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November 26, 2014

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

Re: Cost of Gas Adjustment (COG)  
December 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 (105<sup>th</sup> Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (105<sup>th</sup> Revised Sheet No. 8), showing the December 2014 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$1.4215 per dk for residential and firm general service customers and an increase of \$1.3975 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for December 2014, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$1.3975 per dk since the last COG filing. There has been an increase in pipeline charges of \$0.0240 per dk due to changes in Great Plains' demand portfolio to reflect new gas supply contracts. The net effect of these changes is an increase of \$1.4215 per dk for residential and firm general service customers since the last COG filing.

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

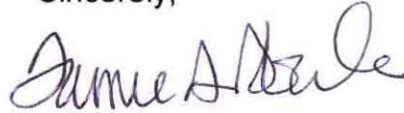
Attachment D shows the calculation of the balancing account since April 30, 2014.

Great Plains also submits herewith its check for \$650.00 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 the monthly COG filings.

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,

A handwritten signature in black ink, appearing to read "Tamie A. Aberle". The signature is fluid and cursive, with the first name being the most prominent.

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

105<sup>th</sup> Revised Sheet No. 1.1

Canceling 104<sup>th</sup> 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	\$8.1061	\$9.3930 9.1707
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	\$6.2088	\$7.3594 7.1109 6.9574
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All dk \$1.2516	\$6.2088	\$7.4604
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: November 26, 2014

Effective Date: Service rendered on and after December 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  
105<sup>th</sup> Revised Sheet No. 8  
Canceling 104<sup>th</sup> 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	(1.3436)	1.3462	1.4476	(1.3291)	0.9696	(0.3595)
Current Adj.	0.0240	1.3975	0.0000	1.4215	1.3975	0.0000	1.3975
Total Adj.	1.4690	0.0539	1.3462	2.8691	0.0684	0.9696	1.0380
Total Rate	\$1.5352	\$5.2247	\$1.3462	\$8.1061	\$5.2392	\$0.9696	\$6.2088

**Date Filed:** November 26, 2014

**Effective Date:** Service rendered on and  
after December 1, 2014

**Issued By:** Tamie A. Aberle  
Director - Regulatory Affairs

**Case No.:**

**GREAT PLAINS NATURAL GAS CO.  
WAHPETON  
COST OF GAS ADJUSTMENT  
DECEMBER 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
BP Seasonal Contract	500	3/	3	33,750	0.0240
LMS Demand 2/					0.0145
Total Demand Charges				\$2,142,780	1.5352
Estimated Weighted Average Commodity Cost	1,409,081	1/ 5.2247		7,362,026	5.2247
Gas Cost Reconciliation Adjustment					1.3462
Total Current Firm Gas Cost				\$9,504,806	8.1061
Base Cost of Gas					5.2370
Accumulated Adjustment					\$2.8691
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$5.2247
Gas Cost Reconciliation Adjustment					0.9696
LMS Demand 2/					0.0145
Total Current Interruptible Gas Cost					6.2088
Base Cost of Gas					5.1708
Accumulated Adjustment					\$1.0380

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

3/ Contract terms are 500 dk/day at \$0.75/dk for the period December 1, 2014 through February 28, 2015.

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

<b>Rates Effective December 1, 2014</b>	<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 Cost:	5.2247	Per Dk

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

**Base Rate Calculation**

Firm

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

Interruptible:

Commodity	\$5.1708	Per Dk
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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 0.99	Therm Factor
	<u>0.82</u>	Per Dk/Mo.
Capacity	x 4,768	
Months	x 12	
	<u>46,814.13</u>	
Volumes	/ 707,222	
	<u>0.0662</u>	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 <sup>1/</sup>	\$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

<sup>1/</sup> Throughout Viking's Statement of Rates and Tariff, "Zone 1-2" shall mean Transportation Service for quantities received in Zone 1 and delivered in Zone 2 or received in Zone 2 and delivered in Zone 1 whether by transport, exchange, or Displacement.

Rate Schedule	Base Tariff Rate	Fuel and Loss Retention Percentages 2/
Commodity Rates 1/		
FT-A – Maximum Rates		
Zone 1-1	\$0.0127	0.00%
Zone 1-2	\$0.0127	0.00%
Zone 2-2	\$0.0127	0.00%
Minimum Rate	\$0.0127	
IT and AOT		
Zone 1-1	\$0.1341	0.00%
Zone 1-2	\$0.1702	0.00%
Zone 2-2	\$0.0816	0.00%
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/ The Fuel and Loss Retention Percentages shall be applicable to all transportation rate schedules and includes the following Gas Lost and Unaccounted For Percentages: 0.00% for Zone 1-1, 0.00% for Zone 1-2, and 0.00% for Zone 2-2. Transportation entirely by Displacement 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

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

Seventh Revised Sheet No. 50  
Superseding  
Sixth Revised Sheet No. 50

RATE SCHEDULE TF

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

COMMODITY RATES 2/		Market Area 3/		Field Mileage 5/		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

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)	1.39%
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, ILD & 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 ILD

Maximum Charge	11.7500
Minimum Charge	0.5044
Performance Obligation Charge	2.0000

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  
December 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 December 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.

Despite domestic production continuing to be strong and national storage levels recovering from very low early summer levels, the typical colder seasonal weather along with mid-month November temperatures that were 15-30% below normal over half of the U.S., likely contributed to the increase in the index price of natural gas for the month of December. The EIA reported storage levels nationwide as of November 14, 2014 were 6.4 percent below the five-year average and 5.3 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 18.



