. coal exports fall back to about 86 MMst in 2012 as supply from other major coal-exporting countries recovers from disruptions. The strong global demand for coal outside the United States also contributed to a 15 percent decline in U.S. coal imports in 2010 (to 19.4 MMst) despite an increase in domestic consumption. EIA expects the lower level of U.S. coal imports to continue, with imports below 20 MMst in 2011 and 2012. U.S. coal imports averaged about 31 MMst annually from 2004 through 2009.

U.S. Coal Prices. Average delivered coal prices to the electric power sector have risen steadily over the last 10 years, with an average annual increase of 6.7 percent. EIA expects that this trend will continue in 2011, with a significant portion of the increase attributed to a sharp rise in transportation costs. Expected declines in consumption and stable transportation costs contribute to a flattening of the electric power sector coal price in 2012. The projected average delivered coal price to the electric power sector, which averaged $2.26 per MMBtu in 2010, is $2.39 per MMBtu for both 2011 and 2012.

Electricity

U.S. Electricity Consumption. Last winter, heating degree-days during the fourth quarter of 2010 in the South Atlantic Census region, where the majority of households heat using electricity as an energy source, were 19 percent higher than normal. This *Outlook* assumes that temperatures in this region during the fourth quarter of 2011 will return to near-normal levels. This reduction in South Atlantic heating demand contributes to the overall decline of 2.6 percent for residential electricity consumption in the region during 2011.

Growth in the total industrial production index slows from 3.7 percent in 2011 to 2.0 percent in 2012. The slowing pace of industrial output growth next year contributes to slowing growth of retail sales of electricity to the industrial sector from 1.4 percent

in 2011 to 0.7 percent in 2012. EIA expects that total consumption of electricity during 2011 will grow by 0.4 percent from last year's level followed by a decline of 0.5 percent in 2012 (U.S. Total Electricity Consumption Chart).

U.S. Electricity Generation. Total generation in the United States is expected to fall by 62,000 megawatt hours per day (0.5 percent) in 2012 from the level during 2011. Hydroelectric generation should return to more normal levels, bringing its share of total generation down from 7.4 percent in 2011 to 6.5 percent next year. In contrast, favorable natural gas prices and additions to renewable generation capacity during 2012 should boost the shares provided by these two energy sources by 0.9 and 0.5 percentage points, respectively (U.S. Electricity Generation by Fuel, all Sectors Chart).

U.S. Electricity Retail Prices. After relatively modest growth of 0.6 percent during 2010, EIA expects rising coal prices for electricity generation to push retail residential electricity prices up by 1.9 percent this year. As fuel costs moderate during the second half of this year and into next year, growth in residential prices should slow to 0.9 percent during 2012 (U.S. Residential Electricity Prices Chart).

Renewables and Carbon Dioxide Emissions

U.S. Renewables. Led by conventional hydropower, the total supply of renewables is projected to grow about 14 percent from 2010 to 2011. EIA expects total renewable energy supply to remain flat in 2012 as the decline in hydropower offsets growth in other renewable energy supply.

Because of high levels of precipitation in regions such as the Pacific Northwest, 2011 promises to be an abundant year for hydropower generation (growth of 0.57 trillion Btu or 23 percent) – the best year since 1999. EIA assumes a return to normal snow and rainfall levels in 2012 with hydropower generation falling by 0.38 trillion Btu (12 percent).

Wind energy is projected to account for 39 percent of total renewable energy supply growth from 2010 to 2012, with increases of 0.24 trillion Btu (26 percent) in 2011 and 0.15 trillion Btu (12 percent) in 2012. The supply of geothermal energy is also projected to rise in both 2011 and 2012 and account for the second largest share of renewables growth (0.20 trillion Btu or 20 percent) from 2010 to 2012.

The wood energy supply is second only to conventional hydropower in terms of the total energy value of renewable sources. However, much of the wood supply is subject to industrial market conditions, especially in the pulp and paper industry, with net growth of 0.04 quadrillion Btu between 2010 and 2012. Solar energy supply

