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

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August 1, 2014

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

Re: Cost of Gas Adjustment (COG)
August 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 (101st Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (101st Revised Sheet No. 8), showing the August 2014 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.8014 per Dk for residential and firm general service customers and a decrease of $0.8014 per Dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for August 2014, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.8014 per Dk for all customers since the last COG filing due to a decrease in the market price of gas.

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

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

Great Plains submitted a check for $600.00 on January 2, 2014 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment covers the $50.00 filing fee associated with this month's COG filing.

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

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

Sincerely,

Tamie A. Aberle
Director of Regulatory Affairs

Attachments

Attachment A

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2

101st Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 100th Revised Sheet No.1.1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/dk
Firm Gas Service - General	2	$3.50 per month	First 10 dk	$1.2869	$6.7708	$8.0577
			Over 10 dk	1.0646		7.8354
Interruptible Gas Service - General	3	$3.50 per month	First 400 dk	$1.1506	$4.8975	$6.0481
			Next 2,600 dk	0.9021		5.7996
			Over 3,000 dk	0.7486		5.6461
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All dk	$1.2516	$4.8975	$6.1491
Transportation Service	5	$3.50 per month	First 400 dk	$1.1506		$1.1506
			Next 2,600 dk	0.9021		0.9021
			Over 3,000 dk	0.7486		0.7486

Date Filed: August 1, 2014

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2

101st Revised Sheet No. 8

Canceling 100th Revised Sheet No. 8

COST OF GAS

Summary:	Firm				Interruptible		
	Est. Wtd. Demand Costs	Average Commodity	GCR Adj.	Est. Wtd. Total Firm	Average Commodity	GCR Adj.	Total Int.
Base Rate	$0.0662	$5.1708	$0.0000	$5.2370	$5.1708	$0.0000	$5.1708
Accumulated Adj.	1.4450	(0.4560)	1.3462	2.3352	(0.4415)	0.9696	0.5281
Current Adj.	0.0000	(0.8014)	0.0000	(0.8014)	(0.8014)	0.0000	(0.8014)
Total Adj.	1.4450	(1.2574)	1.3462	1.5338	(1.2429)	0.9696	(0.2733)
Total Rate	$1.5112	$3.9134	$1.3462	$6.7708	$3.9279	$0.9696	$4.8975

Date Filed: August 1, 2014

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

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

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A - Zone 1-1	8,000		$3.3978	12	$326,189	$0.2315
FT-A - Zone 1-1	5,000		3.6918	5	92,295	0.0655
FT-A Seasonal	2,000		3.6918	5	36,918	0.0262
TFX Seasonal	2,000		15.1530	5	151,530	0.1075
TFX - Winter	13,000		15.1530	5	984,945	0.6990
TFX - Summer	13,000		5.6830	7	517,153	0.3670
LMS Demand 2/						0.0145
Total Demand Charges					$2,109,030	1.5112
Estimated Weighted Average Commodity Cost	1,409,081	1/	3.9134		5,514,298	3.9134
Gas Cost Reconciliation Adjustment						1.3462
Total Current Firm Gas Cost					$7,623,328	6.7708
Base Cost of Gas						5.2370
Accumulated Adjustment						$1.5338

Interruptible	
Estimated Weighted Average Commodity Cost	$3.9134
Gas Cost Reconciliation Adjustment	0.9696
LMS Demand 2/	0.0145
Total Current Interruptible Gas Cost	4.8975
Base Cost of Gas	5.1708
Accumulated Adjustment	($0.2733)

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

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

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

Rates Effective August 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 Cos	3.9134	Per Dk

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

Base Rate Calculation

Firm		
Demand 2/	$0.0662	Per Dk
Commodity	5.1708	Per Dk
Total Firm Base Cost	$5.2370	Per Dk
Interruptible:		
Commodity	$5.1708	Per Dk

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

2/ Demand base rate calculation:

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

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	0.08%
Zone 1-2	$0.0127	0.10%
Zone 2-2	$0.0127	0.02%
Minimum Rate	$0.0127	
IT and AOT		
Zone 1-1	$0.1341	0.08%
Zone 1-2	$0.1702	0.10%
Zone 2-2	$0.0816	0.02%
Minimum Rate	$0.0127	

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

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

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

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

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

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

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

Seventh Revised Sheet No. 50
Superseding
Sixth 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/ TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0364	0.0195			0.0175	0.0000	0.0364	0.0195
Field	Market	0.0364	0.0195	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

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

RATE SCHEDULES TFX and LFT

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	0.0364	0.0195			0.0175	0.0000	0.0364	0.0195
Field	Market	0.0364	0.0195	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

GULF COAST	Reservation 1/ 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 $0.0005 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.
4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
5/ Where applicable, the Field Area Compression charge of $0.0000 and the ACA unit surcharge as set forth on FERC's website at http://www.ferc.gov will be added to the mileage based rates.
6/ In addition to the Maximum and Minimum rates, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.

