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May 30, 2014

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

Re: Cost of Gas Adjustment (COG)
June 2014

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and two (2) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (99th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (99th Revised Sheet No. 8), showing the June 2014 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.1880 per Dk for residential and firm general service customers and an increase of \$0.7454 per Dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for June 2014, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.1968 per Dk for all customers since the last COG filing due to a decrease in the market price of gas.

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

Attachment D shows the calculation of the gas cost reconciliation (GCR) adjustment that will apply during the period of June 1, 2014 through May 31, 2015. The total GCR is \$1.3462 per Dk for residential and general service customers and \$0.9696 per Dk for interruptible customers. The effect of this change is an increase of \$0.3848 for residential and general service customers and an increase of \$0.9422 for interruptible customers.

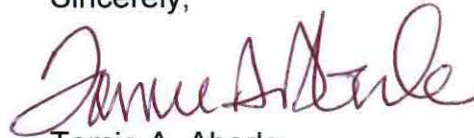
Great Plains submitted a check for \$600.00 on January 2, 2014 pursuant to the

requirements of Section 49-05-05 of the North Dakota Century Code. This payment covers the \$50.00 filing fee associated with this month's COG filing.

Great Plains respectfully requests this filing be accepted as being in full compliance with the filing requirements of this Commission.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,



Tamie A. Aberle
Director of Regulatory Affairs

Attachments

Attachment A

Attachment A



GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota Gas Rate Schedule

NDPSC Volume 2
99th Revised Sheet No. 8
Canceling 98th Revised Sheet No. 8

COST OF GAS

Page 1 of 1

Summary:	Firm			Interruptible			
	Est. Wtd. Demand Costs	Average Commodity	GCR Adj.	Est. Wtd. Total Firm	Average Commodity	GCR Adj.	Total Int.
Base Rate	\$0.0662	\$5.1708	\$0.0000	\$5.2370	\$5.1708	\$0.0000	\$5.1708
Accumulated Adj.	1.4450	(0.4013)	0.9614	2.0051	(0.3868)	0.0274	(0.3594)
Current Adj.	0.0000	(0.1968)	0.3848	0.1880	(0.1968)	0.9422	0.7454
Total Adj.	1.4450	(0.5981)	1.3462	2.1931	(0.5836)	0.9696	0.3860
Total Rate	\$1.5112	\$4.5727	\$1.3462	\$7.4301	\$4.5872	\$0.9696	\$5.5568

Date Filed: May 30, 2014

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:



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

**State of North Dakota
 Gas Rate Schedule**

NDPSC Volume 2

99th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 98th Revised Sheet No.1.1

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/dk	
Firm Gas Service - General	2	\$3.50 per month	First 10 dk Over 10 dk	\$1.2869 1.0646	\$7.4301	\$8.7170 8.4947
Interruptible Gas Service - General	3	\$3.50 per month	First 400 dk Next 2,600 dk Over 3,000 dk	\$1.1506 0.9021 0.7486	\$5.5568	\$6.7074 6.4589 6.3054
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All dk	\$1.2516	\$5.5568	\$6.8084
Transportation Service	5	\$3.50 per month	First 400 dk Next 2,600 dk Over 3,000 dk	\$1.1506 0.9021 0.7486		\$1.1506 0.9021 0.7486

Date Filed: May 30, 2014

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

Issued By: Tamie A. Aberle
 Director - Regulatory Affairs

Case No.:

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

Firm	Billing		Demand Months	Amount	Amount Per dk
	Determinants	Rate			
FT-A - Zone 1-1	8,000	\$3.3978	12	\$326,189	\$0.2315
FT-A - Zone 1-1	5,000	3.6918	5	92,295	0.0655
FT-A Seasonal	2,000	3.6918	5	36,918	0.0262
TFX Seasonal	2,000	15.1530	5	151,530	0.1075
TFX - Winter	13,000	15.1530	5	984,945	0.6990
TFX - Summer	13,000	5.6830	7	517,153	0.3670
LMS Demand 2/					0.0145
Total Demand Charges				\$2,109,030	1.5112
Estimated Weighted Average Commodity Cost	1,409,081	1/ 4.5727		6,443,305	4.5727
Gas Cost Reconciliation Adjustment					1.3462
Total Current Firm Gas Cost				\$8,552,335	7.4301
Base Cost of Gas					5.2370
Accumulated Adjustment					\$2.1931

Interruptible

Estimated Weighted Average Commodity Cost					\$4.5727
Gas Cost Reconciliation Adjustment					0.9696
LMS Demand 2/					0.0145
Total Current Interruptible Gas Cost					5.5568
Base Cost of Gas					5.1708
Accumulated Adjustment					\$0.3860

1/ Three year normalized average Dk sales

2/ Amount divided by 2011-2013 average normalized interruptible sales volumes plus 2011-2013 average normalized firm sales volumes.

LMS Demand	Billing		Demand Months	Amount	Amount Per dk
	Determinants	Rate			
	2,500	\$0.9800	12	\$29,400	\$0.0145

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

Rates Effective June 1, 2014	<u>\$/Dk</u>	
FT-A - Zone 1-1 (Category 1)	\$3.6918	Per Dk/Mo.
FT-A - Zone 1-1 (Category 3)	3.3978	Per Dk/Mo.
FT-A - Seasonal	3.6918	Per Dk/Mo.
TFX	15.1530	Per Dk/Mo.
TFX Seasonal	15.1530	Per Dk/Mo.
LMS Demand	0.9800	Per Dk/Mo.
Estimated Weighted Average Commodity Cost:	4.5727	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

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

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

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

2/ Demand base rate calculation:

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

STATEMENT OF RATES
 (Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
<u>Category 1 (Contract Term of Less than 3 Years)</u>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$3.6918
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$4.7894
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$2.0972
Zone 2-2 Minimum Rate	\$0.0000
<u>Category 2 (Contract Term of 3 Years to less than 5 Years)</u>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$3.5448
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$4.6424
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$1.9502
Zone 2-2 Minimum Rate	\$0.0000
<u>Category 3 (Contract Term of 5 or more Years)</u>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$3.3978
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$4.4954
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$1.8032
Zone 2-2 Minimum Rate	\$0.0000

Rate Schedule	Base Tariff Rate	Fuel and Loss Retention Percentages 2/
Commodity Rates 1/		
FT-A – Maximum Rates		
Zone 1-1	\$0.0127	0.08%
Zone 1-2	\$0.0127	0.10%
Zone 2-2	\$0.0127	0.02%
Minimum Rate	\$0.0127	
IT and AOT		
Zone 1-1	\$0.1341	0.08%
Zone 1-2	\$0.1702	0.10%
Zone 2-2	\$0.0816	0.02%
Minimum Rate	\$0.0127	

1/ Pursuant to Section 19 of the General Terms and Conditions, the maximum and minimum commodity rates shall be increased to include the Commission-authorized Annual Charge Adjustment unit rate as published on the Commission's Web Site located at <http://www.ferc.gov>.

2/ Fuel and Losses Retention Percentages shall be applicable to all transportation rate schedules.

Transportation Fuel and Loss Retention Percentages are inclusive of the following percentages for Gas Lost and Unaccounted For: 0.01% for Zone 1-1, 0.01% for Zone 1-2, and 0.00% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted for percentages.

Rate Schedule	Base Tariff Rate	Adjustment Under Section 27 1/	Rate After Current Adjustment
LMS – Monthly Demand Rate	\$0.9800		\$0.9800
LMS – Daily Overrun Rate	\$0.1702		\$0.1702
LMS – Load Management Cost Reconciliation Adjustment		\$0.0116	

1/ Pursuant to Section 27 of the General Terms and Conditions of this Tariff, a mechanism is established to reconcile through surcharges or credits to the Rate Schedule LMS rate, as appropriate, differences between the cost to maintain Company's line pack gas and the amounts Company receives or pays for such gas arising out of the purchase and sale of such gas.

