

November 1, 2012

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

Re: Cost of Gas Adjustment (COG)
November 2012

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and seven (7) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (80th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (80th Revised Sheet No. 8), showing the November 2012 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$1.1155 per mcf for residential and firm general service customers and an increase of \$1.2830 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for November 2012, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$1.2830 since the last COG filing. There has been a decrease in pipeline charges of \$2.3985 per mcf due to changes in Great Plains' demand portfolio to reflect new gas supply and transportation contracts. The net effect of these changes is a decrease of \$1.1155 per mcf for residential and firm general service customers.

Attachment C explains the change in gas supply and transportation contracts.

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

Attachment E 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.

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
 80th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 79th Revised Sheet No.1.1

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	\$6.2603	\$7.5343 7.3143
Firm Gas Service - General Highway 13	2.5	\$3.50 per month	First 10 MCF \$2.1740 Over 10 MCF 1.9540	\$6.2603	\$8.4343 8.2143
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	\$3.4290	\$4.5681 4.3221 4.1701
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	\$3.4290	\$5.4681 5.2221 5.0701
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$3.4290	\$4.6681
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 1, 2012

Effective Date: November 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
80th Revised Sheet No. 8
Canceling 79th 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.	3.8736	(2.6964)	1.0137	2.1909	(2.6816)	(0.2915)	(2.9731)
Current Adj.	(2.3985)	1.2830	0.0000	(1.1155)	1.2830	0.0000	1.2830
Total Adj.	1.4751	(1.4134)	1.0137	1.0754	(1.3986)	(0.2915)	(1.6901)
Total Rate:	\$1.5409	\$3.7057	\$1.0137	\$6.2603	\$3.7205	(\$0.2915)	\$3.4290

Date Filed: November 1, 2012

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

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

<u>Firm</u>	<u>Billing</u> <u>Determinants</u>	<u>Rate</u>	<u>Demand</u> <u>Months</u>	<u>Amount</u>	<u>Amount</u> <u>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				<u>\$2,136,019</u>	1.5409
Estimated Weighted Average Commodity Cost	1,399,684 1/	3.7057		<u>5,186,809</u>	3.7057
Gas Cost Reconciliation Adjustment					1.0137
Total Current Firm Gas Cost				<u><u>\$7,322,828</u></u>	<u>6.2603</u>
Base Cost of Gas					<u>5.1849</u>
Accumulated Adjustment					<u><u>\$1.0754</u></u>
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$3.7057
Gas Cost Reconciliation Adjustment					(0.2915)
LMS Demand 2/					0.0148
Total Current Interruptible Gas Cost					<u>3.4290</u>
Base Cost of Gas					5.1191
Accumulated Adjustment					<u><u>(\$1.6901)</u></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</u> <u>Determinants</u>	<u>Rate</u>	<u>Demand</u> <u>Months</u>	<u>Amount</u>	<u>Amount</u> <u>Per dk</u>
LMS Demand	2,500	\$1.0000	12	\$30,000	\$0.0148

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
NOVEMBER 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:	3.7057	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
<u>Category 1 (Contract Term of Less than 3 Years)</u>	
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
<u>Category 2 (Contract Term of 3 Years to less than 5 Years)</u>	
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
<u>Category 3 (Contract Term of 5 or more Years)</u>	
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	1.16%
Zone 1-2	\$0.0130	\$0.0018	\$0.0148	1.52%
Zone 2-2	\$0.0130	\$0.0018	\$0.0148	0.36%
Minimum Rate	\$0.0130	\$0.0018	\$0.0148	
IT and AOT				
Zone 1-1	\$0.1368	\$0.0018	\$0.1386	1.16%
Zone 1-2	\$0.1737	\$0.0018	\$0.1755	1.52%
Zone 2-2	\$0.0834	\$0.0018	\$0.0852	0.36%
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: 0.18% for Zone 1-1, 0.23 % for Zone 1-2, and 0.05% 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 Base	TF12 Variable	TF5	TFF
Base Tariff Rates 1/				
Summer (Apr-Oct)	5.683	5.683	-0-	5.473
Winter (Nov-Mar)	10.230	13.866	15.153	9.853

COMMODITY RATES 2/		Market Area 3/		Field Mileage 5/		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

- 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.
Change in Gas Supply and Transportation Contracts
November 1, 2012

