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October 31, 2013

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

Re: Cost of Gas Adjustment (COG)
November 2013

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and two (2) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (92nd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (92nd Revised Sheet No. 8), showing the November 2013 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.2382 per mcf for residential and firm general service customers and an increase of \$0.2509 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for November 2013, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.2509 since the last COG filing and there has been a decrease in pipeline charges of \$0.0127 per mcf. The net effect of these changes is an increase of \$0.2382 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, 2013.

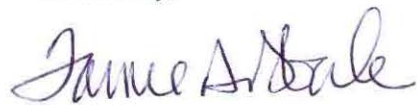
Great Plains submitted a check for \$600.00 on January 2, 2013 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment covers the \$50.00 filing fee associated with this month's COG filing.

Great Plains respectfully requests this filing be accepted as being in full compliance with the filing requirements of this Commission.

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,

A handwritten signature in dark ink, appearing to read "Tamie A. Aberle". The signature is fluid and cursive, with the first name being the most prominent.

Tamie A. Aberle
Director of Regulatory Affairs

Attachments

Attachment A

Attachment A



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

**State of North Dakota
Gas Rate Schedule**

RATE SUMMARY SHEET

NDPSC Volume 2
92nd Revised Sheet No. 1.1
Canceling 91st Revised Sheet No.1.1

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 Over 10 MCF 1.0540	\$6.3746	\$7.6486 7.4286
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411	\$3.9303	\$5.0694 4.8234 4.6714
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$3.9303	\$5.1694
Transportation Service	5	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411		\$1.1391 0.8931 0.7411

Date Filed: October 31, 2013

Effective Date: Service rendered on and after November 1, 2013

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.: PU-13-551 & PU-13-010



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

**State of North Dakota
 Gas Rate Schedule**

NDPSC Volume 2
 92nd Revised Sheet No. 8
 Canceling 91st Revised Sheet No. 8

COST OF GAS

Page 1 of 1

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.	1.4722	(1.4821)	0.9614	0.9515	(1.4671)	0.0274	(1.4397)
Current Adj.	(0.0127)	0.2509	0.0000	0.2382	0.2509	0.0000	0.2509
Total Adj.	1.4595	(1.2312)	0.9614	1.1897	(1.2162)	0.0274	(1.1888)
Total Rate	\$1.5253	\$3.8879	\$0.9614	\$6.3746	\$3.9029	\$0.0274	\$3.9303

Date Filed: October 31, 2013

Effective Date: Service rendered on and after November 1, 2013

Issued By: Tamie A. Aberle
 Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
NOVEMBER 2013

<u>Firm</u>	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
FT-A - Zone 1-1	8,000	\$3.4671	12	\$332,842	\$0.2373
FT-A - Zone 1-1	500	3.7671	5	9,418	0.0067
FT-A - Zone 1-1	4,500	3.7671	5	84,760	0.0604
FT-A Seasonal	2,000	3.7671	5	37,671	0.0269
TFX Seasonal	2,000	15.1530	5	151,530	0.1080
TFX - Winter	13,000	15.1530	5	984,945	0.7023
TFX - Summer	13,000	5.6830	7	517,153	0.3687
LMS Demand 2/					0.0150
Total Demand Charges				\$2,118,319	1.5253
Estimated Weighted Average Commodity Cost	1,402,522	1/ 3.8879		5,452,865	3.8879
Gas Cost Reconciliation Adjustment					0.9614
Total Current Firm Gas Cost				\$7,571,184	6.3746
Base Cost of Gas					5.1849
Accumulated Adjustment					\$1.1897
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$3.8879
Gas Cost Reconciliation Adjustment					0.0274
LMS Demand 2/					0.0150
Total Current Interruptible Gas Cost					3.9303
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$1.1888)

1/ Three year normalized average mcf sales

2/ Amount divided by 2010-2012 average interruptible sales volumes plus 2010-2012 average normalized firm sales volumes.

	<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	\$0.0150

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
NOVEMBER 2013**

Rates Effective November 1, 2013	<u>\$/Dk</u>	
FT-A - Zone 1-1	\$3.7671	Per dk/Mo.
FT-A - Zone 1-1	3.4671	Per dk/Mo.
FT-A - Seasonal	3.7671	Per dk/Mo.
TFX	15.1530	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	3.8879	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	5.1191	Per Mcf
Total Firm Base Cost	<u>\$5.1849</u>	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. 14.0.0 superseding v. 13.0.0
Page 1 of 3

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

Issued: September 27, 2013
Effective: November 1, 2013

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

Part 5.0
Statement of Rates
v. 14.0.0 superseding v. 13.0.0
Page 3 of 3

Rate Schedule	Base Tariff Rate	Fuel and Loss Retention Percentages 2/
Commodity Rates 1/		
FT-A – Maximum Rates		
Zone 1-1	\$0.0130	0.00%
Zone 1-2	\$0.0130	0.00%
Zone 2-2	\$0.0130	0.00%
Minimum Rate	\$0.0130	
IT and AOT		
Zone 1-1	\$0.1368	0.00%
Zone 1-2	\$0.1737	0.00%
Zone 2-2	\$0.0834	0.00%
Minimum Rate	\$0.0130	

1/ Pursuant to Section 19 of the General Terms and Conditions, the maximum and minimum commodity rates shall be increased to include the Commission-authorized Annual Charge Adjustment unit rate as published on the Commission's Web Site located at <http://www.ferc.gov>.

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: 0.00% for Zone 1-1, 0.00 % for Zone 1-2, and 0.00% 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		\$0.0001	

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 Rate Per Dekatherm	Minimum Rate Per Dekatherm
PAL		
NPL, OPL, and APL Service:		
Daily Commodity Rate	\$0.1737	\$0.0000
RPL Service:		
Daily Reservation Rate	\$0.1737	\$0.0000

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

Sixth Revised Sheet No. 50
Superseding
Fifth Revised 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/ 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	0.0359	0.0190			0.0175	0.0000	0.0359	0.0190
Field	Market	0.0359	0.0190	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

- 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 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/ The Maximum and Minimum rates include the Market Area Electric Compression charge of \$0.0000 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at <http://www.ferc.gov>.
- 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, the Field Area Electric Compression charge of \$0.0000 and the ACA unit surcharge as set forth on FERC's website at <http://www.ferc.gov> will be added to the mileage based rates.

