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

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1-877-267-4764

March 31, 2014

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

Re: Cost of Gas Adjustment (COG)
April 2014

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 (97th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (97th Revised Sheet No. 8), showing the April 2014 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $4.5205 per mcf for all customers.

Attachment B shows the calculations supporting the gas costs for April 2014, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $4.5205 per mcf for all customers since the last COG filing.

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

Attachment D shows the calculation of the balancing account since April 30, 2013.

Great Plains submitted a check for $600.00 on January 2, 2014 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment covers the $50.00 filing fee associated with this month's COG filing.

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

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

Sincerely,

Tamie A. Aberle
Director of Regulatory Affairs

Attachments

Attachment A

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
97th Revised Sheet No. 1.1
Canceling 96th Revised Sheet No.1.1
Page 1 of 1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/MCF
Firm Gas Service - General	2	$3.50 per month	First 10 MCF	$1.2740	$7.3513	$8.6253
			Over 10 MCF	1.0540		8.4053
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$4.9136	$6.0527
			Next 2,600 MCF	0.8931		5.8067
			Over 3,000 MCF	0.7411		5.6547
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$4.9136	$6.1527
Transportation Service	5	$3.50 per month	First 400 MCF	$1.1391		$1.1391
			Next 2,600 MCF	0.8931		0.8931
			Over 3,000 MCF	0.7411		0.7411

Date Filed: March 31, 2014

Effective Date: Service rendered on and after April 1, 2014

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
97th Revised Sheet No. 8
Canceling 96th 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.	1.4526	4.2729	0.9614	6.6869	4.2876	0.0274	4.3150
Current Adj.	0.0000	(4.5205)	0.0000	(4.5205)	(4.5205)	0.0000	(4.5205)
Total Adj.	1.4526	(0.2476)	0.9614	2.1664	(0.2329)	0.0274	(0.2055)
Total Rate	$1.5184	$4.8715	$0.9614	$7.3513	$4.8862	$0.0274	$4.9136

Date Filed: March 31, 2014

Effective Date: Service rendered on and after April 1, 2014

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
APRIL 2014

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A - Zone 1-1	8,000		$3.3978	12	$326,189	$0.2326
FT-A - Zone 1-1	5,000		3.6918	5	92,295	0.0658
FT-A Seasonal	2,000		3.6918	5	36,918	0.0263
TFX Seasonal	2,000		15.1530	5	151,530	0.1080
TFX - Winter	13,000		15.1530	5	984,945	0.7023
TFX - Summer	13,000		5.6830	7	517,153	0.3687
LMS Demand 2/						0.0147
Total Demand Charges					$2,109,030	1.5184
Estimated Weighted Average Commodity Cost	1,402,522	1/	4.8715		6,832,386	4.8715
Gas Cost Reconciliation Adjustment						0.9614
Total Current Firm Gas Cost					$8,941,416	7.3513
Base Cost of Gas						5.1849
Accumulated Adjustment						$2.1664

Interruptible	
Estimated Weighted Average Commodity Cost	$4.8715
Gas Cost Reconciliation Adjustment	0.0274
LMS Demand 2/	0.0147
Total Current Interruptible Gas Cost	4.9136
Base Cost of Gas	5.1191
Accumulated Adjustment	($0.2055)

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

	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
LMS Demand	2,500	$0.9800	12	$29,400	$0.0147

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
APRIL 2014

Rates Effective April 1, 2014	$/Dk	
FT-A - Zone 1-1 (Category 1)	$3.6918	Per dk/Mo.
FT-A - Zone 1-1 (Category 3)	3.3978	Per dk/Mo.
FT-A - Seasonal	3.6918	Per dk/Mo.
TFX	15.1530	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
LMS Demand	0.9800	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	4.8715	Per dk

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

Base Rate Calculation		
Firm		
Demand 1/	$0.0658	Per Mcf
Commodity	5.1191	Per Mcf
Total Firm Base Cost	$5.1849	Per Mcf
Interruptible:		
Commodity	$5.1191	Per Mcf

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

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
Category 1 (Contract Term of Less than 3 Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$3.6918
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.7894
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$2.0972
Zone 2-2 Minimum Rate	$0.0000
Category 2 (Contract Term of 3 Years to less than 5 Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$3.5448
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.6424
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$1.9502
Zone 2-2 Minimum Rate	$0.0000
Category 3 (Contract Term of 5 or more Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$3.3978
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.4954
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$1.8032
Zone 2-2 Minimum Rate	$0.0000

Rate Schedule	Base Tariff Rate	Fuel and Loss Retention Percentages 2/
Commodity Rates 1/		
FT-A – Maximum Rates		
Zone 1-1	$0.0127	0.08%
Zone 1-2	$0.0127	0.10%
Zone 2-2	$0.0127	0.02%
Minimum Rate	$0.0127	
IT and AOT		
Zone 1-1	$0.1341	0.08%
Zone 1-2	$0.1702	0.10%
Zone 2-2	$0.0816	0.02%
Minimum Rate	$0.0127	

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

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

Transportation Fuel and Loss Retention Percentages are inclusive of the following percentages for Gas Lost and Unaccounted For: 0.01% for Zone 1-1, 0.01% for Zone 1-2, and 0.00% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted for percentages.

Rate Schedule	Base Tariff Rate	Adjustment Under Section 27 1/	Rate After Current Adjustment
LMS – Monthly Demand Rate	$0.9800		$0.9800
LMS – Daily Overrun Rate	$0.1702		$0.1702
LMS – Load Management Cost Reconciliation Adjustment		$0.0116	

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	$0.1702	$0.0000
RPL Service:		
Daily Reservation Rate	$0.1702	$0.0000

RATE SCHEDULE TF

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

COMMODITY RATES 2/ TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0364	0.0195			0.0175	0.0000	0.0364	0.0195
Field	Market	0.0364	0.0195	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

1/ The minimum reservation rate is equal to zero.
2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the maximum Field Area throughput commodity rates for any transaction involving MIDs. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
3/ The Maximum and Minimum rates include the Market Area Electric Compression charge of $0.0005 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.
4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
5/ Where applicable, the Field Area Electric Compression charge of $0.0000 and the ACA unit surcharge as set forth on FERC's website at http://www.ferc.gov will be added to the mileage based rates.

