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

December 2, 2013

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

Re: Cost of Gas Adjustment (COG)
December 2013

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 (93rd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (93rd Revised Sheet No. 8), showing the December 2013 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.0011 per mcf for all customers.

Attachment B shows the calculations supporting the gas costs for December 2013, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.0011 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, 2013 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,

Rita A. Mulkern
Director of Regulatory Affairs

Attachments

Attachment A

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
93rd Revised Sheet No. 1.1
Canceling 92nd Revised Sheet No.1.1
Page 1 of 1

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	$6.3735	$7.6475
			Over 10 MCF	1.0540		7.4275
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.9292	$5.0683
			Next 2,600 MCF	0.8931		4.8223
			Over 3,000 MCF	0.7411		4.6703
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.9292	$5.1683
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

Date Filed: December 2, 2013

Effective Date: Service rendered on and after December 1, 2013

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
93rd Revised Sheet No. 8
Canceling 92nd Revised Sheet No. 8

COST OF GAS

Summary:	Firm				Interruptible		
	Est. Wtd. Demand Costs	Average Commodity	GCR Adj.	Est. Wtd. Total Firm	Average Commodity	GCR Adj.	Total Int.
Base Rate	$0.0658	$5.1191	$0.0000	$5.1849	$5.1191	$0.0000	$5.1191
Accumulated Adj.	1.4595	(1.2312)	0.9614	1.1897	(1.2162)	0.0274	(1.1888)
Current Adj.	0.0000	(0.0011)	0.0000	(0.0011)	(0.0011)	0.0000	(0.0011)
Total Adj.	1.4595	(1.2323)	0.9614	1.1886	(1.2173)	0.0274	(1.1899)
Total Rate	$1.5253	$3.8868	$0.9614	$6.3735	$3.9018	$0.0274	$3.9292

Date Filed: December 2, 2013

Effective Date: Service rendered on and after December 1, 2013

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
DECEMBER 2013

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A - Zone 1-1	8,000		$3.4671	12	$332,842	$0.2373
FT-A - Zone 1-1	500		3.7671	5	9,418	0.0067
FT-A - Zone 1-1	4,500		3.7671	5	84,760	0.0604
FT-A Seasonal	2,000		3.7671	5	37,671	0.0269
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/						0.0150
Total Demand Charges					$2,118,319	1.5253
Estimated Weighted Average Commodity Cost	1,402,522	1/	3.8868		5,451,323	3.8868
Gas Cost Reconciliation Adjustment						0.9614
Total Current Firm Gas Cost					$7,569,642	6.3735
Base Cost of Gas						5.1849
Accumulated Adjustment						$1.1886

Interruptible	
Estimated Weighted Average Commodity Cost	$3.8868
Gas Cost Reconciliation Adjustment	0.0274
LMS Demand 2/	0.0150
Total Current Interruptible Gas Cost	3.9292
Base Cost of Gas	5.1191
Accumulated Adjustment	($1.1899)

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	$1.0000	12	$30,000	$0.0150

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
DECEMBER 2013

Rates Effective December 1, 2013	$/Dk	
FT-A - Zone 1-1, Category 1	$3.7671	Per dk/Mo.
FT-A - Zone 1-1, Category 3	3.4671	Per dk/Mo.
FT-A - Seasonal	3.7671	Per dk/Mo.
TFX	15.1530	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	3.8868	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	$3.7671
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.8871
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$2.1400
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	$3.6171
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.7371
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$1.9900
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	$3.4671
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.5871
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$1.8400
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	$0.0130	0.00%
Zone 1-2	$0.0130	0.00%
Zone 2-2	$0.0130	0.00%
Minimum Rate	$0.0130	
IT and AOT		
Zone 1-1	$0.1368	0.00%
Zone 1-2	$0.1737	0.00%
Zone 2-2	$0.0834	0.00%
Minimum Rate	$0.0130	

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	$1.0000		$1.0000
LMS – Daily Overrun Rate	$0.1737		$0.1737
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	$0.1737	$0.0000
RPL Service:		
Daily Reservation Rate	$0.1737	$0.0000

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

Sixth Revised Sheet No. 50
Superseding
Fifth Revised Sheet No. 50

RATE SCHEDULE TF

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

COMMODITY RATES 2/				Field Mileage 5/		Carlton			
TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Rate per 100 miles		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

GULF COAST	Reservation 1/ Maximum	Reservation 1/ Minimum	Commodity 6/ Maximum	Commodity 6/ Minimum	Out-of-Balance 6/ Maximum	Out-of-Balance 6/ 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
December 2013

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

Despite the seasonal increase in demand, continued strong production and storage levels were likely the major contributing factors to the index price remaining in the same range as the previous month. The annual storage level in mid-November was the fifth highest level as recorded by the EIA. The EIA reported storage levels nationwide as of November 15, 2013 were 0.4 percent above the five-year average and 2.3 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 15.

