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

705 West Fir Ave.
Mailing Address:
P.O. Box 176
Fergus Falls, MN 56538-0176
1-877-267-4764

February 27, 2014

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

Re: Cost of Gas Adjustment (COG)
March 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 (96th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (96th Revised Sheet No. 8), showing the March 2014 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $1.8640 per mcf for all customers.

Attachment B shows the calculations supporting the gas costs for March 2014, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $1.8640 per mcf for all customers since the last COG filing.

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

Attachment D shows the calculation of the balancing account since April 30, 2013.

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

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

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/MCF
Firm Gas Service - General	2	$3.50 per month	First 10 MCF	$1.2740	$11.8718	$13.1458
			Over 10 MCF	1.0540		12.9258
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$9.4341	$10.5732
			Next 2,600 MCF	0.8931		10.3272
			Over 3,000 MCF	0.7411		10.1752
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$9.4341	$10.6732
Transportation Service	5	$3.50 per month	First 400 MCF	$1.1391		$1.1391
			Next 2,600 MCF	0.8931		0.8931
			Over 3,000 MCF	0.7411		0.7411

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

State of North Dakota
Gas Rate Schedule

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	$0.0658	$5.1191	$0.0000	$5.1849	$5.1191	$0.0000	$5.1191
Accumulated Adj.	1.4526	2.4089	0.9614	4.8229	2.4236	0.0274	2.4510
Current Adj.	0.0000	1.8640	0.0000	1.8640	1.8640	0.0000	1.8640
Total Adj.	1.4526	4.2729	0.9614	6.6869	4.2876	0.0274	4.3150
Total Rate	$1.5184	$9.3920	$0.9614	$11.8718	$9.4067	$0.0274	$9.4341

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MARCH 2014

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A - Zone 1-1	8,000		$3.3978	12	$326,189	$0.2326
FT-A - Zone 1-1	5,000		3.6918	5	92,295	0.0658
FT-A Seasonal	2,000		3.6918	5	36,918	0.0263
TFX Seasonal	2,000		15.1530	5	151,530	0.1080
TFX - Winter	13,000		15.1530	5	984,945	0.7023
TFX - Summer	13,000		5.6830	7	517,153	0.3687
LMS Demand 2/						0.0147
Total Demand Charges					$2,109,030	1.5184
Estimated Weighted Average Commodity Cost	1,402,522	1/	9.3920		13,172,487	9.3920
Gas Cost Reconciliation Adjustment						0.9614
Total Current Firm Gas Cost					$15,281,517	11.8718
Base Cost of Gas						5.1849
Accumulated Adjustment						$6.6869

Interruptible	
Estimated Weighted Average Commodity Cost	$9.3920
Gas Cost Reconciliation Adjustment	0.0274
LMS Demand 2/	0.0147
Total Current Interruptible Gas Cost	9.4341
Base Cost of Gas	5.1191
Accumulated Adjustment	$4.3150

1/ Three year normalized average mcf sales
2/ Amount divided by 2010-2012 average interruptible sales volumes plus 2010-2012 average normalized firm sales volumes.

	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
LMS Demand	2,500	$0.9800	12	$29,400	$0.0147

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MARCH 2014

Rates Effective March 1, 2014	$/Dk	
FT-A - Zone 1-1 (Category 1)	$3.6918	Per dk/Mo.
FT-A - Zone 1-1 (Category 3)	3.3978	Per dk/Mo.
FT-A - Seasonal	3.6918	Per dk/Mo.
TFX	15.1530	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
LMS Demand	0.9800	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	9.3920	Per dk

Base Rate Effective September 1, 1981		
Demand Charge	$0.8100	Per Mcf/Mo.
Commodity Charge	5.1191	Per Mcf

Base Rate Calculation		
Firm		
Demand 1/	$0.0658	Per Mcf
Commodity	5.1191	Per Mcf
Total Firm Base Cost	$5.1849	Per Mcf
Interruptible:		
Commodity	$5.1191	Per Mcf

1/ Demand base rate calculation: 4,768 X 12 X $0.8100 / 707,222

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	$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
Category 2 (Contract Term of 3 Years to less than 5 Years)	
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
Category 3 (Contract Term of 5 or more Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$3.3978
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.4954
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$1.8032
Zone 2-2 Minimum Rate	$0.0000

Rate Schedule	Base Tariff Rate	Fuel and Loss Retention Percentages 2/
Commodity Rates 1/		
FT-A – Maximum Rates		
Zone 1-1	$0.0127	0.00%
Zone 1-2	$0.0127	0.00%
Zone 2-2	$0.0127	0.00%
Minimum Rate	$0.0127	
IT and AOT		
Zone 1-1	$0.1341	0.00%
Zone 1-2	$0.1702	0.00%
Zone 2-2	$0.0816	0.00%
Minimum Rate	$0.0127	

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

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

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

Rate Schedule	Base Tariff Rate	Adjustment Under Section 27 1/	Rate After Current Adjustment
LMS – Monthly Demand Rate	$0.9800		$0.9800
LMS – Daily Overrun Rate	$0.1702		$0.1702
LMS – Load Management Cost Reconciliation Adjustment		$0.0001	

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 TF12 Base	TF12 Variable	TF5	FIELD-TO-FIELD/MARKET DEMARCATION 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	0.0359	0.0190			0.0175	0.0000	0.0359	0.0190
Field	Market	0.0359	0.0190	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 $0.0000 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 Apr-Oct	MARKET-TO-MARKET Nov-Mar	FIELD-TO-FIELD Apr-Oct	FIELD-TO-FIELD 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	0.0359	0.0190			0.0175	0.0000	0.0359	0.0190
Field	Market	0.0359	0.0190	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
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 $0.0000 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.

4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.