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

Seventh Revised Sheet No. 51
Superseding
Sixth Revised Sheet No. 51

RATE SCHEDULES TFX and LFT

	MARKET-TO-MARKET		FIELD-TO-FIELD	
RESERVATION RATES	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	0.0364	0.0195			0.0175	0.0000	0.0364	0.0195
Field	Market	0.0364	0.0195	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

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

1/ The minimum reservation rate is equal to zero.
2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the maximum Field Area throughput commodity rates for any transaction involving MIDs. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
3/ The Maximum and Minimum rates include the Market Area Electric Compression charge of $0.0005 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.
4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
5/ Where applicable, the Field Area Compression charge of $0.0000 and the ACA unit surcharge as set forth on FERC's website at http://www.ferc.gov will be added to the mileage based rates.
6/ In addition to the Maximum and Minimum rates, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.

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

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.97%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.09% 4/ 5/
FDD Storage Fuel	1.76%

	Electric Compression
COMMODITY RATES:	1/
Market Area	$0.0005
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, 2013.

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 2014

The principal gas sources of natural gas for Wahpeton, North Dakota are from the mid-continent area of the United States. The pricing for the majority of this gas is from 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 decrease 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.

The high demand declined and more normal seasonal demands returned, as the unseasonably cold weather warmed in the last few weeks, contributing to the decrease in the index price for April. The EIA reported storage levels nationwide as of March 21, 2014 were 50.8 percent below the five-year average and 50.1 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 17.

Independent Statistics & Analysis
U.S. Energy Information Administration

March 2014

Short-Term Energy Outlook (STEO)

Highlights

- Temperatures east of the Rocky Mountains have been significantly colder this winter (October – February) compared with the same period both last winter and the average for the past 10 years, straining distribution networks and putting upward pressure on consumption and prices of fuels used for space heating. U.S. average heating degree days were 13% higher than last winter (indicating colder weather) and 10% above the October through February 10-year average. The Northeast was 13% colder than last winter, the Midwest and South both 19% colder, while the West was 5% warmer.

- The cold weather this winter had the greatest effect on propane prices, particularly for consumers in the Midwest. Cold temperatures have tightened supplies that were already low heading into the winter heating season. Residential propane prices in the Midwest rose from an average of $2.08 per gallon (gal) on December 2, 2013, to $4.20/gal on January 27; prices have since fallen back to $2.78/gal as of March 3. EIA now expects that propane prices in the Midwest will average $2.62/gal over the winter (51% higher than last winter) while those in the Northeast will average $3.47/gal (15% higher than last winter).

- Cold temperatures have continued to tighten heating oil supplies and helped drive up retail prices. Since the beginning of the year, distillate inventories in the Northeast (Petroleum Administration for Defense Districts 1A and 1B) have fallen by almost 6.9 million barrels to reach 18.3 million barrels on February 28, 6.4 million barrels below inventory levels for the same week in 2013. Weekly U.S. residential heating oil prices increased by $0.20/gal during January and have averaged near $4.24/gal since the beginning of February. Despite the recent increases, EIA expects that U.S. heating oil prices will average $3.83/gal this winter, $0.04/gal (1%) lower than during last year's winter heating season, mainly because of lower crude oil prices.

- The North Sea Brent crude oil spot price in February averaged near $110 per barrel (bbl) for the eighth consecutive month, while West Texas Intermediate (WTI) crude oil prices increased by $6/bbl from the previous month to reach $101/bbl. Continued high refinery runs helped reduce inventories at the Cushing, Oklahoma, storage hub to 32 million barrels, the lowest level since February 2012, and helped strengthen WTI prices. The discount of WTI crude oil to Brent crude oil, which averaged more than $13/bbl from November through January, fell to $8/bbl in February. EIA expects the WTI discount to average $10/bbl in 2014 and $11/bbl in 2015.

- Cold weather also contributed to continuing large withdrawals of natural gas from storage and a surge in natural gas spot prices, which hit record levels in several markets during periods of extreme cold. Natural gas working inventories on February 28 totaled 1.20 trillion cubic feet (Tcf), 0.91 Tcf (43%) below the level at the same time a year ago and 0.76 Tcf (39%) below the five-year average (2009-13). Henry Hub natural gas spot prices were volatile over the past two months, increasing from $3.95 per million British thermal units (MMBtu) on January 10 to a high of $8.15/MMBtu on February 10, before falling back to $4.61/MMBtu on February 27, and then bouncing back up to $7.98/MMBtu on March 4. EIA expects that the Henry Hub natural gas spot price, which averaged $3.73/MMBtu in 2013, will average $4.44/MMBtu in 2014, an increase of $0.28/MMBtu from the 2014 projection in last month's STEO. Residential natural gas prices are expected to average $10.05 per thousand cubic feet (Mcf) this winter, an increase of $0.30/Mcf (3%) from last winter.

Global Petroleum and Other Liquids

EIA projects world petroleum and other liquids supply to increase by 1.3 million barrels per day (bbl/d) in both 2014 and 2015, with most of the growth coming from countries outside of the Organization of the Petroleum Exporting Countries (OPEC). The Americas, in particular the United States, Canada, and Brazil, will account for much of this growth. Projected world liquid fuels consumption grows by an annual average of 1.2 million bbl/d in 2014 and 1.4 million bbl/d in 2015. Countries outside the Organization for Economic Cooperation and Development (OECD), notably China, drive expected consumption growth. Non-OPEC supply growth contributes to an increase in global surplus crude oil production capacity from an average of 2.1 million bbl/d in 2013 to 3.9 million bbl/d in 2015.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 1.2 million bbl/d in 2013, averaging 90.4 million bbl/d for the year. EIA expects global consumption to grow 1.2 million bbl/d in 2014 and 1.4 million bbl/d in 2015. Projected global oil-consumption-weighted real GDP, which increased by an estimated 2.3% in 2013, grows by 3.1% and 3.5% in 2014 and 2015, respectively.

