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

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Fergus Falls, MN 56538-0176
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May 29, 2015

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

Re: Cost of Gas Adjustment (COG)
June 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 (111th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (111th Revised Sheet No. 8), showing the June 2015 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.7941 per dk for residential and firm general service customers and a decrease of $0.5821 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for June 2015, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $0.3414 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 gas cost reconciliation (GCR) adjustment that will apply during the period of June 1, 2015 through May 31, 2016. The total GCR is $0.2107 per Dk for residential and general service customers and $0.0461 per Dk for interruptible customers. The effect of this change is a decrease of $1.1355 for residential and general service customers and a decrease of $0.9235 for interruptible customers.

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

111th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 110th 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	$4.6285	$5.9154
			Over 10 dk	1.0646		5.6931
Interruptible Gas Service - General	3	$3.50 per month	First 400 dk	$1.1506	$2.8657	$4.0163
			Next 2,600 dk	0.9021		3.7678
			Over 3,000 dk	0.7486		3.6143
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All dk	$1.2516	$2.8657	$4.1173
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: May 29, 2015

Effective Date: Service rendered on and after June 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
111th Revised Sheet No. 8
Canceling 110th 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.	1.5320	(2.6926)	1.3462	0.1856	(2.6926)	0.9696	(1.7230)
Current Adj.	0.0000	0.3414	(1.1355)	(0.7941)	0.3414	(0.9235)	(0.5821)
Total Adj.	1.5320	(2.3512)	0.2107	(0.6085)	(2.3512)	0.0461	(2.3051)
Total Rate	$1.5982	$2.8196	$0.2107	$4.6285	$2.8196	$0.0461	$2.8657

Date Filed: May 29, 2015

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

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

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
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					$2,273,231	1.5982
Estimated Weighted Average Commodity Cost	1,422,210	1/	2.8196		4,010,063	2.8196
Gas Cost Reconciliation Adjustment						0.2107
Total Current Firm Gas Cost					$6,283,294	4.6285
Base Cost of Gas						5.2370
Accumulated Adjustment						($0.6085)
Interruptible						
Estimated Weighted Average Commodity Cost						$2.8196
Gas Cost Reconciliation Adjustment						0.0461
Total Current Interruptible Gas Cost						2.8657
Base Cost of Gas						5.1708
Accumulated Adjustment						($2.3051)

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
JUNE 2015

Rates Effective June 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:	2.8196	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		($0.0528)	

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

RATE SCHEDULE TF

	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
		TF12		
RESERVATION RATES	TF12 Base	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	0.0369	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.

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	0.0369	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

	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 $0.0010 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

	Percentages
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%

	Electric Compression
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
June 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 June 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.

Planned and unplanned maintenance and higher temperatures resulting in increased natural gas usage by electric generation likely contributed to the increase in the index price for June. Domestic production levels continue to run near record levels. The EIA reported nationwide storage levels as of May 15, 2015 at 1.7 percent below the five-year average and 59.0 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

May 2015

Short-Term Energy Outlook (STEO)

Highlights

- North Sea Brent crude oil prices averaged $60/barrel (b) in April, a $4/b increase from March and the highest monthly average of 2015. Despite increasing global inventories, several factors contributed to higher prices in April, including indications of higher global oil demand growth, expectations for declining U.S. tight oil production in the coming months, and the growing risk of unplanned supply outages in the Middle East and North Africa.

- EIA forecasts that Brent crude oil prices will average $61/b in 2015 and $70/b in 2016, $1/b higher and $5/b lower than in last month's STEO, respectively. Average WTI prices in 2015 and 2016 are expected to be $6/b and $5/b below Brent, respectively. The current values of futures and options contracts for December 2015 delivery suggest (*Market Prices and Uncertainty Report*) the market's expectations (at the 95% confidence interval) for WTI prices in that month range from $41/b to $97/b.

- While U.S. monthly average regular gasoline retail prices in April were almost unchanged from March at $2.47/gallon (gal), U.S. weekly regular gasoline retail prices reached an average of $2.69/gal on May 11, reflecting rising crude oil prices and several outages at West Coast refineries. EIA expects U.S. regular gasoline retail prices, which averaged $3.36/gal in 2014, to average $2.43/gal in 2015 and $2.63/gal in 2016. The average household is expected to spend $675 less for gasoline in 2015 compared with last year because of lower prices.

- Total U.S. crude oil production averaged an estimated 9.3 million barrels per day (b/d) in March, but it is expected to decline from June through September before growth resumes. Given EIA's price forecast, projected total crude oil production averages 9.2 million b/d in both 2015 and 2016, 40,000 b/d (0.5%) and 100,000 b/d (1.1%) lower than in last month's STEO, respectively.

- Natural gas working inventories were 1,786 billion cubic feet (Bcf) on May 1, which was 71% higher than a year earlier, but 4% lower than the previous five-year (2010-14) average. The winter withdrawal season typically ends in March, and April is typically the beginning of the injection season, which runs through October. EIA projects natural gas inventories will end October 2015 at 3,890 Bcf, a net injection of 2,420 Bcf. This would be the second-highest injection season on record.

- Low natural gas prices in recent months have significantly increased the use of natural gas rather than coal for electricity generation. EIA expects natural gas generation in April and May will almost reach the level of coal generation, resulting in the closest convergence in generation shares between the two fuels since April 2012.

Global Petroleum and Other Liquids

As in last month's STEO, global liquids production continues to exceed demand, resulting in inventory builds. Global oil inventory builds are projected to average 1.8 million b/d through the first half of 2015. Inventory builds moderate to 0.9 million b/d during the second half of the year, as demand rises and non-Organization of the Petroleum Exporting Countries (OPEC) supply growth slows, particularly in the United States. The expected inventory builds in 2015 are on top of an estimated average 1.1 million b/d increase in 2014.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption of petroleum and other liquids grew by 0.9 million b/d in 2014, averaging 92.0 million b/d for the year. EIA expects global consumption will grow by 1.2 million b/d in 2015 and by 1.3 million b/d in 2016. Forecast global consumption growth was revised upward from last month's STEO by an average of 0.2 million b/d in both 2015 and 2016, as lower oil prices stimulate demand growth more than previously expected. Projected global oil-consumption-weighted real gross domestic product (GDP), which increased by an estimated 2.7% in 2014, is projected to grow by 2.5% in 2015 and by 3.0% in 2016.

Consumption outside of the Organization for Economic Cooperation and Development (OECD) countries, which grew by 1.2 million b/d in 2014, is projected to grow by 0.9 million b/d in 2015 and by 1.2 million b/d in 2016. Lower forecast non-OECD consumption growth in 2015 mostly reflects a 0.2 million b/d decline in Russia's consumption as a result of its 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. Nonetheless, 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.

