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October 30, 2014

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

Re: Cost of Gas Adjustment (COG)  
November 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 (104<sup>th</sup> Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (104<sup>th</sup> Revised Sheet No. 8), showing the November 2014 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.1998 per Dk for residential and firm general service customers and a decrease of \$0.1998 per Dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for November 2014, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.1998 per Dk for all customers since the last COG filing due to a decrease in the market price of gas.

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

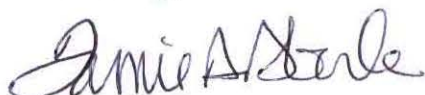
Attachment D shows the calculation of the balancing account since April 30, 2014.

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,

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

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

Canceling 103<sup>rd</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	\$6.6846	\$7.9715 7.7492
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	\$4.8113	\$5.9619 5.7134 5.5599
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All dk \$1.2516	\$4.8113	\$6.0629
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:** October 30, 2014

**Effective Date:** Service rendered on and after November 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

104<sup>th</sup> Revised Sheet No. 8

Canceling 103<sup>rd</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	(1.1438)	1.3462	1.6474	(1.1293)	0.9696	(0.1597)
Current Adj.	0.0000	(0.1998)	0.0000	(0.1998)	(0.1998)	0.0000	(0.1998)
Total Adj.	1.4450	(1.3436)	1.3462	1.4476	(1.3291)	0.9696	(0.3595)
Total Rate	\$1.5112	\$3.8272	\$1.3462	\$6.6846	\$3.8417	\$0.9696	\$4.8113

Date Filed: October 30, 2014

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

Issued By: Tamie A. Aberle  
Director - Regulatory Affairs

Case No.:

**GREAT PLAINS NATURAL GAS CO.  
WAHPETON  
COST OF GAS ADJUSTMENT  
NOVEMBER 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 Cost	1,409,081	1/ 3.8272		5,392,835	3.8272
Gas Cost Reconciliation Adjustment					1.3462
Total Current Firm Gas Cost				\$7,501,865	6.6846
Base Cost of Gas					5.2370
Accumulated Adjustment					\$1.4476
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$3.8272
Gas Cost Reconciliation Adjustment					0.9696
LMS Demand 2/					0.0145
Total Current Interruptible Gas Cost					4.8113
Base Cost of Gas					5.1708
Accumulated Adjustment					(\$0.3595)

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  
NOVEMBER 2014**

**Rates Effective November 1, 2014**

	\$/Dk	
FT-A - Zone 1-1 (Category 1)	\$3.6918	Per Dk/Mo.
FT-A - Zone 1-1 (Category 3)	3.3978	Per Dk/Mo.
FT-A - Seasonal	3.6918	Per Dk/Mo.
TFX	15.1530	Per Dk/Mo.
TFX Seasonal	15.1530	Per Dk/Mo.
LMS Demand	0.9800	Per Dk/Mo.
Estimated Weighted Average Commodity Cost:	3.8272	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**

Firm

Demand 2/	\$0.0662	Per Dk
Commodity	5.1708	Per Dk
Total Firm Base Cost	\$5.2370	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 <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	0.00%
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/ 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: 0.00% for Zone 1-1, 0.00% 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

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		TF5	TFF
	Base	Variable		
Base Tariff Rates 1/				
Summer (Apr-Oct)	5.683	5.683	-0-	5.473
Winter (Nov-Mar)	<u>10.230</u>	<u>13.866</u>	<u>15.153</u>	<u>9.853</u>

COMMODITY RATES 2/		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0364	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/		<u>\$5.683</u>	<u>\$15.153</u>	<u>\$5.473</u>		<u>\$9.853</u>	

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.

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

First Revised Sheet No. 55  
Superseding  
Original Sheet No. 55

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  
November 2014**

The principal 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 November monthly price for the NNG-Ventura Index is expected to decrease from the previous month index. The NNG-Ventura Index is based on negotiated trades during the last five business days of the month, commonly known as bid week, and reported by Platt's Inside FERC's Gas Market Report published the beginning of each month.

For the month of October temperatures across much of the Lower 48 states were mild, without high demand for either heating or cooling. This, in addition to continued record domestic production and storage levels rebounding to more seasonal levels, was likely the contributing factor for the reduction of the November index price. The EIA reported storage levels nationwide as of October 17, 2014 were 9.1 percent below the five-year average and 9.0 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