Non-OECD countries as a group are expected to account for all of the consumption growth in 2014 and nearly all of the growth in 2015. China is the leading contributor to projected global consumption growth, with consumption increasing by 400,000 bbl/d in 2014 and 430,000 bbl/d in 2015. However, China's economic and oil consumption growth rates have moderated compared with rates before 2012, when annual GDP growth exceeded 9% and oil consumption growth averaged 700,000 bbl/d from 2009 through 2012.

EIA expects lower OECD consumption in 2014, led by projected consumption declines in both Japan and Europe. EIA expects Japan's oil consumption to fall by an annual average of 150,000 bbl/d in 2014 and 2015, as the country continues to increase natural gas consumption in the electricity sector and returns some nuclear power plants to service. EIA projects that OECD

Europe's consumption, which fell by 60,000 bbl/d in 2013, will decline by another 60,000 bbl/d in 2014 and then remain mostly flat in 2015. U.S. liquids consumption, which increased by 400,000 bbl/d in 2013, is expected to remain flat in 2014 and then increase by 100,000 bbl/d in 2015.

Non-OPEC Supply. EIA estimates that non-OPEC liquids production grew by 1.3 million bbl/d in 2013, averaging 54.0 million bbl/d for the year. EIA expects non-OPEC liquids production to grow by 1.8 million bbl/d in 2014 and 1.5 million bbl/d in 2015. EIA forecasts production from the United States and Canada to grow by a combined annual average of 1.3 million bbl/d in 2014 and 1.2 million bbl/d in 2015. Brazil's production is expected to increase by an annual average of 0.15 million bbl/d over the next two years, attributable to new deepwater fields. EIA estimates that Asia and Oceania's production will rise by an annual average of 0.18 million bbl/d over the forecast period, led by China.

Unplanned supply disruptions among non-OPEC producers averaged 0.7 million bbl/d in February 2014, unchanged from the previous month. South Sudan, Syria, and Yemen account for about 80% of total non-OPEC supply disruptions. EIA does not assume a disruption to oil supply or demand as a result of ongoing events in Ukraine.

OPEC Supply. EIA estimates that OPEC crude oil production averaged 30.0 million bbl/d in 2013, a decline of 0.9 million bbl/d from the previous year, primarily reflecting increased outages in Libya, Nigeria, and Iraq, and strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.5 million bbl/d and 0.3 million bbl/d in 2014 and 2015, respectively, as some OPEC countries, led by Saudi Arabia, reduce production to accommodate the non-OPEC supply growth in 2014. In recent months, EIA revised upward historic data for OPEC noncrude liquids supply. Projected OPEC noncrude oil liquids production, which averaged an estimated 6.3 million bbl/d in 2013, increases to an average of 6.5 million bbl/d in 2015.

Unplanned crude oil supply disruptions among OPEC producers averaged more than 2.3 million bbl/d in February 2014, almost 0.1 million bbl/d higher than the previous month. Libya continues to experience swings in its production, contributing to changes in the OPEC disruption estimate.

EIA expects that OPEC surplus capacity, which is concentrated in Saudi Arabia, will average 2.6 million bbl/d in 2014 and 3.9 million bbl/d in 2015. This build in surplus capacity reflects production cutbacks by some OPEC members adjusting for the higher supply from non-OPEC producers. These estimates do not include additional capacity that may be available in Iran but is currently offline because of the effects of U.S. and European Union sanctions on Iran's oil sector.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.59 billion barrels by the end of 2013, equivalent to roughly 56 days of consumption in that region.

Projected OECD oil inventories rise to 2.61 billion barrels at the end of 2014 and 2.62 billion barrels at the end of 2015.

Crude Oil Prices. Brent crude oil spot prices in February averaged between $108/bbl and $112/bbl for the eighth consecutive month. EIA expects the Brent crude oil price to weaken as non-OPEC supply growth exceeds growth in world consumption. The Brent crude oil price is projected to average $105/bbl and $101/bbl in 2014 and 2015, respectively.

The WTI crude oil spot price, which fell to $95/bbl in January 2014, increased to an average of $101/bbl in February as a result of strong Midwestern refinery runs after cold-weather-related disruptions in January. EIA expects that WTI crude oil prices will average $95/bbl in 2014, $2/bbl higher than last month's STEO, and $90/bbl during 2015. The discount of WTI crude oil to Brent crude oil averaged $8/bbl in February after averaging more than $13/bbl over the previous three months. EIA expects the discount of WTI crude oil to Brent crude oil to average $10/bbl in 2014 and $11/bbl in 2015, reflecting the economics of transporting and processing the growing production of light sweet crude oil in U.S. and Canadian refineries.

Energy price forecasts are highly uncertain, and the current values of futures and options contracts suggest that prices could differ significantly from the forecast levels (*Market Prices and Uncertainty Report*). WTI futures contracts for June 2014 delivery, traded during the five-day period ending March 6, 2014, averaged $101/bbl. Implied volatility averaged 18%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in June 2014 at $87/bbl and $118/bbl, respectively. Last year at this time, WTI for June 2013 delivery averaged $92/bbl and implied volatility averaged 22%. The corresponding lower and upper limits of the 95% confidence interval were $76/bbl and $111/bbl.

U.S. Petroleum and Other Liquids

Between the beginning of October and the end of February, U.S. average heating degree days were 13% higher than last winter (indicating colder weather) and 10% above the 10-year average. The Northeast was 13% colder than last winter, the Midwest and South both 19% colder, while the West was 5% warmer. The cold weather had the greatest effect on households in the Midwest that primarily use propane and those in the Northeast that rely on heating oil. EIA's current estimate for winter heating expenditures for homes heating with propane in the Midwest is $2,212, which is $759 higher than projected in October. The current estimate for average U.S. expenditures for homes using heating oil is $2,243, which is $197 higher than projected in the October STEO. Unlike residential electricity and natural gas markets, where rates paid by consumers do not immediately reflect price spikes in the spot market, price movements in propane and heating oil are quickly reflected in retail prices.

