



A Division of MDU Resources Group, Inc.

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March 1, 2013

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

Re: Cost of Gas Adjustment (COG)
March 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 (84th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (84th Revised Sheet No. 8), showing the March 2013 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.0632 per mcf for all customers.

Attachment B shows the calculations supporting the gas costs for March 2013, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.0632 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, 2012.

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

Attachment A



GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota Gas Rate Schedule

NDPSC Volume 2

84th Revised Sheet No. 1.1

Canceling 83rd Revised Sheet No.1.1

RATE SUMMARY SHEET

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/MCF
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF \$1.2740 Over 10 MCF 1.0540	\$6.0828	\$7.3568 7.1368
Firm Gas Service - General Highway 13	2.5	\$3.50 per month	First 10 MCF \$2.1740 Over 10 MCF 1.9540	\$6.0828	\$8.2568 8.0368
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411	\$3.2515	\$4.3906 4.1446 3.9926
Interruptible Gas Service - Highway 13	3.5	\$3.50 per month	First 400 MCF \$2.0391 Next 2,600 MCF 1.7931 Over 3,000 MCF 1.6411	\$3.2515	\$5.2906 5.0446 4.8926
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$3.2515	\$4.4906
Transportation Service	5	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411		\$1.1391 0.8931 0.7411

Date Filed: March 1, 2013

Effective Date: Service rendered on and after March 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
84th Revised Sheet No. 8
Canceling 83rd 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.	1.4751	(1.5277)	1.0137	0.9611	(1.5129)	(0.2915)	(1.8044)
Current Adj.	0.0000	(0.0632)	0.0000	(0.0632)	(0.0632)	0.0000	(0.0632)
Total Adj.	1.4751	(1.5909)	1.0137	0.8979	(1.5761)	(0.2915)	(1.8676)
Total Rate:	\$1.5409	\$3.5282	\$1.0137	\$6.0828	\$3.5430	(\$0.2915)	\$3.2515

Date Filed: March 1, 2013

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

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

<u>Firm</u>	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
FT-A	8,000	\$3.4671	12	\$332,842	\$0.2378
FT-A - Zone 1-1	500	3.4671	5	8,668	0.0062
FT-A - Zone 1-2	4,500	4.5871	5	103,210	0.0737
FT-A Seasonal	2,000	3.7671	5	37,671	0.0269
TFX Seasonal	2,000	15.1530	5	151,530	0.1083
TFX - Winter	13,000	15.1530	5	984,945	0.7037
TFX - Summer	13,000	5.6830	7	517,153	0.3695
LMS Demand 2/					0.0148
Total Demand Charges				\$2,136,019	1.5409
Estimated Weighted Average Commodity Cost	1,399,684	1/ 3.5282		4,938,365	3.5282
Gas Cost Reconciliation Adjustment					1.0137
Total Current Firm Gas Cost				<u>\$7,074,384</u>	<u>6.0828</u>
Base Cost of Gas					<u>5.1849</u>
Accumulated Adjustment					<u>\$0.8979</u>
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$3.5282
Gas Cost Reconciliation Adjustment					(0.2915)
LMS Demand 2/					0.0148
Total Current Interruptible Gas Cost					<u>3.2515</u>
Base Cost of Gas					<u>5.1191</u>
Accumulated Adjustment					<u>(\$1.8676)</u>

1/ Three year normalized average Dk sales.

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

	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
LMS Demand	2,500	\$1.0000	12	\$30,000	\$0.0148

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

Rates Effective November 1, 2012	<u>\$/Dk</u>	
FT-A - Zone 1-1	\$3.4671	Per dk/Mo.
FT-A - Zone 1-2	4.5871	Per dk/Mo.
FT-A - Seasonal	3.7671	Per dk/Mo.
TFX	15.1530	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	3.5282	Per dk

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

Base Rate Calculation

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

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

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

Rate Schedule	Base Tariff Rate
<hr/>	
Category 1 (Contract Term of Less than 3 Years)	
<hr/>	
Daily Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$0.1238
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$0.1607
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$0.0704
Zone 2-2 Minimum Rate	\$0.0000
<hr/>	
Category 2 (Contract Term of 3 Years to less than 5 Years)	
<hr/>	
Daily Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$0.1189
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$0.1557
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$0.0654
Zone 2-2 Minimum Rate	\$0.0000
<hr/>	
Category 3 (Contract Term of 5 or more Years)	
<hr/>	
Daily Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$0.1140
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$0.1508
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$0.0605
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	0.76%
Zone 1-2	\$0.0130	\$0.0018	\$0.0148	0.86%
Zone 2-2	\$0.0130	\$0.0018	\$0.0148	0.10%
Minimum Rate	\$0.0130	\$0.0018	\$0.0148	
IT and AOT				
Zone 1-1	\$0.1368	\$0.0018	\$0.1386	0.76%
Zone 1-2	\$0.1737	\$0.0018	\$0.1755	0.86%
Zone 2-2	\$0.0834	\$0.0018	\$0.0852	0.10%
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: 0.15% for Zone 1-1, 0.17 % 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		(\$0.0022)	

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

COMMODITY RATES 2/		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
TF12 Base, TF12 Var., TF5 & TFF	Receipt Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
	Market	0.0378	0.0209			0.0175	0.0000	0.0378	0.0209
	Field	0.0378	0.0209	0.0122	0.0040	0.0175	0.0000		
	Market			0.0122	0.0040				
	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 \$0.0001 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		FIELD-TO-FIELD	
	Apr-Oct	Nov-Mar	Apr-Oct	Nov-Mar
Base Tariff Rates 1/	\$5.683	\$15.153	\$5.473	\$9.853

COMMODITY RATES 2/ TFX and LFT		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0378	0.0209			0.0175	0.0000	0.0378	0.0209
Field	Market	0.0378	0.0209	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/		Commodity 6/		Out-of-Balance 6/	
	Maximum	Minimum	Maximum	Minimum	Maximum	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 \$0.0001 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)	0.97%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.43% 4/ 5/
FDD Storage Fuel	1.09%

	Electric Compression -----
COMMODITY RATES:	1/
Market Area	\$0.0001
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, 2011.
- 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
March 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 much of this gas is the Northern Natural Gas Co. Ventura, Iowa point which is an actively traded market point in North America. The March monthly price for the NNG-Ventura Index is expected to be in the same 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.

