

March 28, 2013

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

Re: Cost of Gas Adjustment (COG)
April 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 (85th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (85th Revised Sheet No. 8), showing the April 2013 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.6099 per mcf for all customers.

Attachment B shows the calculations supporting the gas costs for April 2013, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.6099 since the last COG filing.

Attachment C explains the reasons for the change in the market price of gas.

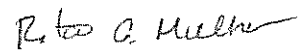
Attachment D shows the calculation of the balancing account since April 30, 2012.

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

85th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 84th Revised Sheet No.1.1

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/MCF
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF \$1.2740 Over 10 MCF 1.0540	\$6.6927	\$7.9667 7.7467
Firm Gas Service - General Highway 13	2.5	\$3.50 per month	First 10 MCF \$2.1740 Over 10 MCF 1.9540	\$6.6927	\$8.8667 8.6467
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	\$3.8614	\$5.0005 4.7545 4.6025
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	\$3.8614	\$5.9005 5.6545 5.5025
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$3.8614	\$5.1005
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 28, 2013

Effective Date: Service rendered on and after April 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
85th Revised Sheet No. 8
Canceling 84th 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	(1.5909)	1.0137	0.8979	(1.5761)	(0.2915)	(1.8676)
Current Adj.	0.0000	0.6099	0.0000	0.6099	0.6099	0.0000	0.6099
Total Adj.	1.4751	(0.9810)	1.0137	1.5078	(0.9662)	(0.2915)	(1.2577)
Total Rate:	\$1.5409	\$4.1381	\$1.0137	\$6.6927	\$4.1529	(\$0.2915)	\$3.8614

Date Filed: March 28, 2013

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after April 1, 2013

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

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

<u>Firm</u>	<u>Billing</u> <u>Determinants</u>	<u>Rate</u>	<u>Demand</u> <u>Months</u>	<u>Amount</u>	<u>Amount</u> <u>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/ 4.1381		5,792,032	4.1381
Gas Cost Reconciliation Adjustment					1.0137
Total Current Firm Gas Cost				\$7,928,051	6.6927
Base Cost of Gas					5.1849
Accumulated Adjustment					\$1.5078
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$4.1381
Gas Cost Reconciliation Adjustment					(0.2915)
LMS Demand 2/					0.0148
Total Current Interruptible Gas Cost					3.8614
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$1.2577)

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

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
APRIL 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:	4.1381	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
<u>Category 1 (Contract Term of Less than 3 Years)</u>	
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
<u>Category 2 (Contract Term of 3 Years to less than 5 Years)</u>	
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
<u>Category 3 (Contract Term of 5 or more Years)</u>	
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/	
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		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	0.0377	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/		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 \$0.0000 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
April 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 April monthly price for the NNG-Ventura Index is expected to increase from the previous month index. The NNG-Ventura Index is based on negotiated trades during the last five business days of the month, commonly known as bid week, and reported by Platt's Inside FERC's Gas Market Report published the beginning of each month.

Colder than normal weather over a widespread portion of the US, likely was the main contributor to the increase in the commodity price of natural gas. Cold weather was accompanied by numerous storms through the midcontinent and the Northeast with substantial snowfall occurring. Energy Information Administration (EIA) reported storage levels nationwide as of March 15, 2013 were 9.5 percent above the five-year average and 21.1 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

March 2013

Short-Term Energy Outlook (STEO)

