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

July 31, 2013

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

Re: Cost of Gas Adjustment (COG)
August 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 (89th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (89th Revised Sheet No. 8), showing the August 2013 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $0.0240 per mcf for all customers.

Attachment B shows the calculations supporting the gas costs for August 2013, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $0.0240 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,

Rita A. Mulkern
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
89th Revised Sheet No. 1.1
Canceling 88th Revised Sheet No.1.1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/MCF
Firm Gas Service - General	2	$3.50 per month	First 10 MCF	$1.2740	$6.2461	$7.5201
			Over 10 MCF	1.0540		7.3001
Firm Gas Service - General Highway 13	2.5	$3.50 per month	First 10 MCF	$2.1740	$6.2461	$8.4201
			Over 10 MCF	1.9540		8.2001
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.7891	$4.9282
			Next 2,600 MCF	0.8931		4.6822
			Over 3,000 MCF	0.7411		4.5302
Interruptible Gas Service - Highway 13	3.5	$3.50 per month	First 400 MCF	$2.0391	$3.7891	$5.8282
			Next 2,600 MCF	1.7931		5.5822
			Over 3,000 MCF	1.6411		5.4302
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.7891	$5.0282
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: July 31, 2013

Effective Date: Service rendered on and after August 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
89th Revised Sheet No. 8
Canceling 88th 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	(1.3964)	0.9614	1.0372	(1.3814)	0.0274	(1.3540)
Current Adj.	0.0000	0.0240	0.0000	0.0240	0.0240	0.0000	0.0240
Total Adj.	1.4722	(1.3724)	0.9614	1.0612	(1.3574)	0.0274	(1.3300)
Total Rate	$1.5380	$3.7467	$0.9614	$6.2461	$3.7617	$0.0274	$3.7891

Date Filed: July 31, 2013

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

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

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
AUGUST 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/	3.7467		5,254,829	3.7467
Gas Cost Reconciliation Adjustment						0.9614
Total Current Firm Gas Cost					$7,390,848	6.2461
Base Cost of Gas						5.1849
Accumulated Adjustment						$1.0612

Interruptible	
Estimated Weighted Average Commodity Cost	$3.7467
Gas Cost Reconciliation Adjustment	0.0274
LMS Demand 2/	0.0150
Total Current Interruptible Gas Cost	3.7891
Base Cost of Gas	5.1191
Accumulated Adjustment	($1.3300)

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
AUGUST 2013

Rates Effective August 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:	3.7467	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	Adjustment Under Section 19 1/	Rate After Current Adjustment	Fuel and Loss Retention Percentages 2/
Commodity Rates				
FT-A – Maximum Rates				
Zone 1-1	$0.0130	$0.0018	$0.0148	0.36%
Zone 1-2	$0.0130	$0.0018	$0.0148	0.47%
Zone 2-2	$0.0130	$0.0018	$0.0148	0.11%
Minimum Rate	$0.0130	$0.0018	$0.0148	
IT and AOT				
Zone 1-1	$0.1368	$0.0018	$0.1386	0.36%
Zone 1-2	$0.1737	$0.0018	$0.1755	0.47%
Zone 2-2	$0.0834	$0.0018	$0.0852	0.11%
Minimum Rate	$0.0130	$0.0018	$0.0148	

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of $0.0018 per Dekatherm shall be added to other charges under Company's Rate Schedules.

2/ Fuel and Losses Retention Percentages shall be applicable to all transportation rate schedules.

Transportation Fuel and Loss Retention Percentages are inclusive of the following percentages for Gas Lost and Unaccounted For: 0.06% 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

	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
		TF12		
RESERVATION RATES	TF12 Base	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/ 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	0.0377	0.0208			0.0175	0.0000	0.0377	0.0208
Field	Market	0.0377	0.0208	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0294	0.0108

1/ The minimum reservation rate is equal to zero.
2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
3/ Maximum and Minimum rates include ACA of $0.0018 and the Market Area Electric Compression charge of $0.0000 where applicable.
4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
5/ Where Applicable, Field Area Electric Compression charge of $0.0000 and ACA will be added to the mileage based rates.

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	0.0377	0.0208			0.0175	0.0000	0.0377	0.0208
Field	Market	0.0377	0.0208	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0294	0.0108

GULF COAST	Reservation 1/ Maximum	Reservation 1/ Minimum	Commodity 6/ Maximum	Commodity 6/ Minimum	Out-of-Balance 6/ Maximum	Out-of-Balance 6/ Minimum
MOPS Gathering	1.0514	0.0000	0.0018	0.0018	0.0018	0.0018
MOPS Transmission	1.5337	0.0000	0.0018	0.0018	0.0018	0.0018
Tivoli - Downstream	0.6827	0.0000	0.0018	0.0018	0.0018	0.0018
Other Gulf Coast	4.8169	0.0000	0.0018	0.0018	0.0018	0.0018

1/ The minimum reservation rate is equal to zero.
2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
3/ Maximum and Minimum rates include ACA of $0.0018 and the Market Area Electric Compression charge of $0.0000 where applicable.
4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
5/ Where applicable, Field Area Compression charge of $0.0000 and ACA will be added to the mileage based rates.
6/ Maximum and Minimum rates include ACA of $0.0018.