5/ Where applicable, the Field Area Compression charge of $0.0000 and the ACA unit surcharge as set forth on FERC's website at http://www.ferc.gov will be added to the mileage based rates.

6/ In addition to the Maximum and Minimum rates, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.

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

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	1.31%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.33% 4/ 5/
FDD Storage Fuel	1.55%

	Electric Compression
COMMODITY RATES:	1/
Market Area	$0.0000
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, 2012.

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

The extreme cold weather across much of the United States continued during much of the month of February. The associated higher than normal demand of natural gas have drawn storage levels to the lowest level in the last ten years and it is projected that the working gas in storage at the end of March will be below the one Tcf mark. These are likely the main reasons for the increase in the index price of gas for the upcoming month. The EIA reported storage levels nationwide as of February 14, 2014 were 33.9 percent below the five-year average and 40.3 percent below last year's balance.

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

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 17.

Independent Statistics & Analysis
U.S. Energy Information Administration

February 2014

Short-Term Energy Outlook (STEO)

Highlights

- Temperatures east of the Rocky Mountains have been significantly colder this winter (October – January) compared with the same period both last winter and the previous 10-year average, putting upward pressure on consumption and prices of fuels used for space heating. U.S. average heating degree days were 12% higher than last winter (indicating colder weather) and 8% above the previous 10-year average. The Northeast was 11% colder than last winter, the Midwest 17% colder, and the South 20% colder, while the West was 3% warmer.

- The cold weather has had the greatest effect on propane prices, particularly for consumers in the Midwest. Cold temperatures have tightened supplies in the East and Midwest regions that were already low heading into the winter heating season. Residential propane prices in the Midwest rose from an average of $2.08 per gallon (gal) on December 2, 2013, to $4.20/gal on January 27; prices fell back to $3.83/gal on February 3. EIA now expects that propane prices in the Midwest will average $2.41/gal over the winter (39% higher than last winter) while those in the Northeast will average $3.43/gal (14% higher than last winter).

- While the North Sea Brent crude oil monthly average spot price fell by almost $3 per barrel (bbl) from December to January, cold temperatures have tightened heating oil supplies and helped drive up retail prices. Weekly U.S. residential heating oil prices increased by $0.14/gal between the end of December and end of January. Despite the recent increases, EIA expects that U.S. heating oil prices will average $3.82/gal this winter, $0.05/gal (1%) lower than during last year's winter heating season.

- Cold weather also contributed to a new record-high withdrawal of natural gas from storage and a surge in natural gas spot prices. Natural gas working inventories on January 31 totaled 1.92 trillion cubic feet (Tcf), 0.78 Tcf below the level at the same time a year ago and 0.56 Tcf below the previous five-year average (2009-13). Henry Hub natural gas spot prices increased from $4.32 per million British thermal units (MMBtu) on January 2 to $5.66/MMBtu on January 27, before falling back to $5.04/MMBtu on January 31. EIA expects that the Henry Hub natural gas spot price, which averaged $3.73/MMBtu in 2013, will average $4.17/MMBtu in 2014, an increase of $0.27/MMBtu from last month's STEO. Residential natural gas prices are expected to average $10.16 per thousand cubic feet (Mcf) this winter, an increase of $0.41/Mcf (4%) from last winter.

Global Petroleum and Other Liquids

Projected world petroleum and other liquids supply increases by 1.7 million barrels per day (bbl/d) in 2014 and 1.4 million bbl/d in 2015, with most of the growth coming from countries outside of the Organization of the Petroleum Exporting Countries (OPEC). The Americas, in particular the United States, Canada, and Brazil, will account for much of this growth. Projected world liquid fuels consumption grows by an annual average of 1.3 million bbl/d in 2014 and 1.4 million bbl/d in 2015. Countries outside the Organization for Economic Cooperation and Development (OECD), notably China, drive expected consumption growth. Non-OPEC supply growth contributes to an increase in global surplus crude oil production capacity from an average of 2.2 million bbl/d in 2013 to 3.8 million bbl/d in 2015.

Global unplanned supply disruptions reached nearly 3.2 million bbl/d by the end of 2013, but fell to 3.0 million bbl/d in January as some of Libya's oil production restarted. OPEC members continue to account for most of the global supply disruptions, averaging 2.3 million bbl/d in January. Supply disruptions present considerable uncertainty over the forecast period because the issues underpinning the disruptions in most countries remain unresolved.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 1.2 million bbl/d in 2013, exceeding 91 million bbl/d by the second half of the year. EIA expects global consumption to grow at a similar pace of nearly 1.3 million bbl/d in 2014 and 1.4 million bbl/d in 2015, exceeding 93 million bbl/d by the second half of 2015.

Non-OECD countries account for almost all consumption growth over the forecast period. 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 have moderated compared with levels before 2012, when GDP growth exceeded 9% and annual oil consumption growth averaged 790,000 bbl/d from 2009 through 2011.

On the other hand, EIA expects OECD consumption to remain relatively flat over the next two years. Projected consumption declines in the OECD are led by Japan and Europe. EIA expects Japan's oil consumption to decrease annually by about 120,000 bbl/d in both 2014 and 2015, as the country continues to increase natural gas consumption in the electricity sector and returns some nuclear power plants to service. EIA projects that OECD Europe's consumption continues to decline by 100,000 bbl/d in 2014 and another 50,000 bbl/d in 2015, albeit at a slower pace compared with previous years. U.S. oil consumption growth, which was 380,000 bbl/d in 2013, is expected to slow to 30,000 bbl/d in 2014 and 60,000 bbl/d in 2015.

Non-OPEC Supply. EIA estimates that non-OPEC production grew by 1.4 million bbl/d in 2013, exceeding 55 million bbl/d by the end of the year. EIA expects non-OPEC liquids production to grow annually by 1.9 million bbl/d in 2014 and 1.5 million bbl/d in 2015, reaching more than 58 million bbl/d by the end of 2015.