Highlights

- The weekly U.S. average regular gasoline retail price fell in early March for the first time since mid-December. The March 11 average was \$3.71 per gallon, down \$0.07 per gallon from February 25. EIA expects that lower crude oil prices will result in monthly average regular gasoline prices staying near the February average of \$3.67 per gallon over the next few months, with the annual average regular gasoline retail price declining from \$3.63 per gallon in 2012 to \$3.55 per gallon in 2013 and \$3.38 per gallon in 2014. Energy price forecasts are highly uncertain and the current values of futures and options contracts suggest that prices could differ significantly from this forecast.
- 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 \$108 per barrel in 2013 and \$101 per barrel in 2014. The projected discount of West Texas Intermediate (WTI) crude oil to Brent, which increased to a monthly average of more than \$20 per barrel in February 2013, will average \$16 per barrel in 2013 and \$9 per barrel in 2014, as planned new pipeline capacity lowers the cost of moving mid-continent crude oil to the Gulf Coast refining centers.
- U.S. crude oil production exceeded an average level of 7 million barrels per day (bbl/d) in November and December 2012, the highest volume since December 1992. EIA estimates that U.S. total crude oil production averaged 6.5 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 is expected to average 7.3 million bbl/d in 2013 and 7.9 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 slightly 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 little change in gasoline and jet fuel consumption.
- Natural gas working inventories ended February 2013 at an estimated 2.08 trillion cubic feet (Tcf), about 0.36 Tcf below the level at the same time a year ago but still 0.27 Tcf greater than the 5-year average (2008-12). EIA expects the Henry Hub natural gas spot price, which averaged \$2.75 per million British thermal units (MMBtu) in 2012, will average \$3.41 per MMBtu in 2013 and \$3.63 per MMBtu in 2014. Current options and futures prices imply that the lower and upper bounds for the 95-percent confidence interval for June 2013 contracts at \$2.79 per MMBtu and \$4.67 per MMBtu, respectively.

Global Crude Oil and Liquid Fuels

Oil market balances have not changed dramatically since last month's STEO, although somewhat lower expectations for production in Libya and Iraq, along with an increase in unplanned outages in countries outside the Organization of the Petroleum Exporting Countries (OPEC), implies slightly tighter conditions in 2013 than previously projected. Positive economic indicators, including upward revisions in estimates of Chinese GDP growth and continuing employment growth in the United States, could lend support to higher prices, but over the past week they have been counterbalanced by renewed uncertainty regarding economic growth in Europe.

EIA estimates that global liquid fuels consumption outpaced production in January and February 2013, resulting in a 1.1-million-bbl/d average draw in global oil stocks (see [The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran](#)). 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. Projected world supply increases by 0.8 million bbl/d in 2013 and 1.9 million bbl/d in 2014, with most of the growth coming from North America and other non-OPEC countries.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by 0.8 million bbl/d in 2012 to reach 89.1 million bbl/d. EIA expects this growth rate will be higher in 2013 and 2014 because of a moderate recovery in global economic growth. World consumption reaches 90.1 million bbl/d in 2013 and 91.5 million bbl/d in 2014.

Non-OECD Asia is the leading regional contributor to expected global consumption growth. EIA expects refinery crude oil inputs in China 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 510,000 bbl/d in 2014. This compares with annual average growth of 540,000 bbl/d from 2004 through 2010.

OECD liquid fuels consumption fell by 0.5 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 recover in response to higher economic growth.

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 almost three-quarters 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.

Unplanned production outages in non-OPEC countries increased to about 0.9 million bbl/d in February 2013. The increase in outages was the result of oil leaks, which forced a North Sea crude oil pipeline to shut down, and production problems at the Buzzard field in the U.K. sector of the North Sea. Syria and South Sudan continue to account for more than 60 percent of the total disruptions to non-OPEC production. EIA assumes production in Syria remains at current levels over the forecast period. EIA assumes that production restarts in South Sudan in the first half of 2014; however, if security problems persist, production may not resume during the forecast period.

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. EIA estimates suggest that Saudi Arabia cut production from an average of 9.9 million bbl/d during third-quarter 2012 to 9.0 million bbl/d in February 2013.

Projected OPEC crude oil supply decreases by 0.4 million bbl/d in 2013 from the year before and then rises by 0.5 million bbl/d in 2014. Most of the decline in 2013 comes from Saudi Arabia, in response to non-OPEC supply growth.

The death of President Hugo Chávez crystallizes political risks in Venezuela, which the market had already internalized to some extent as news about his condition emerged. Though the outcome of the succession process could have implications for the oil sector, EIA is maintaining its Venezuelan production forecast on the assumption that current policies related to the oil sector will be continued. For more information, see ["Political risks focus attention on supply of Venezuelan oil to the United States"](#).