Factors likely contributing to the NNG-Ventura index price remaining in the same range as the previous month were the high national storage levels relative to the five year average and domestic supply remaining strong. The Energy Information Administration (EIA) reported storage levels nationwide as of February 15, 2013 were 17.7 percent above the five-year average and 9.2 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

February 2013

Short-Term Energy Outlook (STEO)

- EIA expects that the Brent crude oil spot price, which averaged \$112 per barrel in 2012 and rose to \$119 per barrel in early February 2013, will average \$109 per barrel in 2013 and \$101 per barrel in 2014. The projected discount of West Texas Intermediate (WTI) crude oil to Brent, which averaged \$18 per barrel in 2012, averages \$9 per barrel in 2014 as planned new pipeline capacity lowers the cost of moving midcontinent crude oil to the Gulf Coast refining centers.
- EIA expects that falling crude prices will contribute to a decline in the national annual average regular gasoline retail price from \$3.63 per gallon in 2012 to \$3.55 per gallon in 2013 and \$3.39 per gallon in 2014, about 11 cents per gallon and 4 cents per gallon higher than forecast in last month's STEO, respectively. Diesel fuel retail prices averaged \$3.97 per gallon during 2012 and are forecast to fall to \$3.92 per gallon in 2013 and to \$3.82 per gallon in 2014.
- EIA estimates U.S. total crude oil production averaged 6.4 million barrels per day (bbl/d) in 2012, an increase of 0.8 million bbl/d from the previous year. Projected domestic crude oil production continues to increase to 7.3 million bbl/d in 2013 and 7.8 million bbl/d in 2014.
- Total U.S. liquid fuels consumption fell from 20.8 million bbl/d in 2005 to 18.6 million bbl/d in 2012. EIA expects total consumption to rise slowly over the next two years to an average of 18.7 million bbl/d in 2014, driven by increases in distillate fuel and liquefied petroleum gas consumption, with mostly flat gasoline and jet fuel consumption.
- Natural gas working inventories reached a record-high level in early November 2012, but ended January 2013 at an estimated 2.7 trillion cubic feet (Tcf), about 0.2 Tcf below the level at the same time the previous year. EIA expects the Henry Hub natural gas spot price, which averaged \$2.75 per million British thermal units (MMBtu) in 2012, will average \$3.53 per MMBtu in 2013 and \$3.84 per MMBtu in 2014.

Global Crude Oil and Liquid Fuels

Market fundamentals and expectations strengthened in January 2013 because of earlier-than-expected cutbacks in Saudi Arabian oil production and greater optimism about economic growth, particularly in China, which have supported higher oil prices. EIA expects oil markets to tighten in the first quarter of 2013, but increasing global supply more than offsets higher global consumption through the rest of the forecast period. Projected world supply increases by 1.1

million bbl/d in 2013 and 2.0 million bbl/d in 2014, with most of the growth coming from outside the Organization of the Petroleum Exporting Countries (OPEC). North America will account for much of this growth. Projected world liquid fuels consumption grows by an annual average of 1.0 million bbl/d in 2013 and 1.4 million bbl/d in 2014. Countries outside the Organization for Economic Cooperation and Development (OECD) drive expected consumption growth.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by 0.9 million bbl/d in 2012 to reach 89.2 million bbl/d. EIA expects that this growth will pick up in 2013 and accelerate in 2014 because of a moderate recovery in global economic growth; consumption reaches 90.2 million bbl/d in 2013 and 91.6 million bbl/d in 2014. Non-OECD Asia is the leading regional contributor to expected global consumption growth.

OECD liquid fuels consumption declined by 0.4 million bbl/d in 2012. EIA projects OECD consumption to further decline by 0.3 million bbl/d in 2013 because of declining consumption in Europe. OECD consumption flattens in 2014 as European consumption begins to flatten in response to higher economic growth.

China's economy has improved since the third quarter of 2012, as key manufacturing indexes and refinery crude oil inputs have increased. Infrastructure investment and consumer spending indicate signs of strong economic growth in China, although not at the high rates seen in recent years. EIA also expects refinery crude oil inputs to be bolstered in 2013 as oil product inventories are restocked and new refining capacity comes on line. EIA estimates that liquid fuels consumption in China increased by 380,000 bbl/d in 2012, and will increase by 450,000 bbl/d in 2013 and by 470,000 bbl/d in 2014.

Non-OPEC Supply. EIA projects non-OPEC liquids production will increase by 1.2 million bbl/d in 2013 and by another 1.4 million bbl/d in 2014. North America accounts for about two-thirds 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 has slightly lowered its forecast for the growth in Canadian oil production in 2013, due in part to further delays in initial production from the Kearl oil sands mining project.

Unplanned production outages in non-OPEC countries persisted at an average level of 0.8 million bbl/d in January 2013. Syria, Sudan, and South Sudan are currently the most significant sources of disruption to non-OPEC production. EIA does not assume a resolution in Syria will occur during the forecast period.