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

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.87%
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
August 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 August 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 country saw relatively stable pricing during the month of July, with the exception of substantial swings in the price of day gas on the East Coast. This can likely be contributed to what appears to be a fairly balanced supply and demand market in North America and the national storage levels continuing to be near the five year average. The EIA reported storage levels nationwide as of July 19, 2013 were 1.6 percent below the five-year average and 12.5 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

July 2013

Short-Term Energy Outlook (STEO)

Highlights

- The U.S. Energy Information Administration (EIA) expects that the Brent crude oil spot price will average $102 per barrel over the second half of 2013, and $100 per barrel in 2014. This forecast assumes there are no disruptions to energy markets arising from the recent unrest in Egypt. After increasing to $119 per barrel in early February 2013, the Brent crude oil spot price fell to a low of $97 per barrel in mid-April and then recovered to an average of $103 per barrel in May and June, about the same as its average over the same two-month period last year.

- The discount of West Texas Intermediate (WTI) crude oil to Brent crude oil, which averaged $18 per barrel in 2012 and increased to a monthly average of more than $20 per barrel in February 2013, fell to less than $5 per barrel in early July 2013. The narrowing of the WTI-Brent price spread is supported by several factors that have depressed Brent prices or raised WTI prices. EIA expects the WTI discount to widen to $8 per barrel by the end of 2013 as crude oil production in Alberta, Canada, recovers following the heavy June flooding and as Midcontinent production continues to grow.

- Regular-grade gasoline prices have fallen from an average of $3.66 per gallon on June 10, 2013, to $3.49 per gallon on July 8, 2013. Midwest gasoline prices have recently returned to normal levels relative to the U.S. average price, helped by the resumption of regional refining activity after planned and unplanned outages, and the movement of gasoline from other parts of the nation. EIA expects the annual average regular gasoline retail price to decline from $3.63 per gallon in 2012 to $3.48 per gallon in 2013 and to $3.37 per gallon in 2014.

- Consumption in OECD (Organization for Economic Cooperation and Development) countries average 45.5 million barrels per day (bbl/d) in 2013 compared with 44.5 million bbl/d for non-OECD countries. EIA forecasts annual average non-OECD total liquids consumption to surpass OECD levels in 2014, averaging 45.9 million bbl/d and 45.4 million bbl/d, respectively. EIA projects non-OPEC liquid fuels production will increase by 1.2 million bbl/d in 2013 and by 1.6 million bbl/d in 2014. North America accounts for most of the projected growth in non-OPEC supply over the next two years because of continued production growth from U.S. tight oil formations and Canadian oil sands.

- U.S. crude oil production increased to an average of 7.3 million bbl/d in April and May 2013, which is the highest level of production since 1992. EIA forecasts U.S. total crude oil production will average 7.3 million bbl/d in 2013 and 8.1 million bbl/d in 2014.

Global Crude Oil and Liquid Fuels

EIA estimates that global liquid fuels production outpaced consumption in the second quarter of 2013, resulting in an average global liquid fuel stock build of 300,000 bbl/d compared with an average second quarter stock draw of about 210,000 bbl/d over the last four years, thus producing a swing of over 500,000 bbl/d. Forecast global liquid fuels consumption comes close to matching liquid fuels production in the third quarter of 2013 with estimated global inventory withdrawal averaging 70,000 bbl/d, compared with the average withdrawal of 890,000 bbl/d during the same period over the previous four years.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by 0.8 million bbl/d in 2012, to 89.2 million bbl/d. EIA expects consumption growth will be higher over the next two years, at 0.9 million bbl/d in 2013 and 1.2 million bbl/d in 2014.

Non-OECD Asia, particularly China, is the leading contributor to projected global consumption growth. EIA expects refinery crude oil inputs in China to increase in 2013 as new refining capacity continues to come on line. EIA estimates that liquid fuels consumption in China increased by 380,000 bbl/d in 2012. Projected consumption in China increases by 410,000 bbl/d in 2013 and by 430,000 bbl/d in 2014, compared with average annual growth of about 510,000 bbl/d from 2004 through 2012. Recent data indicating a weaker industrial sector and a tightening money supply in the first half of 2013 signaled slower economic growth than in prior years and, if it continues, China's oil demand growth could potentially be lower than projected in the current STEO.

OECD liquid fuels consumption fell by 0.6 million bbl/d in 2012. EIA projects that OECD consumption will decline by an additional 0.4 million bbl/d in 2013 and 0.2 million bbl/d in 2014, largely because of declining consumption in Europe and Japan.

Non-OPEC Supply. EIA projects non-OPEC liquid fuels production will increase by 1.2 million bbl/d in 2013 and by 1.6 million bbl/d in 2014. North America accounts for most of the projected growth in non-OPEC supply over the next two years because of continued production growth from U.S. tight oil formations and Canadian oil sands.

