

November 30, 2012

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

Re: Cost of Gas Adjustment (COG)
December 2012

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 (81st Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (81st Revised Sheet No. 8), showing the December 2012 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.2712 per mcf for all customers.

Attachment B shows the calculations supporting the gas costs for December 2012, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.2712 since the last COG filing.

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

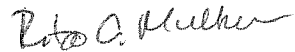
Attachment D shows the calculation of the balancing account since April 30, 2012.

Great Plains submitted a check for \$600.00 on January 4, 2012 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

Attachment A



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

**State of North Dakota
 Gas Rate Schedule**

NDPSC Volume 2

81st Revised Sheet No. 1.1

Canceling 80th Revised Sheet No.1.1

RATE SUMMARY SHEET

Page 1 of 1

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 Over 10 MCF 1.0540	\$6.5315	\$7.8055 7.5855
Firm Gas Service - General Highway 13	2.5	\$3.50 per month	First 10 MCF \$2.1740 Over 10 MCF 1.9540	\$6.5315	\$8.7055 8.4855
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411	\$3.7002	\$4.8393 4.5933 4.4413
Interruptible Gas Service - Highway 13	3.5	\$3.50 per month	First 400 MCF \$2.0391 Next 2,600 MCF 1.7931 Over 3,000 MCF 1.6411	\$3.7002	\$5.7393 5.4933 5.3413
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$3.7002	\$4.9393
Transportation Service	5	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411		\$1.1391 0.8931 0.7411

Date Filed: November 30, 2012

Effective Date: December 1, 2012

Issued By: Tamie A. Aberle
 Regulatory Affairs Manager

Case No.:



GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota Gas Rate Schedule

NDPSC Volume 2
81st Revised Sheet No. 8
Canceling 80th 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.	1.4751	(1.4134)	1.0137	1.0754	(1.3986)	(0.2915)	(1.6901)
Current Adj.	0.0000	0.2712	0.0000	0.2712	0.2712	0.0000	0.2712
Total Adj.	1.4751	(1.1422)	1.0137	1.3466	(1.1274)	(0.2915)	(1.4189)
Total Rate:	\$1.5409	\$3.9769	\$1.0137	\$6.5315	\$3.9917	(\$0.2915)	\$3.7002

Date Filed: November 30, 2012

Effective Date: Service rendered on and after December 1, 2012

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
DECEMBER 2012**

<u>Firm</u>	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
FT-A	8,000	\$3.4671	12	\$332,842	\$0.2378
FT-A - Zone 1-1	500	3.4671	5	8,668	0.0062
FT-A - Zone 1-2	4,500	4.5871	5	103,210	0.0737
FT-A Seasonal	2,000	3.7671	5	37,671	0.0269
TFX Seasonal	2,000	15.1530	5	151,530	0.1083
TFX - Winter	13,000	15.1530	5	984,945	0.7037
TFX - Summer	13,000	5.6830	7	517,153	0.3695
LMS Demand 2/					0.0148
Total Demand Charges				\$2,136,019	1.5409
Estimated Weighted Average Commodity Cost	1,399,684	1/ 3.9769		5,566,403	3.9769
Gas Cost Reconciliation Adjustment					1.0137
Total Current Firm Gas Cost				<u>\$7,702,422</u>	<u>6.5315</u>
Base Cost of Gas					<u>5.1849</u>
Accumulated Adjustment					<u>\$1.3466</u>
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$3.9769
Gas Cost Reconciliation Adjustment					(0.2915)
LMS Demand 2/					0.0148
Total Current Interruptible Gas Cost					3.7002
Base Cost of Gas					5.1191
Accumulated Adjustment					<u>(\$1.4189)</u>

1/ Three year normalized average Dk sales.

2/ Amount divided by 2008-2010 average interruptible sales volumes plus 2008-2010 average normalized firm sales volumes.

	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
LMS Demand	2,500	\$1.0000	12	\$30,000	\$0.0148

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
DECEMBER 2012**

Rates Effective November 1, 2012		<u>\$/Dk</u>	
FT-A - Zone 1-1	\$3.4671		Per dk/Mo.
FT-A - Zone 1-2	4.5871		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:	3.9769		Per dk
Base Rate Effective September 1, 1981			
Demand Charge	\$0.8100		Per Mcf/Mo.
Commodity Charge	5.1191		Per Mcf
Base Rate Calculation			
<u>Firm</u>			
Demand 1/	\$0.0658		Per Mcf
Commodity	5.1191		Per Mcf
Total Firm Base Cost	<u>\$5.1849</u>		Per Mcf
<u>Interruptible:</u>			
Commodity	\$5.1191		Per Mcf

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

Rate Schedule	Base Tariff Rate
Category 1 (Contract Term of Less than 3 Years)	
Daily Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$0.1238
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$0.1607
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$0.0704
Zone 2-2 Minimum Rate	\$0.0000
Category 2 (Contract Term of 3 Years to less than 5 Years)	
Daily Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$0.1189
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$0.1557
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$0.0654
Zone 2-2 Minimum Rate	\$0.0000
Category 3 (Contract Term of 5 or more Years)	
Daily Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$0.1140
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$0.1508
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$0.0605
Zone 2-2 Minimum Rate	\$0.0000

Rate Schedule	Base Tariff Rate	Adjustment Under Section 19 1/	Rate After Current Adjustment	Fuel and Loss Retention Percentages 2/
Commodity Rates				
FT-A – Maximum Rates				
Zone 1-1	\$0.0130	\$0.0018	\$0.0148	0.76%
Zone 1-2	\$0.0130	\$0.0018	\$0.0148	0.86%
Zone 2-2	\$0.0130	\$0.0018	\$0.0148	0.10%
Minimum Rate	\$0.0130	\$0.0018	\$0.0148	
IT and AOT				
Zone 1-1	\$0.1368	\$0.0018	\$0.1386	0.76%
Zone 1-2	\$0.1737	\$0.0018	\$0.1755	0.86%
Zone 2-2	\$0.0834	\$0.0018	\$0.0852	0.10%
Minimum Rate	\$0.0130	\$0.0018	\$0.0148	

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of \$0.0018 per Dekatherm shall be added to other charges under Company's Rate Schedules.