EIA has pushed back the anticipated restart of South Sudan's production due to the persistent uncertainty surrounding border demilitarization. The African Union has set a new and third deadline for Sudan and South Sudan to resolve outstanding issues and avoid sanctions, although the organization has yet to impose any of the sanctions that it has threatened in the past. The countries have three months from January 25, 2013, to resolve pending issues, which include

demilitarizing the contested border. EIA now expects production at the Upper Nile fields to resume in the third quarter of this year, with output restarting at mature fields in the following months. On the upside, two new oil fields recently boosted Sudan's oil production: al-Barsaya (6,000 bbl/d) and Hadida (10,000 bbl/d). EIA expects both fields to double output this year. Combined production of both countries is projected to average 150,000 bbl/d in 2013 and 410,000 bbl/d in 2014.

In Australia, Cyclones Narelle and Peta shut in some production from fields near the northwest coast in January 2013. In Colombia, despite continued attacks by leftist rebels on the nation's energy infrastructure, notably the Caño Limón oil pipeline, initial press reports claimed that the country's oil production passed the 1-million-bbl/d mark in January. An additional threat to South American production is the potential for a strike in February by workers of Petrobras, the Brazilian state-owned oil company.

OPEC Supply. OPEC member countries, particularly Saudi Arabia, cut production heavily in fourth-quarter 2012, which contributed to an increase in crude oil prices at the start of 2013. Projected OPEC crude oil supply decreases by 0.3 million bbl/d in 2013 from the year before and then rises by 0.3 million bbl/d in 2014. Most of the decline in 2013 comes from Saudi Arabia, which responds to non-OPEC growth and increasing production from some OPEC members, such as Iraq, Nigeria, and Angola. In Angola, output at the BP-operated PSVM (Plutão, Saturno, Vénus, and Marte) development recently came on line. Production at PSVM is expected to build this year and peak at 150,000 bbl/d in 2014.

New threats to energy infrastructure in the Middle East and North Africa emerged in January 2013 as a militant group stormed the Ain Amenas natural gas facility in east Algeria causing a four-day standoff that resulted in both facility worker and militant casualties. Militants later attacked a natural gas pipeline. In response, Algeria and international energy firms operating in the country have increased security at oil and gas facilities, and nearby countries such as Tunisia and Libya have followed suit. EIA's oil supply outlook for Algeria remains unchanged, as there has been no indication that recent events have affected current oil operations or deterred future investments.

Libya's energy sector continues to be plagued by a series of small disruptions. Protesters have expressed economic and political grievances by disrupting operations at several key facilities over the last month, including the Ras Lanuf refinery and the Zueitina export terminal, which was responsible for an average of approximately 130,000 bbl/d of Libya's crude oil exports in December 2012. EIA estimates that Libya's crude oil output fell to an average of 1.3 million bbl/d in January 2013, which would be the lowest monthly average since February 2012.

EIA estimates that OPEC surplus capacity, which is overwhelmingly concentrated in Saudi Arabia, was around 2.7 million bbl/d in January 2013, an increase from previous months. Projected OPEC surplus capacity averages 2.9 million bbl/d in 2013 and 3.4 million bbl/d in 2014. These

estimates do not include additional capacity that may be available in Iran but which is currently off line because of the effects of U.S. and EU sanctions on Iran's ability to sell its oil.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories at the end of 2012 totaled 2.66 billion barrels, equivalent to 57.2 days of supply. Projected OECD oil inventories fall slightly and end 2013 at 2.63 billion barrels (56.4 days of supply). Inventories increase slightly to 2.69 billion barrels (57.8 days of supply) by the end of 2014.

Crude Oil Prices. EIA projects the Brent crude oil spot price will fall from an average of \$112 per barrel in 2012 to annual averages of \$109 per barrel and \$101 per barrel in 2013 and 2014, respectively, reflecting the increasing supply of liquid fuels from non-OPEC countries. After averaging \$94 per barrel in 2012, the projected WTI price averages \$93 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 drop in the price discount of WTI to Brent from an average \$18 per barrel in 2012 to \$9 per barrel in 2014.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for May 2013 delivery during the five-day period ending February 7, 2013, averaged \$97.55 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 May 2013 at \$82 per barrel and \$117 per barrel, respectively. Last year at this time, WTI for May 2012 delivery averaged \$99 per barrel and implied volatility averaged 31 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$75 per barrel and \$130 per barrel.

U.S. Crude Oil and Liquid Fuels

The U.S. average regular gasoline retail price increased from \$3.25 per gallon on December 17, 2012, which was the low for all of 2012, to \$3.61 per gallon on February 11, 2013, which was the highest nominal retail price ever for this time of year. An increase in crude oil prices explains much of the rise in gasoline prices. Between mid-December and early February, Brent crude oil spot prices increased from \$109 per barrel to \$119 per barrel, equivalent to about \$0.24 per gallon. There were also some unexpected [refinery outages](#) during January, both in the United States and in Europe, which contributed to higher gasoline prices. Although EIA expects crude oil prices to come off their current peaks, forecast regular gasoline retail prices continue to rise over the next few months to a peak of \$3.73 per gallon in May 2013 because of the seasonal increase in demand and the switch from winter- to more costly summer-grade gasoline.

U.S. Liquid Fuels Consumption. Total liquid fuels consumption has fallen from a peak of 20.8 million bbl/d in 2005 to 18.6 million bbl/d in 2012. The decline in consumption coincided with rising crude oil prices and falling natural gas prices, which motivated fuel conservation, improvements in fuel efficiencies, and fuel switching. Total liquid fuels consumption grows

modestly in this forecast, increasing by 50,000 bbl/d (0.3 percent) in 2013 and by 80,000 bbl/d (0.4 percent) in 2014. Distillate fuel oil consumption, which fell by 140,000 bbl/d in 2012, increases at an average annual rate of 20,000 bbl/d in 2013 and 60,000 bbl/d in 2014. Distillate fuel consumption growth is driven by weather in the Northeast, which is forecast to be colder in comparison with the mild winter months during 2012, and increases in industrial output. Ethane and propane consumption rises because of continued growth in industrial use as well as the assumption of close-to-average weather next winter. Planned expansions at several ethylene plants in 2013 lead to increases in expected ethane and propane of 50,000 bbl/d in 2013 and 30,000 bbl/d in 2014. In contrast, motor gasoline and jet fuel consumption remain flat in 2013 and 2014 as increasing travel is offset by fuel economy improvements.