OECD petroleum and other liquids consumption, which fell by 0.4 million b/d in 2014, is expected to grow by 0.3 million b/d in 2015 and by 0.1 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 stay relatively flat. The United States is the leading contributor to projected OECD consumption growth, with U.S. consumption increasing by 0.3 million b/d in 2015 and by 0.1 million b/d in 2016.

Non-OPEC Petroleum and Other Liquids Supply. EIA estimates that non-OPEC production grew by 2.2 million b/d in 2014. EIA expects non-OPEC production to grow by 0.8 million b/d in 2015 and by 0.4 million b/d in 2016. The slower growth in total non-OPEC supply is largely attributable to slower production growth in the United States and Canada in response to lower

projected oil prices, as well as declining production in Europe and Eurasia. After remaining relatively flat in 2015, production in Eurasia is projected to decline by more than 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 0.7 million b/d in April 2015, almost 0.1 million b/d higher than the previous month because of more outages in Yemen and a new outage in Gabon. Yemen's production, which averaged 130,000 b/d in 2014, was halved when operations at an oil port and refinery were halted following the recent escalation in violence. In Gabon, a labor strike at oil fields resulted in a small supply disruption in April. South Sudan, Syria, and Yemen accounted for 90% of total non-OPEC supply disruptions in April. EIA estimates unplanned non-OPEC supply disruptions averaged 0.6 million b/d in 2014.

OPEC Petroleum and Other Liquids Supply. EIA estimates 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. In EIA's forecast, OPEC crude oil production rises by 0.4 million b/d in 2015 and falls by 0.2 million b/d in 2016. Forecast OPEC crude oil production was revised upward from last month's STEO by 0.3 million b/d in 2015 and by 0.2 million b/d in 2016. Iraq is expected to be the largest contributor to OPEC production growth over the next two years.

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. 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 potential 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, forcing Iran to shut in a substantial portion of its production. Iran's ability to bring back 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 barrels 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 0.3 million b/d in 2015 and by 0.1 million b/d in 2016, led by production increases in Qatar, Iran, and Kuwait.

In April, unplanned crude oil supply disruptions among OPEC producers averaged 2.3 million b/d, almost 0.1 million b/d lower compared with the previous month. Unplanned OPEC crude

supply disruptions averaged 2.4 million b/d in 2014, 0.5 million b/d higher than in the previous year.

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 market. However, the current and forecast levels of global inventory builds make the projected low surplus capacity level in 2015 less significant. Nonetheless, low surplus capacity heightens uncertainty about the market's ability to counteract unforeseen supply outages, particularly in the current geopolitical climate with ongoing conflicts in or next to major oil producing countries in the Middle East and North Africa. These factors may be applying upward pressure on crude oil prices that could continue through the forecast.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.72 billion barrels at the end of 2014, the highest end-of-year level on record and equivalent to roughly 59 days of consumption. Projected OECD oil inventories rise to 2.91 billion barrels at the end of 2015 and then rise slightly to 2.93 billion barrels at the end of 2016.

Crude Oil Prices. North Sea Brent crude oil spot prices increased by $4/b in April to a monthly average of $60/b, which was the highest monthly average for Brent so far this year. Several factors put upward pressure on crude oil prices in April. These factors included indications that global oil demand growth is accelerating, evidence that U.S. tight oil production could decline in the coming months, and the growing risk of unplanned supply outages in the Middle East and North Africa. As of May 1, the number of rigs drilling for crude oil had fallen for 21 consecutive weeks and was more than 50% below its peak in October 2014. Brent crude oil prices increased despite growing global oil inventories, which built by more than 2 million b/d for the second consecutive month in April, compared with an average build of 0.8 million b/d in March and April of last year. Inventory builds are projected to moderate in the coming months.

The monthly average WTI crude oil spot price increased to an average of $54/b in April, up $7/b from March. While crude oil inventories at Cushing, Oklahoma increased in April, they fell by 0.5 million barrels during the week ending April 24, the first decline in 21 weeks, and were unchanged for the week ending May 1. Moderating Cushing inventory builds, along with expected declines in U.S. tight oil production and increasing U.S. refinery runs, have put upward pressure on the price of WTI crude oil.

EIA projects the Brent crude oil price will average $61/b in 2015, $1/b higher that in last month's STEO, with prices rising from an average of $54/b in the first quarter to an average of $63/b for the remainder of the year. The Brent crude oil price is projected to average $70/b in 2016, $5/b lower than in last month's STEO, reflecting an increase in forecast OPEC crude oil production in 2016. However, this price projection remains subject to the uncertainties surrounding the possible lifting of sanctions against Iran and other market events. WTI prices in 2015 and 2016 are expected to average $6/b and $5/b, respectively, below Brent.

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 August 2015 delivery traded during the five-day period ending May 7 averaged $61/b while implied volatility averaged 33%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in August 2015 at $46/b and $81/b, respectively. The 95% confidence interval for market expectations widens over time, with lower and upper limits of $41/b and $97/b for prices in December 2015. Last year at this time, WTI for August 2014 delivery averaged $99/b, and implied volatility averaged 17%. The corresponding lower and upper limits of the 95% confidence interval were $85/b and $115/b.

Given the high level of uncertainty in oil markets, several factors could cause oil prices to deviate significantly from current projections. Among these factors is the potential lifting of sanctions against Iran if a comprehensive agreement is reached. The level of unplanned production outages could also vary from forecast levels for a wide range of producers, including OPEC members Libya, Iraq, 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 revenue to finance their national budgets. The decline in oil prices since mid-2014 has led some governments to curb spending, potentially leading 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 always a major uncertainty in the world oil supply forecast.

U.S. Petroleum and Other Liquids

U.S. weekly regular gasoline retail prices reached a 2015 high of $2.69/gal on May 11, an increase of 28¢/gal from early April. Rising crude oil prices and a series of refinery outages in California have pushed gasoline prices higher in the past month. As a result of these outages, gasoline prices on the West Coast have increased by more than the U.S. average, with prices in Petroleum Administration for Defense District (PADD) 5 averaging $3.44/gal on May 11, an increase of 49¢/gal from the first week in April. In April, monthly average regional gasoline retail prices ranged from a low of $2.23/gal in PADD 3, the Gulf Coast region, to a high of $3.01/gal in PADD 5, along the West Coast.

With crude oil prices projected to be relatively flat in the coming months, the U.S. monthly average gasoline price is projected to reach $2.68/gal in May, then decline as refineries in California resolve outages and refineries in the rest of the country increase production of gasoline following the spring maintenance season. EIA projects regular gasoline retail prices to average $2.51/gal during the third quarter and $2.43/gal for the full year of 2015.

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 70,000 b/d (0.4%) in 2014. In 2015, total liquid fuels consumption is forecast to grow by 340,000 b/d (1.8%). EIA projects that in 2016, liquid fuels consumption growth will slow to 70,000 b/d (0.4%).