Independent Statistics & Analysis
U.S. Energy Information Administration

November 2013

Short-Term Energy Outlook (STEO)

Highlights

- The weekly U.S. average regular gasoline retail price has fallen by more than 40 cents per gallon since the beginning of September. EIA's forecast for the regular gasoline retail price averages $3.24 per gallon in the fourth quarter of 2013, $0.10 per gallon less than forecast in last month's STEO. The annual average regular gasoline retail price, which was $3.63 per gallon in 2012, is expected to average $3.50 per gallon in 2013 and $3.39 per gallon in 2014.

- The North Sea Brent crude oil spot price averaged nearly $110 per barrel for the fourth consecutive month in October. EIA expects the Brent crude oil price to decline gradually, averaging $106 per barrel in December and $103 per barrel in 2014. Projected West Texas Intermediate (WTI) crude oil prices average $95 per barrel during 2014.

- The projected discount of the WTI crude oil spot price to Brent, which averaged more than $20 per barrel in February 2013 and fell below $4 per barrel in July, increased to an average of $9 per barrel in October, driven in part by the seasonal decline in U.S. demand and the resulting increase in crude oil inventories. EIA expects the WTI discount to average $10 per barrel during the fourth quarter of 2013 and $8 per barrel in 2014.

- U.S. crude oil production averaged 7.7 million barrels per day (bbl/d) in October. Monthly estimated domestic crude oil production exceeded crude oil imports in October for the first time since February 1995, while total petroleum net imports were the lowest since February 1991. EIA forecasts U.S. crude oil production will average 7.5 million bbl/d in 2013 and 8.5 million bbl/d in 2014.

- Natural gas working inventories ended October at an estimated 3.81 trillion cubic feet (Tcf), 0.12 Tcf below the level at the same time a year ago but 0.05 Tcf above the previous five-year average (2008-12). EIA expects that the Henry Hub natural gas spot price, which averaged $2.75 per million British thermal units (MMBtu) in 2012, will average $3.68 per MMBtu in 2013 and $3.84 per MMBtu in 2014.

Global Crude Oil and Liquid Fuels

Although total unplanned production outages worldwide remained at 2.9 million bbl/d in October, crude oil prices fell toward the end of the month, reflecting lower seasonal liquid fuels consumption. Outages among producers who are not members of the Organization of the Petroleum Exporting Countries (OPEC) rose by nearly 0.1 million bbl/d month-over-month in October because of new disruptions in the United States, Brazil, Canada, and Colombia.

Nonetheless, expected growth in non-OPEC liquid fuels production leads to a projected decline in the call on OPEC crude oil and global stocks (world consumption less non-OPEC production and OPEC non-crude oil production) from an average of 30.2 million bbl/d in 2013 to 29.6 million bbl/d in 2014.

Global Liquid Fuels Consumption. EIA projects global consumption, which averaged 89.2 million bbl/d in 2012, will grow annually by 1.1 million bbl/d in both 2013 and 2014. China, the Middle East, Central & South America, and other countries outside of the Organization for Economic Cooperation and Development (OECD) account for nearly all consumption growth. Projected OECD liquid fuels consumption declines by 0.1 million bbl/d in 2013 and 0.2 million bbl/d in 2014. The declines in OECD consumption are largely due to lower consumption in Europe and Japan. Non-OECD Asia, particularly China, is the leading contributor to projected global consumption growth. EIA estimates that liquid fuels consumption in China will increase by 420,000 bbl/d in 2013 and by a further 430,000 bbl/d in 2014.

Non-OPEC Supply. Forecast non-OPEC liquid fuels production, which averaged 52.7 million bbl/d in 2012, increases by 1.6 million bbl/d in 2013 and by 1.5 million bbl/d in 2014. The largest non-OPEC supply growth is in North America, where projected production increases by 1.5 million bbl/d and 1.1 million bbl/d in 2013 and 2014, respectively, reflecting continued production growth in U.S. onshore tight oil formations and from Canadian oil sands. EIA expects smaller production growth from a number of other areas, including Central & South America, Asia & Oceania, and Africa. Of the 2.9 million bbl/d of global unplanned supply disruptions in October, approximately 0.7 million bbl/d occurred among non-OPEC producers.

OPEC Supply. EIA projects total OPEC liquid fuels production to decline by 0.8 million bbl/d to 35.9 million bbl/d in 2013 and to stay near that level in 2014. The declines in 2013 mostly reflect supply outages among some OPEC producers, along with an average annual decrease in Saudi Arabia's production in 2013. Nonetheless, Saudi Arabia's crude oil production averaged 10.1 million bbl/d in the third quarter of 2013 as it boosted production in response to a seasonal increase in direct crude burn for electric power generation and lower production by other OPEC producers, including Libya and Iraq. EIA expects Saudi Arabia to begin reducing its production in early 2014 as some of the disrupted production comes back on line and non-OPEC supply continues to grow.