U.S. Liquid Fuels Supply and Imports. EIA expects U.S. crude oil production to continue to grow rapidly over the next two years, increasing from an average 6.4 million bbl/d in 2012 to average 7.3 million bbl/d in 2013 and 7.8 million bbl/d in 2014. Central to this projected growth will be continuing development of onshore basins. Drilling in tight oil plays in the Williston, Western Gulf, and Permian Basins is expected to account for the bulk of forecast production growth over the next two years.

Alaskan crude oil production reached a seasonal low last year of 400,000 bbl/d in August 2012, when summer maintenance typically decreases volumes, but recovered to 550,000 bbl/d in October. EIA expects Alaskan crude oil production will decline from an average of 530,000 bbl/d in 2012 to 500,000 bbl/d in 2013 and 470,000 bbl/d in 2014.

U.S. federal Gulf of Mexico (GOM) crude oil production averaged an estimated 1.3 million bbl/d in 2012, about 50,000 bbl/d lower than during 2011. EIA expects GOM production to increase to an average of 1.4 million bbl/d in 2013. Much of that increase is due to new projects that started producing in 2012, but continued to increase until late 2012 or early 2013, and six new field start-ups. Projected GOM production continues to increase in 2014, averaging 1.5 million bbl/d, as several relatively high-volume deepwater projects are expected onstream.

Since peaking in 2005 at 12.5 million bbl/d, U.S. liquid fuel net imports, including crude oil, have been falling. Total net imports fell to 7.5 million bbl/d in 2012, and EIA expects imports to continue declining to an average of 6.1 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 32 percent in 2014 because of continued substantial increases in domestic crude oil production.

U.S. Petroleum Product Prices. U.S. regular gasoline retail prices averaged \$3.63 per gallon in 2012. U.S. regular gasoline retail prices rose in January 2013 because of the combination of increasing crude prices and [refinery outages](#). Despite the recent run-up in prices, EIA expects falling crude prices will lead to regular gasoline retail prices averaging \$3.55 per gallon in 2013 and \$3.39 per gallon in 2014.

On-highway diesel fuel retail prices averaged \$4.02 per gallon in the fourth quarter of 2012 due to tight market conditions and strong demand for exports. Although U.S. week-ending stocks of distillate fuel in January 2013 reached their highest levels in nine months, they are still at the bottom of their previous five-year (2008-12) range for this time of year. After averaging \$3.97 per gallon in 2012, EIA expects that on-highway diesel fuel retail prices will average \$3.92 per gallon in 2013 and \$3.82 per gallon in 2014.

Natural Gas

Cold weather helped drive northeastern natural gas prices up at the end of January. The U.S. Northeast is [infrastructure-constrained](#) and the tight supply-demand balance during extreme cold or heat often leads to price spikes. Prices at Transcontinental Pipeline's Zone 6 delivery point, which serves New York City, and at the Algonquin Citygate, which serves Boston, both rose above \$30 per MMBtu on [January 24 and 25](#).

Cold weather during January 2013 also affected natural gas production in the western United States. Producers reported wellhead freeze-offs in the San Juan, Green River, Uinta, and Piceance basins, according to recent Bentek Energy reports. As natural gas production in the United States shifts from offshore to inland, [well freeze-offs](#) have become a greater supply disruption risk.

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 70.3 billion cubic feet per day (Bcf/d) in 2013 and 70.0 Bcf/d in 2014. This month's prediction is a significant upward revision from last month's expectation of 69.7 Bcf/d and 69.4 Bcf/d in 2013 and 2014, respectively. The upward revision is mostly the result of changes to historical industrial sector consumption data, which were revised upwards in the recent release of the EIA [Natural Gas Annual](#).

Forecasts for closer-to-average winter temperatures in 2013 and 2014 (compared with the record-warm temperatures in 2012) lead to increases in natural gas used for residential and commercial space heating. Despite Punxsutawney Phil's recent forecast of an early spring this year, a 15-percent increase in U.S. population-weighted heating degree days from 2012 to 2013 is still projected.

The projected increase in natural gas prices contributes to a decline in natural gas used for electric power generation from 25.0 Bcf/d in 2012 to 23.1 Bcf/d in 2013 and 22.6 Bcf/d in 2014. Consumption over the forecast period is less than the record-high 2012 levels, but remains high by historical standards and reflects an ongoing structural shift toward using more natural gas for power generation.

U.S. Natural Gas Production and Imports. EIA's most recent [monthly production data](#) indicated that total U.S. average daily marketed production reached 70.4 Bcf/d in November 2012, 0.4 Bcf/d above the previous month, with upticks in the federal Gulf of Mexico, Oklahoma,

Wyoming, and the category for other states, which includes Pennsylvania. Production in the Marcellus Shale areas of Pennsylvania and West Virginia is expected to continue rising, as recently drilled wells become operational. Despite relatively low natural gas prices, [Pennsylvania drilling](#) continues at a strong pace as producers target combination oil-and-gas wells. Projected marketed production increases from 69.2 Bcf/d in 2012 to 70.0 Bcf/d in 2013, and remains flat in 2014.

