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June 30, 2014

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

Re: Cost of Gas Adjustment (COG)
July 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 (100th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (100th Revised Sheet No. 8), showing the July 2014 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.1421 per Dk for residential and firm general service customers and an increase of \$0.1421 per Dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for July 2014, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.1421 per Dk for all customers since the last COG filing due to an increase in the market price of gas.

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, 2014.

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

Attachment A



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

**State of North Dakota
 Gas Rate Schedule**

NDPSC Volume 2

100th Revised Sheet No. 1.1

Canceling 99th Revised Sheet No.1.1

RATE SUMMARY SHEET

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/dk
Firm Gas Service - General	2	\$3.50 per month	First 10 dk \$1.2869 Over 10 dk 1.0646	\$7.5722	\$8.8591 8.6368
Interruptible Gas Service - General	3	\$3.50 per month	First 400 dk \$1.1506 Next 2,600 dk 0.9021 Over 3,000 dk 0.7486	\$5.6989	\$6.8495 6.6010 6.4475
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All dk \$1.2516	\$5.6989	\$6.9505
Transportation Service	5	\$3.50 per month	First 400 dk \$1.1506 Next 2,600 dk 0.9021 Over 3,000 dk 0.7486		\$1.1506 0.9021 0.7486

Date Filed: June 30, 2014

Effective Date: Service rendered on and after July 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
100th Revised Sheet No. 8
Canceling 99th Revised Sheet No. 8

COST OF GAS

Page 1 of 1

Summary:	Firm			Interruptible			
	Est. Wtd. Demand Costs	Average Commodity	GCR Adj.	Est. Wtd. Total Firm	Average Commodity	GCR Adj.	Total Int.
Base Rate	\$0.0662	\$5.1708	\$0.0000	\$5.2370	\$5.1708	\$0.0000	\$5.1708
Accumulated Adj.	1.4450	(0.5981)	1.3462	2.1931	(0.5836)	0.9696	0.3860
Current Adj.	0.0000	0.1421	0.0000	0.1421	0.1421	0.0000	0.1421
Total Adj.	1.4450	(0.4560)	1.3462	2.3352	(0.4415)	0.9696	0.5281
Total Rate	\$1.5112	\$4.7148	\$1.3462	\$7.5722	\$4.7293	\$0.9696	\$5.6989

Date Filed: June 30, 2014

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JULY 2014**

<u>Firm</u>	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
FT-A - Zone 1-1	8,000	\$3.3978	12	\$326,189	\$0.2315
FT-A - Zone 1-1	5,000	3.6918	5	92,295	0.0655
FT-A Seasonal	2,000	3.6918	5	36,918	0.0262
TFX Seasonal	2,000	15.1530	5	151,530	0.1075
TFX - Winter	13,000	15.1530	5	984,945	0.6990
TFX - Summer	13,000	5.6830	7	517,153	0.3670
LMS Demand 2/					0.0145
Total Demand Charges				\$2,109,030	1.5112
Estimated Weighted Average Commodity Cos	1,409,081	1/ 4.7148		6,643,535	4.7148
Gas Cost Reconciliation Adjustment					1.3462
Total Current Firm Gas Cost				<u>\$8,752,565</u>	<u>7.5722</u>
Base Cost of Gas					<u>5.2370</u>
Accumulated Adjustment					<u>\$2.3352</u>
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$4.7148
Gas Cost Reconciliation Adjustment					0.9696
LMS Demand 2/					0.0145
Total Current Interruptible Gas Cost					<u>5.6989</u>
Base Cost of Gas					<u>5.1708</u>
Accumulated Adjustment					<u>\$0.5281</u>

1/ Three year normalized average Dk sales

2/ Amount divided by 2011-2013 average normalized interruptible sales volumes plus 2011-2013 average normalized firm sales volumes.

	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
LMS Demand	2,500	\$0.9800	12	\$29,400	\$0.0145

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JULY 2014**

Rates Effective July 1, 2014	<u>\$/Dk</u>	
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 Cos	4.7148	Per Dk

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

Base Rate Calculation

<u>Firm</u>		
Demand 2/	\$0.0662	Per Dk
Commodity	5.1708	Per Dk
Total Firm Base Cost	<u>\$5.2370</u>	Per Dk

<u>Interruptible:</u>		
Commodity	\$5.1708	Per Dk

1/ The Firm Gas Base Cost is based on the FERC Gas Tariff, Third Revised Volume No. 1 of Midwestern Gas Transmission Company, effective July 1, 1981.

2/ Demand base rate calculation:

Demand Charge	0.81	Per MCF/Mo.
Convert mcf to dk	x <u>0.99</u>	Therm Factor
	0.82	Per Dk/Mo.
Capacity	x 4,768	
Months	x <u>12</u>	
	46,814.13	
Volumes	/ <u>707,222</u>	
	0.0662	Per Dk

STATEMENT OF RATES
 (Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
<u>Category 1 (Contract Term of Less than 3 Years)</u>	
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
<u>Category 2 (Contract Term of 3 Years to less than 5 Years)</u>	
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
<u>Category 3 (Contract Term of 5 or more Years)</u>	
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

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/		Carlton Surcharges 4/		Out-of-Balance 3/	
TF12 Base	TF12 Var., TFS & TFF	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.