EIA has lowered its expectations for oil production in Libya to reflect the persistence of technical problems and political pressures, which have already curtailed output. Libya's precarious security environment creates downside production risks from the potential for additional disruptions due to attacks, strikes, or poorly maintained infrastructure. In Iraq, payment disputes between Baghdad and the Kurdistan Regional Government will lead to lost output in the north that at least partly offsets increased crude oil exports from the Iraq's southern fields.

EIA estimates that OPEC surplus capacity, which is concentrated in Saudi Arabia, continued at about 2.8 million bbl/d in February 2013, an increase of 0.8 million bbl/d compared with the year-ago level but still 0.2 million bbl/d lower than the previous three-year average. 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 is currently offline 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 2.69 billion barrels, equivalent to 58.4 days of supply. Projected OECD oil

inventories fall slightly and end 2013 at 2.63 billion barrels (56.7 days of supply). Inventories increase to 2.66 billion barrels (57.7 days of supply) by the end of 2014.

U.S. Crude Oil and Liquid Fuels

The U.S. weekly average regular gasoline retail price increased from \$3.25 per gallon on December 17, 2012, which was the low for all of 2012, to \$3.78 per gallon on February 25, 2013, which was the highest nominal retail price ever during the month of February (see *This Week in Petroleum*, February 21, 2013). EIA expects that lower crude oil prices will result in monthly average regular gasoline prices staying near the February average of \$3.67 per gallon over the next few months, with the average annual retail prices projected at \$3.55 per gallon in 2013 and \$3.38 per gallon in 2014. The current values of futures and options contracts suggest that prices could differ significantly from this forecast. For example, there is a 16 percent probability that the New York Harbor reformulated gasoline blendstock for oxygenate blending (RBOB) futures price will exceed \$3.35 per gallon (consistent with a U.S. average regular gasoline retail price above \$4.00 per gallon) in June 2013.

U.S. Liquid Fuels Consumption. Total liquid fuels consumption fell from an annual average of 20.8 million bbl/d in 2005 to 18.6 million bbl/d in 2012. Total liquid fuels consumption grows modestly in this forecast, increasing by 30,000 bbl/d (0.1 percent) in 2013 and by 80,000 bbl/d (0.4 percent) in 2014. Distillate fuel oil consumption, which fell by 160,000 bbl/d in 2012, increases at an average annual rate of 10,000 bbl/d in 2013 and 60,000 bbl/d in 2014. Distillate fuel consumption growth is driven by increases in industrial output and winter weather in the Northeast, which is forecast to be colder in comparison with the mild winter months during 2012. 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 6.5 million bbl/d in 2012 to average 7.3 million bbl/d in 2013 and 7.9 million bbl/d in 2014. 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. Projected Alaskan crude oil production declines 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 and 1.5 million bbl/d in 2014.

EIA expects that U.S. crude oil production will exceed U.S. crude oil imports as early as the end of 2013, the first time this will have occurred since February 1995. Since reaching 12.5 million bbl/d in 2005, total U.S. liquid fuel net imports, including crude oil, have been falling. Total net imports fell to 7.4 million bbl/d in 2012, and EIA expects imports to continue declining to an average of 6.0 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, which would be the lowest level since 1985, because of continued substantial increases in domestic production.

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 \$108 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 \$92 per barrel in both 2013 and 2014. By 2014, several pipeline projects from the mid-continent 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.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for June 2013 delivery during the five-day period ending March 7, 2013, averaged \$91.59 per barrel. Implied volatility averaged 22 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in June 2013 at \$76 per barrel and \$111 per barrel, respectively. Last year at this time, WTI for June 2012 delivery averaged \$109 per barrel and implied volatility averaged 31 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$83 per barrel and \$144 per barrel.

U.S. Petroleum Product Prices. U.S. regular gasoline retail prices averaged \$3.63 per gallon in 2012. EIA expects falling crude prices will lead to regular gasoline retail prices averaging \$3.55 per gallon in 2013 and \$3.38 per gallon in 2014. After averaging \$3.97 per gallon in 2012, EIA expects that on-highway diesel fuel retail prices will average \$3.90 per gallon in 2013 and \$3.80 per gallon in 2014.

As previously discussed, the market's expectation of uncertainty in monthly average gasoline prices is reflected in the pricing and implied volatility of futures and options contracts, which suggest a 16 percent probability that the average national retail pump prices for regular gasoline could exceed \$4.00 per gallon in June 2013.