October 2014

## Short-Term Energy and Winter Fuels Outlook (STEO)

### Highlights

- EIA projects average U.S. household expenditures for natural gas, heating oil, electricity, and propane will decrease this winter heating season (October 1 through March 31) compared with last winter, which was 11% colder than the previous 10-year average nationally. Projected average household expenditures for propane and heating oil are 27% and 15% lower, respectively, because of lower heating demand and prices. Lower heating demand and higher prices contribute to natural gas and electricity expenditures that are 5% and 2% lower than last winter (see EIA [Short-Term Energy Outlook and Winter Fuels Outlook slideshow](#)).
- Driven in large part by falling crude oil prices, U.S. regular gasoline retail prices fell to an average of \$3.41/gallon (gal) in September, 29 cents below the June average. U.S. regular gasoline retail prices are projected to continue to decline to an average of \$3.14/gal in December. EIA expects U.S. regular gasoline retail prices, which averaged \$3.51/gal in 2013, to average \$3.45/gal in 2014 and \$3.38/gal in 2015.
- Weakening global demand helped North Sea Brent crude oil spot prices fall to an average of \$97 per barrel (bbl) in September, the first month Brent prices have averaged below \$100/bbl in more than two years. EIA projects that Brent crude oil prices will average \$98/bbl in fourth-quarter 2014 and \$102/bbl in 2015. The WTI discount to Brent, which averaged \$11/bbl in 2013, is expected to average \$7/bbl in both 2014 and 2015.
- Total U.S. crude oil production averaged an estimated 8.7 million barrels per day (bbl/d) in September, the highest monthly production since July 1986. Total crude oil production, which averaged 7.4 million bbl/d in 2013, is expected to average 9.5 million bbl/d in 2015. If realized, the 2015 forecast would be the highest annual average crude oil production since 1970. 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 September 26 totaled 3.10 trillion cubic feet (Tcf), 0.37 Tcf (11%) below the level at the same time a year ago and 0.40 Tcf (11%) below the previous five-year average (2009-13). Projected natural gas working inventories reach 3.53 Tcf at the end of October, 0.28 Tcf below the level at the same time last year. Despite the lower stocks at the start of this winter's heating season, EIA expects the Henry Hub natural gas

spot price to \$4.00/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.

## Projected Winter Fuel Expenditures by Fuel and Region

The average household winter heating fuel expenditures discussed in this STEO provide a broad guide to changes compared with last winter. However, fuel expenditures for individual households are highly dependent on local weather conditions, market size, the size and energy efficiency of individual homes and their heating equipment, and thermostat settings (see [Winter Fuels Outlook table](#)). Forecast temperatures based on the latest forecasts from the National Oceanic and Atmospheric Administration (NOAA) are much warmer than last winter east of the Rocky Mountains, with the Midwest 16% warmer, the South 12% warmer, the Northeast 11% warmer. However, last winter provides a reminder that weather can be unpredictable, and the Winter Fuels Outlook includes forecasts for scenarios where heating degree days (HDD) in all regions may be 10% higher (colder) or 10% lower (warmer) than forecast.

**Natural Gas.** About half of all U.S. households heat with natural gas, and the average household may expect a 5% decrease in winter natural gas expenditures. EIA projects a 10% decline in residential natural gas consumption this year as temperatures are expected to return to closer-to-normal levels. The savings from lower consumption are partially offset by higher residential prices. Although EIA forecasts lower Henry Hub prices this winter, current spot prices do not directly translate into lower delivered residential prices. Utilities began buying gas in April for the upcoming heating season, and prices in 2014 have averaged higher than last year. Plus, the rates that utilities charge can be set by state utility commissions a year or more in advance.

Under a 10%-colder scenario, EIA projects consumption will be 3% less than last year and expenditures will be 6% greater than last year. Under a 10%-warmer scenario, EIA expects a decline of 17% in consumption and 12% in expenditures compared with last year.

Last winter, [gas-fired power plants in the Northeast](#) had to compete for an increasingly limited amount of available natural gas pipeline capacity from a system that was already constrained, particularly in New England and New York. This caused natural gas spot prices and consequently day-ahead power prices to spike. Pipeline constraints still exist in the area, and day-to-day price volatility is likely. The region has two important marginal sources of supply for times of very high demand: liquefied natural gas (LNG) imports and pipeline imports from Canada. Although LNG imports have declined dramatically in the past several years, GDF Suez still receives cargoes from Trinidad under long-term contracts at its LNG terminal near Boston. One of the terminal's customers is the adjacent Mystic Power Plant. LNG received at the Canaport LNG terminal in New Brunswick, Nova Scotia, also comes to the United States via the Brunswick Pipeline.

Strong production growth this year contributed to a record inventory build. EIA projects working natural gas inventories of 3,532 billion cubic feet (Bcf) at the end of October. EIA

expects working gas inventories to be drawn down to 1,534 Bcf at the end of March 2015. Even in the event of another cold winter, EIA does not expect stocks to fall below 1,000 Bcf by the end of this heating season.

**Heating Oil.** EIA expects households heating primarily with heating oil to spend an average of \$362 (15%) less this winter than last winter, reflecting prices that are \$0.25/gal (6%) lower and consumption that is 10% lower. Heating oil prices are expected to be lower in large part because of lower crude oil prices, with Brent crude oil prices forecast to average \$9/bbl (\$0.22/gal) lower this winter than last. In the 10%-colder-weather scenario, projected expenditures are \$124 lower than last winter, with prices that are \$0.16/gal lower than last winter.

A number of factors contribute to uncertainty in this winter's heating oil market, including weather and oil price volatility, the adequacy of inventories, and changes in fuel specifications. Distillate stocks in the Northeast totaled 29.3 million barrels on September 26, 0.2 million barrels below the same time last year and the lowest level for this time of year since 2000. However, unless severe weather in the Northeast coincides with severe weather in Europe, demand should be readily met via supplies from the Atlantic Basin market.