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: 0.15% for Zone 1-1, 0.17 % for Zone 1-2, and 0.02% 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		(\$0.0022)	

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

RATE SCHEDULE TF

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

COMMODITY RATES 2/		Market Area 3/		Field Mileage 5/		Carlton Surcharge 4/		Out-of Balance 3/	
TF12 Base, TF12 Var., TF5 & TFF		Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Receipt Point	Delivery Point								
Market	Market	0.0378	0.0209			0.0175	0.0000	0.0378	0.0209
Field	Market	0.0378	0.0209	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0294	0.0108

- 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 total 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/ Maximum and Minimum rates include ACA of \$0.0018 and the Market Area Electric Compression charge of \$0.0001 where applicable.
- 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, Field Area Electric Compression charge of \$0.0000 and ACA will be added to the mileage based rates.

RATE SCHEDULES TFX and LFT

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

COMMODITY RATES 2/ TFX and LFT		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0378	0.0209			0.0175	0.0000	0.0378	0.0209
Field	Market	0.0378	0.0209	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0294	0.0108

GULF COAST	Reservation 1/		Commodity 6/		Out-of-Balance 6/	
	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
MOPS Gathering	1.0514	0.0000	0.0018	0.0018	0.0018	0.0018
MOPS Transmission	1.5337	0.0000	0.0018	0.0018	0.0018	0.0018
Tivoli - Downstream	0.6827	0.0000	0.0018	0.0018	0.0018	0.0018
Other Gulf Coast	4.8169	0.0000	0.0018	0.0018	0.0018	0.0018

- 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 total 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/ Maximum and Minimum rates include ACA of \$0.0018 and the Market Area Electric Compression charge of \$0.0001 where applicable.
- 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, Field Area Compression charge of \$0.0000 and ACA will be added to the mileage based rates.
- 6/ Maximum and Minimum rates include ACA of \$0.0018.

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)	0.43% 4/ 5/
FDD Storage Fuel	1.09%
	Electric Compression -----
COMMODITY RATES:	1/
Market Area	\$0.0001
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, 2011.

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 2012**

The principal gas sources of natural gas for Wahpeton, North Dakota are from the mid-continent area of the United States. The pricing for much 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 increase from the previous month index. The NNG-Ventura Index is based on negotiated trades during the last five business days of the month, commonly known as bid week and reported by Platt's Inside FERC's Gas Market Report published the beginning of each month.

Colder weather during the month of November over portions of the U.S and the seasonal increase in residential and commercial demand was likely the major contributing factor to the NNG-Ventura index price increase. The Energy Information Administration (EIA) reported storage levels nationwide as of November 23, 2012 were 5.2 percent above the five-year average and 0.7 percent above last year's balance.

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

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



Short-Term Energy Outlook

- Hurricane Sandy resulted in the loss of electric power to about 8.5 million customers on the East Coast and the shutdown of two refineries, major petroleum distribution terminals, and pipelines because of power outages and flooding. Progress reports on the status of electricity and liquid fuels supply are available in the U.S. Department of Energy's *Hurricane Sandy Situation Reports*.
- EIA projects that the West Texas Intermediate (WTI) crude oil price will average \$89 per barrel in the fourth quarter of 2012, about \$4 per barrel lower than in last month's *Outlook*, while the Brent crude oil price is expected to average about \$1 per barrel less than in last month's forecast at about \$110 per barrel over the same period. The projected WTI discount to Brent crude oil, which averaged \$22 per barrel in October 2012, falls to an average of \$11 per barrel in the fourth quarter of 2013. WTI crude oil is forecasted to average \$88 per barrel in 2013, while the Brent crude oil forecast remains unchanged at \$103 per barrel.
- U.S. regular gasoline retail prices began October 2012 at \$3.80 per gallon and fell to \$3.49 per gallon on November 5, 2012. Projected U.S. regular gasoline retail prices average \$3.56 per gallon during the fourth quarter of 2012. Hurricane Sandy, however, has contributed to higher wholesale gasoline prices on the East Coast, and the recovery schedule for affected refineries, pipelines, and distribution terminals contributes to uncertainty over the near-term price outlook. EIA expects regular gasoline retail prices, which averaged \$3.53 per gallon in 2011, to average \$3.64 per gallon in 2012 and \$3.44 per gallon in 2013.
- EIA expects U.S. total crude oil production to average 6.3 million barrels per day (bbl/d) in 2012, an increase of 0.7 million bbl/d from last year. Projected U.S. domestic crude oil production increases to 6.8 million bbl/d in 2013, the highest level of production since 1993.
- Working natural gas inventories are at a record high level. As of October 26, 2012, working inventories totaled 3,908 billion cubic feet (Bcf), which is 56 Bcf greater than the previous record high of 3,852 Bcf on November 18, 2011. EIA expects the Henry Hub natural gas spot price, which averaged \$4.00 per million British thermal units (MMBtu) in 2011, to average \$2.77 per MMBtu in 2012 and \$3.49 per MMBtu in 2013.

Global Crude Oil and Liquid Fuels

Global Crude Oil and Liquid Fuels Overview. EIA expects global oil markets to loosen in the fourth quarter of 2012 as forecast liquid fuels supply, which was 0.7 million bbl/d lower than world consumption in the third quarter of 2012, outpaces consumption by 0.1 million bbl/d in the fourth quarter, leading to an increase in world inventories. Projected liquid fuels consumption declines by 0.3 million bbl/d from the third quarter of 2012 to the fourth quarter of 2012 while global production increases by 0.5 million bbl/d over the same period, as members of the Organization of the Petroleum Exporting Countries (OPEC) continue to produce more than 30 million bbl/d of crude oil and non-OPEC countries recover from unplanned outages and scheduled maintenance. EIA also expects global inventory builds to continue during the first half of 2013, mostly due to an increase in non-OPEC supply.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by an estimated 1.0 million bbl/d in 2011. EIA expects world consumption growth of about 0.7 million bbl/d in 2012 and 0.9 million bbl/d in 2013, with countries outside of the Organization for Economic Cooperation and Development (OECD) driving global consumption growth.

Projected OECD liquid fuels consumption declines by 0.4 million bbl/d in 2012 and by an additional 0.2 million bbl/d in 2013 below 2012. Although EIA forecasts U.S. liquid fuels consumption to grow by 110 thousand bbl/d in 2013, this is more than offset by declines in consumption in Europe and other OECD countries. At the same time, EIA expects that China's annual consumption growth to increase from 330 thousand bbl/d in 2012 to 430 thousand bbl/d in 2013.

Non-OPEC Supply. EIA estimates non-OPEC liquid fuels production in October 2012 to be 0.3 million bbl/d above the same month last year, primarily because of increased crude oil production from tight oil plays in the United States. Projected non-OPEC production increases by 1.3 million bbl/d in 2013 over 2012, largely due to continued production growth from U.S. tight oil formations and Canadian oil sands. EIA slightly increased its forecast for Canada's oil sands output from last month's *Outlook*, as Cenovus announced that its phased expansions of the Christina Lake project are proceeding faster than expected.