Motor gasoline consumption, which rose by 80,000 b/d in 2014, increases by a projected 120,000 b/d (1.4%) in 2015 as lower prices and employment growth outweigh increases in vehicle fleet efficiency. Gasoline consumption is forecast to fall by 50,000 b/d (0.6%) in 2016, driven by higher prices and a long-term trend toward more-efficient vehicles.

Consumption of distillate fuel, which includes diesel fuel and heating oil, is forecast to rise by 80,000 b/d (2.0%) in 2015 and by 60,000 b/d (1.5%) in 2016. This growth is driven by increasing manufacturing output and foreign trade. Additionally, some of the growth in distillate fuel consumption comes from the implementation of Annex VI to the International Convention for the Prevention of Pollution from Ships (MARPOL Annex VI), which will increase marine distillate use in U.S. waters because of provisions that displace the use of some residual fuel oil.

Hydrocarbon gas liquids (HGL) consumption, which fell 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 1.0 million b/d in 2016. HGL consumption rises as additional natural gas processing and pipeline capacity make HGL supplies more accessible, with HGL production forecast to increase by 520,000 b/d (17%) between 2014 and 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 9.2 million b/d in 2015 and remain flat in 2016. The 2015 and 2016 production forecasts are 40,000 b/d and 100,000 b/d lower than in last month's STEO, respectively. The reduction in the crude oil production forecast reflects a reduced WTI price forecast for 2016 in this STEO and a sustained drop in rig counts beyond what EIA had initially expected. Oil-directed rigs declined to the lowest level in almost five years as of early May.

EIA expects onshore production to decline beginning in the second quarter of 2015 because of unattractive economic returns in some areas of both emerging and mature oil production regions. Reductions in 2015 capital expenditures, cash flows, and low-cost credit availability have encouraged companies to defer investment or redirect investment away from marginal exploration and research drilling to focus on core areas of major tight oil plays. Projected 2015 oil prices remain high enough to support continued development drilling activity in the core areas of the Bakken, Eagle Ford, Niobrara, and Permian basins. Companies with lower drilling and debt-service costs that operate on acreage in the sweet spots of these regions are expected to continue to drill highly productive wells in 2015.

EIA expects U.S. crude oil production to exceed 9.3 million b/d in the second quarter of 2015, then decline by 280,000 b/d through the first quarter of 2016. With forecast WTI crude oil prices rising to an average of $67/b in the second quarter of 2016, drilling activity is expected to increase again. Companies are expected to take advantage of lower costs for acreage leasing, drilling, and well-completion services, resulting in growing production beginning in the second quarter of 2016. However, the forecast remains particularly sensitive to actual prices available at the wellhead, drilling economics that vary across regions and operators, and whether additional

production from the completion of backlogged wells materializes. Projected production in the federal offshore region rises during the forecast period, while production in Alaska falls. Production in these areas is less sensitive to short-term price movements than is onshore production in the Lower 48 states.

HGL production at natural gas processing plants, which reached a record high of 3.1 million b/d in October, is projected to average 3.2 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, while export terminal expansions will allow higher quantities of domestically produced 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 1969.

Petroleum Product Prices. Rising crude oil prices and several California refinery outages contributed to an increase in U.S. regular gasoline retail prices from a monthly average of $2.47/gal in April to $2.69/gal on May 11. The U.S. monthly average gasoline price is projected to reach $2.68/gal in May, and then decline as refineries in California resolve outages and refineries in the rest of the country increase production of gasoline following the spring maintenance season. EIA projects regular gasoline retail prices to average $2.51/gal during the third quarter of 2015.

The U.S. regular gasoline retail price, which averaged $3.36/gal in 2014, is projected to average $2.43/gal in 2015, 3¢/gal higher than in last month's STEO, and $2.63/gal in 2016, which is 10¢/gal lower than in last month's STEO. The diesel fuel retail price, which averaged $3.83/gal in 2014, is projected to fall to an average of $2.88/gal in 2015 and then rise to $3.12/gal in 2016.

As in the case of 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 RBOB futures contracts for August 2015 delivery traded over the five-day period ending May 7 averaged $2.00/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 August 2015 is about 12%.

Natural Gas

Natural gas prices fell throughout April, before rising slightly in early May. Production and inventories remain abundant, which is expected to keep prices at relatively low levels in 2015. Preliminary data indicate recent production has surpassed the December record. Storage injections were strong in April, and EIA expects working inventories in storage will end October at 3,890 Bcf, just above the five-year (2010-14) average. EIA's Henry Hub natural gas price forecast averages $2.93/million British thermal units (MMBtu) in 2015 and $3.32/MMBtu in 2016, 14¢/MMBtu and 13¢/MMBtu, respectively, lower than in last month's STEO.

Natural Gas Consumption. EIA's forecast of U.S. total natural gas consumption averages 76.9 Bcf per day (Bcf/d) in 2015 and 76.3 Bcf/d in 2016, compared with 73.5 Bcf/d in 2014. Consumption growth 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 2.2% in 2016. Low natural gas prices support increased use of natural gas for electricity generation in 2015. Industrial sector consumption increases by 4.0% and by 2.7% in 2015 and 2016, respectively, 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. Consumption of natural gas 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 4.5 Bcf/d (6.0%) and by 1.3 Bcf/d (1.7%) in 2015 and 2016, respectively, reflecting continuing production growth in the Lower 48 states, which more than offsets the long-term declining production in the Gulf of Mexico. Although EIA expects natural gas prices to remain low, 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. Most growth is expected to come from the Marcellus shale, as a backlog of drilled wells are completed and new pipelines come online to deliver Marcellus gas to markets in the Northeast. Preliminary data indicate significant production growth in April and the beginning of May.

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 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.

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 2015 and 2016. EIA projects that LNG gross exports will increase from an average of 0.04 Bcf/d in 2014 to 0.79 Bcf/d in 2016.

Natural Gas Inventories. On May 1, natural gas working inventories totaled 1,786 Bcf, which was 742 Bcf (71%) above the level at the same time in 2014 and 67 Bcf (4%) below the previous five-year (2010-14) average for the week. So far during the refill season, injections have surpassed the five-year average injections by a wide margin. EIA projects end-of-October 2015 inventories will total 3,890 Bcf, 92 Bcf above the five-year average.

Natural Gas Prices. The Henry Hub natural gas spot price averaged $2.61/MMBtu in April, a decline of 22 cents/MMBtu from March. EIA expects monthly average spot prices to remain lower than $3/MMBtu through August, and lower than $4/MMBtu through the remainder of the forecast. The projected Henry Hub natural gas price averages $2.93/MMBtu in 2015 and $3.32/MMBtu in 2016, 14¢/MMBtu and 13¢/MMBtu, respectively, lower than in last month's STEO.