Total OPEC crude oil unplanned disruptions in October averaged 2.2 million bbl/d, falling slightly compared with the September average. The decrease reflects restoration of some of Libya's disrupted volumes in mid-September. However, Libyan disruptions increased again in late October. Because Libya has experienced several major swings in production since June, estimates of the monthly average disruption can obscure developments over shorter time periods.

Planned maintenance work started on Iraq's southern export terminals in September, and should continue through the end of 2013. The planned outage contributed to an almost 400,000 bbl/d monthly decrease in total Iraqi crude oil output in October. EIA excludes planned outages from unplanned outage estimates. EIA estimates that unplanned crude oil disruptions in Iraq were 340,000 bbl/d in October, stemming mostly from additional attacks on the Kirkuk-Ceyhan pipeline between Iraq and Turkey.

Total OPEC surplus crude oil production capacity in the third quarter of 2013 averaged 1.7 million bbl/d, which was 0.3 million bbl/d below the year-ago level and 1.4 million bbl/d lower than the historical 2010-12 average. OPEC surplus crude oil production capacity during the third quarter was the lowest for any quarter since the third quarter of 2008, when it fell below 1.0 million bbl/d.

EIA projects OPEC surplus capacity will increase from an average of 1.7 million bbl/d in September to 2.5 million bbl/d in December 2013, and 4.0 million bbl/d at the end of 2014. These estimates do not include additional capacity that may be available in Iran but is currently off line 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 2012 totaled 2.65 billion barrels, equivalent to roughly 58 days of supply. OECD oil inventories are projected to end 2013 at 2.59 billion barrels and end 2014 at 2.61 billion barrels.

Crude Oil Prices. Brent crude oil spot prices fell from a monthly average of $112 per barrel in September 2013 to an average of $109 per barrel during October. EIA expects the Brent crude oil price to continue to weaken as non-OPEC supply growth exceeds growth in world consumption. The Brent crude oil price is projected to average $106 per barrel by December 2013 and $103 per barrel in 2014.

The forecast WTI crude oil spot price, which averaged $106 per barrel during September, fell to an average of $101 per barrel in October. EIA expects that WTI crude oil prices will average $97 per barrel during the fourth quarter of 2013 and $95 per barrel during 2014. The discount of WTI crude oil to Brent crude oil, which averaged $18 per barrel in 2012 and then fell to $3 per barrel in July 2013, averaged $9 per barrel during October. EIA expects the WTI discount to average $10 per barrel during the fourth quarter of 2013 and $8 per barrel during 2014.

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 February 2014 delivery traded during the five-day period ending November 7, 2013, averaged $95 per barrel. Implied volatility averaged 20%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in February 2014 at $80 per barrel and $112 per barrel, respectively. Last year at this time, WTI for February 2013 delivery averaged $87 per barrel and implied volatility averaged 31%. The corresponding lower and upper limits of the 95% confidence interval were $66 per barrel and $115 per barrel.

U.S. Crude Oil and Liquid Fuels

After reaching $3.68 per gallon on July 22, 2013, the average U.S. regular gasoline retail price fell to $3.27 per gallon on November 11, 2013. Factors contributing to lower gasoline prices include lower seasonal demand, the switchover to winter-grade gasoline, and continued higher refinery utilization rates to accommodate world diesel demand. EIA expects regular gasoline retail prices to average $3.24 per gallon during the fourth quarter of 2013.

U.S. Liquid Fuels Consumption. In 2012, total U.S. liquid fuels consumption witnessed a broad-based decline of 390,000 bbl/d (2.1%), with all of the major liquid fuels except liquefied petroleum gases contributing. In 2013, however, projected total liquid fuels consumption increases by 210,000 bbl/d (1.1%). Distillate fuel oil consumption grows 90,000 bbl/d (2.4%) in 2013, with colder weather and continued growth in industrial production and imports of non-petroleum products accounting for much of that increase. In 2014, growth in total consumption of liquid fuels slows to 30,000 bbl/d (0.1%). EIA expects gasoline consumption to fall by 0.4% next year as continued improvements in new-vehicle fuel economy boost overall fuel efficiency growth, which outpaces growth in highway travel. Distillate consumption rises by 2.0% in 2014, buoyed by increases in industrial production, the imports of goods, and in coal rail shipments.

U.S. Liquid Fuels Supply. EIA expects U.S. crude oil production to rise from an average of 6.5 million bbl/d in 2012 to 7.5 million bbl/d in 2013 and 8.5 million bbl/d in 2014. The continued focus on drilling in tight oil plays in the onshore Bakken, Eagle Ford, and Permian regions is expected to account for the bulk of forecast production growth over the next two years. Offshore production from the Gulf of Mexico is forecast to average 1.2 million bbl/d in 2013 and 1.3 million bbl/d in 2014. The crude oil production forecast in STEO is now informed by EIA's new monthly Drilling Productivity Report (DPR) that provides insight into oil and natural gas drilling and production trends in six onshore U.S. regions.