Reliance on heating oil is highest in the Northeast, where about 23% of households depend on heating oil for space heating. Nationwide, only 5% of households use heating oil. The state of New York, which accounts for about one-third of the region's heating oil market, has required the use of ultra-low sulfur heating oil since July 2012. Five states (Connecticut, Massachusetts, New Jersey, Rhode Island, and Vermont) lowered their heating oil maximum sulfur specification on July 1 from 2,000 parts per million (ppm) (and higher) to 500 ppm. No major impact is expected as suppliers will either blend high-sulfur distillate with ultra-low sulfur diesel (ULSD) or deliver ULSD, which is a readily available fuel.

In January 2015, new regulations will limit marine vessel fuel sulfur levels in certain coastal waters to 1,000 ppm. Some vessels are expected to switch from using residual fuel oil to distillate because of its lower sulfur content. However, the effect on the Northeast heating oil market should be limited because marine fuel demand in this region is relatively small.

**Propane.** About 5% of all U.S. households heat with propane. EIA expects households heating primarily with propane to spend less this winter, but the projected decrease varies across regions. EIA expects that households heating with propane in the Midwest will spend an average of \$767 (34%) less this winter than last winter, reflecting prices that are about 24% lower and consumption that is 13% lower than last winter. Households in the Northeast are expected to spend an average of \$340 (13%) less this winter, with average prices that are about 5% lower and consumption that is 9% lower than last winter.

Heading into the winter months, primary propane stocks in the Gulf Coast (PADD 3) and the Midwest (PADD 2) at the end of September were 6.6 million barrels (18%) and 3.7 million

barrels (15%) higher, respectively, than at the same time last year. Propane spot prices at the Mont Belvieu, Texas and Conway, Kansas delivery points in early October were close to prices at the same time last year. The outlook for propane demand is uncertain given volatility in winter temperatures and another [expected record corn crop](#), which could draw down propane stocks for crop drying. The Cochin Pipeline, which previously delivered propane from Canada to the Midwest, was reversed in early 2014. While this reversal will limit the ability to deliver propane into the region, higher propane production from gas plants in the Midwest and new and expanded rail terminals should help to supply propane to the region this winter.

**Electricity.** Households heating primarily with electricity can expect to spend an average of \$17 (2%) less this winter, with 3% higher prices but 5% less consumption than last winter. About 39% of all U.S. households rely on electricity as their primary heating source, ranging regionally from 15% in the Northeast to 63% in the South.

Under a 10% colder scenario, EIA estimates that U.S. residential electricity consumption this winter would be 1.8% higher than during the winter of 2013-14. Residential electricity prices would not rise immediately, but the effect of colder temperatures would pass through to retail electricity rates over the succeeding months of 2015. For a 10% colder scenario, the average U.S. residential price would rise by 2.7% in 2015 in contrast to the baseline forecast of 1.7% growth. The effect would be greatest in New England where residential prices would rise by 6.0% next year if there's a cold winter, in contrast to the baseline forecast of a 3.6% increase.

[Wholesale electricity prices in the Northeast region spiked last winter](#) because of a winter freeze and constraints on supplying natural gas to power generators. As a result, [retail electricity customers in that area have experienced increases](#) averaging up to 12% so far this year. The natural gas pipeline constraints in New England still exist and deliveries into the region are near capacity. If colder-than-expected temperatures occur this winter, there is the possibility that wholesale electricity prices could rise again. Electricity traders are already factoring in this uncertainty through higher forward market prices for wholesale electricity in the Northeast Independent System Operators.

**Wood.** The use of cord wood and wood pellets as the primary residential space heating fuel has increased by 38% since 2004, to about 2.5 million households in 2013. About 8% of households use wood as a secondary source of heat, making wood second only to electricity as a supplemental heating fuel. About 20% of New England homes (1.1 million) used wood for space heating, water heating, or cooking in 2009 (EIA, [Residential Energy Consumption Survey, 2009](#)), which is nearly twice the national rate. Almost half of all rural households in New England used wood, compared with only 12% of the area's urban households.

## Global Petroleum and Other Liquids

EIA projects world petroleum and other liquids supply to increase by 1.6 million bbl/d in 2014 and by 0.9 million bbl/d in 2015, with most of the growth coming from countries outside of the

Organization of the Petroleum Exporting Countries (OPEC). Forecast non-OPEC supply grows by 1.9 million bbl/d in 2014 and 1.2 million bbl/d in 2015. The United States and Canada account for much of this growth. Projected world liquid fuels consumption grows by an annual average of 1.0 million bbl/d in 2014 and 1.2 million bbl/d in 2015.

Global disruptions to near-term supply have abated since June, when Libya's production and exports were at a minimal level, and violence in northern Iraq escalated, causing northern production (outside of Iraqi Kurdistan) to come nearly to halt. Iraq's southern crude oil exports still remain unaffected by the unrest in northern Iraq. In Libya, production averaged 0.8 million bbl/d in September, its highest level in more than 1 year. However, the security situation in Libya is still precarious, with a significant possibility of intermittent disruptions.

**Global Petroleum and Other Liquids Consumption.** EIA estimates that global consumption grew by 1.3 million bbl/d (1.5%) in 2013, averaging 90.4 million bbl/d for the year. EIA expects global consumption to grow by 1.0 million bbl/d in 2014 and 1.2 million bbl/d in 2015. Projected global oil-consumption-weighted real GDP, which increased by an estimated 2.7% in 2013, grows by 2.7% and 3.3% in 2014 and 2015, respectively.

