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July 31, 2015

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

Re: Cost of Gas Adjustment (COG)  
August 2015

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 (113<sup>th</sup> Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (113<sup>th</sup> Revised Sheet No. 8), showing the August 2015 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.1013 per dk for residential and firm general service customers and an increase of \$0.1013 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for August 2015, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.1013 per dk for all customers since the last COG filing due to an increase in the market price of gas.

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

Attachment D shows the calculation of the balancing account since April 30, 2015.

New rates will be implemented effective with service rendered on and after August 4, 2015, in order to accommodate changes within the billing system.

Great Plains submitted a check for \$650.00 on November 26, 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 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 that reads "Tamie A. Aberle". The signature is written in a cursive style with a large initial "T" and "A".

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

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

Canceling 112<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 Over 10 dk	\$1.2869 1.0646	\$4.6749	\$5.9618 5.7395
Interruptible Gas Service - General	3	\$3.50 per month	First 400 dk Next 2,600 dk Over 3,000 dk	\$1.1506 0.9021 0.7486	\$2.9121	\$4.0627 3.8142 3.6607
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All dk	\$1.2516	\$2.9121	\$4.1637
Transportation Service	5	\$3.50 per month	First 400 dk Next 2,600 dk Over 3,000 dk	\$1.1506 0.9021 0.7486		\$1.1506 0.9021 0.7486

**Date Filed:** July 31, 2015

**Effective Date:** Service rendered on and after August 4, 2015

**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  
113<sup>th</sup> Revised Sheet No. 8  
Canceling 112<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.	1.5320	(2.4061)	0.2107	(0.6634)	(2.4061)	0.0461	(2.3600)
Current Adj.	0.0000	0.1013	0.0000	0.1013	0.1013	0.0000	0.1013
Total Adj.	1.5320	(2.3048)	0.2107	(0.5621)	(2.3048)	0.0461	(2.2587)
Total Rate	\$1.5982	\$2.8660	\$0.2107	\$4.6749	\$2.8660	\$0.0461	\$2.9121

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Director - Regulatory Affairs

**Case No.:**

**GREAT PLAINS NATURAL GAS CO.  
WAHPETON  
COST OF GAS ADJUSTMENT  
AUGUST 2015**

<u>Firm</u>	<u>Billing</u> <u>Determinants</u>	<u>Rate</u>	<u>Demand</u> <u>Months</u>	<u>Amount</u>	<u>Amount</u> <u>Per dk</u>
FT-A - Zone 1-1	8,000	\$4.3706	12	\$419,578	\$0.2950
FT-A - Zone 1-1	5,000	4.7507	5	118,768	0.0835
FT-A Seasonal	2,000	4.7507	5	47,507	0.0334
TFX Seasonal	2,000	15.1530	5	151,530	0.1065
TFX - Winter	13,000	15.1530	5	984,945	0.6925
TFX - Summer	13,000	5.6830	7	517,153	0.3636
BP Seasonal Contract	500	2/	3	33,750	0.0237
Total Demand Charges				<u>\$2,273,231</u>	<u>1.5982</u>
Estimated Weighted Average Commodity Cost	1,422,210	1/ 2.8660		<u>4,076,054</u>	<u>2.8660</u>
Gas Cost Reconciliation Adjustment					<u>0.2107</u>
Total Current Firm Gas Cost				<u><u>\$6,349,285</u></u>	<u><u>4.6749</u></u>
Base Cost of Gas					<u>5.2370</u>
Accumulated Adjustment					<u><u>(\$0.5621)</u></u>
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					<u>\$2.8660</u>
Gas Cost Reconciliation Adjustment					<u>0.0461</u>
Total Current Interruptible Gas Cost					<u>2.9121</u>
Base Cost of Gas					<u>5.1708</u>
Accumulated Adjustment					<u><u>(\$2.2587)</u></u>

1/ Three year normalized average Dk sales

2/ 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  
AUGUST 2015**

<b>Rates Effective August 1, 2015</b>	<u>\$/Dk</u>	
FT-A - Zone 1-1 (Category 1)	\$4.7507	Per Dk/Mo.
FT-A - Zone 1-1 (Category 3)	4.3706	Per Dk/Mo.
FT-A - Seasonal	4.7507	Per Dk/Mo.
TFX	15.1530	Per Dk/Mo.
TFX Seasonal	15.1530	Per Dk/Mo.
Estimated Weighted Average Commodity Cost:	2.8660	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**

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

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

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

2/ Demand base rate calculation:

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

STATEMENT OF RATES  
 (Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
<b>Category 1 (Contract Term of Less than 3 Years)</b>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$4.7507
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate 1/	\$5.7394
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$3.3143
Zone 2-2 Minimum Rate	\$0.0000
<b>Category 2 (Contract Term of 3 Years to less than 5 Years)</b>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$4.5607
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$5.5494
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$3.1243
Zone 2-2 Minimum Rate	\$0.0000
<b>Category 3 (Contract Term of 5 or more Years)</b>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$4.3706
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$5.3593
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$2.9343
Zone 2-2 Minimum Rate	\$0.0000

1/ 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	\$0.0116	0.00%
Zone 1-2	\$0.0116	0.00%
Zone 2-2	\$0.0116	0.00%
Minimum Rate	\$0.0116	
IT and AOT		
Zone 1-1	\$0.1678	0.00%
Zone 1-2	\$0.2003	0.00%
Zone 2-2	\$0.1206	0.00%
Minimum Rate	\$0.0116	

- 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	\$1.00		\$1.00
LMS – Daily Overrun Rate	\$0.2003		\$0.2003
LMS – Load Management Cost Reconciliation Adjustment		(\$0.0528)	

- 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	\$0.2003	\$0.0000
RPL Service:		
Daily Reservation Rate	\$0.2003	\$0.0000

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

Eighth Revised Sheet No. 50  
Superseding  
Seventh Revised Sheet No. 50

RATE SCHEDULE TF

RESERVATION RATES	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
	TF12		TF5	TFF
	TF12 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/		Field Mileage 5/				Carlton		Out-of Balance 3/	
TF12 Base, TF12 Var., TF5 & TFF	Market Area 3/	Rate per 100 miles		Surcharges 4/					
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0369	0.0200			0.0175	0.0000	0.0369	0.0200
Field	Market	0.0369	0.0200	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 \$0.0010 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

Ninth Revised Sheet No. 51  
Superseding  
Eighth 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	0.0369	0.0200			0.0175	0.0000	0.0369	0.0200
Field	Market	0.0369	0.0200	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
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 \$0.0010 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at <http://www.ferc.gov>.
- 4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
- 5/ Where applicable, the Field Area Compression charge of \$0.0000 and the ACA unit surcharge as set forth on FERC's website at <http://www.ferc.gov> will be added to the mileage based rates.
- 6/ In addition to the Maximum and Minimum rates, Shipper shall pay the ACA unit surcharge as posted on FERC's website at <http://www.ferc.gov>.