U.S. Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 400,000 bbl/d (2.1%) in 2013. Consumption of hydrocarbon gas liquids registered the largest

gain, increasing by 150,000 bbl/d (6.4%). Motor gasoline consumption grew by 90,000 bbl/d (1.1%), the largest increase since 2006. Stronger-than-expected growth in highway travel during the second half of 2013 contributed to that increase. Distillate fuel consumption increased by 90,000 bbl/d (2.5%), reflecting colder weather and domestic economic growth.

Projected total liquid fuels consumption remains flat in 2014. Motor gasoline consumption remains largely unchanged as the recent strong growth in highway travel slows and continued improvements in new-vehicle fuel economy boost overall fuel efficiency growth. Distillate fuel oil consumption rises 10,000 bbl/d (0.3%). In 2015, total liquid fuels consumption increases by 100,000 bbl/d (0.5%), driven primarily by increasing transportation demand for distillate fuel oil and industrial demand for hydrocarbon gas liquids.

U.S. Liquid Fuels Supply. Harsh winter conditions over the past few months negatively affected well completion activity in the northern U.S. plays. As more evidence of this seasonal slowdown has appeared in the data, EIA has revised downward initial estimates for December 2013 and January 2014 U.S. crude oil production. Because the weather effects are temporary, much of the production slowdown is expected to be made up by accelerated completion activity over the next few months.

EIA expects strong crude oil production growth, primarily concentrated in the Bakken, Eagle Ford, and Permian regions, continuing through 2015. Forecast production increases from an estimated 7.5 million bbl/d in 2013 to 8.4 million bbl/d in 2014 and 9.2 million bbl/d in 2015. The highest historical annual average U.S. production level was 9.6 million bbl/d in 1970.

Crude oil production from the Bakken formation in North Dakota and Montana averaged 0.9 million bbl/d in 2013. While production briefly reached 1.0 million bbl/d in November 2013, logistical issues resulting from winter storms caused production to decline in December. Bakken production is expected to return to 1.0 million bbl/d in the first quarter of 2014. Production in the Eagle Ford formation in South Texas averaged 1.1 million bbl/d in 2013, reaching an estimated 1.3 million bbl/d in December 2013.

U.S. federal Gulf of Mexico (GOM) crude oil production averaged 1.3 million bbl/d in 2013, down slightly from 2012. EIA forecasts 1.4 million bbl/d of GOM crude oil production in 2014 and 1.6 million bbl/d in 2015. Production growth in 2014 comes from eight projects expected to come on line: Jack, St. Malo, Entrada, Big Foot, Tubular Bells, Atlantis Phase 2, Hadrian South, and Lucius. Further production growth in 2015 comes from an additional 10 projects: Axe, Cardamom Deep, Dalmatian, Deimos South, Kodiak, Pony, Samurai, West Boreas, Winter, and Mars B.

As domestic production of crude oil continues to increase, U.S. refiners have announced expansions to process more light crude oil. Marathon and Kinder Morgan have announced plans to build condensate splitters in 2014 and 2015 to process production from the Utica and Eagle Ford formations. Small topping refineries are being built in North Dakota to process Bakken crude, and Valero is expanding its Gulf Coast refining capacity. Projected crude oil

inputs to refineries increase from 15.31 million bbl/d in 2013 to 15.52 million bbl/d in 2014 and rise further to 15.61 in 2015, surpassing the previous high of 15.48 million bbl/d in 2004.

The growth in domestic production has contributed to a significant decline in petroleum imports. The share of total U.S. liquid fuels consumption met by net imports peaked at more than 60% in 2005 and fell to an average of 33% in 2013. EIA expects the net import share to decline to 25% in 2015, which would be the lowest level since 1971.

U.S. Petroleum Product Prices. Led by falling crude oil prices, the projected U.S. annual average regular gasoline retail price, which fell from $3.63/gal in 2012 to an average of $3.51/gal in 2013, will continue to fall to $3.45/gal in 2014 and $3.37 in 2015. Diesel fuel prices, which averaged $3.92/gal in 2013, are projected to average $3.85/gal in 2014 and $3.78/gal in 2015.

Natural Gas

More frigid weather in February led to another large downward revision to the STEO's end-of-March 2014 projection for working natural gas inventories. Projected inventories now end March at 965 billion cubic feet (Bcf), ending the season below 1,000 Bcf for the first time since 2003. Much colder-than-normal temperatures in February led to large stock withdrawals in response to high demand from the residential, commercial, and electric power sectors. According to data from Bentek Energy, three of the top five months for total natural gas demand over the last eight years have occurred this heating season (December 2013, January 2014, and February 2014).

The stage is now set for a record stock build over the injection season. Projected end-of-October inventories total 3,459 Bcf, a build of almost 2,500 Bcf. This month's STEO raises the outlook for natural gas prices, which will spur additional production. Expectations for lower demand from the electric power sector compared with the past several years should help enable a record-high stock build.

U.S. Natural Gas Consumption. EIA expects total natural gas consumption will average 71.3 Bcf per day (Bcf/d) in 2014, a drop of 0.1 Bcf/d from 2013. The projected year-over-year increases in natural gas prices contribute to declines in natural gas used for electric power generation from 24.9 Bcf/d in 2012 to 22.3 Bcf/d in 2013 and 22.0 Bcf/d in 2014. In 2015, total natural gas consumption falls by 0.3 Bcf/d as a decline in residential and commercial consumption more than offsets consumption growth in the industrial and electric power sectors. EIA expects natural gas consumption in the power sector to increase to 22.6 Bcf/d in 2015 with the retirement of some coal plants.

U.S. Natural Gas Production and Trade. EIA expects natural gas marketed production will grow at an average rate of 2.5% in 2014 and 1.1% in 2015. Rapid natural gas production growth in the Marcellus formation is causing natural gas forward prices in the Northeast to fall even with or

below Henry Hub prices outside of peak-demand winter months. Consequently, some drilling activity may move away from the Marcellus back to Gulf Coast plays such as the Haynesville and Barnett, where prices are closer to the Henry Hub spot price.