Consumption outside of the Organization for Economic Cooperation and Development (OECD) is projected to grow by 1.2 million bbl/d in 2014 and 1.1 million bbl/d in 2015, accounting for nearly all forecast global consumption growth during that period. China is the leading contributor to projected global consumption growth, with consumption increasing by 0.37 million bbl/d in both 2014 and 2015.

EIA expects a 0.20-million-bbl/d decline in OECD consumption in 2014. Japan and Europe are expected to account for much of the projected OECD consumption declines. EIA expects Japan's consumption, which fell by 0.16 million bbl/d in 2013, to continue to decline by an annual average of 0.13 million bbl/d in 2014 and 0.14 million bbl/d in 2015. Japan's oil consumption is expected to fall as the country continues to reduce its share of oil used in the electricity sector, replacing it with natural gas, coal, and nuclear power as the country returns some nuclear power plants to service in 2015. EIA projects that OECD Europe's consumption, which fell by 0.15 million bbl/d in 2013, will decline by 0.13 million bbl/d in 2014 and by a further 0.02 million bbl/d in 2015. U.S. consumption, which increased by 0.47 million bbl/d in 2013, is expected to decline by 0.04 million bbl/d in 2014 and then increase by 0.17 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 54.1 million bbl/d for the year. EIA expects non-OPEC production to grow by 1.9 million bbl/d in 2014 and 1.2 million bbl/d in 2015. The United States is the leading contributor to forecast non-OPEC supply growth, increasing by 1.48 million bbl/d in 2014 and 1.23 million bbl/d in 2015. EIA estimates that Eurasia's production will rise by an annual average of 0.08 million bbl/d in 2014 and 0.02 million bbl/d in 2015. This forecast assumes the current economic sanctions on Russia do not affect Russian oil production in the short term.

Unplanned supply disruptions among non-OPEC producers averaged nearly 0.6 million bbl/d in September, down slightly from the previous month. South Sudan, Syria, and Yemen accounted for more than 90% of total non-OPEC supply disruptions. EIA does not assume a disruption to oil supply or demand as a result of ongoing events in Ukraine.

**OPEC Petroleum and Other Liquids Supply.** EIA estimates that OPEC crude oil production averaged 29.9 million bbl/d in 2013, a decline of 0.99 million bbl/d from the previous year, primarily reflecting increased outages in Libya, Nigeria, and Iraq, along with strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.2 million bbl/d in 2014 and by more than 0.4 million bbl/d in 2015 to accommodate growing production in non-OPEC countries.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.2 million bbl/d in September 2014, 0.2 million bbl/d lower than the previous month because of decreased outages in Libya. Libya's production increased to 0.8 million bbl/d in September, 0.3 million bbl/d higher than the previous month, but still well below the 1.4 million bbl/d the country produced before the major blockades started in mid-2013. Libya still faces a considerable challenge in ramping up production to its full capacity or even sustaining it at the current level. Despite the recent production increase, the security situation has deteriorated in parts of the country, and the evacuation of foreign workers is inhibiting production levels from reaching capacity at some fields. As a result, EIA does not expect Libya's oil production to recover to its pre-blockade level over the forecast period.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to average 2.2 million bbl/d in 2014 and 3.0 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 2.62 billion barrels at the end of 2014.

**Crude Oil Prices.** North Sea Brent crude oil spot prices averaged \$97/bbl in September, a decrease of \$5/bbl from August and the first month Brent crude oil prices have averaged below \$100/bbl since June 2012. Brent crude oil prices were driven downward in large part because of weakening global oil demand and higher Libyan oil exports (EIA, *This Week in Petroleum*, September 24, 2014). The forecast Brent crude oil price averages \$104/bbl in 2014 and \$102/bbl in 2015, \$2/bbl lower and \$1/bbl lower than projected in last month's STEO, respectively.

The monthly average WTI crude oil spot price fell from an average of \$97/bbl in August to \$93/bbl in September. High refinery runs contributed to the discount of WTI crude oil to Brent

crude oil falling from an average of \$8/bbl during the first half of this year to an average of \$4/bbl in the third quarter. EIA now expects WTI crude oil prices to average \$91/bbl in the fourth quarter of 2014 and \$95/bbl in 2015. The discount of WTI to Brent crude oil is forecast to widen from current levels, averaging \$7/bbl in the fourth quarter of 2014 and 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 January 2015 delivery, traded during the five-day period ending October 2, averaged \$91/bbl. Implied volatility averaged 19%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in January 2015 at \$76/bbl and \$107/bbl, respectively. Last year at this time, WTI for January 2014 delivery averaged \$102/bbl and implied volatility averaged 20%. The corresponding lower and upper limits of the 95% confidence interval were \$85/bbl and \$121/bbl.

## U.S. Petroleum and Other Liquids

**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 all the major liquid fuels rose, except residual fuel oil. 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 40,000 bbl/d (0.2%), with declines in the consumption of motor gasoline, HGL, residual fuel oil, and other oils offsetting increases in distillate fuel and unfinished oils consumption. Total consumption grows by 170,000 bbl/d in 2015, with HGL consumption accounting for three-fourths of the increase.

