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

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February 26, 2015

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

Re: Cost of Gas Adjustment (COG)
March 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 (108th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (108th Revised Sheet No. 8), showing the March 2015 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $0.2947 per dk for residential and firm general service customers and an increase of $0.2947 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for March 2015, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $0.2947 per dk since the last COG filing.

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

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

Great Plains 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,

Tamie A. Aberle
Director of Regulatory Affairs

Attachments

Attachment A

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2

108th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 107th Revised Sheet No.1.1

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	$6.4275	$7.7144
			Over 10 dk	1.0646		7.4921
Interruptible Gas Service - General	3	$3.50 per month	First 400 dk	$1.1506	$4.4376	$5.5882
			Next 2,600 dk	0.9021		5.3397
			Over 3,000 dk	0.7486		5.1862
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All dk	$1.2516	$4.4376	$5.6892
Transportation Service	5	$3.50 per month	First 400 dk	$1.1506		$1.1506
			Next 2,600 dk	0.9021		0.9021
			Over 3,000 dk	0.7486		0.7486

Date Filed: February 26, 2015

Effective Date: Service rendered on and after March 1, 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
108th Revised Sheet No. 8
Canceling 107th Revised Sheet No. 8

COST OF GAS

Summary:	Firm				Interruptible		
	Est. Wtd. Demand Costs	Average Commodity	GCR Adj.	Est. Wtd. Total Firm	Average Commodity	GCR Adj.	Total Int.
Base Rate	$0.0662	$5.1708	$0.0000	$5.2370	$5.1708	$0.0000	$5.1708
Accumulated Adj.	1.5471	(1.9975)	1.3462	0.8958	(1.9975)	0.9696	(1.0279)
Current Adj.	0.0000	0.2947	0.0000	0.2947	0.2947	0.0000	0.2947
Total Adj.	1.5471	(1.7028)	1.3462	1.1905	(1.7028)	0.9696	(0.7332)
Total Rate	$1.6133	$3.4680	$1.3462	$6.4275	$3.4680	$0.9696	$4.4376

Date Filed: February 26, 2015

Effective Date: Service rendered on and after March 1, 2015

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MARCH 2015

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A - Zone 1-1	8,000		$4.3706	12	$419,578	$0.2978
FT-A - Zone 1-1	5,000		4.7507	5	118,768	0.0843
FT-A Seasonal	2,000		4.7507	5	47,507	0.0337
TFX Seasonal	2,000		15.1530	5	151,530	0.1075
TFX - Winter	13,000		15.1530	5	984,945	0.6990
TFX - Summer	13,000		5.6830	7	517,153	0.3670
BP Seasonal Contract	500		2/	3	33,750	0.0240
Total Demand Charges					$2,273,231	1.6133
Estimated Weighted Average Commodity Cost	1,409,081	1/	3.4680		4,886,693	3.4680
Gas Cost Reconciliation Adjustment						1.3462
Total Current Firm Gas Cost					$7,159,924	6.4275
Base Cost of Gas						5.2370
Accumulated Adjustment						$1.1905
Interruptible						
Estimated Weighted Average Commodity Cost						$3.4680
Gas Cost Reconciliation Adjustment						0.9696
Total Current Interruptible Gas Cost						4.4376
Base Cost of Gas						5.1708
Accumulated Adjustment						($0.7332)

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
MARCH 2015

Rates Effective March 1, 2015	$/Dk	
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:	3.4680	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

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

2/ Demand base rate calculation:

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

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
Category 1 (Contract Term of Less than 3 Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$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
Category 2 (Contract Term of 3 Years to less than 5 Years)	
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
Category 3 (Contract Term of 5 or more Years)	
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		$0.0116	

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

RATE SCHEDULE TF

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

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

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

RATE SCHEDULES TFX and LFT

	MARKET-TO-MARKET		FIELD-TO-FIELD	
RESERVATION RATES	Apr-Oct	Nov-Mar	Apr-Oct	Nov-Mar
Base Tariff Rates 1/	$5.683	$15.153	$5.473	$9.853

COMMODITY RATES 2/ TFX and LFT		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0364	0.0195			0.0175	0.0000	0.0364	0.0195
Field	Market	0.0364	0.0195	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

	Reservation 1/		Commodity 6/		Out-of-Balance 6/	
GULF COAST	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Other Gulf Coast	4.8169	0.0000	0.0000	0.0000	0.0000	0.0000

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

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

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	1.39%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.09% 4/ 5/
FDD Storage Fuel	1.76%

	Electric Compression
COMMODITY RATES:	1/
Market Area	$0.0005
Field Area	$0.0000

1/ Northern will adjust its Fuel percentages and electric compression commodity rates in accordance with Sections 53A and 53B, respectively, of the General Terms and Conditions of this Tariff.

2/ Fuel shall be determined by Mileage Indicator Districts (MIDS) for the Field Area.

3/ Fuel charged in the Field and Market Areas for a pooling transaction or for processing plant transactions will not exceed the fuel charged on a unified Field-to-Market transaction having the same initial Field receipt point and ultimate Market delivery point, i.e., the total fuel collected for transactions that go into and out of pooling points or processing plants in either the Field Area or the Market Area will be no greater than the fuel collected on the total path between the original receipt point and the ultimate delivery point, subject to the shipper(s) providing Northern the requisite information.

4/ The Unaccounted For percentage utilizes the most recent twelve-month period ending December 31, 2013.

5/ Sheet No. 54A identifies the specific transportation transactions exempt from fuel and unaccounted-for retention charges.

6/ The Out-of-Balance Fuel Percentage for deliveries in MIDS 1-7 shall be the applicable Section 1 Mainline Fuel percentage, and for deliveries in MIDS 8-16B shall be the applicable Section 2 Mainline Fuel percentage.

In the event facilities have been abandoned, Northern shall have the right to file to reduce the applicable MID fuel percentage(s) on a common basis for all transactions affected by the abandonment to reflect the reduction in use for the remainder of the PRA period. In the event such abandoned facilities (gas compressors) have been replaced with electric compressors installed after October 1, 1998, and Northern reduces the applicable MID fuel percentages, Northern has the right to file to increase the applicable electric compression commodity rate.

RATE SCHEDULES FDD, PDD, IDD, 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
March 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. point in Ventura, Iowa, which is an actively traded market point in North America. The March 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.