EIA revised its production capacity numbers for several non-OPEC countries this month—including Syria and Yemen—which resulted in lower overall outage numbers for non-OPEC suppliers compared with last month's STEO. Total unplanned production outages averaged 0.7 million bbl/d in May 2013, but increased to an average of 0.8 million bbl/d in June 2013. Although unplanned outages in Sudan and South Sudan fell in May and June, new production

shut-ins occurred in June in the aftermath of floods in Alberta, Canada. The floods forced disruptions on a number of pipelines and production areas, and resulted in an average of 190,000 bbl/d of disrupted production volume in June.

Sudan and South Sudan, Syria, and Yemen continue to account for more than half of the total unplanned non-OPEC supply disruptions. EIA expects supply disruptions to persist in Syria and Yemen over the forecast period and projects average production of about 100,000 bbl/d in Syria and 130,000 bbl/d in Yemen over the next two years. EIA expects total non-OPEC outages to lessen in the second half of this year as South Sudan resumes oil production. Although EIA expects South Sudanese output to ramp up to 300,000 bbl/d by the end of 2013, if Sudan and South Sudan do not resolve their security problems, production from South Sudan may again be disrupted.

OPEC Supply. OPEC total liquid fuels production fell by 0.5 million bbl/d in the second quarter of 2013 from the same period last year because of lower crude oil output in Saudi Arabia, Iran, Nigeria, Algeria, and Libya (*Availability and Price of Petroleum and Petroleum Products Produced in Countries other than Iran*). Production of non-crude liquids among OPEC members increased by 0.3 million bbl/d in second quarter 2013 compared with year-ago levels. Projected OPEC total liquid fuel supply falls by 0.5 million bbl/d in 2013 and remains relatively unchanged in 2014. Most of the decline in 2013 comes from Saudi Arabia in response to non-OPEC supply growth, although Saudi production increases for the next few months to meet seasonal demand.

Nigerian crude oil production fell by 220,000 bbl/d between December 2012 and June 2013, averaging 1.9 million bbl/d in June. Nigeria's main crude streams have been intermittently placed under force majeure this year because of infrastructure damage linked to pipeline theft. The latest supply outage occurred in Usan, Nigeria's newest deepwater field, which experienced technical problems.

Libyan crude oil production fell to 1.2 million bbl/d in June 2013, which is its lowest level since early 2012 when the country was bringing its production back on line after the civil war. Libya's oil sector has been plagued by a series of labor-related protests that have compromised output at several oil fields. Protests escalated in June and took an average of about 230,000 bbl/d off line.

EIA estimates that OPEC surplus capacity, mainly held in Saudi Arabia, averaged 2.7 million bbl/d in the first quarter of 2013. This was higher than the 2.1 million bbl/d average during the same period last year but lower than the average 3.8 million bbl/d from 2009 through 2011. EIA projects OPEC surplus capacity will increase to an average of 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 off line 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. Projected OECD oil inventories stay relatively steady in 2013, ending the year at 2.66 billion barrels. Projected inventories increase to 2.68 billion barrels (58.2 days of supply) at the end of 2014.

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 $103 per barrel in both May and June. EIA projects the Brent crude oil spot price will fall from an average of $112 per barrel in 2012 to annual averages of $105 per barrel and $100 per barrel in 2013 and 2014, respectively, reflecting the increasing supply of liquid fuels from non-OPEC countries.

The price discount of WTI crude oil to Brent, which averaged $18 per barrel in 2012 and was more than $23 per barrel in February 2013, has since fallen to below $5 per barrel in early July 2013. The narrowing of the WTI-Brent price spread is supported by several factors that have depressed Brent prices or raised WTI prices. EIA expects the WTI discount to begin widening again, to $8 per barrel by the end of 2013, as crude oil production in Alberta, Canada, recovers following the heavy June flooding and Midcontinent production continues to grow. After averaging $94 per barrel in 2012, the forecast WTI crude oil spot price averages $95 per barrel in 2013 and $92 per barrel in 2014. By 2014, several pipeline projects from the Midcontinent to the Gulf Coast refining centers are expected to come on line, reducing the cost of transporting crude oil to refiners, which is reflected in a narrowing in the WTI price discount to Brent next year.

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 October 2013 delivery traded during the five-day period ending July 3, 2013, averaged $97.52 per barrel. Implied volatility averaged 21 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in September 2013 at $81 per barrel and $118 per barrel, respectively. Last year at this time, WTI for October 2012 delivery averaged $85 per barrel and implied volatility averaged 33 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $64 per barrel and $114 per barrel.

U.S. Crude Oil and Liquid Fuels

Refinery outages across the Midwest helped push the U.S. average regular gasoline retail price up from $3.52 per gallon on April 29, 2013, to $3.66 per gallon on June 10, 2013. Midwest gasoline prices have recently returned to normal levels relative to the U.S. average price, helped by resumption of refining and the movement of gasoline from other parts of the nation, with the U.S. regular gasoline retail price averaging $3.50 per gallon on July 1, 2013. The expected recovery in refinery production combined with the total gasoline inventory of 224 million barrels on June 28, 2013, which is the highest level for this time of year since 1992, contribute to lower projected regular gasoline retail prices, averaging $3.38 per gallon in the second half of 2013.

The current values of futures and options contracts suggest that gasoline prices could differ significantly from this forecast. For example, there is a 5-percent 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 October 2013.