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

Sixth Revised Sheet No. 51
Superseding
Fifth Revised 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	0.0359	0.0190			0.0175	0.0000	0.0359	0.0190
Field	Market	0.0359	0.0190	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

GULF COAST	Reservation 1/		Commodity 6/		Out-of-Balance 6/	
	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
MOPS Gathering	1.0514	0.0000	0.0000	0.0000	0.0000	0.0000
MOPS Transmission	1.5337	0.0000	0.0000	0.0000	0.0000	0.0000
Tivoli - Downstream	0.6827	0.0000	0.0000	0.0000	0.0000	0.0000
Other Gulf Coast	4.8169	0.0000	0.0000	0.0000	0.0000	0.0000

- 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 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/ The Maximum and Minimum rates include the Market Area Electric Compression charge of \$0.0000 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at <http://www.ferc.gov>.
- 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, the Field Area Compression charge of \$0.0000 and the ACA unit surcharge as set forth on FERC's website at <http://www.ferc.gov> will be added to the mileage based rates.
- 6/ In addition to the Maximum and Minimum rates, Shipper shall pay the ACA unit surcharge as posted on FERC's website at <http://www.ferc.gov>.

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

Fuel Percentages/Electric Compression Rates

	<u>Percentages</u>
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	1.31%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.33% 4/ 5/
FDD Storage Fuel	1.55%
	<u>Electric Compression</u>
COMMODITY RATES:	1/
Market Area	\$0.0000
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, 2012.

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 2013**

The principal gas sources of natural gas for Wahpeton, North Dakota are from the mid-continent area of the United States. The pricing for the majority of this gas is the Northern Natural Gas Co. Ventura, Iowa point which is an actively traded market point in North America. The November monthly price for the NNG-Ventura Index is expected to increase from the previous month index. The NNG-Ventura Index is based on negotiated trades during the last five business days of the month. This is commonly known as bid week, and reported by Platt's Inside FERC's Gas Market Report, published the beginning of each month.

The major contributing factor to the expected increase in demand is the increase in demand associated with the start of the seasonal heating. According to the EIA domestic demand was greater than supply for first time since April. The EIA reported storage levels nationwide as of October 18, 2013 were 2.1 percent above the five-year average and 2.4 percent below last year's balance.

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

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 17.



Independent Statistics & Analysis

U.S. Energy Information
Administration

October 2013

Short-Term Energy and Winter Fuels Outlook (STEO)

Highlights

- EIA projects average U.S. household expenditures for natural gas and propane will increase by 13% and 9%, respectively, this winter heating season (October 1 through March 31) compared with last winter. Projected U.S. household expenditures are 2% higher for electricity and 2% lower for heating oil this winter. Although EIA expects average expenditures for households that heat with natural gas will be significantly higher than last winter, spending for gas heat will still be lower than the previous 5-year average (see EIA [Short-Term Energy and Winter Fuels Outlook slideshow](#)).
- Brent crude oil spot prices fell from a recent peak of \$117 per barrel in early September to \$108 per barrel at the end of the month as some crude oil production restarted in Libya and concerns over the conflict in Syria moderated. EIA expects the Brent crude oil price to continue to weaken, averaging \$107 per barrel during the fourth quarter of 2013 and \$102 per barrel in 2014. Projected West Texas Intermediate (WTI) crude oil prices average \$101 per barrel during the fourth quarter of 2013 and \$96 per barrel during 2014.
- The weekly U.S. average regular gasoline retail price fell by 18 cents per gallon during September, ending the month at \$3.43 per gallon. EIA's forecast for the regular gasoline retail price averages \$3.34 per gallon in the fourth quarter of 2013. The annual average regular gasoline retail price, which was \$3.63 per gallon in 2012, is expected to be \$3.52 per gallon in 2013 and \$3.40 per gallon in 2014.
- Natural gas working inventories ended September at an estimated 3.52 trillion cubic feet (Tcf), 0.17 Tcf below the level at the same time a year ago and 0.04 Tcf above the previous five-year average (2008-12). EIA expects that the Henry Hub natural gas spot price, which averaged \$2.75 per million British thermal units (MMBtu) in 2012, will average \$3.71 per MMBtu in 2013 and \$4.00 per MMBtu in 2014.
- Despite a rise in natural gas prices from their 2012 level, stable coal prices and an increase in electricity generation from coal contribute to only modest increases in retail electricity prices. EIA expects residential electricity prices to increase by 2% in 2013 and 1% in 2014.

Projected Winter Fuel Expenditures by Fuel and Region

The average household winter heating fuel expenditures discussed in this STEO provide a broad guide to changes compared with last winter. However, 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](#)). Forecast temperatures are close to last winter nationally, with the Northeast about 3% colder and the West 3% warmer.

Natural Gas. About one-half of U.S. households use natural gas as their primary heating fuel. EIA expects households heating with natural gas to spend an average of \$80 (13%) more this winter than last winter. The increase in natural gas expenditures represents a 14% increase in the average U.S. residential price from last winter, with consumption that is slightly lower than last winter nationally. The projected changes in residential natural gas prices this winter range from a 10% increase in the West to a 15% increase in the Northeast. Several factors contribute to this regional variation, including differences in weather patterns, regional changes in production and pipeline 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 \$46 (2%) less this winter than last winter, reflecting a 5% decrease in prices and a 3% increase in consumption. Although winter temperatures are expected to be similar to last winter nationally, weather in the Northeast is expected to be 3% colder than last winter. Reliance on heating oil is highest in the Northeast, where about 25% of households depend on heating oil for space heating, compared with 6% of households nationally. The state of New York, which accounts for about one-third of the region's heating oil market, has required the use of ultra-low sulfur heating oil since July 2012. A number of other states will begin to move away from higher-sulfur heating oil in the coming years.