While the national storage levels continue to increase, prolonged cold weather resulting in record usage in the eastern portion of the U.S. was the main reason for the expected increase of natural gas. The extreme cold weather also results in freeze off of production wells which would also contribute to the price increase. The EIA reported storage levels nationwide as of February 13, 2015 were 2.8 percent above the five-year average and 45.8 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 17.

Independent Statistics & Analysis
U.S. Energy Information Administration

February 2015

Short-Term Energy Outlook (STEO)

Highlights

- January was the seventh consecutive month in which monthly average North Sea Brent crude oil prices decreased, reaching $48/barrel (bbl), the lowest since March 2009. The price decline reflects continued growth in U.S. tight oil production and strong global supply, amid weaker global oil demand growth, which contributed to rising global oil inventories. In January, estimated Organization for Economic Cooperation and Development (OECD) total commercial oil inventories reached their highest level since August 2010.

- EIA forecasts that Brent crude oil prices will average $58/bbl in 2015 and $75/bbl in 2016, with 2015 and 2016 annual average West Texas Intermediate (WTI) prices expected to be $3/bbl and $4/bbl, respectively, below Brent. This price outlook is unchanged from last month's forecast. The current values of futures and options contracts continue to suggest very high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for May 2015 delivery, traded during the five-day period ending February 5, averaged $52/bbl while implied volatility averaged 52%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in May 2015 at $33/bbl and $81/bbl, respectively. The 95% confidence interval for market expectations widens over time, with lower and upper limits of $32/bbl and $108/bbl for prices in December 2015.

- Total U.S. crude oil production averaged an estimated 9.2 million barrels per day (bbl/d) in January. Forecast total crude oil production averages 9.3 million bbl/d in 2015. Given EIA's price forecast, projected crude oil production averages 9.5 million bbl/d in 2016, close to the highest annual average level of production in U.S. history of 9.6 million bbl/d in 1970.

- Driven largely by falling crude oil prices, U.S. weekly regular gasoline retail prices averaged $2.04/gallon (gal) on January 26, the lowest since April 6, 2009, before increasing to $2.19/gal on February 9. EIA expects U.S. regular gasoline retail prices, which averaged $3.36/gal in 2014, to average $2.33/gal in 2015. The average household is now expected to spend about $750 less for gasoline in 2015 compared with last year because of lower prices. The projected regular gasoline retail price increases to an average of $2.73/gal in 2016.

- Natural gas working inventories on January 30 totaled 2,428 Bcf, 468 Bcf (24%) above the level at the same time in 2014 and 29 Bcf (1%) below the previous five-year (2010-14) average. EIA expects the Henry Hub natural gas spot price to average $3.34/million British

thermal units (MMBtu) this winter (2014-15) compared with $4.53/MMBtu last winter (2013-14), reflecting both lower-than-expected space heating demand and higher natural gas production this winter. EIA expects the Henry Hub natural gas spot price, which averaged $4.39/MMBtu in 2014, to average $3.05/MMBtu in 2015 and $3.47/MMBtu in 2016, $0.39/MMBtu lower for both years than in last month's STEO.

Global Petroleum and Other Liquids

Market fundamentals remain largely unchanged since last month's forecast, as global production continues to be higher than demand, contributing to inventory builds. Global oil inventory builds averaging 0.9 million bbl/d are projected through the first half of 2015, with the builds moderating during the second half of the year, as non-OPEC supply growth, particularly from the United States, weakens because of lower oil prices. The expected inventory builds in 2015 are on top of an estimated 0.8 million bbl/d increase in 2014.

EIA revised historical global supply and demand levels to reflect improved data estimates for various countries. These changes to history affected forecast levels of supply and demand, but did not affect forecast growth rates.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 0.9 million bbl/d in 2014, averaging 92.1 million bbl/d for the year. EIA expects global consumption to grow by 1.0 million bbl/d in both 2015 and 2016. Projected global oil-consumption-weighted real gross domestic product (GDP), which increased by an estimated 2.7% in 2014, is projected to grow by 2.8% in 2015 and by 3.2% in 2016.

Non-OECD consumption growth is the main driver of global consumption growth in the forecast, with projected growth of 0.8 million bbl/d in 2015 and of 1.1 million bbl/d in 2016, both lower than the estimated 1.2 million bbl/d of growth in 2014. China's consumption is projected to increase by an annual average of 0.3 million bbl/d in both 2015 and 2016, below the 0.4 million bbl/d of growth in 2014. China's economic growth slowed in the latter half of 2014, as key manufacturing indexes decreased. Nonetheless, China remains the main source of non-OECD consumption growth. Projected declines in Russia's oil consumption because of its economic downturn also contribute to lower non-OECD consumption growth over the forecast period compared with 2014. Russia's consumption is expected to decline by 0.2 million bbl/d in both 2015 and 2016.

OECD consumption, which fell by 0.3 million bbl/d in 2014, is expected to grow by 0.2 million bbl/d in 2015 and then decline by 0.1 million bbl/d in 2016. Japan and Europe accounted for almost the entire decline in 2014 and are expected to continue to decline over the next two years, albeit at a lesser rate than in 2014. The United States is the leading contributor to projected OECD consumption growth, with U.S. consumption increasing by 0.3 million bbl/d in 2015 and by 0.1 million bbl/d in 2016.

Non-OPEC Petroleum and Other Liquids Supply. After increasing by 2.1 million bbl/d in 2014, non-OPEC supply is expected to grow more slowly, by 0.8 million bbl/d annually in both 2015 and 2016, in part because of lower projected oil prices. The slower growth in non-OPEC supply over the forecast period is largely attributable to slower production growth in the United States, Canada, and South America. Additionally, oil production in Europe and Eurasia is projected to decline. The United States remains the leading contributor to non-OPEC supply in the forecast.

Unplanned supply disruptions among non-OPEC producers averaged slightly more than 0.6 million bbl/d in 2014, 0.2 million bbl/d less than in 2013. In January 2015, non-OPEC supply disruptions were 0.6 million bbl/d, similar to the previous month. South Sudan, Syria, and Yemen accounted for more than 85% of total non-OPEC supply disruptions.

