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

705 West Fir Ave.
Mailing Address:
P.O. Box 176
Fergus Falls, MN 56538-0176
1-877-267-4764

September 30, 2013

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

Re: Cost of Gas Adjustment (COG)
October 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 (91st Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (91st Revised Sheet No. 8), showing the October 2013 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.0036 per mcf for all customers.

Attachment B shows the calculations supporting the gas costs for October 2013, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.0036 since the last COG filing.

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.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Tamie A. Aberle
Director of Regulatory Affairs

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
91st Revised Sheet No. 1.1
Canceling 90th Revised Sheet No.1.1
Page 1 of 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	$6.1364	$7.4104
			Over 10 MCF	1.0540		7.1904
Firm Gas Service - General Highway 13	2.5	$3.50 per month	First 10 MCF	$2.1740	$6.1364	$8.3104
			Over 10 MCF	1.9540		8.0904
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.6794	$4.8185
			Next 2,600 MCF	0.8931		4.5725
			Over 3,000 MCF	0.7411		4.4205
Interruptible Gas Service - Highway 13	3.5	$3.50 per month	First 400 MCF	$2.0391	$3.6794	$5.7185
			Next 2,600 MCF	1.7931		5.4725
			Over 3,000 MCF	1.6411		5.3205
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.6794	$4.9185
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: September 30, 2013

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
91st Revised Sheet No. 8
Canceling 90th 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.	1.4722	(1.4785)	0.9614	0.9551	(1.4635)	0.0274	(1.4361)
Current Adj.	0.0000	(0.0036)	0.0000	(0.0036)	(0.0036)	0.0000	(0.0036)
Total Adj.	1.4722	(1.4821)	0.9614	0.9515	(1.4671)	0.0274	(1.4397)
Total Rate	$1.5380	$3.6370	$0.9614	$6.1364	$3.6520	$0.0274	$3.6794

Date Filed: September 30, 2013

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

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

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A	8,000		$3.4671	12	$332,842	$0.2373
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	0.0269
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					$2,136,019	1.5380
Estimated Weighted Average Commodity Cost	1,402,522	1/	3.6370		5,100,973	3.6370
Gas Cost Reconciliation Adjustment						0.9614
Total Current Firm Gas Cost					$7,236,992	6.1364
Base Cost of Gas						5.1849
Accumulated Adjustment						$0.9515

Interruptible	
Estimated Weighted Average Commodity Cost	$3.6370
Gas Cost Reconciliation Adjustment	0.0274
LMS Demand 2/	0.0150
Total Current Interruptible Gas Cost	3.6794
Base Cost of Gas	5.1191
Accumulated Adjustment	($1.4397)

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.

	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
LMS Demand	2,500	$1.0000	12	$30,000	$0.0150

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

Rates Effective October 1, 2013	$/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	15.1530	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	3.6370	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

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

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	Fuel and Loss Retention Percentages 2/
Commodity Rates 1/		
FT-A – Maximum Rates		
Zone 1-1	$0.0130	0.36%
Zone 1-2	$0.0130	0.47%
Zone 2-2	$0.0130	0.11%
Minimum Rate	$0.0130	
IT and AOT		
Zone 1-1	$0.1368	0.36%
Zone 1-2	$0.1737	0.47%
Zone 2-2	$0.0834	0.11%
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: 0.06% for Zone 1-1, 0.08 % for Zone 1-2, and 0.02% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted for percentages.

Rate Schedule	Base Tariff Rate	Adjustment Under Section 27 1/	Rate After Current Adjustment
LMS – Monthly Demand Rate	$1.0000		$1.0000
LMS – Daily Overrun Rate	$0.1737		$0.1737
LMS – Load Management Cost Reconciliation Adjustment		$0.0001	

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

RATE SCHEDULE TF

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

COMMODITY RATES 2/ TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0359	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.

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	0.0359	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/ 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	0.0000	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

	Percentages
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.87%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.33% 4/ 5/
FDD Storage Fuel	1.55%

	Electric Compression
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
October 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 October monthly price for the NNG-Ventura Index is expected to be in the same price range as the previous month index. The NNG-Ventura Index is based on negotiated trades during the last five business days of the month, commonly known as bid week, and reported by Platt's Inside FERC's Gas Market Report published the beginning of each month.

The combination of continued strong domestic production, lower year over year consumption of natural gas in the electric generation segment, and storage near the five year average, likely contributed to the index remaining in the same price range as the previous month. The EIA reported storage levels nationwide as of September 20, 2013 were 0.9 percent above the five-year average and 5.0 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 16.