Natural Gas

In the past few years, U.S. pipeline exports of natural gas to Mexico have increased substantially, from around 0.9 billion cubic feet per day (Bcf/d) in 2010 to 1.7 Bcf/d in 2012. Mexico has expanded its natural-gas-fired power generation in recent years, and plans to continue to do so. Competitively-priced natural gas from the United States makes pipeline imports by Mexico an attractive option.

According to EIA's monthly natural gas gross production report, gross withdrawals fell in December 2012 from the month before in all major producing areas except Alaska. Total gross withdrawals fell about 0.7 percent from the November 2012 level to 82.6 Bcf/d in December

2012, equivalent to about 69.3 Bcf/d of marketed production. As natural gas production in the United States shifts inland, well freeze-offs have become a greater supply disruption risk during the winter. The 3.5-percent decline between November and December in New Mexico production was the largest of any state or region, as operators reported shut-ins resulting from freeze-offs. Well freeze-offs continued to affect production in western U.S. states in January 2013.

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 70.0 Bcf/d in both 2013 and 2014. 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. 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 22.7 Bcf/d in 2014.

U.S. Natural Gas Production and Imports. Projected natural gas marketed production increases from 69.1 Bcf/d in 2012 to 69.6 Bcf/d in 2013, and remains flat in 2014. Onshore production increases slightly over the forecast period, while GOM production declines.

Natural gas pipeline gross imports, which have declined over the last five years, are projected to remain near their 2012 level over the forecast period. Liquefied natural gas (LNG) imports are expected to remain at minimal levels of less than 0.5 Bcf/d in both 2013 and 2014.

U.S. Natural Gas Inventories. As of March 1, 2013, working gas stocks totaled 2,083 Bcf, which is 361 Bcf less than at the same time in 2012, but 269 Bcf greater than the five-year (2008-12) average, according to EIA's Weekly Natural Gas Storage Report. 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 well above 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 February 2013, relatively unchanged from the previous two months. EIA expects the Henry Hub price will increase from an average of \$2.75 per million Btu in 2012 to \$3.41 per MMBtu in 2013 and \$3.63 per MMBtu in 2014.

Natural gas futures prices for June 2013 delivery (for the five-day period ending March 7, 2013) averaged \$3.61 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for June 2013 contracts at \$2.79 per MMBtu and \$4.67 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for June 2012 averaged \$2.771 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were \$1.903 per MMBtu and \$4.06 per MMBtu.

Coal

The U.S. coal market may have received a small boost from recent coal supply disruptions in Colombia, which include a strike at its largest exporter. Force majeure, a contract clause that allows a company to suspend contractual obligations in the face of unexpected events, was declared on several coal shipments destined for markets in Europe and the United States. According to preliminary data from [Form EIA-923](#), U.S. electric power producers imported 5.2 million short tons (MMst) of Colombian coal in 2012. This amount was over 95 percent of coal imported by the electric power sector and more than 57 percent of all U.S. coal imports for the year. A preliminary accord between striking union workers and the Colombian mine was reported on March 4, 2013.

U.S. Coal Consumption. Total coal consumption fell by 114 million short tons (MMst) (11.3 percent) in 2012, led by an 11.6-percent decline in coal use for electricity generation. EIA projects total coal consumption will increase from 889 MMst in 2012 to 941 MMst in 2013 and 955 MMst in 2014. EIA expects consumption in the electric power sector to increase over the forecast period as a result of higher electricity demand and higher natural gas prices, but remain below 900 MMst.

U.S. Coal Supply. Coal production is expected to increase by 1.0 percent in 2013 as primary and secondary inventory draws, combined with an increase in coal imports, meet most of the growth in consumption. Coal production is forecast to grow by 1.3 percent in 2014.

U.S. Coal Trade. Coal exports totaled 126 MMst in 2012, surpassing the previous peak of 113 MMst exported in 1981 by nearly 12 percent. EIA expects exports to average near 110 MMst in both 2013 and 2014. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), falling international coal prices, and increasing production in other coal-exporting countries are the primary reasons for the expected decline in U.S. coal exports.