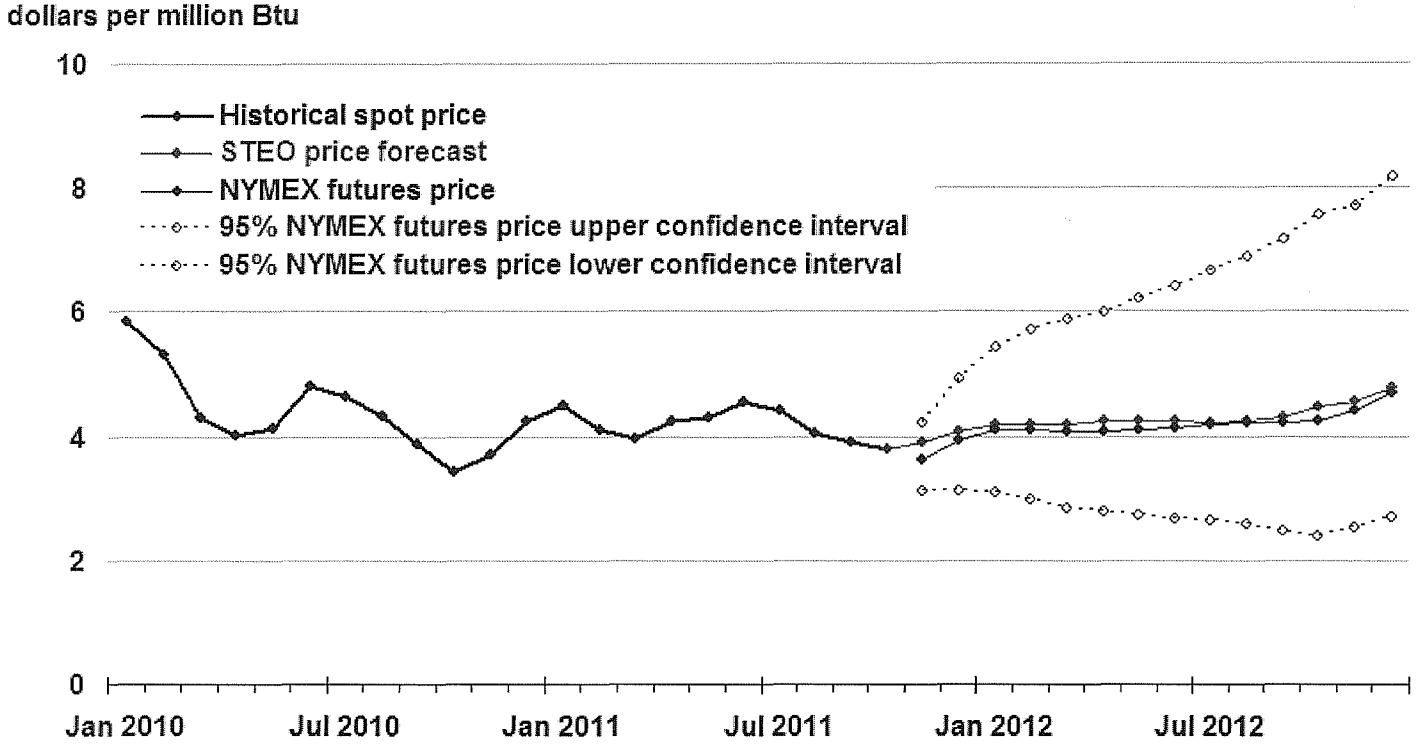
represents about 1.5 percent of total renewable energy supply and is projected to grow by 3.9 percent and 9.0 percent in 2011 and 2012, respectively.

In terms of liquid renewable fuels, EIA projects that biodiesel production in 2011 will average about 56 thousand bbl/d (860 million gallons total annual production), surpassing the 2011 Renewable Fuel Standard (RFS) Biomass Based Diesel mandate of 800 million gallons, taking advantage of the $1 per gallon biodiesel tax credit which expires at the end of the year. RFS credits generated above the current mandate can be banked and used for compliance in the following year for up to 20 percent of the requirement. In 2012, biodiesel production is forecast to grow slightly higher to 61 thousand bbl/d (940 million gallons), just reaching the 2012 RFS mandate of 1.0 billion gallons after accounting for 60 million gallons of 2011 credits.

Ethanol production growth, which averaged 120 thousand bbl/d annually between 2005 and 2010, is expected to slow, increasing by 30 thousand bbl/d in 2011 and 10 thousand bbl/d in 2012, to an average 910 thousand bbl/d in 2012. Ethanol exports reduce the volume of ethanol blended into gasoline. Assuming ethanol net exports average about 40 thousand bbl/d next year, EIA expects that 870 thousand bbl/d of ethanol will be blended into gasoline in 2012, which is sufficient to satisfy RFS requirements. The expiration of the Federal motor fuels excise tax credit for ethanol blending is expected to have little effect on ethanol blending levels, as ethanol producers do not currently appear to be capturing much of the value of the credit.