Unplanned production outages in non-OPEC countries declined in October to 0.9 million bbl/d, from an average of 1.1 million bbl/d in September. The decrease was mostly due to the return of the U.S. production in the U.S. Gulf of Mexico following disruptions related to the late August landfall of Hurricane Isaac. Hurricane Isaac led to a peak shut-in of 1.3 million bbl/d of U.S. production in the Gulf of Mexico and average disruption volumes of 210 thousand bbl/d in August and September.

Other unplanned disruptions persist in non-OPEC countries, including those in Syria and Sudan. An estimated 220 thousand bbl/d of production was offline in Syria in October, an increase relative to September's outage of 180 thousand bbl/d as a result of infrastructure damage

related to cross-border shelling between Turkey and Syria. South Sudan's production still remains offline as well, though the government recently ordered oil companies to restart production and estimated that exports would resume in the following three months. EIA forecasts Sudan and South Sudan's production to average 120 thousand bbl/d in 2012 and recover to 310 thousand bbl/d in 2013, still well below the pre-shut-in level of around 460 thousand bbl/d.

OPEC Supply. EIA expects that OPEC members will continue to produce more than 30 million bbl/d of crude oil over the next two years to accommodate the projected increase in world oil consumption and to counterbalance supply disruptions. Projected OPEC crude oil production increases by about 1.2 million bbl/d in 2012 and falls by 0.5 million bbl/d in 2013. OPEC production of noncrude oil liquids, which are not subject to production targets, increases by 0.3 million bbl/d and 0.2 million bbl/d in 2012 and 2013, respectively.

Production from OPEC member states has increased over the past year, especially in Libya and Iraq, while Saudi Arabia continues to produce nearly 10 million bbl/d. There has also been growth, although smaller, in Kuwait and the United Arab Emirates. Iraq's production increased to 3.2 million bbl/d in October 2012, compared with the year-ago level of 2.7 million bbl/d. The increased production was boosted by new infrastructure that facilitates exports of oil from Iraq's southern fields. Furthermore, new agreements on payments between the central government in Baghdad and the Kurdistan Regional Government (KRG) have resulted in resumed exports from the oil fields located in the area controlled by the KRG. Libyan crude oil production remained near 1.5 million bbl/d in October, slowly approaching the pre-crisis level of near 1.7 million bbl/d.

A number of recently published reports indicate that Iranian crude oil exports experienced precipitous declines in July, due to the enforcement of the latest round of U.S. and European Union (EU) sanctions, although Iran's difficulties in exporting its oil seemed to have eased somewhat since then. See the U.S. Energy Information Administration's October 25, 2012, report *The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran*.

Nigerian oil production declined for a second consecutive month in October to slightly less than 2.0 million bbl/d. Maintenance-related outages reduced Nigeria's production in September, which fell again in October due to floods and pipeline sabotage. The floods mostly affected onshore oil and gas production from Total and Eni and curtailed natural gas shipments to the Bonny liquefied natural gas (LNG) facility. However, Total stated that increases from some of its offshore oil fields partially compensated for the lost output. Meanwhile, pipeline sabotage caused production delays and led Shell to declare force majeure on Bonny and Forcados crude oil exports in mid-October.

Global OPEC surplus capacity, overwhelmingly concentrated in Saudi Arabia, remains relatively tight by historical standards, and is estimated at 2.0 million bbl/d over the past two months.

OPEC surplus capacity grows slowly over the next year to 3.3 million bbl/d by the second quarter of 2013. This estimate does not include additional capacity that may be available in Iran, but which is currently offline due to the impacts of U.S. and EU sanctions on Iran's ability to sell its oil.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories ended 2011 at 2.60 billion barrels, equivalent to just under 56 days of forward-cover. Projected OECD oil inventories increase to 2.65 billion barrels and just over 57 days of forward-cover by the end of 2012. Forecast days of supply are at the highest end-of-year levels since 1991 because of the decline in OECD consumption over the past seven years.

Crude Oil Prices. EIA projects the price of Brent crude oil will average \$112 per barrel in 2012 and \$103 per barrel in 2013, both mostly unchanged from last month's *Outlook*. EIA expects the WTI price to average \$89 per barrel in the fourth quarter of 2012, about \$4 lower than last month's *Outlook*, and to mostly remain at this level throughout the forecast period averaging \$88 per barrel in 2013. After increasing to \$22 per barrel in October of this year, the WTI crude oil spot price discount to the Brent crude oil spot price will average \$20 per barrel in the fourth quarter of 2012 before falling to \$11 per barrel by the end of 2013, according to EIA.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for February 2013 delivery during the five-day period ending November 1, 2012, averaged \$87.21 per barrel. Implied volatility averaged 31 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in February 2013 at \$66 per barrel and \$115 per barrel, respectively. Last year at this time, WTI for February 2012 delivery averaged \$93 per barrel and implied volatility averaged 39 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$66 per barrel and \$130 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total liquid fuels consumption fell 230 thousand bbl/d (1.2 percent) in 2011, driven by a 240-thousand-bbl/d drop in motor gasoline consumption. Forecast total liquid fuels consumption falls by 290 thousand bbl/d (1.5 percent) in 2012, including a decline in motor gasoline consumption of 30 thousand bbl/d. Warm weather during the first half of the year contributes to a projected 120-thousand-bbl/d decline in distillate fuel oil consumption in 2012. In 2013, total liquid fuels consumption increases by 110 thousand bbl/d (0.6 percent). Most of the recovery in consumption next year comes from distillate fuel oil and natural gas liquids consumption, which rise because of continued growth in freight shipments and industrial use as well as the assumption of near-normal weather this coming winter compared with warmer weather last winter.

Despite higher assumed growth in U.S. real disposable income and a projected decline in retail gasoline pump prices of 5.6 percent in 2013, forecast motor gasoline consumption remains

almost unchanged from 2012 because of continued slow growth in the driving-age population, improvements in the average fuel economy of new vehicles, and increased rates of retirement of older, less-fuel-efficient vehicles.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by an estimated 170 thousand bbl/d (3.0 percent) to 5.65 million bbl/d in 2011. Forecast crude oil production increases to 6.33 million bbl/d in 2012 with Lower-48 (excluding the federal Gulf of Mexico) crude oil production growing by 790 thousand bbl/d, primarily from the Bakken, Permian Basin, and Eagle Ford producing areas. Total crude oil output rises a further 520 thousand bbl/d in 2013. The number of oil-directed drilling rigs reported by Baker Hughes has increased from 777 at the beginning of 2011 to 1,191 at the start of 2012, and to 1,414 as of June 8, 2012; the oil rig count has remained near 1,400 since then.