Motor gasoline consumption grew by 160,000 bbl/d (1.9%) in 2013, the largest increase since 2004. But consumption of that fuel falls by 20,000 bbl/d (0.2%) in 2014 and by a further 20,000 bbl/d in 2015 as improving fuel economy in new vehicles offsets highway travel growth. Distillate fuel consumption increases by 150,000 bbl/d (3.9%) in 2014, reflecting colder-than-average first-quarter weather and economic growth. Consumption of that fuel rises by a more moderate 70,000 bbl/d (1.9%) in 2015 under assumptions of normal winter weather.

**Liquid Fuels Supply.** The forecast for total U.S. crude oil production increases from 7.4 million bbl/d in 2013 to 8.5 million bbl/d in 2014 and 9.5 million bbl/d in 2015. The highest previous annual average U.S. production level was 9.6 million bbl/d in 1970. Oil production from the Gulf of Mexico is expected to increase from 1.3 million bbl/d in 2013 to 1.6 million bbl/d in 2015, with 11 projects starting this year. Six projects began production in the first half of 2014: Na Kika Phase 3, Mars B, Dalmatian, Entrada, Atlantis Phase 2, and Tubular Bells. Additional wells are expected to come online in the fourth quarter of 2014 from the Cardamom Deep, South Deimos/West Boreas, Hadrian South, Jack/St. Malo, and Lucius projects.

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. Most of this growth is expected to come from additional ethane and propane production that will meet growing demand associated with expanding domestic ethylene and propylene 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 fell from 60% in 2005 to an average of 33% in 2013. EIA expects the net import share to decline to 20% in 2015, which would be the lowest level since 1968.

**Petroleum Product Prices.** Monthly average regular gasoline retail prices fell from \$3.69/gal in June to \$3.41/gal in September. EIA expects average regular gasoline retail prices to continue falling to \$3.14/gal in December. The U.S. annual average regular gasoline retail price, which averaged \$3.51/gal in 2013, is projected to average \$3.45/gal in 2014 and \$3.38/gal in 2015. Diesel fuel prices, which averaged \$3.92/gal in 2013, are projected to fall to an average of \$3.85/gal in 2014 and \$3.80/gal in 2015. 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.

## Natural Gas

**Natural Gas Consumption.** EIA expects that total natural gas consumption to average 72.5 Bcf/d in 2014, an increase of 1.6% from 2013, with the industrial sector leading the growth. In 2015, total natural gas consumption will increase 0.3%, 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 2.3% decline in natural gas consumption in the power sector to 21.8 Bcf/d in 2014. EIA expects natural gas consumption in the power sector to increase to 22.6 Bcf/d in 2015.

**Natural Gas Production and Trade.** EIA expects natural gas marketed production to grow by an annual rate of 5.4% in 2014 and 2.0% in 2015. STEO projects that the strong increases already seen in the Lower 48 states this year will continue, offsetting declines in the Gulf of Mexico. As of July, the most recent month for which EIA data are available, marketed production was 4.2 Bcf/d greater than it was in July 2013.

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.

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 picture, 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 3,100 Bcf as of September 26, which was 373 Bcf lower than at the same time last year and 399 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 (2009-13) average throughout most of the injection season. EIA expects working gas stocks will reach 3,532 Bcf at the end of October, 283 Bcf lower than at the same time last year. Heading into next summer, EIA projects end-of-March 2015 inventories will be 122 Bcf below the five-year (2010-14) average.

**Natural Gas Prices.** The Henry Hub natural gas spot price averaged \$3.92/MMBtu in September, a slight increase from August. EIA expects spot prices to remain below \$4.00/MMBtu through November, before rising with winter heating demand. Projected Henry Hub natural gas prices average \$4.45/MMBtu in 2014 and \$3.84/MMBtu in 2015.

Natural gas futures prices for January 2015 delivery (for the five-day period ending October 2) 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 December 2014 contracts at \$2.96/MMBtu and \$5.94/MMBtu, respectively. At this time last year, the natural gas futures contract for January 2014 averaged \$3.83/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$2.91/MMBtu and \$5.04/MMBtu.

## Coal

According to data compiled by [the Association of American Railroads \(AAR\)](#), [year-to-date rail coal shipments](#) were down by 0.1% as of September 27. AAR data show that total U.S. rail traffic is up 4.4% year-to-date and shipments of petroleum and grain are up by 12.5% and 17.7%, respectively.

Two railways that serve Powder River Basin (PRB) producers, Union Pacific and BNSF, provided the [U.S. Surface Transportation Board \(STB\)](#) with their assessments of their ability to provide rail service for the remainder of the year (fall peak period) and the upcoming winter season. The STB annually requests the assessments from all [Class I railroads](#). Union Pacific stated that it has responded by activating surge resources, which included acquiring more locomotives, hiring more employees, and increasing coal train sizes where possible. [BNSF](#) also plans to expand its locomotive fleet and increase coal train sizes, but they emphasized that their priority will be to transport coal that is currently contracted.