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	0.0364	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

GULF COAST	Reservation 1/		Commodity 6/		Out-of-Balance 6/	
	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

	<u>Percentages</u>
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%
	<u>Electric Compression</u>
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
July 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 the Northern Natural Gas Co. Ventura, Iowa point which is an actively traded market point in North America. The July 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.

Warmer summer time temperatures requiring additional gas used for power burn and the U.S. storage levels remaining well below the five year average were likely the main contributing factors to the increase of the July index. The EIA reported storage levels nationwide as of June 13, 2014 were 33.1 percent below the five-year average and 29.1 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

June 2014

Short-Term Energy Outlook (STEO)

Highlights

- North Sea Brent crude oil spot prices increased from a monthly average of \$108/barrel (bbl) in April to \$110/bbl in May. This was the 11th consecutive month in which the average Brent crude oil spot price fell within a relatively narrow range of \$107/bbl to \$112/bbl. The discount of West Texas Intermediate (WTI) crude oil to Brent crude oil, which averaged more than \$13/bbl from November through January, fell below \$4/bbl in early April before increasing to an average of \$7/bbl in May. EIA projects Brent crude oil prices to average \$108/bbl in 2014 and \$102/bbl in 2015 and the WTI discount to Brent to average \$9/bbl and \$11/bbl in 2014 and 2015, respectively.
- During the April-through-September summer driving season this year, regular gasoline retail prices are forecast to average \$3.62/gallon (gal), 4 cents higher than last year. The projected monthly national average regular gasoline retail price falls from the high this year of \$3.67/gal in May to \$3.54/gal in September. EIA expects regular gasoline retail prices to average \$3.50/gal in 2014 and \$3.38/gal in 2015, compared with \$3.51/gal in 2013.
- EIA estimates that U.S. total crude oil production averaged almost 8.4 million barrels/day (bbl/d) in May, the highest monthly average production since March 1988. U.S. total crude oil production, which averaged 7.4 million bbl/d in 2013, is expected to average 8.4 million bbl/d in 2014 and 9.3 million bbl/d in 2015. The 2015 forecast represents the highest annual average level of oil production since 1972.
- Natural gas working inventories on May 30 totaled 1.50 trillion cubic feet (Tcf), 0.74 Tcf (33%) below the level at the same time a year ago and 0.90 Tcf (37%) below the previous five-year average (2009-13). EIA expects that the Henry Hub natural gas spot price, which averaged \$3.73/MMBtu in 2013, will average \$4.74/MMBtu in 2014 and \$4.49/MMBtu in 2015.
- Based on the outlook from the National Oceanic and Atmospheric Administration (NOAA) for near- to below-normal tropical weather activity this year, EIA's mean estimates of shut-in production in the federal Gulf of Mexico (GOM) during the current hurricane season (June through November) total 12 million bbl of crude oil and 30 billion cubic feet (Bcf) of natural gas (see [2014 Outlook for Gulf of Mexico Hurricane-Related Production Outages](#)). Actual shut-ins are likely to differ significantly from this estimate depending on the number, track, and strength of hurricanes as the season progresses.

Global Petroleum and Other Liquids

EIA expects the combination of total liquids supply growth from countries outside of the Organization of the Petroleum Exporting Countries (OPEC) and non-crude oil supply growth in OPEC member countries to exceed world liquids demand growth over the next two years. The call on OPEC crude oil and global stocks (world consumption less non-OPEC supply and OPEC Non-crude oil supply) is forecast to fall from an average of 30.1 million bbl/d in 2013 to 29.6 million bbl/d in 2015. Expected non-OPEC supply growth also contributes to an increase in global surplus crude oil production capacity held by OPEC countries from an average of 2.1 million bbl/d in 2013 to 3.5 million bbl/d in 2015.

Global Petroleum and Other Liquids Consumption. EIA estimates that global petroleum and other liquids consumption grew by 1.3 million bbl/d in 2013, averaging 90.5 million bbl/d for the year. EIA expects global consumption to grow by 1.3 million bbl/d in both 2014 and 2015. Projected global oil-consumption-weighted real GDP, which increased by an estimated 2.6% in 2013, grows by 3.0% and 3.5% in 2014 and 2015, respectively.

Countries outside of the Organization for Economic Cooperation and Development (OECD) account for nearly all of the expected consumption growth in 2014 and 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. China's economic and oil consumption growth rates have moderated compared with rates before 2012, when annual GDP growth exceeded 9% and annual oil consumption growth averaged almost 800,000 bbl/d from 2009 through 2011. Forecast consumption growth in Russia slows from 100,000 bbl/d last year to 30,000 bbl/d in 2014 and almost flat in 2015.

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 140,000 bbl/d in 2014 and 160,000 bbl/d in 2015, as the country continues to increase natural gas and coal consumption in the electricity sector and returns some nuclear power plants to service in the second half of 2014 and in 2015. EIA projects that OECD Europe's consumption, which fell by 120,000 bbl/d in 2013, will decline by 60,000 bbl/d in 2014 and then remain flat in 2015. U.S. liquids consumption, which increased by 400,000 bbl/d in 2013, is expected to increase by only 50,000 bbl/d in both 2014 and 2015.