Propane. About 5% of all U.S. households heat with propane. EIA expects households heating primarily with propane to spend more this winter, but the projected increase varies across regions. EIA expects that households heating with propane in the Midwest will spend an average of \$120 (9%) more this winter than last winter, reflecting prices that are about 10% higher and consumption that is 1% lower than last winter. Households in the Northeast are expected to spend an average of \$206 (11%) more this winter with average prices that are about 8% higher and consumption that is 3% higher than last year.

Electricity. Households heating primarily with electricity can expect to spend an average of \$18 (2%) more this winter with 2% higher prices but consumption slightly lower than last winter. About 39% of all U.S. households rely on electricity as their primary heating source, ranging from 14% in the Northeast to 63% in the South.

Wood. The use of cord wood and wood pellets as the primary residential space heating fuel has increased by 39% since 2004, to about 2.5 million households in 2012. About 8% of households

use wood as a secondary source of heat, making wood second only to electricity as a supplemental heating fuel. About 20% of New England homes (1.1 million) used wood for space heating, water heating, or cooking in 2009 (EIA, [Residential Energy Consumption Survey, 2009](#)), which is nearly twice the national rate. Almost half of all rural households in New England used wood compared with only 12% of the area's urban households that used the fuel.

Global Crude Oil and Liquid Fuels

Estimated global liquid fuels supply disruptions in September averaged 3.0 million barrels per day (bbl/d), which is unchanged from the revised August estimate and remains at the highest level since at least January 2011. However, some of Libya's production restarted in the second half of September after coming to a near-halt earlier in the month. EIA expects Libya's production to remain at its current level for October, although output still remains considerably below the precrisis level. EIA expects total unplanned outages from both OPEC and non-OPEC countries to decline in October.

Global Liquid Fuels Consumption. EIA projects global consumption to grow by 1.0 million bbl/d in 2013 and by another 1.2 million bbl/d in 2014, with China, the Middle East, Central & South America, and other countries outside of the Organization for Economic Cooperation and Development (OECD) accounting for essentially all consumption growth. Projected OECD liquid fuels consumption declines by 0.2 million bbl/d in 2013 and 0.1 million bbl/d in 2014. The declines in OECD consumption are largely due to lower consumption in Europe and Japan.

Non-OECD Asia, particularly China, is the leading contributor to projected global consumption growth. EIA estimates that liquid fuels consumption in China will increase by 420,000 bbl/d in 2013 and by a further 430,000 bbl/d in 2014, compared with average annual growth of about 510,000 bbl/d from 2003 through 2012. China's steady growth in oil demand has led it to become the world's largest net oil importer, exceeding the United States in September 2013. EIA forecasts this trend to continue through 2014.

Non-OPEC Supply. Forecast non-OPEC liquid fuels production increases by 1.5 million bbl/d in both 2013 and 2014. Growing non-OPEC liquid fuels production contributes to a decline in the call on OPEC crude oil and global stocks (world consumption less non-OPEC production and OPEC non-crude oil production), which falls from an average of 30.2 million bbl/d in 2013 to 29.6 million bbl/d in 2014.

The largest area of non-OPEC supply growth is North America, where production increases by 1.4 million bbl/d and 1.1 million bbl/d in 2013 and 2014, respectively, resulting from continued production growth in U.S. onshore tight oil formations and from Canadian oil sands. EIA expects smaller production growth from a number of other areas, including Central & South America, Asia & Oceania, and Africa. In Central & South America, forecast liquid fuels supply increases by 0.1 million bbl/d and 0.2 million bbl/d in 2013 and 2014, respectively, mainly driven by increases

in Brazil's offshore, pre-salt oilfields output. EIA expects total liquid fuels supply in Asia & Oceania to increase by 0.2 million bbl/d in 2014, led by Malaysia.

[Kazakhstan's Kashagan oilfield](#) is the largest to be discovered in the past 35 years. The project's operator expects commercial production to start in October. While the oilfield has significant potential, technical challenges and high development costs may limit its expansion and EIA expects field production to reach just 25,000 bbl/d by the end of 2013.

EIA made upward revisions of 0.2 million bbl/d to estimated non-OPEC outages in both July and August, putting outages at 1.0 million bbl/d and 0.8 million bbl/d, respectively. The change resulted from downward revisions to China's production for both months because of flooding in southwestern and northern China that curbed output from the major Changqing and Daqing fields.

Of the estimated 3.0 million bbl/d of global unplanned supply disruptions in September, approximately 0.6 million bbl/d occurred among non-OPEC producers. Total non-OPEC supply disruptions have fallen since July largely because of a decline in outages in Canada, Brazil, and Colombia. In September, Syria, Yemen, South Sudan, and China accounted for all non-OPEC supply disruptions, although EIA expects outages in the latter two countries to decline in October.

OPEC Supply. EIA projects total OPEC liquid fuels production to decline by 0.8 million bbl/d in 2013 and by an additional 0.3 million bbl/d in 2014. The declines in 2013 mostly reflect supply outages among some OPEC producers, along with an overall decrease in Saudi Arabia's production in response to the increase in non-OPEC supply. Over the first three months of 2013, Saudi Arabia's crude oil production averaged 830,000 bbl/d lower than the same period last year. However, Saudi Arabia's crude oil production rose from 9.1 million bbl/d in March to 10.2 million bbl/d in August, in part to offset recent global supply disruptions. EIA expects Saudi Arabia and other OPEC members to begin cutting back as some of the disrupted production comes back online and non-OPEC supply continues to grow.

Overall OPEC crude oil unplanned disruptions in September averaged 2.4 million bbl/d, an increase of 0.2 million bbl/d over the previous month attributed solely to Libya. Widespread protests at key oil installations in Libya resulted in an average of 1.2 million bbl/d offline in September. The situation improved somewhat in the latter half of September after oilfields and loading ports in western Libya restarted operations. Libya's outage volume at the end of the month stood at 930,000 bbl/d.