The share of total U.S. consumption met by liquid fuel net imports of both crude oil and products has been falling since peaking at over 60 percent in 2005. In 2011, it averaged 45 percent, down from 49 percent in 2010. EIA expects that the total net import share of consumption will continue to decline to 41 percent in 2012 and to 39 percent in 2013 because of the substantial increases in domestic crude oil production. If the 2013 forecast holds true, it would be the first time the share of total U.S. consumption met by liquid fuel net imports is less than 40 percent since 1991.

U.S. Petroleum Product Prices. U.S. monthly average regular gasoline retail prices increased from \$3.44 per gallon in July to \$3.85 in September. Prices then fell by 10 cents to \$3.75 per gallon in October, as the gasoline market transitioned from summer-grade to lower-cost winter-grade gasoline specifications, and crude oil prices fell. Projected regular gasoline retail prices average \$3.56 per gallon during the fourth quarter of 2012, down slightly from \$3.60 per gallon projected in last month's *Outlook*. However, outages caused by Hurricane Sandy and low gasoline and distillate stocks on the East Coast could put upward pressure on prices in this region. Projected regular gasoline retail prices average \$3.64 per gallon in 2012 and \$3.44 per gallon in 2013.

Diesel fuel retail prices rose from a monthly average of \$3.83 per gallon to January 2012 to a high of \$4.13 per gallon in March, and then fell to a low of \$3.72 per gallon in July. After reaching an average of \$4.12 per gallon in September, continued tight market conditions and strong global demand kept on-highway diesel fuel prices at an average of \$4.09 per gallon in October. EIA expects that on-highway diesel fuel retail prices will average \$4.00 per gallon during the fourth quarter of this year and \$3.83 per gallon in 2013. Wholesale diesel margins (the difference between the wholesale price of diesel and the U.S. average refiner acquisition cost of crude oil) averaged \$0.60 per gallon in the first half of 2012 before climbing to an estimated \$0.97 per gallon in October, the highest level since October 2005. EIA projects those margins will average \$0.72 per gallon in 2012 and \$0.75 per gallon in 2013, compared with the previous 5-year average of \$0.52 per gallon.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 69.7 Bcf/d in 2012, an increase of 3.2 Bcf/d (4.8 percent) from 2011. Large gains in electric power use in 2012 more than offset declines in residential and commercial use. Projected consumption of natural gas in the electric power sector averages 25.4 Bcf/d in 2012, 22 percent higher than in 2011, primarily driven by the increased relative cost advantages of natural gas over coal for power generation in some regions. Consumption in the electric power sector during 2012 reached a record level of 35.3 Bcf/d in July 2012, when electricity demand for air conditioning was highest.

Projected total natural gas consumption decreases by 0.5 Bcf/d (0.7 percent) in 2013. Expected declines in the electric power sector offset increases in residential, commercial, and industrial consumption. A forecast of near-normal weather during the upcoming winter (but colder than last year's abnormally warm winter) drives 2013 increases in residential and commercial consumption of 11.5 percent and 10.2 percent, respectively. Although projected higher natural gas prices contribute to a 11.2-percent decline in forecast natural gas consumption in the electric power sector in 2013, consumption in the power sector next year is still expected to be about 1.8 Bcf/d higher than 2011 levels and high by historical standards. The consumption forecast for 2012 and 2013 is largely unchanged from last month's *Outlook*.

U.S. Natural Gas Production and Imports. Total marketed production of natural gas grew by 4.8 Bcf/d (7.9 percent) in 2011. EIA forecasts that total marketed production growth will slow in 2012, and that 2013 production will be near the 2012 level. So far during 2012, production has fluctuated slightly around an average of 69 Bcf/d, in contrast to the strong upward growth seen between 2009 and 2011. EIA expects some small declines in production in the coming months, related to recent drops in the rig count. According to Baker Hughes, the natural gas rig count was 424 as of November 2, 2012, compared with 811 at the start of 2012. EIA expects that growth in associated gas from crude oil, as well as continued drilling in liquids-rich areas, will help offset the decline in drilling activity. This month's 2013 forecast represents a downward revision of 0.4 Bcf/d from last month's *Outlook*.

EIA expects pipeline gross imports will fall by 0.2 Bcf/d (2.6 percent) in 2012, as domestic supply continues to displace Canadian sources. The warm winter in the United States early this year also added to the year-over-year decline in imports, particularly to the Northeast where imported natural gas can serve as additional supply in times of very cold weather. EIA expects an increase of 0.1 Bcf/d in (1.3 percent) in pipeline gross imports in 2013. Pipeline gross exports grew by 1.0 Bcf/d (33 percent) in 2011, driven by increased exports to Mexico, but are expected to remain mostly flat in 2012, and grow by 0.1 Bcf/d in 2013.

Liquefied natural gas (LNG) imports are expected to fall by about one-half in 2012 from the year before. EIA expects that an average of slightly less than 0.5 Bcf/d will arrive in the United States (mainly at the Elba Island terminal in Georgia and the Everett terminal in New England) both in

2012 and 2013, either to fulfill long-term contract obligations or to take advantage of temporarily high local prices due to cold snaps and disruptions. Higher prices for LNG, particularly in Asian markets, have made the United States a market of last resort for LNG suppliers. Even as natural gas prices are expected to rise in the United States next year, prices in Japanese and Korean markets have historically been much higher.

U.S. Natural Gas Inventories. Working natural gas inventories are at a record high level. As of October 26, 2012, according to EIA's *Weekly Natural Gas Storage Report*, working inventories totaled 3,908 Bcf, which is 56 Bcf greater than the previous weekly high of 3,852 Bcf on November 18, 2011. Inventories are 136 Bcf greater than last year's level and 259 Bcf above the five-year average. EIA expects that inventory levels at the end of October 2012 will total 3,935 Bcf, and injections are likely to continue for a few weeks in November. Because of very high inventories at the start of the summer injection season this year, working inventories have remained high and weekly stock builds have been below both the five-year average and last year's level since April 2012, with a few exceptions. The projected increase of 1,458 Bcf in working gas inventory during the 2012 injection season (from the beginning of April through the end of October) would be the smallest build since 1991. Last year's inventory build from April through October, for comparison, was 2,224 Bcf.