U.S. Liquid Fuels Consumption. In 2012, total liquid fuels consumption declined by 390,000 bbl/d (2.1 percent). Total liquid fuels consumption for the first half of 2013 rose an estimated 140,000 bbl/d (0.8 percent) compared with the same period last year, led by increases in liquefied petroleum gas and distillate consumption. Part of that increase was because of colder weather, with heating degree days in the Northeast 21 percent higher than the first quarter of 2012. The second half of 2013 sees a forecast year-over-year increase in total liquid fuels consumption of 70,000 bbl/d (0.4 percent). For 2014, the forecast of total liquid fuels consumption growth slows to 30,000 bbl/d (0.2 percent). Motor gasoline consumption, which fell by 50,000 bbl/d in 2012, falls by 40,000 bbl/d in 2013, then flattens out in 2014 as increases in vehicle fuel economy are offset by projected growth in highway travel.

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 7.3 million bbl/d in 2013 and 8.1 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.

Gulf of Mexico oil production is expected to increase by approximately 150,000 bbl/d between June and July, to 1.3 million bbl/d, as wells that were shut in for processing plant maintenance and the installation of an offshore platform during June come to full production. 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 5.7 million bbl/d by 2014. Similarly, the share of total U.S. consumption met by liquid fuel net imports peaked at more than 60 percent in 2005 and fell to an average of 40 percent in 2012. EIA expects the net import share to fall to continue to fall to 31 percent 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 $3.69 per gallon last summer, will average $3.53 per gallon during the current summer (April through September) driving season. The projected monthly average regular gasoline retail price falls from $3.63 per gallon in June 2013 to $3.41 per gallon in September 2013. Diesel fuel prices, which averaged $3.95 per gallon last summer, are projected to average $3.84 per gallon this summer. As noted at the top of this section, the pricing and implied volatility of futures and

options contracts indicate the market's recognition that future monthly average gasoline prices could differ significantly from EIA's current forecast.

Natural Gas

Natural gas use during the first five months of 2013 for industrial purposes was more than 4 percent, or 0.9 Bcf/d, greater compared with the same period in 2012. Higher industrial gas usage reflects recent economic gains and sustained, historically low natural gas prices that have provided operators of natural-gas-intensive industrial facilities in the United States a cost advantage compared with competing facilities that rely on higher-cost energy sources. Projected industrial sector natural gas use increases by 2.2 percent in 2013 and 1.3 percent in 2014.

U.S. Natural Gas Consumption. EIA expects that natural gas consumption, which averaged 69.7 Bcf/d in 2012, will average 70.1 Bcf/d and 69.7 Bcf/d in 2013 and 2014, respectively. Colder winter temperatures forecast for 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 22.4 Bcf/d in 2013 and 22.2 Bcf/d in 2014, although these forecast levels are still high by historical standards.

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. 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 remain near their 2012 level over the forecast. 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 June 28, 2013, working gas stocks totaled 2,605 Bcf, which is 491 Bcf less than at the same time last year, but only 30 Bcf below the five-year (2008-12) average for that week. EIA projects working gas stocks at the end of this summer's stock-build season (end of October) will reach 3,809 Bcf, about 120 Bcf below the level at the same time last year.

U.S. Natural Gas Prices. Natural gas spot prices averaged $3.83 per MMBtu at the Henry Hub in June 2013, down 21 cents from the previous month's price. EIA expects the Henry Hub price will increase from an average of $2.75 per MMBtu in 2012 to $3.76 per MMBtu in 2013 and $3.91 per MMBtu in 2014.

Natural gas futures prices for October 2013 delivery (for the five-day period ending July 3, 2013) averaged $3.62 per MMBtu. Current options and futures prices imply that market participants

place the lower and upper bounds for the 95-percent confidence interval for October 2013 contracts at $2.69 per MMBtu and $4.88 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for October 2012 averaged $2.90 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were $1.74 per MMBtu and $4.82 per MMBtu.

Coal

Coal prices were down 2.9 percent for the first four months of 2013 compared with the same period last year. EIA expects this trend to continue, with nominal annual average coal prices to the electric power industry falling for the first time since 2000, from $2.40 per MMBtu in 2012 to $2.36 MMBtu in 2013. EIA forecasts average delivered coal prices of $2.40 per MMBtu in 2014.

U.S. Coal Consumption. EIA expects total coal consumption to increase from 890 million short tons (MMst) in 2012 to 950 MMst in 2013 as consumption in the electric power sector rises due to higher electricity demand and higher natural gas prices. Consumption grows at a more modest pace of 1.7 percent to 966 MMst in 2014.

U.S. Coal Supply. Coal production is expected to change very little from last year, totaling 1,017 MMst in 2013. Inventory draws, combined with a small increase in coal imports, meet most of the growth in consumption in 2013. Coal production is forecast to grow by 3.3 percent in 2014 to 1,050 MMst as inventories stabilize in the face of increasing consumption.

U.S. Coal Exports. EIA expects exports to decline from 126 MMst in 2012 to 112 MMst in 2013 despite record exports of 13.6 MMst in March. Exports are projected to total 108 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.