**Coal Supply.** EIA estimates that coal production for the first three quarters of this year, 742 million short tons (MMst), was slightly lower (3 MMst, or 0.4%) than production over the same period last year. Year-to-date production in the West, which includes the PRB, is down by nearly

2 MMst, and has been hindered by rail transportation problems. EIA expects that U.S. coal production will accelerate in the fourth quarter and annual production will grow 1.4% to 998 MMst in 2014. In 2015, forecast U.S. coal production increases by 0.4% to 1,002 MMst.

Electric power sector coal inventories fell to 125 MMst at the end of July, 7 MMst lower than the previous month. This stock drawdown was 4 MMst less than the same time last year. Coal inventory reductions in the Midwest and South, two regions that rely heavily on coal-fired generation, were down 1 MMst and 2 MMst, respectively, when compared with last year.

**Coal Consumption.** Higher electricity demand and higher power sector natural gas prices that are more than 21% above their 2013 level contributed to a 3.0% increase in electric power sector coal consumption for the first seven months of this year from the same period last year. EIA projects total coal consumption of 941 MMst in 2014, an increase of 1.7% from last year. Total coal consumption is projected to fall by 2.0% 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 0.6%, and natural gas prices fall relative to coal prices.

**Coal Trade.** EIA estimates that coal exports for the first seven months of this year were 15.5% (10.9 MMst) lower compared with last year, with tonnage declines for steam coal exports more than 4 times those for metallurgical coal. 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. EIA projects coal exports to remain nearly flat in 2015.

Coal imports for the first seven months of this year increased by 36.5% (1.8 MMst) compared with last year. 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.** Annual average coal prices to the electric power industry fell from \$2.39/MMBtu in 2011 to \$2.35/MMBtu in 2013. EIA expects the average delivered coal prices to be \$2.36/MMBtu in 2014 and remain at that level in 2015.

## Electricity

**Electricity Consumption.** Forecast U.S. sales of electricity to the residential sector are 1.7% higher in 2014 compared with last year, driven in large part by the cold weather experienced early in the year. Residential electricity sales fall by 0.3% in 2015. U.S. commercial sector electricity sales are expected to average 0.9% higher in 2014 than sales last year and then grow by 0.4% in 2015. EIA expects U.S. industrial sector electricity sales to remain flat during 2014 and grow by 2.1% in 2015.

**Electricity Generation.** EIA projects that average daily U.S. electricity generation in 2014 will grow by 105 gigawatthours per day (0.9%) from 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 39.8% this year, while the share supplied by natural gas falls from 27.4% to 26.8%. In 2015, EIA expects that natural gas' fuel share will rise to 27.6% and coal's fuel share will decline to 38.7%.

**Electricity Retail Prices.** EIA expects the U.S. residential price to average 12.5 cents per kilowatthour 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

**Electricity and Heat Generation from Renewables.** EIA projects that total renewables used for electricity and heat generation will grow by 2.2% in 2014. Conventional hydropower generation is projected to fall by 4.2%, while nonhydropower renewables rise by 5.6%. [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 4.6%, as a result of a 4.3% increase in hydropower and a 4.7% increase in nonhydropower renewables.

EIA projects that wind power capacity will increase by 8.8% in 2014 and 16.2% in 2015. Electricity generation from wind is projected to contribute 4.7% 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 0.6% in 2015. 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 about 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 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 average of 909,000 bbl/d in September. EIA expects ethanol production to average 927,000 bbl/d in 2014 and 933,000 bbl/d in 2015. 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 2.5% in 2013 from the previous year. Emissions are forecast to rise by 1.1% in 2014, and then to decline by 0.4% in 2015. The increase in total emissions in 2013 and 2014 reflects increases in emissions from coal of 4.2% and 1.8%, 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 \$0.91/MMBtu in 2014, contributing to an increase in coal use. Coal emissions are projected to decline by 1.9% in 2015.

## U.S. Economic Assumptions

**Recent Economic Indicators.** Economic growth improved substantially in the second quarter of 2014. The U.S. Bureau of Economic Analysis (BEA) reported that second quarter real gross domestic product (GDP) grew at an annualized rate of 4.6% from the first quarter of 2014, which reflects an upward revision of 0.4% from its previous estimate. Recent housing data have been mixed. The Census Bureau reported that new home sales in August rose 18% over July levels, and 33% over levels in August 2013. Existing home sales in August, however, fell by 1.8% from July according to the National Association of Realtors. Census also reported that new orders for durable goods fell 18.2% from July to August, but rose 0.7% excluding transportation.

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

**Production and Income.** Real GDP growth reaches 2.2% in 2014 and accelerates to 2.9% in 2015, similar to the forecast last month. Exports are expected to pick up in the latter half of 2014 relative to imports, but a strong dollar will slow these gains in 2015. Housing starts more than make up for this in 2015. Real disposable income grows by 2.5% in 2014, the same as last month, and total industrial production grows by 4.1% in 2014, up from 3.9% forecast last month. In 2015, these variables grow at 2.5% and 3.7%, respectively.