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

Fuel Percentages/Electric Compression Rates

	<u>Percentages</u>
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.62%
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	\$0.0010
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, 2014. For deliveries subject only to UAF, the UAF rate is zero; provided, however Northern will issue a volume credit on the Shipper's monthly imbalance statement equivalent to -0.09% for the period April 2015 through March 2016 for such deliveries.

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  
August 2015**

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 August 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.

Hot weather over much of the U.S. resulting in increased demand for electric generation and maintenance outages at coal and nuclear sites likely contributed to the expected increase in the monthly index. Production continues to be at or near historical highs and the national storage level has recovered to slightly higher than the five year average. The EIA reported nationwide storage levels as of July 17, 2015 at 2.9 percent above the five-year average and 28.2 percent above 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

July 2015

## Short-Term Energy Outlook (STEO)

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### Highlights

- North Sea Brent crude oil prices averaged \$61/barrel (b) in June, a \$3/b decrease from May. Crude oil prices fell by about \$4/b on July 6 in the aftermath of the "no" vote in Greece on the economic program, as well as lingering concerns about lower economic growth in China, higher oil exports from Iran, and continuing growth in global petroleum and other liquids inventories. A percent price change of this extent on a single day is unusual, but despite daily price volatility, monthly Brent crude oil prices have averaged between \$55/b and \$65/b per month since falling to \$48/b in January.
- EIA forecasts that Brent crude oil prices will average \$60/b in 2015 and \$67/b in 2016. Forecast West Texas Intermediate (WTI) crude oil prices in both 2015 and 2016 average \$5/b less than the Brent price. The current values of futures and options contracts for December 2015 delivery (*Market Prices and Uncertainty Report*) suggest the market expects WTI prices in December 2015 to range from \$41/b to \$89/b (at the 95% confidence interval).
- U.S. regular gasoline monthly average retail prices reached \$2.80/gallon (gal) in June, an increase of 8 cents/gal from May but 89 cents/gal lower than in June 2014. The price rise between May and June reflects signals of strong gasoline demand in the United States and abroad. EIA expects monthly average gasoline prices to decline gradually from their June level to an average of \$2.49/gal during the second half of 2015. EIA forecasts U.S. regular gasoline retail prices to average \$2.48/gal for all of 2015.
- EIA estimates total U.S. crude oil production declined by 50,000 barrels per day (b/d) in May compared with April. Production is expected to generally continue falling through early 2016 before growth resumes. Projected U.S. crude oil production averages 9.5 million b/d in 2015 and 9.3 million b/d in 2016.
- Natural gas working inventories were 2,577 billion cubic feet (Bcf) on June 26, which was 35% higher than a year earlier and 1% higher than the previous five-year average (2010-14). Although injections have been strong most weeks, hot temperatures and high demand from the electric power sector contributed to lower-than-average injections during late June. Nevertheless, working inventories are on pace to end the injection season above the previous five-year average. EIA projects end-of-October stocks will be 3,919 Bcf, 121 Bcf (3.2%) more than the five-year average.

## Global Petroleum and Other Liquids

Global liquids production continues to exceed consumption, resulting in inventory builds. Global oil inventory builds are estimated to have averaged 2.2 million b/d through the first half of 2015 and are projected to average 1.5 million b/d during the second half of the year. The slowing increases in inventory reflect rising demand and slowing production growth outside of the Organization of the Petroleum Exporting Countries (OPEC), particularly in the United States. The expected inventory builds in 2015 are on top of an estimated 0.9 million b/d increase in 2014. By 2016, inventory builds are expected to moderate to 0.6 million b/d.

**Global Petroleum and Other Liquids Consumption.** EIA estimates global consumption of petroleum and other liquids grew by 1.1 million b/d in 2014, averaging 92.4 million b/d for the year. EIA expects global consumption of petroleum and other liquids to grow by 1.3 million b/d in 2015 and by 1.4 million b/d in 2016. Projected real gross domestic product (GDP) weighted for oil consumption, which increased by an estimated 2.8% in 2014, is projected to grow by 2.5% in 2015 and by 3.1% in 2016.

Consumption of petroleum and other liquids outside Organization for Economic Cooperation and Development (OECD) countries grew by 1.4 million b/d in 2014 and is projected to grow by 0.8 million b/d in 2015 and by 1.1 million b/d in 2016. Lower forecast growth for non-OECD consumption in 2015 mostly reflects a 0.2 million b/d decline in Russia's consumption as a result of the country's economic downturn. Russia's oil consumption is expected to decline by a similar amount in 2016, although it is offset by growth elsewhere. China's economic growth slowed in the second half of 2014 and in the beginning of 2015. However, China remains the main source of non-OECD oil consumption growth, with a projected annual average increase of 0.3 million b/d in both 2015 and 2016, down from growth of 0.4 million b/d in 2014. India's economic and manufacturing growth continued to rise in the first half of 2015, and EIA projects India's petroleum and other liquids consumption will increase by 0.2 million b/d in 2015 and 2016, compared with 0.1 million b/d in 2014.