*Independent Statistics & Analysis*

U.S. Energy Information  
Administration

November 2014

## Short-Term Energy Outlook (STEO)

### Highlights

- North Sea Brent crude oil spot prices fell from \$95/barrel (bbl) on October 1 to \$84/bbl at the end of the month. The causes included weakening outlooks for global economic and oil demand growth, the return to the market of previously disrupted Libyan crude oil production, and continued growth in U.S. tight oil production. Brent crude oil spot prices averaged \$87/bbl in October, the first month Brent prices have averaged below \$90/bbl since November 2010. EIA projects that Brent crude oil prices will average \$83/bbl in 2015, \$18/bbl lower than forecast in last month's STEO. There is significant uncertainty over the crude oil price forecast because of the range of potential supply responses from the Organization of the Petroleum Exporting Countries (OPEC), particularly Saudi Arabia, and U.S. tight oil producers to the new lower oil price environment.
- Driven largely by falling crude oil prices, U.S. weekly regular gasoline retail prices averaged \$2.99/gallon (gal) on November 3, the lowest level since December 20, 2010. U.S. regular gasoline retail prices are projected to continue to decline for the remainder of the year to an average of \$2.80/gal in December, \$0.33/gal lower than in last month's STEO. EIA expects U.S. regular gasoline retail prices, which averaged \$3.51/gal in 2013, to average \$3.39/gal in 2014 and \$2.94/gal in 2015.
- Total U.S. crude oil production averaged an estimated 8.9 million barrels per day (bbl/d) in October, and monthly average production is forecast to surpass 9.0 million bbl/d in December 2014. Projected total crude oil production averages 9.4 million bbl/d in 2015, a reduction of 0.1 million bbl/d from last month's STEO. If realized, the 2015 forecast would be the highest annual average crude oil production since 1972. Natural gas plant liquids production is expected to increase from an average of 2.6 million bbl/d in 2013 to 3.2 million bbl/d in 2015.
- Natural gas working inventories on October 31 totaled 3.57 trillion cubic feet (Tcf), 0.24 Tcf (6%) below the level at the same time a year ago and 0.26 Tcf (7%) below the previous five-year average (2009-13). Despite the lower stocks at the start of this winter's heating season, EIA expects the Henry Hub natural gas spot price to average \$3.97/million British thermal units (MMBtu) this winter compared with \$4.53/MMBtu last winter. This price forecast reflects both lower expected heating demand and significantly higher natural gas production this winter.

## Global Petroleum and Other Liquids

EIA made significant changes to its forecast global oil balance for this month's STEO. EIA expects that global oil markets will be looser than projected in last month's STEO, as global oil supply outpaces consumption by a larger amount, resulting in a global stock build of 0.4 million bbl/d in the fourth quarter of 2014 and a build of 0.4 million bbl/d in 2015. EIA's global supply forecast was revised upward by 0.2 million bbl/d to average 92.9 million bbl/d in 2015, mostly reflecting a smaller decline in Saudi Arabia's production compared with last month's forecast. The global demand forecast was revised downward by 0.2 million bbl/d to average 92.5 million bbl/d in 2015, based on weaker global economic growth prospects for next year.

Saudi Arabia's role in the oil market going forward is highly uncertain. Saudi Arabia has stated that it would rather maintain its export market share than cut production to keep prices higher. In the past, Saudi Arabia often played the role of the swing producer, cutting its production to accommodate supply growth elsewhere or increasing its output level to make up for a supply shortfall. EIA assumes that Saudi Arabia will continue to play some role as a swing producer, but perhaps to a lesser extent, as the country is sensitive to significant losses in market share. Saudi Arabia's production is still projected to decline in 2015 compared with this year, but by a smaller amount than previously expected. EIA projects that Saudi Arabia will cut production below its current level of 9.5 million bbl/d to avoid further downward pressure on oil prices amid high non-OPEC supply growth, but will maintain output above 9.0 million bbl/d through 2015.

EIA's projected global oil balance may be looser or tighter than expected depending on changes to Saudi Arabia's production level, Libya's supply outages, and global demand. Libya's crude oil production reached 1.0 million bbl/d in October 2014, its highest production level since early July 2013. However, Libya's production has since fallen because of new production outages. Intermittent supply outages in Libya will most likely persist as the country faces political instability and a deteriorated security environment in parts of the country.

**Global Petroleum and Other Liquids Consumption.** EIA estimates that global 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 0.9 million bbl/d in 2014 and 1.1 million bbl/d in 2015. Projected global oil-consumption-weighted real gross domestic product (GDP), which increased by an estimated 2.7% in 2013, grows by 2.7% and 3.2% in 2014 and 2015, respectively. Global consumption was revised downward by 0.2 million bbl/d in 2015, based on a 0.1% reduction to forecast global oil-consumption-weighted real GDP growth. Short-term elasticities of demand with respect to income are more powerful (negatively) than the positive effects on demand from lower prices.

Consumption outside of the Organization for Economic Cooperation and Development (OECD) is projected to grow by 1.2 million bbl/d in 2014 and 1.0 million bbl/d in 2015, accounting for nearly all forecast global consumption growth during that period. China is the leading

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contributor to projected global consumption growth, with consumption increasing by an annual average of 0.36 million bbl/d in 2014 and 2015.

EIA expects a 0.3-million-bbl/d decline in OECD consumption in 2014. Japan and Europe are expected to account for much of the projected OECD consumption decline. EIA expects Japan's consumption, which fell by 0.16 million bbl/d in 2013, to continue to decline by 0.14 million bbl/d in 2014 and 0.12 million bbl/d in 2015. Japan's oil consumption is expected to fall with less oil used in the electricity sector as the country returns some nuclear power plants to service in 2015 and increases the use of natural gas and coal to generate electricity. EIA projects that OECD Europe's consumption, which fell by 0.15 million bbl/d in 2013, will decline by 0.14 million bbl/d in 2014 and by a further 0.07 million bbl/d in 2015. U.S. consumption, which increased by 0.47 million bbl/d in 2013, is expected to decline by 0.06 million bbl/d in 2014 and then increase by 0.16 million bbl/d in 2015.