Independent Statistics & Analysis
U.S. Energy Information Administration

September 2013

Short-Term Energy Outlook (STEO)

Highlights

- Monthly average crude oil prices increased for the fourth consecutive month in August 2013, as supply disruptions in Libya increased and concerns over the conflict in Syria intensified. The U.S. Energy Information Administration's (EIA) forecast for Brent crude oil spot price, which averaged $108 per barrel during the first half of 2013, averages $109 per barrel over the second half of 2013 and $102 per barrel in 2014, $5 per barrel and $2 per barrel higher than forecast in last month's STEO, respectively. Projected West Texas Intermediate (WTI) crude oil prices average $101 per barrel during the fourth quarter of 2013 and $96 per barrel during 2014. Energy price forecasts are highly uncertain and could differ significantly from the projected levels. The current values of futures and options contracts suggest the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in December 2013 at $86 per barrel and $131 per barrel, respectively.

- In August, unplanned disruptions among the Organization of the Petroleum Exporting Countries (OPEC) and non-OPEC producers reached an estimated 2.7 million barrels per day (bbl/d), the highest level since at least January 2011 (see *EIA Estimates of Crude Oil and Liquid Fuels Supply Disruptions* and *Status of Libyan Loading Ports and Oil and Natural Gas Fields*). Of this volume, 0.6 million bbl/d was attributable to non-OPEC producers, while OPEC producers accounted for the remaining 2.1 million bbl/d of outages. OPEC disruptions reached the highest level since at least January 2009, when EIA began tracking this information.

- EIA's forecast for the regular gasoline retail price averages $3.44 per gallon in the fourth quarter of 2013, 11 cents per gallon higher than in last month's STEO. The annual average regular gasoline retail, which was $3.63 per gallon in 2012, is expected to be $3.55 per gallon in 2013 and $3.43 per gallon in 2014. As in the case of crude oil, the current value of futures and options contracts suggests a wide uncertainty in market expectations.

- U.S. crude oil production increased to an average of 7.6 million bbl/d in August, the highest monthly level of production since 1989. EIA forecasts U.S. total crude oil production will average 7.5 million bbl/d in 2013 and 8.4 million bbl/d in 2014, about 0.1 million bbl/d and 0.2 million bbl/d higher, respectively, than forecast in last month's STEO.

- Natural gas working inventories ended August at an estimated 3.2 trillion cubic feet (Tcf), 0.21 Tcf below the level at the same time a year ago and 0.04 Tcf above the five-year average (2008-12). EIA expects the Henry Hub natural gas spot price, which averaged $2.75 per million British thermal units (MMBtu) in 2012, will average $3.68 per MMBtu in 2013 and $3.91 per MMBtu in 2014.

Global Crude Oil and Liquid Fuels

An increase in unplanned liquid fuels production disruptions in August combined with peak summer demand and exacerbated by rising concerns over the conflict in Syria and its regional implications, contributed to a tighter world oil market during the month. The total volume of world production that is offline because of unplanned outages among OPEC and non-OPEC producers in August was the highest since at least January 2011(see *EIA Estimates of Crude Oil and Liquid Fuels Supply Disruptions* and *Status of Libyan Loading Ports and Oil and Natural Gas Fields*). Liquid fuels production disruptions in August reached 2.7 million bbl/d, with 2.1 million bbl/d of crude oil production outages from OPEC producers. This level of crude oil production outages among OPEC producers is the highest since at least January 2009, when EIA began tracking OPEC outages.

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) falling from an average 30.0 million bbl/d in 2013 to 29.4 million bbl/d in 2014.

Global Liquid Fuels Consumption. EIA projects global consumption to grow by 1.1 million bbl/d in 2013 and by another 1.2 million bbl/d in 2014, with China, the Middle East, Central and 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 both 2013 and 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.

Non-OPEC Supply. Forecast non-OPEC liquid fuels production increases by 1.6 million bbl/d in 2013 and by 1.4 million bbl/d in 2014. The largest area of non-OPEC 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 and Asia & Oceania. 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 0.1 million bbl/d in 2013 and 0.2 million bbl/d in 2014. The increase in supply in 2014 in this region comes mostly from production growth in China, Malaysia, and Australia.

Of the 2.7 million bbl/d of total supply disruptions globally, approximately 0.6 million bbl/d of the outages occurred among non-OPEC producers. These estimates of unplanned liquid fuels outages exclude normal maintenance and reflect the level of volumes shut in compared with an assessment of effective production capacity, which EIA periodically updates. Sudan and South Sudan, Syria, and Yemen accounted for more than 80% of all non-OPEC disruptions, with smaller volumes shut in elsewhere, including Brazil and the North Sea.