Planned maintenance work started on Iraq's southern export terminals in September, contributing to an almost 450,000 bbl/d month-over-month decrease in total crude oil output. EIA excludes this volume from unplanned outage estimates. EIA estimates that unplanned crude oil disruptions in Iraq were 260,000 bbl/d in September, stemming mostly from persistent attacks on the Kirkuk-Ceyhan pipeline between Iraq and Turkey.

Total OPEC surplus crude oil production capacity in the third quarter of 2013 averaged 1.7 million bbl/d, which is 0.3 million bbl/d below the year-ago level and 1.4 million bbl/d lower than the historical 2010-12 average. EIA projects OPEC surplus capacity will increase to an average of 2.4 million bbl/d in the fourth quarter of 2013, and 4.2 million bbl/d in the fourth quarter of 2014. These estimates do not include additional capacity that may be available in Iran but is currently offline because of the effects of U.S. and European Union sanctions on Iran's oil sector.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories at the end of 2012 totaled 2.65 billion barrels, equivalent to roughly 58 days of supply. OECD oil inventories are projected to end 2013 at 2.58 billion barrels and end 2014 at 2.57 billion barrels (56 days of supply).

Crude Oil Prices. Brent crude oil spot prices fell from a recent peak of \$117 per barrel in early September to \$108 per barrel at the end of the month. EIA expects the Brent crude oil price to continue to weaken as non-OPEC supply grows, averaging \$107 per barrel during the fourth quarter of 2013 and \$102 per barrel in 2014.

The forecast WTI crude oil spot price, which averaged \$106 per barrel during September, averages \$101 per barrel during the fourth quarter of 2013 and \$96 per barrel during 2014. The discount of WTI crude oil to Brent crude oil, which averaged \$18 per barrel in 2012 and then fell to \$3 per barrel in July 2013, averaged \$5 per barrel during September. EIA expects the WTI discount to average \$6 per barrel during the fourth quarter of 2013 and during 2014.

Energy price forecasts are highly uncertain, and the current values of futures and options contracts suggest that prices could differ significantly from the forecast levels ([Market Prices and Uncertainty Report](#)). WTI futures contracts for January 2014 delivery traded during the five-day period ending October 3, 2013, averaged \$102 per barrel. Implied volatility averaged 20%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in January 2014 at \$85 per barrel and \$121 per barrel, respectively. Last year at this time, WTI for January 2013 delivery averaged \$92 per barrel and implied volatility averaged 31%. The corresponding lower and upper limits of the 95% confidence interval were \$70 per barrel and \$121 per barrel.

U.S. Crude Oil and Liquid Fuels

After reaching \$3.68 per gallon on July 22, 2013, U.S. regular gasoline retail prices fell to \$3.43 per gallon on September 30, 2013. The [largest declines in retail gasoline prices before Labor Day were seen along the West Coast](#), with ample inventories and an absence of refinery outages such as those that occurred during the summer of 2012. EIA expects regular gasoline retail prices to average \$3.34 per gallon during the fourth quarter of 2013.

U.S. Liquid Fuels Consumption. In 2012, total liquid fuels consumption declined by 390,000 bbl/d (2.1%). Total liquid fuels consumption for the first three quarters of 2013 rose 110,000 bbl/d (0.6%) compared with the same period last year, led by increases in liquefied petroleum gas and distillate consumption. Motor gasoline and jet fuel consumption, however, remained relatively flat, reflecting moderate growth in travel activity offset by continued efficiency growth for both fuels. These patterns extend to the fourth quarter, resulting in overall liquid consumption growth of 0.7% for the year as a whole. In 2014, total consumption of liquid fuels remains close to its 2013 level. EIA continues to expect [gasoline consumption to decline](#) in 2014 by 0.4% as continued improvements in new-vehicle fuel economy boost overall fuel efficiency growth, which outpaces growth in highway travel. Distillate consumption rises by 2.1% in 2014, buoyed by growth in industrial production, in the imports of goods, and an increase in coal production.

U.S. Liquid Fuels Supply. EIA expects U.S. crude oil production to rise from an average of 6.5 million bbl/d in 2012 to 7.5 million bbl/d in 2013 and 8.5 million bbl/d in 2014. The continued focus on drilling in tight oil plays in the onshore Williston, Western Gulf, and Permian basins is expected to account for the bulk of forecast production growth over the next two years. Offshore production from the Gulf of Mexico is forecast to average 1.3 million bbl/d in 2013 and 1.4 million bbl/d in 2014.

Since reaching 12.5 million bbl/d in 2005, total U.S. liquid fuel net imports, including crude oil and petroleum products, have been falling. Total liquid fuel net imports fell to 7.4 million bbl/d in 2012, and EIA expects net imports to continue declining to an average of 5.3 million bbl/d by 2014. Similarly, the share of total U.S. consumption met by liquid fuel net imports peaked at more than 60% in 2005 and fell to an average of 40% in 2012. EIA expects the net import share to decline to 28% in 2014, which would be the lowest level since 1985.

U.S. Petroleum Product Prices. EIA expects that regular-grade gasoline retail prices, which averaged \$3.53 per gallon during September, will average \$3.34 per gallon during the fourth quarter of 2013. Led by falling crude oil prices, the projected U.S. annual average regular gasoline retail price falls from \$3.63 per gallon in 2012 to an average of \$3.52 per gallon in 2013 and \$3.40 per gallon in 2014. Diesel fuel prices, which averaged \$3.97 per gallon in 2012, are projected to average \$3.93 per gallon in 2013 and \$3.76 per gallon in 2014.