**Non-OPEC Petroleum and Other Liquids Supply.** EIA estimates that non-OPEC production grew by 1.4 million bbl/d in 2013, averaging 54.2 million bbl/d for the year. EIA expects non-OPEC production to grow by 1.9 million bbl/d in 2014 and 0.9 million bbl/d in 2015. The United States is the leading contributor to forecast non-OPEC supply growth, increasing by 1.5 million bbl/d in 2014 and 1.1 million bbl/d in 2015. EIA revised downward its U.S. total supply growth forecast by 0.1 million bbl/d in 2015 because of the recent decline in crude oil prices and the expectation that West Texas Intermediate crude oil spot prices will remain near \$80/bbl through 2015. EIA estimates that Eurasia's production will rise by an annual average of 0.06 million bbl/d in 2014 and decline by 0.09 million bbl/d in 2015, reflecting declines in Russia and Azerbaijan. In Russia, inadequate investment to offset natural decline rates at mature oil fields causes forecast production to decline by 0.05 million bbl/d in 2015.

Unplanned supply disruptions among non-OPEC producers averaged slightly lower than 0.6 million bbl/d in October, virtually unchanged from the previous month. South Sudan, Syria, and Yemen accounted for more than 90% of total non-OPEC supply disruptions.

**OPEC Petroleum and Other Liquids Supply.** EIA estimates that OPEC crude oil production averaged 29.9 million bbl/d in 2013, a decline of almost 1.0 million bbl/d from the previous year, primarily reflecting increased outages in Libya, Nigeria, Iran, and Iraq, along with strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.10 million bbl/d in 2014 and by 0.15 million bbl/d in 2015. In last month's STEO, OPEC crude oil production was projected to decline by more than 0.4 million bbl/d in 2015, but the projected decline was reduced based on a reassessment of Saudi Arabia's willingness to cut production.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.0 million bbl/d in October 2014, slightly lower than the previous month, as fewer outages in Libya offset new outages in the Neutral Zone shared by Kuwait and Saudi Arabia. Libya's production increased to 1.0 million bbl/d in October, its highest production level since early July 2013, but Libya's production has since fallen because of new production outages. Intermittent supply outages in

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Libya will most likely persist as the country faces political instability and a deteriorated security environment. As a result, EIA does not expect Libya's oil production to recover to its pre-blockade level of 1.4 million bbl/d over the forecast period.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to average 2.1 million bbl/d in 2014 and 2.7 million bbl/d in 2015. These estimates do not include additional capacity that may be available in Iran but is offline because of the effects of U.S. and European Union sanctions on Iran's ability to sell its oil.

**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 rise to 2.65 billion barrels at the end of 2014.

**Crude Oil Prices.** North Sea Brent crude oil spot prices averaged \$87/bbl in October, a decrease of \$10/bbl from September and the first month Brent crude oil prices have averaged below \$90/bbl since November 2010. The combination of robust world crude oil supply and weak global demand contributed to [rising global inventories and lower crude oil prices](#). The forecast Brent crude oil price averages \$83/bbl in 2015, \$18/bbl lower than projected in last month's STEO.

The monthly average WTI crude oil spot price fell from an average of \$93/bbl in September to \$84/bbl in October. High refinery runs contributed to the discount of WTI crude oil to Brent crude oil narrowing from an average of \$8/bbl during the first half of this year to an average of \$3/bbl in July. More recently, lower-than-expected demand in Europe and Asia combined with continued [growth in global liquids supply depressed global crude oil benchmarks like Brent](#), contributed to the WTI discount to Brent again falling to \$3/bbl in October. EIA now expects WTI crude oil prices to average \$80/bbl in the fourth quarter of 2014 and \$78/bbl in 2015, \$11/bbl and \$17/bbl lower than projected in last month's STEO, respectively. The discount of WTI to Brent crude oil is forecast to widen slightly from current levels, averaging \$6/bbl in 2015.

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 February 2015 delivery, traded during the five-day period ending November 6, averaged \$79/bbl. Implied volatility averaged 28%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in February 2015 at \$63/bbl and \$99/bbl, respectively. Last year at this time, WTI for February 2014 delivery averaged \$95/bbl and implied volatility averaged 20%. The corresponding lower and upper limits of the 95% confidence interval were \$80/bbl and \$112/bbl.

## U.S. Petroleum and Other Liquids

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U.S. weekly regular gasoline retail prices averaged \$2.99/gal on November 3, which marked a decrease of 36 cents since the end of September and the first time gasoline prices have averaged below \$3.00/gal since December 20, 2010. In addition to typical seasonal downturns in gasoline demand and the switchover to winter-grade gasoline, [falling crude oil prices have been largely responsible](#) for the drop in retail gasoline prices. EIA expects that low crude oil prices and weak demand will help gasoline prices decrease further in the coming months, falling to an average of \$2.80/gal in December.

**Liquid Fuels Consumption.** Total U.S. liquid fuels consumption rose by 470,000 bbl/d (2.5%) in 2013, the largest increase since 2004. Consumption of hydrocarbon gas liquids (HGL) registered the largest gain, increasing by 190,000 bbl/d (8.5%). In 2014, total liquid fuels consumption is expected to fall by 60,000 bbl/d (0.3%), with declines in the consumption of HGL, residual fuel oil, and other oils offsetting increases in distillate fuel, jet fuel, and unfinished oils consumption. Total consumption grows by 160,000 bbl/d in 2015, with distillate consumption accounting for 100,000 bbl/d of the growth.