OPEC Petroleum and Other Liquids Supply. EIA estimates that OPEC crude oil production averaged 30.1 million bbl/d in 2014, unchanged from the previous year. Crude oil production declines in Libya, Angola, Algeria, and Kuwait more than offset production growth in Iraq and Iran. EIA expects OPEC crude oil production to fall by 0.1 million bbl/d in 2015, and to fall by 0.4 million bbl/d in 2016. Iraq is the largest contributor to OPEC production growth over the forecast period, but its growth is expected to be offset by production declines from other Persian Gulf producers. However, the threat of the Islamic State of Iraq and the Levant (ISIL) on northern Iraqi production and exports still looms, and as a result, Iraq is a major wild card in the world oil production forecast.

EIA estimates that OPEC produced 6.4 million bbl/d of noncrude oil liquids in 2014, slightly less than its production in 2013. OPEC noncrude liquids production is expected to increase by less than 0.1 million bbl/d in both 2015 and 2016, led by Iran and Qatar.

In January 2015, unplanned crude oil supply disruptions among OPEC producers averaged 2.6 million bbl/d, an increase of less than 0.1 million bbl/d compared with the previous month. This increase was attributable to rising outages in Libya, which have been growing since late 2014. Unplanned OPEC crude supply disruptions averaged 2.4 million bbl/d in 2014, 0.6 million bbl/d higher than in the previous year. Libya and Iraq accounted for almost all of the growth in OPEC disruptions. The high level of OPEC disruptions contributed to higher crude oil prices during the first half of 2014. However, with continuous growth in non-OPEC production and strong production in Saudi Arabia outpacing world oil demand growth, the current volume of supply disruptions has become less significant. Unplanned supply disruptions could still affect crude oil prices, but the threshold that the market can bear has risen in light of robust global production.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to increase to an annual average of 2.3 million bbl/d in 2015 and 2.7 million bbl/d in 2016, after averaging about 2.0 million bbl/d in 2014. Surplus capacity is typically an indication of market conditions, and surplus capacity below 2.5 million bbl/d is an indicator of a relatively tight market. However, the current and forecast levels of global inventory builds make the projected low surplus capacity level in 2015 less significant.

OECD Commercial Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.74 billion barrels at the end of 2014, the highest end-of-year level on record and equivalent to roughly 58 days of consumption. Projected OECD oil inventories rise to 2.83 billion barrels at the end of 2015 and again total 2.83 billion barrels at the end of 2016.

Crude Oil Prices. North Sea Brent crude oil spot prices averaged $48/bbl in January, the lowest monthly average Brent price since March 2009, down $15/bbl from the December average. The combination of robust world crude oil supply growth and weak global demand has contributed to rising global inventories and falling crude oil prices (EIA, *This Week in Petroleum*, January 28, 2015).

EIA expects global oil inventories to continue to build in 2015, limiting upward pressure on oil prices because of declining drilling activity. The forecast Brent crude oil price averages $58/bbl in 2015, unchanged from last month's STEO. Based on current market balances, EIA expects prices to be relatively flat in the first half of 2015, when global inventory builds are projected to be significant. EIA projects that Brent prices will average $67/bbl during the fourth quarter.

The monthly average WTI crude oil spot price fell from an average of $59/bbl in December to $47/bbl in January, its lowest level since February 2009. EIA expects the WTI crude oil price to average $55/bbl in 2015 and $71/bbl in 2016, both unchanged from last month's STEO. The discount of WTI to Brent crude oil averaged less than $1/bbl in January, the narrowest monthly average price spread since August 2010. In the forecast, the discount of WTI to Brent is projected to average $3/bbl in 2015 and $4/bbl in 2016.

The current values of futures and options contracts suggest continuing high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for May 2015 delivery, traded during the five-day period ending February 5, averaged $52/bbl. Implied volatility averaged 52%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in May 2015 at $33/bbl and $81/bbl, respectively. The 95% confidence interval for market expectations widens over time, with lower and upper limits of $32/bbl and $108/bbl for prices in December 2015. Last year at this time, WTI for May 2014 delivery averaged $96/bbl, and implied volatility averaged 19%. The corresponding lower and upper limits of the 95% confidence interval were $81/bbl and $113/bbl.

The recent declines in oil prices and associated increase in oil price volatility continue to contribute to a particularly uncertain forecasting environment, and several factors could cause oil prices to deviate significantly from current projections. Among these factors is the responsiveness of supply to lower prices. Despite OPEC's November 2014 decision to leave its crude oil production target at 30 million bbl/d, key producers could decide to reduce output, tightening market balances. The level of unplanned production outages could also vary from forecast levels for a wide range of producers, including OPEC members Libya, Iraq, Iran, Nigeria,

and Venezuela. The degree to which non-OPEC supply growth is affected by lower oil prices will also affect market balances and prices.

Several OPEC and non-OPEC oil producers rely heavily on oil revenues to finance national budgets. Some producers have already started adjusting their upcoming budgets to reflect the crude oil price decline. If crude oil prices fall further or are sustained at current levels, then oil-dependent producers will face tough decisions. These decisions could potentially lead to austerity programs and fuel subsidy cuts that could spark social unrest, leaving some countries vulnerable to supply disruptions if protesters target oil infrastructure. Potential new supply disruptions are a real possibility and present a major uncertainty in the world oil supply forecast.

U.S. Petroleum and Other Liquids

Falling crude oil prices and high inventories of gasoline helped U.S. weekly regular gasoline retail prices fall to an average of $2.04/gal on January 26, the lowest weekly price since April 6, 2009 (EIA, *This Week in Petroleum*, January 22, 2015). U.S. average weekly regular gasoline retail prices have since increased to $2.19/gal as of February 9. In January, monthly average regional gasoline retail prices ranged from a low of $1.90/gal in Petroleum Administration for Defense District (PADD) 3 to a high of $2.45/gal in PADD 5. EIA expects retail gasoline prices to average $2.13/gal during the first quarter of 2015 and $2.33/gal for the full year.

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 60,000 bbl/d (0.3%) in 2014. Motor gasoline consumption increased by 80,000 bbl/d (0.8%) reflecting an increase in highway travel that was partially offset by fleetwide increases in fuel efficiency. Distillate consumption grew by 160,000 bbl/d (4.2%), as a result of colder-than-average weather in the first quarter as well as increases in industrial production. Jet fuel consumption increased by 30,000 bbl/d (2.2%). Hydrocarbon gas liquids (HGL) and residual fuel oil consumption fell by an estimated 100,000 bbl/d (4.1%) and 60,000 bbl/d (19.7%), respectively.