Natural gas pipeline imports, which have declined over the last 5 years, are projected to remain near their 2012 level over the forecast. LNG imports are expected to remain at minimal levels of less than 0.5 Bcf/d in both 2013 and 2014. LNG imports mainly arrive at the Elba Island terminal in Georgia and the Everett terminal in New England, either to fulfill long-term contract obligations or to take advantage of temporarily high local prices due to cold snaps and disruptions. Higher prices for LNG elsewhere in the world have made the United States a market of last resort for LNG suppliers. Natural gas exports to Mexico have grown substantially since 2010, and EIA expects pipeline exports to continue increasing through 2014.

U.S. Natural Gas Inventories. As of February 1, 2013, working gas stocks totaled 2,684 Bcf, which is 226 Bcf less than at the same time in 2012, but 351 Bcf greater than the previous five-year (2008-12) average, according to EIA's [Weekly Natural Gas Storage Report](#). While warmer-than-average temperatures in December limited withdrawals, cold temperatures in January 2013 led to several big storage drawdowns. EIA expects an end-of-March level of just under 2,000 Bcf, which is less than the unusually high 2,477 Bcf at the end of March 2012, but still more than the five-year average of 1,726 Bcf.

U.S. Natural Gas Prices. Natural gas spot prices averaged \$3.33 per MMBtu at the Henry Hub in January 2013, relatively unchanged from December, despite colder weather in January. EIA expects the Henry Hub price will average \$3.53 per MMBtu in 2013 (compared with \$2.75 per MMBtu in 2012) and \$3.84 per MMBtu in 2014.

Natural gas futures prices for May 2013 delivery (for the five-day period ending February 7, 2013) averaged \$3.46 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for May 2013 contracts at \$2.61 per MMBtu and \$4.58 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for May 2012 averaged \$2.81 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were \$1.83 per MMBtu and \$4.31 per MMBtu.

Coal

Because of last year's drought, [stretches of the upper Mississippi River](#) have approached record lows. The [U.S. Army Corps of Engineers](#) continue to dredge and excavate rocks along the Middle Mississippi River between St. Louis and Cairo, IL., where the Ohio River joins the Mississippi.

Rock removal, coupled with water releases from Red Rock Lake in Iowa and Carlyle Lake in Illinois, allowed for continued barge traffic on the river with only minor interruptions and delays.

U.S. Coal Consumption. EIA expects coal consumption in the electric power sector to increase over the forecast period, as electricity demand and natural gas prices rise, but still remain significantly lower than the 1,003 million short tons (MMst) averaged during 2000-09. EIA expects that coal consumption in the electric power sector will be 859 MMst in 2013 and 870 MMst in 2014. EIA projects that annual nonpower-sector coal consumption will average more than 65 MMst during the forecast period, similar to the amount of consumption estimated in 2012.

U.S. Coal Supply. EIA estimates that coal production fell by 6.9 percent in 2012. Coal production is expected to decline by an additional 1.2 percent in 2013 because primary and secondary inventory draws and a small increase in coal imports will meet growth in consumption. Coal production is forecast to grow by 2.0 percent in 2014.

U.S. Coal Trade. EIA estimates coal exports totaled a record 124 MMst in 2012. EIA expects exports to total 108 MMst in 2013 and 112 MMst in 2014. Continuing economic weakness in Europe (which takes the most U.S. coal exports), falling international coal prices, and increasing production in other coal-exporting countries are the primary reasons for the expected decline in coal exports. U.S. coal exports could be higher if there are significant supply disruptions from any of the major coal-exporting countries. Coal exports averaged 54 MMst during 2000-09.

U.S. Coal Prices. Delivered coal prices to the electric power industry increased steadily over an 11-year period through 2011, when the delivered coal price averaged \$2.39 per MMBtu (a 5-percent increase from 2010). EIA expects changing market conditions, including weaker domestic demand for coal and higher coal inventories, will slow increases in coal prices and contribute to the shut-in of higher-cost production. EIA estimates that the delivered coal price averaged \$2.40 per MMBtu in 2012, and forecasts averaged delivered prices of \$2.41 per MMBtu in 2013 and \$2.45 in 2014.

Electricity

Natural gas supply constraints in New England were exacerbated by a [late-January cold snap](#), which raised wholesale power prices in the New York Independent System Operator (ISO) and ISO New England (the regional transmission organizations that serve the northeastern United States). While short-term wholesale power price spikes rarely have visible effects on retail electricity rates, wholesale prices were likely high enough to make it economically attractive to use petroleum-fired power generation for a few days.

U.S. Electricity Consumption. U.S. residential electricity sales during December 2012 and January 2013 are estimated to have averaged 1.3 percent more than the same months a year ago. EIA is assuming that temperatures during the upcoming summer will be milder than last

summer's record-breaking heat. U.S. cooling degree days during June, July, and August 2013 are expected to total about 13 percent lower than last summer and about 6 percent lower than the prior 10-year average. EIA projects U.S. residential sales of electricity during the upcoming summer will average 6 percent below the summer of 2012. Overall, U.S. residential electricity sales decline by 0.4 percent during 2013 but then grow by 0.4 percent in 2014.

U.S. Electricity Generation. EIA expects total generation of electricity across all sectors will grow by 0.5 percent in 2013 and by 0.8 percent in 2014. Generation from renewable energy sources other than hydropower exhibited the highest rate of growth among all generation sources in recent years, and similar growth is expected to continue during the next two years. EIA estimates that the electric power sector added over 12 gigawatts of new wind power capacity during 2012, about 40 percent of which came on line in December before the scheduled end-of-year deadline, which has been extended, for wind capacity to be operational in order to be eligible for the production tax credit. This additional capacity contributes to an expected 12-percent increase in generation from renewable sources other than hydropower during 2013. Nonhydro renewable energy accounts for 6.0 percent of total generation in 2013 and 6.4 percent in 2014, compared with 5.4 percent in 2012.