Natural Gas

Under the baseline winter weather scenario, EIA expects end-of-October working gas inventories will total 3,830 billion cubic feet (Bcf) and end March 2014 at 1,890 Bcf. The projected 1,940 Bcf inventory drawdown during this winter is similar to the previous five-winters (October 2008 – March 2013) average of 1,940 Bcf. Because storage withdrawals are primarily used to meet winter heating demand, changes in weather can significantly alter winter drawdowns. This year's Winter Fuels Outlook projects a drawdown of 2,340 Bcf in the cold-

winter scenario (heating degree days 10% higher than projected), and 1,560 Bcf in the warm-winter scenario (10% fewer heating degree days). In the cold-winter scenario, storage inventories exit the heating season with a projected 1,450 Bcf at the end of March. However, this cold-winter scenario ending stock level is still higher than the average 1,271 Bcf end-of-winter stocks during the previous decade (2000-2009), reflecting increases in storage capacity as well as production over the last few years.

U.S. Natural Gas Consumption. EIA expects that natural gas consumption, which averaged 69.7 Bcf/d in 2012, will average 70.0 Bcf/d and 69.4 Bcf/d in 2013 and 2014, respectively. Colder winter temperatures in 2013 and 2014 (compared with the record-warm temperatures in 2012) are expected to increase the amount of natural gas used for residential and commercial space heating. However, the projected year-over-year increases in natural gas prices contribute to declines in natural gas used for electric power generation from 25.0 Bcf/d in 2012 to 22.1 Bcf/d in 2013 and 21.6 Bcf/d in 2014.

U.S. Natural Gas Production and Trade. Natural gas marketed production is projected to increase from 69.2 Bcf/d in 2012 to 70.0 Bcf/d in 2013 and to 70.4 Bcf/d in 2014. Natural gas pipeline gross imports, which have fallen over the past five years, are projected to fall by 0.3 Bcf/d in 2013 and then remain near 2013 levels in 2014. LNG imports are expected to remain at minimal levels of around 0.4 Bcf/d in both 2013 and 2014.

U.S. Natural Gas Inventories. As of September 27, working gas stocks totaled 3,487 Bcf, which is 155 Bcf less than at the same time last year, and 49 Bcf greater than the previous five-year (2008-12) average for that week. EIA projects inventories will total 3,830 Bcf at the end of the injection season, and 1,890 Bcf at the end of March 2014, the end of the winter heating season.

U.S. Natural Gas Prices. Natural gas spot prices averaged \$3.62 per MMBtu at the Henry Hub in September, up 19 cents from the previous month's price. While prices declined from April through August, they began increasing last month in anticipation of winter heating demand. EIA expects the Henry Hub price will increase from an average of \$2.75 per MMBtu in 2012 to \$3.71 per MMBtu in 2013 and \$4.00 per MMBtu in 2014.

Natural gas futures prices for January 2014 delivery (for the five-day period ending October 3, 2013) averaged \$3.83 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for January 2014 contracts at \$2.91 per MMBtu and \$5.04 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for January 2013 averaged \$3.84 per MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$2.77 per MMBtu and \$5.31 per MMBtu.

Coal

Coal production, based on preliminary data for the first eight months, is down 3% from the same period last year. Production was down in nearly every coal-producing region (Illinois Basin (ILB) production was up 3%), but the largest decline was in the Appalachian region. Coal production in the Appalachian region was down 7% with Central Appalachian Basin (CAP) production down 12%. A recent report released by the [Kentucky Energy and Environment Cabinet](#) (KEEC) showed that employment at the state's coal mines was at its lowest level since the data was first collected in 1927. In the two years since July 2011, the KEEC reported that employment at eastern Kentucky (CAP) mines fell by nearly 42%. Western Kentucky (ILB) mines saw employment fall only 2% over the same time period. There are signs that the shift in production will continue as several power generators have announced plans to shift from CAP coal to cheaper, though higher in sulfur content, ILB coal. Retrofitting of coal-fired generating units with flue-gas desulfurization (FGD), or scrubbers, contributes to this shift to higher-sulfur coal.

U.S. Coal Supply. Coal production in the first half of 2013 was 488 million short tons (MMst), 20 MMst (3.9%) lower than in the same period of 2012. EIA projects higher production in all regions during the second half of 2013 with total coal production of 1,012 MMst in 2013. Coal production is forecast to grow by 3.1% in 2014 to 1,043 MMst as inventories stabilize and consumption increases.

Inventory draws are expected to meet most of the growth in consumption in 2013. Total coal inventories fell by 19 MMst during the first half of 2013. EIA forecasts an additional 10 MMst of inventory withdrawals over the second half of 2013.

U.S. Coal Consumption. EIA estimates that total coal consumption for the first half of 2013 was 446 MMst, or 36 MMst (8.8%) higher than the amount of coal consumed in the first six months of 2012. The increase was primarily a result of consumption growth in the electric power sector because of higher electricity demand and higher natural gas prices. EIA expects that this trend will continue in the second half of 2013 with total coal consumption for the year of 936 MMst (a 5.1% increase over 2012). Consumption grows at about half that rate (2.8%), to 962 MMst in 2014.

U.S. Coal Exports. EIA estimates that first-half 2013 exports totaled 61 MMst, which was 5 MMst lower than the same period last year. Exports for the next six months are expected to continue declining, with second-half exports totaling 53 MMst, down 7 MMst from last year. Exports are projected to total 105 MMst in 2014. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, increasing coal output in other coal-exporting countries, and falling international coal prices are the primary reasons for the expected decline in U.S. coal exports.

U.S. Coal Prices. EIA expects nominal annual average coal prices to the electric power industry to fall for the first time since 2000, from \$2.40 per MMBtu in 2012 to \$2.33 per MMBtu in 2013. EIA forecasts average delivered coal prices of \$2.34 per MMBtu in 2014.

Electricity

The electricity industry retired 10.5 gigawatts (GW) of coal-fired generating capacity during 2012. Most of this capacity consisted of older, inefficient units, which generators found uneconomical to run as a result of low natural gas prices and slow growth in electricity demand. Coal capacity retirements have continued into 2013, albeit at a slower pace, with 1.4 GW reported to EIA through July. Despite the retirements, coal-fired generation during the first seven months of 2013 was 7.5% higher than the same period last year as generators utilized existing capacity at higher rates in response to rising natural gas prices.