OPEC Supply. EIA projects total OPEC liquid fuels production to decline by 0.8 million bbl/d in 2013 and 0.2 million bbl/d in 2014. These declines reflect unplanned outages of crude oil production among some OPEC producers as well as decreases in Saudi Arabia's production in response to the increase in non-OPEC supply.

Overall OPEC crude oil unplanned disruptions in August totaled about 2.1 million bbl/d. Additional details in EIA's estimates of unplanned disruptions are provided in a supplement to this release of the STEO.

Total OPEC surplus crude oil production capacity in the second quarter of 2013 averaged 2.2 million bbl/d, which is 0.2 million bbl/d above the year-ago level, but still nearly 1.0 million bbl/d lower than the historical three-year average. EIA projects OPEC surplus capacity will increase to an average of 2.5 million bbl/d in the fourth quarter of 2013, and 4.6 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 EU 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 57.7 days of supply. OECD oil inventories are projected to end 2013 at 2.66 billion barrels (57.3 days of supply) and end 2014 at 2.69 billion barrels (58.1 days of supply).

Crude Oil Prices. After declining to a 2013 year-to-date low of $97 per barrel on April 17, Brent crude oil spot prices increased to an average of $111 per barrel in August. EIA projects the Brent crude oil spot price will fall to an average $105 per barrel in December. The Brent crude oil annual average spot price declines from $112 per barrel in 2012 to $108 per barrel and $102 per barrel in 2013 and 2014, respectively, reflecting the increasing supply of liquid fuels from non-OPEC countries.

The forecast WTI crude oil spot price averages $99 per barrel in 2013 and $96 per barrel in 2014, $2 per barrel and $3 per barrel higher, respectively, than last month's STEO. The discount of WTI crude oil to Brent crude oil, which averaged $18 per barrel in 2012 and increased to a

monthly average of $21 per barrel in February 2013 before falling to $3 per barrel in July, reached $8 per barrel at the end of August, and averaged $5 per barrel for the month. Supply disruptions in Libya, growing tensions in Syria, and seasonal maintenance in the North Sea contributed to Brent crude oil prices increasing more than WTI crude oil over the last two weeks of August. EIA expects the WTI discount to average $6.50 per barrel during the fourth quarter of 2013 as U.S. refinery runs fall from summer highs and midcontinent crude oil production growth outpaces increases in capacity to transport crude oil from the region to other refining centers.

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 December 2013 delivery traded during the five-day period ending September 5, 2013, averaged $106 per barrel. Implied volatility averaged 25%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in December 2013 at $86 per barrel and $131 per barrel, respectively. Last year at this time, WTI for December 2012 delivery averaged $96 per barrel and implied volatility averaged 31%. The corresponding lower and upper limits of the 95-% confidence interval were $74 per barrel and $126 per barrel.

U.S. Crude Oil and Liquid Fuels

After reaching a weekly peak of $3.68 per gallon on July 22, 2013, U.S. regular gasoline retail prices averaged $3.57 per gallon during August. The largest declines in retail gasoline prices were seen along the West Coast, with ample inventories and an absence of refinery outages such as those during the summer of 2012. EIA expects regular gasoline retail prices to average $3.44 per gallon during the fourth quarter of 2013 as crude oil prices begin to fall and the summer driving season comes to a close.

U.S. Liquid Fuels Consumption. In 2012, total liquid fuels consumption declined by 395,000 bbl/d (2.1%). Total liquid fuels consumption for the first half of 2013 rose by 70,000 bbl/d (0.4%) compared with the same period last year, led by increases in liquefied petroleum gas and distillate consumption. Projected total liquids consumption during the second half of 2013 increases 180,000 bbl/d (1%) from the same period last year, with all of the finished products contributing to that growth. However, EIA continues to expect declining gasoline consumption in 2014 as improving fuel economy of new vehicles continues to outpace growth in highway travel. Also, jet fuel consumption remains flat as increased fuel efficiencies brought about by fleet turnover more than offset increases in air freight and travel. In 2014, total consumption of liquid fuels increases by only 30,000 bbl/d (0.2%) with further declines in motor gasoline offset by higher distillate fuel consumption.