Non-OPEC Supply. EIA estimates that non-OPEC liquids production grew by 1.4 million bbl/d in 2013, averaging 54.1 million bbl/d for the year. EIA expects non-OPEC liquids production to grow by 1.5 million bbl/d in 2014 and 1.2 million bbl/d in 2015. EIA forecasts production from the United States and Canada to grow by a combined annual average of 1.4 million bbl/d and 1.2 million bbl/d in 2014 and 2015, respectively. Forecast production increases by 0.17 million bbl/d in 2014 in countries of the Former Soviet Union, led by Russia. However, oil production growth in the region slows to 0.05 million bbl/d in 2015. The forecast completion of phase 1 of

Kazakhstan's Kashagan field has been pushed back to the second half of 2015 because of continued problems delaying the start of commercial production.

Unplanned supply disruptions among non-OPEC producers averaged 0.72 million bbl/d in May 2014, up from the 0.66-million-bbl/d April average. South Sudan, Syria, and Yemen accounted for 75% of total non-OPEC supply disruptions, and Brazil, Colombia, and Mexico made up the remaining portion. EIA does not assume a disruption to oil supply as a result of ongoing events in Ukraine.

OPEC Supply. EIA estimates that OPEC crude oil production averaged 29.9 million bbl/d in 2013, a decline of 1.0 million bbl/d from the previous year, primarily reflecting production declines in Iran, increased unplanned outages in Libya, Nigeria, and Iraq, and strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.1 million bbl/d in 2014 and an additional 0.1 million bbl/d in 2015 to accommodate growing production in non-OPEC countries.

EIA revised downward its estimate for Iranian total liquid fuels production in 2013 by 0.2 million bbl/d to 3.2 million bbl/d, based on a review of annual production and exports data from multiple sources. The revision was made to Iran's production of crude oil and natural gas plant liquids. EIA estimates that Iran's total liquid fuels production averaged 3.4 million bbl/d in May.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.6 million bbl/d in May, down from the 2.7-million-bbl/d average in April. Libya continues to experience variation 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 2.2 million bbl/d in 2014 and 3.5 million bbl/d in 2015. This build in surplus capacity mainly reflects a reduction in production cutbacks by some OPEC members to accommodate higher supply from Iraq, Angola, and Libya as well as some non-OPEC countries. 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 2.55 billion barrels at the end of 2013, equivalent to roughly 55 days of consumption. Projected OECD oil inventories remain near 2.60 billion barrels at the end of both 2014 and 2015.

Crude Oil Prices. North Sea Brent crude oil spot prices averaged \$110/bbl in May, an increase of \$2/bbl from April. This was the 11th consecutive month in which average Brent crude oil spot prices fell within a relatively narrow range of \$107/bbl to \$112/bbl. Reported record-high levels of Chinese crude oil imports in recent months and the ongoing tensions in Libya and Ukraine contributed to the upward price pressure for Brent crude oil. China's net crude oil imports reached a reported 6.8 million bbl/d in April, compared with an average of 5.6 million bbl/d during 2013. Higher volumes of crude oil imports and domestic production are outpacing China's refining input, indicating some crude oil is being stored in strategic or commercial

reserves. The forecast Brent crude oil price averages \$108/bbl in 2014, \$2/bbl higher than in last month's STEO, and \$102/bbl in 2015.

The January 2014 startup of TransCanada's Marketlink pipeline, moving crude oil from Cushing to the Gulf Coast, and strong refinery runs contributed to an increase in the WTI crude oil spot price from an average of \$95/bbl in January to \$102/bbl in both April and May. Crude oil inventory levels at the Cushing, Oklahoma, storage hub, the delivery point for WTI, have fallen by almost half since the start of the year, from 41 million barrels on January 3 to less than 22 million barrels at the end of May, the lowest level since November 2008. The discount of WTI crude oil to Brent crude oil, which averaged more than \$13/bbl from November 2013 through January 2014, has since fallen to \$7/bbl in May. EIA expects high seasonal demand for refined products and strong refinery runs to help keep the discount of WTI crude oil to Brent crude oil around \$7/bbl over the next few months, before widening later in the year to reach \$12/bbl in December. EIA expects the discount to average of \$9/bbl in 2014 and \$11/bbl in 2015, reflecting [the economics of transporting and processing](#) the growing production of high API gravity (very light) sweet crude oil in the United States.

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 September 2014 delivery, traded during the five-day period ending June 5, averaged \$101/bbl. Implied volatility averaged 14%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in September 2014 at \$89/bbl and \$114/bbl, respectively. Last year at this time, WTI for September 2013 delivery averaged \$94/bbl and implied volatility averaged 23%. The corresponding lower and upper limits of the 95% confidence interval were \$77/bbl and \$114/bbl.

U.S. Petroleum and Other Liquids

Regular gasoline monthly average prices have increased for six consecutive months to an average of \$3.67/gal in May. EIA expects U.S. average regular gasoline retail prices to fall from current levels to average \$3.54/gal in September. Gasoline prices have recently increased in the Midwest (PADD 2), where the average regular retail price climbed \$0.10/gal over the last two weeks to reach \$3.71/gal on June 2. Total gasoline stocks fell below the bottom of their five-year range in May and a recent outage at one of the country's largest refineries further tightened gasoline supplies in PADD 2. A tornado on May 28 damaged a cooling water system at Marathon's Garyville, Louisiana refinery, causing the No. 1 crude unit and other units to be taken off-line. The Garyville refinery is the third-largest refinery in the country at 522,000 bbl/d of capacity, and a supplier of product to the Midwest. Marathon anticipates the crude unit will be operational by mid-June.