Liquefied natural gas (LNG) imports have declined over the past several years because higher prices in Europe and Asia are more attractive to sellers than the relatively low prices in the United States. Several companies are planning to build liquefaction capacity to export LNG from the United States. Cheniere Energy's Sabine Pass facility is planned to be the first to liquefy natural gas produced in the Lower 48 states for export. The facility has a total liquefaction capacity of 3 Bcf/d and is scheduled to come online in stages beginning in late 2015.

Growing domestic production over the past several years has displaced some pipeline imports from Canada, while exports to Mexico have increased. EIA expects these trends will continue through 2015. EIA projects net imports of 3.6 Bcf/d in 2014 and 2.6 Bcf/d in 2015, which would be the lowest level since 1987. Over the longer term, the EIA *Annual Energy Outlook 2014* projects the United States will be a net exporter of natural gas beginning in 2018.

U.S. Natural Gas Inventories. Natural gas working inventories fell by 152 Bcf to 1,196 Bcf during the week ending February 28, 2014. Colder-than-normal temperatures during the month resulted in increased heating demand, prompting larger-than-normal withdrawals. Stocks are now 908 Bcf less than last year at this time and 758 Bcf less than the five-year (2009-13) average for this time of year. Total stocks, as well as stocks in all three regions, are currently less than their five-year (2009-13) minimums.

U.S. Natural Gas Prices. Natural gas spot prices averaged $6.00/MMBtu at the Henry Hub in February, up $1.29/MMBtu from January, the result of bitterly cold weather during the month. At the end of February, both spot and futures prices declined rapidly, falling below $5/MMBtu. EIA projects that the March spot price will average $4.48/MMBtu, and will continue to decline in the spring. Projected Henry Hub natural gas prices average $4.44/MMBtu in 2014 and $4.14/MMBtu in 2015.

Natural gas futures prices for June 2014 delivery (for the five-day period ending March 6, 2014) averaged $4.55/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for June 2014 contracts at $3.51/MMBtu and $5.90/MMBtu, respectively. At this time last year, the natural gas futures contract for June 2013 averaged $3.61/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $2.79/MMBtu and $4.67/MMBtu.

Coal

Coal exports totaled nearly 118 million short tons (MMst) in 2013, the second-highest total ever for U.S. coalexports. It was also the third consecutive year that exports totaled more than 100

MMst. Despite the 2013 pullback in both volume and value, coal exports will continue to be important for companies involved in coal production and transportation.

U.S. Coal Supply. EIA projects coal production will grow 3.2% to 1,028 MMst in 2014. The increase this year is primarily a result of higher consumption and a smaller inventory draw. Coal production is projected to fall 1.4% in 2015 to 1,013 MMst.

Primary (producer and distributor) and secondary (consumer) inventories fell by an estimated 40 MMst in 2013, which accounted for 4.4% of the year's total consumption. Inventory withdrawals are projected to supply 0.9% (9 MMst) of consumption in 2014, and inventory changes in 2015 are expected to be less than 1 MMst.

U.S. Coal Consumption. EIA estimates total coal consumption for 2013 to be 923 MMst, a 3.9% increase over 2012. The increase was primarily a result of increased consumption in the electric power sector due to higher natural gas prices. Projected consumption grows 4.6% to 966 MMst in 2014 as electricity demand grows and natural gas prices remain well above their 2012 level. Total coal consumption is projected to decline by 3.1% in 2015, as retirements of coal power plants rise in response to the implementation of the Mercury and Air Toxics Standards, and generation from renewable resources (wind, hydro, biomass, geothermal, and solar) grows by more than 7%.

U.S. Coal Exports. Exports are projected to total 103 MMst in 2014, making it the fourth consecutive year with more than 100 MMst of coal exports. This would be the second time that exports have exceeded 100 MMst for four consecutive years, with the first being from 1989 to 1992. Projected exports fall back to 99 MMst in 2015. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, increasing coal output in other coal-exporting countries, and falling international coal prices are the primary reasons for the expected decline in U.S. coal exports.

U.S. Coal Prices. Annual average coal prices to the electric power industry fell for the second consecutive year, from $2.38/MMBtu in 2012 to $2.35/MMBtu in 2013. EIA forecasts average delivered coal prices of $2.36/MMBtu in 2014 and $2.37/MMBtu in 2015.

Electricity

U.S. power generation over the past three months (December-February) is estimated to total about 5% more than generation during the same period last winter, primarily because of the much colder weather experienced in the eastern United States. EIA estimates natural gas-fired generation in the eastern United States (Northeast, Midwest, and South Census regions) accounted for 23.3% of its total generation last month compared with 25.3% in February 2013. Power generators in the West census region have not been affected as much by natural gas costs, and the region's share of total generation fueled by natural gas this winter has remained at levels similar to last winter.

U.S. Electricity Consumption. Much of the increased electricity demand this winter was driven by the residential sector in the eastern United States, where retail sales for the period of October through February were an estimated 9% higher than last winter. U.S. commercial electricity sales grew by about 3% this winter, while industrial sales fell by about 1%. For all of 2014, EIA forecasts residential electricity sales will grow by 1.2% and commercial sales will grow by 0.6%. Industrial electricity consumption is expected to rebound later this year, growing 2.8% for all of 2014.

U.S. Electricity Generation. EIA projects total U.S. electricity generation will average 11.3 terawatthours per day in 2014, an increase of 1.3% from last year. The projected share of total generation fueled by natural gas falls from 27.4% in 2013 to 26.9% this year, in response to higher natural gas prices. The natural gas generation share rises back to 27.5% in 2015 as fuel costs fall slightly next year. The decline in natural gas prices next year, along with increased retirement of coal-fired generating units, leads to a rise in the natural gas generation share to 27.5% in 2015 as the expected share of generation fueled by coal drops from 40.5% in 2014 to 38.9% next year.

U.S. Electricity Retail Prices. EIA expects the U.S. residential price of electricity to average 12.3 cents per kilowatthour during 2014, an increase of 1.9% from 2013. Residential electricity prices increase 2.0% during 2015.