Rate Schedule	Maximum Rate Per Dekatherm	Minimum Rate Per Dekatherm
PAL		
NPL, OPL, and APL Service:		
Daily Commodity Rate	\$0.1702	\$0.0000
RPL Service:		
Daily Reservation Rate	\$0.1702	\$0.0000

RATE SCHEDULE TF

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

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

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

GULF COAST	Reservation 1/		Commodity 6/		Out-of-Balance 6/	
	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
MOPS Gathering	1.0514	0.0000	0.0000	0.0000	0.0000	0.0000
MOPS Transmission	1.5337	0.0000	0.0000	0.0000	0.0000	0.0000
Tivoli - Downstream	0.6827	0.0000	0.0000	0.0000	0.0000	0.0000
Other Gulf Coast	4.8169	0.0000	0.0000	0.0000	0.0000	0.0000

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

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

Fuel Percentages/Electric Compression Rates

	<u>Percentages</u>
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.97%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.09% 4/ 5/
FDD Storage Fuel	1.76%
	<u>Electric Compression</u>
COMMODITY RATES:	1/
Market Area	\$0.0005
Field Area	\$0.0000

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

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

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

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

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

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

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

RATE SCHEDULES FDD, PDD, IDD & 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 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 2014**

The principal gas sources of natural gas for Wahpeton, North Dakota are from the mid-continent area of the United States. The pricing for the majority of this gas is the Northern Natural Gas Co. Ventura, Iowa point which is an actively traded market point in North America. The June monthly price for the NNG-Ventura Index is expected to decrease slightly 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.

Cooler than normal weather across portions of the country reduced the demand for natural gas for power burn and the continued strong domestic production were likely reasons for the index trading near the same level as last month. The EIA reported storage levels nationwide as of May 16, 2014 were 42.7 percent below the five-year average and 37.9 percent below last year's balance.

The Department of Energy's (DOE) Energy Information Administration (EIA) provides various publications on energy issues. The information is available on the DOE website: <http://www.eia.doe.gov>.

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided on pages 2 through 16.



Independent Statistics & Analysis

U.S. Energy Information
Administration

May 2014

Short-Term Energy Outlook (STEO)

Highlights

- During the April-through-September summer driving season this year, regular gasoline retail prices are forecast to average \$3.61/gallon (gal), 3 cents higher than last year and 4 cents higher than projected in last month's STEO. The projected monthly national average regular gasoline retail price falls from \$3.72/gal in May to \$3.51/gal in September. EIA expects regular gasoline retail prices to average \$3.48/gal in 2014 and \$3.39/gal in 2015, compared with \$3.51/gal in 2013.
- Brent crude oil spot prices averaged \$108/barrel (bbl) in April. This was the 10th consecutive month in which the average Brent crude oil spot prices fell within a relatively narrow range of \$107/bbl to \$112/bbl. New pipeline capacity from the Midwest into the Gulf Coast helped reduce inventories at the Cushing, Oklahoma storage hub to 25 million barrels by the end of April, the lowest level since October 2009. The discount of WTI crude oil to Brent crude oil, which averaged more than \$13/bbl from November through January, fell below \$4/bbl in early April. Total U.S. commercial crude oil stocks at the end of April reached a record high of nearly 400 million barrels, which is expected to put downward pressure on crude oil prices. EIA projects Brent crude oil prices to average \$106/bbl in 2014 and \$102/bbl in 2015 and the WTI discount to Brent to average \$10/bbl and \$11/bbl in 2014 and 2015, respectively.
- EIA estimates U.S. total crude oil production averaged 8.3 million barrels/day (bbl/d) in April 2014, which would be the highest monthly average production since March 1988. U.S. total crude oil production, which averaged 7.4 million bbl/d in 2013, is expected to increase to 8.5 million bbl/d in 2014 and 9.2 million bbl/d in 2015. The 2015 forecast represents the highest annual average level of production since 1972.
- Natural gas working inventories on April 25 totaled 0.98 trillion cubic feet (Tcf), 0.79 Tcf (45%) below the level at the same time a year ago and 0.98 Tcf (50%) below the previous five-year average (2009-13). Very cold weather and low inventories contributed to volatile Henry Hub natural gas spot prices over the past few months, increasing from \$3.95 per million British thermal units (MMBtu) on January 10 to a high of \$8.15/MMBtu on February 10, before falling back to \$4.61/MMBtu on February 27, and then bouncing back up to \$7.98/MMBtu on March 4. EIA expects that the Henry Hub natural gas spot price, which averaged \$3.73/MMBtu in 2013, will average \$4.74/MMBtu in 2014, \$0.30 higher than in last month's STEO, and \$4.33/MMBtu in 2015.

Global Petroleum and Other Liquids

EIA expects the combination of total liquids supply growth from countries outside of the Organization of the Petroleum Exporting Countries (OPEC) and noncrude oil supply growth in OPEC member countries to exceed world liquids demand growth over the next two years. The call on OPEC crude oil and global stocks (world consumption less non-OPEC supply and OPEC noncrude oil supply) is forecast to fall from an average of 30.0 million bbl/d in 2013 to 29.5 million bbl/d in 2015. Expected non-OPEC supply growth also contributes to an increase in global surplus crude oil production capacity held by OPEC countries from an average of 2.1 million bbl/d in 2013 to 3.5 million bbl/d in 2015.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 1.2 million bbl/d in 2013, averaging 90.4 million bbl/d for the year. EIA expects global consumption to grow 1.2 million bbl/d in both 2014 and 2015. Projected global oil-consumption-weighted real GDP, which increased by an estimated 2.3% in 2013, grows by 2.8% and 3.3% in 2014 and 2015, respectively.

Countries outside of the Organization for Economic Cooperation and Development (OECD) account for nearly all of the expected consumption growth in 2014 and 2015. China is the leading contributor to projected global consumption growth, with consumption increasing by 400,000 bbl/d in 2014 and 430,000 bbl/d in 2015. However, China's economic and oil consumption growth rates have moderated compared with rates before 2012, when annual GDP growth exceeded 9% and annual oil consumption growth averaged almost 800,000 bbl/d from 2009 through 2011.

EIA expects lower OECD consumption in 2014, led by projected consumption declines in both Japan and Europe. EIA expects Japan's oil consumption to fall by an annual average of 130,000 bbl/d in 2014 and 160,000 bbl/d in 2015, as the country continues to increase natural gas and coal consumption in the electricity sector and returns some nuclear power plants to service in the second half of 2014 and in 2015. EIA projects that OECD Europe's consumption, which fell by 100,000 bbl/d in 2013, will decline by 70,000 bbl/d in 2014 and then remain flat in 2015. U.S. liquid fuel consumption, which increased by 400,000 bbl/d in 2013, is expected to increase by only 40,000 bbl/d in 2014 and then increase by 60,000 bbl/d in 2015.

Non-OPEC Supply. EIA estimates that non-OPEC liquid fuel production grew by 1.3 million bbl/d in 2013, averaging 54.0 million bbl/d for the year. EIA expects non-OPEC liquid fuel production to grow by 1.5 million bbl/d in 2014 and 1.1 million bbl/d in 2015. EIA forecasts production from the United States and Canada to grow by a combined annual average of 1.4 million bbl/d in 2014 and 1.1 million bbl/d in 2015. EIA estimates that production will rise by an annual average of 0.21 million bbl/d in 2014 in countries of the Former Soviet Union, led by Russia. However, production in the region only rises by 30,000 bbl/d in 2015. The forecast of completion of phase 1 of Kazakhstan's Kashagan field has been pushed back to the second half of 2015 because of continued problems delaying the start of commercial production at the field.

Unplanned supply disruptions among non-OPEC producers averaged 0.6 million bbl/d in April 2014, roughly unchanged from March. South Sudan, Syria, and Yemen accounted for almost 90% of total non-OPEC supply disruptions. EIA does not assume a disruption to oil supply or demand as a result of ongoing events in Ukraine.