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

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.97%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.09% 4/ 5/
FDD Storage Fuel	1.76%

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

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

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

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

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

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

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

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

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

Cooler than normal weather over the Midwest and East resulting in lower gas demand for power generation, and continued strong production numbers led to strong storage injection during the month of July and likely were contributing factors to the decrease of the August index. The EIA reported storage levels nationwide as of July 18, 2014 were 23.5 percent below the five-year average and 20.2 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

July 2014

Short-Term Energy Outlook (STEO)

Highlights

- Unrest in Iraq put upward pressure on world oil prices last month, helping North Sea Brent crude oil spot prices reach their highest daily level of the year at just over $115/barrel (bbl) on June 19. North Sea Brent crude oil spot prices increased from a monthly average of $110/bbl in May to $112/bbl in June. This was the 12th consecutive month in which the average Brent crude oil spot price ranged between $107/bbl and $112/bbl. EIA projects Brent crude oil prices to average $110/bbl in 2014 and $105/bbl in 2015, $2/bbl and $3/bbl higher than projected in last month's STEO, respectively. The West Texas Intermediate (WTI) crude oil price discount to Brent is expected to average $9/bbl and $10/bbl in 2014 and 2015, respectively.

- During this year's April-through-September summer driving season, regular gasoline retail prices are forecast to average $3.66/gallon (gal), 8 cents higher than last year. Regular gasoline retail prices are projected to fall from an average of $3.68/gal during the second quarter to $3.64/gal during the third quarter as lower refinery margins more than offset higher crude oil prices. EIA expects regular gasoline retail prices to average $3.54/gal in 2014 and $3.45/gal in 2015, compared with $3.51/gal in 2013.

- U.S. total crude oil production, which averaged 7.4 million barrels per day (bbl/d) in 2013, is expected to average 8.5 million bbl/d in 2014 and 9.3 million bbl/d in 2015. The 2015 forecast represents the highest annual average level of oil production since 1972. Natural gas plant liquids production increases from an average of 2.6 million bbl/d in 2013 to 3.0 million bbl/d in 2015. 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 fell from 60% in 2005 to an average of 33% in 2013. EIA expects the net import share to decline to 22% in 2015, which would be the lowest level since 1970.

- Natural gas working inventories on June 27 totaled 1.93 trillion cubic feet (Tcf), 0.67 Tcf (26%) below the level at the same time a year ago and 0.79 Tcf (29%) below the previous five-year average (2009-13). Projected natural gas working inventories reach 3.43 Tcf at the end of October, 0.38 Tcf below the level at the same time last year. EIA expects that the Henry Hub natural gas spot price, which averaged $3.73 per million British thermal units (MMBtu) in 2013, will average $4.77/MMBtu in 2014 and $4.50/MMBtu in 2015.

Global Petroleum and Other Liquids

EIA projects world petroleum and other liquids supply to increase by 1.5 million bbl/d in 2014 and by another 1.2 million bbl/d in 2015, with most of the growth coming from countries outside of the Organization of the Petroleum Exporting Countries (OPEC). Forecast non-OPEC supply grows by 1.7 million bbl/d in 2014 and 1.0 million bbl/d in 2015. The United States and Canada account for much of this growth. Projected world liquid fuels consumption grows by an annual average of 1.1 million bbl/d in 2014 and 1.5 million bbl/d in 2015. Countries outside the Organization for Economic Cooperation and Development (OECD), notably China, drive expected consumption growth.

The escalation of violence in northern Iraq that started in June has introduced significant uncertainty into the Iraq oil production outlook. EIA has reduced Iraq's production forecast from last month's STEO, maintaining production near 3.3 million bbl/d over the forecast, which was Iraq's average production level during the first half of 2014.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 1.3 million bbl/d (1.5%) in 2013, averaging 90.5 million bbl/d for the year. EIA expects global consumption to grow by 1.1 million bbl/d in 2014 and 1.5 million bbl/d in 2015. Projected global oil-consumption-weighted real GDP, which increased by an estimated 2.6% in 2013, grows by 2.8% and 3.4% in 2014 and 2015, respectively.

Non-OECD countries account for nearly all of the expected consumption growth in 2014 and 2015. China is the leading contributor to projected global consumption growth, with consumption increasing by 400,000 bbl/d (3.7%) in 2014 and 430,000 bbl/d in 2015. However, China's economic and oil consumption growth rates have moderated compared with rates before 2012, when annual GDP growth exceeded 9% and oil consumption growth averaged almost 800,000 bbl/d from 2009 through 2011.

EIA expects a decline in OECD consumption in 2014, led by projected consumption declines in both Japan and Europe. EIA expects Japan's oil consumption to fall by an annual average of 130,000 bbl/d in 2014 and 160,000 bbl/d in 2015, as the country continues to increase natural gas and coal consumption in the electricity sector and returns some nuclear power plants to service in 2015. EIA projects that OECD Europe's consumption, which fell by 110,000 bbl/d in 2013, will decline by 120,000 bbl/d in 2014 and then increase by 60,000 bbl/d in 2015. U.S. liquids consumption, which increased by 400,000 bbl/d in 2013, is expected to be largely unchanged in 2014 and then increase by 70,000 bbl/d in 2015.

Non-OPEC Supply. EIA estimates that non-OPEC liquids production grew by 1.4 million bbl/d in 2013, averaging 54.1 million bbl/d for the year. EIA expects non-OPEC liquids production to grow by 1.7 million bbl/d in 2014 and 1.0 million bbl/d in 2015. EIA forecasts production from the United States and Canada to grow by a combined annual average of 1.6 million bbl/d in 2014 and 1.0 million bbl/d in 2015. EIA estimates that the Former Soviet Union's production will rise

by an annual average of 120,000 bbl/d in 2014, led by Russia. However, production in the region declines by 100,000 bbl/d in 2015. The expected completion of phase one of Kazakhstan's Kashagan field has been pushed back to the first half of 2016 because of continued problems delaying the start of commercial production.