OECD petroleum and other liquids consumption, which fell by 0.4 million b/d in 2014, is expected to grow by 0.4 million b/d in 2015 and by 0.3 million b/d in 2016. Japan and Europe accounted for nearly all of the 2014 decline in OECD oil consumption. Japan's consumption is expected to continue declining over the next two years, albeit at a slower rate than in 2014, while Europe's consumption is expected to grow slowly. The United States is the leading contributor to projected OECD consumption growth in 2015, with U.S. consumption increasing by 0.4 million b/d, while consumption in both the United States and Europe increases by about 0.1 million b/d in 2016. The degree to which global oil demand responds to lower oil prices is only beginning to become apparent in the data, and, if that response deviates from forecast values, it could affect market balances and prices.

**Non-OPEC Petroleum and Other Liquids Supply.** EIA estimates that non-OPEC petroleum and other liquids production grew by 2.3 million b/d in 2014, which mainly reflects production growth in the United States. EIA expects non-OPEC production to grow by 1.4 million b/d in

2015 and by 0.2 million b/d in 2016. After remaining relatively flat in 2015, production in Eurasia is projected to decline by 0.1 million b/d in 2016. The projected decline reflects reduced investment in Russia's oil sector stemming from low oil prices and international sanctions.

Unplanned supply disruptions among non-OPEC producers averaged about 0.8 million b/d in June 2015, unchanged compared with the previous month as May outages in Canada extended into June. Wildfires in western Canada that started in the second half of May led to oil sands production outages averaging about 0.1 million b/d for May and June. Oil sands projects that had been shut down because of the fires resumed production in the second week of June. Recent violence in Yemen continues to interrupt operations at an oil port and refinery. South Sudan, Syria, and Yemen accounted for more than 75% of total non-OPEC supply disruptions in June.

**OPEC Petroleum and Other Liquids Supply.** EIA estimates that OPEC crude oil production averaged 30.1 million b/d in 2014, unchanged from the previous year. Crude oil production declines in Libya, Angola, Algeria, and Kuwait offset production growth in Iraq and Iran. EIA forecasts OPEC crude oil production to increase by 0.6 million b/d in 2015 and decrease by 0.2 million b/d in 2016. Iraq is expected to be the largest contributor to OPEC production growth in 2015. At the OPEC meeting on June 5, the group did not change its 30 million b/d crude oil production target. EIA forecasts OPEC crude oil production will continue to exceed that target over the forecast period, contributing to expected global inventory builds.

On April 2, Iran and the five permanent members of the United Nations Security Council plus Germany (P5+1) reached a framework agreement to guide negotiations targeting a comprehensive agreement by June 30. Negotiations continued beyond the June 30 target, and July 7 was agreed as the new target date for a comprehensive agreement. However, no agreement had been reached by the time of this writing. A comprehensive agreement could result in the lifting of oil-related sanctions against Iran and a subsequent increase in Iran's crude oil production and exports, although the timing and details of any suspension of sanctions are uncertain. EIA has not changed its short-term projection for Iranian crude oil production, which assumes that production will stay close to the current level.

Iran produced 3.6 million b/d of crude oil in late 2011, before the recent round of sanctions was enacted. The sanctions forced Iran to shut in a substantial portion of its production, lowering output to an estimated 2.9 million b/d in June 2015. Iran's ability to bring online previously shut-in volumes and increase exports depends on several factors, including the current condition of oil fields and infrastructure that were shut in, the pace of sanctions relief, and the ability of Iran to find buyers in the present market. If a comprehensive agreement is reached, EIA estimates that the re-entry of more Iranian oil could result in a \$5/b-\$15/b lower baseline STEO price forecast for 2016 (see the analysis box on page 5 of the April 2015 STEO for further discussion).

OPEC noncrude liquids production, which averaged 6.3 million b/d in 2014, is expected to increase by 0.1 million b/d in 2015 and by 0.2 million b/d in 2016, led by production increases in Qatar, Iran, and Kuwait.

In June, unplanned crude oil supply disruptions among OPEC producers averaged 2.5 million b/d, unchanged from May. Higher disruptions in May in Kuwait and Saudi Arabia extended into June. Production at the Wafra field, located in the Neutral Zone that straddles Kuwait and Saudi Arabia, ceased in mid-May as the operators attempted to resolve a contract dispute. The continued suspension of Wafra's production increased disruptions in June by a total of 0.1 million b/d, split between Kuwait and Saudi Arabia. This suspension came after the previous production shut-in at the Khafji field in the Neutral Zone.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to decrease to an average of 1.8 million b/d in 2015 and increase to 2.1 million b/d in 2016, after averaging 2.0 million b/d in 2014. Surplus capacity is typically an indication of market conditions, and surplus capacity below 2.5 million b/d is an indicator of a relatively tight oil market, but the current and forecast levels of global inventory builds make the projected low surplus capacity level in 2015 less significant.

**OECD Petroleum Inventories.** EIA estimates that OECD commercial oil inventories totaled 2.69 billion barrels at the end of 2014, equivalent to roughly 59 days of consumption. Projected OECD oil inventories rise to 2.95 billion barrels at the end of 2015 and then to 3.00 billion barrels at the end of 2016.

**Crude Oil Prices.** North Sea Brent crude oil spot prices decreased by \$3/b in June to a monthly average of \$61/b. Oil prices have been relatively stable in recent months despite consistent growth in global petroleum and other liquids inventories, which grew by an estimated 1.9 million b/d in June and an average of almost 3.0 million b/d April and May, compared with an average build of 0.8 million b/d in the second quarter of 2014. Inventory builds are projected to moderate somewhat in the coming months, but are expected to remain high compared with previous years.

The monthly average WTI crude oil spot price increased to an average of \$60/b in June, up \$1/b from May. After increasing for 20 consecutive weeks to a record 62.2 million barrels on April 17, crude oil inventories at Cushing, Oklahoma, have since decreased by 5.8 million barrels as of June 26. Along with falling Cushing inventories, strong U.S. refinery runs and production outages in Canada have put upward pressure on the price of WTI crude oil.

EIA projects the Brent crude oil price will average \$60/b in 2015 and \$67/b in 2016, both unchanged from last month's STEO. WTI prices in both 2015 and 2016 are expected to average \$5/b less than the Brent crude oil price. However, this price projection remains subject to the uncertainties surrounding the possible lifting of sanctions against Iran and other market events. In addition, there is potential downward price pressure in the second half 2015 once refinery runs moderate following the seasonal peaks in demand from the summer driving season.