OPEC Supply. EIA estimates that OPEC crude oil production averaged 30.0 million bbl/d in 2013, a decline of 0.9 million bbl/d from the previous year, primarily reflecting production declines in Iran, increased unplanned outages in Libya, Nigeria, and Iraq, and strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.4 million bbl/d in 2014 and an additional 0.1 million bbl/d in 2015, as a result of supply disruptions in OPEC and cutbacks in crude oil production to accommodate increased supplies in non-OPEC countries.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.6 million bbl/d in April, slightly lower than the previous month. Libya continues to experience swings in its production, contributing to changes in the OPEC disruption estimate.

EIA expects that OPEC surplus capacity, which is concentrated in Saudi Arabia, will average 2.3 million bbl/d in 2014 and 3.5 million bbl/d in 2015. This build in surplus capacity reflects production cutbacks by some OPEC members adjusting for the higher supply from non-OPEC producers. These estimates do not include additional capacity that may be available in Iran but is currently offline because of the effects of U.S. and European Union sanctions on Iran's oil sector.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.58 billion barrels at the end of 2013, equivalent to roughly 55 days of consumption. Projected OECD oil inventories remain near 2.60 billion barrels at the end of both 2014 and 2015.

Crude Oil Prices. North Sea Brent crude oil spot prices averaged \$108/bbl in April. This was the 10th consecutive month in which average Brent crude oil spot prices fell within a relatively narrow range of \$107/bbl to \$112/bbl. The forecast Brent crude oil price averages \$106/bbl and \$102/bbl in 2014 and 2015, respectively, both \$1/bbl higher than in last month's STEO.

The January 2014 startup of TransCanada's Marketlink pipeline, moving crude from Cushing to the Gulf Coast, and strong refinery runs contributed to an increase in the WTI crude oil spot price from an average of \$94/bbl in January to \$102/bbl in April. The discount of WTI crude oil to Brent crude oil, which averaged more than \$13/bbl from November 2013 through January 2014, fell to an average of less than \$6/bbl in April. EIA expects the discount of WTI crude oil to Brent crude oil to grow in the coming months to an average \$10/bbl in 2014 and \$11/bbl in 2015, reflecting [the economics of transporting and processing](#) the growing production of high API gravity (very light) sweet crude oil in the United States.

Energy price forecasts are highly uncertain, and the current values of futures and options contracts suggest that prices could differ significantly from the forecast levels ([Market Prices](#)

and Uncertainty Report). WTI futures contracts for August 2014 delivery, traded during the five-day period ending May 1, 2014, averaged \$99/bbl. Implied volatility averaged 17%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in August 2014 at \$85/bbl and \$115/bbl, respectively. Last year at this time, WTI for August 2013 delivery averaged \$93/bbl and implied volatility averaged 22%. The corresponding lower and upper limits of the 95% confidence interval were \$77/bbl and \$113/bbl.

U.S. Petroleum and Other Liquids

U.S. regular gasoline retail prices increased for the 12th consecutive week in late April 2014, rising from a weekly average of \$3.29/gal on February 3 to reach \$3.71/gal as of April 28. This price is about \$0.19/gal higher than at the same time last year, and has been driven by higher crude oil prices, strong demand for gasoline (both domestically and for export) and lower inventory levels. However, EIA expects crude oil prices to decline this summer, in contrast to last year when oil prices rose over the same time period. Consequently, the regular gasoline retail price is expected to average only 3 cents higher this summer compared with last summer.

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 400,000 bbl/d (2.1%) in 2013. Total consumption growth slows, to 40,000 bbl/d in 2014 and 70,000 bbl/d in 2015. Consumption of hydrocarbon gas liquids (HGL) registered the largest gain in 2013, increasing by 150,000 bbl/d (6.4%). HGL consumption growth of 30,000 bbl/d in 2014 and 50,000 bbl/d in 2015 is led by increasing ethane use as a feedstock in ethylene production units.

Motor gasoline consumption grew by 90,000 bbl/d (1.1%) in 2013, the largest increase since 2006. Motor gasoline consumption grows by 20,000 bbl/d in 2014 and remains flat in 2015 as improving new vehicle fuel economy increasingly offsets highway travel growth. Distillate fuel consumption increased by 90,000 bbl/d (2.5%) last year, reflecting colder weather and domestic economic growth. Distillate fuel oil consumption rises by 70,000 bbl/d and 60,000 bbl/d in 2014 and 2015, respectively. The increases in HGL, gasoline, and distillate consumption are partially offset by declines in consumption of residual fuel oil and unfinished oils.

Liquid Fuels Supply. Forecast total U.S. crude oil production increases from an estimated 7.4 million bbl/d in 2013 to 8.5 million bbl/d in 2014 and 9.2 million bbl/d in 2015. The highest previous annual average U.S. production level was 9.6 million bbl/d in 1970. EIA has increased its Gulf of Mexico crude oil production forecast as new wells in the Mars field began producing ahead of schedule in February 2014. The Olympus platform and Mars B infrastructure, owned by Shell and BP, is the first major expansion of the Mars field. Mars B production is expected to reach 100,000 bbl/d in 2015. Although the peak production levels have not changed, earlier reports indicated that the Mars B system would begin producing in late 2014 or early 2015. U.S. federal Gulf of Mexico (GOM) production, which has fallen for four consecutive years, is projected to increase by 150,000 bbl/d in 2014 and by an additional 240,000 bbl/d in 2015.

HGL production at natural gas liquids plants is projected to rise from 2.6 million bbl/d in 2013 to 2.9 million bbl/d in 2015. About half of this growth is expected to come from ethane production to meet growing demand associated with expanding domestic ethylene production and export capacity. Ethane exports recently began flowing to Canada on the Mariner West and Vantage pipelines. In the second half of 2015, the Mariner East pipeline and new infrastructure at Marcus Hook, near Philadelphia, are expected to facilitate the movement of ethane from the Marcellus and Utica shales to Europe.

The growth in domestic production has contributed to a significant decline in petroleum imports. The share of total U.S. liquid fuels consumption met by net imports peaked at more than 60% in 2005 and fell to an average of 33% in 2013. EIA expects the net import share to decline to 23% in 2015, which would be the lowest level since 1970.

Petroleum Product Prices. Led by falling crude oil prices, the projected U.S. annual average regular gasoline retail price, which fell from \$3.63/gal in 2012 to an average of \$3.51/gal in 2013, will continue to fall to \$3.48/gal in 2014 and \$3.39 in 2015. Diesel fuel prices, which averaged \$3.92/gal in 2013, are projected to average \$3.87/gal in 2014 and \$3.78/gal in 2015.

EIA expects that the monthly average regular gasoline retail price, which was \$3.66/gal in April, will peak at \$3.72/gal in May and then fall to \$3.51/gal in September. The August 2014 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged \$2.90/gal for the five trading days ending May 1. Based on the market value of futures and options contracts for this key petroleum component of gasoline, there is a 4% probability that its price at expiration will exceed \$3.35/gal, consistent with a monthly average regular-grade gasoline retail price exceeding \$4.00/gal in August 2014. 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 exceeding the national average price by 30 cents/gal or more.

Natural Gas

On April 23, one of the five units at the [Williams Company's Opal, Wyoming, natural gas processing plant exploded and caught on fire](#). The plant, which had been processing about 1.0 Bcf/d according to Williams, partially returned to service by Thursday, May 1. While the plant was down, natural gas pipeline flows into California and the Southwest (Arizona, Nevada, and New Mexico) from the Permian Basin in West Texas and New Mexico, and rerouted production from the Rockies, offset lost output from Opal. This limited natural gas price increases in the region that could result from temporary supply shortages.

Natural Gas Consumption. EIA expects total natural gas consumption will average 72.3 billion cubic feet per day (Bcf/d) in 2014, an increase of 1.3% from 2013, led by the industrial sector. In 2015, total natural gas consumption falls by 0.1 Bcf/d as a return to near-normal winter weather contributes to lower residential and commercial consumption. Higher natural gas prices this

year contribute to a 0.4% decline in natural gas consumption in the power sector to 22.2 Bcf/d in 2014. EIA expects natural gas consumption in the power sector to increase to 23.1 Bcf/d in 2015 with the retirement of some coal plants.