Unplanned supply disruptions among non-OPEC producers averaged 0.6 million bbl/d in June, down from an estimated 0.7 million bbl/d in May. South Sudan, Syria, and Yemen accounted for 83% of total non-OPEC supply disruptions. EIA does not assume a disruption to oil supply or demand as a result of ongoing events in Ukraine.

OPEC Supply. EIA estimates that OPEC crude oil production averaged 29.9 million bbl/d in 2013, a decline of 1.0 million bbl/d from the previous year, primarily reflecting increased outages in Libya, Nigeria, and Iraq, along with strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.3 million bbl/d in 2014 and by an additional 0.1 million bbl/d in 2015 to accommodate growing production in non-OPEC countries.

In Libya, force majeure on oil exports from the two largest eastern oil ports (Es-Sidra and Ras Lanuf - combined effective export capacity of 550,000 bbl/d) were lifted after the rebel group blockading the ports agreed to return them to the government. Although the deal is a major step forward, given the fragility of the situation and the failure of past deals, it is highly uncertain if this deal will materialize into a sustained recovery of Libya's eastern exports. In April 2014, a similar deal was made to return control of two smaller eastern ports (Marsa al-Hariga and Zueitina with combined export capacity of 200,000 bbl/d). However, the deal did not lead to a substantial increase in production and exports because instability and sporadic blockades continued. For now, EIA's short-term forecast for Libya remains unchanged, assuming a small recovery in 2015 but still well below the 2012 crude production level of 1.37 million bbl/d.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.7 million bbl/d in June 2014, slightly higher than the previous month because of increased outages in Iraq. The escalation of violence in northern Iraq that started in June has not reduced the availability of exports to the global market, as southern exports have been unaffected and northern exports were halted in early March 2014. The recent events have mainly affected Iraq's crude oil supply to its largest domestic refinery, which had been processing approximately 0.2 million bbl/d of crude oil. The northern Baiji refinery was shut down during the second half of June, reducing northern Iraqi crude oil and petroleum product production. Crude oil production in southern Iraq of roughly 2.8 million bbl/d and in the Iraqi Kurdistan Region of roughly 0.2 million bbl/d has not been disrupted.

Recent events have introduced a high level of uncertainty in Iraq, and as a result, EIA has reduced its forecast production growth in Iraq by about 0.3 million bbl/d in both 2014 and 2015. EIA does not expect Iraq's crude production to exceed 3.3 million bbl/d, its average level during the first half of 2014, during the STEO forecast period. EIA expects Saudi Arabia to maintain a

higher production level through 2014 to offset the loss of Iraq's growth. In 2015, Saudi Arabia's annual production is still projected to decline to accommodate growing output in non-OPEC countries, albeit to a lesser extent than previously expected.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to average 2.0 million bbl/d in 2014 and 2.7 million bbl/d in 2015. These surplus capacity projections are 0.2 million bbl/d and 0.8 million bbl/d lower than last month's STEO, respectively. The reduction in surplus capacity from last month's STEO mainly reflects increased forecast production from Saudi Arabia. These estimates do not include additional capacity that may be available in Iran but is offline because of the effects of U.S. and European Union sanctions on Iran's ability to sell its oil.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.55 billion barrels at the end of 2013, equivalent to roughly 55 days of consumption. Projected OECD oil inventories rise to 2.60 billion barrels at the end of 2014.

Crude Oil Prices. North Sea Brent crude oil spot prices averaged $112/bbl in June, an increase of $2/bbl from May. This was the 12th consecutive month in which average Brent crude oil spot prices fell within a relatively narrow range of $107/bbl to $112/bbl. The escalating conflict in Iraq, continued record-high levels of Chinese crude oil imports in 2014, and ongoing delays to Libyan oil exports have contributed to upward price pressure. The forecast Brent crude oil price averages $110/bbl in 2014, $2/bbl higher than estimated for 2014 in last month's STEO, and $105/bbl in 2015, which is $3/bbl higher than in last month's STEO.

The WTI crude oil spot price increased from an average of $102/bbl in May to $106/bbl in June. Driven in part by the relocation of crude oil to refining centers along the Gulf Coast through new pipelines, crude oil inventory levels at the Cushing, Oklahoma, storage hub, the delivery point for WTI, have fallen by more than half since the start of the year, from 42 million barrels on January 24 to below 21 million barrels on June 27, the lowest level since November 2008. The discount of WTI crude oil to Brent crude oil, which averaged more than $13/bbl from November 2013 through January 2014, has since fallen to $6/bbl in June. The U.S. Commerce Department's Bureau of Industry and Security (BIS) recently authorized two companies to export stabilized lease condensate processed in a distillation tower. EIA now expects the discount of WTI to Brent crude oil to average $9/bbl in the second half of 2014, which is $1/bbl lower than last month's STEO. EIA expects the discount to average $10/bbl in 2015.

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 October 2014 delivery, traded during the five-day period ending July 2, averaged $104/bbl. Implied volatility averaged 14%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in October 2014 at $92/bbl and $118/bbl, respectively. Last year at this time, WTI for October 2013 delivery averaged $98/bbl and implied volatility averaged 21%.

The corresponding lower and upper limits of the 95% confidence interval were $81/bbl and $118/bbl.