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 8.4 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 net imports fell to 7.4 million bbl/d in 2012, and EIA expects net imports to continue declining to an average of 5.4 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 29% 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 $3.59 per gallon during the first half of 2013, will average $3.60 per gallon and $3.44 per gallon during the third and fourth quarters of 2013, respectively. As the summer driving season (April through September) comes to a close, regular gasoline retail prices are expected to average $3.60 per gallon during the summer of 2013, 9 cents per gallon lower than in 2012. Led by falling crude oil prices, the projected U.S. average regular gasoline retail price falls from $3.63 per gallon in 2012 to an average $3.55 per gallon in 2013 and $3.43 per gallon in 2014. Diesel fuel prices, which averaged $3.97 per gallon in 2012, are projected to average $3.96 per gallon in 2013 and $3.82 per gallon in 2014.

The current values of futures and options contracts suggest that gasoline prices could differ significantly from this forecast. For example, there is a 18% probability that the New York Harbor reformulated gasoline blendstock for oxygenate blending (RBOB) futures price will exceed $3.10 per gallon (consistent with a U.S. average regular gasoline retail price above $3.75 per gallon) in December 2013.

Natural Gas

Working natural gas in storage is expected to total about 3,820 billion cubic feet (Bcf) at the end of next month, the nominal end of the 2013 injection season. Injections of natural gas into storage often continue into November, depending on weather and storage levels at the time.

This month's STEO increases the end-of-October projection for working gas in storage by about 20 Bcf from last month's forecast. In addition to the reclassification of 14 Bcf of base gas to working gas during August, cooler-than-expected August weather has moderated demand for air conditioning, allowing for more natural gas to go into storage. The new end-of-October projection is still about 100 Bcf short of the all-time high of 3,929 Bcf, reached last October. EIA expects the sum of injections from April through October will total around 2,100 Bcf, which is relatively normal compared with recent years, and much higher than last year's unusually low cumulative injection of 1,451 Bcf, which began the injection season on April 1 with higher stock levels.

U.S. Natural Gas Consumption. EIA expects that natural gas consumption, which averaged 69.7 Bcf/d in 2012, will average 69.9 Bcf/d and 69.3 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 69.9 Bcf/d in 2013 and to 70.4 Bcf/d in 2014. Onshore production increases over the forecast period, while federal Gulf of Mexico production from existing fields declines as the economics of onshore drilling remain more favorable. Natural gas pipeline gross imports, which have fallen over the past five years, are projected to fall by 0.2 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 August 30, working gas stocks totaled 3,188 Bcf, which is 210 Bcf less than at the same time last year, and 43 Bcf greater than the five-year (2008-12) average for that week. EIA projects inventories will total 3,820 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 $3.43 per MMBtu at the Henry Hub in August , down 20 cents from the previous month's price. While prices have been declining since April, EIA expects this pattern will reverse in September as the weather becomes cooler and natural gas demand for space heating begins to become a factor. EIA expects the Henry Hub price will increase from an average of $2.75 per MMBtu in 2012 to $3.68 per MMBtu in 2013 and $3.91 per MMBtu in 2014.

Natural gas futures prices for December 2013 delivery (for the five-day period ending September 5, 2013) averaged $3.87 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for December 2013 contracts at $2.98 per MMBtu and $5.04 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for December 2012 averaged $3.20 per MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $2.20 per MMBtu and $4.65 per MMBtu.

Coal

Based on preliminary monthly data for July 2013, coal production totaled 88.9 million short tons (MMst) for the month, the highest level since August 2012 and up 3.0% from the previous July's total. Coal production in the Appalachian and Western regions was up 3.0% and 4.8%, respectively. Although Interior region production declined by 2.8% year-over-year in July, Illinois

basin production did increase slightly. July also saw a significant reduction in coal inventories held by electric power producers.

U.S. Coal Supply. Coal production in the first half of 2013 was 486 MMst, 21 MMst (4.2%) lower than in the same period of 2012. EIA projects higher production in all regions during the second half of 2013 compared with the same period last year, with total coal production of 1,013 MMst in 2013. Coal production is forecast to grow by 3.0% in 2014 to 1,044 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 9 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 (8.7%) 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 942 MMst (a 5.8% increase over 2012). Consumption grows at a more modest rate of 1.8% to 959 MMst in 2014.

U.S. Coal Exports. EIA estimates that first half 2013 exports totaled 61.3 MMst, which was 4.9 MMst lower than the same period last year. Exports for the next six months are expected to continue declining, with second-half exports totaling 54 MMst, down 6 MMst from last year. Exports are projected to total 109 MMst in 2014. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, increasing supply 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 $2.36 per MMBtu in 2013. EIA forecasts average delivered coal prices of $2.39 per MMBtu in 2014.