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 400,000 bbl/d (2.1%) in 2013. Total consumption growth slows to 50,000 bbl/d in both 2014 and 2015.

Consumption of hydrocarbon gas liquids (HGL) registered the largest gain in 2013, increasing by 150,000 bbl/d (6.4%). HGL consumption increases by 80,000 bbl/d between 2013 and 2015, led by increasing ethane use as a feedstock in ethylene production units.

Motor gasoline consumption grew by 90,000 bbl/d (1.1%) in 2013, the largest increase since 2006. Motor gasoline consumption grows by 30,000 bbl/d in 2014 and declines by 10,000 bbl/d in 2015 as improving new vehicle fuel economy increasingly offsets highway travel growth. Distillate fuel consumption increased by 90,000 bbl/d (2.5%) last year, reflecting colder weather and economic growth. Consumption of that fuel rises by 130,000 bbl/d and 40,000 bbl/d in 2014 and 2015, respectively. The increases in HGL, gasoline, and distillate consumption are partially offset by declines in consumption of residual fuel oil and unfinished oils.

Liquid Fuels Supply. Forecast total U.S. crude oil production increases from an estimated 7.4 million bbl/d in 2013 to 8.4 million bbl/d in 2014 and 9.3 million bbl/d in 2015. The highest previous annual average U.S. production level was 9.6 million bbl/d in 1970. Recent U.S. crude oil production growth has consisted primarily of lighter, sweet crude (a description of crude quality, as measured by API gravity and sulfur content) from tight resource formations. Roughly 96% of the 1.8-million-bbl/d growth in production between 2011 and 2013 consisted of sweet grades with API gravity of 40 or above. [EIA analysis of current and forecast crude oil production](#) indicates that U.S. supply of lighter API gravity crude will continue to outpace that of medium and heavier crudes. More than 60% of EIA's forecast of production growth for 2014 and 2015 consists of light, sweet grades with API gravity of 40 or above.

NOAA predicts a [relatively quiet hurricane season](#) this year with near- to below-normal tropical weather activity in the Atlantic basin. Based on NOAA's projections, EIA's mean estimate is for 12 million barrels of crude oil production in the federally administered Gulf of Mexico to be shut in at some point because of disruptions during the 2014 hurricane season. There is a wide range of uncertainty around this forecast (see the [2014 Outlook for Gulf of Mexico Hurricane-Related Production Outages](#)). EIA's simulation results indicate a 69% probability of offshore crude oil production experiencing outages during the 2014 hurricane season that are equal to or larger than the 3.1 million barrels of production shut in last season.

HGL production at natural gas liquids plants is projected to rise from 2.6 million bbl/d in 2013 to 2.9 million bbl/d in 2015. About half of this growth is expected to come from ethane production to meet growing demand associated with expanding domestic ethylene production and export capacity.

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 23% in 2015, which would be the lowest level since 1970.

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 \$3.50/gal in 2014 and \$3.38 in 2015. EIA expects that the monthly average regular gasoline retail price has peaked at \$3.67/gal in May and will fall to \$3.54/gal in September. Diesel fuel prices, which averaged \$3.92/gal in 2013, are projected to average \$3.90/gal in 2014 and \$3.78/gal in 2015.

Natural Gas

Total marketed production of natural gas hit a record high of 72.7 Bcf/d in March, an increase of 1.5% from the previous month. The increase was partially due to better weather conditions, as cold temperatures this winter hampered production, and also the result of new wells coming on line in Texas and the Appalachian and Uinta basins.

This month's STEO raises the 2014 and 2015 outlook for onshore Lower 48 marketed production by 0.7 Bcf/d and 0.4 Bcf/d, respectively. Projected total marketed production, which averaged 70.2 Bcf/d in 2013, averages 73.0 Bcf/d in 2014 and 74.0 Bcf/d in 2015. EIA expects that [new infrastructure projects will support production growth](#) in the Marcellus formation, which is largely driving increases in overall production. [Several new projects](#) to support Marcellus production have either recently come on line or will begin operations this year. For example, in April, ANR Pipeline's Lebanon Lateral began sending Marcellus natural gas west to ANR's mainline; additionally, in November 2014 Texas Eastern Transmission expects to bring on line 0.9 Bcf/d of capacity to move gas out of Appalachia.

Natural Gas Consumption. EIA expects total natural gas consumption will average 72.5 Bcf/d in 2014, an increase of 1.7% from 2013, led by the industrial sector. In 2015, total natural gas consumption falls by 0.2 Bcf/d as a return to near-normal winter weather contributes to lower residential and commercial consumption. Higher natural gas prices this year contribute to a 0.5% decline in natural gas consumption in the power sector to 22.2 Bcf/d in 2014. EIA expects natural gas consumption in the power sector to increase to 23.0 Bcf/d in 2015 with lower natural gas prices and the retirement of some coal plants.

Natural Gas Production and Trade. EIA expects natural gas marketed production to grow by an average rate of 4.0% in 2014 and 1.3% in 2015. Rapid natural gas production growth in the Marcellus formation is contributing to falling [natural gas forward prices in the Northeast](#), which often fall below Henry Hub prices outside of peak winter demand 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.