EIA forecasts production from the United States and Canada to grow by a combined annual average of 1.2 million bbl/d in both 2014 and 2015. Brazil's production is expected to increase by an annual average of 0.15 million bbl/d over the next two years, attributed to new deepwater fields. EIA expects Kazakhstan's production to grow by 0.09 million bbl/d in 2014 and by 0.13 million bbl/d in 2015 as output ramps up at the Kashagan oil field. EIA estimates that Asia and Oceania's production will rise by an annual average of 0.17 million bbl/d over the forecast period, led by China.

Unplanned supply disruptions among non-OPEC producers averaged 0.8 million bbl/d in 2013, a slight decline from 0.9 million bbl/d in 2012 but still considerably above the 2011 level of 0.5 million bbl/d. In January 2014, non-OPEC supply disruptions were less than 0.7 million bbl/d. South Sudan, Syria, and Yemen continue to account for more than 80% of total non-OPEC supply disruptions.

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 resulting from increased outages in Libya, Nigeria, and Iraq. EIA expects OPEC crude oil production to fall by 0.4 million bbl/d and 0.3 million bbl/d in 2014 and 2015, respectively, as some OPEC countries, led by Saudi Arabia, reduce production to accommodate the non-OPEC supply growth in 2014. Projected OPEC non-crude oil liquids, which averaged an estimated 5.9 million barrels per day in 2013, increases to an average of 6.3 million bbl/d in 2015.

Unplanned crude oil supply disruptions among OPEC producers averaged 1.8 million bbl/d in 2013, nearly double the amount from the previous year. OPEC disruptions increased in the second half of 2013, reaching 2.6 million bbl/d by the end of the year because of increased outages in Libya. In January 2014, crude oil output in Libya partially recovered as the El Sharara field resumed production. OPEC supply disruptions fell to 2.3 million bbl/d in January 2014.

EIA expects that OPEC surplus capacity, which is concentrated in Saudi Arabia, will average 2.2 million bbl/d in the first quarter of 2014, reflecting the upward movement that began in the second half of 2013. Projected surplus crude oil production capacity increases over the forecast period, averaging 2.5 million bbl/d in 2014 and 3.8 million bbl/d in 2015. This build in surplus capacity reflects production cutbacks by some OPEC members adjusting for the higher supply from other OPEC members and 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 at the end of 2013 totaled 2.61 billion barrels, equivalent to roughly 56 days of supply. Projected OECD oil inventories rise to 2.63 billion barrels by the end of 2014 and continue increasing to 2.64 billion barrels by the end of 2015.

Crude Oil Prices. Brent crude oil spot prices averaged between $108/bbl and $112/bbl for the seventh consecutive month in January. EIA expects the Brent crude oil price to weaken as non-

OPEC supply growth exceeds growth in world consumption. The Brent crude oil price is projected to average $105/bbl and $101/bbl in 2014 and 2015, respectively.

The forecast WTI crude oil spot price, which increased from a monthly average of $94/bbl in November to $98/bbl in December because of strong U.S. refinery crude oil runs, fell back to $95/bbl in January 2014. EIA expects that WTI crude oil prices will average $93/bbl in 2014 and $90/bbl during 2015. The discount of WTI crude oil to Brent crude oil, which averaged $18/bbl in 2012 and then fell below $4/bbl in July 2013, averaged $14/bbl in January 2014. EIA expects the discount of WTI crude oil to Brent crude oil to average $11/bbl over the forecast, reflecting the economics of transporting and processing the growing production of light sweet crude oil in U.S. and Canadian refineries.

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 May 2014 delivery, traded during the five-day period ending February 6, 2014, averaged $96/bbl. Implied volatility averaged 19%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in May 2014 at $81/bbl and $113/bbl, respectively. Last year at this time, WTI for May 2013 delivery averaged $98/bbl and implied volatility averaged 21%. The corresponding lower and upper limits of the 95% confidence interval were $82/bbl and $117/bbl.

U.S. Petroleum and Other Liquids

Despite relatively stable crude oil prices over the winter months, consistently cold temperatures east of the Rocky Mountains have tightened fuel supplies for both propane and heating. Propane stocks began the winter heating season at low levels because of heavy demand for drying an unusually wet fall corn crop harvest and have since fallen further. PADD 2 (Midwest) propane stocks started the winter heating season (end of September) at 24.4 million barrels, 3.5 million barrels lower than the same time the previous year and 2.5 million barrels lower than the previous 5-year average. The region's propane stocks were 8.8 million barrels the week ending January 24, which was 8.4 million barrels lower than the same week last year and the lowest recorded by EIA for January. By January 31 Midwest stocks had increased to 9.6 million barrels. These low propane inventories combined with consistently cold temperatures contributed to significant price increases for many consumers in the region. As of January 27, residential propane prices in PADD 2 increased to an average of $4.20/gal, which was an increase of 65% in just one week's time and the highest nominal price ever recorded for the region. By February 3, regional prices had fallen to an average of $3.83/gal.

Less-severe, but still considerable, tightness in Northeast heating oil supplies has similarly driven up heating oil prices in recent weeks as a result of cold winter temperatures and high residential heating demand. Distillate inventories in the Northeast (PADDs 1A and 1B) declined by 7.0 million barrels between January 3 through January 31, which is significantly greater than the average stock draw of 2.6 million barrels during the four weeks of January over the previous five years. Distillate stocks in the Northeast ended January at 18.2 million barrels, more than 10 million barrels lower than the same time last year. Residential heating oil prices in New England, which began 2014 at an average of $4.01/gal, increased to $4.17/gal on February 3.