Renewables and Carbon Dioxide Emissions

U.S. Electricity and Heat Generation from Renewables. EIA projects renewables used for electricity and heat generation will grow by about 0.9% in 2014. Hydropower is projected to decrease by 1.7%, while nonhydropower renewables rise by 2.4%. In 2015, renewables consumption for electric power and heat generation is projected to increase by 6.0% from 2014, as a 5.0% increase in hydropower is combined with a 6.6% increase in nonhydropower renewables.

EIA estimates that wind power capacity will increase by 8.3% in 2014 to about 65 gigawatts (GW) by the end of the year and will increase 17.9% to total more than 77 GW at the end of 2015. Electricity generation from wind is projected to contribute 4.6% of total electricity generation in 2015.

EIA expects continued robust growth in solar electricity generation, although the amount of utility-scale generation remains a small share of total U.S. generation at about 0.4% in 2015. While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity grew by 96% in 2013. EIA currently expects that utility-scale solar capacity will increase by approximately 52% between year-end 2013 and year-end 2015. However, customer-sited photovoltaic (PV) capacity growth, which the STEO does not

forecast, is still projected to exceed utility-scale solar growth between 2013 and 2015, according to EIA's *Annual Energy Outlook 2014*.

U.S. Liquid Biofuels. Ethanol production increased from an average of 825,000 bbl/d in December 2012 to 949,000 bbl/d during December 2013 and is forecast to average 910,000 bbl/d during 2014. Biodiesel production, which averaged 64,000 bbl/d (1.0 billion gallons per year) in 2012, rose to 104,000 bbl/d (135 million gallons) in December 2013, 7 million gallons higher than in November. A biodiesel production tax credit expired at the end of 2013. Biodiesel production to average about 87,000 bbl/d in 2013 and is forecast to average about 85,000 bbl/d in 2014 and 2015.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels increased by 2.0% in 2013 from the previous year. Emissions are forecast to rise 1.7% in 2014, followed by a decline in 2015 of 0.9%. The increase in emissions in 2013 reflects growth in consumption of liquid fuels and coal, while projected growth in 2014 is mainly due to higher coal use in electric power generation. Coal emissions are projected to decline by 3.0% in 2015 as the power sector responds to increasing coal plant retirements.

U.S. Economic Assumptions

The U.S. Bureau of Economic Analysis revised its estimate of GDP growth in the fourth quarter of 2013 downwards, from 3.2% to 2.4%. Consumer spending grew at a slower rate than initially reported, while businesses accumulated fewer inventories. Final sales growth (GDP excluding inventories) was revised down from 2.8% to 2.3%, slightly below the third quarter's 2.5% growth rate. Additionally, the Federal Reserve Board reported that U.S. industrial production fell in January by 0.3%, after rising the same amount in December. Manufacturing and mining production fell by 0.8% and 0.9%, respectively, while utilities production rose by 4.1%. Similarly, both new housing starts and building permits fell in January from their December levels, according to the U.S. Census Bureau. Still, the ISM manufacturing index rose to 53.2 in February, up from 51.3 in January (values above 50 indicate expansion), which suggests weather may have played a role in the weaker numbers above.

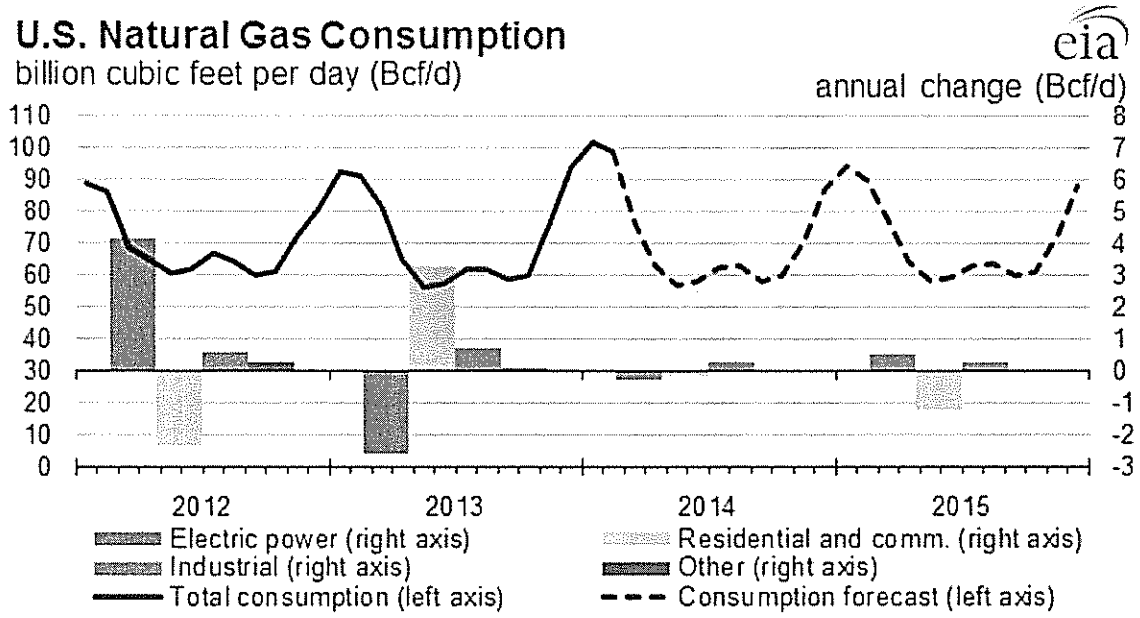
EIA uses the IHS/Global Insight macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

U.S. Production and Income. Forecast U.S. real GDP grows by 2.6% in 2014 and 3.2% in 2015. Even though forecast real GDP growth accelerates over the next two years, it is only in 2015 that GDP growth exceeds the economy's average annual growth of 3% from 1990 through 2007. Forecast real disposable income increases 2.6% in 2014 and 3.6% in 2015. Total industrial production grows at 2.8% in 2014, and is projected to grow 4.0% in 2015.