U.S. Natural Gas Prices. Natural gas spot prices averaged \$3.31 per MMBtu at the Henry Hub in October 2012, up \$0.46 per MMBtu from the September 2012 average and \$0.25 per MMBtu less than the October 2011 average. EIA expects the Henry Hub natural gas price will average \$2.77 per MMBtu in 2012 and \$3.49 per MMBtu in 2013, increases of \$0.06 per MMBtu in 2012 and \$0.14 per MMBtu in 2013 from last month's *Outlook*.

Natural gas futures prices for February 2013 delivery (for the five-day period ending November 1, 2012) averaged \$3.86 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for February 2013 contracts at \$2.76 per MMBtu and \$5.39 per MMBtu, respectively. At this time last year, the February 2012 natural gas futures contract averaged \$3.97 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were \$2.89 per MMBtu and \$5.45 per MMBtu.

Coal

U.S. Coal Consumption. EIA expects that coal consumption in the electric power sector will be below 1 billion short tons for a fourth consecutive year in 2012. EIA forecasts coal consumption in the electric power sector to total 825 million short tons (MMst) in 2012. Lower natural gas prices to electric generators have led to a significant increase in the share of natural gas-fired generation. EIA projects power sector coal consumption to grow by 6 percent in 2013 as higher natural gas prices lead to a reduction in natural gas-fired generation.

U.S. Coal Supply. EIA forecasts that coal production will decline by 7 percent in 2012 as domestic consumption falls. Coal production for the first three quarters (January-September) of 2012 was 46 million short tons (MMst) below the same period in 2011. EIA expects production to remain flat in 2013 as inventory draws and lower exports offset an increase in domestic consumption in the forecast. Electric power sector stocks, which ended 2011 at 175 MMst, are forecast to total 185 MMst at the end of the 2012 and 180 MMst in 2013.

U.S. Coal Trade. EIA expects U.S. coal exports to remain strong in 2012 and exceed the 107 MMst exported in 2011. The 98 MMst of coal exported in the first three quarters of 2012 was larger than any annual total exported from 1993 through 2009. EIA projects coal exports to total a record 125 MMst in 2012. EIA expects that coal exports will decline in 2013 but remain above 100 MMst for the third straight year. Continuing economic weakness in Europe, lower international coal prices, and increasing production in Asia are primary reasons for the expected decline in coal exports. U.S. exports could be higher if there are significant supply disruptions from any of the major coal-exporting countries.

U.S. Coal Prices. Delivered coal prices to the electric power industry increased steadily over the 10-year period ending in 2011, when the delivered coal price averaged \$2.39 per MMBtu (a 6-percent increase from 2010). However, EIA expects the decline in domestic demand for coal, combined with large coal inventories, will slow increases in coal prices and contribute to the shut-in of higher-cost production. EIA forecasts that the delivered coal price will average \$2.40 per MMBtu in 2012 and \$2.44 per MMBtu in 2013.

Electricity

U.S. Electricity Consumption. Residential sales of electricity in the United States are projected to fall by 3.5 percent in 2012. The decline in residential sales this year reflects the mild winter temperatures in the first quarter of this year, particularly in the south where many households heat using electricity. Residential electricity sales decline by 0.5 percent in 2013 as lower electricity demand for space cooling during the summer offsets the increase in first quarter consumption.

According to the U.S. Department of Energy's [*Hurricane Sandy Situation Report*](#), at least 8.5 million customers were without power at some point as a result of Hurricane Sandy, compared with a peak number of 6.7 million customers during Hurricane Irene in August 2011. EIA expects outages caused by Hurricane Sandy will reduce October and November total retail sales of electricity in the Mid-Atlantic region (New Jersey, New York, and Pennsylvania) by about 2 to 3 percent from their forecasted level absent disruptions caused by the storm.

U.S. Electricity Generation. The shares of total U.S. electricity generation fueled by natural gas and coal during 2012 averaged 30.6 percent and 37.2 percent, respectively. EIA expects that prices for natural gas delivered to electric generators during 2013 will average 22 percent higher than during 2012, while the average cost of coal is just over 1 percent higher. The projected

higher price of natural gas relative to coal contributes to a decline in the share of total generation fueled by natural gas 27.2 percent next year and an increase in the coal share to 40.1 percent.

U.S. Electricity Retail Prices. EIA expects the nominal U.S. residential electricity price will rise by just 0.1 percent during 2012, which would be the smallest year-over-year increase in ten years. Residential prices during 2013 are projected to rise by 1.5 percent to an average of 11.98 cents per kilowatthour.

Renewables and Carbon Dioxide Emissions

U.S. Renewables. After growing by 14.0 percent in 2011, total renewable energy consumption is projected to decline by 2.6 percent in 2012. This decrease is the result of hydropower use falling by 0.4 quadrillion Btu (13.8 percent) as it begins to return to its long-term average. The decline in hydropower from 2011 to 2012 more than offsets the projected growth in the consumption of other renewable energy forms. Renewable energy consumption increases 2.5 percent in 2013 as hydropower continues to decline (2.4 percent) but nonhydropower renewables grow by an average of 5.0 percent.

Under current law, federal production tax credits for wind-powered generation will not be available for turbines that begin operating after the end of 2012. Wind-powered generation, which grew by 27 percent in 2011, is forecast to grow an additional 16 percent in 2012. The outlook for wind capacity additions and generation in 2013 will likely depend on whatever decision is made regarding the extension of production tax credits.

Solar energy continues robust growth, although the total amount remains relatively small. Consumption is projected to grow by about 30 percent in both 2012 and 2013.