Since reaching an annual average high of 12.5 million bbl/d in 2005, total U.S. liquid fuel net imports, including crude oil and petroleum products, have been falling. Total liquid fuel net imports during October were the lowest since February 1991. The share of total U.S.

consumption met by liquid fuel net imports peaked at more than 60% in 2005 and fell to an average of 40% in 2012. EIA expects the net import share to decline to 28% in 2014, which would be the lowest level since 1985.

U.S. Petroleum Product Prices. EIA expects that regular-grade gasoline retail prices, which averaged $3.34 per gallon during October, will average $3.24 per gallon during the fourth quarter of 2013. Led by falling Brent crude oil prices, the projected U.S. annual average regular gasoline retail price falls from $3.63 per gallon in 2012 to an average of $3.50 per gallon in 2013 and $3.39 per gallon in 2014. Diesel fuel prices, which averaged $3.97 per gallon in 2012, are projected to average $3.91 per gallon in 2013 and $3.73 per gallon in 2014.

Natural Gas

The natural gas production forecast in STEO is now informed by EIA's new monthly Drilling Productivity Report (DPR), which provides a new gauge for looking at oil and natural gas production growth in six key regions. This month's STEO raises the projection for marketed natural gas production by 0.4% in 2013 and 0.9% in 2014 from the previous STEO. In the past several months, natural gas production has hit record high levels, even as prices declined this summer. The Marcellus Shale has been the main driver of growth. EIA publishes a monthly production estimate for several major producing states (such as Texas, Louisiana, and Oklahoma) and an other states category, which includes the Marcellus. August 2013 production for the other states category was 17% (or 3.7 billion cubic feet per day (Bcf/d)) greater than August 2012. Very strong growth in the Marcellus Shale (and to a smaller extent, the Eagle Ford Shale) has more than outpaced declines in the Gulf of Mexico and the Haynesville Shale. Over the past several years, domestic production growth has displaced pipeline imports of natural gas from Canada. This month's forecast lowers the outlook for pipeline imports as domestic production increases.

U.S. Natural Gas Consumption. EIA expects that natural gas consumption, which averaged 69.7 Bcf/d in 2012, will average 70.1 Bcf/d and 69.6 Bcf/d in 2013 and 2014, respectively. Colder winter temperatures in 2013 and 2014 (compared with the record-warm temperatures in 2012) are expected to increase the amount of natural gas used for residential and commercial space heating. However, the projected year-over-year increases in natural gas prices contribute to declines in natural gas used for electric power generation from 25.0 Bcf/d in 2012 to 22.1 Bcf/d in 2013 and 21.9 Bcf/d in 2014.

U.S. Natural Gas Production and Trade. Natural gas marketed production is projected to increase from 69.2 Bcf/d in 2012 to 70.3 Bcf/d in 2013 and to 71.0 Bcf/d in 2014. Natural gas pipeline gross imports, which have fallen over the past five years, are projected to fall by 0.6 Bcf/d in 2013 and 0.1 Bcf/d in 2014. Liquefied natural gas (LNG) imports are expected to remain at minimal levels of around 0.4 Bcf/d in both 2013 and 2014.

U.S. Natural Gas Inventories. Natural gas working inventories reached 3,814 Bcf on November 1, 57 Bcf above the previous 5-year (2008-12) average, but 112 Bcf less than last year's record-setting inventory level.

U.S. Natural Gas Prices. Natural gas spot prices averaged $3.68 per MMBtu at the Henry Hub in October, up 6 cents from the previous month's price. While prices declined from April through August, they began increasing in September in anticipation of winter heating demand. EIA expects the Henry Hub price will increase from an average of $2.75 per MMBtu in 2012 to $3.68 per MMBtu in 2013 and $3.84 per MMBtu in 2014.

Natural gas futures prices for February 2014 delivery (for the five-day period ending November 7, 2013) averaged $3.57 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for February 2014 contracts at $2.70 per MMBtu and $4.73 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for February 2013 averaged $3.86 per MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $2.76 per MMBtu and $5.39 per MMBtu.

Coal

National coal mining employment, based on data from the U.S. Bureau of Labor Statistics (BLS) for the first 10 months, is down 2.2% from the same period last year, after increasing by approximately 7% from 2008 to 2012. Nowhere is this trend more evident than in the state of Kentucky, which has seen coal mining employment fall by nearly 24% so far this year, and approximately 13% from 2008 to 2012. By comparison, coal mining employment in Pennsylvania, the leading coal producer in the Northern Appalachian Basin (NAPP), saw employment decline only 0.6% through August of this year, after increasing by 10% from 2008 to 2012. Shifts in production from Central Appalachian (CAPP) coals to coals produced in the NAPP and Illinois basins, driven by changing economic, technological, and regulatory factors, are likely to continue; and accompanying changes in employment patterns are likely to continue as well.