Natural Gas Production and Trade. EIA expects natural gas marketed production will grow by an average rate of 3.0% in 2014 and 1.8% in 2015. Rapid natural gas production growth in the Marcellus formation is contributing to falling natural gas forward prices in the Northeast, which often fall even with or below Henry Hub prices outside of peak winter demand months. Consequently, some drilling activity may move away from the Marcellus back to Gulf Coast plays such as the Haynesville and Barnett, where prices are closer to the Henry Hub spot price.

Liquefied natural gas (LNG) imports have declined over the past several years because higher prices in Europe and Asia are more attractive to sellers than the relatively low prices in the United States. [Several companies are planning to build liquefaction capacity](#) to export LNG from the United States. Cheniere Energy's Sabine Pass facility is expected to be the first to liquefy natural gas produced in the Lower 48 states for export. The facility has a total liquefaction capacity of 3 Bcf/d and is scheduled to come online in stages beginning in late 2015.

Growing domestic production over the past several years has displaced some [pipeline imports from Canada](#), while [exports to Mexico](#) have increased. EIA projects net imports of 3.7 Bcf/d in 2014 and 3.1 Bcf/d in 2015, which would be the lowest level since 1987. Over the longer term, the [EIA Annual Energy Outlook 2014](#) projects the United States will be a net exporter of natural gas beginning in 2018.

Natural Gas Inventories. Natural gas working inventories increased by 159 Bcf over the last four weeks to reach 981 Bcf on April 25, which is 790 Bcf lower than the same time last year and 984 Bcf lower than the previous 5-year (2009-2013) average. The injection season has started somewhat slowly, but EIA expects injections will pick up over the summer to end October at just over 3,400 Bcf. EIA projects the rate of injections between April 25 and the end of October will average about 90 Bcf per week, which is 20 Bcf greater than the average weekly injection during the past five years.

Natural Gas Prices. Natural gas spot prices averaged \$4.66/MMBtu at the Henry Hub in April, down \$0.24/MMBtu from March, as spring weather finally arrived in much of the United States. EIA projects that spot prices will continue to decline but at a slower pace through the spring and summer. Projected Henry Hub natural gas prices average \$4.74/MMBtu in 2014 and \$4.33/MMBtu in 2015.

Natural gas futures prices for August 2014 delivery (for the five-day period ending May 1) averaged \$4.78/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for August 2014 contracts at \$3.63/MMBtu and \$6.31/MMBtu, respectively. At this time last year, the natural gas futures

contract for August 2013 averaged \$4.34/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$3.22/MMBtu and \$5.84/MMBtu.

Coal

The severe winter weather, which increased power demand, combined with rail shipment constraints, contributed to a large drawdown in coal inventories. Power sector stockpiles have fallen by 34 million short tons (MMst) (21%) between the end of November and the end of March. Recent milder weather has helped to relieve some of the [rail congestion experienced this winter](#). According to [Association of American Railroads](#) data for the week ending April 26, total coal shipments increased 8.0% compared with the same week in 2013. It was the seventh consecutive week in which coal shipments increased, and year-to-date shipments of coal are up slightly (1.2%) from the same period last year.

Coal Supply. EIA projects U.S. coal production will grow 4.4% to 1,028 MMst in 2014, driven by higher consumption. In 2015, forecast U.S. coal production falls by 1.1% to 1,016 MMst.

Coal Consumption. EIA projects that U.S. consumption will grow at a rate of 5.0% to 971 MMst in 2014 as electricity demand grows and natural gas prices remain well above their 2013 level. Total coal consumption is projected to decline by 3.2% in 2015, as retirements of coal power plants rise in response to the implementation of the [Mercury and Air Toxics Standards](#), and generation from renewable resources (wind, hydro, biomass, geothermal, and solar) grows by more than 3.0%. EIA is currently not forecasting any additional changes in coal use based on the April 29 decision by the U.S. Supreme Court reversing a lower court opinion that vacated the [Cross-State Air Pollution Rule \(CSAPR\)](#). CSAPR will replace the [Clean Air Interstate Rule \(CAIR\)](#). The U.S. Environmental Protection Agency (EPA) is currently reviewing the Supreme Court opinion, and the EPA has stated that “At this time, CAIR remains in place and no immediate action from states or affected sources is expected.”

Coal Exports. Exports are projected to total nearly 100 MMst in 2014. Coal exports totaled more than 100 MMst per year between 2011 and 2013. Before that, coal exports had not reached 100 MMst since 1992. In 2015, projected exports fall back to 91 MMst, primarily because of continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, and increasing coal output in other coal-exporting countries.

Coal Prices. Annual average coal prices to the electric power industry fell for the second consecutive year, from \$2.38/MMBtu in 2012 to \$2.35/MMBtu in 2013. EIA forecasts average delivered coal prices of \$2.34/MMBtu in 2014 and \$2.35/MMBtu in 2015.

Electricity

Retail electricity prices increased in many areas of the country during the first quarter of 2014, especially in the Northeast where high fuel costs drove up utilities' generation costs and the costs of purchasing electricity on wholesale power markets. EIA estimates first quarter retail electricity prices for the residential sector in New England were 11% higher than the same time last year, and residential prices in the Middle Atlantic region were 8% higher. Year-over-year increases in commercial sector electricity prices were highest in the Middle Atlantic (11%) and Pacific (8%) regions, while industrial prices increased the most in Middle Atlantic (19%) and South Atlantic (9%) regions.

Electricity Consumption. U.S. cooling degree days during the summer months (April-September) of 2014 are projected to total 5.7% more than last summer, when average summer temperatures in the United States were lower than normal. The increased need for space cooling contributes to the expected 1.5% summer-over-summer increase in U.S. electricity sales to the residential sector and the 2.2% increase in sales to the commercial sector.

Electricity Generation. EIA projects total U.S. electricity generation will average 11.4 terawatt-hours per day in 2014, an increase of 2.2% from last year. The use of coal for power generation rises 6.4% this year while natural gas-fired generation falls 2.0% and nuclear generation falls 2.7% from last year's levels. Both coal-fired and natural gas-fired generation decline in the West, as more hydropower and other renewable generation becomes available. There is little change in total generation during 2015, but the relative share of generation fueled by coal declines 1.5 percentage points to 39.2% next year, while the share fueled by natural gas rises to 27.4%.

Electricity Retail Prices. EIA has raised its forecasts for retail electricity prices from last month's STEO to reflect the higher-than-expected first quarter rate increases in the Northeast. The U.S. residential price of electricity is forecast to average 12.5 cents per kilowatt-hour during 2014, an increase of 2.9% from 2013. Projected residential prices increase an additional 2.1% during 2015.

Renewables and Carbon Dioxide Emissions

Electricity and Heat Generation from Renewables. EIA projects total renewables consumption for electricity and heat generation will grow by about 3.3% in 2014. Hydropower is projected to increase by 2.9%, while nonhydropower renewables rise by 3.6%. In 2015, projected renewables consumption for electric power and heat generation increases by 3.2% from 2014, as a 0.3% decrease in hydropower is combined with a 5.1% increase in nonhydropower renewables.

EIA estimates that wind power capacity will increase by 9.0% in 2014 and 15.5% in 2015. Electricity generation from wind is projected to contribute 4.5% of total electricity generation in 2015.

EIA expects continued robust growth in solar electricity generation, although the amount of utility-scale generation remains a small share of total U.S. generation at about 0.5% in 2015. While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity doubled in 2013. EIA currently expects that utility-scale solar capacity will increase by 56% between the end of 2013 and the end of 2015. About 70% of this new capacity is being built in California. However, customer-sited photovoltaic capacity growth, which the STEO does not forecast, is expected to exceed utility-scale solar growth between 2013 and 2015, according to [EIA's Annual Energy Outlook 2014](#).