Electricity

The western United States has experienced extreme temperatures so far this summer. Cooling degree days in the West Census Region averaged about 190 last month, 23 percent higher than June 2012 and 20 percent higher than the previous 10-year average for that month. The California Independent System Operator (CAISO) issued Flex Alerts for July 1 and 2 asking electricity customers to turn off lights, raise air conditioning temperatures, and postpone appliance use. CAISO issues Flex Alerts when forecast day-ahead peak electricity demand approaches available resources. Other areas of the United States have experienced milder temperatures so far this summer. In the Midwest Census Region, cooling degree days in June averaged 26 percent lower than the same month last year.

U.S. Electricity Consumption. Although U.S. cooling degree days during June averaged 4 percent higher than the previous 10-year average, NOAA projects overall U.S. temperatures during July and August will fall slightly below average. EIA projects the average U.S. residential customer will consume 3,212 kilowatthours of electricity during the summer months of June through August, 4.3 percent lower than the summer of 2012. For the entire year, EIA expects residential retail sales of electricity in the United States to grow by 1.6 percent. Forecast retail sales of electricity to the commercial sector increase by 0.5 percent in 2013, while retail sales to the industrial sector fall by 0.4 percent.

U.S. Electricity Generation. EIA expects total U.S. electricity generation will grow by 0.8 percent in 2013 and by 1.0 percent in 2014. Electric generators have been running their existing coal capacity at higher rates so far this year in response to the increasing cost of natural gas relative to coal. As a result, the share of total U.S. generation fueled by coal during the first four months of 2013 averaged 39.5 percent compared with 35.4 percent during the same period last year. In contrast, the share of generation fueled by natural gas fell from an average of 29.5 percent during January-April 2012 to 25.8 percent this year. EIA expects coal power plants to continue their increased level of generation, averaging 40.1 percent of total generation in both 2013 and 2014. The share of U.S. generation fueled by natural gas averages 27.6 percent in 2013 and 27.3 percent in 2014.

U.S. Electricity Retail Prices. The U.S. residential electricity price averaged 11.9 cents per kWh in 2012. EIA expects the average residential price will grow by 1.1 percent in 2013 and by 1.6 percent in 2014. The residential price during the summer months this year (June-August) is expected to average 12.3 cents/kWh, a 2.1-percent increase from the price last summer.

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 3.6 percent in 2013. While hydropower declines by 3.0 percent, nonhydropower renewables used for electricity and heat grow by an average of 7.8 percent in 2013. In 2014, the growth in renewables consumption for electric power and heat generation is projected to continue at a rate of 4.2 percent, as a 2.4-percent increase in hydropower is combined with a 5.2-percent increase in nonhydropower renewables.

EIA currently estimates that wind capacity will increase by 6 percent this year to about 62.6 gigawatts, and reach almost 73 gigawatts in 2014. However, electricity generation from wind is projected to increase by 19 percent in 2013, as capacity that came on line at the end of 2012 is available for the entire year in 2013. Wind-powered generation is projected to grow by 8 percent in 2014.

EIA expects continued robust growth in the generation of solar energy, both from central-station and distributed capacity, although the amount of utility-scale generation remains a small

share of total U.S. generation, about 0.2 percent in 2013. Central-station capacity, which until recently experienced little growth compared with distributed capacity, is projected to more than double between 2012 and 2014. Photovoltaics (PV) accounted for all central-station 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 central station and distributed capacity additions in 2013 and 2014. Solar generation increases 79 percent in 2013 and 49 percent 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. Ethanol production has been increasing since April, driven in part by increasing Renewable Fuel Standard (RFS) targets and strong demand for Renewable Identification Numbers (RINs). EIA expects ethanol production to remain near its June 2013 level of 870,000 bbl/d through the third quarter before recovering to pre-drought production levels, averaging 870,000 bbl/d for the year. Ethanol production is expected to average 920,000 bbl/d in 2014. Biodiesel production, which averaged 63,000 bbl/d (1.0 billion gallons per year) in 2012, is forecast to average about 82,000 bbl/d in 2013 and 88,000 bbl/d in 2014 (1.4 billion gallons per year). This forecast assumes that the 2014 renewable fuel volume obligations are identical to those in 2013.

The U.S. Environmental Protection Agency (EPA) proposed 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 9.63 percent of the gasoline or diesel fuel they sell domestically (not counting the biofuels blended into it). The market price of ethanol D6 RINs increased dramatically during the first quarter of 2013, from $0.05 per gallon at the start of the year to as high as $1.05 per gallon on March 11, and has recently begun approaching the $1.00 per gallon level again in June, averaging over $0.90 per gallon.

The increase in the ethanol RIN price provides an economic incentive for two changes in the market. First, although present RIN prices do not appear sufficient to make E85 an economical fuel choice, a higher ethanol RIN price tends to lower the market price of E85 gasoline relative to E10 gasoline. Second, an ethanol RIN price equal to or near the biodiesel RIN price may motivate blending of biodiesel that exceeds the biodiesel blending target that EPA announced in the 2013 RFS program.