U.S. Electricity Consumption. EIA expects U.S. retail sales of electricity to the residential sector to grow by 0.4% in 2013 and fall by 1.0% in 2014. About two-thirds of households in the South Census region use electricity as their primary heating source. Heating degree days in this region during the upcoming winter months (October-March) are expected to be slightly higher than last winter. Growth in the total number of households, leads to a 1.0% winter-over-winter increase in residential electricity sales in the South region.

U.S. Electricity Generation. EIA expects total U.S. electricity generation will grow by 0.1% in 2013 and by 0.4% in 2014. Despite the retirement of coal-fired generating capacity, higher prices for natural gas delivered to electric generators drive a projected 6.1% increase in coal generation this year while natural gas-fired generation falls by 9.8%. The addition of new capacity leads to a 14% increase in generation from renewable energy sources other than hydropower during 2013, and contributes about 6% of total generation.

U.S. Electricity Retail Prices. The rising cost of generation fuels, particularly natural gas, contributes to a projected increase in the residential price of electricity. During the upcoming winter months, EIA expects the U.S. residential electricity price to average 11.9 cents per kilowatthour, which is 2.3% higher than the winter of 2012-13.

Renewables and Carbon Dioxide Emissions

U.S. Electricity and Heat Generation from Renewables. EIA projects renewable energy consumption for electricity and heat generation to increase by 4.5% in 2013. While hydropower declines by 1.5%, nonhydropower renewables used for electricity and heat generation grow by an average of 8.3% in 2013. In 2014, the growth in renewables consumption for electric power and heat generation is projected to continue at a rate of 2.3%, as a 0.9% increase in hydropower is combined with a 3.1% increase in nonhydropower renewables.

EIA estimates that wind capacity will increase by 2.5% this year to about 61 GW and will total more than 66 GW in 2014. EIA has lowered the 2014 capacity projection for wind by 3.5% from last month's STEO, under the assumption that some wind power projects will be delayed to the following year. Recently updated Internal Revenue Service guidance on production tax credits (PTC) has clarified that all projects that begin construction by the end of 2013 and enter service by the end of 2015 will qualify for the PTC. Electricity generation from wind is projected to increase by 19% in 2013 and by 2.4% in 2014, contributing more than 4% of total electricity generation.

EIA expects continued robust growth in the generation of solar energy, although the amount of utility-scale generation remains a small share of total U.S. generation, about 0.3% by 2014. Utility-scale capacity, which until recently experienced little growth compared with customer-sited distributed generation capacity, is projected to more than double between 2012 and 2014. Photovoltaics (PV) accounted for all utility-scale solar growth in 2012, but EIA expects that several large solar thermal generation projects will enter service in 2013 and 2014. However, PV is still expected to account for most of the capacity additions in 2013 and 2014. Solar generation by the electric power sector increases 79% in 2013 and 80% in 2014.

U.S. Liquid Biofuels. The ethanol industry is beginning to show some recovery from last year's drought when fuel ethanol production fell from an average 900,000 bbl/d in the first half of 2012 to an average of 820,000 bbl/d from July 2012 through March 2013. Ethanol production averaged 850,000 bbl/d during September 2013 and is forecast to average 880,000 bbl/d during 2014. Biodiesel production, which averaged 63,000 bbl/d (1.0 billion gallons per year) in 2012, has been rising this year and reached a record level of 128 million gallons (98,000 bbl/d) in July 2013. Biodiesel production is forecast to average about 82,000 bbl/d in 2013 and 87,000 bbl/d in 2014.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels declined by 4.0% in 2012, and projects increases of 1.7% in 2013 and 0.9% in 2014. The increase in emissions over the forecast period primarily reflects the projected increase in coal use for electricity generation, especially in 2013 as it rebounds from the 2012 decline.

U.S. Economic Assumptions

EIA uses the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO. The GI simulation used in this STEO includes recent revisions to the National Income and Product Accounts (NIPA) by the U.S. Bureau of Economic Analysis (BEA). It also assumes that the spending cuts mandated in the Budget Control Act of 2011 (sequestration) are replaced by a combination of tax and spending changes that are implemented in 2014. In addition, the GI forecast does not make any assumptions about the economic impacts of a government shutdown, but assumes there will be an agreement reached to increase the amount of debt that can be issued by the U.S. Treasury.

U.S. Current Trends. The [U.S. Bureau of Economic Analysis](#) reported that real disposable personal income rose 0.3% from July to August 2013, while real consumption expenditures rose 0.2% over the same time period. The [U.S. Department of Labor](#) also reported that initial weekly unemployment insurance claims were 308,000 in the week ending September 28, 2013, an increase of 1,000 from the previous week's figure, but still lowering the 4-week moving average to 305,000. The [U.S. Census Bureau](#) reported that new orders for manufactured durable goods rose 0.1% in August, following a revised 8.1% decrease in July.

U.S. Production and Income. Forecast U.S. real GDP grows by 1.6% in 2013 and 2.6% in 2014. Year-on-year real GDP growth begins to accelerate in the second half of 2014, eventually rising to 3.0% in the fourth quarter of 2014. Forecast real disposable income increases 0.5% in 2013 and 3.2% in 2014. Total industrial production grows almost one percentage point faster than real GDP in 2013 at 2.3%, and its projected growth of 3.0% in 2014 is still well above the growth rate of real GDP.

U.S. Expenditures. Private real fixed investment growth averages 4.6% and 8.0% over 2013 and 2014, respectively. Real consumption expenditures grow faster than real GDP in 2013, at 1.9%, but slows below the rate of real GDP growth in 2014, at 2.5%. Export growth triples from 1.7% to 5.1% over the same two years. Government expenditures fall 3.0% in 2013, and rise by 0.1% in 2014.