U.S. Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 380,000 bbl/d (2.1%) in 2013. Consumption of hydrocarbon gas liquids registered the largest gain, increasing by 140,000 bbl/d (6.2%). Motor gasoline consumption grew by 100,000 bbl/d (1.1%), the largest increase since 2004. Stronger-than-expected growth in highway travel during the second half of 2013 contributed to that increase. Distillate fuel consumption increased 80,000 bbl/d (2.0%), reflecting colder weather and domestic economic growth.

Projected total liquid fuels consumption increases 30,000 bbl/d (0.2%) in 2014. Motor gasoline consumption remains unchanged as the recent strong growth in highway travel slows and continued improvements in new-vehicle fuel economy boost overall fuel efficiency growth. Distillate fuel oil consumption rises 60,000 bbl/d (1.5%). Growing distillate demands from the transportation and industrial sectors as well as increased heating oil use in the current quarter contribute to that growth. Ethane consumption increases by an average of 50,000 bbl/d (5.4%), as ethylene plant capacity expansions contribute to an increase in ethane cracking capacity. In 2015, total liquid fuels consumption increases by 60,000 bbl/d (0.3%), driven primarily by increasing transportation demand for distillate fuel oil and industrial demand for hydrocarbon gas liquids.

U.S. Liquid Fuels Supply. EIA expects strong crude oil production growth, primarily concentrated in the Bakken, Eagle Ford, and Permian regions, continuing through 2015. Forecast production increases from an estimated 7.4 million bbl/d in 2013 to 8.4 million bbl/d in 2014 and 9.2 million bbl/d in 2015. The U.S. crude oil production forecast for both 2014 and 2015 was revised downward by 0.1 million bbl/d from last month's STEO because of indications that severe weather this winter has caused temporary slowdowns in completing new wells. The highest historical annual average U.S. production level was 9.6 million bbl/d in 1970.

Crude oil production from the Bakken formation in North Dakota and Montana averaged 0.88 million bbl/d in 2013, and surpassed 1 million bbl/d in December 2013. Production in the Eagle Ford formation in South Texas surpassed 1 million bbl/d in May 2013, reaching an estimated 1.22 million bbl/d in December 2013.

U.S. Federal Gulf of Mexico (GOM) crude oil production averaged 1.25 million bbl/d in 2013, down slightly from 2012. EIA forecasts 1.38 million bbl/d of GOM crude oil production in 2014 and 1.59 million bbl/d in 2015. Production growth in 2014 comes from eight projects expected to come online: Jack, St. Malo, Entrada, Big Foot, Tubular Bells, Atlantis Phase 2, Hadrian South, and Lucius. Further production growth in 2015 comes from an additional 10 projects: Axe, Cardamom Deep, Dalmatian, Deimos South, Kodiak, Pony, Samurai, West Boreas, Winter, and Mars B.

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 25% in 2015, which would be the lowest level since 1971.

U.S. 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 $3.44/gal in 2014 and $3.37 in 2015. Diesel fuel prices, which averaged $3.92/gal in 2013, are projected to average $3.83/gal in 2014 and $3.73/gal in 2015.

Natural Gas

Very cold temperatures in early January led to new record-high withdrawals of natural gas from storage in a season already characterized by larger-than-normal storage withdrawals. Several more days of brutal cold came in the following weeks of January with working natural gas storage withdrawals exceeding 200 billion cubic feet (Bcf) for three of the weeks during the month. For the second month in a row, the forecast end-of-March 2014 working inventory has been revised downward to reflect recent very high withdrawals. EIA now projects inventories will end this heating season at 1,331 Bcf, the lowest end-of-season level since 2008.

The natural gas February futures contract expired at $5.56/MMBtu, which was a four-year high. Pipeline constraints in the Northeast often lead to price increases during times of high winter demand. Last month, spot market prices in the Northeast were routinely in the double digits, with New York prices settling in the $90/MMBtu range on several days in January. The effect of spot market fluctuations on end-use prices depends on several factors. Utilities begin buying natural gas in the spring, and policies for price-setting vary by state. Additionally, per-unit prices are lower in the winter and during times of high consumption, as a utility's high fixed costs are distributed over larger volumes. Residential natural gas prices are expected to average $10.16 per thousand cubic feet (Mcf) this winter, an increase of $0.41/Mcf (4.2%) from last winter. Last winter, natural gas consumers spent an average of $603 on their heating bills. This season, consumers can expect to spend $649 on natural gas heating for the winter months, a 7.7% increase.

U.S. Natural Gas Consumption. EIA expects total natural gas consumption will average 70.2 Bcf/d in 2014. This represents an upward revision of 0.6 Bcf/d from last month's STEO and is largely attributable to an increase in January consumption. The projected year-over-year increases in natural gas prices contribute to declines in natural gas used for electric power generation from 24.9 Bcf/d in 2012 to 22.3 Bcf/d in 2013 and 22.0 Bcf/d in 2014. In 2015, total natural gas consumption increases by 0.8 Bcf/d with growth in use by the industrial and electric power sectors. EIA expects natural gas consumption in the power sector to increase to 22.6 Bcf/d in 2015 with the retirement of some coal plants.

U.S. Natural Gas Production and Trade. EIA expects natural gas marketed production will grow at an average rate of 2.2% in 2014 and 1.2% in 2015. Rapid Marcellus production growth is causing natural gas forward prices in the Northeast to fall even with or below Henry Hub prices outside of peak-demand winter 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. EIA projects Gulf of Mexico production will increase by 1.7% in 2014 before falling 2.3% in 2015.

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. The first of the new facilities to liquefy gas produced in the Lower-48 states for export is expected to come online in the fourth quarter of 2015.

Growing domestic production over the past several years has replaced pipeline imports from Canada, while exports to Mexico have increased. EIA expects these trends will continue through 2015. EIA projects net imports of 3.5 Bcf/d in 2014 and 2.6 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.