Liquid Biofuels. [Railroad delays because of extreme winter temperatures in the Midwest contributed to sharp ethanol price increases across the United States](#) in February and March, especially in PADD 1 (East Coast). These rail constraints have since eased and ethanol prices fell as ethanol production increased from an average of 890,000 bbl/d in March to more than 910,000 bbl/d in April. Ethanol production is forecast to average 911,000 bbl/d during 2014 and 922,000 bbl/d in 2015.

Biodiesel production reached [104,000 bbl/d \(135 million gallons\) in December 2013](#), then fell to 54,000 bbl/d in January following the expiration of the biodiesel production tax credit at the end of 2013. Biodiesel production averaged 89,000 bbl/d in 2013 and is forecast to average 84,000 bbl/d in 2014 and 86,000 bbl/d in 2015.

Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels increased by 2.2% in 2013 from the previous year. Emissions are forecast to rise 2.3% in 2014, followed by a 1.0% decline in 2015. The increase in emissions in 2013 and 2014 reflects growth in coal consumption because of its higher use in electric power generation. Coal emissions are projected to decline by 3.3% in 2015 with increasing coal plant retirements.

U.S. Economic Assumptions

New orders for durable goods rose 2.6% from February to March according to the [U.S. Census Bureau](#), up from the 2.1% reported last month. The gain was more broad-based than from January to February, as it was driven by transportation, defense, and core capital goods, beating expectations of 0.6%. The [Federal Reserve's industrial production index](#) also gained 0.7% percent in March, and the February estimate was revised upwards. The news on the housing market, however, was less upbeat. [Census](#) reported that sales of new single-family homes fell 14.5% from February to March, and were 13.3% below the March 2013 estimate.

EIA uses the IHS/Global Insight macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

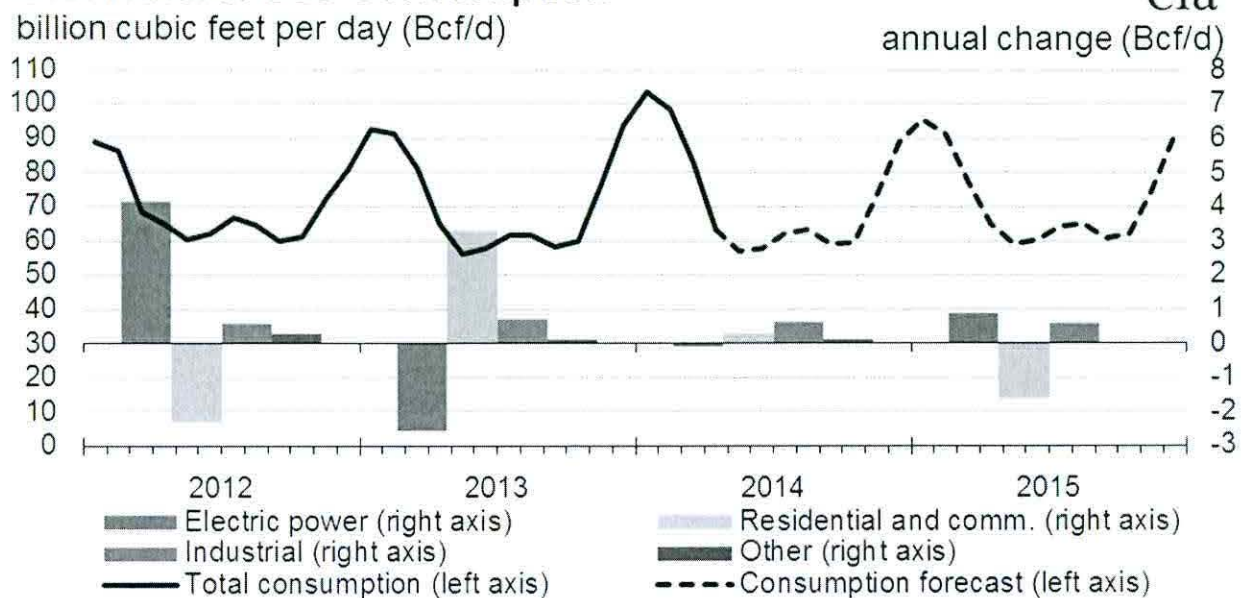
Production and Income. The [Bureau of Economic Analysis](#) estimates that real gross domestic product increased at an annual rate of 0.1 percent in the first quarter (that is, from the fourth quarter of 2013 to the first quarter of 2014). Forecast real GDP grows by 2.3% in 2014 and 2.9% in 2015, lower than the 2.5% and 3.2% forecast last month. The lower 2014 GDP growth forecast reflects concerns about lower inventory growth, first quarter weather, and capital spending and exports. In 2015, the reduced growth rate results from lower expectations of growth in the housing market and residential construction, and the subsequent impact on housing-related expenditures. Forecast real disposable income increases 2.1% in 2014 and 3.4% in 2015. Total industrial production grows at 3.6% in 2014 and 3.2% in 2015.

Expenditures. Private real fixed investment growth averages 5.5% and 8.7% in 2014 and 2015, respectively, with equipment and structures both growing around 6% in 2014. Real consumption expenditures grow at nearly the same rate as real GDP in 2014 and 2015, at 2.4% and 2.9%. Durable goods expenditures drive consumption spending. Export growth is 4.2% and 4.1% over the same two years, while import growth is 2.9% in 2014 and 6.2% in 2015. Total government expenditures fall 0.6% in 2014, but increase by 0.4% in 2015.

Employment, Housing, and Prices. Projected growth in nonfarm employment averages 1.6% in 2014 and 1.8% in 2015. This is accompanied by a gradually declining unemployment rate that reaches 6.4% by the end of 2014 and 5.9% at the end of 2015. The employment growth in 2014 and 2015 is slower than projected last month with more modest declines in unemployment. These reflect the lowering of the real GDP growth forecasts for 2014 and 2015. Housing starts grow an average of 12.0% and 32.5% in 2014 and 2015, respectively. Both consumer and producer price indexes continue to increase at a moderate pace, as wages continue to show modest gains.

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the U.S. Department of Energy or other federal agencies.

U.S. Natural Gas Consumption



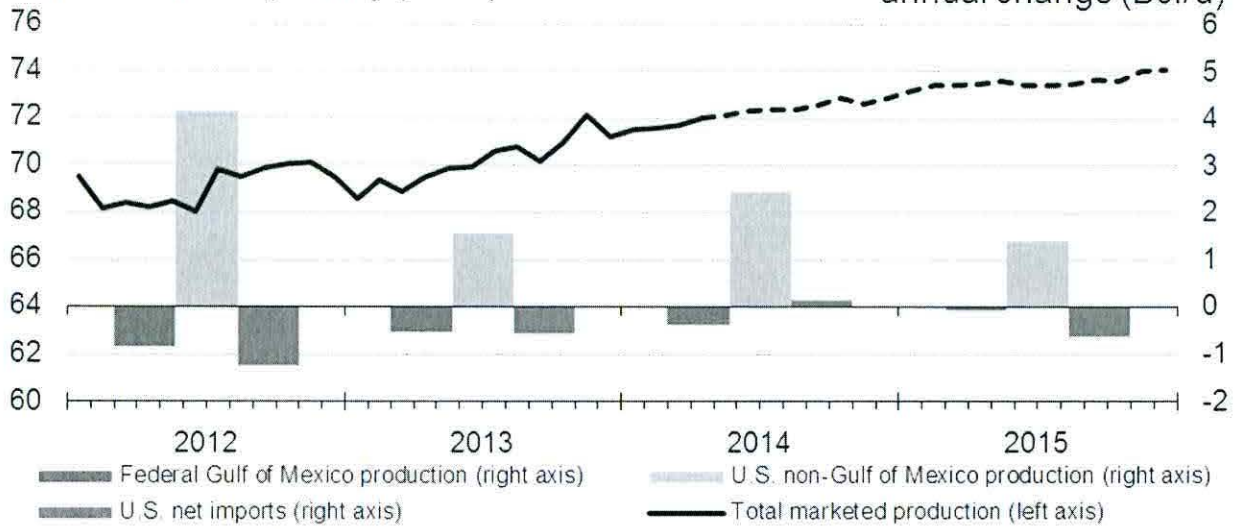
Source: Short-Term Energy Outlook, May 2014.