U.S. Petroleum and Other Liquids

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by 400,000 bbl/d (2.1%) in 2013. Consumption of hydrocarbon gas liquids (HGL) registered the largest gain in 2013, increasing by 150,000 bbl/d (6.4%). Total consumption is expected to fall by 10,000 bbl/d in 2014, with declines in the consumption of residual fuel oil and unfinished oils offsetting increases in distillate fuel and gasoline. Total consumption grows by 70,000 bbl/d in 2015, with HGL consumption increasing by 80,000 bbl/d.

Motor gasoline consumption grew by 90,000 bbl/d (1.1%) in 2013, the largest increase since 2006. Motor gasoline consumption grows by 30,000 bbl/d in 2014 and then falls by 10,000 bbl/d in 2015 as improving fuel economy in new vehicles increasingly offsets highway travel growth. Distillate fuel consumption increased by 90,000 bbl/d (2.5%) last year, reflecting colder weather and economic growth. Consumption of that fuel rises by 120,000 bbl/d and 60,000 bbl/d in 2014 and 2015, respectively.

Liquid Fuels Supply. The forecast for total U.S. crude oil production increases from an estimated 7.4 million bbl/d in 2013 to 8.5 million bbl/d in 2014 and 9.3 million bbl/d in 2015. The highest previous annual average U.S. production level was 9.6 million bbl/d in 1970. Recent U.S. crude oil production growth has consisted primarily of lighter, sweet crude (a description of crude quality, as measured by API gravity and sulfur content) from tight resource formations. Roughly 96% of the 1.8-million-bbl/d growth in production between 2011 and 2013 consisted of sweet grades with lighter API gravity of 40 or above. EIA analysis of current and forecast crude oil production indicates that U.S. supply of lighter API gravity crude will continue to outpace that of medium and heavier crudes. More than 60% of EIA's forecast production growth for 2014 and 2015 consists of light, sweet grades with API gravity of 40 or above.

HGL production at natural gas liquids plants is projected to rise from 2.6 million bbl/d in 2013 to 3.0 million bbl/d in 2015. About half of this growth is expected to come from ethane production to meet growing demand associated with expanding domestic ethylene production and export capacity.

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 fell from 60% in 2005 to an average of 33% in 2013. EIA expects the net import share to decline to 22% in 2015, which would be the lowest level since 1970.

Petroleum Product Prices. The U.S. annual average regular gasoline retail price, which averaged $3.51/gal in 2013, is projected to increase to an average of $3.54/gal in 2014 before falling to $3.45/gal in 2015. Diesel fuel prices, which averaged $3.92/gal in 2013, are projected to average

$3.93/gal in 2014 and $3.88/gal in 2015, 3 cents and 10 cents higher than projected in last month's STEO, respectively.

EIA expects that the monthly average regular gasoline retail price will fall from $3.69/gal in June to $3.61/gal in September. The September 2014 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged $3.01/gal for the five trading days ending July 2. Based on the market value of futures and options contracts for this key petroleum component of gasoline, there is a 4% probability that its price at expiration will exceed $3.35/gal, consistent with a monthly average regular-grade gasoline retail price exceeding $4.00/gal in September 2014. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas exceeding the national average price by 30 cents/gal or more.

Natural Gas

While this year's natural gas injection season began slowly in April, injections into storage during May and June were very strong. According to preliminary data from EIA's *Weekly Natural Gas Storage Report*, net injections were 100 billion cubic feet (Bcf) or greater for each of the past eight weeks. Over the previous four years, weekly injections during May and June exceeded 100 Bcf on only three occasions. EIA expects injections will slow during July and August as more natural gas goes to the electric power sector to meet air conditioning demand. The strength in storage injections is the result of strong production growth and moderate demand. Marketed production in April set a record high, at 73.5 Bcf/d, according to EIA's most recent data, with the largest increases coming from areas in Texas.

Natural Gas Consumption. EIA expects total natural gas consumption will average 72.4 Bcf/d in 2014, an increase of 1.4% from 2013, led by the industrial sector. In 2015, total natural gas consumption falls by 0.3 Bcf/d as a return to near-normal winter weather contributes to lower residential and commercial consumption. Higher natural gas prices this year contribute to a 1.1% decline in natural gas consumption in the power sector to 22.1 Bcf/d in 2014. EIA expects natural gas consumption in the power sector to increase to 22.8 Bcf/d in 2015 with lower natural gas prices and the retirement of some coal plants.

Natural Gas Production and Trade. EIA expects natural gas marketed production to grow by an average rate of 4.1% in 2014 and 1.2% in 2015. Rapid natural gas production growth in the Marcellus formation has contributed to low natural gas forward prices in the Northeast, and as a result new infrastructure has been proposed to take gas to other market regions. In June, the eastward-flowing Rockies Express Pipeline (REX) began service on its Seneca Lateral pipeline, which will take Marcellus gas westward to the Midwest. REX's parent company, Tallgrass Energy, plans to add bidirectional capability on a significant portion of REX's easternmost segment.

Growing domestic production is expected to continue to put downward pressure on natural gas imports from Canada. EIA projects net imports of 3.7 Bcf/d in 2014 and 3.1 Bcf/d in 2015, which would be the lowest level since 1987. Liquefied natural gas (LNG) imports have fallen over the past several years because higher prices in Europe and Asia are more attractive to sellers than the relatively low prices in the United States. Several companies are planning to build liquefaction capacity to export LNG from the United States. Cheniere Energy's Sabine Pass facility is expected to be the first to liquefy natural gas produced in the Lower 48 states for export. It is scheduled to come online in stages beginning in late 2015.