NOAA predicts a [relatively quiet hurricane season](#) this year with near- to below-normal tropical weather activity in the Atlantic basin. Based on NOAA's projections, EIA's mean estimate is for 30 Bcf of natural gas production in the federally administered Gulf of Mexico to be shut in at some point as a result of disruptions during the 2013 hurricane season (see the [2014 Outlook for](#)

Gulf of Mexico Hurricane-Related Production Outages). EIA's simulation results indicate a 69% probability of offshore natural gas production experiencing outages during the 2014 hurricane season that are equal to or larger than the 6.7 Bcf of production shut in last season. Despite the potential for significant outages if a strong hurricane were to pass through the GOM producing region, the overall effect on U.S. supply would not be as severe as in past years because the share of total U.S. natural gas production originating in the GOM has declined sharply. In 1997, 26% of the nation's natural gas was produced in the federal Gulf of Mexico; by 2013, that share had fallen to 5%.

Growing domestic production is expected to continue to put downward pressure on natural gas imports from Canada. EIA projects net imports of 3.6 Bcf/d in 2014 and 3.1 Bcf/d in 2015, which would be the lowest level since 1987. Liquefied natural gas (LNG) imports have fallen 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 expected to be the first to liquefy natural gas produced in the Lower 48 states for export. It is scheduled to come on line in stages beginning in late 2015.

Natural Gas Inventories. Natural gas working inventories totaled 1,499 Bcf on May 30, which is 737 Bcf lower than the same time last year and 896 Bcf lower than the previous five-year (2009-2013) average. The injection season began April somewhat slowly, but has picked up in May, with injections over the last four weeks totaling 444 Bcf. EIA expects working gas stocks will reach 3,424 Bcf at the end of October, 392 Bcf lower than at the same time last year.

Natural Gas Prices. Natural gas spot prices averaged \$4.58/MMBtu at the Henry Hub in May, down \$0.08/MMBtu from April. EIA expects spot prices will remain near current levels until the start of the next winter heating season. Projected Henry Hub natural gas prices average \$4.74/MMBtu in 2014 and \$4.49/MMBtu in 2015.

Natural gas futures prices for September 2014 delivery (for the five-day period ending June 5) averaged \$4.58/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for September 2014 contracts at \$3.54/MMBtu and \$5.92/MMBtu, respectively. At this time last year, the natural gas futures contract for September 2013 averaged \$3.97/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$3.03/MMBtu and \$5.21/MMBtu.

Coal

Power sector stockpiles fell by 30 million short tons (MMst) (20%) between the end of December and the end of March. [The average supply of coal](#) held at electric power generators in December 2013 dropped below 60 days of burn (a function of both inventory levels and anticipated consumption) and EIA projects that stockpiles will remain below this level in 2014.

The 108 MMst of power sector coal inventories forecast for August 2014 would be the lowest monthly level since February 2006 and nearly 46 MMst lower than last August's stockpiles. Recent milder weather and [increased coal shipments](#) may help to increase inventory levels, but a warmer-than-forecast summer will increase the chance of even lower power sector stockpiles.

Coal Supply. EIA estimates of U.S. coal production (242 MMst) for the first quarter of 2014 were down 3 MMst (1.1%) from last year. EIA expects U.S. coal production will grow 3.4% to 1,017 MMst in 2014, driven by higher consumption. In 2015, forecast U.S. coal production falls by 0.8% to 1,009 MMst.

Coal Consumption. EIA estimates that 232 MMst of coal was consumed by the electric power sector during the first three months of 2014. This is a 20-MMst (9.3%) increase over the same period in 2013. EIA projects total coal consumption growth of 3.9% to 961 MMst in 2014 as electricity demand grows and natural gas prices remain more than 25% above their 2013 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 4.1%.

Coal Exports. Coal exports for the first quarter of 2014 are estimated at 28 MMst, 12.9% (4 MMst) below last year. Coal exports are projected to total 99 MMst in 2014. Coal exports totaled more than 100 MMst per year between 2011 and 2013. Before that, coal exports had not reached 100 MMst since 1992. In 2015, projected exports fall to 93 MMst, primarily because of slowing world coal demand growth, and increasing coal output in other coal-exporting countries.

Coal Prices. First quarter average coal prices to the electric power industry fell slightly (0.8%) compared with last year. Annual average prices have fallen over the past two years, from \$2.39/MMBtu in 2011 to \$2.35/MMBtu in 2013. EIA forecasts average delivered coal prices to increase over the forecast period, with prices of \$2.36/MMBtu in 2014 and \$2.38/MMBtu in 2015.

Electricity

Summer Residential Electricity Outlook. EIA forecasts that the average U.S. residential electricity customer will spend 4.9% more during summer (June, July, and August) than during the same time last year. This increase in the average residential bill reflects a projected 1.2% increase in average electricity usage and a 3.7% increase in the average retail price of electricity.

There is wide variation in the average usage projections, with the average customer in New England consuming 3.7% less electricity than last summer while customers in the East South Central area consume 3.9% more electricity. Electricity prices in all areas of the United States,

except for the West North Central, are expected to be higher than last summer. New England retail electricity prices rise by 9.6%, but the average bill only increases 5.6% because of reduced electricity usage. Customers in the East South Central states experience the highest overall increase in average electricity bills this summer (8.7%).