The current values of futures and options contracts continue to suggest high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for October 2015 delivery traded during the five-day period ending July 1 averaged \$59/b, while implied volatility averaged 31%. These levels established the lower and upper limits of the 95% confidence

interval for the market's expectations of monthly average WTI prices in October 2015 at \$45/b and \$79/b, respectively. The 95% confidence interval for market expectations widens over time, with lower and upper limits of \$41/b and \$89/b for prices in December 2015. Last year at this time, WTI for October 2014 delivery averaged \$104/b, and implied volatility averaged 14%. The corresponding lower and upper limits of the 95% confidence interval were \$92/b and \$118/b.

## U.S. Petroleum and Other Liquids

U.S. weekly regular gasoline retail prices reached a 2015 year-to-date high of \$2.84/gal on June 15, an increase of 43 cents/gal from early in the second quarter but 85 cents/gal below the same time last year. Strong demand for gasoline in both the United States and abroad has driven gasoline prices higher over the past two months despite relatively stable crude oil prices. Data from the U.S. Federal Highway Administration show Americans drove a record 988 billion miles during the first four months of 2015, compared with the previous record of 966 billion miles driven in the first four months of 2007. As a result, refinery wholesale gasoline margins (the difference between the wholesale price of gasoline and the price of Brent crude oil) have been strong in recent months leading to record high levels of refinery runs. U.S. average wholesale gasoline margins averaged 62 cents/gal in June, 28 cents/gal higher than June of last year and 25 cents/gal higher than the five-year average (2010-14) for June.

Refinery outages on the West Coast have contributed to gasoline prices in that region rising by more than the U.S. average during May. As those outages have abated and imports have helped resupply the market, regular gasoline prices in Petroleum Administration for Defense District (PADD) 5 declined to an average of \$3.31/gal on June 29, 20 cents/gal lower than their recent peak on May 18. In June, monthly average regional gasoline retail prices ranged from a low of \$2.55/gal in PADD 3, the Gulf Coast region, to a high of \$3.36/gal in PADD 5, the West Coast. EIA expects gasoline prices to fall from their current peaks, with the U.S. regular gasoline price averaging \$2.49/gal over the second half of 2015, 6 cents/gal higher than forecast in last month's STEO.

**Liquid Fuels Consumption.** Total U.S. liquid fuels consumption rose by an estimated 70,000 b/d (0.4%) in 2014. Total liquid fuels consumption is forecast to grow by 400,000 b/d (2.1%) in 2015 and by 120,000 b/d (0.6%) in 2016. The 2015 and 2016 consumption forecasts are about 20,000 b/d higher and 70,000 b/d higher, respectively, than forecast in last month's STEO.

Motor gasoline consumption, which rose by 80,000 b/d in 2014, will increase by a projected 170,000 b/d (1.9%) in 2015 as the effects of employment growth and lower gasoline prices outweigh increases in vehicle fleet efficiency. Gasoline consumption is forecast to fall by 20,000 b/d (0.2%) in 2016, driven by higher prices and a long-term trend toward more fuel-efficient vehicles.

Consumption of distillate fuel, which includes diesel fuel and heating oil, is forecast to rise by 90,000 b/d (2.3%) in 2015 and by 70,000 b/d (1.7%) in 2016. This growth is driven by increasing manufacturing output, foreign trade, and marine fuel use.

Hydrocarbon gas liquids (HGL) consumption, which decreased by 100,000 b/d (4.0%) in 2014, is projected to increase by 120,000 b/d in 2015 and by 60,000 b/d in 2016, as new petrochemical plant capacity increases the use of HGL as a feedstock. In addition, new HGL export terminal capacity contributes to an increase in HGL net exports from an average of 560,000 b/d in 2014 to 1.1 million b/d in 2016.

**Liquid Fuels Supply.** U.S. crude oil production is projected to increase from an average of 8.7 million b/d in 2014 to 9.5 million b/d in 2015 and then decline to 9.3 million b/d in 2016. The forecast is about 40,000 b/d higher for both 2015 and 2016 than in last month's STEO. The increase in the crude oil production forecast reflects upward revisions to estimated Gulf of Mexico production in the second quarter of 2015.

EIA estimates that U.S. crude oil production averaged almost 9.6 million b/d in the first half of 2015. This level is 0.3 million b/d higher than the average production during the fourth quarter of 2014, despite a 60% decline in the total U.S. oil-directed rig count since October 2014.

The most recent production estimates, which include historical data through April 2015, indicate U.S. output was 9.7 million b/d in April. EIA estimates that total U.S. production began declining in May, falling 50,000 b/d from the April level. Although total U.S. production increased in April, the data indicate that onshore production began declining in April. While the production estimates are subject to revision as new data become available from the states, the preliminary evidence is supported by reported April production declines in major producing states such as North Dakota.

EIA expects U.S. crude oil production declines to continue into early 2016, when total production is forecast to average 9.2 million b/d in the first quarter. Production is forecast to begin rising in the second quarter of 2016, returning to an average of 9.6 million b/d in the fourth quarter. A total of 13 projects are scheduled to come online in the Gulf of Mexico in 2015 and 2016, pushing Gulf of Mexico production up from an average of 1.4 million b/d in the fourth quarter of 2014 to almost 1.7 million b/d in the same period of 2016, an increase of 17%.

Expected crude oil production declines from April 2015 through February 2016 are largely attributable to unattractive economic returns in some areas of both emerging and mature onshore oil production regions, as well as seasonal factors such as anticipated hurricane-related production disruptions in the Gulf of Mexico. Reductions in 2015 cash flows and capital expenditures have prompted companies to defer or redirect investment away from marginal exploration and research drilling to focus on core areas of major tight oil plays. Reduced investment has resulted in the lowest count of oil-directed rigs in nearly five years.

Projected 2015 oil prices remain high enough to support continued development drilling in the core areas of the Bakken, Eagle Ford, Niobrara, and Permian basins. Forecast WTI crude oil prices create conditions in which continued increases in rig and well productivity and falling drilling and completion costs make rig count increases and resumption of onshore production growth possible in 2016. The forecast remains sensitive to actual wellhead prices and rapidly changing drilling economics that vary across regions and operators. While projected oil

production in the Gulf of Mexico rises during the forecast period, Alaska oil production falls. Production in these areas is less sensitive to short-term price movements than onshore production in the Lower 48 states and reflects anticipated growth from new projects and declines from legacy fields.