Natural Gas Inventories. Natural gas working inventories totaled 1,929 Bcf as of June 27, which was 666 Bcf lower than the same time last year and 790 Bcf lower than the previous five-year (2009-2013) average. The injection season began somewhat slowly in April, but picked up in May and June with more than 1 Tcf was added to storage. EIA expects working gas stocks will reach around 3,430 Bcf at the end of October, 380 Bcf lower than at the same time last year.

Natural Gas Prices. Natural gas spot prices averaged $4.59/MMBtu at the Henry Hub in June. EIA expects spot prices will remain near current levels until the start of the next winter heating season. Projected Henry Hub natural gas prices average $4.77/MMBtu in 2014 and $4.50/MMBtu in 2015.

Natural gas futures prices for October 2014 delivery (for the five-day period ending July 2) averaged $4.40/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for October 2014 contracts at $3.37/MMBtu and $5.76/MMBtu, respectively. At this time last year, the natural gas futures contract for October 2013 averaged $3.62/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $2.69/MMBtu and $4.88/MMBtu.

Coal

Coal Supply. EIA expects U.S. coal production will grow 2.7% to 1,011 million short tons (MMst) in 2014, driven by higher consumption. In 2015, forecast U.S. coal production falls by 0.9% to 1,002 MMst.

Coal Consumption. EIA projects total coal consumption growth of 2.8% to 951 MMst in 2014 because of higher electricity demand and power sector natural gas prices nearly 30% above their 2013 level. Total coal consumption is projected to fall by 2.8% in 2015, as retirements of coal power plants rise in response to the implementation of the Mercury and Air Toxics Standards, electricity sales growth slows to 0.1%, and natural gas prices fall relative to coal prices.

Coal Exports. In April, coal exports were 16.6% (1.6 MMst) lower compared with last year, with steam coal exports falling by 1.5 MMst (33.4%). Coal exports are projected to total 99 MMst in

2014, primarily because of slowing world coal demand growth and increasing coal output in other coal-exporting countries. In 2015, projected exports fall to 95 MMst.

Coal Prices. Annual average coal prices to the electric power industry fell over the past two years, from $2.39/MMBtu in 2011 to $2.35/MMBtu in 2013. Monthly average coal prices have increased by 10 cents per MMBtu since the beginning of the year, with the April price averaging $2.40/MMBtu. EIA expects average delivered coal prices to increase over the forecast period, with prices of $2.39/MMBtu in 2014 and $2.41/MMBtu in 2015.

Electricity

A large proportion of U.S. conventional hydroelectric output is produced in states west of the Mississippi River, especially in the Pacific Northwest. The level of hydroelectric generation is heavily influenced by precipitation patterns, and the western states have experienced widely divergent levels of rainfall and snowfall in recent months. A higher-than-normal snowpack in the Rocky Mountains contributed to an 11.6% increase in year-to-date (January-April) hydroelectric generation in the Mountain Census Division, compared with the same period in 2013. Low precipitation levels in the Pacific Northwest earlier this year were offset by a very wet March, leading to relatively flat year-to-date change in hydroelectric generation in Oregon and Washington. In contrast, exceptional drought in California has caused a 46.6% year-to-date decline in that state's hydroelectric generation.

Electricity Consumption. EIA estimates that total consumption of electricity during the first half of 2014 was 2.5% higher than during the same period last year. This increased consumption occurred primarily in the residential and commercial sectors during the first quarter of the year as a result of colder temperatures in the eastern half of the United States. Retail sales of electricity to the industrial sector during the first half are estimated to be down 1.0% from last year. A 5.1% year-over-year increase in cooling degree days during the second half of 2014 and projected improvements in energy efficiency contribute to the forecast of 0.6% growth in total electricity consumption during the remainder of 2014. EIA expects little change in electricity consumption in 2015.

Electricity Generation. EIA projects that total U.S. electricity generation in 2014 will grow by 1.6% from last year to an average of 11,300 gigawatthours per day. Recently rising costs for natural gas have driven power generators to use relatively more coal for supplying electricity. During the first half of 2014, EIA estimates that 40.0% of total generation was fueled by coal, compared with 39.0% during the first half of last year. In contrast, the share of generation supplied by natural gas fell from 26.1% last year to 24.8% during the first half of 2014. EIA expects that coal's share of generation will fall to an average of 38.8% in 2015 while the natural gas fuel share rises to 27.5%.

Electricity Retail Prices. EIA expects the U.S. residential annual average electricity price to increase by 3.1% this year, which would be the highest growth rate since 2008, primarily in response to higher fuel costs for power generation. The largest price increases occur in the Northeast region. Projected residential prices increase by an additional 2.4% during 2015.

Renewables and Carbon Dioxide Emissions

Electricity and Heat Generation from Renewables. EIA projects total renewables use for electricity and heat generation will grow by 2.9% in 2014. Conventional hydropower generation is projected to fall by 0.8%, while nonhydropower renewables rise by 4.9%. In 2015, total renewables consumption for electric power and heat generation increases by 4.0%, as a result of a 3.5% increase in hydropower and a 4.2% increase in nonhydropower renewables.

EIA projects that wind power capacity will increase by 8.6% in 2014 and 13.9% in 2015. Electricity generation from wind is projected to contribute 4.5% of total electricity generation in 2015.