At the retail level, EIA expects diesel fuel prices to be most affected by higher RIN prices as typical biodiesel blending yields only about one-third of the RINs required and diesel fuel refiners and blenders must make up for the shortfall by purchasing the now higher-priced RINs.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels declined by 3.9 percent in 2012, and projects increases of 2.4 percent in 2013

and 0.6 percent 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 model used in this STEO assumes that the spending cuts mandated in the Budget Control Act of 2011 (sequestration) will be replaced by a combination of income tax increases and spending cuts that are implemented in 2014. The GI model also assumes there will be an agreement reached to increase the amount of debt that can be issued by the U.S. Treasury (the debt ceiling) in the near term.

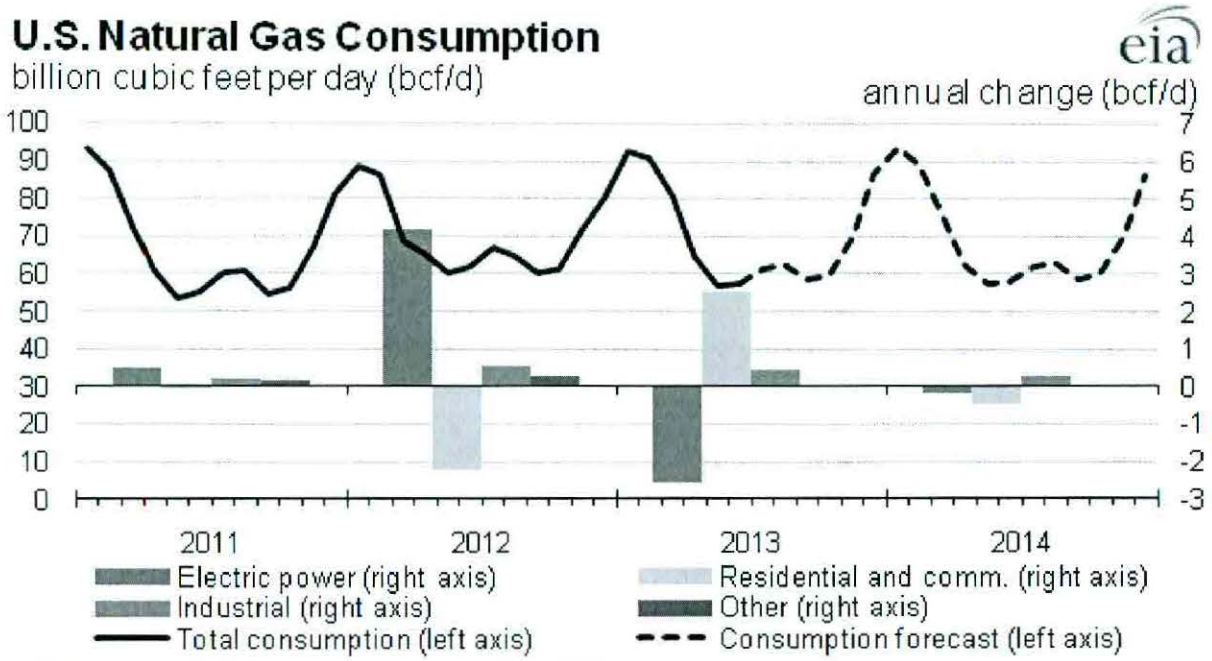
U.S. Current Trends. Current economic indicators continue to send mixed signals about the state of the U.S. economy. The most positive news is in the housing sector, where the National Association of Home Builders (NAHB) reported that new home sales in May reached their highest level in nearly five years. The pending home sales index from the National Association of Realtors (NAR) also reached its highest level since December 2006. On the income side, the U.S. Bureau of Economic Analysis (BEA) reported that real disposable income increased by 0.5 percent in May, up from growth of 0.1 percent in April. However, the BEA revised down real GDP growth in the first quarter of 2013 from 2.4 to 1.8 percent, primarily due to lower consumer spending on services and exports. For the last three months, the ISM manufacturing index has been close to 50, signaling no upcoming growth. The ISM Non-Manufacturing index has averaged in the mid-50s; however, exports and hiring indexes have shown recent sharp declines.

U.S. Production. This STEO assumes U.S. real GDP growth of 1.7 percent in 2013, rising to 2.9 percent in 2014. Year-on-year real GDP growth begins to accelerate in 2014, eventually rising to 3.4 percent in its final quarter. Forecast real disposable income increases 0.5 percent in 2013 and 3.3 percent in 2014. Total industrial production grows at a faster rate than real GDP in 2013 and 2014, at 2.6 and 3.6 percent respectively. Industrial production growth in the manufacturing sector is 2.6 percent in 2013, but accelerates to 3.7 percent in 2014.

U.S. Income and Expenditures. Private fixed investment growth averages 6.1 and 8.6 percent over 2013 and 2014, respectively. This is driven partly by business equipment and software spending, as well as increasing expenditures on buildings. Real consumption expenditures grow faster than real GDP in 2013, at 2.0 percent, but slow below the rate of real GDP growth in 2014, at 2.4 percent. Export growth more than triples from 1.7 to 5.3 percent over the same two years. Government expenditures fall by 3.2 percent in 2013, and rise by 0.2 percent in 2014.