HGL production at natural gas processing plants is estimated to have reached a record level of 3.3 million b/d in April 2015, and it is projected to average 3.3 million b/d in 2015 and 3.5 million b/d in 2016. EIA expects higher ethane recovery rates following planned increases in petrochemical plant feedstock demand. Export terminal expansions will allow higher quantities of domestically produced ethane, propane, and butanes to reach the international market.

The growth in domestic crude oil and other liquids production has contributed to a significant decline in imports. The share of total U.S. liquid fuels consumption met by net imports fell from 60% in 2005 to an estimated 26% in 2014. EIA expects the net import share to decline to 21% in 2016, which would be the lowest level since 1968.

**Petroleum Product Prices.** Rising crude oil prices, strong demand for U.S. gasoline, and several refinery outages in the Midwest and West Coast contributed to an increase in U.S. regular gasoline retail prices from a monthly average of \$2.47/gal in April to \$2.80/gal in June. EIA expects monthly average prices to decline through the summer as refineries continue to produce high levels of gasoline and as demand begins to decrease following the peak in the summer driving season. EIA projects regular gasoline retail prices to average \$2.63/gal during the third quarter of 2015, 11 cents/gal higher than in last month's STEO, and \$2.34/gal in the fourth quarter.

The U.S. regular gasoline retail price, which averaged \$3.36/gal in 2014, is projected to average \$2.48/gal in 2015, 4 cents/gal higher than in last month's STEO, and \$2.55/gal in 2016, which is unchanged from last month's STEO.

The diesel fuel retail price, which averaged \$3.83/gal in 2014, is projected to fall to an average of \$2.86/gal in 2015, 2 cents/gal lower than in last month's STEO, and then rise to \$3.03/gal in 2016.

As with crude oil, the market's expectation of uncertainty in monthly average gasoline prices is reflected in the pricing and implied volatility of futures and options contracts. New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contracts for October 2015 delivery, traded over the five-day period ending July 1, averaged \$1.80/gal. The probability that the RBOB futures price will exceed \$2.35/gal (consistent with a U.S. average regular gasoline retail price above \$3.00/gal) in October 2015 is about 5%.

## Natural Gas

Preliminary data indicate that natural gas production in the Northeast declined during May and June, contributing to total U.S. natural gas production in June averaging 78.2 Bcf per day (Bcf/d), down 1.2 Bcf/d from the April level. The decline largely reflects maintenance and construction in

the Marcellus producing area. Transcontinental Pipeline restricted capacity on segments of its Leidy Line, which flows natural gas produced in the Marcellus Shale to market areas, beginning May 1 and lasting through late June. The capacity restrictions were related to construction on an expansion that will ultimately increase Marcellus takeaway capacity. EIA expects production growth will resume in July.

**Natural Gas Consumption.** EIA's forecast of U.S. total natural gas consumption averages 76.5 Bcf/d in 2015 and 76.4 Bcf/d in 2016, compared with 73.5 Bcf/d in 2014. Consumption growth in 2015 is largely driven by demand in the industrial and electric power sectors. EIA projects natural gas consumption in the power sector to grow by 12.9% in 2015 and then fall by 2.7% in 2016. Low natural gas prices support increased use of natural gas for electricity generation in 2015. Industrial sector consumption increases by 3.3% in 2015 and by 3.9% in 2016, as new industrial projects come online, particularly in the fertilizer and chemicals sectors, and as industrial consumers continue to take advantage of low natural gas prices. Natural gas consumption in the residential and commercial sectors is projected to decline in 2015 and 2016.

**Natural Gas Production and Trade.** EIA expects that marketed natural gas production will increase by 4.3 Bcf/d (5.7%) and by 1.6 Bcf/d (2.0%) in 2015 and 2016, respectively. Despite recent declines, natural gas production remains high, and EIA expects continued growth through 2016, with increases in the Lower 48 states expected to more than offset long-term production declines in the Gulf of Mexico. Increases in drilling efficiency will continue to support growing natural gas production in the forecast despite relatively low natural gas prices. Most of the growth is expected to come from the Marcellus Shale, as the backlog of uncompleted wells is reduced and new pipelines come online to deliver Marcellus natural gas to markets in the Northeast.

Increases in domestic natural gas production are expected to reduce demand for natural gas imports from Canada and to support growth in exports to Mexico. EIA expects natural gas exports to Mexico, particularly from the Eagle Ford Shale in South Texas, to increase because of growing demand from Mexico's electric power sector, coupled with flat Mexican natural gas production.

EIA projects LNG gross exports will increase to an average of 0.79 Bcf/d in 2016, with the startup of a major LNG liquefaction plant in the Lower 48 states.

**Natural Gas Inventories.** On June 26, natural gas working inventories totaled 2,577 Bcf, which was 662 Bcf (35%) above the level at the same time in 2014 and 29 Bcf (1%) above the previous five-year average (2010-14) for that week. To this point in the inventory refill season, injections have surpassed the five-year average injections by a wide margin. EIA projects end-of-October 2015 inventories will total 3,919 Bcf, 121 Bcf (3.2%) above the five-year average for that time.

**Natural Gas Prices.** The Henry Hub natural gas spot price averaged \$2.78/million British thermal units (MMBtu) in June, a decrease of 7 cents/MMBtu from the May price. EIA expects monthly average spot prices to remain lower than \$3/MMBtu in July, and lower than \$4/MMBtu through

the remainder of the forecast. The projected Henry Hub natural gas price averages \$2.97/MMBtu in 2015 and \$3.31/MMBtu in 2016.

Natural gas futures contracts for October 2015 delivery traded during the five-day period ending July 1 averaged \$2.85/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for October 2015 contracts at \$1.92/MMBtu and \$4.24/MMBtu, respectively. At this time last year, the natural gas futures contract for October 2014 delivery averaged \$4.40/MMBtu, and the corresponding lower and upper limits of the 95% confidence interval were \$3.37/MMBtu and \$5.76/MMBtu, respectively.