EIA expects continued robust growth in solar electricity generation, although the amount of utility-scale generation remains a small share of total U.S. generation at about 0.5% in 2015. While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity doubled in 2013. EIA expects that utility-scale solar capacity will increase by 88% between the end of 2013 and the end of 2015; about 70% of this new capacity is being built in California. However, customer-sited photovoltaic capacity growth, which the STEO does not forecast, is expected to exceed utility-scale solar growth between 2013 and 2015, according to EIA's *Annual Energy Outlook 2014*.

Liquid Biofuels. Ethanol production increased from an average of 907,000 bbl/d in March to an estimated 949,000 bbl/d in June, which was the highest monthly level of the year and included the highest weekly level ever recorded at 972,000 bbl/d for the week ending June 13. Ethanol production is forecast to average 932,000 bbl/d in 2014 and 940,000 bbl/d in 2015. Biodiesel production averaged 89,000 bbl/d in 2013 and is forecast to average 80,000 bbl/d in 2014 and 84,000 bbl/d in 2015.

Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide (CO_2) emissions from fossil fuels increased by 2.2% in 2013 from the previous year. Emissions are forecast to rise by 1.7% in 2014, and then to decline by 0.9% in 2015. The increase in emissions in 2013 and 2014 reflects growth in coal consumption for electric power generation. Coal emissions are projected to decline by 2.6% in 2015.

On June 4, the 24th allowance auction was held for the Regional Greenhouse Gas Initiative (RGGI). RGGI involves nine northeastern and mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont). Each allowance permits one short ton of CO_2 emissions. The clearing price was $5.02 per short ton,

and more than 18 million allowances were sold to 43 bidders. The average clearing prices in prior-year auctions were $1.93 per short ton in 2012 and $2.92 per short ton in 2013.

U.S. Economic Assumptions

Recent Economic Indicators. Economic growth slowed in the first quarter of 2014, with recent economic indicators showing signs of improvement later in the year. The Bureau of Economic Analysis (BEA) reported that real gross domestic product (GDP) fell at an annualized rate of 2.9% from the fourth quarter of 2013 to the first quarter of 2014. This was a revision from BEA's first and second estimates, which reported an annualized increase of 0.1% and an annualized decrease of 1.0%, respectively. The first revision was associated with a significant decline in inventory investment, while the latest was more broad-based with downward revisions in consumer spending and trade.

Recent employment indicators are more positive; the U.S. Bureau of Labor Statistics (BLS) reported that the four-week moving average of initial seasonally adjusted unemployment insurance claims for the week ending June 28 was 315,000. According to BLS, the U.S. economy added 288,000 jobs in June, and the unemployment rate fell to 6.1%. New orders for durable goods contracted in May, according to the U.S. Census Bureau (Census), as new orders fell 1%, compared with the 0.8% increase reported in April. BEA also reported that real personal consumption expenditures fell 0.1% between April and May, following a 0.2% drop from March to April. Census reported that sales of new single-family homes rose 18.6% from April to May, a level 16.9% above the May 2013 sales estimate.

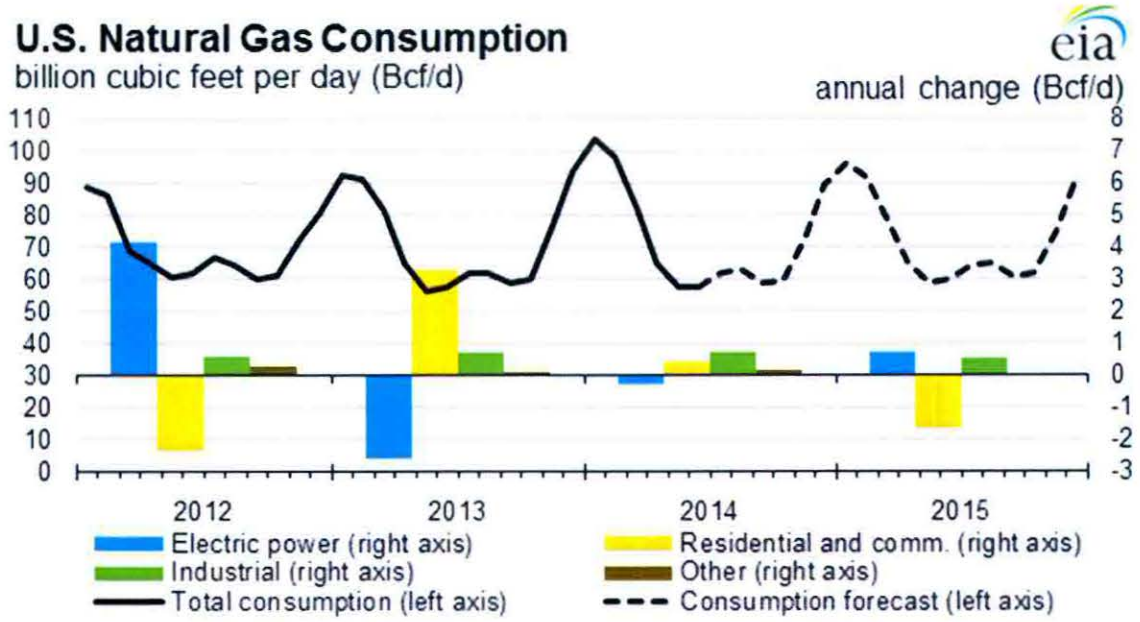
EIA used the June 2014 version of the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO. This GI forecast does not reflect recent macroeconomic data, such as the second downward revision to first quarter real U.S. GDP growth.