Motor gasoline consumption grew by 160,000 bbl/d (1.9%) in 2013, the largest increase since 2004. EIA expects gasoline consumption to remain mostly unchanged in 2014 and then decline by 20,000 bbl/d in 2015, as improving fuel economy in new vehicles continues to offset highway travel growth. Distillate fuel consumption increases by 110,000 bbl/d (3.0%) in 2014, reflecting colder-than-average first-quarter weather and economic growth. Consumption of that fuel rises by a further 100,000 bbl/d (2.5%) in 2015. Some of the growth in distillate fuel consumption in 2015 comes from [Annex VI to the International Convention for the Prevention of Pollution from Ships](#) (MARPOL Annex VI), which is an international agreement that generally requires the use of fuels below 1,000 parts per million sulfur by marine vessels in most U.S. waters, unless alternative devices, procedures, or compliance methods are used to achieve equivalent emissions reductions. However, EIA also expects low-sulfur distillate fuels will continue to be blended into residual fuel to meet the new sulfur limit and reported as residual fuel production and consumption.

**Liquid Fuels Supply.** Forecast U.S. crude oil production increases from an average of 7.5 million bbl/d in 2013 to 8.6 million bbl/d in 2014 and 9.4 million bbl/d in 2015. Because of the recent decline in crude oil prices, EIA has revised U.S. crude oil production in 2015 downward by an average of 80,000 bbl/d compared with last month's forecast. As the WTI crude oil price is forecast to average \$78/bbl in 2015, EIA expects to see some reduction in drilling activity because of marginal economic returns in some areas. This will primarily occur in noncore areas of emerging and mature tight oil basins, where low-producing wells become less attractive at lower prices and companies scale back expensive exploration and research drilling. The production forecast is not affected significantly because the wells that will not be drilled at these prices produce relatively little compared to wells in the core areas of a formation. Oil prices remain high enough to support most drilling activity in the Bakken, Eagle Ford, Niobrara, and Permian Basin, which contribute the majority of U.S. oil production growth.

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HGL production at natural gas liquids plants is projected to increase from 2.6 million bbl/d in 2013 to 3.2 million bbl/d in 2015. Ethane and propane are expected to contribute most to the projected growth, with the majority of production directed towards domestic petrochemical use or exports. EIA expects higher rates of ethane recoveries as a result of planned increases in petrochemical facility feedstock demand, while export terminal expansions will allow higher quantities of domestically produced propane and butanes to reach the international market.

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 fell from 60% in 2005 to an average of 33% in 2013. EIA expects the net import share to decline to 21% in 2015, which would be the lowest level since 1969.

**Petroleum Product Prices.** Monthly U.S. average regular gasoline retail prices fell from \$3.69/gal in June to \$3.17/gal in October. EIA expects that U.S. regular gasoline retail prices will continue to fall to an average of \$2.80/gal in December 2014. The U.S. annual average regular gasoline retail price, which averaged \$3.51/gal in 2013, is projected to average \$3.39/gal in 2014 and \$2.94/gal in 2015, \$0.06/gal and \$0.44/gal lower than in last month's STEO, respectively. Diesel fuel prices, which averaged \$3.92/gal in 2013, are projected to fall to an average of \$3.82/gal in 2014 and \$3.38/gal in 2015, \$0.04 and \$0.41 lower than in last month's STEO, respectively.

The February 2015 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged \$2.12/gal for the five trading days ending November 6, 2014. Based on the market value of futures and options contracts for this key petroleum component of gasoline, there is a 15% probability that the RBOB futures contract price at expiration will fall below \$1.85/gal, consistent with a monthly average regular-grade gasoline retail price less than \$2.50/gal in February 2015. There is also a 19% probability that the RBOB futures contract price at expiration may exceed \$2.35/gal, consistent with a retail price of \$3.00/gal or higher. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas falling above or below the national average price by \$0.30/gal or more.

Lower projected crude oil prices also contribute to a reduction in the forecast residential heating oil price and average household heating oil expenditures this winter. The average household that uses heating oil as its primary space heating fuel is expected to pay an average of \$3.27/gal this winter, \$0.36/gal lower than projected in last month's STEO. The average household is now expected to spend \$1,779 for heating oil this winter, \$213 lower than in last month's STEO.

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## Natural Gas

Following a strong injection season, working gas in storage ended the summer refill season at an estimated 3,571 Bcf. Sustained cold weather early this year left Lower 48 working gas stocks at 857 Bcf at the end of March, the lowest level since 2003. Beginning in mid-April, weekly storage injections have exceeded the five-year average for 29 consecutive weeks because of strong domestic production growth and a mild summer (implying less demand from electric generators to meet air conditioning demand). In addition, natural gas prices declined over the summer, as strong injections and production eased concerns about supply for this winter. Based on a forecast for a close-to-normal winter, EIA projects that inventories will end the winter season on March 31 at 1,562 Bcf.

**Natural Gas Consumption.** EIA expects total natural gas consumption to average 73.2 Bcf/d in 2014, an increase of 2.2% from 2013, with the industrial sector leading the growth. In 2015, total projected natural gas consumption is expected to be flat as continued industrial sector growth and higher electric power sector consumption offset lower residential and commercial consumption. Higher natural gas prices this year contribute to a 1.7% decline in natural gas consumption in the power sector to 22.0 Bcf/d in 2014. EIA expects natural gas consumption in the power sector to increase to 22.7 Bcf/d in 2015.