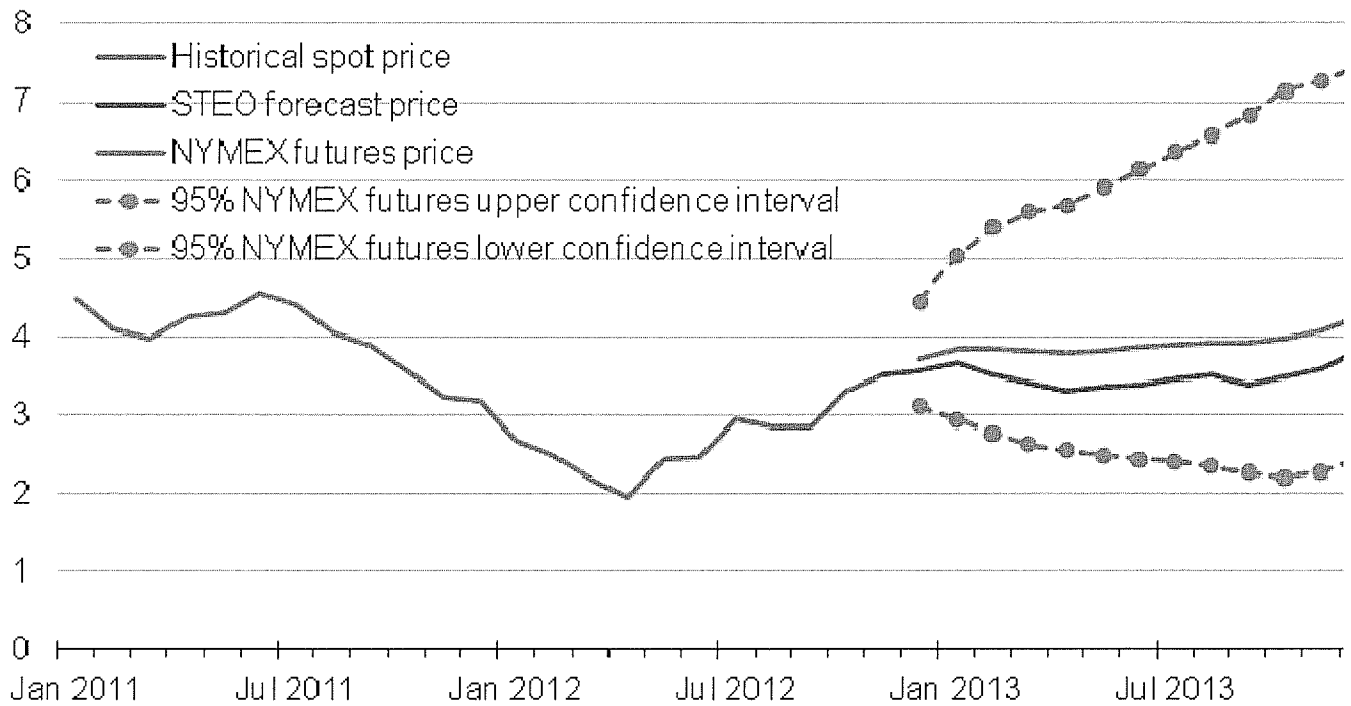
As a result of drought conditions depressing corn harvests throughout the Midwest, fuel ethanol production fell from an average of 890 thousand bbl/d during the second quarter of 2012 to an average of about 806 thousand bbl/d in October 2012. EIA expects ethanol production will remain near current levels through the first half of 2013 and recover in the second half of 2013, averaging over 850 thousand bbl/d (13.0 billion gallons) for the year. The projected lower ethanol production is generally matched by higher ethanol imports and lower ethanol exports. Biodiesel production averaged about 63 thousand bbl/d (0.97 billion gallons) in 2011. Forecast biodiesel production averages 67 thousand bbl/d in 2012 and 82 thousand bbl/d in 2013, with biodiesel blending meeting the Renewable Fuel Standard requirements of 1.0 billion gallons and 1.28 billion gallons, respectively, in those years.

U.S. Energy-Related Carbon Dioxide Emissions. After declining by 2.1 percent in 2011, fossil fuel emissions are projected to further decline by 2.9 percent in 2012. This decline is followed by an increase of 2.2 percent in 2013. Petroleum emissions fall by 1.5 percent in 2012 and grow by 0.2 percent in 2013. Projected natural gas emissions rise by 5.1 percent in 2012 and fall by

0.8 percent in 2013. Forecast coal emissions decline 10.1 percent in 2012, but are projected to rise by 7.2 percent in 2013 as rising natural gas prices lead to increases in coal-fired electricity generation.

Henry Hub Natural Gas Price

dollars per million btu



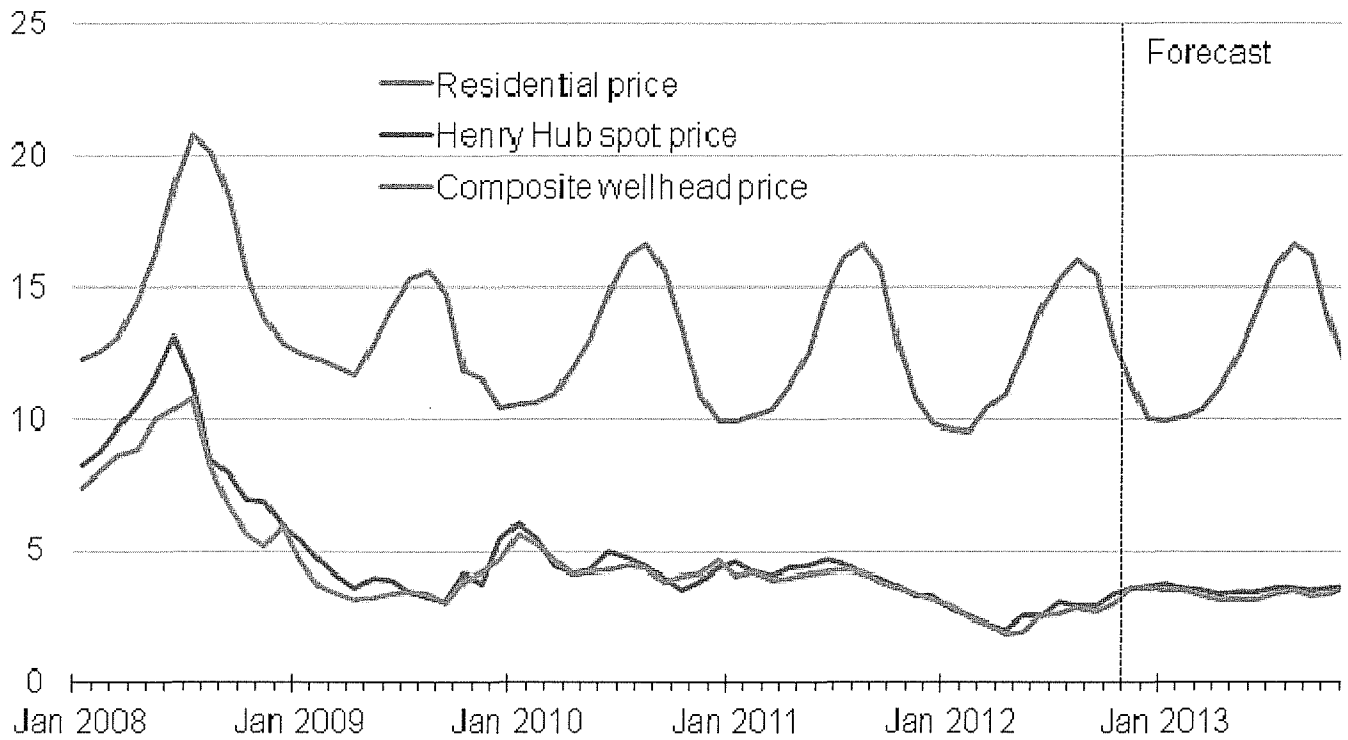
Note: Confidence interval derived from options market information for the 5 trading days ending November 1, 2012. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, November 2012