U.S. Natural Gas Production and Imports



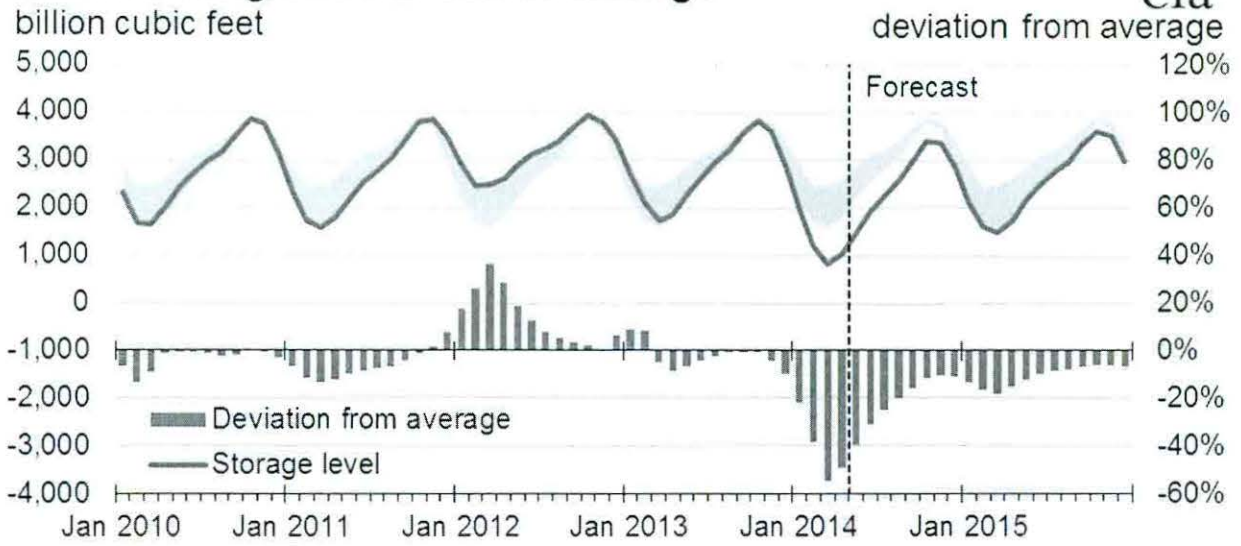
billion cubic feet per day (Bcf/d)

annual change (Bcf/d)



Source: Short-Term Energy Outlook, May 2014.

U.S. Working Natural Gas in Storage

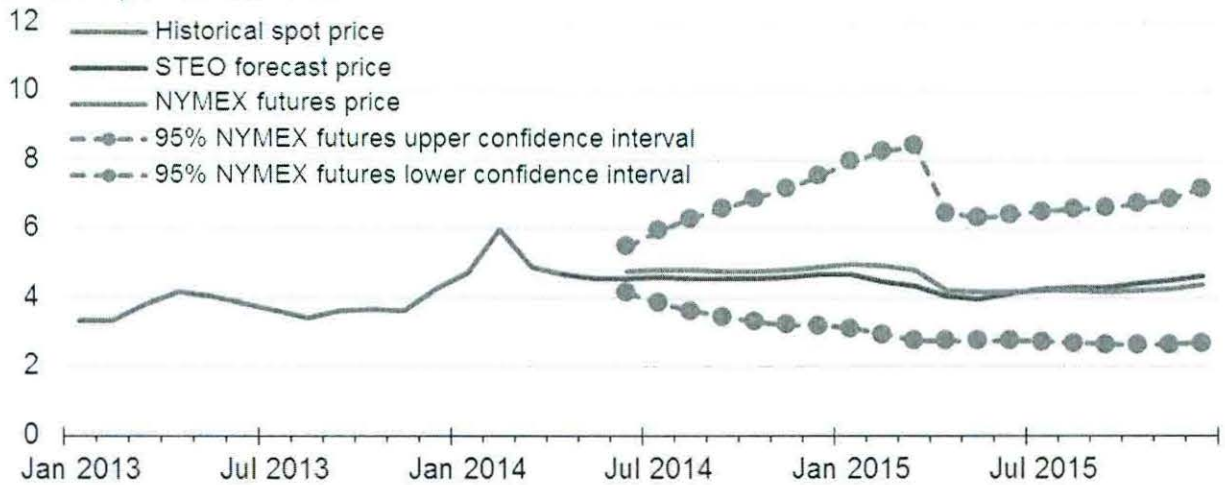


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2009 - Dec. 2013.

Source: Short-Term Energy Outlook, May 2014.

Henry Hub Natural Gas Price

dollars per million Btu

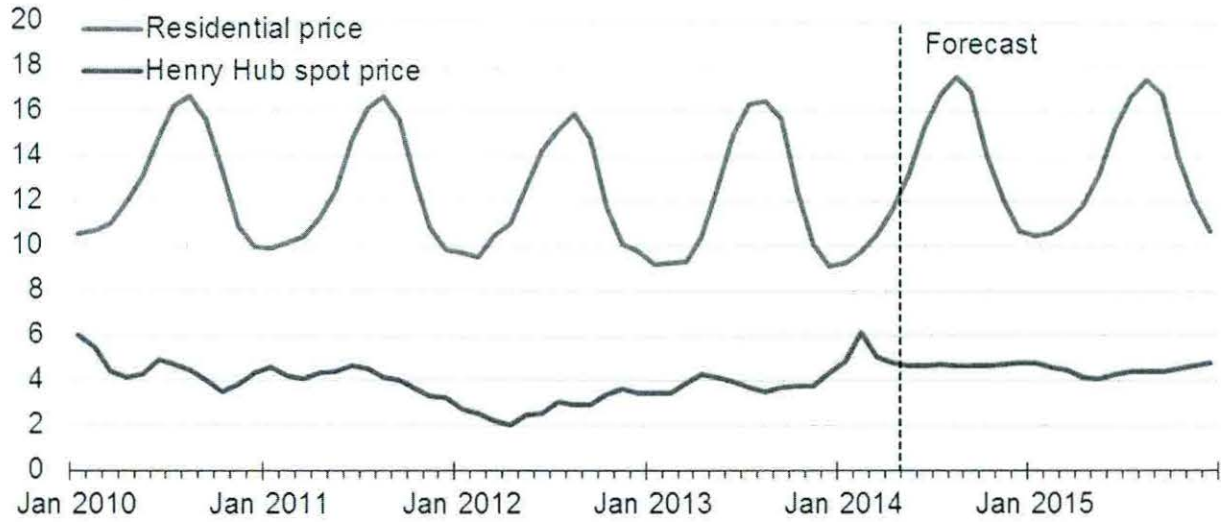


Note: Confidence interval derived from options market information for the 5 trading days ending May. 1, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, May 2014.

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, May 2014.