**Natural Gas Production and Trade.** EIA expects natural gas marketed production to grow by an annual rate of 4.8% in 2014 and 2.3% in 2015. EIA projects that the strong increases already seen in the Lower 48 states for most of this year will continue, more than offsetting the long-term declining trend in the Gulf of Mexico. As of August, the most recent month for which EIA data are available, dry natural gas production was 3.4 Bcf/d greater than it was in August 2013. Production usually declines in September; however, preliminary data indicate that growth has continued, with new production offsetting maintenance declines.

Growing domestic production is expected to continue to put downward pressure on natural gas imports from Canada and spur exports to Mexico. Exports to Mexico, particularly from the Eagle Ford Shale in South Texas, are expected to increase because of growing demand from Mexico's electric power sector and flat Mexican production.

Liquefied natural gas (LNG) imports have fallen over the past four years because higher prices in Europe and Asia are more attractive to sellers than the relatively low prices in the United States. LNG exports are still a very small part of the total market, however, and overall the United States will remain a net importer of natural gas because of pipeline imports from Canada.

**Natural Gas Inventories.** Natural gas working inventories totaled 3,571 Bcf as of October 31, which was 238 Bcf lower than at the same time last year and 261 Bcf lower than the previous five-year (2009-13) average. The injection season began somewhat slowly in April, but has continued at a strong pace, with injections above the five-year average throughout most of the injection season. The deficit to the five-year average and to last year's level has narrowed over

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the injection season with substantial weekly stock builds. Heading into next summer, EIA projects that end-of-March 2015 inventories will total 1,562 Bcf, 94 Bcf below the five-year (2010-14) average.

**Natural Gas Prices.** The Henry Hub natural gas spot price averaged \$3.78/MMBtu in October, a decline of 14 cents from September. EIA expects spot prices to remain relatively low but to rise slightly with winter heating demand. Projected Henry Hub natural gas prices average \$4.44/MMBtu in 2014 and \$3.83/MMBtu in 2015.

Natural gas futures prices for February 2015 delivery (for the five-day period ending November 6) averaged \$4.19/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for February 2015 contracts at \$2.76/MMBtu and \$6.38/MMBtu, respectively. At this time last year, the natural gas futures contract for February 2014 averaged \$3.57/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$2.70/MMBtu and \$4.73/MMBtu.

## Coal

According to data compiled by the Association of American Railroads (AAR), [year-to-date rail traffic](#) was up 4.5% as of November 1. AAR data show that, despite the large increase in overall rail traffic, [coal shipments](#) were only up 0.3%. Shipments of petroleum and grain are up year-to-date by 13.4% and 15.0%, respectively.

On October 8, the U.S. Surface Transportation Board (STB) announced that it is requiring all major freight (Class I) railroads that operate in the United States to publicly file [weekly data reports](#) regarding service performance. The measure was in response to ongoing rail service problems, particularly in the Midwest. These data, for which no ending date for their submission has been determined, are in addition to the STB annual requests for service assessments from all Class I railroads.

Several utilities in Minnesota and other Midwest states have cut back or curtailed operation of coal-fired generating units to conserve coal inventories. As a result, the governor of Minnesota and members of the state's congressional delegation [requested](#) that the Federal Energy Regulatory Commission (FERC) act to "convene a meeting to hear from utility and railroad representatives to discuss railroad coal-delivery matters and their impact on electric markets and reliability." The letter asked FERC "to protect utility consumers in Minnesota and the other impacted states from the adverse consequences of BNSF's service failures." BNSF, in a [response](#) to a petition filed earlier, stated to the STB that it would deliver approximately 24 million tons of coal in October, its highest total since August 2013.

**Coal Supply.** EIA estimates that coal production for the first 10 months of this year, 823 million short tons (MMst), was slightly lower (by 2 MMst, or 0.3%) than production over the same

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period last year. EIA expects that annual production will grow by 0.8% to 992 MMst in 2014. In 2015, forecast U.S. coal production increases by 0.7% to 999 MMst.

Electric power sector coal inventories fell to 121 MMst at the end of August, 4 MMst lower than the previous month. This stock drawdown was 1 MMst less than the same time last year. Coal inventories are more than 33 MMst lower when compared with last year.

**Coal Consumption.** Higher electricity demand and higher power sector natural gas prices are contributing to an increase in electric power sector coal consumption this year. EIA projects total coal consumption of 936 MMst in 2014 (870 MMst in the electric power sector), an increase of 1.2% from last year. Total coal consumption is projected to fall by 1.2% in 2015, as retirements of coal power plants rise in response to the implementation of the [Mercury and Air Toxics Standards](#), electricity sales growth slows to 0.7%, and natural gas prices fall relative to coal prices.

**Coal Trade.** Exports of coal are projected to decline to 96 MMst in 2014 from 118 MMst in 2013, primarily because of slowing world coal demand growth, lower international coal prices, and increasing coal output in other coal-exporting countries. With no improvement in conditions in global markets, EIA projects coal exports to fall below 90 MMst in 2015, the lowest since 2010.

EIA expects coal imports, which account for about 1% of U.S. coal consumption, to total 11.4 MMst in 2014 and fall slightly to 10.7 MMst in 2015.

**Coal Prices.** The annual average coal price to the electric power industry fell from a historically high \$2.39/MMBtu in 2011 to \$2.35/MMBtu in 2013. EIA expects the average delivered coal price to be \$2.36/MMBtu in 2014 and remain at that level in 2015.