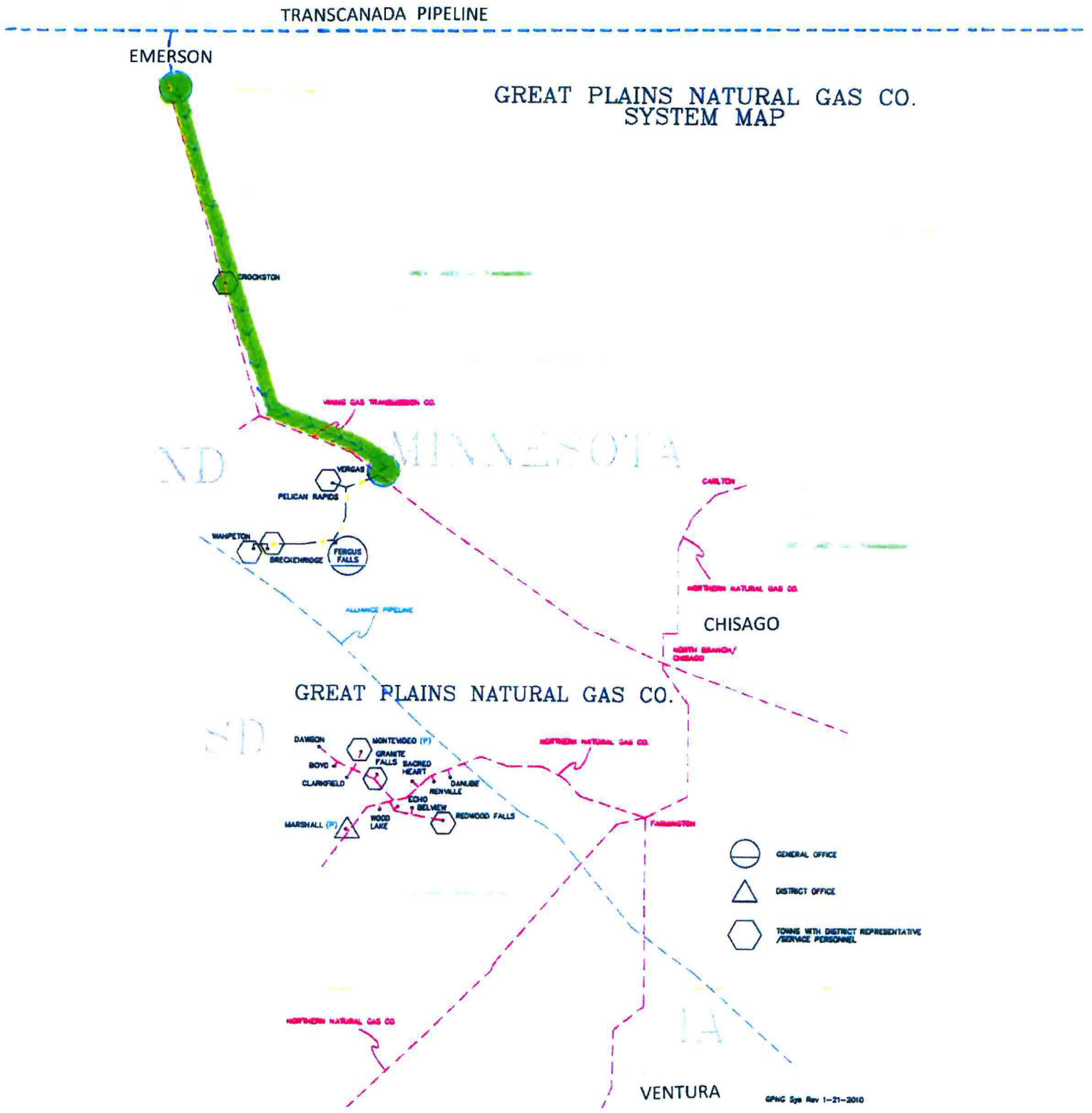
In the North District, which consists of the communities of Wahpeton, North Dakota and Fergus Falls, Pelican Rapids, Vergas, Breckinridge and Crookston, Minnesota, Great Plains has entered into new upstream gas supply and transportation contracts to replace Great Plains' long term transportation and supply contract with ProGas, which expires on October 31, 2012. As described below, Great Plains' customers will benefit considerably from this change.