In 2015, total liquid fuels consumption is forecast to grow by 290,000 bbl/d (1.5%). Lower pump prices contribute to an 80,000-bbl/d increase (0.9%) in motor gasoline consumption. HGL consumption is expected to reverse 2014's decline, increasing by 140,000 bbl/d (5.7%). Consumption of distillate fuel is projected to increase by 80,000 bbl/d, driven largely by expanding industrial production. Additionally, some of the growth in distillate fuel consumption comes from Annex VI to the International Convention for the Prevention of Pollution from Ships (MARPOL Annex VI), which is an international agreement that generally requires the use of fuels below 1,000 parts per million sulfur by marine vessels in most U.S. waters, unless alternative devices, procedures, or compliance methods are used to achieve equivalent emissions reductions. The increase in marine distillate use because of MARPOL regulations will displace the use of residual fuel oil.

EIA projects that in 2016 liquid fuels consumption growth will slow to 100,000 bbl/d (0.5%). Motor gasoline consumption declines by 50,000 bbl/d (0.5%) as the annual average retail

gasoline price is projected to increase 17% from the 2015 level. Continuing industrial growth contributes to a 100,000 bbl/d (3.9%) increase in HGL consumption and a 60,000 bbl/d (1.5%) increase in distillate use. Jet fuel consumption declines by 10,000 bbl/d (0.4%) despite moderate increases in air travel, as the introduction of new aircraft improves fuel efficiency.

Liquid Fuels Supply. Forecast U.S. crude oil production increases from an average of 8.6 million bbl/d in 2014 to 9.3 million bbl/d in 2015 and 9.5 million bbl/d in 2016. With WTI crude oil prices expected to average $50/bbl in the first half of 2015, EIA expects 2015 drilling activity to decline because of unattractive economic returns in some areas of both emerging and mature oil production regions. Many companies have begun redirecting investment away from marginal exploration and research drilling and focusing on core areas of major tight oil plays. Projected 2015 oil prices remain high enough to support some development drilling activity in the Bakken, Eagle Ford, Niobrara, and Permian Basin, albeit at lower levels than previously forecast. Companies that have lower drilling and debt costs and have acreage in the sweet spots of these regions will continue to drill highly productive wells in 2015.

Nevertheless, EIA expects 2015 production to reach 9.4 million bbl/d in the second quarter, then decline by 180,000 bbl/d in the third quarter. With projected WTI crude oil prices rising in the second half of 2015, drilling activity is expected to increase again as companies take advantage of lower costs for both leasing acreage and drilling services, resulting in growing production despite the relatively low WTI price. A notable risk to the production forecast is that some drilled wells will not be completed. EIA will continue monitoring the inventory of uncompleted wells to inform the production forecast. Additionally, this forecast remains particularly sensitive to actual prices available at the wellhead and drilling economics that vary across regions and operators. Projected production for the federal offshore region and Alaska, which rise and fall respectively, are less sensitive to short-term price movements than onshore production in the Lower 48 states.

HGL production at natural gas liquids plants, which reached a record high of 3.1 million bbl/d in October, is projected to increase to 3.3 million bbl/d by the end of 2015. Ethane and propane are expected to contribute most to the projected growth, with most of the production supplying domestic petrochemical demand or exports. EIA expects higher rates of ethane recoveries as a result of planned increases in petrochemical facility feedstock demand, while export terminal expansions will allow higher quantities of domestically produced propane and butanes to reach the international market.

The growth in domestic production has contributed to a significant decline in imports of crude oil and other liquids. The share of total U.S. liquid fuels consumption met by net imports fell from 60% in 2005 to an estimated 27% in 2014. EIA expects the net import share to decline to 20% in 2016, which would be the lowest level since 1968.

Petroleum Product Prices. U.S. average regular gasoline retail prices averaged $2.12/gal in January, the lowest monthly average since April 2009. The U.S. regular gasoline retail price, which averaged $3.36/gal in 2014, is projected to average $2.33/gal in 2015 and $2.73/gal in

2016, almost unchanged from last month's STEO. Diesel fuel retail prices, which averaged $3.83/gal in 2014, are projected to fall to an average of $2.83/gal in 2015 and then rise to $3.24/gal in 2016.

The May 2015 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged $1.77/gal for the five trading days ending February 5, 2015, and has a 15% probability of exceeding $2.10/gal (consistent with a retail price of $2.75/gal) at expiration. The current values of futures and options contracts suggest there is a 5% probability that the RBOB futures contract price at expiration may exceed $2.35/gal, consistent with a retail price of $3.00/gal or higher, and a 8% probability that the RBOB futures price may fall below $1.35/gal, consistent with a retail price of $2.00/gal or lower. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas falling above or below the national average price by $0.30/gal or more.

Lower projected crude oil prices also contribute to lower expected residential heating oil prices. Average retail heating oil prices are expected to average $2.96/gal this winter, $0.92/gal lower than last winter. The average household that uses heating oil as its primary space heating fuel is now expected to spend $1,645 for heating this winter, $710 lower than last winter. Propane prices are expected to be 17% lower in the Northeast and 27% lower in the Midwest compared with last winter, resulting in households spending 23% and 35% less on propane in those regions, respectively.

Natural Gas

Recent data indicate marketed natural gas production reached a record 77.3 Bcf/d in November. Despite cold weather and reports of production freeze-offs this winter, supply has remained abundant and prices have fallen. The February 2015 natural gas futures contract expired at $2.87/MMBtu, and prices for the March contract have fallen further, settling at $2.60/MMBtu on February 5. Henry Hub spot prices are now projected to average $3.05/MMBtu in 2015, $1.34/MMBtu lower than in 2014 and $0.39/MMBtu lower than in last month's forecast. Lower expected prices in 2015 contribute to increasing consumption of natural gas for power generation, which is projected to be 5.5% above the 2014 level.

Natural Gas Consumption. EIA projects that U.S. total natural gas consumption will average 74.3 Bcf/d in 2015 and 75.2 Bcf/d in 2016, compared with an estimated 73.3 Bcf/d in 2014. Growth is largely driven by demand in the industrial and electric power sectors, while residential and commercial consumption is projected to decline in 2015 and 2016. Natural gas consumption in the power sector is expected to average 23.5 Bcf/d in 2015, a 0.5 Bcf/d increase from last month's STEO. EIA expects power sector consumption to grow by 2.6%, to 24.1 Bcf/d, in 2016. Industrial sector consumption increases by 5.6% and 1.9% in 2015 and 2016, respectively, as new industrial projects come online, particularly in the fertilizer and chemicals sectors, and industrial consumers are able to take advantage of low natural gas prices.