## Coal

**Coal Supply.** Lower coal demand for domestic consumption and exports is projected to contribute to a 75 million short ton (MMst) decline in production for 2015. Coal production is expected to decline in all coal-producing regions, and coal production is projected to remain near 2015 levels in 2016.

Electric power sector stockpiles increased to 168 MMst in April (the most recent month for which data are available), nearly 40 MMst higher than in April 2014.

**Coal Consumption.** EIA expects a 7% decrease in coal consumption in the electric power sector in 2015. Lower natural gas prices are the primary factor driving the decline. Projected low natural gas prices make it more economical to run natural gas-fired generating units at higher utilization rates even in regions of the country that typically rely more heavily on coal-fired generation (Midwest, South). Retirements of coal power plants in response to the implementation of the Mercury and Air Toxics Standards (MATS) have a lesser impact on coal demand in the power sector in 2015.

The full effect of the coal plant retirements on capacity resulting from MATS, which the Supreme Court recently sent back to the Court of Appeals for the D.C. Circuit for further review, will occur in 2016. However, projected rising electricity demand and higher natural gas prices are expected to contribute to higher utilization rates among the remaining coal-fired fleet. Even with continued MATS implementation, coal consumption in the electric power sector is forecast to increase 1.3% in 2016.

**Coal Trade.** Slower growth in world coal demand, lower international coal prices, and higher coal output in other coal-exporting countries have led to a two-year decline in U.S. coal exports. EIA projects coal exports will fall by 10 MMst, to 87 MMst, in 2015, but coal exports are expected to increase slightly in 2016. U.S. coal imports, which increased by more than 2 MMst in 2014 to 11 MMst, are expected to remain near that level over the next two years.

**Coal Prices.** The annual average coal price to the electric power sector fell from \$2.39/MMBtu in 2011 to \$2.36/MMBtu in 2014. EIA expects the delivered coal price to average \$2.29/MMBtu in 2015 and \$2.30/MMBtu in 2016.

## Electricity

The North American Electric Reliability Corporation (NERC) indicates that there are adequate resources available this summer to meet projected peak electricity demand levels. Even in areas of the United States that have experienced constraints in certain power generation supplies, reliability of the bulk power system should not be a concern this summer. California's drought has significantly lowered available hydroelectric resources within the state, but the California Independent System Operator has determined that recent additions of renewable generation capacity and increased imports of electricity from the Pacific Northwest should be enough to cover peak power demand this year, even under an extreme scenario of high electricity consumption and possible generator outages.

**Electricity Consumption.** EIA forecasts that the typical U.S. residential electricity customer will use an average of 1,044 kilowatthours per month this summer (June, July, and August). This level of consumption would be 3.7% higher than the same period last year. The increase is driven primarily by an expected 13% increase in summer cooling degree days. For the year, EIA expects U.S. retail sales of electricity to the residential sector during 2015 to grow by 0.3% from 2014 levels. Residential sales of electricity are expected to fall by 1.0% in 2016 in response to projected milder summer and winter temperatures next year that reduce cooling and heating-related consumption.

**Electricity Generation.** U.S. generation of electricity fueled by natural gas exceeded coal-fired generation for the first time on record in April 2015, primarily because of sustained low natural gas prices. Normal seasonal fluctuations in the fuel mix and projected increases in the cost of natural gas for power generation should result in coal-fired generation exceeding natural gas generation for the rest of 2015. EIA forecasts coal's share of U.S. total generation will average 35.6% in 2015, down from 38.7% in 2014. In contrast, the natural gas fuel share averages 30.9% this year, up from 27.4% in 2014.

**Electricity Retail Prices.** The U.S. retail price of electricity to the residential sector is projected to average 12.8 cents per kilowatthour in 2015, which is 2.5% higher than the average price last year. This year-over-year increase in average electricity prices, combined with higher expected summer residential use, leads to a forecast 5.9% (\$23) increase in the typical residential customer's summer electricity expenditures compared with last summer.

## Renewables and Carbon Dioxide Emissions

**Electricity and Heat Generation from Renewables.** EIA expects renewables used in the electric power sector will grow by 1.8% in 2015; conventional hydropower generation decreases by 2.0% and nonhydropower renewable power generation increases by 5.5%. The 2015 decrease in hydropower generation reflects the effects of the California drought, which are only partially offset by growth in use of hydropower elsewhere. Generation from hydropower is expected to increase by 5.4% in 2016. Total renewables consumption for electric power and heat generation decreases by 1.2% in 2015 and increases by 5.5% in 2016.

EIA expects continued growth in utility-scale solar power generation, which is projected to average 86 gigawatthours per day (GWh/d) in 2016. Because the growth is from a small base, utility-scale solar power averages only 0.8% of total U.S. electricity generation in 2016. Although solar growth has historically been concentrated in customer-sited distributed generation installations (rooftop panels), EIA expects utility-scale solar capacity will increase by 90% between the end of 2014 and the end of 2016, with more than half of this new capacity being built in California. Other leading states include North Carolina, Nevada, Texas, and Utah, which, combined with California, account for more than 90% of the projected utility-scale capacity additions for 2015 and 2016. According to current law, projects coming online after the end of 2016 will see a federal investment tax credit of 10%, below the 30% investment tax credit available for projects that come online before the end of 2016. This impending decline in the tax credit provides a strong incentive for projects to enter service before the end of 2016.

Wind capacity, which grew by 8.3% in 2014, is forecast to increase by 12.8% in 2015 and by 13.0% in 2016. Because wind is starting from a much larger base than solar, even though the growth rate is lower, the absolute increase in wind capacity is twice that of solar: 18 GW of wind compared with 9 GW of utility-scale solar between 2014 and 2016.