**GREAT PLAINS NATURAL GAS CO.
GAS COST RECONCILIATION ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
FIRM
TO BE EFFECTIVE JUNE 1, 2014 THROUGH MAY 31, 2015**

(Over)/under recovered gas costs @ April 30, 2014: \$404,569

Less projected recovery from rates already established:

	Volume	Rate	Amount
May	11,800	\$0.9614	\$11,345

Additional recovery required \$393,224

Projected sales volumes			
June 2014	9,400		
July	9,500		
August	9,500		
September	11,100		
October	20,300		
November	32,100		
December	44,800		
January 2015	48,200		
February	40,100		
March	34,200		
April	20,900		
May	12,000		
Total			292,100

Total gas cost reconciliation adjustment
to be effective June 1, 2014 through May 31, 2015 \$1.3462

Change in Surcharge \$0.3848

**GREAT PLAINS NATURAL GAS CO.
GAS COST RECONCILIATION ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE
TO BE EFFECTIVE JUNE 1, 2014 THROUGH MAY 31, 2015**

(Over)/under recovered gas costs @ April 30, 2014: \$388,932

Less projected recovery from rates already established:

	Volume	Rate	Amount
May	39,300	\$0.0274	\$1,077

Additional recovery required \$387,855

Projected sales volumes

June 2014		18,700	
July		13,900	
August		11,700	
September		12,800	
October		21,100	
November		45,000	
December		64,600	
January 2015		44,500	
February		38,100	
March		46,300	
April		44,000	
May		39,300	
Total			<u><u>400,000</u></u>

Total gas cost reconciliation adjustment
to be effective June 1, 2014 through May 31, 2015 \$0.9696

Change in Surcharge \$0.9422

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change</u>	<u>Cumulative Balance</u>
Balance @ April 30, 2013									<u>\$303,312</u>
May	(\$12,469)		\$1,860	(\$10,609)	21,400	\$1.0137	\$21,693	(\$32,302)	271,010
June	4,837		1,626	6,463	9,214	0.9614	9,167 2/	(2,704)	268,306
July	19,011		1,601	20,612	6,004	0.9614	5,772	14,840	283,146
August	16,638	(17,889)	1,701	450	5,505	0.9614	5,292	(4,842)	278,304
September	296		1,659	1,955	5,691	0.9614	5,471	(3,516)	274,788
October	5,896		1,626	7,522	8,207	0.9614	7,889	(367)	274,421
November	1,646		1,618	3,264	21,099	0.9614	20,284	(17,020)	257,401
December	46		1,501	1,547	42,237	0.9614	40,607	(39,060)	218,341
January 2014	35,892		1,244	37,136	59,754	0.9614	57,447	(20,311)	198,030
February	117,836		1,138	118,974	56,223	0.9614	54,053	64,921	262,951
March	146,903		1,643	148,546	48,181	0.9614	46,321	102,225	365,176
April	67,921		2,408	70,329	32,179	0.9614	30,936	39,393	404,569
Total	<u>\$404,453</u>	<u>(\$17,889)</u>	<u>\$19,625</u>	<u>\$406,189</u>	<u>315,694</u>		<u>\$304,932</u>	<u>\$101,257</u>	<u>\$404,569</u>

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

2/ Reflects 3,302.1 dk @ \$0.9614 and 5,911.4 dk @ \$1.0137.

**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 Mcf	Total Adjustment Amount	Net Change	Cumulative Balance
Balance @ April 30, 2013								<u>\$4,747</u>
May	(\$19,392)	(\$4)	(\$19,396)	49,736	(\$0.2915)	(\$14,498)	(\$4,898)	(151)
June	(13,383)	(46)	(13,429)	23,704	0.0274	(4,253) 2/	(9,176)	(9,327)
July	(9,266)	(115)	(9,381)	17,578	0.0274	482	(9,863)	(19,190)
August	(1,455)	(188)	(1,643)	14,808	0.0274	406	(2,049)	(21,239)
September	(28,850)	(203)	(29,053)	16,181	0.0274	443	(29,496)	(50,735)
October	4,119	(416)	3,703	26,693	0.0274	731	2,972	(47,763)
November	5,534	(395)	5,139	56,951	0.0274	1,561	3,578	(44,185)
December	13,821	(373)	13,448	81,821	0.0274	2,242	11,206	(32,979)
January 2014	29,697	(300)	29,397	56,375	0.0274	1,545	27,852	(5,127)
February	144,558	(104)	144,454	48,233	0.0274	1,322	143,132	138,005
March	207,850	921	208,771	58,630	0.0274	1,606	207,165	345,170
April	42,888	2,400	45,288	55,708	0.0274	1,526	43,762	388,932
Total	<u>\$376,121</u>	<u>\$1,177</u>	<u>\$377,298</u>	<u>506,418</u>		<u>(\$6,887)</u>	<u>\$384,185</u>	
Balance @ April 30, 2014								<u>\$388,932</u>

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

2/ Reflects 8,331.7 dk @ \$0.0274 and 15,372.2 dk @ (\$0.2915).

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

	1/	2/	3/	Total
<u>May 2013</u>				
Cost of Gas - Actual	\$5.03540	\$5.16230	\$5.03540	
Cost of Gas - Recovered	5.77810	5.67900	5.67900	
(Over) Under recovery per dk	(\$0.74270)	(\$0.51670)	(\$0.64360)	
dk billed	6,413	15,282	(295)	21,400
(Over) Under recovery	(\$4,763)	(\$7,896)	\$190	(\$12,469)
<u>June 2013</u>				
Cost of Gas - Actual	\$7.60410	\$5.03540	\$7.60410	
Cost of Gas - Recovered	5.72580	5.77810	5.77810	
(Over) Under recovery per dk	\$1.87830	(\$0.74270)	\$1.82600	
dk billed	3,302	4,734	1,178	9,214
(Over) Under recovery	\$6,202	(\$3,516)	\$2,151	\$4,837
<u>July 2013</u>				
Cost of Gas - Actual	\$8.78250	\$7.60410	\$8.78250	
Cost of Gas - Recovered	5.26070	5.72580	5.72580	
(Over) Under recovery per dk	\$3.52180	\$1.87830	\$3.05670	
dk billed	2,387	383	3,234	6,004
(Over) Under recovery	\$8,407	\$719	\$9,885	\$19,011
<u>August 2013</u>				
Cost of Gas - Actual	\$8.27080	\$8.78250	\$8.27080	
Cost of Gas - Recovered	5.28470	5.26070	5.26070	
(Over) Under recovery per dk	\$2.98610	\$3.52180	\$3.01010	
dk billed	2,261	237	3,007	5,505
(Over) Under recovery	\$6,752	\$835 4/	\$9,051	\$16,638
<u>September 2013</u>				
Cost of Gas - Actual	\$8.11230	\$8.27080	\$8.11230	
Cost of Gas - Recovered	5.17860	5.28470	5.28470	
(Over) Under recovery per dk	\$2.93370	\$2.98610	\$2.82760	
dk billed	2,407	2,087	1,197	5,691
(Over) Under recovery	\$7,061	(\$10,150)	\$3,385	\$296
<u>October 2013</u>				
Cost of Gas - Actual	\$5.12750	\$8.11230	\$5.12750	
Cost of Gas - Recovered	5.17500	5.17860	5.17860	
(Over) Under recovery per dk	(\$0.04750)	\$2.93370	(\$0.05110)	
dk billed	3,840	2,111	2,256	8,207
(Over) Under recovery	(\$182)	\$6,193	(\$115)	\$5,896