U.S. Coal Supply. Coal production for the first three quarters of 2013 was estimated to total 752 million short tons (MMst), 15 MMst (2%) lower than in the same period of 2012. EIA projects total coal production of 1,012 MMst in 2013. Coal production is forecast to grow by 2.7% in 2014 to 1,039 MMst as inventories stabilize and consumption increases. Inventory draws of nearly 30 MMst are expected to meet most of the growth in consumption in 2013.

U.S. Coal Consumption. EIA estimates that total coal consumption for the first three quarters of 2013 was 700 MMst, or 35 MMst (5.3%) higher than the amount of coal consumed in the first nine months of 2012. The increase was primarily a result of increased consumption in the electric power sector due to higher natural gas prices. EIA expects total coal consumption for

2013 to reach 930 MMst (a 4.4% increase over 2012). Projected consumption grows over half that rate (2.9%) to 957 MMst in 2014.

U.S. Coal Exports. EIA estimates that exports for the first eight months of 2013 totaled 80 MMst, which was 9% lower than the same period last year. EIA expects exports to total 118 MMst in 2013, down 7 MMst from last year. Exports are projected to total 107 MMst in 2014. 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.

U.S. Coal Prices. EIA expects nominal annual average coal prices to the electric power industry to fall for the first time since 2000, from $2.40 per MMBtu in 2012 to $2.34 per MMBtu in 2013. EIA forecasts average delivered coal prices of $2.36 per MMBtu in 2014.

Electricity

Electricity generation from renewable energy sources other than hydropower currently accounts for about 6% of total U.S. generation in all sectors. However, non-hydro renewables have experienced the highest growth of any power generation source over the last few years, averaging an estimated annual growth rate of 13% in 2012 and 2013. The share of generation supplied by non-hydro renewables has grown strongly in California in recent years. Development of new renewable energy generating capacity in California has been encouraged by a combination of an ambitious state renewable portfolio standard, continued federal tax credits, and the implementation of a state greenhouse gas emissions cap-and-trade program. During the first eight months of 2013, renewable energy excluding hydropower supplied 19.2% of total electricity generation in California compared with 12.2% during the same period five years ago.

U.S. Electricity Consumption. Electricity use for primary residential space heating is most common in the South Census region, where about two-thirds of households heat their homes with electricity. Heating degree days in this region during the winter months (October-March) are expected to total about 1% lower than last winter. Milder winter temperatures in the South contribute to a 0.3% year-over-year decline in regional residential electricity consumption for heating. EIA expects U.S. residential retail sales of electricity this winter to average 0.6% higher than last winter, while U.S. electricity sales to the commercial and industrial sectors grow by 0.4% and 1.9%, respectively, this winter.

U.S. Electricity Generation. EIA expects total U.S. electricity generation during the winter months will be 0.7% higher than last winter. Higher prices for natural gas delivered to electric generators drive a projected 3.1% increase in coal generation this winter, while natural gas-fired generation falls by 3.0%. Generation fueled by nuclear energy this winter declines by 0.9%, driven by the retirement of four nuclear units during the past year. Non-hydro renewable power generation rises by 3.6% this winter, which is a lower growth rate than in recent years.

Additions to wind power generating capacity slowed considerably during 2013 following the renewal of the production tax credit.

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. During the upcoming winter months, EIA expects the U.S. residential electricity price to average 11.9 cents per kilowatthour, which is 2.2% higher than the winter of 2012-13.

Renewables and Carbon Dioxide Emissions

U.S. Electricity and Heat Generation from Renewables. EIA projects renewable energy consumption for electricity and heat generation in all sectors to increase by 4.4% in 2013. While hydropower declines by 1.2%, nonhydropower renewables used for electricity and heat generation grow by an average of 8.1% in 2013. In 2014, the growth in renewables consumption for electric power and heat generation is projected to continue at a rate of 2.6%, as a 0.6% increase in hydropower is combined with a 3.7% increase in non-hydropower renewables.

EIA estimates that wind capacity will increase by 2.7% in 2013 to about 61 gigawatts (GW) at the end of this year and will total more than 66 GW at the end of 2014. Electricity generation from wind is projected to increase by 17.3% in 2013 and by 3.7% in 2014, contributing more than 4% of total electricity generation.

EIA expects continued robust growth in the generation of solar energy, although the amount of utility-scale generation remains a small share of total U.S. generation at about 0.4% by 2014. Utility-scale capacity, which until recently experienced little growth compared with customer-sited distributed generation capacity, is projected to more than double between 2012 and 2014. Photovoltaics (PV) accounted for all utility-scale solar growth in 2012, but EIA expects that several large solar thermal generation projects will enter service in 2013 and 2014.

U.S. Liquid Biofuels. Ethanol and biodiesel production have recovered from last year's drought. Ethanol production increased from an average of 806,000 bbl/d in October 2012 to 892,000 bbl/d during October 2013 and is forecast to average 900,000 bbl/d during 2014. Biodiesel production, which averaged 64,000 bbl/d (1.0 billion gallons per year) in 2012, has been rising this year and reached a record level of 128 million gallons (98,000 bbl/d) in August.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels declined by 3.9% in 2012 from the previous year, and projects increases of 1.6% in 2013 and 1.0% in 2014. The increase in emissions over the forecast period primarily reflects projected growth in coal use for electricity generation in response to higher natural gas prices relative to coal.