**Expenditures.** Private real fixed investment growth averages 5.5% and 7.4% in 2014 and 2015, respectively, led by industrial and transportation equipment in 2014 and a broad array of equipment categories in 2015. Real consumption expenditures grow at the same rate as real GDP in 2014 at 2.2%, but fall below the real GDP growth rate in 2015 at 2.6%. Durable goods expenditures drive consumption spending in both years. Export growth is 2.8% and 4.9% over the same two years, while import growth is 3.2% in 2014 and 4.2% 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 5.7% at the end of 2015. The employment growth in 2015 is slower than projected last month and the declines in the unemployment rate are the same. Housing starts grow an average of 8.9% and 25.4% in 2014 and 2015, respectively. Both consumer and producer price indexes increase at a moderate pace, and wages continue to show modest gains.

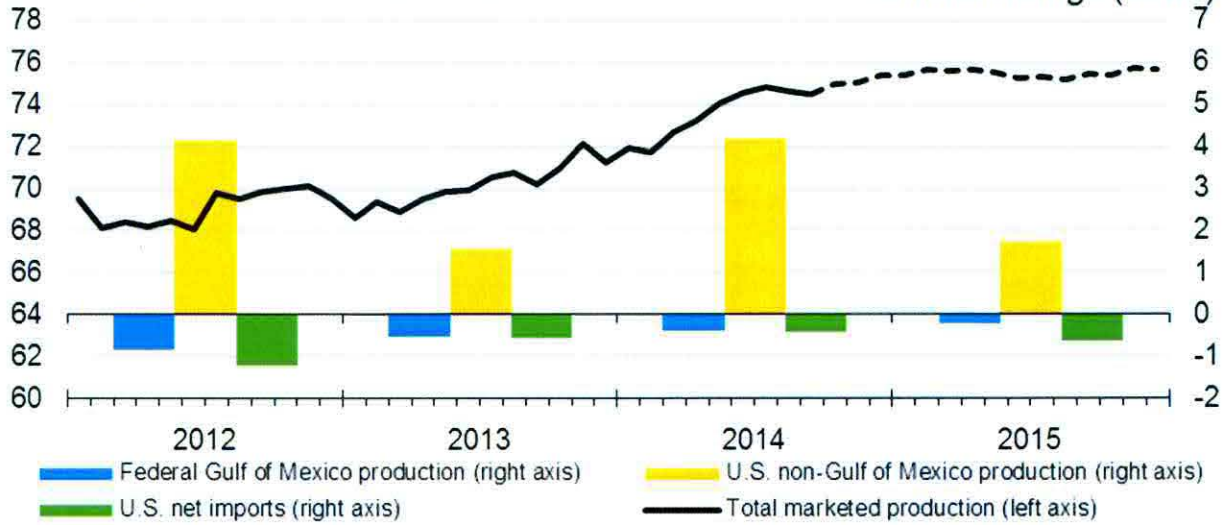
This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views 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 Production and Imports



billion cubic feet per day (Bcf/d)

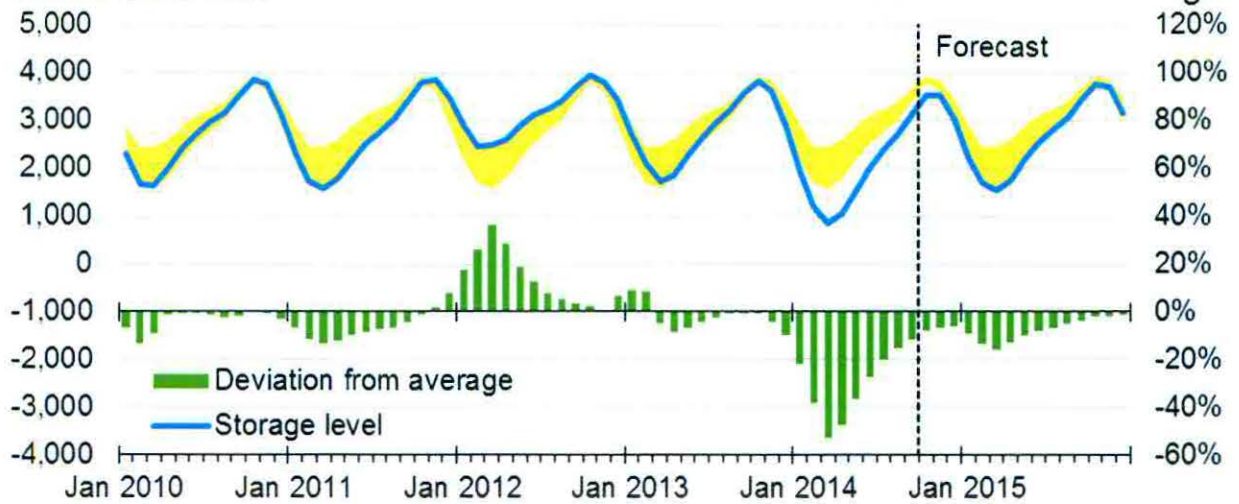
annual change (Bcf/d)



Source: Short-Term Energy Outlook, October 2014.