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 estimates that the delivered coal price averaged \$2.40 per MMBtu in 2012, and forecasts average delivered prices of \$2.42 per MMBtu in 2013 and \$2.45 per MMBtu in 2014.

Electricity

Preliminary data from the EIA [Electric Power Monthly](#) indicate that 7.9 gigawatts (GW) of coal-fired generation capacity was retired in the electric industry during 2012, which represents 2.5 percent of installed coal capacity at the beginning of the year (and about 0.8 percent of total generating unit capacity). Two-thirds of the coal capacity retired in 2012 was located in the Midwest and Southeast regions of the United States. In comparison, the U.S. electric industry

retired 2.6 GW of coal capacity in 2011 and retired an average of 1.0 GW each year between 2006 and 2010. The coal-fired capacity retired during 2012 was offset somewhat by the addition of five new coal-fired generating units with a combined capacity of 3.6 GW.

U.S. Electricity Consumption. EIA projects U.S. residential sales of electricity during the upcoming summer months (June, July, and August) will average 6 percent below sales during the summer of 2012. EIA assumes that U.S. cooling degree days during June, July, and August 2013 will total about 10 percent lower than last summer and about 4 percent lower than the prior 10-year average. Overall, U.S. residential electricity sales decline by 0.6 percent during 2013 but are projected to grow by 1.0 percent in 2014. U.S. retail electricity sales to the commercial sector increase by 0.5 percent in 2013 and by 1.1 percent in 2014. Industrial electricity sales increase by 1.6 percent and 1.0 percent in 2013 and 2014, respectively.

U.S. Electricity Generation. EIA expects total U.S. generation of electricity across all sectors will grow by 0.5 percent in 2013 and by 1.0 percent in 2014. EIA expects generators to increase their utilization of existing coal capacity, leading to a 6.2-percent increase in U.S. coal generation during 2013. This increase, which results because of the increasing cost of natural gas relative to coal, raises the share of total generation fueled by coal from 37.4 percent 2012 to 39.5 percent in 2013, still below coal's 42.3-percent fuel share in 2011. Conversely, the rising cost of natural gas pushes the share of generation fueled by natural gas down from 30.4 percent in 2012 to 28.3 percent this year, compared with a share of 24.7 percent in 2011.

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 1.4 percent during 2012, EIA expects U.S. retail residential electricity prices will grow by 1.9 percent in 2013 and by 1.8 percent in 2014.

Renewables and Carbon Dioxide Emissions

U.S. Electricity Generation Renewables. EIA estimates that total renewable energy consumption declined by 2.2 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 3.2 percent, nonhydropower renewables grow by an average of 5.5 percent. In 2014, the growth in total renewables is projected to continue at a rate of 4.5 percent, as a 2.6-percent increase in hydropower is combined with a 5.4-percent increase in nonhydropower renewables.

EIA currently estimates that wind capacity will increase by 6 percent in 2013 and by 14 percent in 2014. However, electricity generation from wind is projected to increase by 16 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 9 percent in 2014.

EIA expects a continuation of robust growth in the generation of solar energy, although the total amount remains a small share of total U.S. generation.

U.S. Liquid Biofuels. Fuel ethanol production averaged 865,000 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 pre-drought production levels, averaging 857,000 bbl/d for the year. Ethanol production is expected to rise in 2014, averaging 922,000 bbl/d. 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. Biodiesel production, which averaged 63,000 bbl/d (1.0 billion gallons) in 2012 is forecast to increase to 82,000 bbl/d (1.3 billion gallons) in both 2013 and 2014. This forecast assumes that the 2014 renewable fuel volume obligations for biodiesel and advanced biofuel are identical to those in 2013.

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 1.9 percent in 2013 and 0.7 percent in 2014. The increase in emissions over the forecast primarily reflects the projected increase in coal use for electricity generation, especially in 2013.