U.S. Economic Assumptions

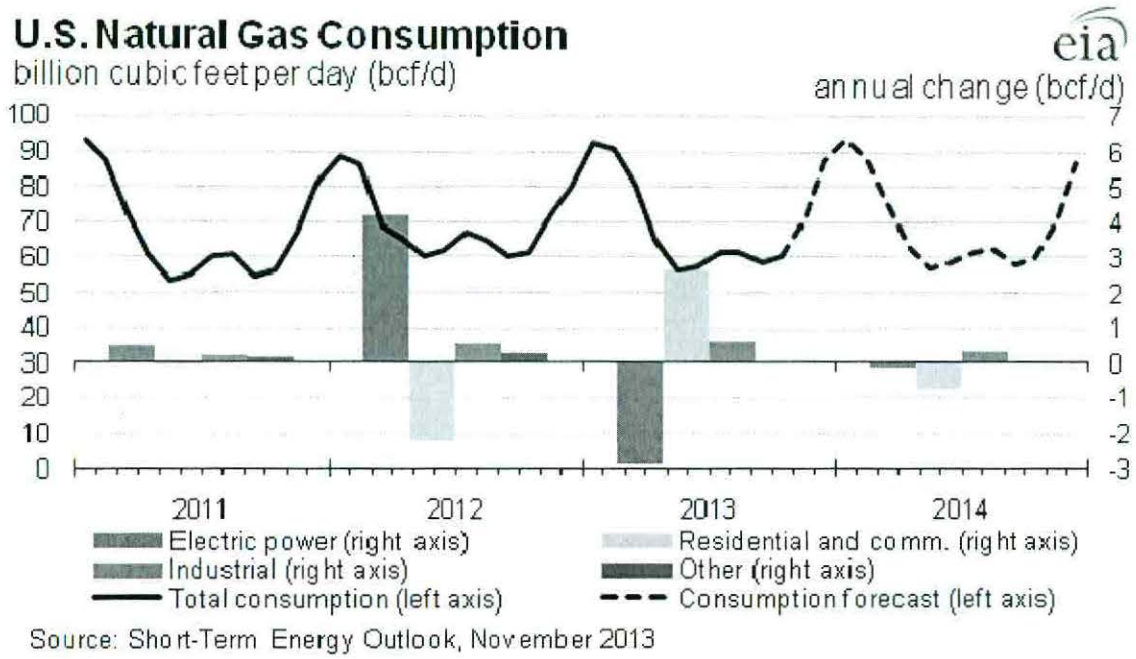
EIA uses the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO. The GI simulation assumes that the spending cuts mandated in the Budget Control Act of 2011 (sequestration) are replaced by a combination of tax and spending changes that are implemented in 2014.

U.S. Current Trends. Recent indicators point to positive growth in U.S. manufacturing output. The Institute for Supply Management (ISM) reported that its national Purchasing Managers Index (PMI) in October rose from 56.2 to 56.4 (a value above 50 indicates expansion). ISM's Chicago PMI rose from 55.7 to 65.9 in October, the highest reading since March 2011. And the Federal Reserve Board also reported that U.S. industrial production rose in September by 0.6%, up from a rise of 0.4% in August. Employment gains, however, remain subdued. The U.S. Department of Labor reported that initial weekly unemployment insurance claims were 336,000 in the week ending November 2, a decrease of 9,000 from the previous week's figure, and the four-week moving average remained above 348,000.

U.S. Production and Income. Forecast U.S. real GDP grows by 1.5% in 2013 and 2.5% in 2014. Year-on-year real GDP growth begins to accelerate in the second half of 2014, eventually rising to 3.0% in the fourth quarter of 2014. Forecast real disposable income increases 0.6% in 2013 and 3.2% in 2014. Total industrial production grows almost one percentage point faster than real GDP in 2013 at 2.4%, and its projected growth of 3.2% in 2014 is still well above the growth rate of real GDP.