Natural Gas Production and Trade. EIA expects that marketed natural gas production will increase by 2.9 Bcf/d (3.8%) and 1.7 Bcf/d (2.2%) in 2015 and 2016, respectively. This increase reflects continuing strong production in the Lower 48 states, which more than offsets the long-term declining production in the Gulf of Mexico. Although natural gas prices have fallen dramatically in recent months, EIA expects that increases in drilling efficiency and growth in oil production (albeit at a slower rate) will continue to support growing natural gas production in the forecast. Additionally, preliminary data indicate freeze-offs modestly reduced production in January, but production has quickly recovered and growth continues. With most growth expected to come from the Marcellus Shale, a backlog of drilled but uncompleted wells will continue to support production growth, as new pipelines come online in the Northeast.

Increases in domestic natural gas production are expected to contribute to lower demand for natural gas imports from Canada and increasing exports to Mexico. EIA expects 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.

Liquefied natural gas (LNG) imports have fallen over the past five years because higher prices in Europe and Asia are more attractive to LNG exporters than the relatively low prices in the United States. Forecast LNG gross imports average 0.2 Bcf/d in both 2015 and 2016. EIA projects that LNG gross exports will increase from an average of 0.04 Bcf/d in 2014 to almost 0.8 Bcf/d in 2016.

Natural Gas Inventories. On January 30, natural gas working inventories totaled 2,428 Bcf, 468 Bcf (24%) above the level at the same time in 2014 and 29 Bcf (1%) below the previous five-year (2010-14) average. Following last year's extremely cold winter, inventories fell 1,000 Bcf below the five-year average in mid-April but since then have consistently narrowed the gap. EIA projects that end-of-March 2015 inventories will total 1,699 Bcf, 43 Bcf more than the five-year (2010-14) average.

Natural Gas Prices. The Henry Hub natural gas spot price averaged $2.99/MMBtu in January, a decline of $0.49/MMBtu from December, and the first monthly average price under $3/MMBtu since September 2012. EIA expects monthly average spot prices to remain less than $3/MMBtu through the winter, and less than $4/MMBtu through the remainder of the forecast. The projected Henry Hub natural gas price averages $3.05/MMBtu in 2015 and $3.47/MMBtu in 2016.

Natural gas futures contracts for May 2015 delivery, traded during the five-day period ending February 5, averaged $2.71/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for May 2015 contracts at $1.79/MMBtu and $4.11/MMBtu, respectively. At this time last year, the natural gas futures contract for May 2014 delivery averaged $4.48/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $3.28/MMBtu and $6.13/MMBtu.

Coal

Total electric power sector coal stocks increased by 6 million short tons (MMst) in November 2014 to 142 MMst at month-end. The increase in coal stocks followed the typical seasonal pattern where coal-fired electric power plants build stocks during the autumn months in preparation for increased coal consumption during the winter. Despite the increase, end-of-November 2014 stocks were 14 MMst (9%) below a year ago and 21% lower than the previous five-year (2009-13) average for November.

Coal Supply. EIA estimates that coal production for 2014 totaled 997 MMst, 13 MMst (1%) higher than in 2013. EIA expects that annual production will decline in both 2015 and 2016, totaling 966 MMst and 960 MMst, respectively.

Coal Consumption. Electric power sector coal consumption was largely unchanged in 2014 compared with the previous year. Power sector coal consumption is projected to decrease by 1.5% in 2015, despite an increase in electricity demand, as natural gas prices decline relative to coal prices and retirements of coal power plants rise in response to the implementation of the Mercury and Air Toxics Standards. The full effect of the coal plant retirements will be felt in 2016, as projected electric power sector coal consumption declines by an additional 0.6%.

Coal Trade. Coal exports in 2014 were estimated at 97 MMst, a 17% decline from 2013. The decline was primarily a result of slowing world coal demand growth, lower international coal prices, and increasing coal output in other coal-exporting countries. EIA expects no significant change in global market conditions, and coal exports will fall 15% to 82 MMst in both 2015 and 2016.

Coal Prices. The annual average coal price to the electric power industry fell from a record-high $2.39/MMBtu in 2011 to an estimated $2.35/MMBtu in 2014. EIA expects the delivered coal price to average $2.33/MMBtu in 2015 and $2.34/MMBtu in 2016.

Electricity

At the end of 2014, the nuclear generating unit at the Vermont Yankee power plant shut down for decommissioning after more than 40 years of operation. Five other nuclear units have been retired in the past two years. There are 99 remaining nuclear units in the United States, including 23 in the Northeast Census region, where Vermont Yankee operated.

Electricity Consumption. Despite the January snowstorms in the Midwest and Northeast, average U.S. heating degree days (HDD) for the month were 10% lower than in January 2014. Based on weather forecasts from the National Oceanic and Atmospheric Administration, EIA expects HDD during the first quarter of 2015 to be 13% lower than last year. Cooling degree days during the summer months (April—September) are expected to be 6% higher than last summer. Lower consumption of electricity for space heating coupled with efficiency

improvements are projected to offset increased air-conditioning use during the summer, leading to a projected 0.4% year-over-year decline in residential electricity sales during 2015. Residential electricity sales are projected to grow by 0.9% in 2016. Projected sales of electricity to the commercial sector increase by 1.3% in 2015 and by 0.5% in 2016. Projected industrial electricity sales rise by an average of 1.8% annually in both 2015 and 2016.

Electricity Generation. EIA forecasts that U.S. electricity generation will grow by an average of 1.0% 2015 and 0.9% 2016. The cost of natural gas used for power generation has fallen in recent months, with the Henry Hub spot price declining from an average of $4.29/MMBtu last summer to an average of $2.99/MMBtu in January. This decline in fuel costs, combined with upcoming coal plant retirements, is likely to increase the use of natural gas-fired generating capacity. EIA expects the share of total generation fueled by natural gas to average 28.4% during 2015, up from 27.2% last year. In contrast, the share of generation provided by coal falls from 38.9% to 37.8%. The retirement of the Vermont Yankee plant contributes to a decline in the Northeast region's nuclear power fuel share from 35.5% in 2014 to 33.3% this year.