Electricity Consumption. Total consumption of electricity during the first quarter of 2014 was 5.0% higher than the same period last year. Much of this increase was driven by colder temperatures in the eastern half of the United States, which caused a 9.9% year-over-year increase in electricity sales to the residential sector and a 4.4% increase in commercial sector sales. A 0.8% decline in industrial sales slightly offset growth in the other sectors. During the second half of 2014, EIA projects overall electricity consumption will rise by 0.9% from the same period last year. This second-half growth is driven by a 5.1% year-over-year increase in cooling degree days and a 2.3% increase in GDP.

Electricity Generation. EIA projects total U.S. electricity generation in 2014 will grow by 1.9% from last year to an average of 11,335 gigawatthours per day (GWh/d). Recently rising costs for natural gas have driven power generators to use relatively more coal for supplying electricity. The use of coal for power generation rises 248 GWh/d (5.7%) this year while natural gas-fired generation falls 51 GWh/d (1.7%) and nuclear generation falls 53 GWh/d (2.5%) from last year's levels. The use of renewable energy sources grows by an average of 59 GWh/d (4.1%).

Electricity Retail Prices. Some areas of the United States, especially the Northeast, have experienced rapid increases in retail electricity prices in recent months. EIA expects the U.S. residential price of electricity to average 12.5 cents per kilowatthour during 2014, an increase of 3.4% from 2013. Growth in the electricity prices charged to the commercial and industrial sectors are higher than the residential sector this year: 4.8% and 4.6%, respectively. Projected residential prices increase an additional 2.4% during 2015.

Renewables and Carbon Dioxide Emissions

Electricity and Heat Generation from Renewables. EIA projects total renewables consumption for electricity and heat generation will grow by 2.9% in 2014. Conventional hydropower is projected to increase by 0.5%, while nonhydropower renewables rise by 4.2%. In 2015, total renewables consumption for electric power and heat generation increases an additional 3.4%, as a result of a 2.2% increase in hydropower and a 4.0% increase in nonhydropower renewables.

EIA estimates that wind power capacity will increase by 7.3% in 2014 and 14.0% in 2015. Electricity generation from wind is projected to contribute 4.5% 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 0.5% in 2015. While solar growth has historically been concentrated in customer-sited distributed generation

installations, utility-scale solar capacity doubled in 2013. EIA expects that utility-scale solar capacity will increase by 57% between the end of 2013 and the end of 2015. About 70% of this new capacity is being built in California. However, customer-sited photovoltaic capacity growth, which the STEO does not forecast, is expected to exceed utility-scale solar growth between 2013 and 2015, according to [EIA's Annual Energy Outlook 2014](#).

Liquid Biofuels. Ethanol production increased from an average of 907,000 bbl/d in March to 926,000 bbl/d in May, the highest level of the year. Ethanol production is forecast to average 920,000 bbl/d during 2014 and 935,000 bbl/d in 2015. Biodiesel production has recovered from the recent low of 56,000 bbl/d in January to 75,000 bbl/d in March. Biodiesel production averaged 89,000 bbl/d in 2013 and is forecast to average 81,000 bbl/d in 2014 and 84,000 bbl/d in 2015.

Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels increased by 2.2% in 2013 from the previous year. Emissions are forecast to rise again by 2.2% in 2014, followed by a 1.1% decline in 2015. The increase in emissions in 2013 and 2014 reflects growth in coal consumption for electric power generation. Coal emissions are projected to decline by 3.2% in 2015 with increasing coal plant retirements.

U.S. Economic Assumptions

Recent Economic Indicators. Recent economic indicators signal economic growth slowing in the first quarter of 2014 with signs of improvement later in the year. The Bureau of Economic Analysis (BEA) reported that [real gross domestic product \(GDP\)](#) fell at an annual rate of 1.0 % in the first quarter (that is, from the fourth quarter of 2013 to the first quarter of 2014). This was a revision from BEA's initial first quarter estimate that reported an annualized 0.1% increase in real GDP. The revision was associated with a significant decline in inventory investment. According to the [U.S. Bureau of Labor Statistics](#) (BLS), the U.S. economy added 217,000 jobs in May, and the unemployment rate was unchanged at 6.3%.

[New orders for durable goods](#) also show recent deceleration in growth, as April's new orders rose 0.8%, according to the U.S. Census Bureau, compared to the 3.6% increase reported in March. Orders fell 0.8% excluding defense, but rose 0.1% excluding transportation. BEA also reported that [real personal disposable income](#) rose 0.2% between March and April, while real personal consumption expenditures fell 0.3%. Census reported that [sales of new single-family homes](#) rose 6.4% from March to April, but is 4.2% below the April 2013 sales estimate. The Bureau of Labor Statistics (BLS) reported that the [consumer price index for all urban consumers](#) rose 2.0% from April 2013 to April 2014, the largest year-over-year increase since July 2013, primarily due to increases in the prices of food and gasoline.

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.