**Liquid Biofuels.** On May 29, the U.S. Environmental Protection Agency (EPA) proposed a rule setting Renewable Fuel Standard (RFS) volumes for 2014 through 2016. Although these volumes could be modified before the final rule is issued, they are used in developing the current STEO. Ethanol production, which averaged 935,000 b/d in 2014, is forecast to remain near current levels in 2015 and 2016. Ethanol consumption, which averaged 878,000 b/d in 2014, is forecast to average 894,000 b/d in 2015 and 902,000 b/d in 2016, resulting in an average 9.9% ethanol share of the total gasoline pool in 2015 and 2016. EIA does not expect measurable increases in E15 or E85 consumption over the forecast period. The proposed RFS targets are expected to encourage imports of Brazilian sugarcane ethanol, which were 3,000 b/d in 2014. Because of the expected increase in ethanol gross imports, net exports of ethanol are forecast to fall from 51,000 b/d in 2014, to 44,000 b/d in 2015, and to 36,000 b/d in 2016.

EIA expects the biggest effect of the proposed RFS targets to be on biodiesel consumption, which contributes to meeting the biomass-based diesel, advanced biofuel, and total renewable fuel RFS targets. Biodiesel production averaged an estimated 81,000 b/d in 2014 and is forecast to average 91,000 b/d in 2015 and 98,000 b/d in 2016. Net imports of biomass-based diesel are also expected to increase from 16,000 b/d in 2014, to 24,000 b/d in 2015, and to 35,000 b/d in 2016. EIA expects that a combination of higher biomass-based diesel consumption, higher consumption of domestic and imported ethanol, and banked Renewable Identification Numbers (RINs) will help meet the newly proposed RFS volumes through 2016.

**Energy-Related Carbon Dioxide Emissions.** EIA estimates that emissions grew by 1.0% in 2014. Emissions are projected to decrease by 0.2% in 2015 and then rise by 0.4% in 2016. These forecasts are sensitive to both weather and economic assumptions.

## U.S. Economic Assumptions

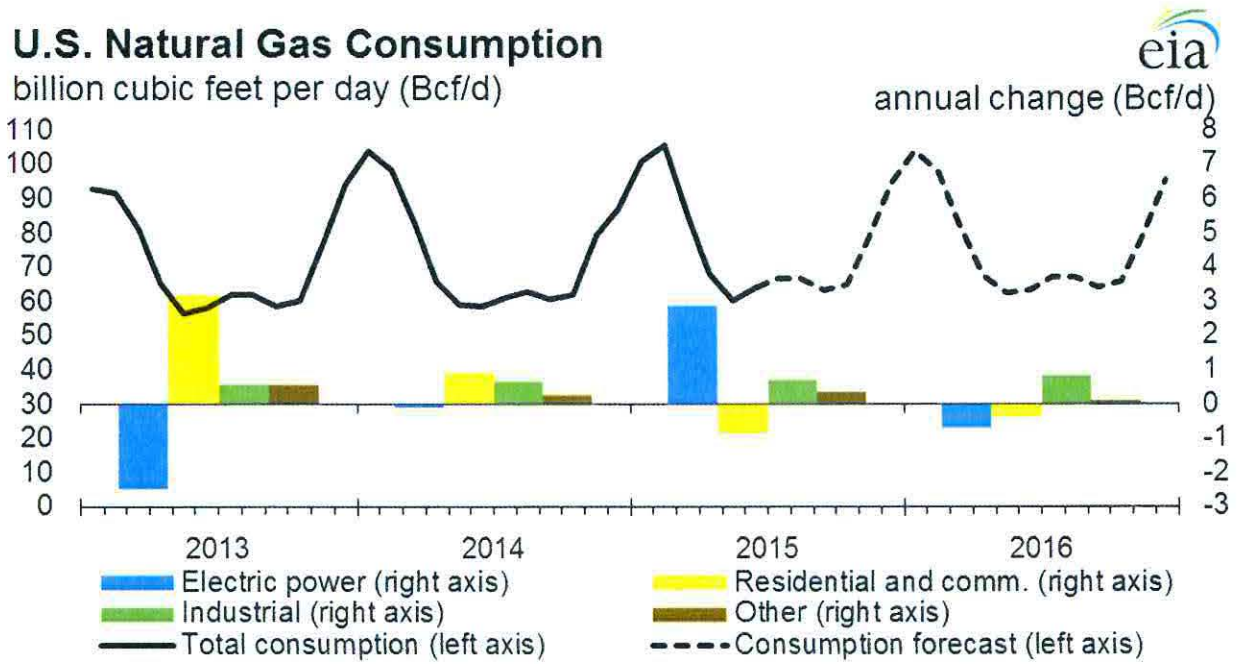
**Recent Economic Indicators.** The Bureau of Economic Analysis (BEA) reported that real GDP decreased at an annual rate of 0.2% in the first quarter of 2015, above the previous estimate of a 0.7% decrease. With this estimate for the first quarter, exports decreased less than previously estimated and personal consumption expenditures and imports increased more.

EIA used the June 2015 version of the IHS macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

**Production, Income, and Employment.** Forecast real GDP growth is 2.0% in 2015 and rises to 2.8% in 2016. The 2015 growth is below the 2.2% forecast last month, while the 2016 growth is above the 2.6% forecast of last month. Real disposable income grows by 3.5% in 2015, above the 3.3% forecast last month, and by 2.5% in 2016. Total industrial production grows at 1.7% in 2015 and 3.4% in 2016. Projected growth in nonfarm employment averages 2.0% in 2015 and 1.4% in 2016.

**Expenditures.** Forecast private real fixed investment growth averages 4.4% and 7.6% in 2015 and 2016, respectively, led by equipment in 2015 and 2016 and by equipment and structures in 2016. Real consumption expenditures grow faster than real GDP in 2015, at 2.8%, and below real GDP in 2016 at 2.7%. Durable goods expenditures drive consumption spending in both years. Export growth is 1.6% and 4.9% over the same two years, while import growth is 5.4% in 2015 and 5.8% in 2016. Total government expenditures rise 0.8% in 2015 and 0.7% in 2016.

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.