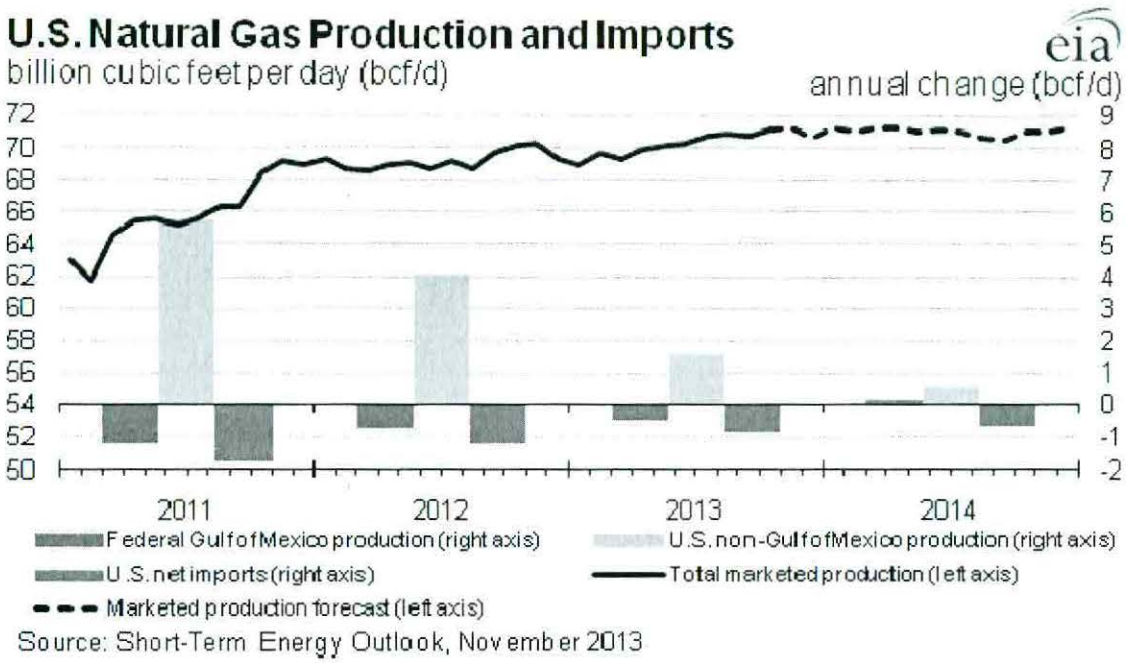
U.S. Expenditures. Private real fixed investment growth averages 4.5% and 7.3% over 2013 and 2014, respectively. Real consumption expenditures grow faster than real GDP in 2013, at 1.9%, and match the rate of real GDP growth in 2014, at 2.5%. Export growth more than doubles from 2.2% to 4.9% over the same two years. Government expenditures fall 2.2% in 2013, and rise by 0.2% in 2014.

U.S. Employment, Housing, and Prices. The unemployment rate in the forecast averages 7.5% over 2013, and gradually falls to 6.7% at the end of 2014. This is accompanied by nonfarm employment growth averaging 1.6% in 2013 and 1.8% in 2014. Consistent with an improving housing sector, housing starts grow an average of 16.9% and 26.1% in 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.



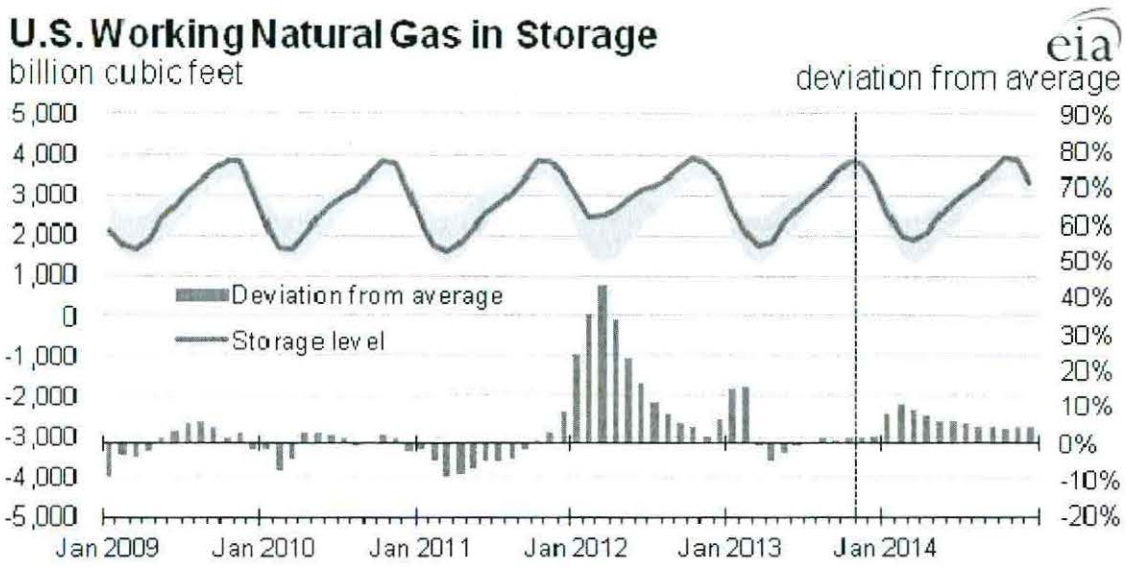
Source: Short-Term Energy Outlook, November 2013