Production and Income. Forecast real GDP grows by 2.2% in 2014 and by 2.9% in 2015, down from the 2.4% and 3.1% increases, respectively, forecast in last month's STEO. Weaker real GDP growth in this month's forecast reflects BEA's first downward revision to first-quarter real GDP growth and a downward revision in 2015 real disposable income growth to 3.1% from 3.6% forecast in last month's STEO. Total industrial production grows by 3.4% in 2014 and 3.0% in 2015. Growth in industrial production in the manufacturing sector is lower than in total industrial production in 2014, at 3.3%, but moves higher in 2015 to 3.4%.

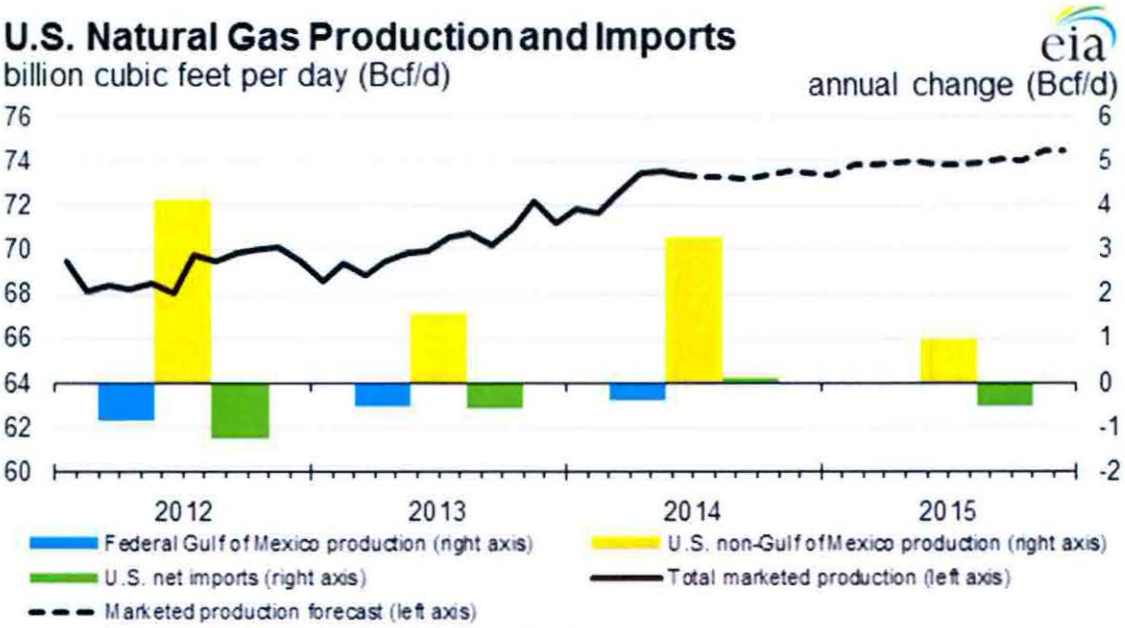
Expenditures. Private real fixed investment growth averages 3.9% and 8.5% in 2014 and 2015, respectively, led by industrial and transportation equipment in 2014 and by a broad array of equipment categories in 2015. Real consumption expenditures grow faster than real GDP in 2014 at 2.7%, but fall below the real GDP growth rate in 2015 at 2.6%. Durable goods expenditures drive consumption spending in both years. Export growth is 3.3% and 4.8% over

the same two years, while import growth is 2.8% in 2014 and 5.2% in 2015. Total government expenditures fall by 0.9% in 2014, but increase by 0.3% in 2015.

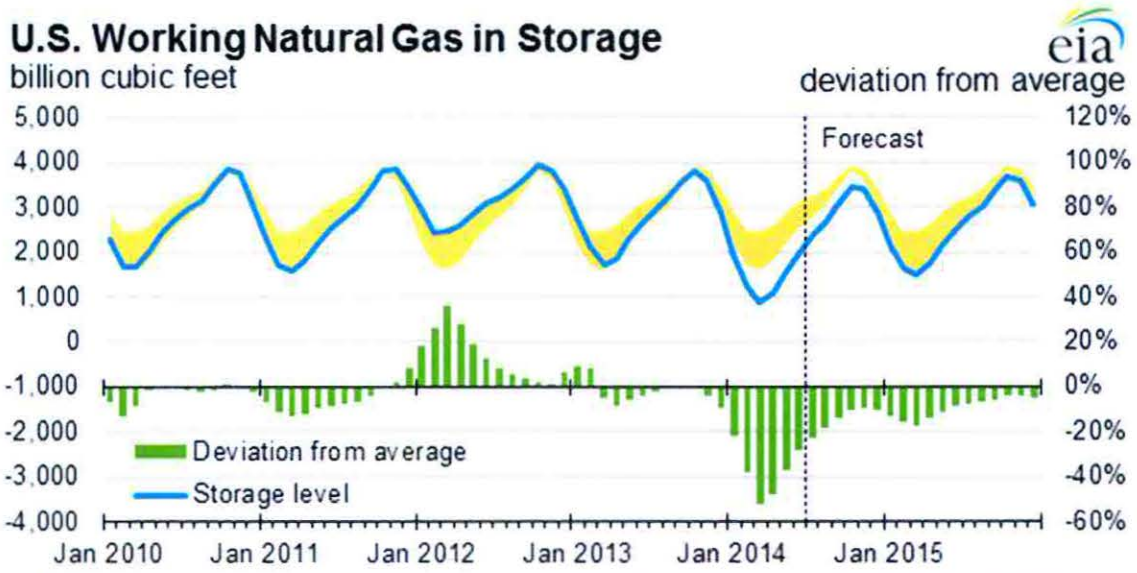
U.S. Employment, Housing, and Prices. Projected growth in nonfarm employment averages 1.7% in 2014 and 1.8% in 2015. This is accompanied by a gradually declining unemployment rate that reaches 5.9% at the end of 2015. The employment growth in 2014 and 2015 is slower than projected last month and the declines in the unemployment rate are about the same. Housing starts grow an average of 14.3% and 28.2% 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, July 2014.