Electricity Retail Prices. EIA expects continued growth in average residential electricity prices over the forecast period, albeit at a slower pace than in 2014. The U.S. retail residential price is projected to increase by 1.1% in 2015 and by 1.8% in 2016. Electricity prices in most areas of the country are projected to increase in 2015. Projected price increases in 2015 are highest in the Midwest states (2.6%).

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 3.8% in 2015. Conventional hydropower generation increases by 5.7%, while nonhydropower renewables generation increases by 2.9%. In 2016, total renewables consumption for electric power and heat generation increases by 2.9% as a result of a 3.2% decline in hydropower and a 6.0% increase in nonhydropower renewables.

In 2013, the electricity generation shares were 6.6% and 6.2% from hydropower and nonhydropower renewables, respectively. In 2014, 6.3% of generation came from hydropower and 6.9% from nonhydropower renewables. This trend is expected to continue, with the electricity generation share from nonhydropower renewables rising to 7.9% by 2016, and the hydropower share remaining near 6.5%. Wind is the largest source of nonhydropower renewable generation, and it is projected to contribute 5.2% of total electricity generation in 2016.

EIA expects continued growth in utility-scale solar power generation, which is projected to average almost 80 gigawatthours (GWh) per day in 2016. Despite this growth, solar power averages only 0.7% of total U.S. electricity generation in 2016. Although solar growth has historically been concentrated in customer-sited distributed generation installations, EIA expects that utility-scale solar capacity will increase by more than 60% between the end of 2014

and the end of 2016, with about half of this new capacity being built in California. Wind capacity, which grew by 7.7% in 2014, is forecast to increase by 16.1% in 2015 and by another 6.5% in 2016. Because wind is starting from a much larger base than solar, even though the growth rate is lower, the absolute amount of the increase in capacity is more than twice that of solar: 15 GW of wind versus 6 GW of utility-scale solar between 2014 and 2016.

Liquid Biofuels. After reaching a record monthly average of 978,000 bbl/d in December 2014, ethanol production in January 2015 is estimated to be 969,000 bbl/d. Ethanol production averaged 933,000 bbl/d in 2014, and EIA expects it to average 938,000 bbl/d in 2015 and 936,000 bbl/d in 2016. Biodiesel production averaged an estimated 80,000 bbl/d in 2014 and is forecast to average 84,000 bbl/d in both 2015 and 2016.

Energy-Related Carbon Dioxide Emissions. EIA estimates that emissions grew 0.9% in 2014. Emissions are forecast to increase by 0.3% in 2015 and 0.5% in 2016. These forecasts are sensitive to both weather and economic assumptions.

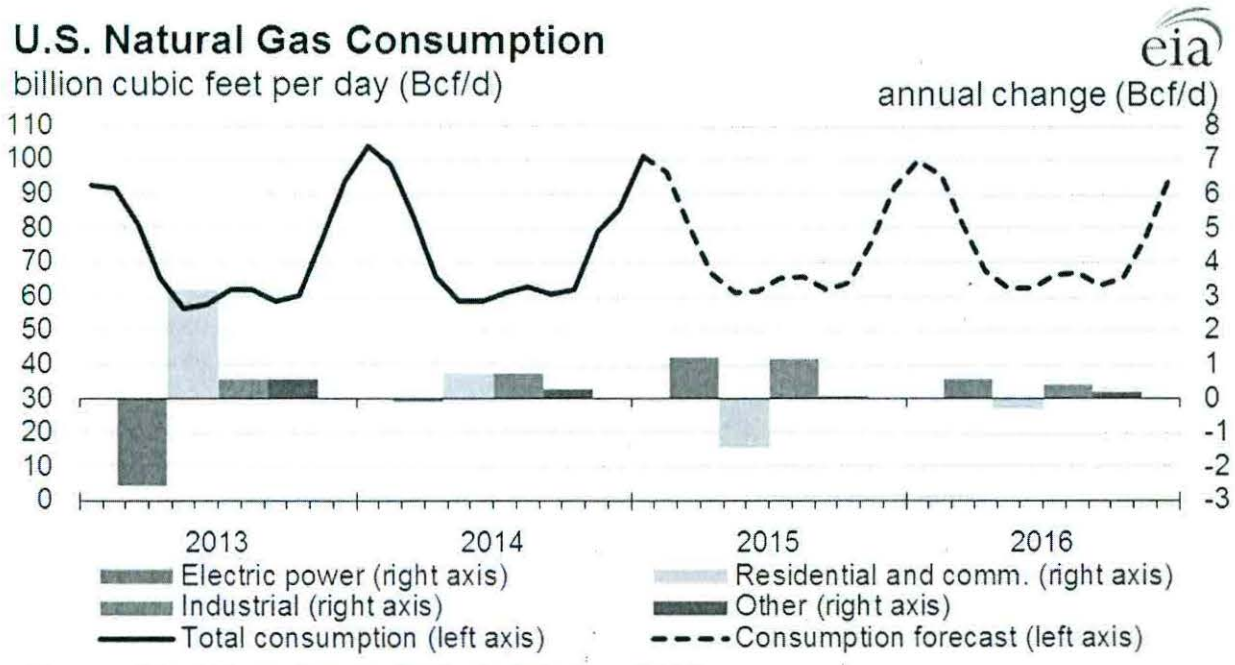
U.S. Economic Assumptions

Recent Economic Indicators. The Commerce Dapartment's Bureau of Economic Analysis (BEA) reported that real GDP grew at an annualized rate of 2.6% from the third quarter to the fourth quarter of 2014. The increase in real GDP in the fourth quarter reflected positive contributions from personal consumption expenditures and investment. Growth in the third quarter of 2014 was 5.0%.