## Electricity

Nuclear plant outages during October 2014 averaged 9% more than in October 2013, as some plants on 18-month schedules refueled their units and performed other maintenance. The Vermont Yankee nuclear facility will only be operating for another month or two before beginning the process of retiring. The closure of this plant [will have a measureable impact](#) on the mix of fuels used for supplying electricity to the region. In recent years, the electricity industry in New England has been moving toward natural gas as a primary fuel for power generation, along with [increased imports of hydroelectricity](#) from Canada.

**Electricity Consumption.** Total U.S. electricity retail sales, which increased by 0.2% in 2013, grow by 0.9% and 0.7% in 2014 and 2015, respectively. U.S. residential electricity sales during 2014 are estimated to reach an average that is 1.5% higher than 2013, driven primarily by high consumption during the winter months earlier in the year. EIA expects relatively flat residential sales during 2015 as weather returns closer to normal levels.

**Electricity Generation.** EIA estimates that U.S. electricity generation in 2014 will average 11.2 terawatt-hours per day (TWh/d), which would be 0.1 TWh/d higher than average generation last year. Relative fuel costs have favored coal-fired generation over natural gas this year, leading to an expected increase in coal's share of total generation from 39.1% in 2013 to 39.6% this year, while the share supplied by natural gas falls from 27.4% to 27.0%. In 2015, EIA expects that natural gas's fuel share will rise to 27.6% and coal's fuel share will decline to 38.8%. Within the Northeast region, the share of total generation supplied by nuclear power falls from 35.1% in 2014 to 33.2% in 2015.

**Electricity Retail Prices.** EIA expects the U.S. residential price to average 12.5 cents per kilowatt-hour in 2014, which is 3.0% higher than the average last year. Prices increase in all regions of the country except along the Pacific Coast. Average U.S. residential electricity prices grow at a slower rate of 1.7% in 2015.

## Renewables and Carbon Dioxide Emissions

California's drought, which began in 2011, has [significantly limited hydropower](#), requiring generation from other sources to make up for the shortfall. While the drought's effect on hydropower generation is most noticeable in California, the western United States as a whole has experienced a decline. Conventional hydropower, which is seasonal and typically peaks in the late spring and early summer, contributed 40% of electric power generation in the western United States in May 2011. That monthly maximum has steadily declined each year since. In May 2014, the maximum monthly contribution to western generation by the electric power sector from hydropower was 30%.

**Electricity and Heat Generation from Renewables.** EIA projects that total renewables used for electricity and heat generation will grow by 1.8% in 2014. Conventional hydropower generation is projected to fall by 4.2%, while nonhydropower renewables rise by 5.1%. [Nonhydropower renewables generation surpasses hydropower](#) on an annual basis for the first time in 2014. In 2015, total renewables consumption for electric power and heat generation increases by 4.5% as a result of a 4.2% increase in hydropower and a 4.6% increase in nonhydropower renewables.

EIA projects that wind power capacity will increase by 7.6% in 2014 and 17.8% in 2015. Electricity generation from wind is projected to contribute 4.7% of total electricity generation in 2015.

EIA expects continued robust growth in utility-scale solar power generation to an average of more than 60 gigawatt-hours per day in 2015, although this remains a small share (0.6%) of total U.S. generation. While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity slightly more than doubled in 2013. EIA expects that utility-scale solar capacity will nearly double again between the end of 2013 and the end of 2015; about two-thirds of this new capacity is being built in California. However, customer-sited photovoltaic capacity growth, which the STEO does not forecast, is

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expected to exceed utility-scale solar growth between 2013 and 2015, according to [EIA's Annual Energy Outlook 2014](#).

**Liquid Biofuels.** Ethanol production in June matched the monthly average production record of 959,000 bbl/d set in December 2011, and then fell back to an estimated average of 911,000 bbl/d in October. EIA expects ethanol production to average 927,000 bbl/d in 2014 and 934,000 bbl/d in 2015. Biodiesel production averaged 89,000 bbl/d in 2013 and is forecast to average 80,000 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 2.5% in 2013](#) from the previous year. [Emissions are forecast to rise by 1.0% in 2014](#), primarily because of cold weather early in the year, and then to decline by 0.1% in 2015. The increase in total emissions in 2013 and 2014 reflects increases in emissions from coal of 4.2% and 1.2%, respectively. The price of natural gas to electric power generators was \$0.91/MMBtu above its 2012 level in 2013 and is expected to rise by \$0.83/MMBtu in 2014, contributing to an increase in coal use. Coal emissions are projected to decline by 1.0% in 2015.

## U.S. Economic Assumptions

**Recent Economic Indicators.** The U.S. Bureau of Economic Analysis (BEA) reported that third-quarter [real gross domestic product \(GDP\)](#) grew at an annualized rate of 3.5% from the second quarter of 2014. Third-quarter GDP rose primarily because of increased government expenditures and exports. Results from other economic data show mixed impacts on consumption and investment. The Census Bureau reported that [new home sales](#) in September rose by 0.2% over August 2014 levels, and by 17.0% over September 2013 levels. Census also reported that [new orders for durable goods](#) fell by 1.3% from August to September, and fell by 0.2% excluding transportation. [Real personal consumption expenditures](#) fell by 0.2% from August to September, according to BEA, although real personal disposable income was unchanged during this time.

EIA used the October 2014 version of the IHS macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the current STEO.

**Production and Income.** Real GDP growth reaches 2.3% in 2014 and accelerates to 2.7% in 2015, above the 2.2% forecast last month for 2014, but below the 2.9% forecast last month for 2015. The combination of increased investment spending and higher exports is behind the stronger 2014 forecast. The projection for real GDP growth in 2015 has been lowered because of reduced expectations for growth in exports, resulting from a stronger dollar and less demand from slower-growing economies. Real disposable income grows by 2.6% in 2014, just above the 2.5% forecast last month, and total industrial production grows at 4.0% in 2014, just below the 4.1% forecast last month. In 2015, these economic indicators grow at 2.7% and 2.9%, respectively.