Because of the increasing cost of natural gas relative to coal, the share of electricity generated by natural gas is expected to fall from 30.3 percent in 2012 to 27.6 percent in 2014. EIA expects the share of generation fueled by coal to rise from 37.4 percent in 2012 to 39.1 percent in 2014.

U.S. Electricity Retail Prices. Rising costs of infrastructure upgrades continue to drive increases in residential electricity rates, although lower fuel prices in recent years have kept growth in retail rates relatively modest. After an increase of 1.3 percent during 2012, EIA expects retail residential electricity prices will grow by 1.7 percent in 2013 and by 2.0 percent in 2014.

Renewables and Carbon Dioxide Emissions

U.S. Electricity Generation Renewables. EIA estimates that total renewable energy consumption declined by 2.0 percent in 2012, as the decrease in hydropower more than offset the growth in the consumption of other renewable energy forms. This drop was the result of hydropower production falling by 13 percent as water supply in the Pacific Northwest fell from the unusually high levels seen in 2011. EIA projects renewable energy consumption to increase by 2.6 percent in 2013. While hydropower declines by 2.7 percent, nonhydropower renewables grow by an average of 5.2 percent. In 2014, the growth in total renewables is projected to continue at a rate of 4.1 percent, as a 1.3-percent increase in hydropower is combined with a 5.3-percent increase in nonhydropower renewables.

EIA currently estimates that wind capacity will increase by 7 percent in 2013 and by 10 percent in 2014. However, electricity generation from wind is projected to increase by 15 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.

Forecast solar energy continues robust growth, although the total amount remains a small share of total U.S. generation. Projected consumption grows by 33 percent in 2012, 29 percent in 2013, and 30 percent in 2014. Solar energy is not directly affected by the changes in the PTC, but the effect could be indirect as more wind energy is available to meet state renewable portfolio standards.

U.S. Liquid Biofuels. The U.S. Environmental Protection Agency published a notice of proposed rulemaking on January 31, 2013, for the [2013 renewable fuel volume obligations](#) under the Renewable Fuel Standard program (RFS2) that lowers the 2013 mandate for cellulosic biofuels from the statutory target of 1.0 billion gallons to 14 million gallons. However, the statutory targets for advanced biofuel and total biofuels in 2013, 2.75 billion gallons and 16.55 billion gallons, respectively (all volumes are ethanol-equivalent) were maintained by the proposed rule. This forecast assumes that the 2014 renewable fuel volume obligations for biodiesel and advanced biofuel are identical to those in 2013.

Because of drought conditions, fuel ethanol production averaged 864,000 bbl/d (13.3 billion gallons) in 2012, its lowest average since 2009. EIA expects ethanol production to remain near current levels of about 800,000 bbl/d through mid-2013 before recovering to predrought production levels, averaging 852,000 bbl/d (13.1 billion gallons) for the year. Ethanol production is expected to rise in 2014, averaging 916,000 bbl/d (14.0 billion gallons), as previously idled capacity comes back on line. Despite the forecast increase in ethanol production, EIA expects the drawdown of banked [renewable identification numbers](#), as the average ethanol share of the gasoline pool increases only modestly between 2012 and 2014.

The \$1-per-gallon biodiesel excise tax credit was reinstated retroactively beginning January 1, 2012, through the end of 2013 as part of the year-end fiscal package. Biodiesel production that averaged 63,000 bbl/d (1.0 billion gallons) in 2012 is forecast to increase to 84,000 bbl/d (1.3 billion gallons) in both 2013 and 2014.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels declined by 3.7 percent in 2012, and projects increases of 1.4 percent in 2013 and 0.6 percent in 2014. The increase in emissions over the forecast primarily reflects the projected increase in coal use for electricity generation.

U.S. Economic Assumptions

The economic projections in the STEO are derived from the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs. The GI model used in this STEO incorporates recent tax changes due to the American Taxpayer Relief Act of 2012. It is also assumed that 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.

Current Trends. Despite a slight (0.1 percent on an annualized basis) fall in U.S. real gross domestic product (GDP) in the fourth quarter of 2012 compared with the third quarter, most recent economic indicators reflect growth. Nonfarm payroll employment grew by 157,000 in January, according to the [Bureau of Labor Statistics \(BLS\)](#). BLS also revised upward employment growth in both November and December of 2012, although the unemployment rate increased slightly in January to 7.9 percent. The [Institute for Supply Management \(ISM\) manufacturing index](#) rose in January to 53.1, indicating expansion in the manufacturing sector (a value above 50 indicates expansion), and both industrial production and capacity utilization rose in December according to the [Federal Reserve](#). However, the [Federal Reserve Bank of Philadelphia's business outlook survey](#) and the [Federal Reserve Bank of Kansas City's manufacturing survey](#) both showed modest regional contractions in manufacturing activity during January.

U.S. Production. The STEO assumes 1.7 percent U.S. real GDP growth in 2013, rising to 2.6 percent in 2014. Relatively slower growth in the beginning of 2013 follows the expiration of the payroll tax cut. After mid-2013, real GDP year-over-year growth gradually increases until it reaches 3.0 percent in the final quarter of 2014. Residential and nonresidential investment, as well as exports, are important components of this growth.