U.S. Natural Gas Prices

dollars per thousand cubic feet



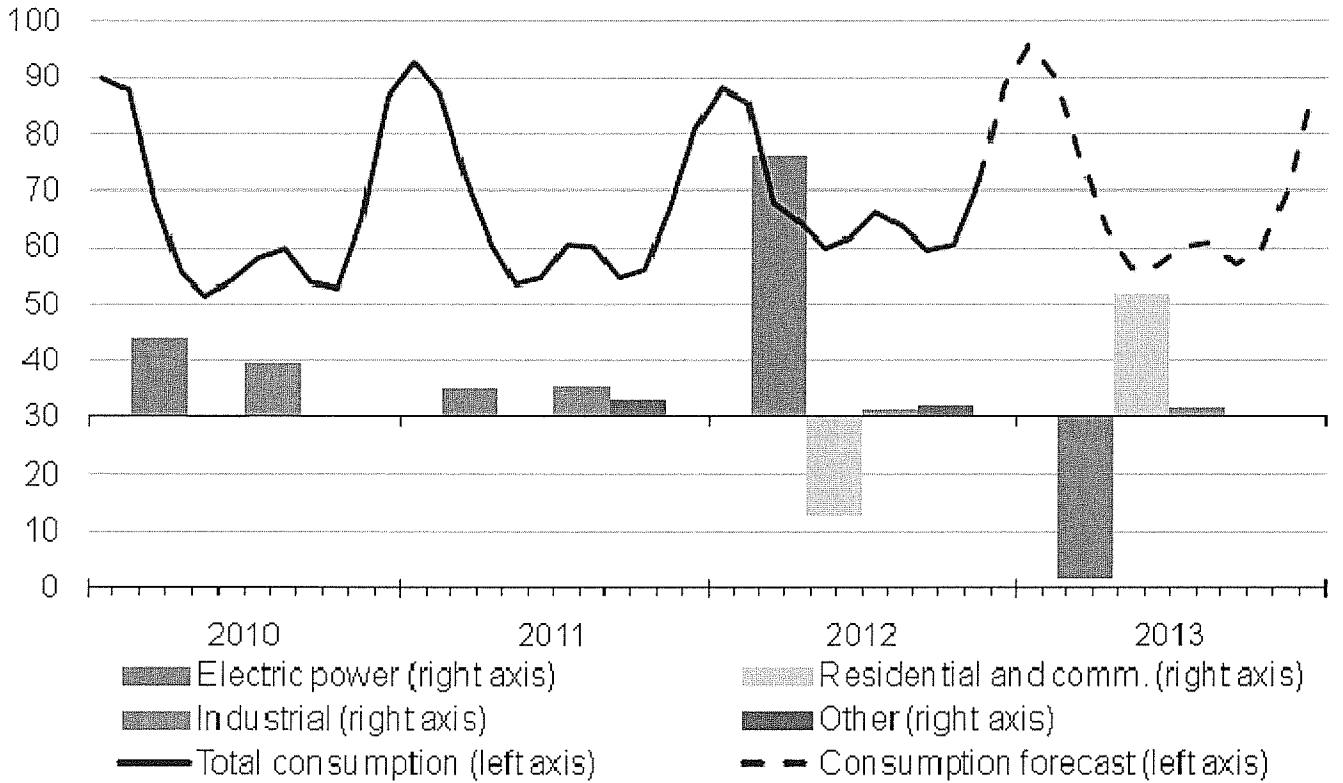
Source: Short-Term Energy Outlook, November 2012



U.S. Natural Gas Consumption

billion cubic feet per day (bcf/d)

annual change (bcf/d)



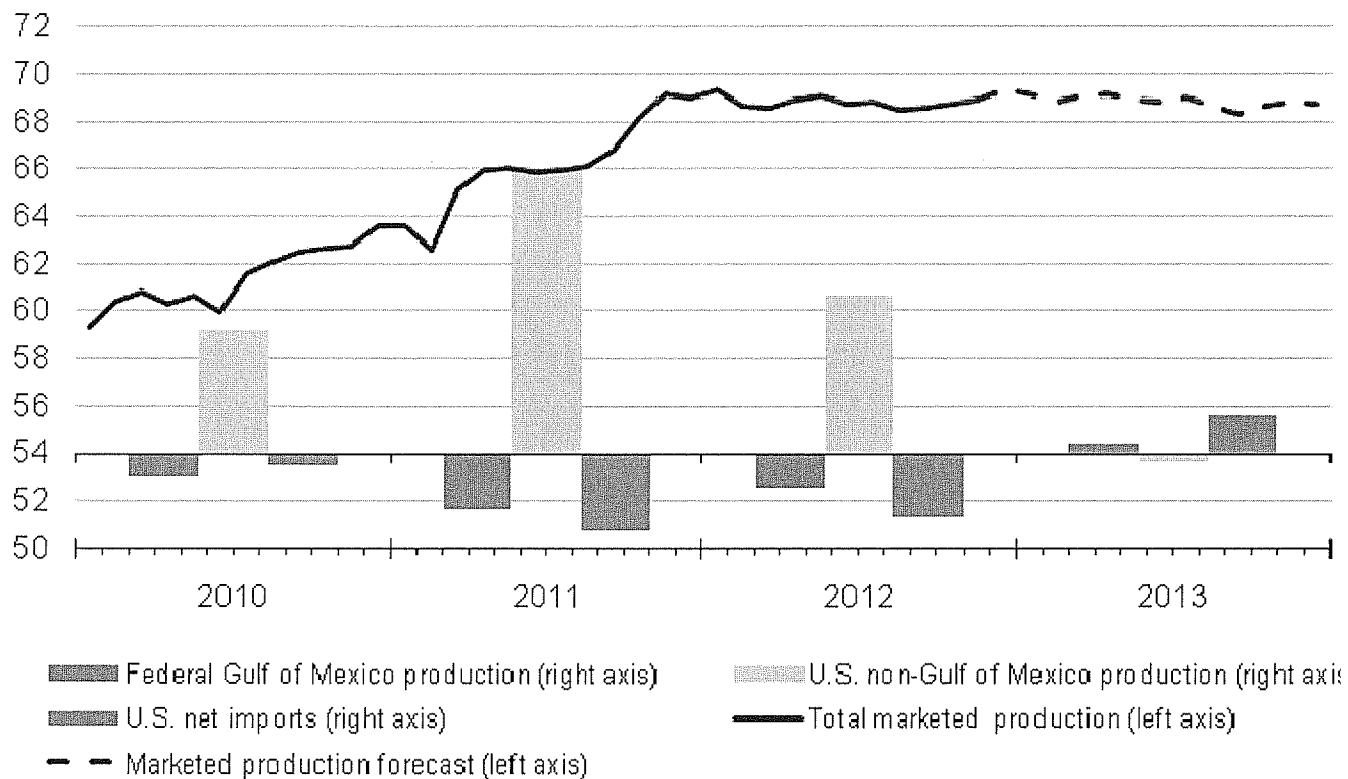
Source: Short-Term Energy Outlook, November 2012