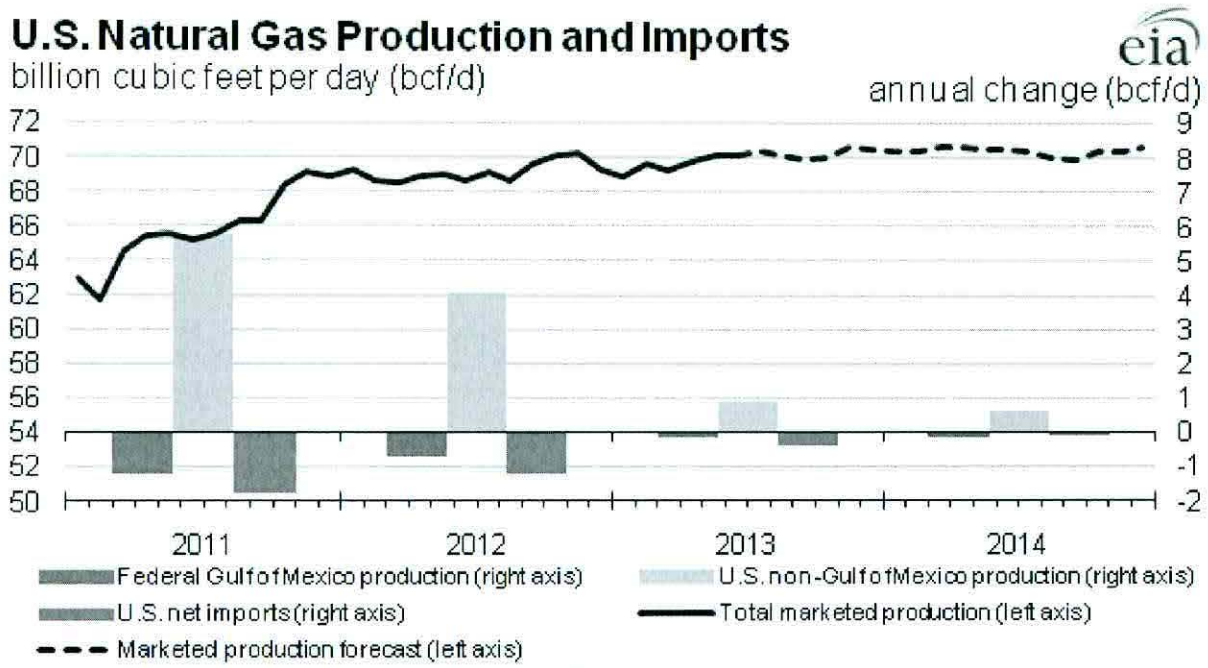
U.S. Employment, Housing, and Prices. The unemployment rate in the forecast averages 7.6 percent over 2013, and gradually falls to 7.0 percent at the end of 2014. This is accompanied by nonfarm employment growth averaging 1.6 percent in 2013 and 1.5 percent in 2014. Consistent with an improving housing sector, housing starts grow an average of 23.1 percent and 26.6

percent over 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.