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

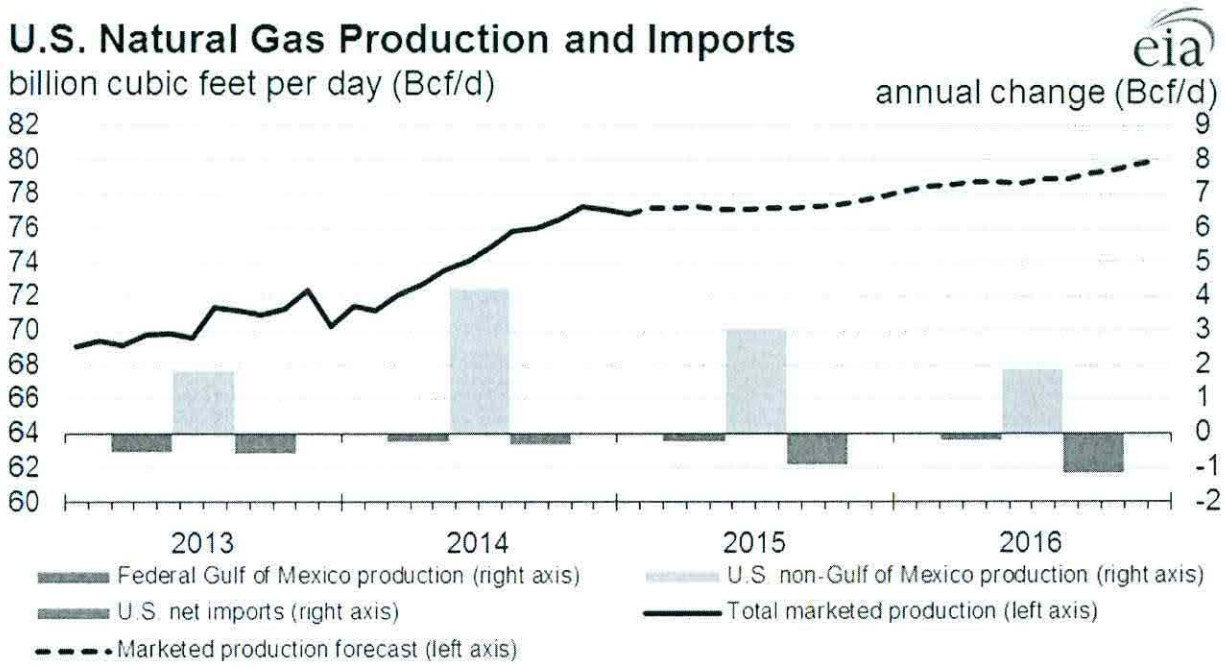
Production, Income, and Employment. After expanding by 2.4% in 2014, real GDP is projected to grow by 3.1% in 2015 and by 2.5% in 2016. Growth is expected to rise in 2015 because of higher business investment spending, increases in consumer purchases, and recent declines in gasoline prices. However, a stronger dollar and lower demand from slower-growing economies are expected to reduce export growth and raise import growth. Real disposable income is projected to grow by 3.3% in 2015 (compared with 2.8% forecast last month) and by 2.6% in 2016. Projected total industrial production grows by 3.4% in both 2015 and 2016. Projected growth in nonfarm employment averages 2.1% in 2015 and 1.7% in 2016.

Expenditures. Forecast private real fixed investment growth averages 6.0% and 6.6% in 2015 and 2016, respectively. Real consumption expenditures grow faster than real GDP in 2015 and 2016, at 3.5% and 2.9%, respectively. Durable goods expenditures drive consumption spending in both years. Export growth is 3.9% and 3.2% over the same two years, while import growth is 5.3% in both 2015 and 2016. Total government expenditures rise by 0.6% in 2015 and 0.4% in 2016.

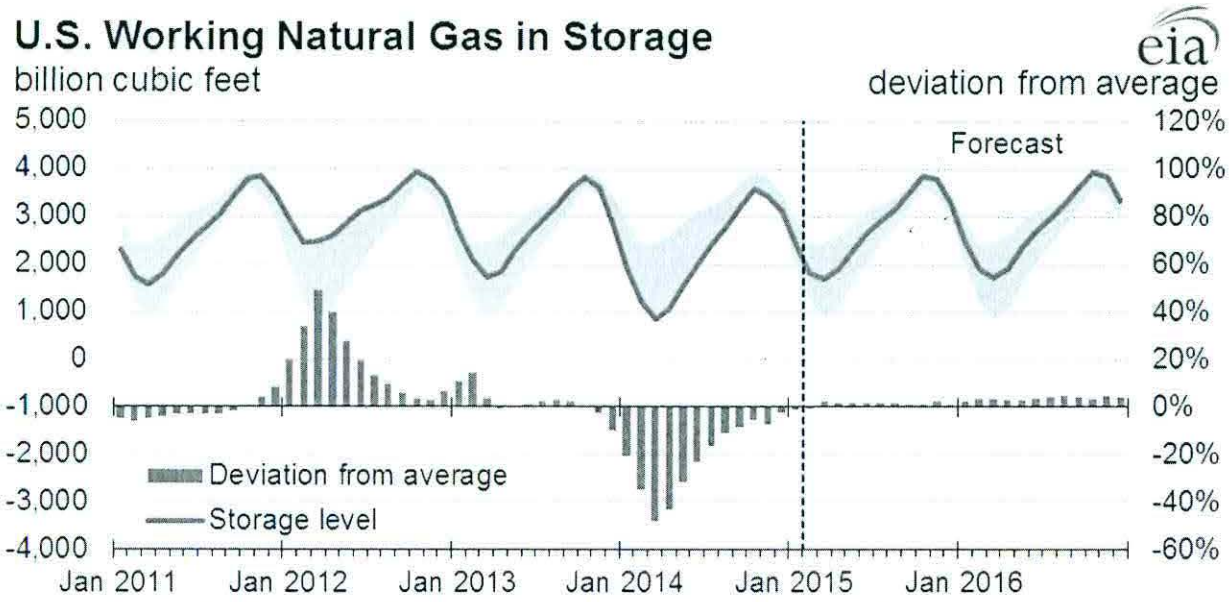


Source: Short-Term Energy Outlook, February 2015.