U.S. Natural Gas Production and Imports

billion cubic feet per day (bcf/d)

annual change (bcf/d)

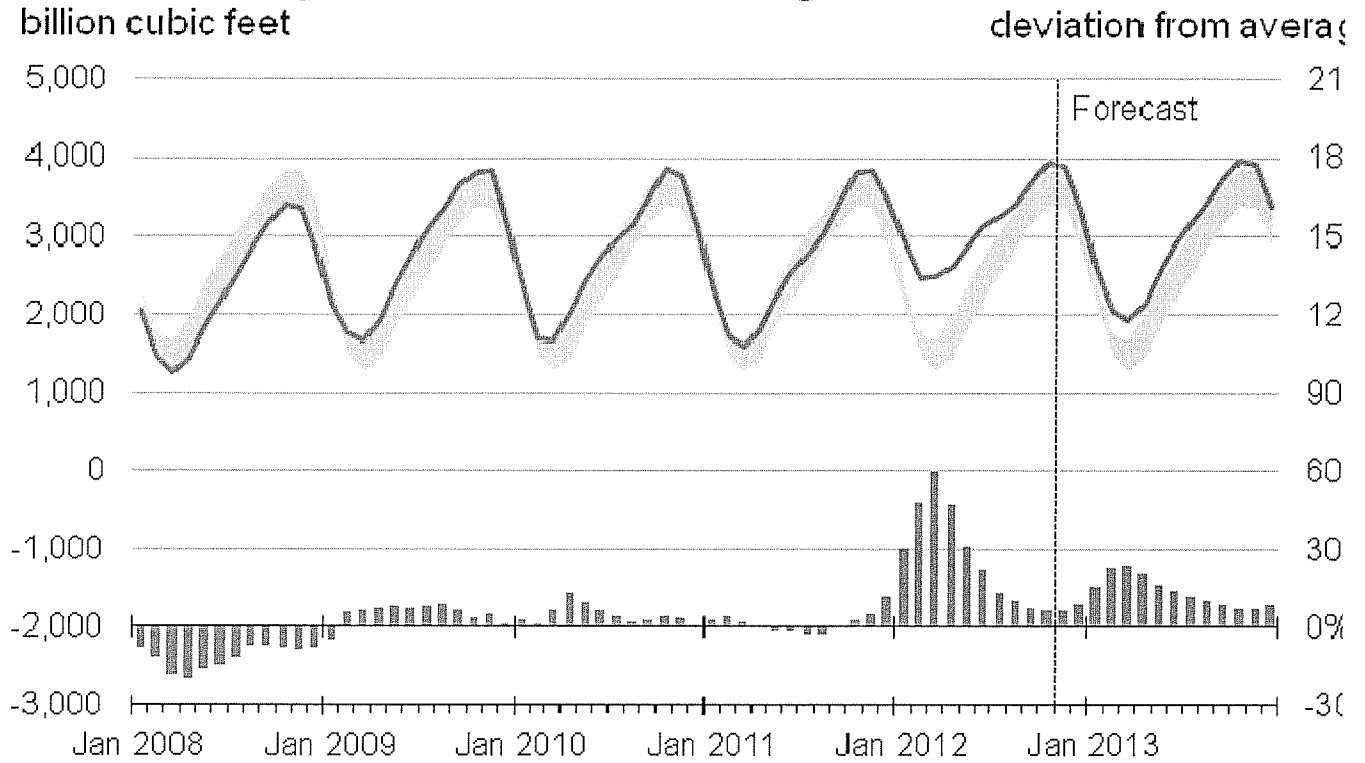


Source: Short-Term Energy Outlook, November 2012



U.S. Working Natural Gas in Storage

billion cubic feet



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2007 - Dec. 2011.

Source: Short-Term Energy Outlook, November 2012



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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ April 30, 2012									<u><u>\$311,764</u></u>
May	\$30,099	\$0	\$2,016	\$32,115	13,138	\$0.5102	\$6,702	\$25,413	337,177
June	52,819	0	2,192	55,011	6,558	1.0137	4,625 2/	50,386	387,563
July	57,568	0	2,542	60,110	5,776	1.0137	5,855	54,255	441,818
August	58,888	0	2,918	61,806	5,143	1.0137	5,213	56,593	498,411
September	26,138	0	3,308	29,446	6,241	1.0137	6,327	23,119	521,530
October	36,902	0	3,454	40,356	10,185	1.0137	10,325	30,031	551,561
Balance @ October 31, 2012									<u><u>\$551,561</u></u>

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

2/ Reflects 4,017.3 dk @ \$0.5102 and 2,540.6 dk @ \$1.0137.

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

	(Over) Under Recovery	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, 2012									<u><u>(\$72,396)</u></u>
May	(\$11,426)	\$0	(\$557)	(\$11,983)	23,670	(\$0.0178)	(\$422)	(\$11,561)	(83,957)
June	(6,055)	0	(637)	(6,692)	13,697	(0.2915)	(1,509) 2/	(5,183)	(89,140)
July	(16,584)	0	(671)	(17,255)	13,108	(0.2915)	(3,821)	(13,434)	(102,574)
August	(2,356)	0	(765)	(3,121)	14,195	(0.2915)	(4,138)	1,017	(101,557)
September	(20,241)	0	(754)	(20,995)	21,085	(0.2915)	(6,146)	(14,849)	(116,406)
October	325	0	(859)	(534)	37,029	(0.2915)	(10,794)	10,260	(106,146)
Balance @ October 31, 2012									<u><u>(\$106,146)</u></u>

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 9,073.4 dk @ (\$0.0178) and 4,623.6 dk @ (\$0.2915).