Natural gas futures contracts for August 2015 delivery traded during the five-day period ending May 7 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 August 2015 contracts at $1.98/MMBtu and $4.11/MMBtu, respectively. At this time last year, the natural gas futures contract for August 2014 delivery averaged $4.78/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $3.63/MMBtu and $6.31/MMBtu.

Coal

Coal Consumption. EIA expects a 6% decrease in coal consumption in the electric power sector in 2015, despite a 1% increase in total electric power generation. Lower natural gas prices are the main driver of the decline. Projected low natural gas prices will make it more economical to run natural gas-fired generating units at higher utilization rates even in regions of the country (Midwest, South) that typically rely more heavily on coal-fired generation. The retirements of coal power plants in response to the implementation of the Mercury and Air Toxics Standards also reduces coal demand in the power sector in 2015. The full effect of the coal plant retirements on capacity will be felt in 2016, but projected rising electricity demand and higher natural gas prices increase the use of the remaining coal-fired fleet, mitigating the effects of the retirements as projected coal consumption in the electric power sector increases by 1% next year.

Coal Supply. EIA estimates that U.S. coal production for 2014 totaled 997 million short tons (MMst), 13 MMst (1.3%) higher than in 2013. Lower demand for coal (domestic consumption and exports) contributes to a projected 7% (66 MMst) decline in 2015 production. EIA projects a decline in all coal-producing regions with the largest decline occurring in Appalachia (34 MMst, or 13%). Declines in the Interior and Western regions are projected to be 2% and 5%, respectively. Coal production growth is projected to be flat 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, and then increase by 2 MMst 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 an estimated $2.36/MMBtu in 2014. EIA expects the delivered coal price to average $2.31/MMBtu in 2015 and $2.32/MMBtu in 2016.

Electricity

Henry Hub natural gas prices below $3/MMBtu have led to a shift away from the use of coal and toward natural gas for fueling power generation. During the first two months of 2015, coal fueled 37.4% of total U.S. electricity generation, down from 43.0% during the same period in 2014. In contrast, natural gas generation accounted for 27.6% of total generation, up from

23.7% during the first two months of 2014. The January-February natural gas fuel share of total electricity generation has been higher only once, in 2012, when it averaged 27.9%.

Electricity Consumption. The National Oceanic and Atmospheric Administration projects warmer temperatures this summer than last year's mild summer. U.S. cooling degree days during the summer months (April-September) of 2015 are projected to total about 6% more than the same period last year. Higher temperatures should lead to increased use of electricity for air conditioning. EIA forecasts U.S. retail sales of electricity to the residential sector will be 3,920 gigawatthours per day (GWh/d) during the summer of 2015, which is 2.9% higher than last summer. Higher residential consumption of electricity this summer is offset somewhat by a year-over-year decline in sales during the first quarter, leading to forecast 2015 annual growth in U.S. residential electricity sales of 0.5%. EIA expects U.S. retail sales of electricity to the commercial and industrial sectors to grow by 1.5% and 0.6%, respectively, during 2015.

Electricity Generation. Total U.S. generation of electricity is forecast to average about 11,340 GWh/d in 2015, which is 1.2% higher than total generation last year. The use of coal for power generation stays low by historical standards as the forecast natural gas price at Henry Hub remains below $3/MMBtu through August. Lower use of existing coal capacity, combined with some coal retirements and regular seasonal maintenance, reduce projected U.S. coal generation in April and May so that its share of total generation is only 1.2 percentage points higher than the natural gas generation share. This is the closest convergence in generation shares between the two fuels since April 2012. EIA forecasts coal's share of U.S. total generation will be 35.8% in 2015, down from 38.7% in 2014. In contrast, the natural gas fuel share averages 30.7% this year, up from 27.4% in 2014.

Electricity Retail Prices. EIA expects continued growth in average U.S. residential electricity prices over the forecast period, but at a slower pace than last year. The forecast U.S. retail residential price increases by 1.6% in 2015 and by 1.8% in 2016. Industrial electricity prices, which are more responsive to changes in fuel costs, are expected to fall by 2.4% in 2015 and then rise by 1.2% in 2016.

Renewables and Carbon Dioxide Emissions

Electricity and Heat Generation from Renewables. EIA expects renewables used in the electric power sector will grow by 3.0% in 2015 as conventional hydropower generation decreases by 0.9%, while nonhydropower renewable power generation increases 6.8%. The 2015 decrease in hydropower generation occurs because the effects of the California drought are only partially offset by resources elsewhere. Generation from hydropower is expected to return to longer-term average levels with an increase of 4.0% in 2016. Total renewables consumption for electric power and heat generation decreases by 0.4% in 2015 but increases by 4.5% in 2016.

EIA expects continued growth in utility-scale solar power generation, which is projected to average 83 GWh/d in 2016. Despite this growth, utility-scale 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 utility-scale

solar capacity will increase by 84% between the end of 2014 and the end of 2016, with about 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 about 90% of the projected utility-scale capacity additions for 2015 and 2016. According to current law, projects coming online after the end of next year will see a federal investment tax credit of 10%, well 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 8.1% in 2014, is forecast to increase by 13.0% in 2015 and by another 11.3% 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 more than twice that of solar: 17 GW of wind compared with 8 GW of utility-scale solar between 2014 and 2016.

Liquid Biofuels. After ethanol production in December 2014 topped 1.0 million b/d for the first time, it is estimated to have fallen to an average of 927,000 b/d in April 2015. Ethanol production averaged 935,000 b/d in 2014, and EIA expects it to average 936,000 b/d in 2015 and 937,000 b/d in 2016. Biodiesel production averaged an estimated 81,000 b/d in 2014 and is forecast to average 81,000 b/d in 2015 and 84,000 b/d in 2016.

Energy-Related Carbon Dioxide Emissions. EIA estimates that emissions grew 1.0% in 2014 and are projected to remain flat over the forecast period. These forecasts are sensitive to both weather and economic assumptions.