Production and Income. Forecast real GDP growth reaches 2.4% in 2014 and accelerates to 3.1% in 2015, above the 2.3% and 2.9% forecast last month. The increases reflect greater optimism about exports of capital goods and investment in capital equipment for the remainder of 2014 and into 2015. Forecast real disposable income increases 2.0% in 2014 and 3.6% in 2015. Total industrial production grows at 3.7% in 2014 and 3.5% in 2015. Growth in industrial production in the manufacturing sector is lower than total industrial production in 2014, at 3.6%, but jumps higher in 2015 to 4.0%.

Expenditures. Private real fixed investment growth averages 4.1% and 9.6% in 2014 and 2015, respectively, led by transportation equipment in 2014 and by a broad array of equipment categories in 2015. Real consumption expenditures grow faster than real GDP in 2014 at 2.7%, but fall slightly below the real GDP growth rate in 2015 at 3.0%. Durable goods expenditures drive consumption spending in both years. Export growth is 2.8% and 5.3% over the same two years, while import growth is 2.1% in 2014 and 6.5% in 2015. Total government expenditures fall 0.8% in 2014, but increase by 0.4% in 2015.

Employment, Housing, and Prices. Projected growth in nonfarm employment averages 1.8% in 2014 and 1.9% in 2015. This is accompanied by a gradually declining unemployment rate that reaches 6.3% by the end of 2014 and 5.8% at the end of 2015. The employment growth in 2014 and 2015 is faster than projected last month and the declines in the unemployment rate are about the same. Housing starts grow an average of 10.3% and 35.6% 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.

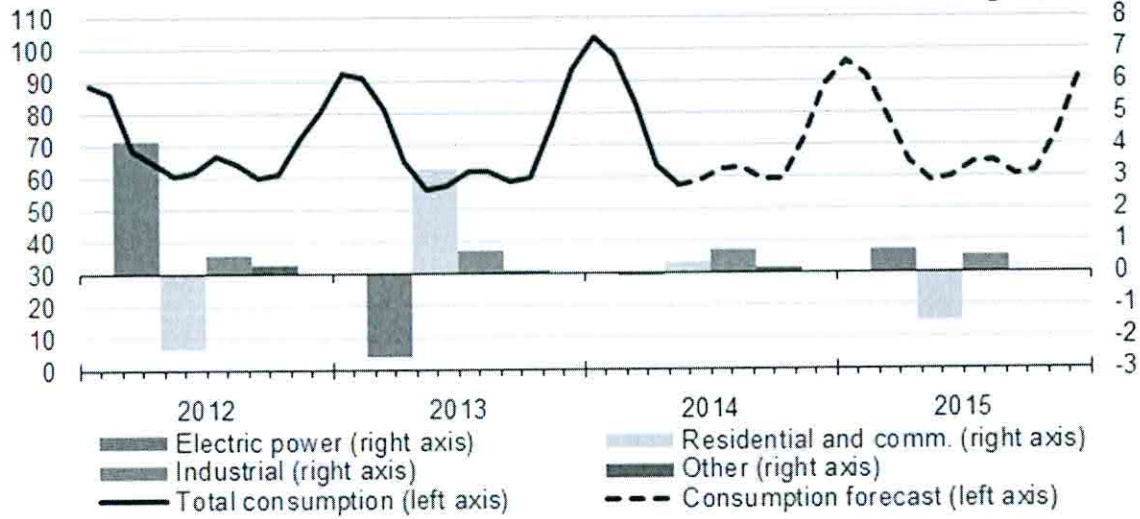
This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views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

U.S. Natural Gas Consumption

billion cubic feet per day (Bcf/d)

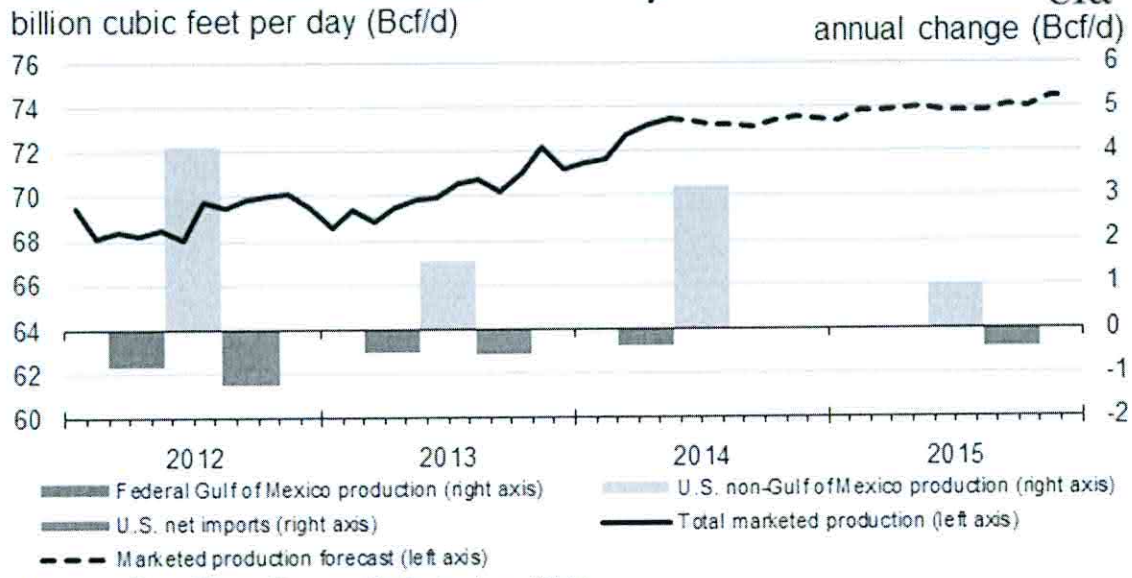


annual change (Bcf/d)