The new contracts will provide firm transportation capacity on Northern and supply from the Ventura, Iowa interconnect point between Northern Border Pipeline (Northern Border) and Northern. While the existing contract with ProGas proved to be a reliable source of natural gas, with the loss of demand for pipeline capacity on the TransCanada Pipeline (TransCanada) system, the demand charges have increased to a point that is cost-prohibitive to continue serving the North District customers via this pipeline.

Under Great Plains' replacement contracts, North District customers will continue to receive natural gas through Viking Gas Transmission Company (Viking), however, the source of the natural gas will switch from the Emerson receipt point on TransCanada Pipeline to Northern's pipeline at the interconnect between Northern and Viking. Effective November 1, 2012, the firm transportation services upstream of Viking will originate on Northern's pipeline system at the interconnect with Northern Border at Ventura, Iowa. The North District supply of natural gas will enter Viking's system at the receipt point between Northern and Viking known as the Chisago interconnect. Please see pages 2-3 for a map illustrating the changes in the interconnection points. By accessing natural gas from Northern Border, Great Plains will have access to numerous marketers with which Great Plains has established working relationships. The Northern Border-Ventura point is a liquid point with active trading.

The new Northern contract has a term of 11.5 years and will supply 13,000 dk per day of capacity to the North District customers. In addition to the 13,000 dk per day, Great Plains will continue to utilize the 2,000 dk per day on Northern that, in the past, has been used to meet the peak day demand of its firm sales customers. The total supply allocated to the North District will be 15,000 dk per day, a modest increase of 159 dk from the 2011-2012 winter levels.

In conjunction with the new Northern contracts, Great Plains will retain 5,000 dk per day of forward haul on the Viking system. In addition to the 5,000 dk of forward haul capacity, 8,000 dk per day of new firm back haul capacity will be contracted to meet the peak day requirement. This will be in addition to the current seasonal firm back haul capacity of 2,000 dk per day which Great Plains has contracted for and utilized for many years. This will result in a total of 10,000 dk per day of firm back haul capacity during the heating season, thus meeting the 15,000 dk per day of supply noted above.



 Existing Capacity - VIKING

TRANSCANADA PIPELINE

GREAT PLAINS NATURAL GAS CO.
SYSTEM MAP

EMERSON

CROOKSTON

VIKING GAS TRANSMISSION CO.

VERSA
PELICAN RAPIDS

WAMPETON
BRECKENRIDGE
FERGUS FALLS

ALLIANCE PIPELINE

CARLTON

NORTHERN NATURAL GAS CO.

CHISAGO
NORTH BRANCH
CHISAGO

GREAT PLAINS NATURAL GAS CO.

DANSON
BOYO
CLARKFIELD
MARSHALL
MONTEVIDEO (P)
GRANITE FALLS
SACRED HEART
ECHO
WELVEY
WOOD LAKE
DANLISE
REXVILLE
REDWOOD FALLS

NORTHERN NATURAL GAS CO.

NORTHERN NATURAL GAS CO.

FARMINGTON

-  GENERAL OFFICE
-  DISTRICT OFFICE
-  TOWNS WITH DISTRICT REPRESENTATIVE / SERVICE PERSONNEL

VENTURA

GPNG Sys Rev 1-21-2010

 New Capacity - NNG/VIKING
Effective November 1, 2012

**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
November 2012**

Effective November 1, 2012 the principal source of natural gas for Wahpeton, North Dakota changed from the large Western Canadian Sedimentary Basin (WCSB) to the U.S. midcontinent supply points off the Northern Natural Gas(NNG) pipeline system. The pricing point for much of this gas is the NNG Ventura trading point which is very liquid and has access to gas supply from the midcontinent such as the Marcellus and the shale formations located in south central U.S. The reason for the change in supply basins is due to a change in the supply and transportation contracts that served Wahpeton, which expired October 31, 2012. In the review of replacement contracts for supply and pipeline capacity, the least cost replacement option was to purchase gas off the NNG pipeline system. The NNG Ventura monthly index price is determined by deals completed during the last five trading days of the month, which is referred to as bidweek.

The midcontinent monthly index price increases were likely driven by the onset of the winter heating season and the associated increase in demand. The Energy Information Administration (EIA) reported storage levels nationwide as of October 19, 2012 were 7.0 percent above the five-year average and 4.1 percent above last year's balance. The national storage balance is expected to be at record levels entering the heating season.