U.S. Economic Assumptions

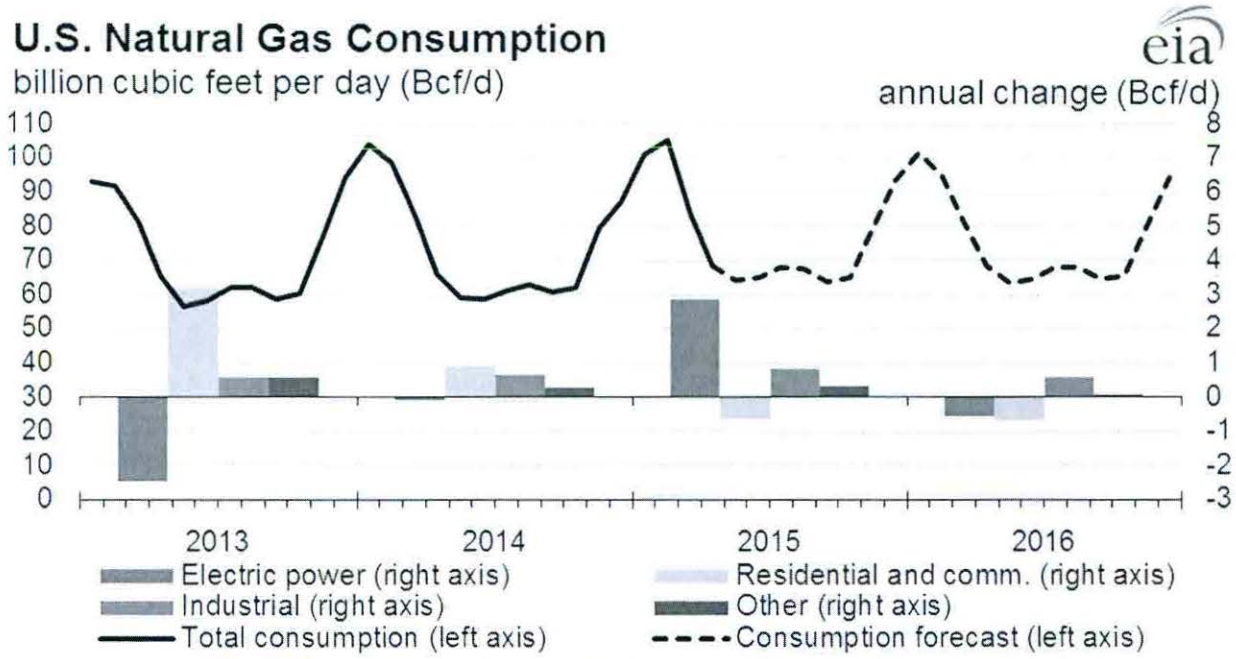
Recent Economic Indicators. The Bureau of Economic Analysis reported that real gross domestic product (GDP) grew at an annual rate of 0.2% in the first quarter of 2015. Personal consumption expenditures and private inventory investment contributed positively to this initial estimate, and they were partly offset by negative contributions from exports and nonresidential fixed investment.

EIA used the April 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 reaches 2.6% in 2015 and slows to 2.4% in 2016. Growth is expected to rise in 2015 because of increases in consumer purchases. However, a stronger dollar and lower demand from slower-growing economies are expected to reduce export growth and raise import growth. Real disposable income grows by 3.3% in 2015, above the 3.1% forecast last month, and by 2.0% in 2016. Total industrial production grows at 1.6% in 2015 and 2.5% in 2016. Projected growth in nonfarm employment averages 2.0% in 2015 and 1.2% in 2016.

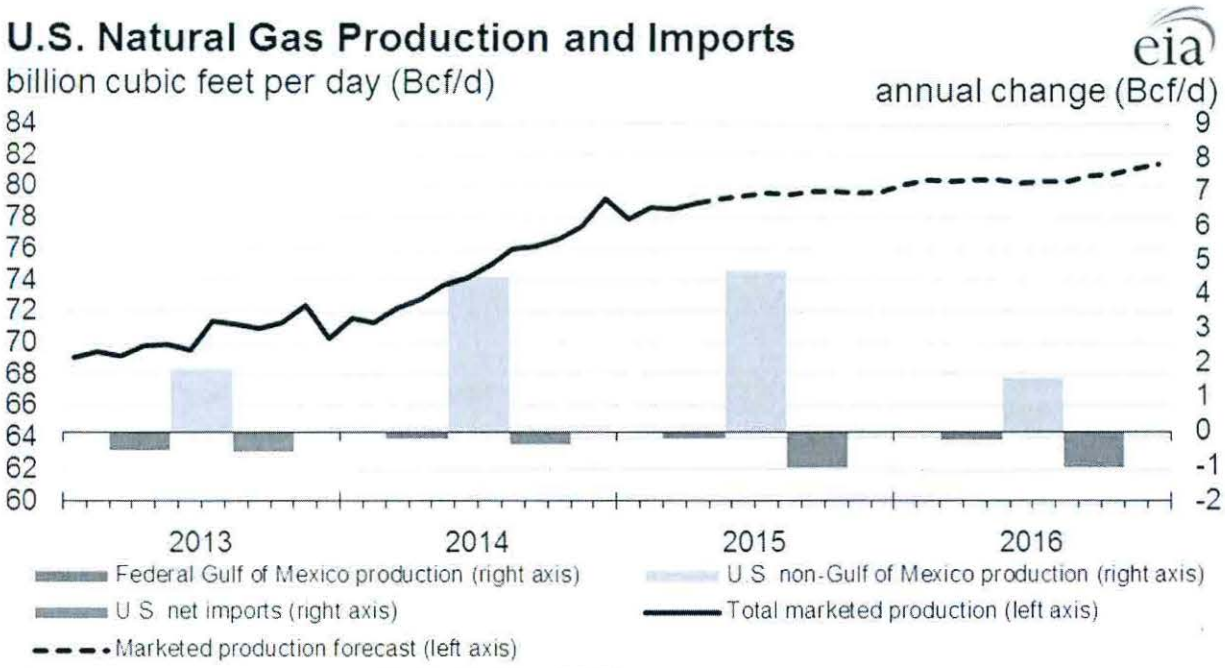
Expenditures. Forecast private real fixed investment growth averages 4.6% and 7.1% in 2015 and 2016, respectively, led by equipment in 2015 and 2016 and by equipment and structures in

2016. Real consumption expenditures grow faster than real GDP in 2015 and 2016, at 3.1% and 2.6%, respectively. Durable goods expenditures drive consumption spending in both years. Export growth is 2.1% and 4.2% over the same two years, while import growth is 3.7% in 2015 and 7.1% in 2016. Total government expenditures rise 0.9% in 2015 and 0.4% in 2016.