http://www.eia.gov/forecasts/steo/images/Fig17.png

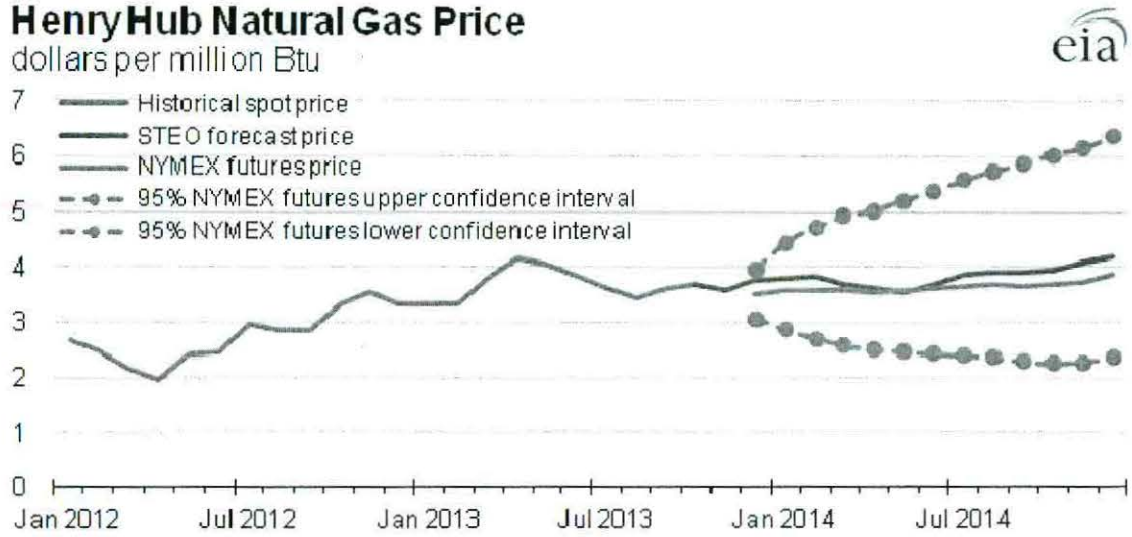


Source: Short-Term Energy Outlook, November 2013

http://www.eia.gov/forecasts/steo/images/Fig18.png



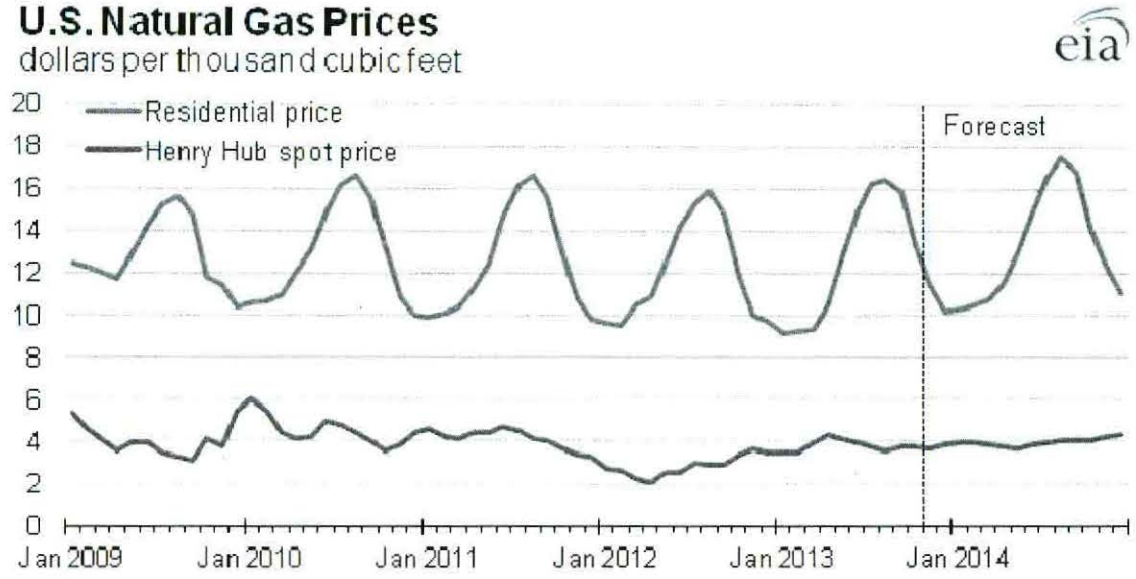
Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2008 - Dec. 2012.
Source: Short-Term Energy Outlook, November 2013



Note: Confidence interval derived from options market information for the 5 trading days ending November 7, 2013. Intervals not calculated for months with sparse trading in near-the-money options

Source: Short-Term Energy Outlook, November 2013

http://www.eia.gov/forecasts/steo/images/Fig4.png



Source: Short-Term Energy Outlook, November 2013

http://www.eia.gov/forecasts/steo/images/Fig5.png

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	($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
Total	$34,209	(17,889)	$10,071	$26,391	56,020		$55,284	($28,893)	
Balance @ October 31, 2013									**$274,418**

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	($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)
Total	($68,226)	0	($972)	($69,198)	148,700		($16,689)	($52,509)	
Balance @ October 31, 2013									**($47,762)**

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.