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 3 through 18.



Independent Statistics & Analysis

U.S. Energy Information
Administration

October 2012

Short-Term Energy and Winter Fuels Outlook

- EIA projects average household expenditures for heating oil and natural gas will increase by 19 percent and 15 percent, respectively, this winter (October 1 through March 31) compared with last winter. Projected household expenditures are 5 percent higher for electricity and 13 percent higher for propane this winter. Average expenditures for households that heat with heating oil are forecast to be higher than any previous winter on record (see EIA [Short-Term Energy and Winter Fuels Outlook slideshow](#)).
- The forecast for higher household expenditures primarily reflects a return to roughly normal winter temperatures east of the Rocky Mountains compared with last winter's unusual warmth. According to the National Oceanic and Atmospheric Administration's (NOAA) most recent projection of heating degree days, the Northeast, Midwest, and South will be about 2 percent warmer than the 30-year average (1971 – 2000), but still 20 percent to 27 percent colder than last winter, while the West is projected to be only about 1 percent colder than last winter.
- Projected residential heating oil prices average 2 percent higher and natural gas prices 1 percent higher this winter. Winter average electricity and propane prices average about 2 percent and 4 percent lower than last winter, respectively.
- 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 6.9 million bbl/d in 2013, the highest level of production since 1993.
- Forecast U.S. real gross domestic product (GDP) grows by 2.2 percent this year and by 1.7 percent next year. Projected world oil-consumption-weighted real GDP grows by 2.7 percent and 2.5 percent in 2012 and 2013, respectively, similar to last month's *Outlook*. EIA expects Brent crude oil prices to fall from recent highs over the rest of 2012, averaging \$111 per barrel over the fourth quarter of 2012 and \$103 per barrel in 2013. EIA expects WTI spot prices to average \$93 per barrel in 2013, with the WTI discount to Brent narrowing to \$9 per barrel by the end of 2013.
- Natural gas working inventories ended September 2012 at an estimated 3.7 trillion cubic feet (Tcf), about 8 percent above the same time last year. EIA expects the Henry Hub

natural gas spot price, which averaged \$4.00 per million British thermal units (MMBtu) in 2011, to average \$2.71 per MMBtu in 2012 and \$3.35 per MMBtu in 2013.

Projected Winter Fuel Expenditures by Fuel and Region

The average household winter heating fuel expenditures discussed in this *Outlook* provide a broad guide to changes compared with last winter, but fuel expenditures for individual households are highly dependent on local weather conditions, market size, the size and energy efficiency of individual homes and their heating equipment, and thermostat settings (see [Winter Fuels Outlook table](#)).

Natural Gas. About one-half of U.S. households use natural gas as their primary heating fuel. EIA expects households heating with natural gas to spend an average of \$89 (15 percent) more this winter than last winter. The increase in natural gas expenditures represents less than a 1-percent increase in the average U.S. residential price from last winter and a 14-percent increase in consumption. The expected increase in consumption is the result of the forecast of near-normal temperatures this winter, in contrast to the unusually warm winter of 2011-12. The projected changes in residential natural gas prices this winter range from a 3-percent decline in the South to a 4-percent increase in the Northeast. Price changes vary across regions because of a number of factors such as regional changes in production, pipeline supply capacity, and differences in regulatory constraints in passing price changes through to customers.

Heating Oil. EIA expects households heating primarily with heating oil to spend an average of about \$407 (19 percent) more this winter than last winter as a result of a 2-percent increase in prices and a 17-percent increase in consumption. About 6 percent of U.S. households depend on heating oil for space heating; however, the Northeast accounts for about 80 percent of these households. Low distillate stocks in the East Coast and Gulf Coast states, which provide over 60 percent of the Northeast's distillate supply, and the state of New York's switchover from higher sulfur heating oil to fuel with less than 15 parts per million sulfur, all contribute to an expected tighter market this winter.

Propane. About 5 percent of total U.S. households heat with propane. EIA expects households heating primarily with propane to spend more this winter, but that increase varies across regions. EIA expects that households in the Midwest will see an average increase in both propane consumption and winter propane expenditures of 17 percent and 11 percent, respectively, with residential propane prices 5 percent lower than last winter. With consumption projected to increase by 16 percent over last winter in the Northeast, households there may see an increase in expenditures of 15 percent with prices lower by an average 1 percent.