Electricity

In late August, owners of the Vermont Yankee nuclear station announced a decision to retire the plant next year, making it the fifth announced retirement of a nuclear power reactor in the past 12 months (San Onofre units 2 and 3 in California, Kewaunee unit 1 in Wisconsin, and Crystal River unit 3 in Florida). Operators of these plants have cited declining profitability and concerns over maintenance costs as important factors in the retirement decisions. Vermont Yankee contributed about 4% of the average monthly electricity retail sales in New England. Natural gas has become the dominant fuel used for power generation in that region in recent years,

accounting for 52% of total generation during 2012. New England also imports a significant amount of electricity from Canada.

U.S. Electricity Consumption. Residential electricity sales during the first half of this year increased by 3.4% over the same period last year. EIA expects that residential sales during the second half of 2013 will fall by 1.9% compared with the same period last year, in response to milder temperatures during the third quarter of this year. Forecast retail sales of electricity to the residential sector fall by 1.1% in 2014 while commercial sector retail electricity sales remain relatively flat and industrial sales grow by 2.1%.

U.S. Electricity Generation. EIA expects total U.S. electricity generation will grow by 0.2% in 2013 and by 0.4% in 2014. Higher prices for natural gas delivered to electric generators push down natural gas-fired generation by 9.6% during 2013. Much of this generation is picked up by coal generation, which EIA expects will grow by 7.1% this year. Nuclear generation during 2013 is expected to be 0.4% lower than generation last year, primarily as a result of unplanned outages this year. As discussed below, generation from renewable sources, particularly wind, increases in both 2013 and 2014.

U.S. Electricity Retail Prices. Generation fuel costs and wholesale electricity prices have increased this year after a considerable decline in 2012. Changes in the costs of providing electricity are not immediately reflected on retail customer bills because state regulatory commissions must approve rate changes in many areas of the country. EIA expects the residential retail price of electricity in 2013 will grow by 2.2% to an average of 12.1 cents per kilowatthour. Prices are expected to grow by another 1.5% in 2014.

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 3.3% in 2013. While hydropower declines by 3.8%, nonhydropower renewables used for electricity and heat generation grow by an average of 7.8% in 2013. In 2014, the growth in renewables consumption for electric power and heat generation is projected to continue at a rate of 3.8%, as a 3.2% increase in hydropower is combined with a 4.1% increase in nonhydropower renewables.

EIA estimates that wind capacity will increase by 3.9% this year to about 61 gigawatts and reach nearly 69 gigawatts in 2014. However, electricity generation from wind is projected to increase by 18% in 2013, as capacity that came on line at the end of 2012 is available for all of 2013. Wind-powered generation is projected to grow by 5% in 2014 and will contribute over 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 81% in 2013 and 76% in 2014.

U.S. Liquid Biofuels. Smaller corn harvests due to widespread drought resulted in U.S. fuel ethanol production falling from an average of approximately 900,000 bbl/d (13.9 billion gallons per year) in the first half of 2012 to an average of 820,000 bbl/d (12.6 billion gallons per year) from July 2012 through March 2013. Forecast ethanol production increases to an average 890,000 bbl/d in 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 113 million gallons (89,000 bbl/d) in June 2013. Biodiesel production is forecast to average about 81,000 bbl/d in 2013 and 87,000 bbl/d in 2014.

The U.S. Environmental Protection Agency's (EPA) final rule for the 2013 RFS program year maintains the statutory target of 16.55 billion ethanol-equivalent gallons of total renewable fuels. It would require refiners and importers of gasoline and diesel fuel to deliver RINs equivalent to the 2013 renewable volume obligation (RVO) of 9.63% of the gasoline or diesel fuel they sell domestically (not counting the biofuels blended into it). This forecast assumes that the 2014 renewable fuel standards are identical to those for 2013.

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 2.0% in 2013 and 0.5% 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 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, GI assumes there will be an agreement reached to increase the amount of debt that can be issued by the U.S. Treasury.