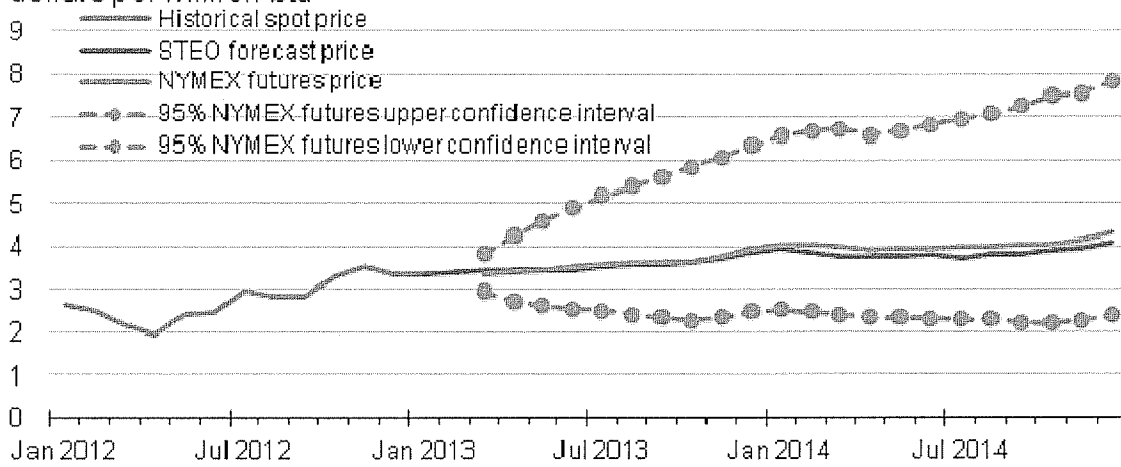
Total industrial production grows at a similar rate to real GDP in 2013 and 2014, at 1.7 percent and 3.0 percent, respectively. Industrial production growth in the manufacturing sector is slower than total production in 2013 at 1.5 percent, but accelerates to 3.4 percent in 2014. Both of these indexes mirror the rise in demand due to higher growth in real GDP.

U.S. Income and Expenditures. Real consumption expenditures grow in line with real GDP in 2013, at 1.7 percent, but growth in 2014 of 2.4 percent is slightly below GDP growth in that year. The expiration of the payroll tax cut also has an effect, as real disposable income grows only 0.6 percent in 2013. Private fixed investment jumps to 8.8-percent growth in 2014 from 5.5 percent this year, highlighting its importance for overall economic expansion, and export growth accelerates as well. Government expenditures fall more than 1 percent in both years.

U.S. Employment, Housing, and Prices. The unemployment rate in the forecast gradually falls from an average of 7.7 percent in 2013 to 7.4 percent in 2014. This is accompanied by nonfarm employment growth averaging 1.0 percent in 2013 and 1.6 percent in 2014. Consistent with an improving housing sector, housing starts show relatively fast growth, expanding by 23.0 percent and 32.5 percent in 2013 and 2014, respectively. Both consumer and producer prices continue to increase at a moderate pace of less than 2 percent per year.

HenryHub Natural Gas Price

dollars per million btu

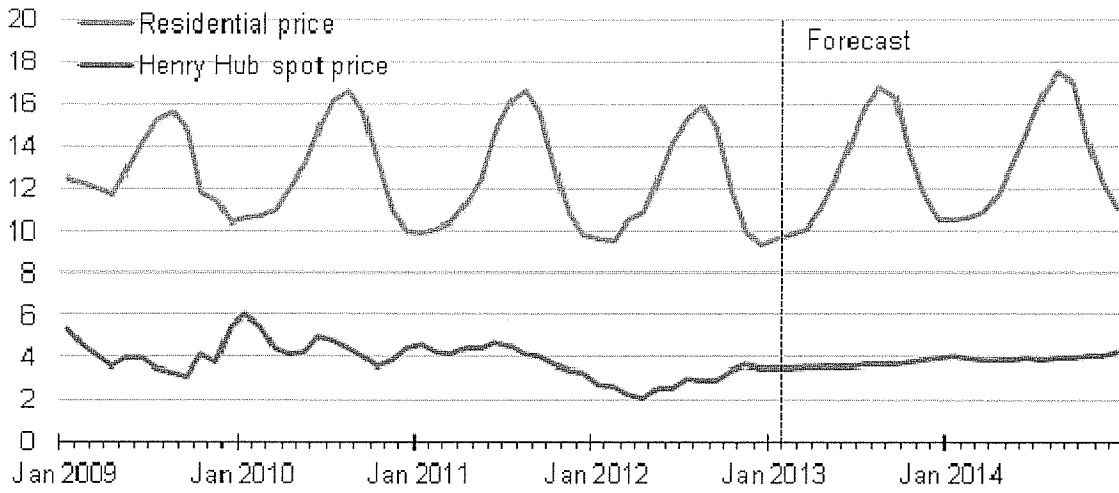


Note: Confidence interval derived from options market information for the 5 trading days ending February 7, 2013. Intervals not calculated for months with sparse trading in near-the-money options

Source: Short-Term Energy Outlook, February 2013

U.S. Natural Gas Prices

dollars per thousand cubic feet



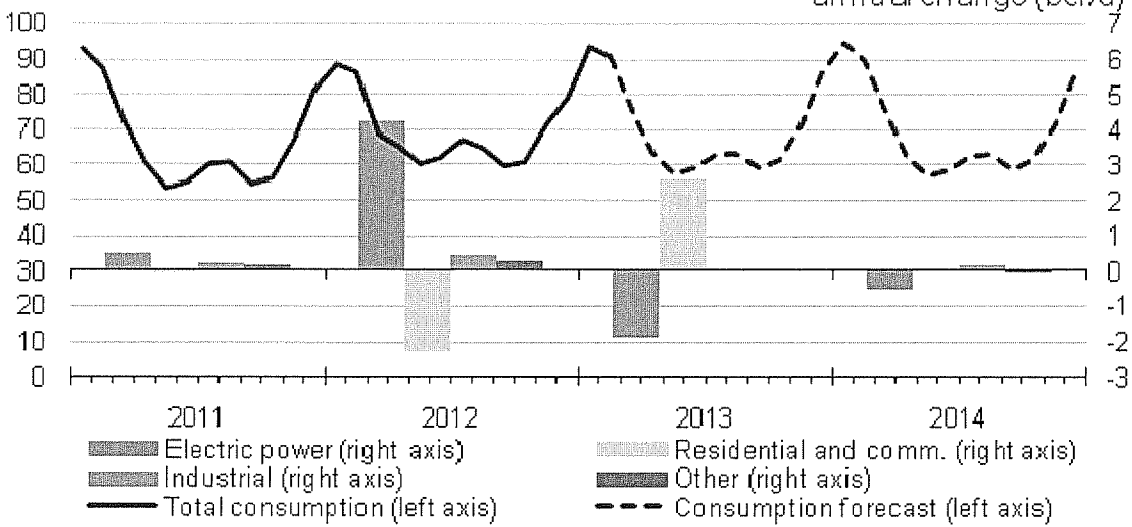
Source: Short-Term Energy Outlook, February 2013