U.S. CO_2 Emissions. EIA estimates that CO_2 emissions from fossil fuels increased by 3.9 percent in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). Forecast fossil-fuel CO_2 emissions fall by 0.7 percent in 2011, as emission increases from higher natural gas consumption are offset by declines in coal and petroleum consumption. Increases in hydroelectric generation and other renewable energy sources in 2011 also help to mitigate emissions growth. Fossil-fuel CO_2 emissions in 2012 fall by almost 1 percent as expected declines in coal emissions more than outweigh the increases in emissions from petroleum and natural gas.

Henry Hub Natural Gas Price

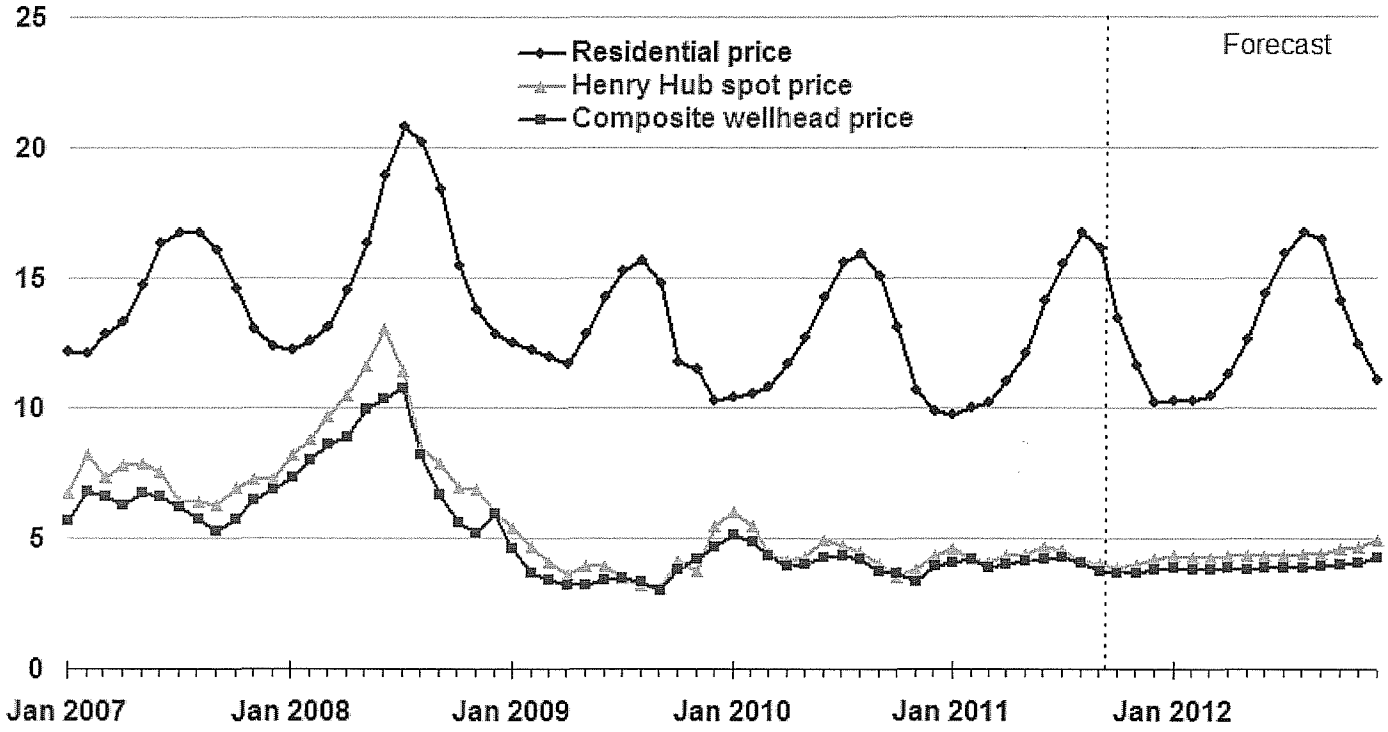


Note: Confidence interval derived from options market information for the 5 trading days ending October 6, 2011
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: Short-Term Energy Outlook, October 2011