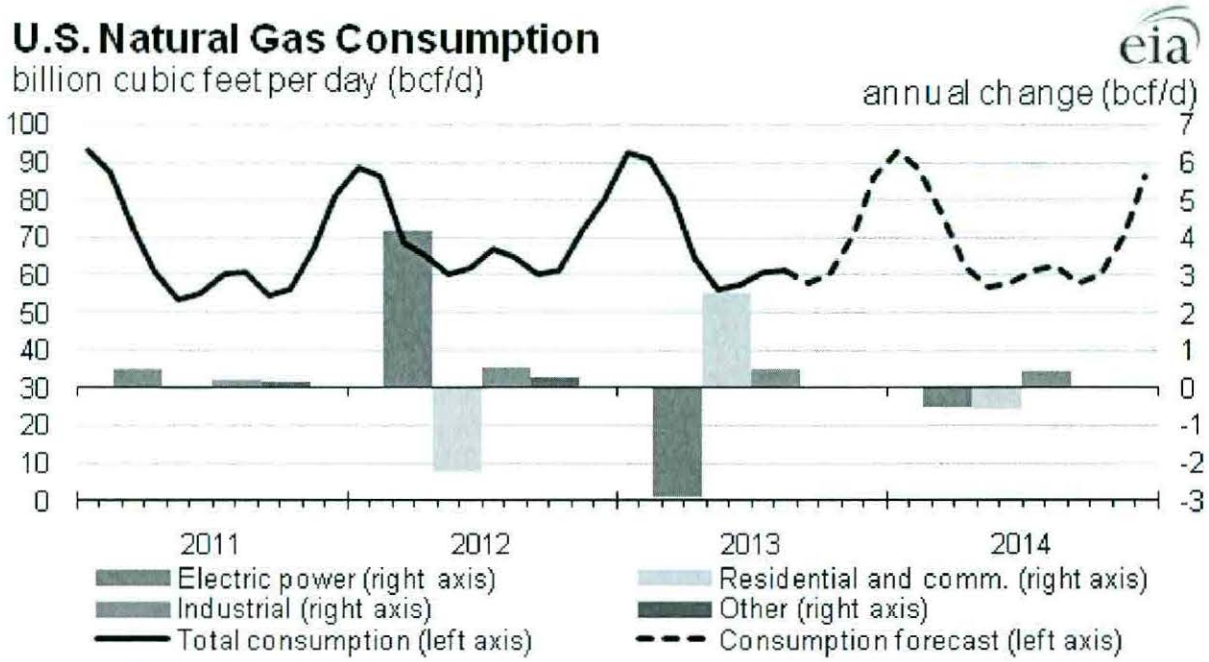
U.S. Current Trends. The U.S. Census Bureau reported that new orders for manufactured durable goods fell 7.3% in July, following a revised 3.9% increase in June. However, the July decrease is 0.6% if the transportation sector is excluded. The U.S. Commerce Department also reported that sales of new single-family homes increased by over 6.8% from July 2012 to July 2013, and fell 13.4% from June 2013 to July 2013. The Federal Reserve Board reported that total U.S. industrial production was unchanged from June to July 2013, while capacity utilization

fell by 0.1% over the same time period. The U.S. Bureau of Economic Analysis revised up real GDP annualized growth from the first to the second quarter of 2013 to 2.5% (from 1.7%).

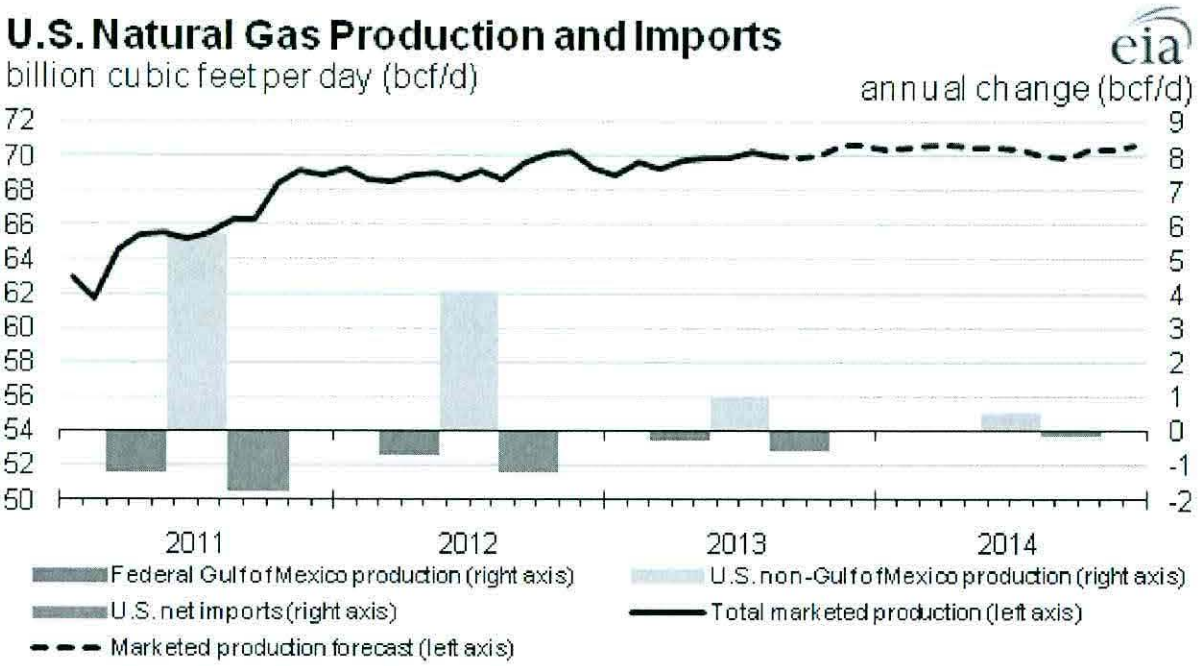
U.S. Production and Income. The STEO assumes 1.6% real U.S. GDP growth in 2013, rising to 2.6% in 2014. Year-on-year real GDP growth begins to accelerate in the second half of 2014, eventually rising to 3.2% in the fourth quarter of 2014. Forecast real disposable income increases 0.4% in 2013 and 3.5% in 2014. Total industrial production grows almost one percentage point faster than real GDP in 2013 at 2.5%, and its projected growth of 3.3% in 2014 is still well above the growth rate of real GDP.