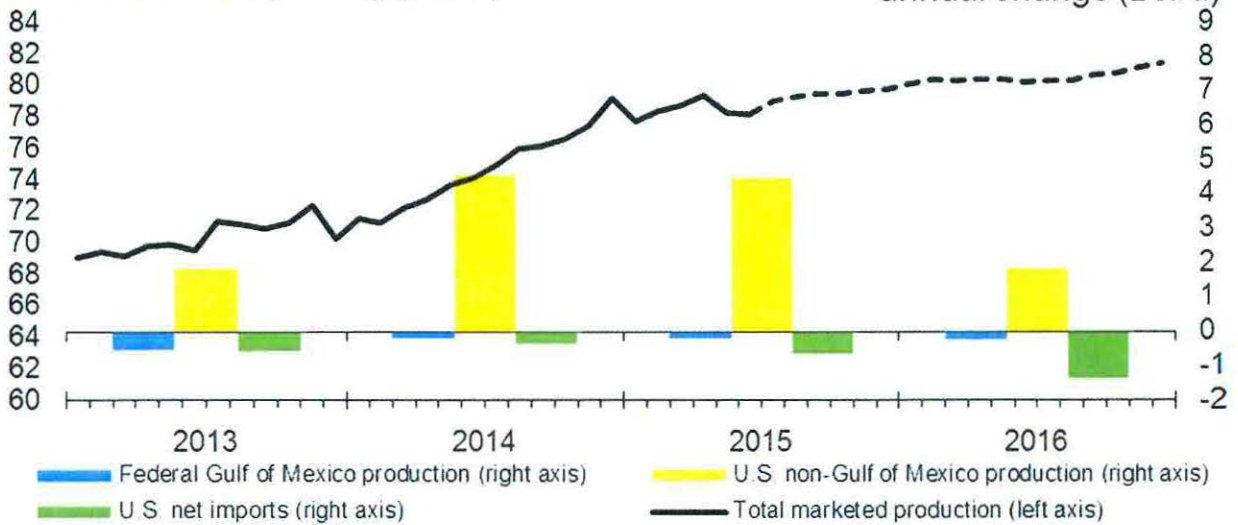


Source: Short-Term Energy Outlook, July 2015.

## U.S. Natural Gas Production and Imports

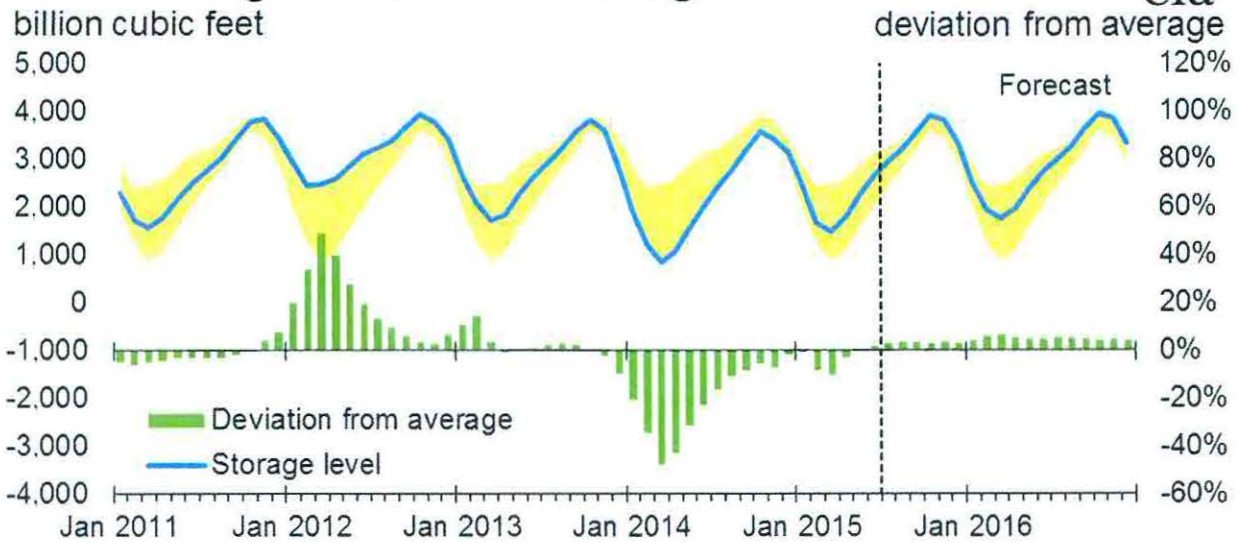
billion cubic feet per day (Bcf/d)

eia  
annual change (Bcf/d)



Source: Short-Term Energy Outlook, July 2015.

## U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2010 - Dec. 2014.

Source: Short-Term Energy Outlook, July 2015.

## Henry Hub Natural Gas Price

dollars per million Btu



Note: Confidence interval derived from options market information for the 5 trading days ending Jul. 1, 2015. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, July 2015.



### U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, July 2015.

**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 Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ April 30, 2015</b>									<b><u><u>\$74,482</u></u></b>
May 2015	(\$3,948)	0	\$293	(\$3,655)	13,744	\$1.3462	\$18,502	(\$22,157)	52,325
June	923	0	211	1,134	9,387	0.2107	9,293 2/	(8,159)	44,166
Total	<u>(\$3,025)</u>	<u>0</u>	<u>\$504</u>	<u>(\$2,521)</u>	<u>23,131</u>		<u>\$27,795</u>	<u>(\$30,316)</u>	
<b>Balance @ June 30, 2015.</b>									<b><u><u>\$44,166</u></u></b>

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

2/ Reflects 6,442.6 dk @ \$1.3462 and 2,944.3 dk @ \$0.2107

**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 Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ April 30, 2015</b>									<b><u><u>\$35,759</u></u></b>
May 2015	(\$8,261)	0	\$2	(\$8,259)	20,827	\$0.9696	\$20,194	(\$28,453)	7,306
June	(8,730)	0	(311)	(9,041)	28,071	0.0461	20,202 2/	(\$29,243)	(21,937)
Total	<u>(\$16,991)</u>	<u>0</u>	<u>(\$309)</u>	<u>(\$17,300)</u>	<u>48,898</u>		<u>\$40,396</u>	<u>(\$57,696)</u>	
<b>Balance @ June 30, 2015.</b>									<b><u><u>(\$21,937)</u></u></b>

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

2/ Reflects 20,473.8 dk @ \$0.9696 and 7,597.5 dk @ \$0.0461.