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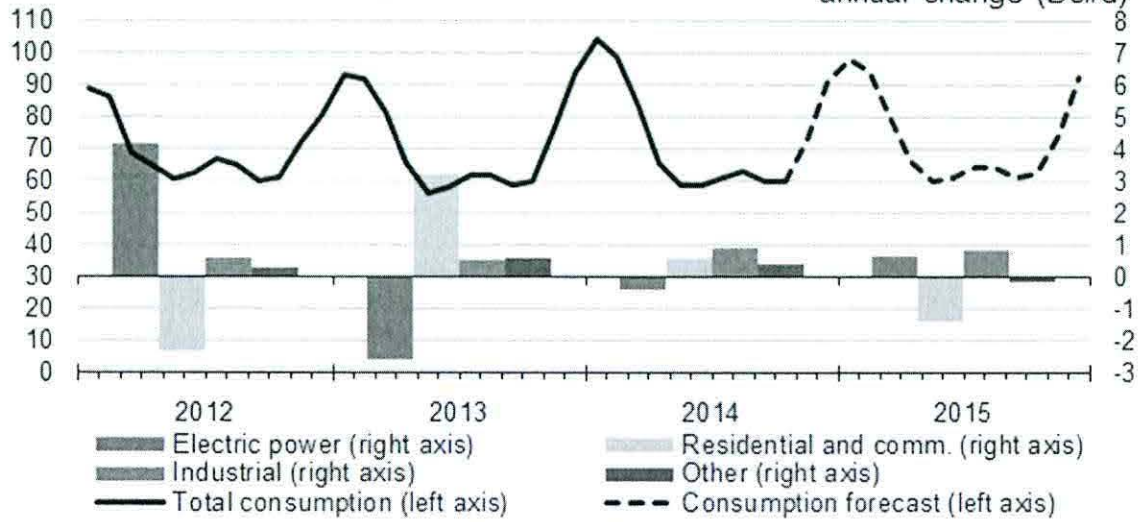
**Expenditures.** Private real fixed investment growth averages 5.5% and 6.9% in 2014 and 2015, respectively. Growth is led by industrial and transportation equipment in 2014 and by a broad array of equipment categories in 2015. Real consumption expenditures grow at the same rate as real GDP in 2014 and 2015, at 2.3% and 2.7%. Durable goods expenditures drive consumption spending in both years. Export growth is 3.1% and 3.6% over the same two years, while import growth is 3.3% in 2014 and 4.0% in 2015. Total government expenditures fall by 0.4% in 2014, but increase by 0.5% in 2015.

**U.S. Employment, Housing, and Prices.** Projected growth in nonfarm employment averages 1.8% in 2014 and 2015. This is accompanied by a gradually declining unemployment rate that reaches 5.6% at the end of 2015. The employment growth in 2015 is the same as projected last month, and the declines in the unemployment rate are slightly greater. Housing starts grow at an average of 7.2% and 19.6% in 2014 and 2015, respectively. Both consumer and producer price indexes increase at a moderate pace, and 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)

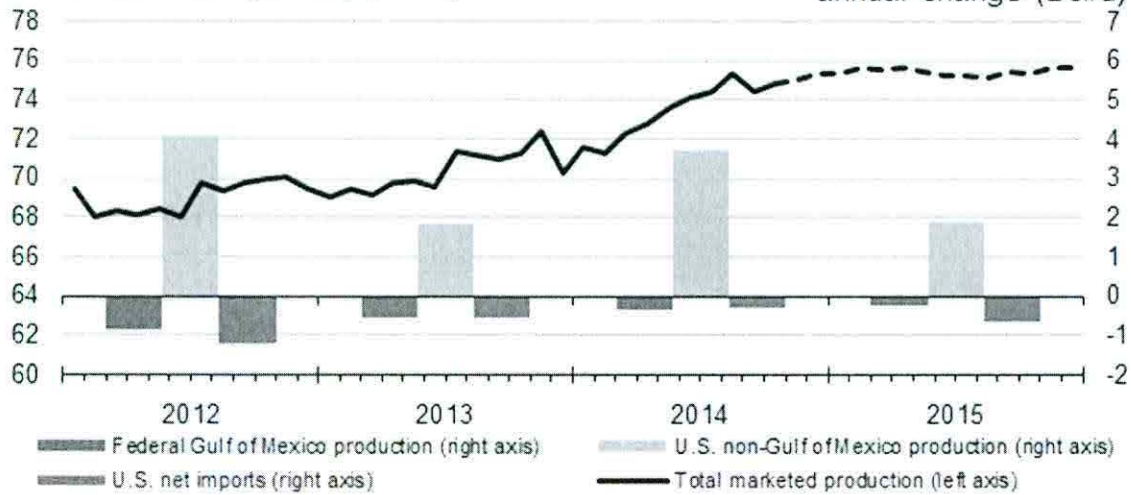


Source: Short-Term Energy Outlook, November 2014.