U.S. Employment, Housing, and Prices. The unemployment rate in the forecast averages 7.6% over 2013, and gradually falls to 6.9% at the end of 2014. This is accompanied by nonfarm employment growth averaging 1.7% in both 2013 and 2014. Consistent with an improving housing sector, housing starts grow an average of 20% and 29% in 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.

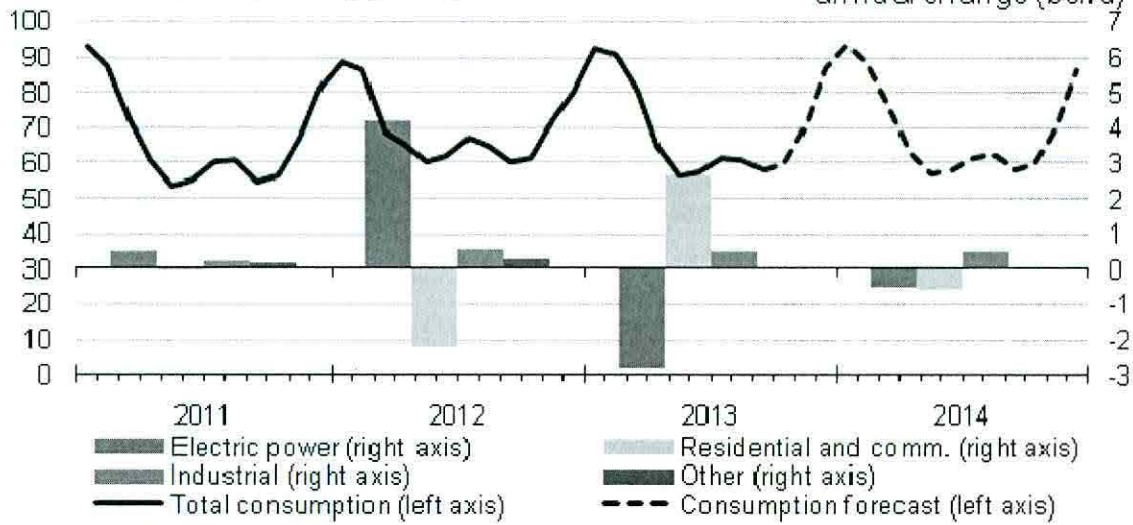
This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the U.S. Department of Energy or other federal agencies.

U.S. Natural Gas Consumption

billion cubic feet per day (bcf/d)



annual change (bcf/d)

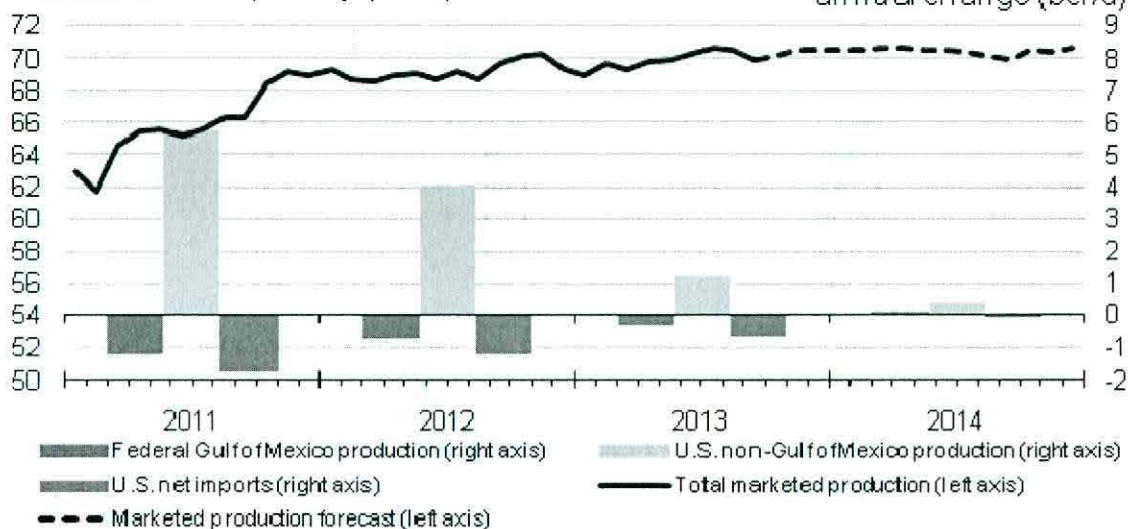


Source: Short-Term Energy Outlook, October 2013

U.S. Natural Gas Production and Imports

billion cubic feet per day (bcf/d)

annual change (bcf/d)



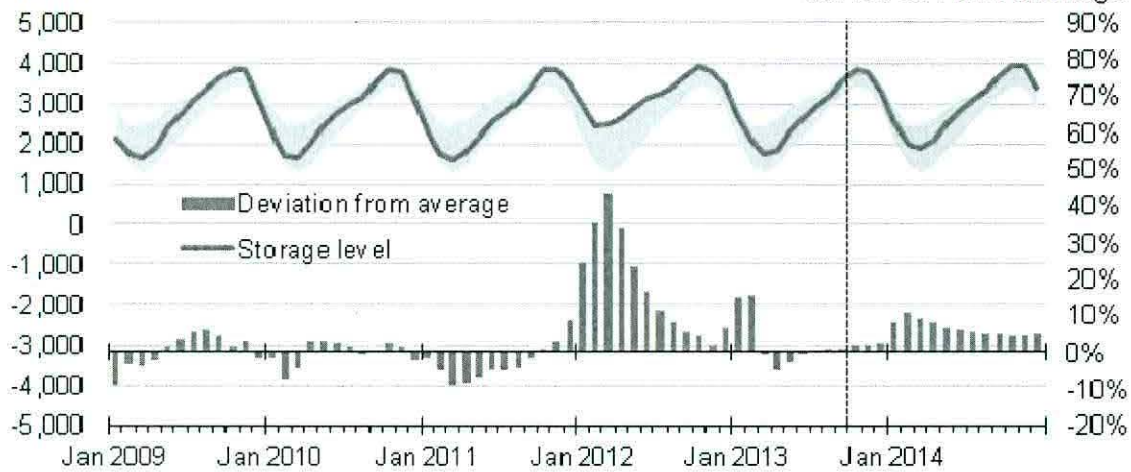
Source: Short-Term Energy Outlook, October 2013