U.S. Expenditures. Private real fixed investment growth averages 6.0% and 7.8% over 2013 and 2014, respectively. Real consumption expenditures grow faster than real GDP in 2013, at 1.9%, but slow below the rate of real GDP growth in 2014, at 2.3%. 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 7.0% at the end of 2014. This is accompanied by nonfarm employment growth averaging 1.6% in 2013 and 1.5% in 2014. Consistent with an improving housing sector, housing starts grow an average of 22.7% and 26.8% in 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.

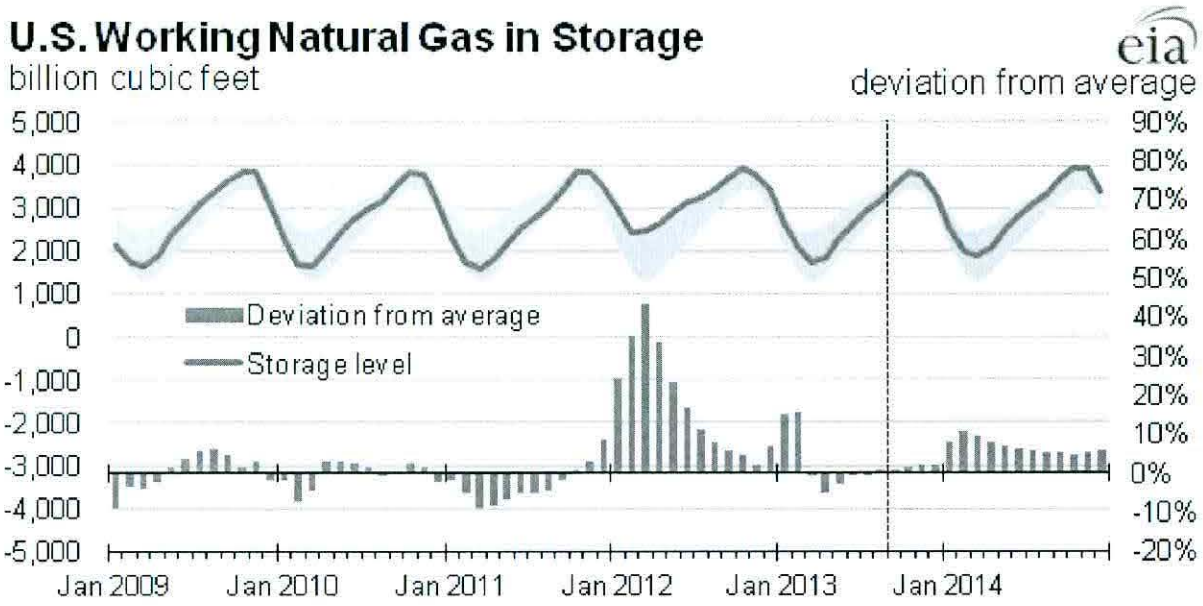


Source: Short-Term Energy Outlook, September 2013



Source: Short-Term Energy Outlook, September 2013

U.S. Working Natural Gas in Storage

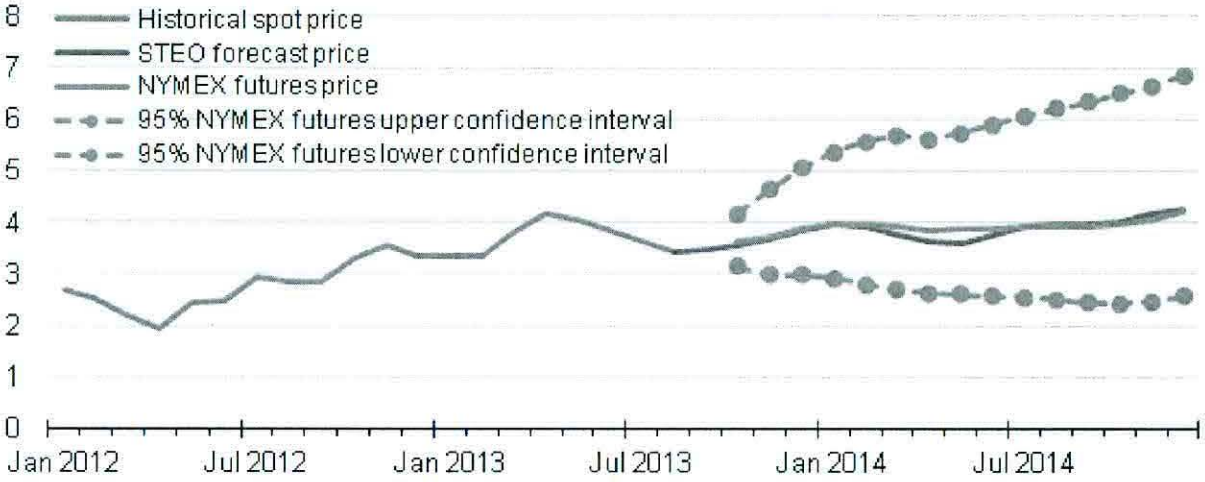


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2008 - Dec. 2012.

Source: Short-Term Energy Outlook, September 2013