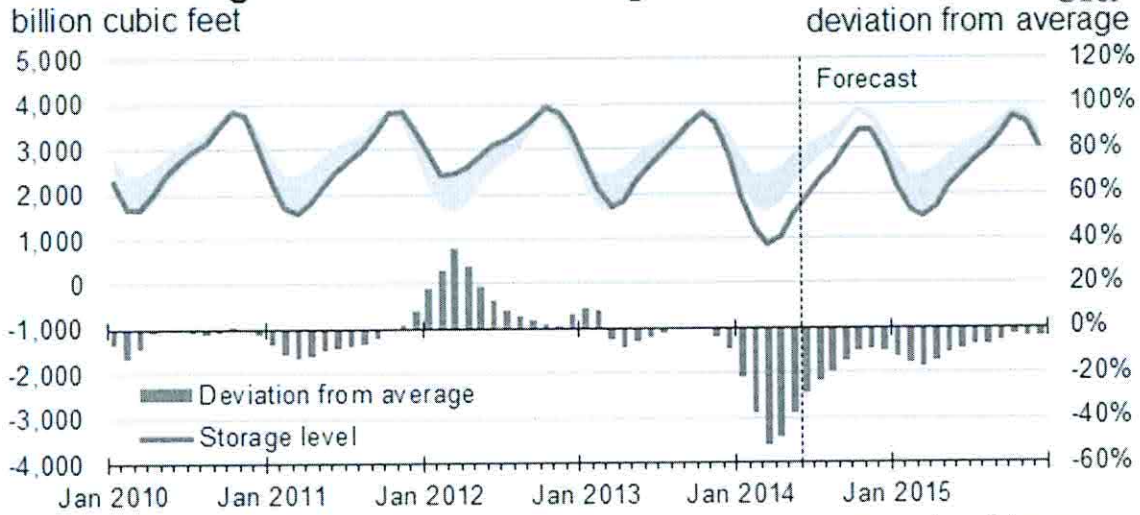
Source: Short-Term Energy Outlook, June 2014.

U.S. Natural Gas Production and Imports



Source: Short-Term Energy Outlook, June 2014.

U.S. Working Natural Gas in Storage



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

Henry Hub Natural Gas Price

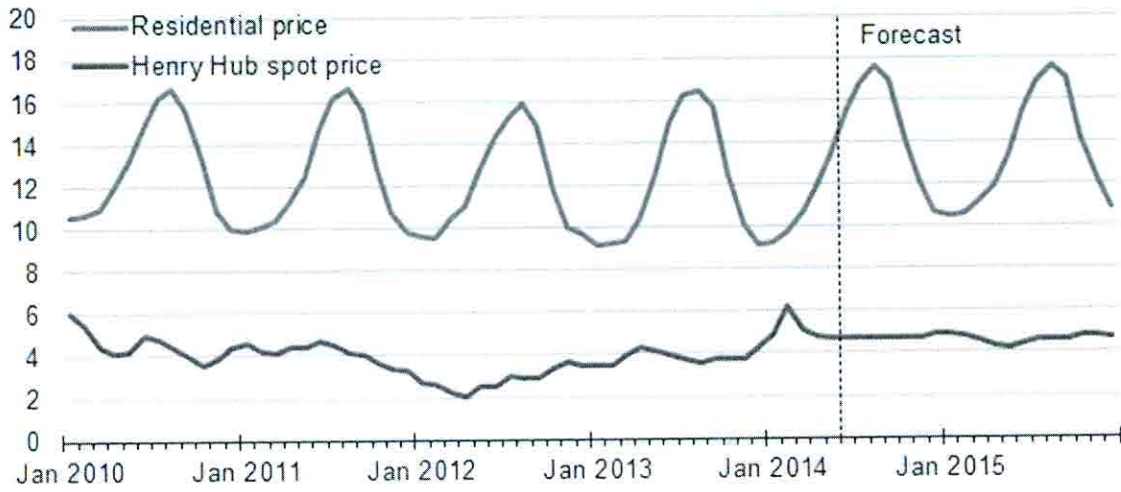
dollars per million Btu



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

Source: Short-Term Energy Outlook, June 2014.

U.S. Natural Gas Prices dollars per thousand cubic feet



Source: Short-Term Energy Outlook, June 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, 2014									\$404,569
May 2014	(\$15,520)	0	\$2,700	(\$12,820)	18,641	\$0.9614	\$17,921	(\$30,741)	373,828
Total	(\$15,520)	0	\$2,700	(\$12,820)	18,641		\$17,921	(\$30,741)	
Balance @ May 31, 2014									\$373,828

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

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, 2014									\$388,932
May 2014	(\$22,536)	0	\$2,691	(\$19,845)	42,002	\$0.0274	\$1,151	(\$20,996)	367,936
Total	(\$22,536)	0	\$2,691	(\$19,845)	42,002		\$1,151	(\$20,996)	
Balance @ May 31, 2014									\$367,936

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