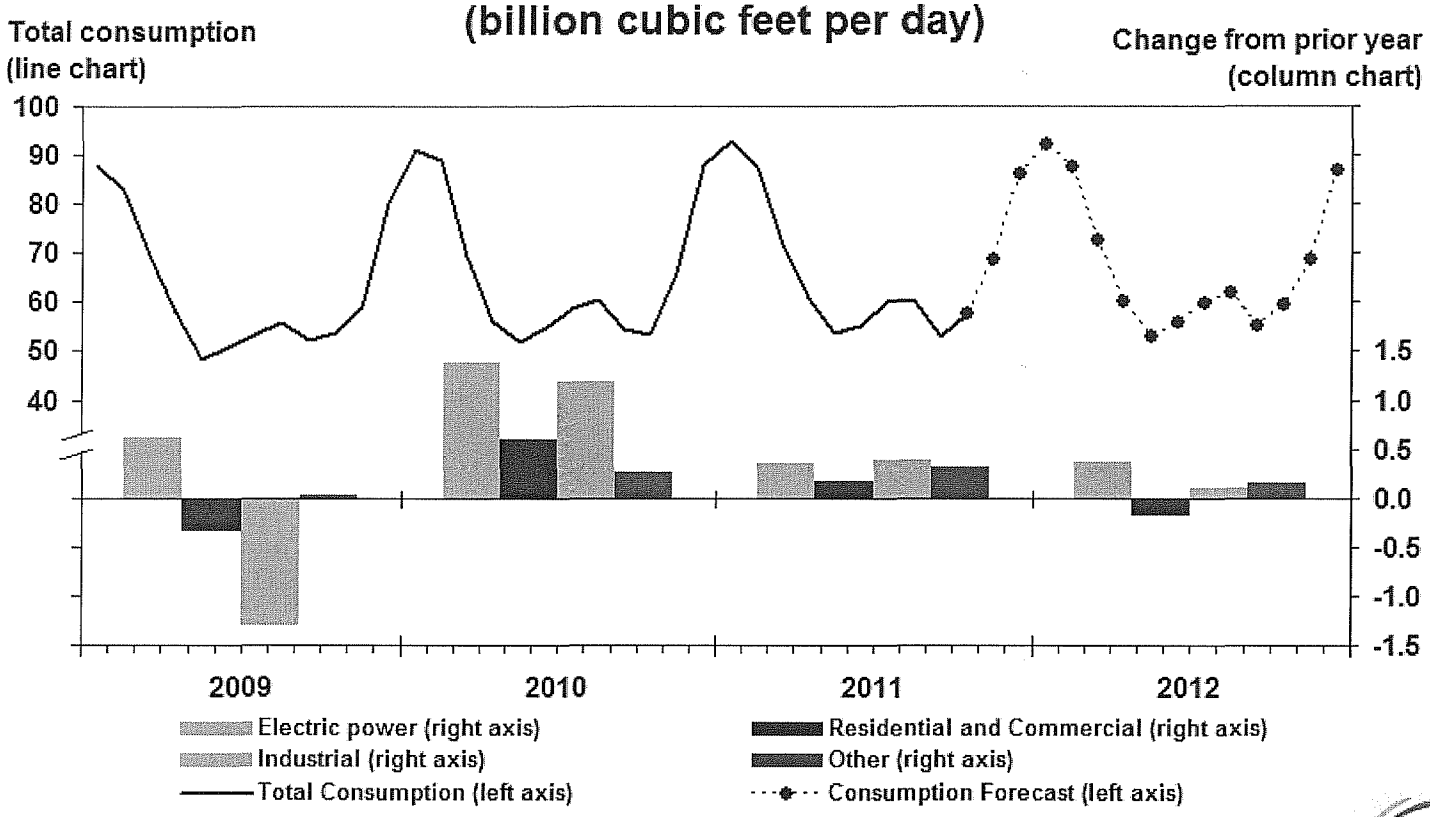
U.S. Natural Gas Prices

dollars per thousand cubic feet



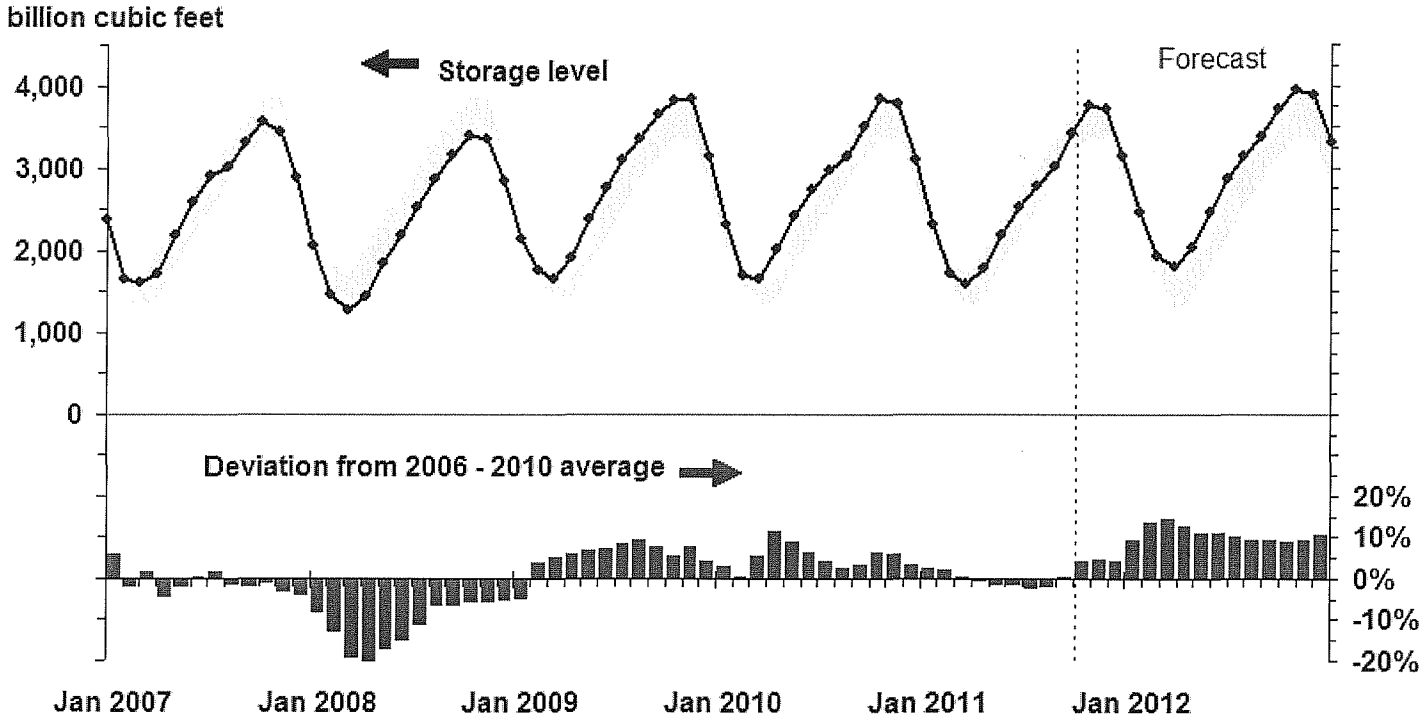
Source: Short-Term Energy Outlook, October 2011

U.S. Natural Gas Consumption (billion cubic feet per day)



Source: Short-Term Energy Outlook, October 2011

U.S. Working Natural Gas in Storage



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

Source: Short-Term Energy Outlook, October 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, 2011										**$148,188**
May	($1,396)	$0	$892	($504)	17,596	$0.3941	$6,935		($7,439)	140,749
June	33,915	0	837	34,752	9,855	0.5102	4,258	2/	30,494	171,243
July	68,988	0	1,054	70,042	6,564	0.5102	3,349		66,693	237,936
August	76,995	0	1,530	78,525	5,973	0.5102	3,047		75,478	313,414
September	25,141	0	2,066	27,207	6,611	0.5102	3,373		23,834	337,248
Balance @ September 30, 2011										**$337,248**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 6,634.4 dk @ $0.3941 and 3,220.6 dk @ $0.5102.

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, 2011									**($5,922)**
May	($17,358)	$0	($95)	($17,453)	22,049	($0.1136)	($2,505)	($14,948)	(20,870)
June	(11,488)	0	(208)	(11,696)	8,011	(0.0178)	(653) 2/	(11,043)	(31,913)
July	(4,652)	0	(288)	(4,940)	9,020	(0.0178)	(161)	(4,779)	(36,692)
August	(3,906)	0	(320)	(4,226)	9,676	(0.0178)	(172)	(4,054)	(40,746)
September	(25,158)	0	(348)	(25,506)	10,802	(0.0178)	(192)	(25,314)	(66,060)
Balance @ September 30, 2011									**($66,060)**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 5,327.7 dk @ ($0.1136) and 2,683 dk @ ($0.0178).