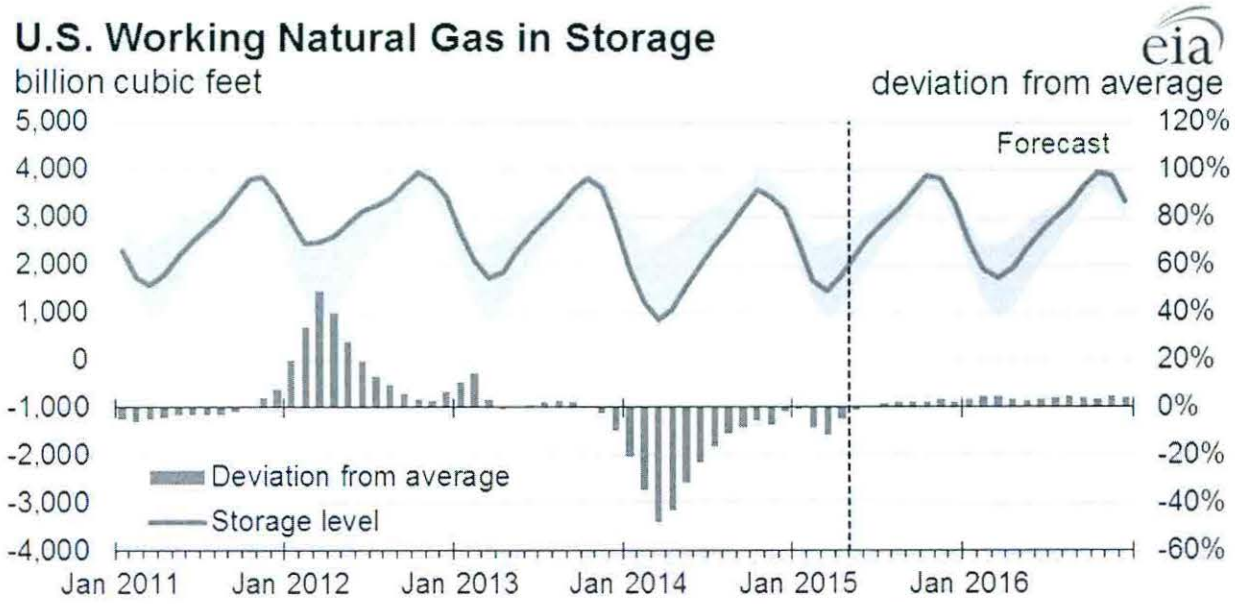


Source: Short-Term Energy Outlook, May 2015.

U.S. Natural Gas Production and Imports



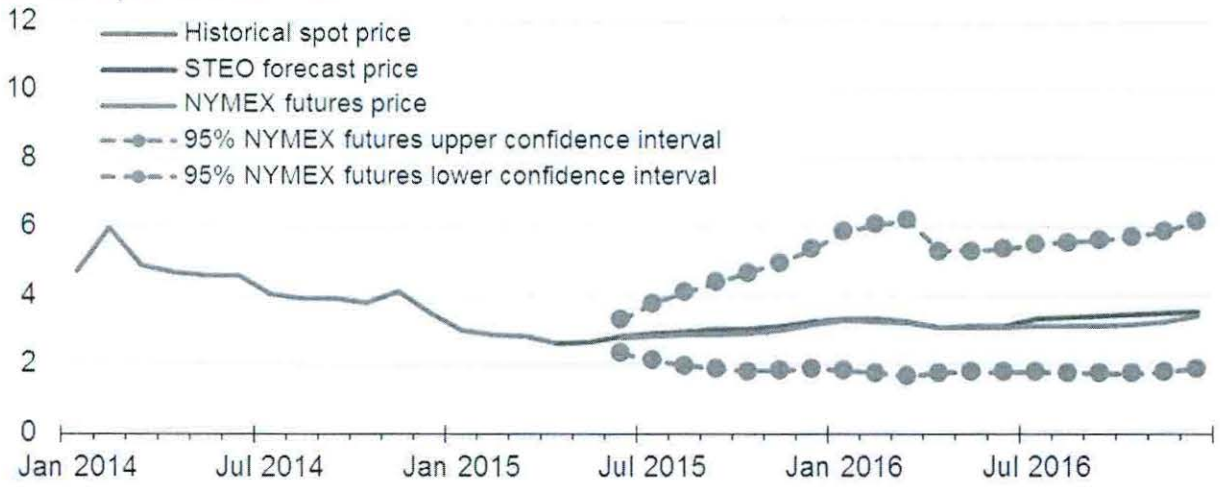
Source: Short-Term Energy Outlook, May 2015.



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

Henry Hub Natural Gas Price

dollars per million Btu

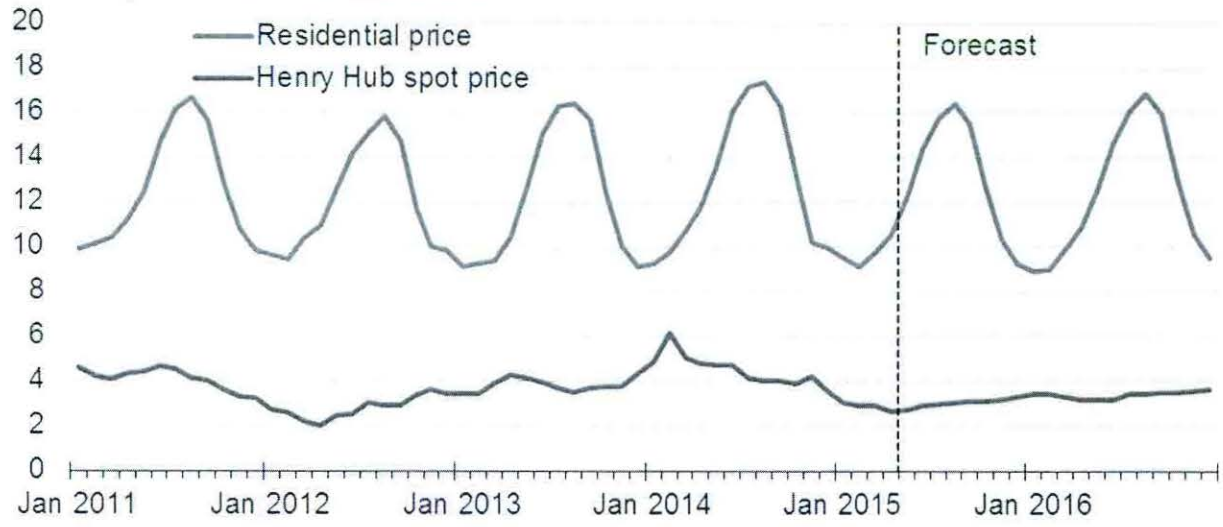


Note: Confidence interval derived from options market information for the 5 trading days ending May. 7, 2015. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, May 2015.

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, May 2015.