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 incorporates recent tax changes in the American Taxpayer Relief Act of 2012. The GI model simulation also 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 and 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. Recent economic indicators suggest that growth may be picking up, particularly in the manufacturing sector. The Institute for Supply Management (ISM) manufacturing index rose in February to its highest level since June 2011, at 54.2. The U.S. Bureau of Economic Analysis also reported that the annualized growth rate of fourth-quarter GDP for 2012 was revised upward to a positive 0.1 percent, higher than the originally estimated decline of 0.1 percent. The U.S. Census Bureau reported that new home sales in January 2013 were at their highest level since July 2008, increasing by 15.6 percent from the previous month. However, real disposable income fell by 4 percent in January from the preceding month according to the U.S. Bureau of Economic Analysis, although much of this is attributable to special factors related to higher payouts of dividends and bonuses in December and the ending of the payroll-tax holiday in January.

U.S. Production. The STEO assumes 1.8 percent U.S. real GDP growth in 2013, rising to 2.7 percent in 2014. Relatively slower growth in the beginning of 2013 follows the expiration of the payroll tax cut, which is also reflected in annual growth in real disposable income of only 0.5 percent. After mid-2013, real GDP year-over-year growth gradually increases through the final quarter of 2014, and the same is true for real disposable income. Residential and nonresidential investment are important components of growth in both 2013 and 2014.

Total industrial production grows at a faster rate than real GDP in 2013 and 2014, at 2.2 percent and 3.0 percent, respectively. Industrial production growth in the manufacturing sector is the same as total industrial production in 2013 at 2.2 percent, but accelerates to 3.6 percent in 2014.

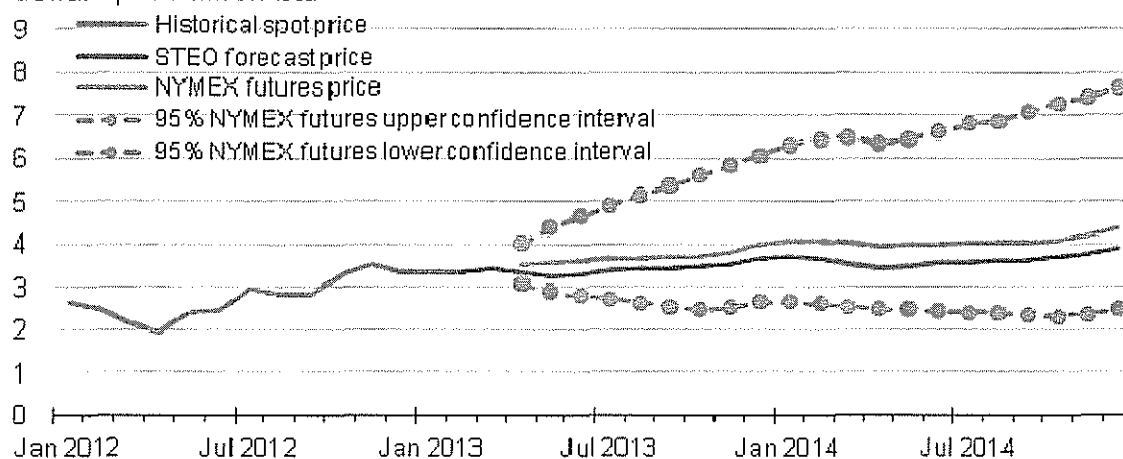
U.S. Income and Expenditures. Real consumption expenditures grow at the same rate as real GDP in 2013, at 1.8 percent, but slow below the rate of real GDP growth in 2014 at 2.3 percent. Private fixed investment jumps to 9.1-percent growth in 2014 from 5.5 percent in 2013, highlighting its importance for overall economic expansion. Export growth more than doubles from 2.4 to 5.3 percent, while 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 7.7 percent in February 2013 to 7.1 percent in December 2014. This is accompanied by nonfarm employment growth averaging 1.5 percent in 2013 and 1.6 percent in 2014. Consistent with an improving housing sector, housing starts show relatively fast growth, expanding by 22.0 percent and 31.6 percent in 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.