U.S. Natural Gas Inventories. Natural gas working inventories fell by 262 Bcf to 1,923 Bcf during the week ending January 31, 2014. Colder-than-normal temperatures during the month resulted in increased heating demand, prompting larger-than-normal withdrawals, and a new record high monthly withdrawal (surpassing the previous record set in December 2013). Stocks are now 778 Bcf less than last year at this time and 556 Bcf less than the five-year (2009-13) average for this time of year.

U.S. Natural Gas Prices. Natural gas spot prices averaged $4.71/MMBtu at the Henry Hub in January, up $0.47/MMBtu from December, the result of bitterly cold weather during the month. EIA expects the price increases of the past few months will reverse at the end of winter. Projected Henry Hub natural gas prices average $4.17/MMBtu in 2014 and $4.11/MMBtu in 2015.

Natural gas futures prices for May 2014 delivery (for the five-day period ending February 6, 2014) averaged $4.48/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for May 2014 contracts at $3.28/MMBtu and $6.13/MMBtu, respectively. At this time last year, the natural gas futures contract for May 2013 averaged $3.46/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $2.61/MMBtu and $4.58/MMBtu.

Coal

Coal production for 2013 totaled an estimated 996 million short tons (MMst), 21 MMst (2%) lower than in 2012. It is the first time in 20 years that annual coal production was below 1 billion short tons. Coal production has fallen by nearly 100 MMst since 2011, with nearly identical declines in the Appalachian and Western coal regions. Coal production in the Interior region, which includes the Illinois Basin, increased by about 14 MMst over the same time.

U.S. Coal Supply. EIA projects coal production will grow 3.9% to 1,035 MMst in 2014 as inventories stabilize and consumption increases. Coal production is projected to fall 1.5% in 2015 to 1,019 MMst.

U.S. Coal Consumption. EIA estimates total coal consumption for 2013 to be 920 MMst, a 3.5% increase over 2012. The increase was primarily a result of increased consumption in the electric power sector due to higher natural gas prices. Projected consumption grows 4.1% to 958 MMst in 2014 as electricity demand grows and natural gas prices continue to rise. Total coal consumption is projected to decline by 2.1% in 2015, as retirements of coal power plants rise in response to the implementation of the Mercury and Air Toxics Standards.

U.S. Coal Exports. EIA estimates that exports for 2013 totaled 118 MMst, about 8 MMst lower than 2012. Exports are projected to total 106 MMst in 2014 and 105 MMst in 2015. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, increasing coal output in other coal-exporting countries, and falling international coal prices are the primary reasons for the expected decline in U.S. coal exports. However, a supply disruption in Colombia could provide a temporary boost to U.S. exports. Columbian steam coal exports are expected to drop by about a third after a new law, which took effect on January 1, only allows coal exporters to load ships using enclosed conveyor belts and prohibits the use of cranes and barges. Upgraded loading facilities are currently slated for completion in March.

U.S. Coal Prices. Nominal 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 $2.36/MMBtu in 2014 and $2.37/MMBtu in 2015.

Electricity

The cold weather experienced east of the Rocky Mountains last month led to an increase in electricity demand. The colder temperatures contrast with the mild weather experienced last January in much of the United States. EIA estimates residential electricity sales in the Midwest during January 2014 were about 10% higher than last January and residential sales in the Northeast are estimated to have been 6% higher.

Electricity supply in the Northeast was particularly affected by the colder weather. In recent years, power generators in this region have become increasingly reliant on natural gas, which is also used by many households for space heating. Periods of cold weather can temporarily raise natural gas prices, which can lead to spikes in wholesale electricity prices. During the early January freeze in New England, day-ahead on-peak power prices at the Massachusetts hub rose above $235 per megawatthour.

U.S. Electricity Consumption. EIA has raised its forecast for electricity demand during the first quarter as a result of the colder weather that occurred in January. U.S. residential electricity sales during the first quarter of 2014 are expected to increase 2.1% compared with the same period last year. The East South Central area of the country, where a large number of homes heat with electricity, shows the strongest year-over-year growth of 4.8% during the first quarter. U.S. sales of electricity to the commercial and industrial sectors grow by 1.2% and 1.4%, respectively, during the first quarter of 2014.

U.S. Electricity Generation. EIA projects total U.S. electricity generation will average 11.2 terawatthours per day in 2014, an increase of 1.0% from last year. Natural-gas-fired generation accounts for a 27.0% share of total generation during 2014, down from 27.5% in 2013 as a result of rising natural gas prices. In contrast, the share of generation fueled by coal increases from 39.0% in 2013 to 40.3% in 2014. Renewable energy sources, including hydropower, account for 12.9% of total generation this year, the same as in 2013.

U.S. Electricity Retail Prices. The rising cost of generation fuels, particularly natural gas, contributes to a projected increase in the residential price of electricity. EIA expects the U.S. residential price of electricity to average 12.4 cents per kilowatthour during 2014, an increase of 2.2% from 2013. Residential electricity prices increase 1.9% during 2015.

Renewables and Carbon Dioxide Emissions

U.S. Electricity and Heat Generation from Renewables. EIA projects renewables used for electricity and heat generation will grow by about 0.7% in 2014. Hydropower is projected to decrease by 2.0%, while nonhydropower renewables rise by 2.2%. In 2015, renewables consumption for electric power and heat generation is projected to increase by a rate of 5.8% from 2014, as a 5.0% increase in hydropower is combined with a 6.2% increase in nonhydropower renewables.

EIA estimates that wind capacity will increase by 8.7% in 2014 to about 66 gigawatts (GW) by the end of the year and will increase 15.1% to total more than 75 GW at the end of 2015. Electricity generation from wind is projected to remain flat in 2014 but increase by 11.8% in 2015, contributing 4.6% 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 0.4% by 2015.