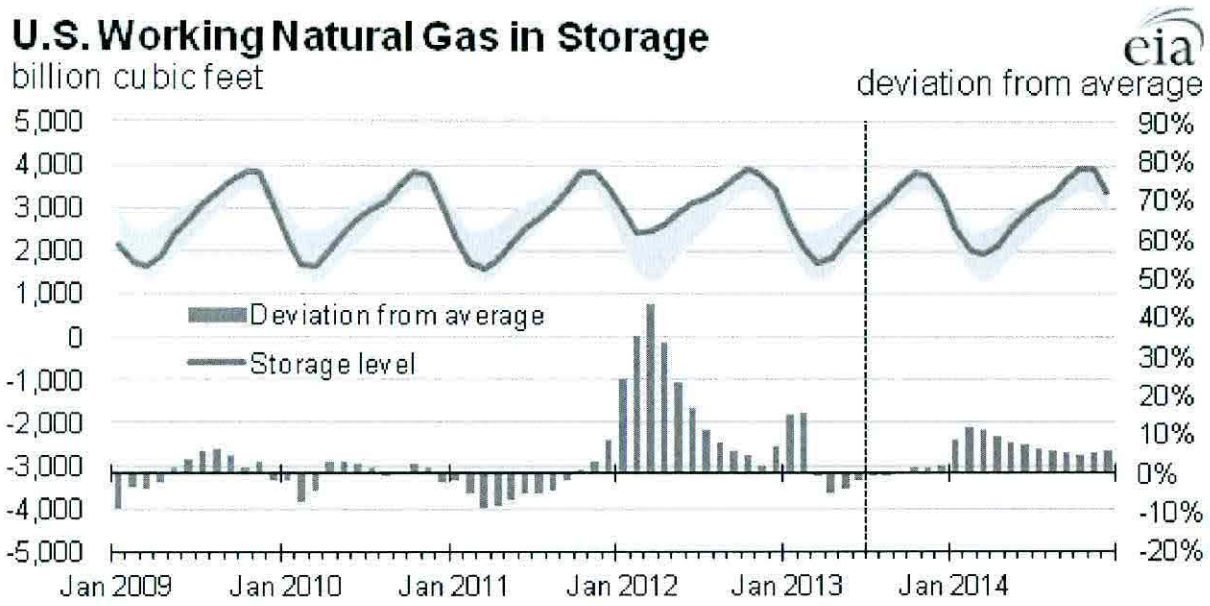


Source: Short-Term Energy Outlook, July 2013

U.S. Natural Gas Production and Imports



Source: Short-Term Energy Outlook, July 2013

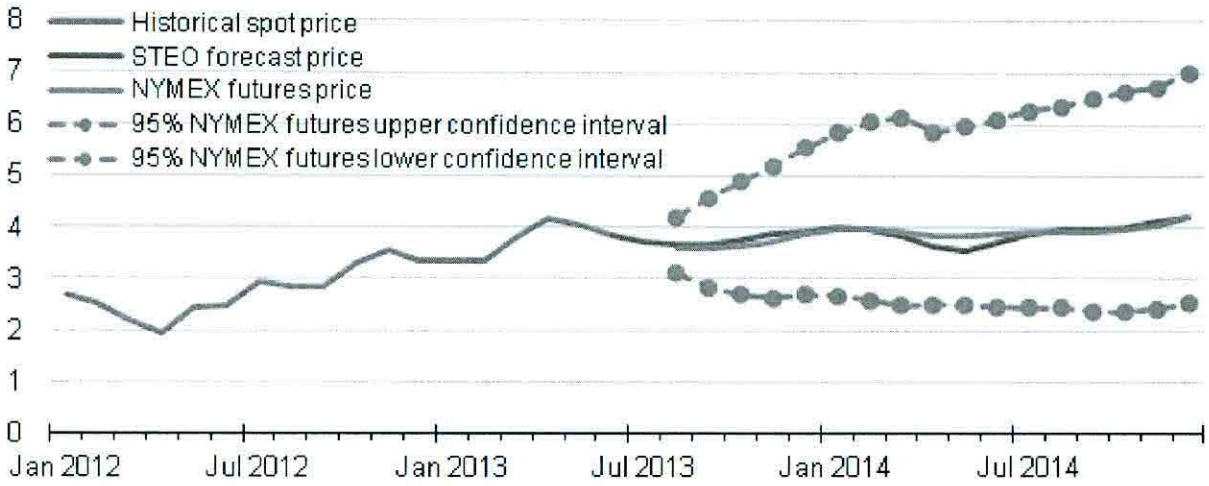


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2008 - Dec. 2012.

Source: Short-Term Energy Outlook, July 2013

Henry Hub Natural Gas Price

dollars per million btu

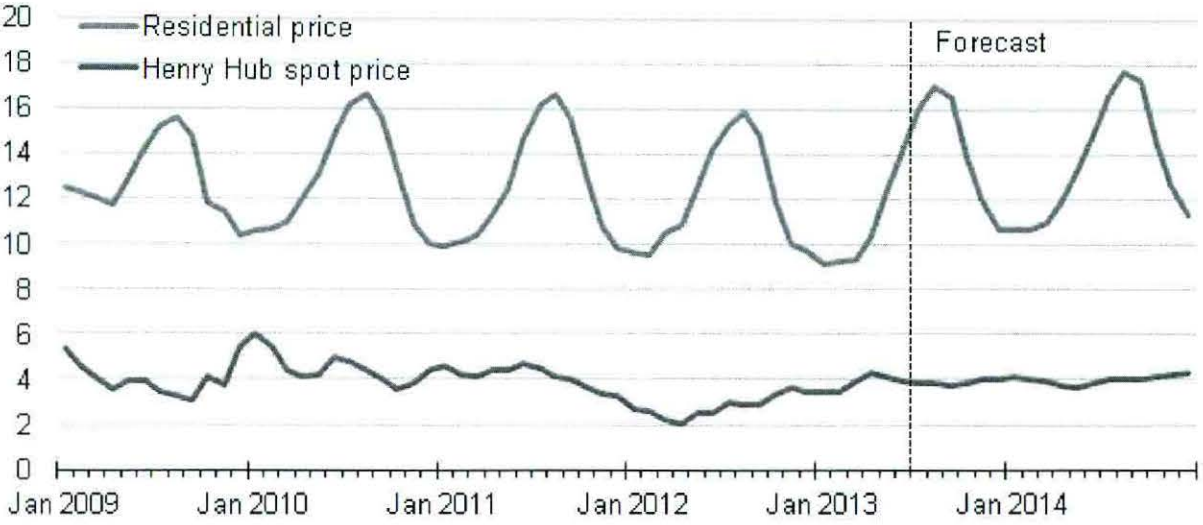


Note: Confidence interval derived from options market information for the 5 trading days ending July 3, 2013. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, July 2013

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, July 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
Total	($7,632)	0	$3,486	($4,146)	30,614		$30,859	($35,005)	
Balance @ June 30, 2013									**$268,306**

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)
Total	($32,774)	0	($50)	($32,824)	73,440		($18,751)	($14,073)	
Balance @ June 30, 2013									**($9,326)**

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.