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

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>November 2013</u>				
Cost of Gas - Actual	\$5.62960	\$5.12750	\$5.62960	
Cost of Gas - Recovered	5.41320	5.17500	5.17500	
(Over) Under recovery per dk	<u>\$0.21640</u>	<u>(\$0.04750)</u>	<u>\$0.45460</u>	
dk billed	7,807	12,120	1,172	21,099
(Over) Under recovery	<u>\$1,689</u>	<u>(\$576)</u>	<u>\$533</u>	<u>\$1,646</u>
<u>December 2013</u>				
Cost of Gas - Actual	\$5.22370	\$5.62960	\$5.22370	
Cost of Gas - Recovered	5.41210	5.41320	5.41320	
(Over) Under recovery per dk	<u>(\$0.18840)</u>	<u>\$0.21640</u>	<u>(\$0.18950)</u>	
dk billed	16,201	19,786	6,250	42,237
(Over) Under recovery	<u>(\$3,052)</u>	<u>\$4,282</u>	<u>(\$1,184)</u>	<u>\$46</u>
<u>January 2014</u>				
Cost of Gas - Actual	\$7.47880	\$5.22370	\$7.47880	
Cost of Gas - Recovered	6.37530	5.41210	5.41210	
(Over) Under recovery per dk	<u>\$1.10350</u>	<u>(\$0.18840)</u>	<u>\$2.06670</u>	
dk billed	21,586	29,626	8,542	59,754
(Over) Under recovery	<u>\$23,820</u>	<u>(\$5,582)</u>	<u>\$17,654</u>	<u>\$35,892</u>
<u>February 2014</u>				
Cost of Gas - Actual	\$11.40360	\$7.47880	\$11.40360	
Cost of Gas - Recovered	9.04640	6.37530	6.37530	
(Over) Under recovery per dk	<u>\$2.35720</u>	<u>\$1.10350</u>	<u>\$5.02830</u>	
dk billed	19,838	28,506	7,879	56,223
(Over) Under recovery	<u>\$46,762</u>	<u>\$31,456</u>	<u>\$39,618</u>	<u>\$117,836</u>
<u>March 2014</u>				
Cost of Gas - Actual	\$14.26220	\$11.40360	\$14.26220	
Cost of Gas - Recovered	10.91040	9.04640	9.04640	
(Over) Under recovery per dk	<u>\$3.35180</u>	<u>\$2.35720</u>	<u>\$5.21580</u>	
dk billed	18,212	24,646	5,323	48,181
(Over) Under recovery	<u>\$61,043</u>	<u>\$58,096</u>	<u>\$27,764</u>	<u>\$146,903</u>
<u>April 2014</u>				
Cost of Gas - Actual	\$5.75720	\$14.26220	\$5.75720	
Cost of Gas - Recovered	6.38990	10.91040	10.91040	
(Over) Under recovery per dk	<u>(\$0.63270)</u>	<u>\$3.35180</u>	<u>(\$5.15320)</u>	
dk billed	10,328	21,994	(143)	32,179
(Over) Under recovery	<u>(\$6,535)</u>	<u>\$73,719</u>	<u>\$737</u>	<u>\$67,921</u>

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**

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>May 2013</u>				
Cost of Gas - Actual	\$3.38740	\$4.27760	\$3.38740	
Cost of Gas - Recovered	4.25510	4.15290	4.15290	
(Over) Under recovery per dk	<u>(\$0.86770)</u>	<u>\$0.12470</u>	<u>(\$0.76550)</u>	
dk billed	17,978	23,050	8,708	49,736
(Over) Under recovery	<u>(\$15,600)</u>	<u>\$2,874</u>	<u>(\$6,666)</u>	<u>(\$19,392)</u>
<u>June 2013</u>				
Cost of Gas - Actual	\$3.86940	\$3.38740	\$3.86940	
Cost of Gas - Recovered	4.20280	4.25510	4.25510	
(Over) Under recovery per dk	<u>(\$0.33340)</u>	<u>(\$0.86770)</u>	<u>(\$0.38570)</u>	
dk billed	8,332	9,702	5,670	23,704
(Over) Under recovery	<u>(\$2,778)</u>	<u>(\$8,418)</u>	<u>(\$2,187)</u>	<u>(\$13,383)</u>
<u>July 2013</u>				
Cost of Gas - Actual	\$3.49150	\$3.86940	\$3.49150	
Cost of Gas - Recovered	3.73770	4.20280	4.20280	
(Over) Under recovery per dk	<u>(\$0.24620)</u>	<u>(\$0.33340)</u>	<u>(\$0.71130)</u>	
dk billed	6,148	1,001	10,429	17,578
(Over) Under recovery	<u>(\$1,514)</u>	<u>(\$334)</u>	<u>(\$7,418)</u>	<u>(\$9,266)</u>
<u>August 2013</u>				
Cost of Gas - Actual	\$3.65620	\$3.49150	\$3.65620	
Cost of Gas - Recovered	3.76170	3.73770	3.73770	
(Over) Under recovery per dk	<u>(\$0.10550)</u>	<u>(\$0.24620)</u>	<u>(\$0.08150)</u>	
dk billed	4,344	872	9,592	14,808
(Over) Under recovery	<u>(\$458)</u>	<u>(\$215)</u> 4/	<u>(\$782)</u>	<u>(\$1,455)</u>
<u>September 2013</u>				
Cost of Gas - Actual	\$3.77370	\$3.65620	\$3.77370	
Cost of Gas - Recovered	3.65560	3.76170	3.76170	
(Over) Under recovery per dk	<u>\$0.11810</u>	<u>(\$0.10550)</u>	<u>\$0.01200</u>	
dk billed	4,721	8,236	3,224	16,181
(Over) Under recovery	<u>\$558</u>	<u>(\$29,447)</u>	<u>\$39</u>	<u>(\$28,850)</u>
<u>October 2013</u>				
Cost of Gas - Actual	\$3.82980	\$3.77370	\$3.82980	
Cost of Gas - Recovered	3.65200	3.65560	3.65560	
(Over) Under recovery per dk	<u>\$0.17780</u>	<u>\$0.11810</u>	<u>\$0.17420</u>	
dk billed	12,842	10,281	3,570	26,693
(Over) Under recovery	<u>\$2,283</u>	<u>\$1,214</u>	<u>\$622</u>	<u>\$4,119</u>

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

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>November 2013</u>				
Cost of Gas - Actual	\$3.85220	\$3.82980	\$3.85220	
Cost of Gas - Recovered	3.90290	3.65200	3.65200	
(Over) Under recovery per dk	<u>(\$0.05070)</u>	<u>\$0.17780</u>	<u>\$0.20020</u>	
dk billed	20,615	31,047	5,289	56,951
(Over) Under recovery	<u>(\$1,045)</u>	<u>\$5,520</u>	<u>\$1,059</u>	<u>\$5,534</u>
<u>December 2013</u>				
Cost of Gas - Actual	\$4.36450	\$3.85220	\$4.36450	
Cost of Gas - Recovered	3.90180	3.90290	3.90290	
(Over) Under recovery per dk	<u>\$0.46270</u>	<u>(\$0.05070)</u>	<u>\$0.46160</u>	
dk billed	36,162	46,823	(1,164)	81,821
(Over) Under recovery	<u>\$16,732</u>	<u>(\$2,374)</u>	<u>(\$537)</u>	<u>\$13,821</u>
<u>January 2014</u>				
Cost of Gas - Actual	\$6.60470	\$4.36450	\$6.60470	
Cost of Gas - Recovered	4.87160	3.90180	3.90180	
(Over) Under recovery per dk	<u>\$1.73310</u>	<u>\$0.46270</u>	<u>\$2.70290</u>	
dk billed	20,590	45,849	(10,064)	56,375
(Over) Under recovery	<u>\$35,685</u>	<u>\$21,214</u>	<u>(\$27,202)</u>	<u>\$29,697</u>
<u>February 2014</u>				
Cost of Gas - Actual	\$10.39620	\$6.60470	\$10.39620	
Cost of Gas - Recovered	7.54270	4.87160	4.87160	
(Over) Under recovery per dk	<u>\$2.85350</u>	<u>\$1.73310</u>	<u>\$5.52460</u>	
dk billed	15,051	21,550	11,632	48,233
(Over) Under recovery	<u>\$42,948</u>	<u>\$37,348</u>	<u>\$64,262</u>	<u>\$144,558</u>
<u>March 2014</u>				
Cost of Gas - Actual	\$12.88410	\$10.39620	\$12.88410	
Cost of Gas - Recovered	9.40670	7.54270	7.54270	
(Over) Under recovery per dk	<u>\$3.47740</u>	<u>\$2.85350</u>	<u>\$5.34140</u>	
dk billed	24,892	23,681	10,057	58,630
(Over) Under recovery	<u>\$86,559</u>	<u>\$67,573</u>	<u>\$53,718</u>	<u>\$207,850</u>
<u>April 2014</u>				
Cost of Gas - Actual	\$4.88750	\$12.88410	\$4.88750	
Cost of Gas - Recovered	4.88620	9.40670	9.40670	
(Over) Under recovery per dk	<u>\$0.00130</u>	<u>\$3.47740</u>	<u>(\$4.51920)</u>	
dk billed	22,484	24,136	9,088	55,708
(Over) Under recovery	<u>\$29</u>	<u>\$83,931</u>	<u>(\$41,072)</u>	<u>\$42,888</u>

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