GREAT PLAINS NATURAL GAS CO.
GAS COST RECONCILIATION ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
FIRM
TO BE EFFECTIVE JUNE 1, 2015 THROUGH MAY 31, 2016

(Over)/under recovered gas costs @ April 30, 2015:			$74,482
Less projected recovery from rates already established:			
	Volume	Rate	Amount
May	9,900	$1.3462	$13,327
Additional recovery required			$61,155
Projected sales volumes			
June 2015		6,900	
July		7,100	
August		7,100	
September		8,700	
October		19,700	
November		33,200	
December		46,600	
January 2016		51,400	
February		43,900	
March		35,300	
April		20,400	
May		10,000	
Total			290,300
Total gas cost reconciliation adjustment to be effective June 1, 2015 through May 31, 2016			$0.2107

Change in Surcharge ($1.1355)

GREAT PLAINS NATURAL GAS CO.
GAS COST RECONCILIATION ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE
TO BE EFFECTIVE JUNE 1, 2015 THROUGH MAY 31, 2016

(Over)/under recovered gas costs @ April 30, 2015:			$35,759
Less projected recovery from rates already established:			
	Volume	Rate	Amount
May	19,300	$0.9696	$18,713
Additional recovery required			$17,046
Projected sales volumes			
June 2015		13,400	
July		13,000	
August		14,500	
September		17,600	
October		31,700	
November		44,400	
December		53,500	
January 2016		40,400	
February		32,300	
March		44,700	
April		45,200	
May		19,300	
Total			370,000
Total gas cost reconciliation adjustment to be effective June 1, 2015 through May 31, 2016			$0.0461
Change in Surcharge	($0.9235)		

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 Dk	Total Adjustment Amount		Net Change	Cumulative Balance
Balance @ April 30, 2014										**$404,569**
May	($15,520)		$2,700	($12,820)	18,641	$0.9614	$17,921		($30,741)	373,828
June	(1,551)		2,475	924	9,299	1.3462	10,015	2/	(9,091)	364,737
July	13,177		2,399	15,576	6,189	1.3462	8,332		7,244	371,981
August	13,687		2,437	16,124	5,378	1.3462	7,240		8,884	380,865
September	(855)		2,486	1,631	6,094	1.3462	8,204		(6,573)	374,292
October	5,798		2,424	8,222	9,359	1.3462	12,599		(4,377)	369,915
November	2,922		2,379	5,301	19,077	1.3462	25,681		(20,380)	349,535
December	22,567		2,225	24,792	41,354	1.3462	55,671		(30,879)	318,656
January 2014	(20,659)		2,006	(18,653)	47,085	1.3462	63,384		(82,037)	236,619
February	(12,916)		1,424	(11,492)	45,293	1.3462	60,973		(72,465)	164,154
March	2,475		913	3,388	47,446	1.3462	63,872		(60,484)	103,670
April	5,128		494	5,622	25,858	1.3462	34,810		(29,188)	74,482
Total	$14,253	$0	$24,362	$38,615	281,073		$368,702		($330,087)	
Balance @ April 30, 2015										**$74,482**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 6,507.2 dk @ $0.9614 and 2,792.4 dk @ $1.3462

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

	(Over) Under Recovery	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Dk	Total Adjustment Amount		Net Change	Cumulative Balance
Balance @ April 30, 2014									**$388,932**
May	($22,536)	$2,691	($19,845)	42,002	0.0274	$1,151		($20,996)	367,936
June	(17,420)	2,515	(14,905)	19,773	0.9696	5,999	2/	(20,904)	347,032
July	(3,815)	2,345	(1,470)	11,278	0.9696	10,936		(12,406)	334,626
August	(6,429)	2,239	(4,190)	13,996	0.9696	13,571		(17,761)	316,865
September	(26,713)	2,095	(24,618)	13,154	0.9696	12,755		(37,373)	279,492
October	879	1,811	2,690	27,455	0.9696	26,620		(23,930)	255,562
November	7,159	1,626	8,785	31,401	0.9696	30,446		(21,661)	233,901
December	204	1,459	1,663	30,497	0.9696	29,569		(27,906)	205,995
January 2014	8,505	1,248	9,753	48,709	0.9696	47,228		(37,475)	168,520
February	2,220	970	3,190	50,226	0.9696	48,699		(45,509)	123,011
March	24,229	636	24,865	62,797	0.9696	60,889		(36,024)	86,987
April	(10,521)	373	(10,148)	42,368	0.9696	41,080		(51,228)	35,759
Total	($44,238)	$20,008	($24,230)	393,656		$328,943		($353,173)	
Balance @ April 30, 2015									**$35,759**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 13,980.6 dk @ $0.0274 and 5,791.7 dk @ $0.9696.

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
FIRM

	1/	2/	3/	Total
May 2014				
Cost of Gas - Actual	$5.09270	$5.75720	$5.09270	
Cost of Gas - Recovered	6.28070	6.38990	6.38990	
(Over) Under recovery per dk	($1.18800)	($0.63270)	($1.29720)	
dk billed	3,960	12,382	2,299	18,641
(Over) Under recovery	($4,704)	($7,834)	($2,982)	($15,520)
June 2014				
Cost of Gas - Actual	$6.85130	$5.09270	$6.85130	
Cost of Gas - Recovered	6.08390	6.28070	6.28070	
(Over) Under recovery per dk	$0.76740	($1.18800)	$0.57060	
dk billed	2,792	4,212	2,295	9,299
(Over) Under recovery	$2,143	($5,004)	$1,310	($1,551)
July 2014				
Cost of Gas - Actual	$8.31880	$6.85130	$8.31880	
Cost of Gas - Recovered	6.22600	6.08390	6.08390	
(Over) Under recovery per dk	$2.09280	$0.76740	$2.23490	
dk billed	2,708	184	3,297	6,189
(Over) Under recovery	$5,667	$141	$7,369	$13,177
August 2014				
Cost of Gas - Actual	$8.42910	$8.31880	$8.42910	
Cost of Gas - Recovered	5.42460	6.22600	6.22600	
(Over) Under recovery per dk	$3.00450	$2.09280	$2.20310	
dk billed	2,373	574	2,431	5,378
(Over) Under recovery	$7,130	$1,201 4/	$5,356	$13,687
September 2014				
Cost of Gas - Actual	$7.24420	$8.42910	$7.24420	
Cost of Gas - Recovered	5.60190	5.42460	5.42460	
(Over) Under recovery per dk	$1.64230	$3.00450	$1.81960	
dk billed	2,626	2,764	704	6,094
(Over) Under recovery	$4,313	($6,449)	$1,281	($855)
October 2014				
Cost of Gas - Actual	$5.72570	$7.24420	$5.72570	
Cost of Gas - Recovered	5.53820	5.60190	5.60190	
(Over) Under recovery per dk	$0.18750	$1.64230	$0.12380	
dk billed	4,139	2,882	2,338	9,359
(Over) Under recovery	$776	$4,733	$289	$5,798