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

Henry Hub Natural Gas Price

dollars per million btu

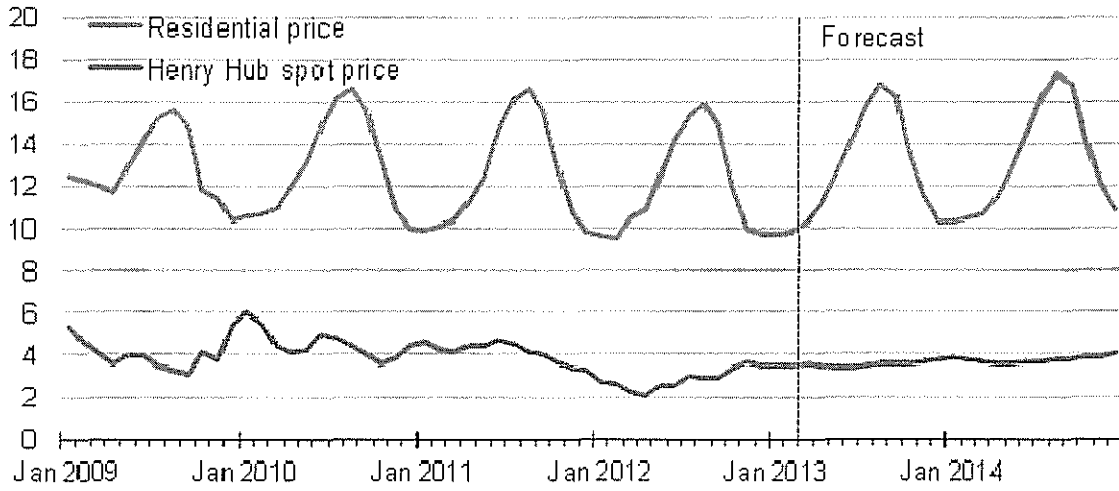


Note: Confidence interval derived from options market information for the 5 trading days ending March 7, 2013. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, March 2013

U.S. Natural Gas Prices

dollars per thousand cubic feet



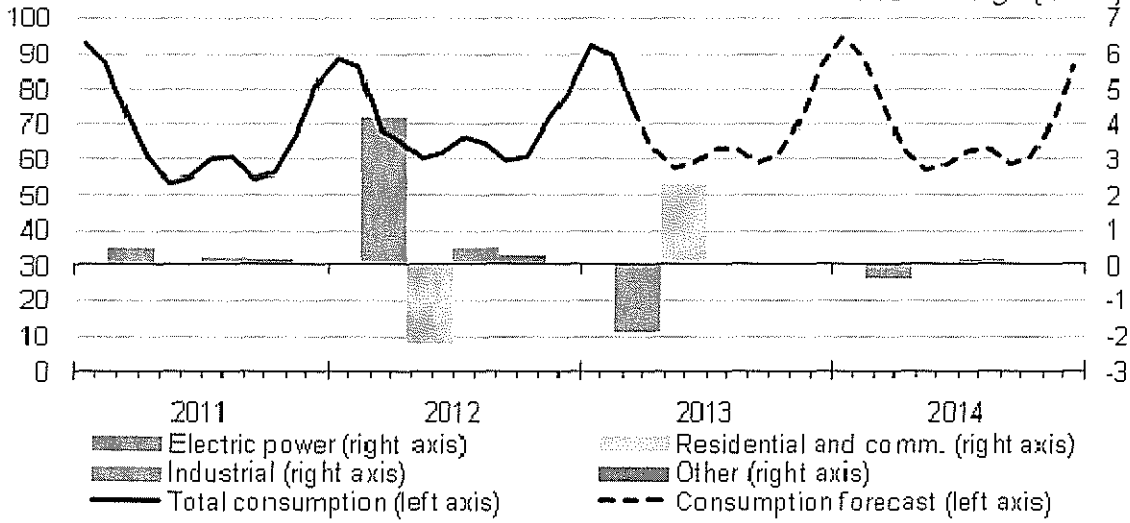
Source: Short-Term Energy Outlook, March 2013

U.S. Natural Gas Consumption

billion cubic feet per day (bcf/d)



annual change (bcf/d)