## U.S. Natural Gas Production and Imports

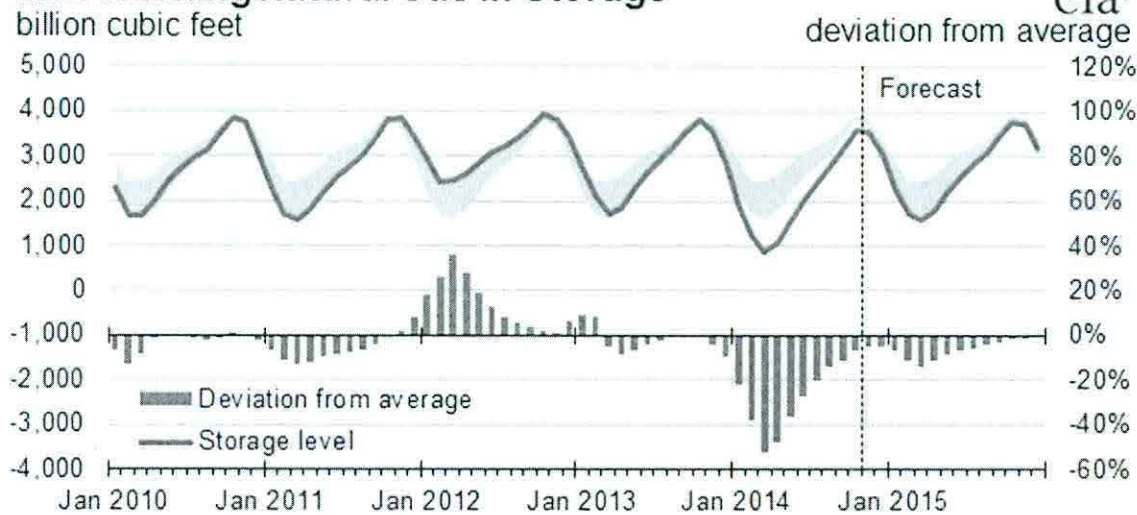
billion cubic feet per day (Bcf/d)

eia  
annual change (Bcf/d)



Source: Short-Term Energy Outlook, November 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, November 2014.

## Henry Hub Natural Gas Price

dollars per million Btu

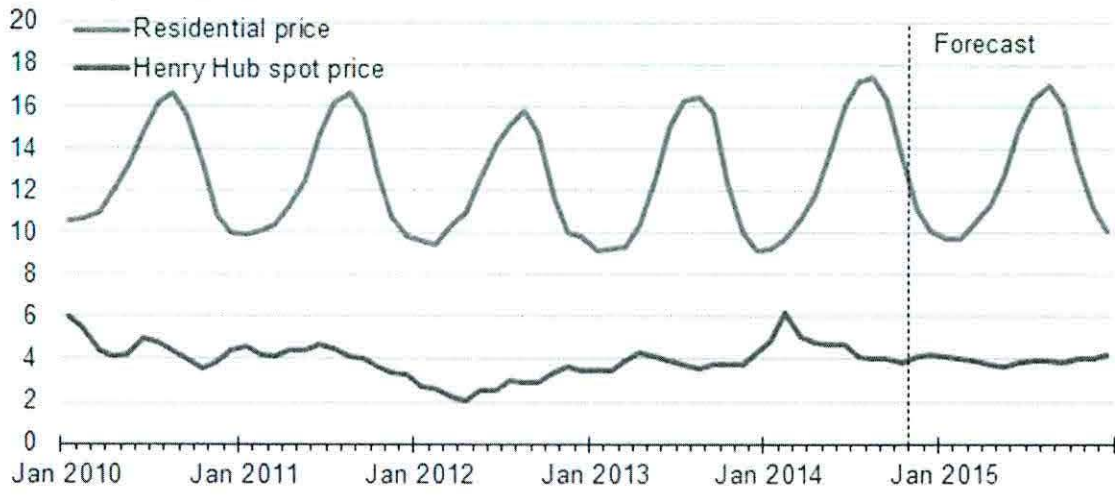


Note: Confidence interval derived from options market information for the 5 trading days ending Nov. 6, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, November 2014.

### U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, November 2014.

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

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ April 30, 2014</b>									<b><u><u>\$404,569</u></u></b>
May 2014	(\$15,520)	0	\$2,700	(\$12,820)	18,641	\$0.9614	\$17,921	(\$30,741)	373,828
June	(1,551)	0	2,475	924	9,300	1.3462	10,015 2/	(9,092)	364,736
July	13,177	0	2,399	15,576	6,189	1.3462	8,331	7,245	371,981
August	13,687	0	2,437	16,124	5,378	1.3462	7,240	8,884	380,865
September	(855)	0	2,486	1,631	6,094	1.3462	8,204	(6,573)	374,292
October	5,798	0	2,424	8,222	9,358	1.3462	12,598	(4,376)	369,916
Total	\$14,736	0	\$14,921	\$29,657	54,960		\$64,309	(\$34,653)	
<b>Balance @ October 31, 2014</b>									<b><u><u>\$369,916</u></u></b>

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

2/ Reflects 6,507.2 dk at \$0.9614 and 2,792.4 dk at \$1.3462.

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

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ April 30, 2014</b>									<b><u>\$388,932</u></b>
May 2014	(\$22,536)	0	\$2,691	(\$19,845)	42,002	\$0.0274	\$1,151	(\$20,996)	367,936
June	(17,420)	0	2,515	(14,905)	19,772	0.9696	5,999 2/	(20,903)	347,033
July	(3,815)	0	2,344	(1,471)	11,279	0.9696	10,936	(12,407)	334,626
August	(6,429)	0	2,239	(4,190)	13,996	0.9696	13,571	(17,761)	316,865
September	(26,713)	0	2,095	(24,618)	13,155	0.9696	12,755	(37,373)	279,492
October	879	0	1,811	2,690	27,455	0.9696	26,620	(23,930)	255,562
Total	(\$76,034)	0	\$13,695	(\$62,339)	127,659		\$71,032	(\$133,370)	
<b>Balance @ October 31, 2014</b>									<b><u>\$255,562</u></b>

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

2/ Reflects 13,980.6 dk at \$0.0274 and 5,791.7 dk at \$0.9696.