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
FIRM

	1/	2/	3/	Total
November 2014				
Cost of Gas - Actual	$5.57610	$5.72570	$5.57610	
Cost of Gas - Recovered	5.33840	5.53820	5.53820	
(Over) Under recovery per dk	$0.23770	$0.18750	$0.03790	
dk billed	7,719	4,391	6,967	19,077
(Over) Under recovery	$1,835	$823	$264	$2,922
December 2014				
Cost of Gas - Actual	$6.64870	$5.57610	$6.64870	
Cost of Gas - Recovered	6.75991	5.33840	5.33840	
(Over) Under recovery per dk	($0.11121)	$0.23770	$1.31030	
dk billed	13,637	11,406	16,311	41,354
(Over) Under recovery	($1,517)	$2,711	$21,373	$22,567
January 2015				
Cost of Gas - Actual	$4.84780	$6.64870	$4.84780	
Cost of Gas - Recovered	5.25090	6.75991	6.75991	
(Over) Under recovery per dk	($0.40310)	($0.11121)	($1.91211)	
dk billed	15,154	25,823	6,108	47,085
(Over) Under recovery	($6,108)	($2,872)	($11,679)	($20,659)
February 2015				
Cost of Gas - Actual	$4.85360	$4.84780	$4.85360	
Cost of Gas - Recovered	4.78660	5.25090	5.25090	
(Over) Under recovery per dk	$0.06700	($0.40310)	($0.39730)	
dk billed	11,308	29,605	4,380	45,293
(Over) Under recovery	$758	($11,934)	($1,740)	($12,916)
March 2015				
Cost of Gas - Actual	$5.34840	$4.85360	$5.34840	
Cost of Gas - Recovered	5.08130	4.78660	4.78660	
(Over) Under recovery per dk	$0.26710	$0.06700	$0.56180	
dk billed	16,864	38,824	(8,242)	47,446
(Over) Under recovery	$4,504	$2,601	($4,630)	$2,475
April 2015				
Cost of Gas - Actual	$3.84370	$5.34840	$3.84370	
Cost of Gas - Recovered	4.51350	5.08130	5.08130	
(Over) Under recovery per dk	($0.66980)	$0.26710	($1.23760)	
dk billed	8,427	21,496	(4,065)	25,858
(Over) Under recovery	($5,644)	$5,741	$5,031	$5,128

1/ Consumed in current month.
2/ Consumed in prior month.
3/ True-up of prior month volumes.
4/ Includes annual unbilled adjustment.

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE

	1/	2/	3/	Total
May 2014				
Cost of Gas - Actual	$3.83880	$4.88750	$3.83880	
Cost of Gas - Recovered	4.78400	4.88620	4.88620	
(Over) Under recovery per dk	($0.94520)	$0.00130	($1.04740)	
dk billed	5,683	19,907	16,412	42,002
(Over) Under recovery	($5,372)	$26	($17,190)	($22,536)
June 2014				
Cost of Gas - Actual	$3.85210	$3.83880	$3.85210	
Cost of Gas - Recovered	4.58720	4.78400	4.78400	
(Over) Under recovery per dk	($0.73510)	($0.94520)	($0.93190)	
dk billed	5,792	10,049	3,932	19,773
(Over) Under recovery	($4,258)	($9,498)	($3,664)	($17,420)
July 2014				
Cost of Gas - Actual	$4.32370	$3.85210	$4.32370	
Cost of Gas - Recovered	4.72930	4.58720	4.58720	
(Over) Under recovery per dk	($0.40560)	($0.73510)	($0.26350)	
dk billed	4,365	472	6,441	11,278
(Over) Under recovery	($1,771)	($347)	($1,697)	($3,815)
August 2014				
Cost of Gas - Actual	$3.91720	$4.32370	$3.91720	
Cost of Gas - Recovered	3.92790	4.72930	4.72930	
(Over) Under recovery per dk	($0.01070)	($0.40560)	($0.81210)	
dk billed	5,231	1,832	6,933	13,996
(Over) Under recovery	($56)	($743) 4/	($5,630)	($6,429)
September 2014				
Cost of Gas - Actual	$4.14730	$3.91720	$4.14730	
Cost of Gas - Recovered	4.10520	3.92790	3.92790	
(Over) Under recovery per dk	$0.04210	($0.01070)	$0.21940	
dk billed	3,914	10,663	(1,423)	13,154
(Over) Under recovery	$165	($26,566)	($312)	($26,713)
October 2014				
Cost of Gas - Actual	$4.07930	$4.14730	$4.07930	
Cost of Gas - Recovered	4.04150	4.10520	4.10520	
(Over) Under recovery per dk	$0.03780	$0.04210	($0.02590)	
dk billed	13,038	11,175	3,242	27,455
(Over) Under recovery	$493	$470	($84)	$879

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE

	1/	2/	3/	Total
November 2014				
Cost of Gas - Actual	$4.22160	$4.07930	$4.22160	
Cost of Gas - Recovered	3.84170	4.04150	4.04150	
(Over) Under recovery per dk	$0.37990	$0.03780	$0.18010	
dk billed	15,708	11,489	4,204	31,401
(Over) Under recovery	$5,967	$435	$757	$7,159
December 2014				
Cost of Gas - Actual	$5.39640	$4.22160	$5.39640	
Cost of Gas - Recovered	5.23920	3.84170	3.84170	
(Over) Under recovery per dk	$0.15720	$0.37990	$1.55470	
dk billed	7,981	30,691	(8,175)	30,497
(Over) Under recovery	$1,255	$11,659	($12,710)	$204
January 2015				
Cost of Gas - Actual	$3.62170	$5.39640	$3.62170	
Cost of Gas - Recovered	3.63760	5.23920	5.23920	
(Over) Under recovery per dk	($0.01590)	$0.15720	($1.61750)	
dk billed	11,972	38,383	(1,646)	48,709
(Over) Under recovery	($190)	$6,034	$2,661	$8,505
February 2015				
Cost of Gas - Actual	$3.70260	$3.62170	$3.70260	
Cost of Gas - Recovered	3.17330	3.63760	3.63760	
(Over) Under recovery per dk	$0.52930	($0.01590)	$0.06500	
dk billed	5,420	44,024	782	50,226
(Over) Under recovery	$2,869	($700)	$51	$2,220
March 2015				
Cost of Gas - Actual	$3.56600	$3.70260	$3.56600	
Cost of Gas - Recovered	3.46800	3.17330	3.17330	
(Over) Under recovery per dk	$0.09800	$0.52930	$0.39270	
dk billed	19,433	38,767	4,597	62,797
(Over) Under recovery	$1,905	$20,519	$1,805	$24,229
April 2015				
Cost of Gas - Actual	$2.46370	$3.56600	$2.46370	
Cost of Gas - Recovered	2.90020	3.46800	3.46800	
(Over) Under recovery per dk	($0.43650)	$0.09800	($1.00430)	
dk billed	9,619	24,101	8,648	42,368
(Over) Under recovery	($4,198)	$2,362	($8,685)	($10,521)

1/ Consumed in current month.
2/ Consumed in prior month.
3/ True-up of prior month volumes.
4/ Includes annual unbilled adjustment.