U.S. Expenditures. Private real fixed investment growth averages 6.5% and 9.2% over 2014 and 2015, respectively, with equipment spending accounting for most of investment's growth. Real

consumption expenditures grow more slowly than real GDP in 2014, at 2.5%, and remain below the rate of real GDP growth in 2015, at 2.9%. Durable goods expenditures drive the consumption spending. Export growth is 4.9% and 4.5% over the same two years, while import growth is 3% in 2014 and 6% in 2015. Total government expenditures fall 0.5% in 2014, but increase by 0.5% in 2015.

U.S. Employment, Housing, and Prices. The unemployment rate in the forecast averages 6.5% over 2014, and gradually falls to 5.7% at the end of 2015, which is slightly higher than the 5.5% projected last month. This is accompanied by nonfarm employment growth averaging 1.6% in 2014 and 2.1% in 2015. Housing starts grow an average of 21% and 30% in 2014 and 2015, respectively. Both consumer and producer price indexes continue to increase at a moderate pace, as wages continue to show modest gains.

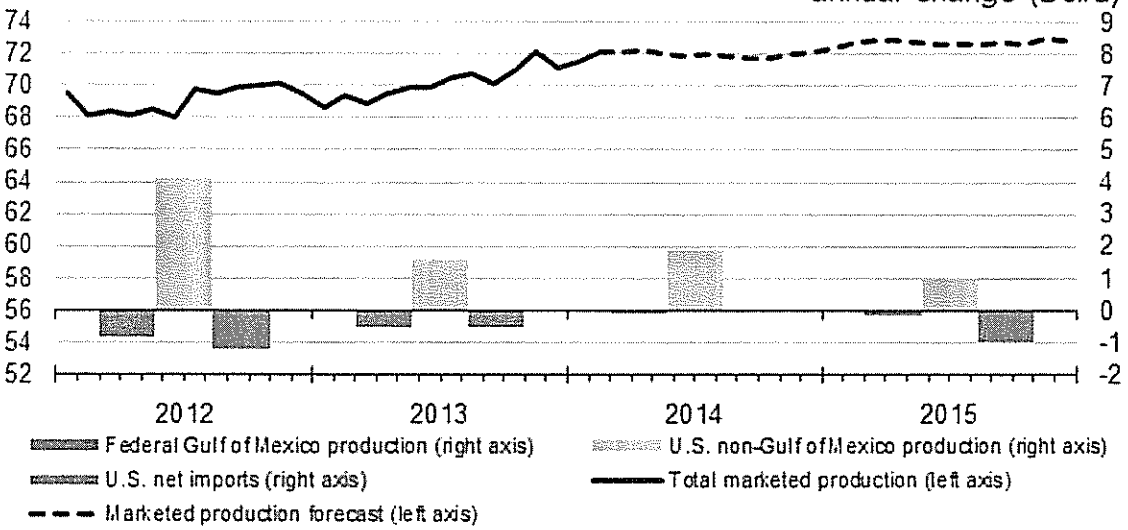


Source: Short-Term Energy Outlook, March 2014.

U.S. Natural Gas Production and Imports

billion cubic feet per day (Bcf/d)

annual change (Bcf/d)



Federal Gulf of Mexico production (right axis)

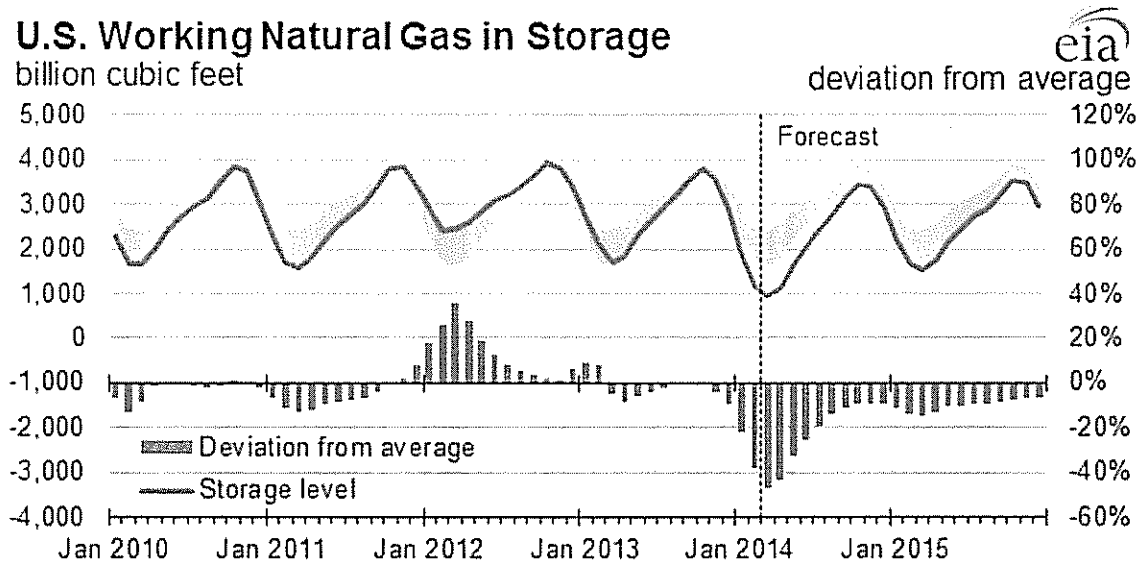
U.S. non-Gulf of Mexico production (right axis)

U.S. net imports (right axis)

Total marketed production (left axis)

Marketed production forecast (left axis)