While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity grew by 96% in 2013. EIA currently projects that utility-scale solar capacity will increase by approximately 47% between year-end 2013 and year-end 2015. However, customer-sited photovoltaic (PV) capacity growth, which the STEO does not forecast, is still projected to exceed utility-scale solar growth between 2013 and 2015 according to EIA's *Annual Energy Outlook 2014*.

U.S. Liquid Biofuels. Ethanol and biodiesel production have recovered from last year's drought. Ethanol production increased from an average of 825,000 bbl/d in December 2012 to an estimated 925,000 bbl/d during December 2013 and is forecast to average 908,000 bbl/d during 2014. Biodiesel production, which averaged 64,000 bbl/d (1.0 billion gallons per year) in 2012, rose to a record-high level of 101,000 bbl/d (132 million gallons) in October 2013 and fell slightly to 128 million gallons in November 2013. Biodiesel production averaged about 87,000 bbl/d in 2013 and is forecast to average 84,000 bbl/d in both 2014 and 2015.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels increased by 1.9% in 2013 from the previous year. Emissions are forecast to rise 1.2% in 2014, followed possibly by a small decline in 2015. The increase in emissions in 2013 and 2014 primarily reflected growth in coal use for electricity generation in response to higher natural gas prices relative to coal. Coal emissions are projected to decline by 2.1% in 2015 as the power sector responds to increasing coal plant retirements.

U.S. Economic Assumptions

Reported economic indicators showed mixed signals for first quarter 2014 growth. The U.S. Bureau of Economic Analysis reported that real gross domestic product (GDP) increased at an annual rate of 3.2% during the fourth quarter of 2013, and 1.9% for 2013 as a whole. The U.S. Department of Labor reported that initial weekly unemployment insurance claims were 331,000 in the week ending February 1, an decrease of 20,000 from the previous week's revised figure, and the four-week moving average rose slightly to 334,000. The U.S. Census Bureau reported that new orders for manufactured durable goods fell 4.3% in December, following a 2.6% increase in November. The Federal Reserve Board reported that U.S. industrial production rose in December by 0.3%, following a 1.0% gain in November. The ISM purchasing manager's index fell to 51.3 in January 2014, from December's 56.5, where a measure above 50 indicates expansion in the manufacturing sector.

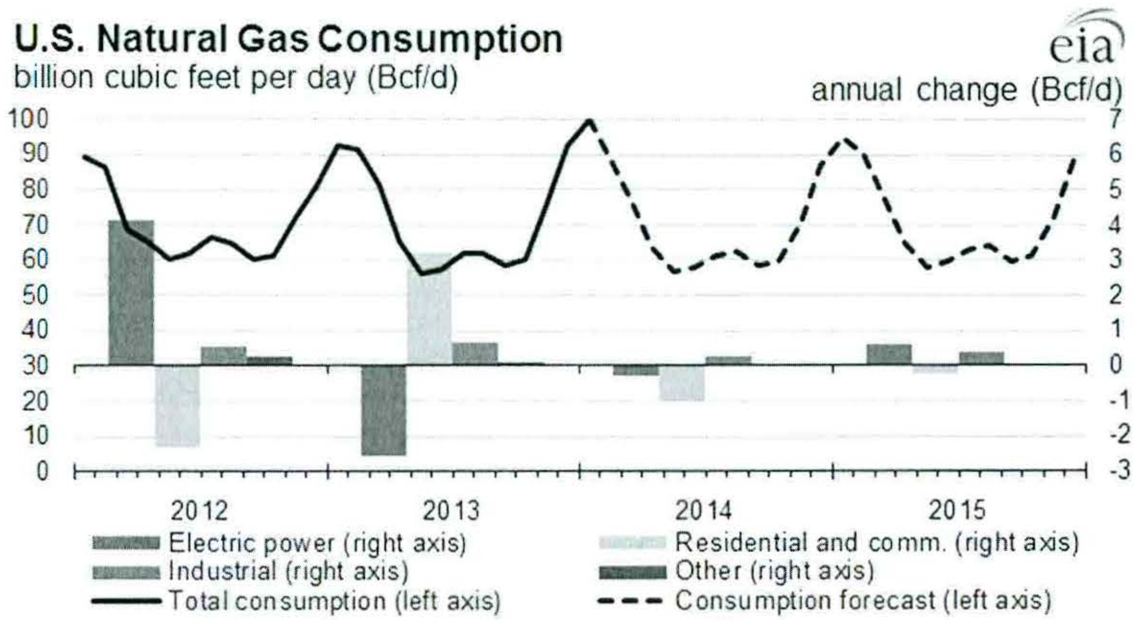
EIA uses the IHS/Global Insight macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

U.S. Production and Income. Forecast U.S. real GDP grows by 2.6% in 2014 and 3.2% in 2015. Even though forecast real GDP growth accelerates over the next two years, it is only in 2015 that GDP growth exceeds the economy's average annual growth of 3% from 1990 through 2007.