Henry Hub Natural Gas Price

dollars per million btu

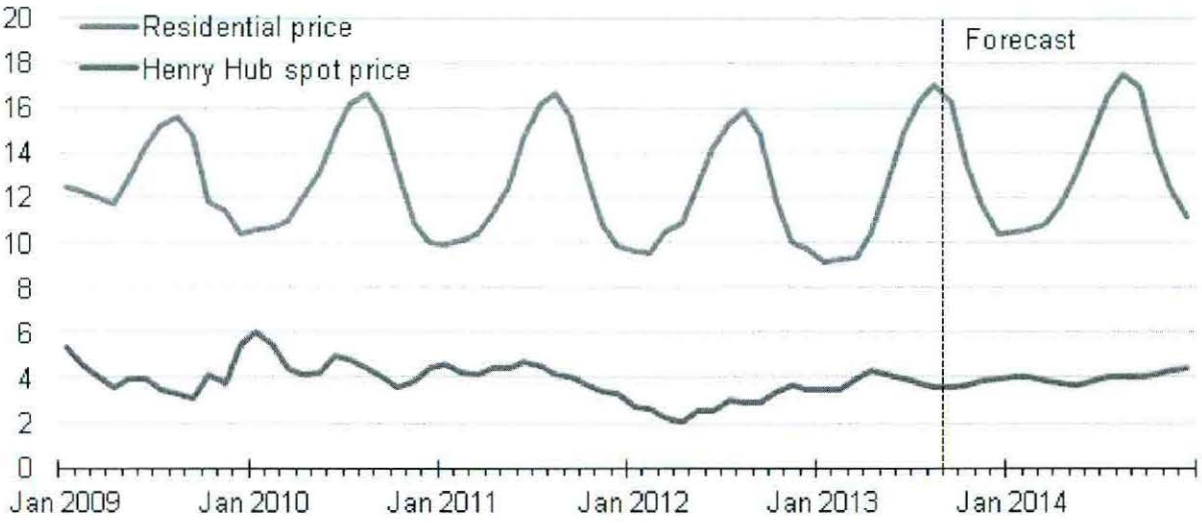


Note: Confidence interval derived from options market information for the 5 trading days ending September 5, 2013. Intervals not calculated for months with sparse trading in near-the-money options

Source: Short-Term Energy Outlook, September 2013

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, September 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										**$303,311**
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
Total	$28,017	0	$6,788	$34,805	42,123		$41,924		($7,119)	
Balance @ August 31, 2013										**$296,192**

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									**$4,747**
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)
Total	($43,494)	0	($353)	($43,847)	105,825		($17,863)	($25,984)	
Balance @ August 31, 2013									**($21,237)**

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.