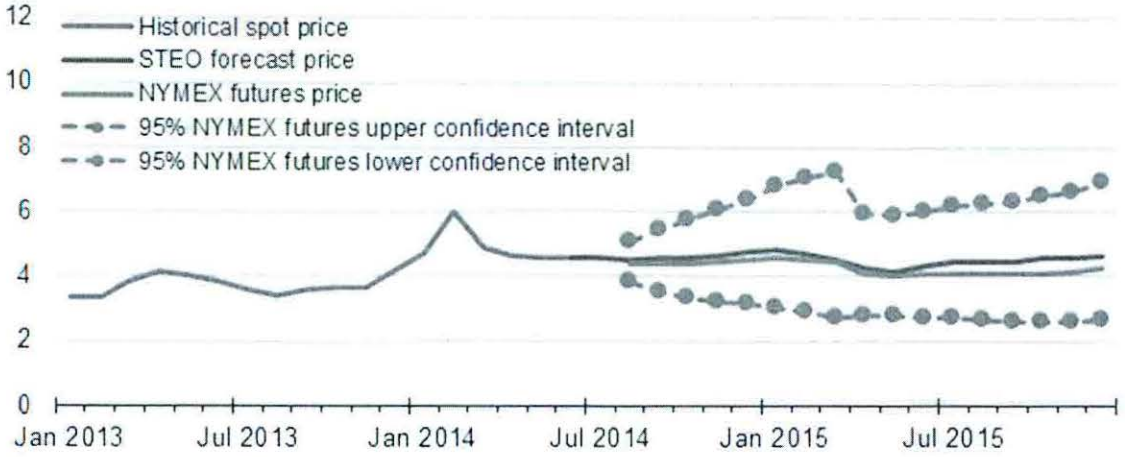
Source: Short-Term Energy Outlook, July 2014.



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2009 - Dec. 2013.
Source: Short-Term Energy Outlook, July 2014.

Henry Hub Natural Gas Price

dollars per million Btu

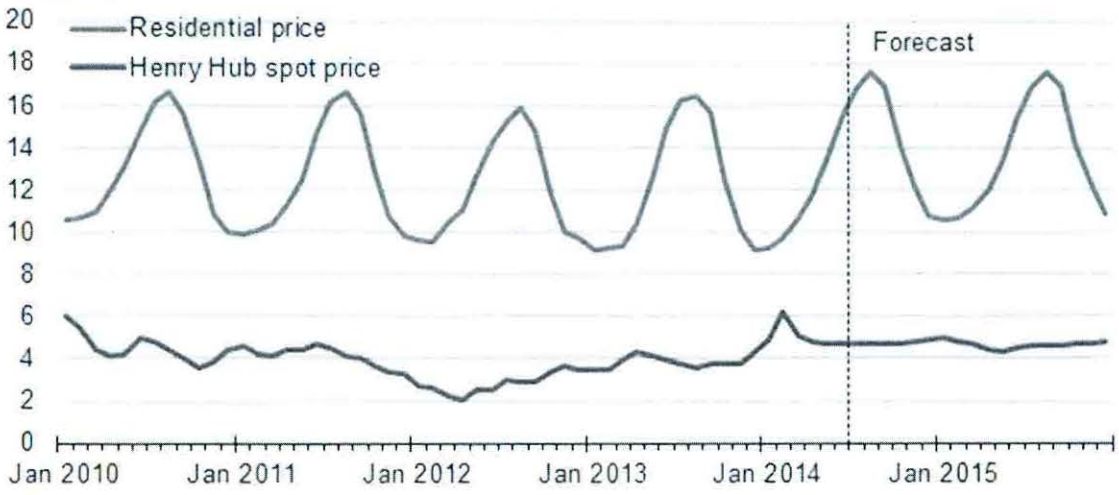


Note: Confidence interval derived from options market information for the 5 trading days ending Jul. 2, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, July 2014

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, July 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, 2014										**$404,569**
May 2014	($15,520)	0	$2,700	($12,820)	18,641	$0.9614	$17,921		($30,741)	373,828
June	($1,551)	0	$2,475	924	9,300	1.3462	$10,015	2/	(9,092)	364,736
Total	($17,071)	0	$5,175	($11,896)	27,941		$27,936		($39,833)	
Balance @ June 30, 2014										**$364,736**

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

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2014									**$388,932**
May 2014	($22,536)	0	$2,691	($19,845)	42,002	$0.0274	$1,151	($20,996)	367,936
June	($17,420)	0	$2,515	(14,905)	19,772	0.9696	$5,999 2/	($20,903)	347,033
Total	($39,956)	0	$5,206	($34,750)	61,774		$7,150	($41,899)	
Balance @ June 30, 2014									**$347,033**

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