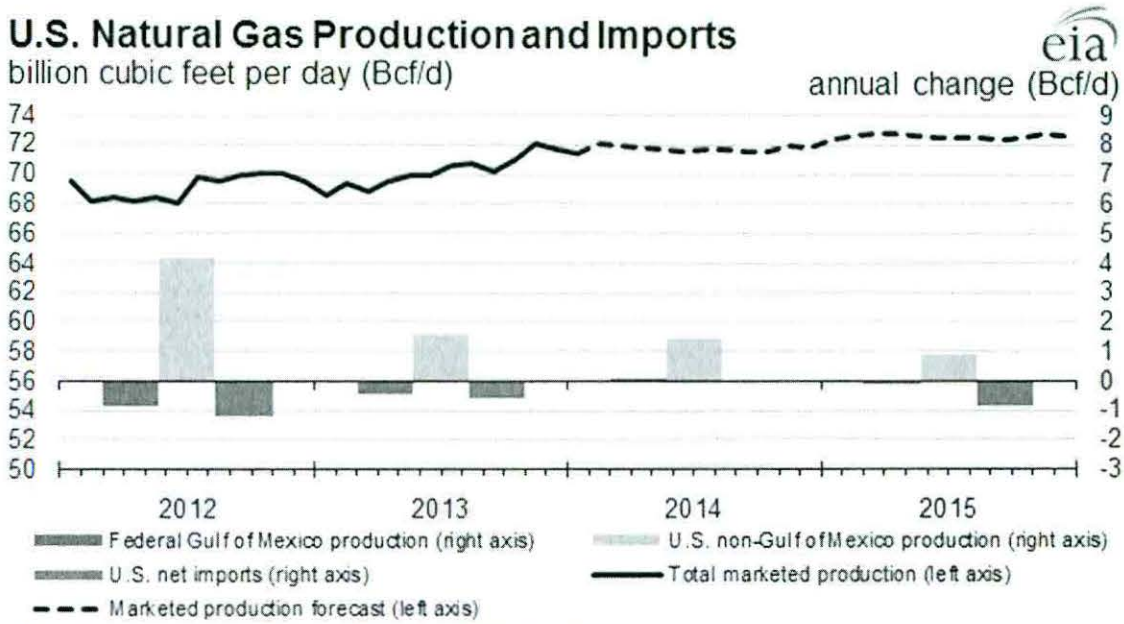
Forecast real disposable income increases 3.1% in 2014 and 3.5% in 2015. Total industrial production grows at 3.0% in 2014, and is projected to grow 3.5% in 2015, reflecting the acceleration in growth of real fixed investment spending.

U.S. Expenditures. Private real fixed investment growth averages 6.8% and 8.5% over 2014 and 2015, respectively, with equipment spending accounting for most of investment's growth. Real consumption expenditures grow faster than real GDP in 2014, at 2.7%, but are below the rate of real GDP growth in 2015, at 3.0%. Export growth is 4.6% and 5.1% over the same two years. Government expenditures fall 0.2% in 2014, but increase by 0.4% in 2015.

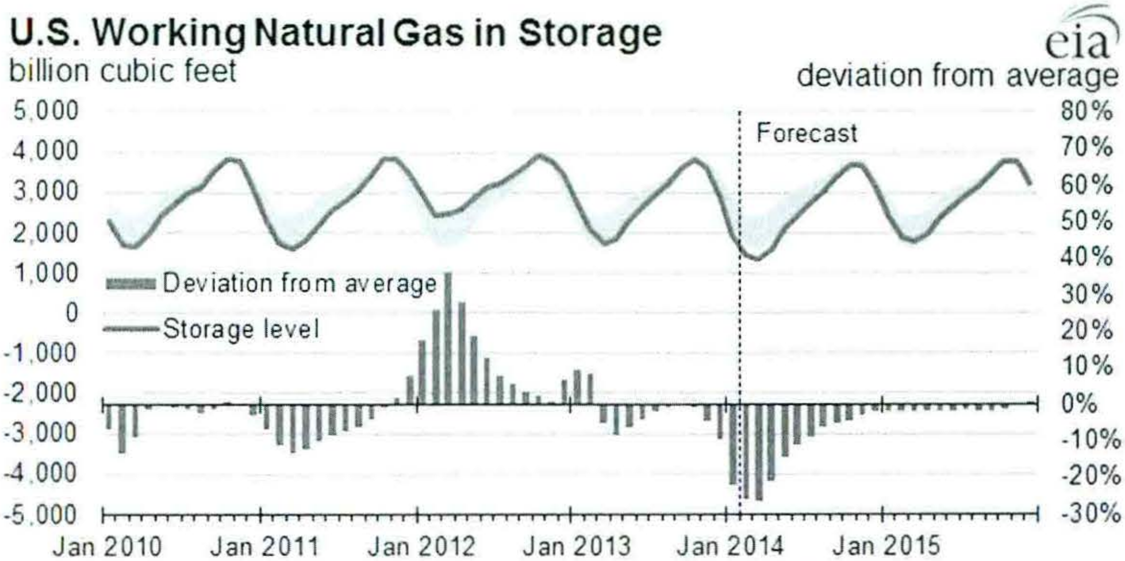
U.S. Employment, Housing, and Prices. The unemployment rate in the forecast averages 6.4% over 2014, and gradually falls to 5.5% at the end of 2015. This is accompanied by nonfarm employment growth averaging 1.7% in 2014 and 1.9% in 2015. Housing starts grow an average of 23.5% and 27.4% in 2014 and 2015, respectively. Both consumer and producer price indexes continue to increase at a moderate pace, as wages continue to show modest gains.



Source: Short-Term Energy Outlook, February 2014.