U.S. Natural Gas Consumption

billion cubic feet per day (bcf/d)



annual change (bcf/d)

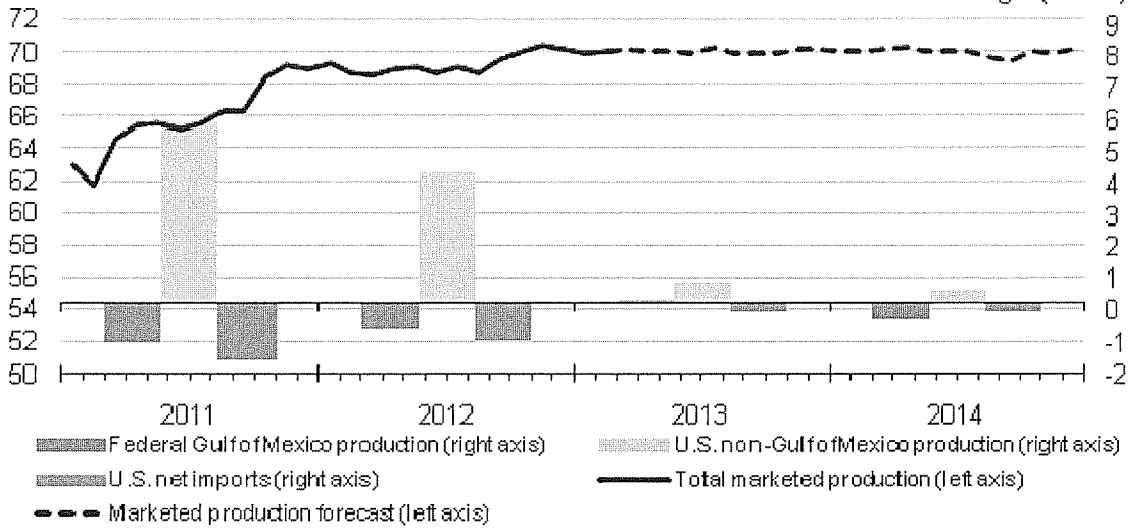


Source: Short-Term Energy Outlook, February 2013

U.S. Natural Gas Production and Imports

billion cubic feet per day (bcf/d)

annual change (bcf/d)



Source: Short-Term Energy Outlook, February 2013

**GREAT PLAINS NATURAL GAS CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
APPLICABLE TO NORTH DAKOTA
FIRM**

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ April 30, 2012									<u><u>\$311,764</u></u>
May	\$30,099	\$0	\$2,016	\$32,115	13,138	\$0.5102	\$6,702	\$25,413	337,177
June	52,819	0	2,192	55,011	6,558	1.0137	4,625 2/	50,386	387,563
July	57,568	0	2,542	60,110	5,776	1.0137	5,855	54,255	441,818
August	58,888	0	2,918	61,806	5,143	1.0137	5,213	56,593	498,411
September	26,138	0	3,308	29,446	6,241	1.0137	6,327	23,119	521,530
October	36,902	0	3,454	40,356	10,185	1.0137	10,325	30,031	551,561
November	8,143	0	3,651	11,794	20,404	1.0137	20,684	(8,890)	542,671
December	7	0	3,572	3,579	31,222	1.0137	31,650	(28,071)	514,600
January 2013	(22,865)	0	3,361	(19,504)	49,729	1.0137	50,410	(69,914)	444,686
Balance @ January 31, 2013									<u><u>\$444,686</u></u>

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

2/ Reflects 4,017.3 dk @ \$0.5102 and 2,540.6 dk @ \$1.0137.

**GREAT PLAINS NATURAL GAS CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE**

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ April 30, 2012									<u><u>(\$72,396)</u></u>
May	(\$11,426)	\$0	(\$557)	(\$11,983)	23,670	(\$0.0178)	(\$422)	(\$11,561)	(83,957)
June	(6,055)	0	(637)	(6,692)	13,697	(0.2915)	(1,509) 2/	(5,183)	(89,140)
July	(16,584)	0	(671)	(17,255)	13,108	(0.2915)	(3,821)	(13,434)	(102,574)
August	(2,356)	0	(765)	(3,121)	14,195	(0.2915)	(4,138)	1,017	(101,557)
September	(20,241)	0	(754)	(20,995)	21,085	(0.2915)	(6,146)	(14,849)	(116,406)
October	325	0	(859)	(534)	37,029	(0.2915)	(10,794)	10,260	(106,146)
November	6,923	0	(784)	6,139	41,796	(0.2915)	(12,184)	18,323	(87,823)
December	(3,340)	0	(652)	(3,992)	49,581	(0.2915)	(14,452)	10,460	(77,363)
January 2013	(4,644)	0	(579)	(5,223)	56,465	(0.2915)	(16,460)	11,237	(66,126)
Balance @ January 31, 2013									<u><u>(\$66,126)</u></u>

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 9,073.4 dk @ (\$0.0178) and 4,623.6 dk @ (\$0.2915).