Electricity. Households heating primarily with electricity can expect to spend an average of \$49 (5 percent) more this winter because of forecasted colder weather despite a projected 2-

percent decrease in prices. About 38 percent of all U.S. households rely on electricity as their primary heating fuel, ranging from 14 percent in the Northeast to 62 percent in the South.

Wood. Wood consumption in homes has risen over the past 10 years, reversing a trend seen in the last two decades of the 20th century. In 2009, U.S. households consumed about 0.5 quadrillion Btu (quads) of wood. Household fuel oil consumption, by comparison, was only slightly higher at 0.6 quads. In homes across the United States, wood is most commonly used as a secondary source of heat and is second only to electricity as a supplemental heating fuel. Twenty percent of New England homes (1.1 million) used wood for space heating, water heating, or cooking in 2009 (EIA, [Residential Energy Consumption Survey, 2009](#)). This is nearly twice the national rate. Almost half of all rural households used wood in this area of the country. In contrast, only 12 percent of urban New England households used the fuel.

Global Crude Oil and Liquid Fuels

Global Crude Oil and Liquid Fuels Overview. EIA expects the oil market to loosen in the fourth quarter of 2012, as global liquid fuels consumption falls from its seasonal peak and output from countries outside of the Organization of the Petroleum Exporting Countries (OPEC) recovers from unplanned outages and scheduled maintenance. Persistent unplanned production outages in non-OPEC countries helped keep the spot price for Brent crude oil near \$110 per barrel in the third quarter of 2012. EIA forecasts that Brent crude, a benchmark for the global oil price, will average \$111 per barrel for the fourth quarter of 2012. In 2013, EIA projects the Brent crude price to fall to an average of \$103 per barrel, although a lingering supply risk because of instability in the Middle East and North Africa could keep prices higher. EIA also expects global inventory builds in the first half of 2013 to reach higher levels relative to the same period in 2012, mostly due to an increase in non-OPEC supply.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by an estimated 1.1 million bbl/d in 2011. EIA expects consumption growth of about 0.8 million bbl/d in 2012 and 0.9 million bbl/d in 2013, with China, the Middle East, Central and South America, and other countries outside of the Organization for Economic Cooperation and Development (OECD) accounting for essentially all consumption growth. However, forecast consumption falls by 0.5 million bbl/d during the fourth quarters of 2012, following the end of the global seasonal demand peak in the third quarter.

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. Although EIA forecasts U.S. liquid fuels consumption to grow by 0.1 million bbl/d in 2013, this is more than offset by declines in consumption in Europe and other OECD countries. One possible exception is Japan, where only a handful of nuclear facilities, at best, will be brought back online in 2013, which could cause its oil consumption to remain relatively resilient through the forecast period.

China has been experiencing a slowing of its economic growth rate. EIA's forecast for China's oil consumption growth remains at lower levels than the country experienced in previous years. EIA projects China's liquid fuels consumption to rise by 3.6 percent (355 thousand bbl/d) in 2012, the lowest rate of annual growth since 2001, and by 400 thousand bbl/d in 2013.

Non-OPEC Supply. EIA expects non-OPEC liquid fuels production to rise by 570 thousand bbl/d in 2012, and by a further 1.2 million bbl/d in 2013. The largest area of non-OPEC growth is North America, where production increases by 1.0 million bbl/d and 670 thousand bbl/d in 2012 and 2013, respectively, due to continued production growth from U.S. onshore shale and other tight oil formations and from Canadian oil sands.

Some large non-OPEC producers continue to undergo planned maintenance that traditionally takes place during this time of the year. Kazakhstan's crude and condensate production was down by about 160 thousand bbl/d in September 2012 because of planned maintenance at Tengiz. The field is slowly returning to normal operations. In the North Sea the Buzzard, Elgin, and Franklin fields are currently out for maintenance. Buzzard is expected to return to full production at the end of October. Total announced that Elgin and Franklin maintenance will be extended through December. Maintenance in Norway's fields reduced output by more than 20 thousand bbl/d in September 2012. This was mainly due to maintenance at the Troll field, but also includes smaller volumes from other fields, such as Gullfaks and Ekofisk.