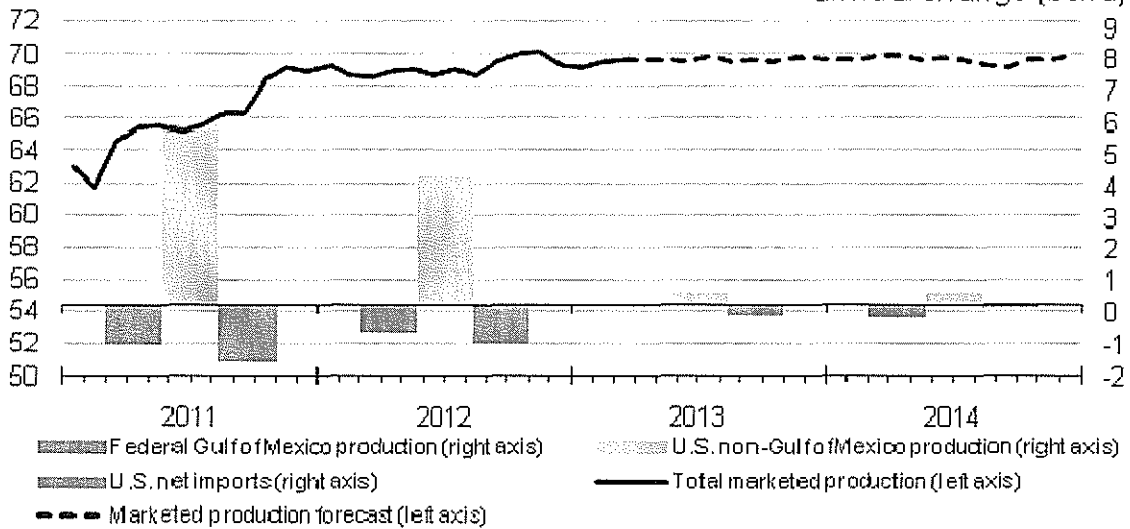


Source: Short-Term Energy Outlook, March 2013

U.S. Natural Gas Production and Imports

billion cubic feet per day (bcf/d)

eia
annual change (bcf/d)



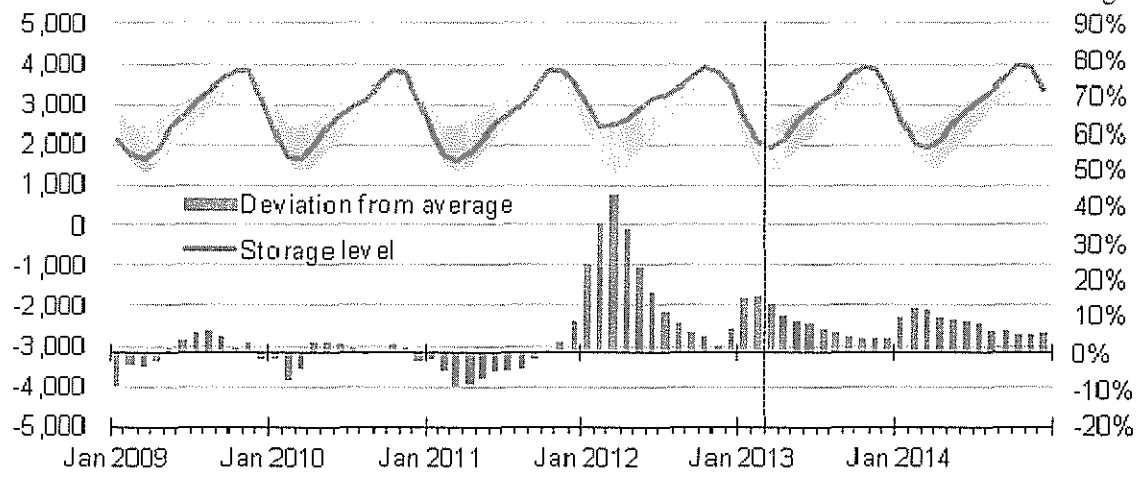
Source: Short-Term Energy Outlook, March 2013

U.S. Working Natural Gas in Storage

billion cubic feet



deviation from average



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2008 - Dec. 2012.
Source: Short-Term Energy Outlook, March 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>\$311,764</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
February	(16,652)	0	2,861	(13,791)	50,381	1.0137	51,071	(64,862)	379,824
Balance @ February 28, 2013									<u>\$379,824</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)
February	934	0	(501)	433	48,952	(0.2915)	(14,270)	14,703	(51,423)
Balance @ February 28, 2013									<u><u>(\$51,423)</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).