U.S. Natural Gas Production and Imports



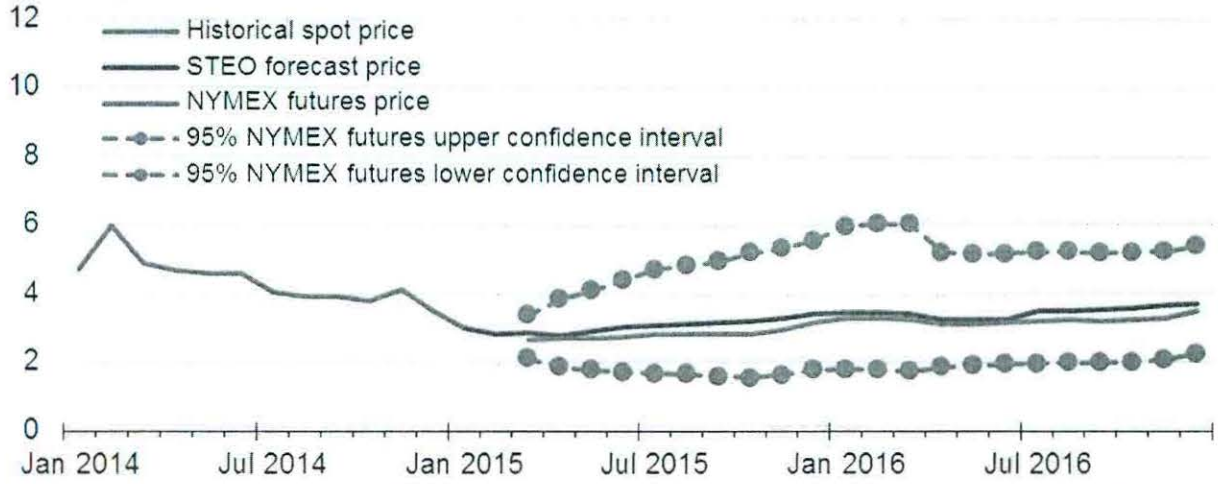
Source: Short-Term Energy Outlook, February 2015.



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2010 - Dec. 2014.
Source: Short-Term Energy Outlook, February 2015.

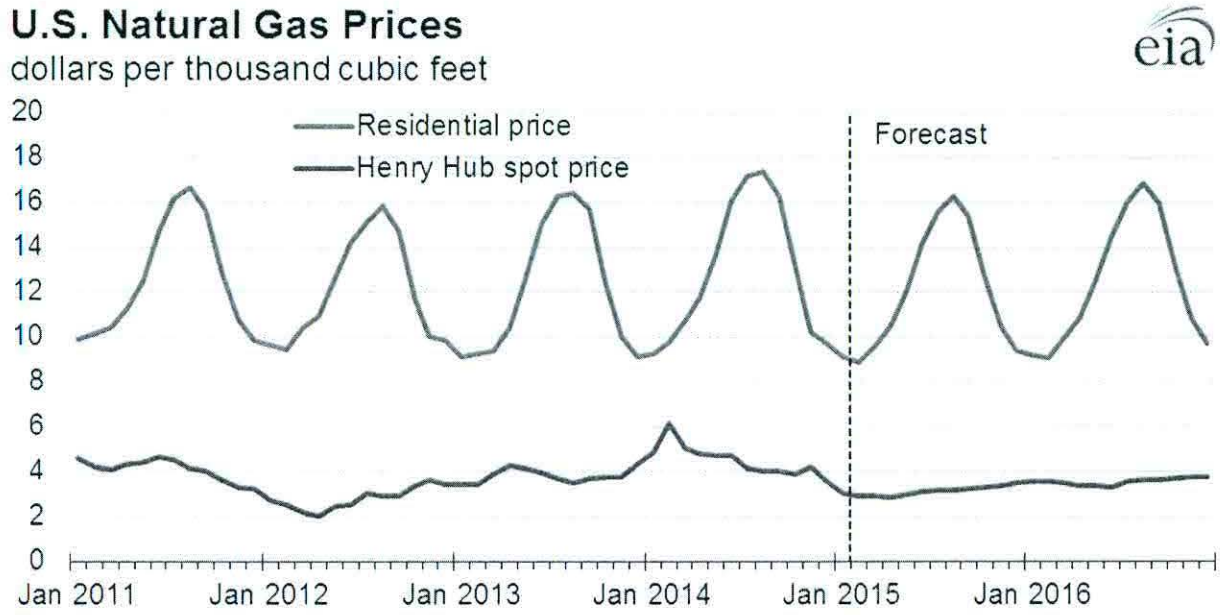
Henry Hub Natural Gas Price

dollars per million Btu



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

Source: Short-Term Energy Outlook, February 2015.



Source: Short-Term Energy Outlook, February 2015.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2014									**$404,569**
May 2014	($15,520)	0	$2,700	($12,820)	18,641	$0.9614	$17,921	($30,741)	373,828
June	(1,551)	0	2,475	924	9,300	1.3462	10,015 2/	(9,092)	364,736
July	13,177	0	2,399	15,576	6,189	1.3462	8,331	7,245	371,981
August	13,687	0	2,437	16,124	5,378	1.3462	7,240	8,884	380,865
September	(855)	0	2,486	1,631	6,094	1.3462	8,204	(6,573)	374,292
October	5,798	0	2,424	8,222	9,358	1.3462	12,598	(4,376)	369,916
November	2,922	0	2,379	5,301	19,077	1.3462	25,681	(20,380)	349,536
December	22,567	0	2,225	24,792	41,354	1.3462	55,671	(30,879)	318,657
January 2015	(20,659)	0	2,006	(18,653)	47,084	1.3462	63,384	(82,037)	236,620
Total	$19,566	0	$21,531	$41,097	162,475		$209,045	($167,949)	
Balance @ January 31, 2015.									**$236,620**

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
Balance @ April 30, 2014										**$388,932**
May 2014	($22,536)	0	$2,691	($19,845)	42,002	$0.0274	$1,151		($20,996)	367,936
June	(17,420)	0	2,515	(14,905)	19,772	0.9696	5,999	2/	(20,903)	347,033
July	(3,815)	0	2,344	(1,471)	11,279	0.9696	10,936		(12,407)	334,626
August	(6,429)	0	2,239	(4,190)	13,996	0.9696	13,571		(17,761)	316,865
September	(26,713)	0	2,095	(24,618)	13,155	0.9696	12,755		(37,373)	279,492
October	879	0	1,811	2,690	27,455	0.9696	26,620		(23,930)	255,562
November	7,159	0	1,626	8,785	31,401	0.9696	30,446		(21,661)	233,901
December	204	0	1,459	1,663	30,496	0.9696	29,569		(27,906)	205,995
January 2015	8,505	0	1,248	9,753	48,709	0.9696	47,228		(37,475)	168,520
Total	($60,166)	0	$18,028	($42,138)	238,265		$178,275		($220,412)	
Balance @ January 31, 2015.										**$168,520**

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.