Unplanned outages and disruptions to non-OPEC production increased in August and September, averaging around 1.1 million bbl/d. Hurricane Isaac contributed to production shut-ins in the Gulf of Mexico averaging about 210 thousand bbl/d in both August and September.

EIA has made slight adjustments in its forecasts for Colombia and Brazil, the two leading sources of non-OPEC supply in South America, due in part to lower output in recent months. In Colombia, anti-government rebels had intensified the frequency and severity of their attacks on the Caño Limón pipeline and other oil infrastructure, which contributed to an estimated decline in August production relative to the previous month and year-ago levels. However, security threats have abated in anticipation of peace talks and Colombian oil production is estimated to have partially recovered in September, which has led to renewed optimism that the country can resume its production gains. Brazilian liquid fuels production has also consistently failed to meet expectations in recent months due to persistent maintenance-related shutdowns, larger-than-expected field declines, the impacts of a relatively poor sugarcane harvest on ethanol production, and the continued outage at the Chevron-operated Frade field. Unless output is quickly restored, Brazilian liquids production is likely to decline on a year-to-year basis.

Sudan and South Sudan signed a series of agreements to settle their dispute and restart oil production in the South, eight months after South Sudan halted its crude oil exports via pipelines through Sudan and shut in all production. Sudan and South Sudan had already reached an understanding on oil transit fees, but the resumption of production was contingent on a broader deal on border security. The two countries have now signed an agreement on security

arrangements; however, some post-independence issues such as border demarcation, rights to the disputed Abyei region, and Sudan's claim for compensation of Sudapet's assets that went to South Sudan remain unresolved. Nonetheless, South Sudan expects to restart production and exports before the end of this year, but has previously cautioned it could take four to six months to bring output back to full volumes, possibly longer for areas damaged during military clashes.

Forecasting South Sudan's oil restart and the pace of the ramp-up remains a challenge given uncertainties include: the extent of damage to infrastructure at fields within the Greater Nile Oil Project; the ability for some mature fields that were previously declining in output to reach pre-shut-in levels; the extent to which the shut-in left any permanent irreversible damage that could compromise future output; how quickly export pipelines will be flushed out; and any other mechanical issues that may arise during the restart. EIA does not expect South Sudan's production to return to pre-shut-in levels in the forecast period.

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 remains mostly flat in 2013. OPEC non-crude oil liquids (condensates, natural gas liquids, and gas-to-liquids), which are not covered by OPEC's production quotas, averaged 5.3 million bbl/d in 2011 and are forecast to increase by 0.3 million bbl/d in 2012 and by 0.2 million bbl/d in 2013.

EIA estimates that Iran's crude oil production declined by 50 thousand bbl/d in September 2012, following a 100-thousand-bbl/d decline the month before. EIA expects Iran's crude oil production to fall by about 1 million bbl/d by the end of 2012, relative to an estimated output level of 3.6 million bbl/d at the end of 2011. The decline in Iran's crude oil production capacity will continue due to the country's inability to carry out investment projects that are necessary to offset the natural decline in production from existing wells.

It is difficult to differentiate between the effects of the latest round of sanctions on Iran and those enacted in previous years when assessing impacts on Iranian oil production. While countries in the European Union appear to have ceased imports of Iranian crude oil, the reinsurance ban affected Iran's ability to sell its crude to some of its largest customers in Asia, including Japan and South Korea. Most of Iran's crude oil customers have been able to replace insurance coverage, once provided by European protection and indemnity (P&I) clubs, over the last two months, although preliminary data show a very small increase in imports of Iranian crude oil by those customers in August. EIA bases this assessment on preliminary commercial data on tanker liftings from Iran, press reports, official Iranian statements, and other relevant information. This tentative interpretation of a very fluid situation could change as data are revised and more details emerge.

The attacks on American personnel in Benghazi, Libya, serve as a tragic reminder that insecurity continues to plague the country, including some areas in which oil infrastructure is

concentrated. Though Libya has continued to maintain production at relatively high levels and recently restarted its largest refinery, it poses a downside risk to the supply forecast given the possibility of future disruption.

World oil surplus production capacity is almost entirely concentrated in one country: Saudi Arabia. With Saudi Arabian oil production at or near 10 million bbl/d for much of 2012, global surplus production capacity has been in the neighborhood of 2 million bbl/d during this time.