## U.S. Working Natural Gas in Storage

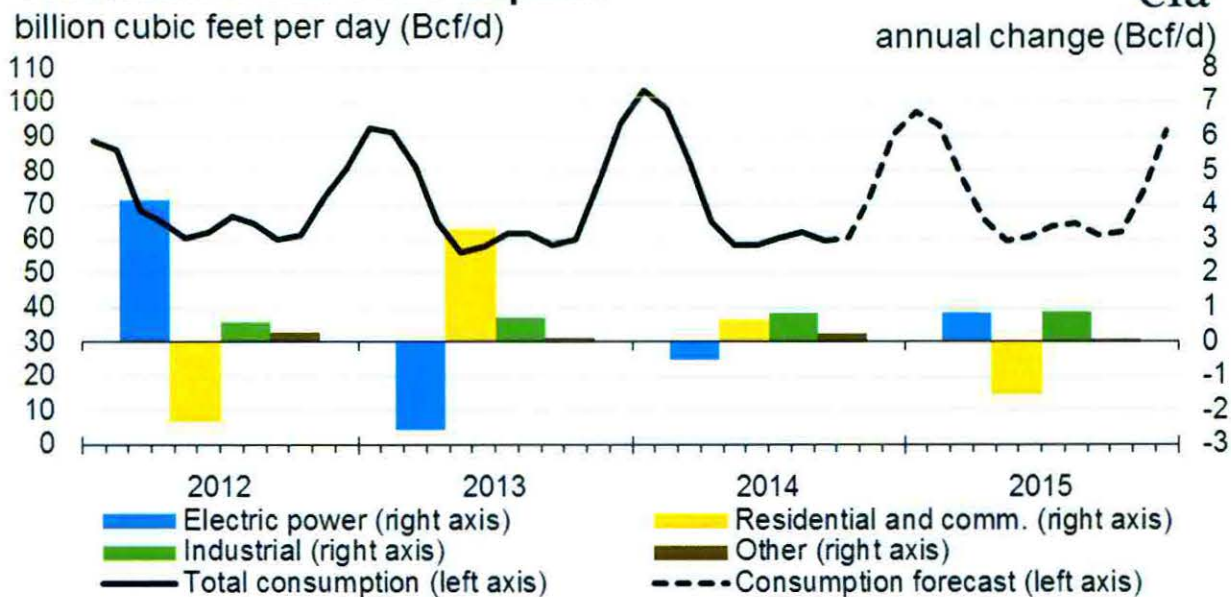
billion cubic feet



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2009 - Dec. 2013.

Source: Short-Term Energy Outlook, October 2014.

## U.S. Natural Gas Consumption



Source: Short-Term Energy Outlook, October 2014.

## Henry Hub Natural Gas Price

dollars per million Btu

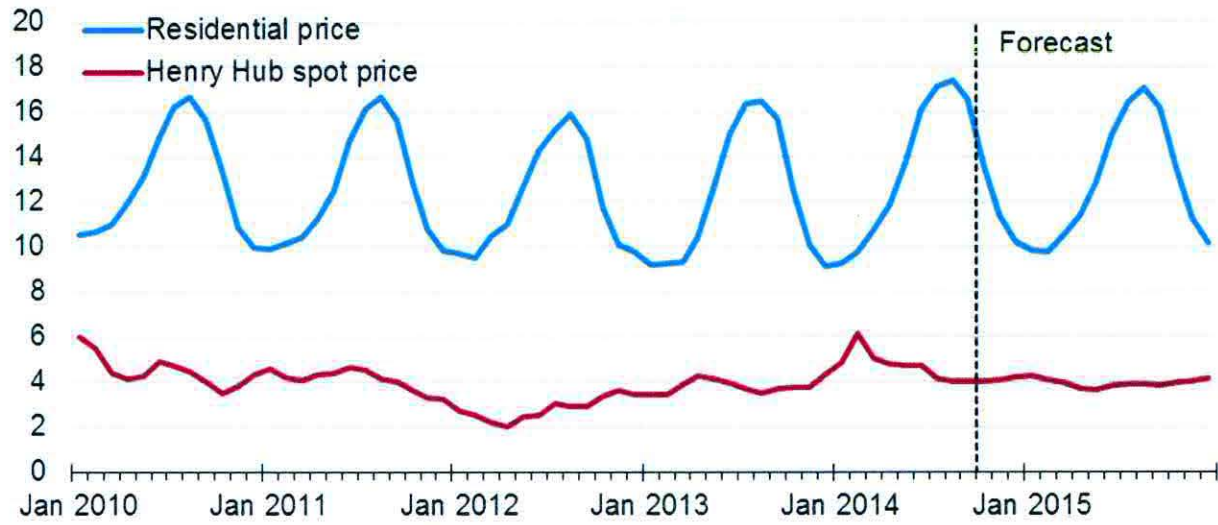


Note: Confidence interval derived from options market information for the 5 trading days ending Oct. 2, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, October 2014.

## U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, October 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>\$404,569</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
Total	<u>\$8,938</u>	<u>0</u>	<u>\$12,497</u>	<u>\$21,435</u>	<u>45,602</u>		<u>\$51,711</u>	<u>(\$30,277)</u>	
<b>Balance @ September 30, 2014</b>									<b><u>\$374,292</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**

	(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
<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
Total	(\$76,913)	0	\$11,884	(\$65,029)	100,204		\$44,412	(\$109,440)	
<b>Balance @ September 30, 2014</b>									<b><u>\$279,492</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.