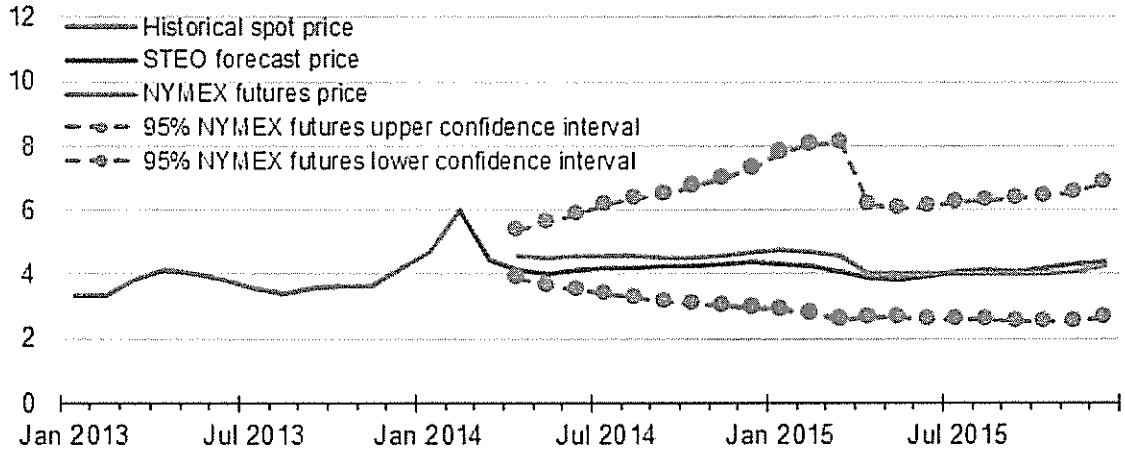
Source: Short-Term Energy Outlook, March 2014.



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2009 - Dec. 2013.
Source: Short-Term Energy Outlook, March 2014.

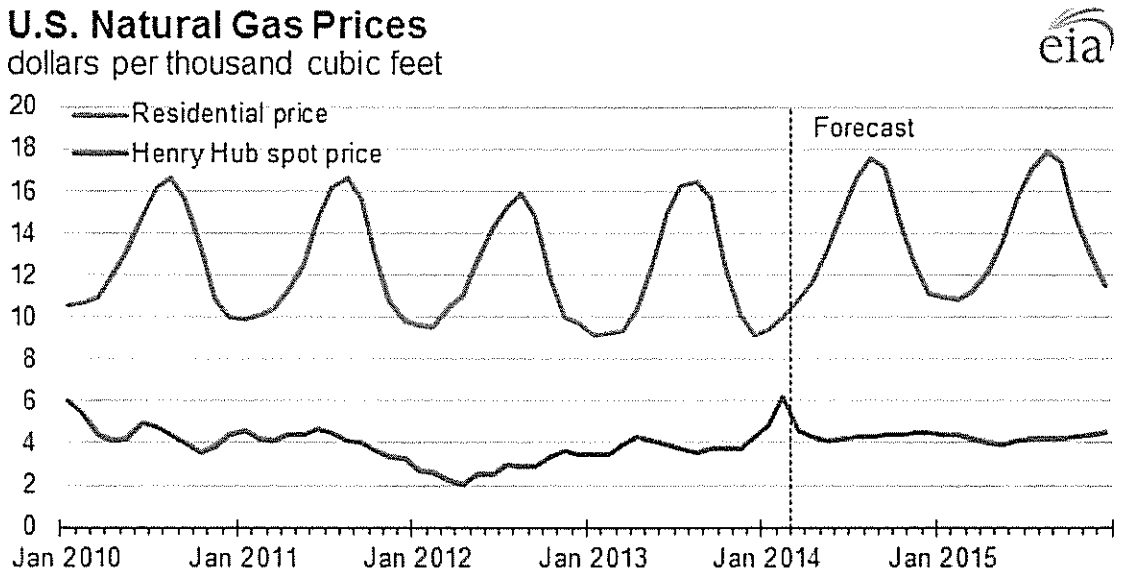
Henry Hub Natural Gas Price

dollars per million Btu



Note: Confidence interval derived from options market information for the 5 trading days ending Mar. 6, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, March 2014.



Source: Short-Term Energy Outlook, March 2014.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2013									**$303,311**
May 2013	($12,469)	0	$1,860	($10,609)	21,400	$1.0137	$21,692	($32,301)	271,010
June	4,837	0	1,626	6,463	9,214	0.9614	9,167 2/	(2,704)	268,306
July	19,011	0	1,601	20,612	6,004	0.9614	5,772	14,840	283,146
August	16,638	(17,889)	1,701	450	5,505	0.9614	5,293	(4,843)	278,303
September	296	0	1,658	1,954	5,691	0.9614	5,471	(3,517)	274,786
October	5,896	0	1,625	7,521	8,206	0.9614	7,889	(368)	274,418
November	1,647	0	1,618	3,265	21,099	0.9614	20,285	(17,020)	257,398
December	45	0	1,501	1,546	42,237	0.9614	40,607	(39,060)	218,338
January 2014	35,892	0	1,244	37,136	59,753	0.9614	57,447	(20,311)	198,027
February	117,838	0	1,138	118,976	56,223	0.9614	54,053	64,923	262,950
Total	$189,631	(17,889)	$15,572	$187,314	235,332		$227,676	($40,361)	
Balance @ February 28, 2014									**$262,950**

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

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2013									**$4,747**
May 2013	($19,391)	0	($4)	($19,395)	49,736	($0.2915)	($14,498)	($4,897)	(150)
June	(13,383)	0	(46)	(13,429)	23,704	0.0274	(4,253) 2/	(9,176)	(9,326)
July	(9,266)	0	(115)	(9,381)	17,577	0.0274	482	(9,863)	(19,189)
August	(1,454)	0	(188)	(1,642)	14,808	0.0274	406	(2,048)	(21,237)
September	(28,851)	0	(203)	(29,054)	16,181	0.0274	443	(29,497)	(50,734)
October	4,119	0	(416)	3,703	26,694	0.0274	731	2,972	(47,762)
November	5,534	0	(395)	5,139	56,950	0.0274	1,560	3,579	(44,183)
December	13,820	0	(373)	13,447	81,821	0.0274	2,242	11,205	(32,978)
January 2014	29,696	0	(300)	29,396	56,375	0.0274	1,545	27,852	(5,126)
February	144,559	0	(104)	144,455	48,233	0.0274	1,322	143,133	138,007
Total	$125,383	0	($2,144)	$123,239	392,079		($10,020)	$133,260	
Balance @ February 28, 2014									**$138,007**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 15,372.2 Mcf @ ($0.2915) and 8,331.7 Mcf @ $0.0274.