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 2.64 billion barrels and 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 last 7 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 \$93 per barrel in the second half of 2012 and largely remain at this level throughout the forecast period. After increasing to as high as \$19 per barrel in August and September of this year, EIA expects that the WTI crude oil spot price discount to the Brent crude oil spot price will average \$17 per barrel in the fourth quarter of 2012 before falling to \$9 per barrel by the end of 2013.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for January 2013 delivery during the five-day period ending October 4, 2012, averaged \$92.09 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 January 2013 at \$70 per barrel and \$121 per barrel, respectively. Last year at this time, WTI for January 2012 delivery averaged \$79 per barrel and implied volatility averaged 50 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$51 per barrel and \$123 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 280 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 110-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.

Despite higher assumed growth in U.S. real disposable income and projected declines in retail gasoline pump prices of 6 percent in 2013, forecast motor gasoline consumption remains almost unchanged from that of the previous year 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 180 thousand bbl/d (3.2 percent) to 5.7 million bbl/d in 2011. Forecast crude oil production increases to 6.3 million bbl/d in 2012 with lower-48 (excluding the federal Gulf of Mexico) crude oil production growing by 780 thousand bbl/d, primarily from the Bakken, Permian basin, and Eagle Ford producing areas. Hurricane Isaac in the Gulf of Mexico led to U.S. crude oil production shut-ins averaging 220 thousand bbl/d in August and 200 thousand bbl/d in September. Total crude oil output rises a further 530 thousand bbl/d in 2013. The number of onshore 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 1,398 as of October 5, 2012.

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. After a sharp increase in retail gasoline prices earlier this year, the monthly average price for regular grade gasoline reached \$3.90 per gallon in April 2012. Prices then fell for three consecutive months, averaging \$3.44 per gallon in July. Rising crude prices contributed to a second run-up in regular gasoline retail prices to an average of \$3.85 per gallon in September 2012. EIA expects retail gasoline prices to begin declining in October as the gasoline market transitions from summer-grade to winter-grade gasoline specifications and forecast crude oil prices begin to fall. Projected regular gasoline retail prices average \$3.60 per gallon during the fourth quarter of 2012, up slightly from \$3.58 per gallon projected in last month's *Outlook*. Projected regular gasoline retail prices average \$3.65 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 in March, then fell to a low of \$3.72 in July. Tight market conditions and increasing crude oil prices drove on-highway diesel fuel prices back near monthly highs for the year average \$4.12 per gallon in September. EIA expects that on-highway diesel fuel retail prices will average \$3.98 per gallon during the fourth quarter of this year and \$3.81 per gallon in 2013. Wholesale diesel margins (the difference between the wholesale price of diesel and the refiner acquisition cost of crude oil) averaged 60 cents per gallon the first half of 2012 before climbing to an estimated 85 cents per gallon in September, the highest level since May 2008. In 2012,

EIA projects those margins will average 68 cents per gallon in 2012 and 63 cents per gallon in 2013, compared with the previous 5-year average of 52 cents per gallon.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 69.8 billion cubic feet per day (Bcf/d) in 2012, an increase of 3.1 Bcf/d (4.7 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 improved relative cost advantages of natural gas over coal for power generation in some regions. Consumption in the electric power sector during 2012 was 35.1 Bcf/d in July 2012, when electricity demand for air conditioning was highest.

Projected total natural gas consumption decreases by 0.2 Bcf/d (0.2 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 (i.e., colder than last year's abnormally warm winter) drives 2013 increases in residential and commercial consumption of 11.5 percent and 10.3 percent, respectively. Although projected higher natural gas prices contribute to a 10.4-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 1.9 Bcf/d higher than 2011 levels and high by historical standards.

U.S. Natural Gas Production and Imports. Total marketed production of natural gas grew by 4.8 Bcf/d (7.9 percent) in 2011. This strong growth was driven in large part by increases in shale gas production. So far during 2012, production has fluctuated with small ups and downs, 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 437 as of October 4, 2012, compared with 811 at the start of 2012. EIA forecasts that total marketed production growth will slow to 2.6 Bcf/d in 2012 and 0.4 Bcf/d in 2013, as the reduction in drilling activity is offset by growth in production from liquids-rich natural gas production areas such as the Eagle Ford and wet areas of the Marcellus Shale, and associated gas from the growth in domestic crude oil production.