U.S. Working Natural Gas in Storage

billion cubic feet



deviation from average

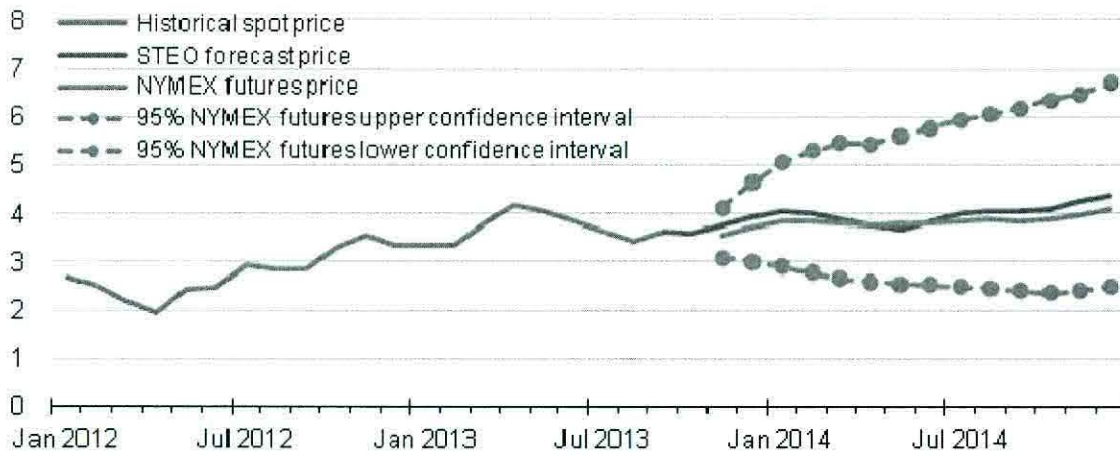


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2008 - Dec. 2012.

Source: Short-Term Energy Outlook, October 2013

Henry Hub Natural Gas Price

dollars per million Btu

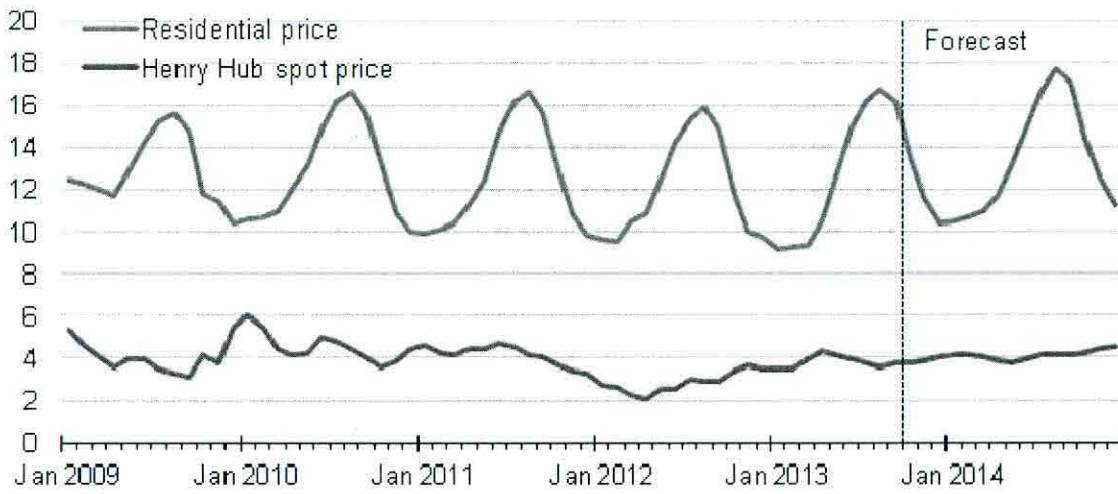


Note: Confidence interval derived from options market information for the 5 trading days ending October 3, 2013. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, October 2013

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, October 2013

**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, 2013									<u>\$303,311</u>
May	(\$12,469)	0	\$1,860	(\$10,609)	21,400	\$1.0137	\$21,692	(\$32,301)	271,010
June	4,837	0	1,626	6,463	9,214	0.9614	9,167 2/	(2,704)	268,306
July	19,011	0	1,601	20,612	6,004	0.9614	5,772	14,840	283,146
August	16,638	0	1,701	18,339	5,505	0.9614	5,293	13,046	296,192
September	296	0	1,658	1,954	5,691	0.9614	5,471	(3,517)	292,675
Total	\$28,313	0	\$8,446	\$36,759	47,814		\$47,395	(\$10,636)	
Balance @ September 30, 2013									<u>\$292,675</u>

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 5,911.4 dk @ \$1.0137 and 3,302.1 dk @ \$0.9614.

**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, 2013									<u>\$4,747</u>
May	(\$19,391)	0	(\$4)	(\$19,395)	49,736	(\$0.2915)	(\$14,498)	(\$4,897)	(150)
June	(13,383)	0	(46)	(13,429)	23,704	0.0274	(4,253) 2/	(9,176)	(9,326)
July	(9,266)	0	(115)	(9,381)	17,577	0.0274	482	(9,863)	(19,189)
August	(1,454)	0	(188)	(1,642)	14,808	0.0274	406	(2,048)	(21,237)
September	(28,851)	0	(203)	(29,054)	16,181	0.0274	443	(29,497)	(50,734)
Total	(\$72,345)	0	(\$556)	(\$72,901)	122,006		(\$17,420)	(\$55,481)	
Balance @ September 30, 2013									<u>(\$50,734)</u>

1/ Interest calculated at 13.3%, the authorized rate of return.

2/ Reflects 15,372.2 dk @ (\$0.2915) and 8,331.7 dk @ \$0.0274.