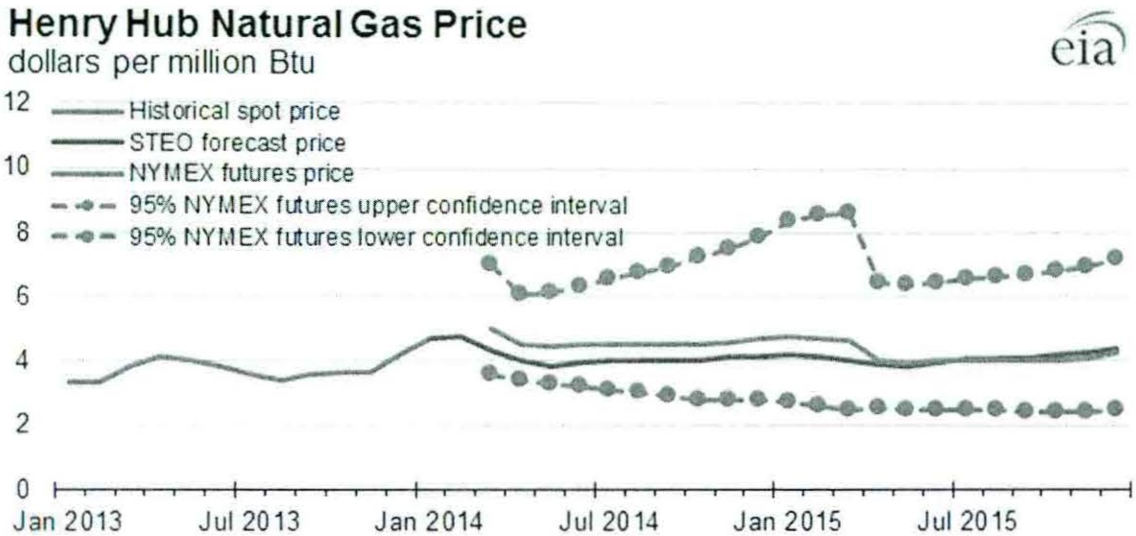
Source: Short-Term Energy Outlook, February 2014.



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

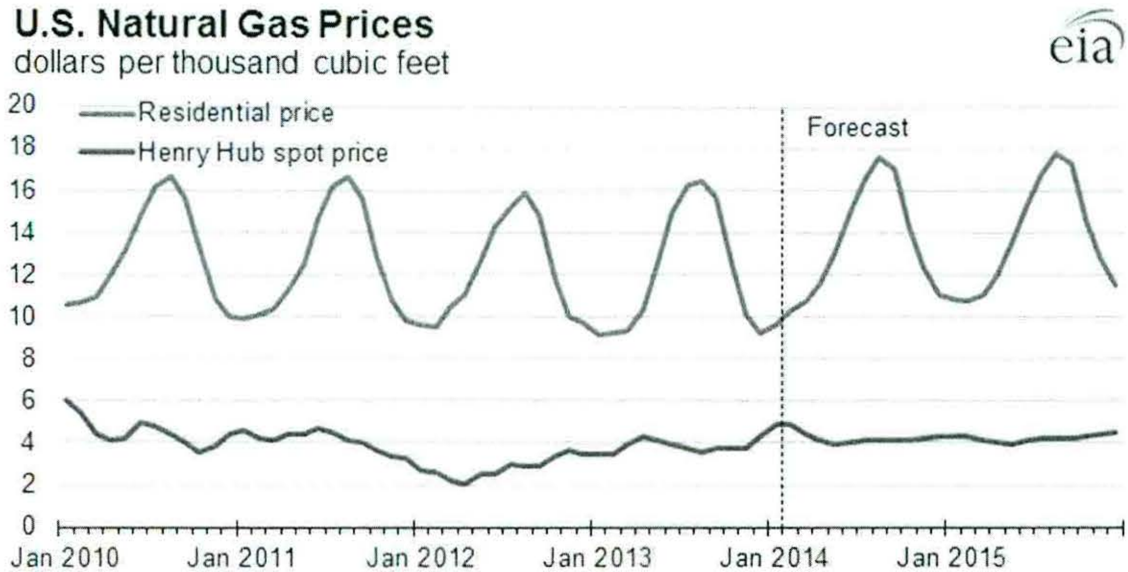
Source: Short-Term Energy Outlook, February 2014.

Henry Hub Natural Gas Price
dollars per million Btu



Note: Confidence interval derived from options market information for the 5 trading days ending Feb. 6, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, February 2014.



Source: Short-Term Energy Outlook, February 2014.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount		Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2013										**$303,311**
May 2013	($12,469)	0	$1,860	($10,609)	21,400	$1.0137	$21,692		($32,301)	271,010
June	4,837	0	1,626	6,463	9,214	0.9614	9,167	2/	(2,704)	268,306
July	19,011	0	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	5,293		(4,843)	278,303
September	296	0	1,658	1,954	5,691	0.9614	5,471		(3,517)	274,786
October	5,896	0	1,625	7,521	8,206	0.9614	7,889		(368)	274,418
November	1,647	0	1,618	3,265	21,099	0.9614	20,285		(17,020)	257,398
December	45	0	1,501	1,546	42,237	0.9614	40,607		(39,060)	218,338
January 2014	35,892	0	1,244	37,136	59,753	0.9614	57,447		(20,311)	198,027
Total	$71,793	(17,889)	$14,434	$68,338	179,109		$173,623		($105,284)	
Balance @ January 31, 2014										**$198,027**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 5,911.4 Mcf @ $1.0137 and 3,302.1 Mcf @ $0.9614.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2013									**$4,747**
May 2013	($19,391)	0	($4)	($19,395)	49,736	($0.2915)	($14,498)	($4,897)	(150)
June	(13,383)	0	(46)	(13,429)	23,704	0.0274	(4,253) 2/	(9,176)	(9,326)
July	(9,266)	0	(115)	(9,381)	17,577	0.0274	482	(9,863)	(19,189)
August	(1,454)	0	(188)	(1,642)	14,808	0.0274	406	(2,048)	(21,237)
September	(28,851)	0	(203)	(29,054)	16,181	0.0274	443	(29,497)	(50,734)
October	4,119	0	(416)	3,703	26,694	0.0274	731	2,972	(47,762)
November	5,534	0	(395)	5,139	56,950	0.0274	1,560	3,579	(44,183)
December	13,820	0	(373)	13,447	81,821	0.0274	2,242	11,205	(32,978)
January 2014	29,696	0	(300)	29,396	56,375	0.0274	1,545	27,852	(5,126)
Total	($19,176)	0	($2,040)	($21,216)	343,846		($11,342)	($9,873)	
Balance @ January 31, 2014									**($5,126)**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 15,372.2 Mcf @ ($0.2915) and 8,331.7 Mcf @ $0.0274.