EIA expects pipeline gross imports will fall by 0.2 Bcf/d (2.3 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 little change 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 about 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.

U.S. Natural Gas Inventories. Working natural gas inventories remain at historically high levels for this time of year. As of September 28, 2012, according to EIA's [*Weekly Natural Gas Storage Report*](#), working inventories totaled 3,653 Bcf, which is 272 Bcf greater than last year's level and 281 Bcf above the five-year average. EIA expects that inventory levels at the end of October 2012 will set a record high of 3,903 Bcf. Because of very high inventories at the start of the summer injection season this year, working inventories have remained high and 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 1,426 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 1987.

U.S. Natural Gas Prices. Natural gas spot prices averaged \$2.85 per MMBtu at the Henry Hub in September 2012, up \$0.01 per MMBtu from the August average and \$1.05 per MMBtu (27 percent) lower than the September 2011 average. While abundant supplies have kept prices relatively low, a hot summer and associated increases in demand for natural gas for power generation contributed to Henry Hub spot price increases this summer, from the monthly average low of \$1.95 per MMBtu in April 2012. EIA expects the Henry Hub natural gas price will average \$2.71 per MMBtu in 2012 and \$3.35 per MMBtu in 2013.

Natural gas futures prices for January 2013 delivery (for the five-day period ending October 4, 2012) averaged \$3.84 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for January 2013 contracts at \$2.77 per MMBtu and \$5.31 per MMBtu, respectively. At this time last year, the January 2012 natural gas futures contract averaged \$4.10 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were \$3.10 per MMBtu and \$5.40 per MMBtu.

Coal

U.S. Coal Supply. EIA forecasts that coal production will decline by 6 percent in 2012 as domestic consumption falls. EIA expects that production will total 1,027 million short tons (MMst) in 2012, 68 MMst below the 2011 total. EIA expects production to fall by 1 percent (12 MMst) 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 187 MMst at the end of the 2012. Inventories are expected to decline slightly in 2013, but they will remain at elevated levels.

U.S. Coal Trade. EIA expects U.S. coal exports to remain strong in 2012 and exceed the 107 MMst exported in 2011. The United States exported 11.6 MMst of coal in July, the fifth consecutive month with exports exceeding 11 MMst. 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. Falling international coal prices and slower economic growth, particularly in China, 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 exports averaged 56 MMst in the decade preceding 2011.

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 \$2.40 per MMBtu (a 6-percent increase from 2010). However, EIA expects the decline in demand for coal, combined with large coal inventories, will begin to put downward pressure on 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 \$2.42 per MMBtu in 2013.

Electricity

U.S. Electricity Consumption. During this past winter, U.S. heating degree days during the fourth quarter of 2011 and the first quarter of 2012 totaled 18 percent below the 30-year normal. Temperatures this winter are expected to be colder than last winter. In particular, projected heating degree days in the southern states, where a majority of homes heat with electricity, are 27 percent higher than last winter. As a result of the colder weather, EIA projects retail sales of electricity to the residential sector this winter will average 6.2 percent more than retail sales last winter.

U.S. Electricity Generation. Natural gas prices have risen steadily since this past spring. In September, the Henry Hub price averaged \$2.85 per million Btu, which was 46 percent higher than the average in April. With higher natural gas prices EIA expects natural gas to lose some of its recent gains in electricity generation market share. The share of total generation fueled by natural gas in the fourth quarter of 2012 is projected to average 27.8 percent compared with 25.4 percent during the same period last year. By the beginning of 2013, higher natural gas prices should contribute to year-over-year declines in natural gas's share of total generation. EIA expects natural gas to fuel 25.8 percent of generation during the first quarter of 2013, which is 2.8 percentage points lower than during the first quarter of 2012.

U.S. Electricity Retail Prices. EIA expects the nominal U.S. residential electricity price will rise by 0.4 percent during 2012 to an average of 11.84 cents per kilowatthour. During 2013, U.S. residential retail electricity prices increase 1.3 percent over the average 2012 price. When measured in real terms, the U.S. residential electricity price declines by 1.7 percent in 2012 and by 0.3 percent in 2013.

Renewables and Carbon Dioxide Emissions

U.S. Renewables. After growing by 13.9 percent in 2011, total renewable energy consumption is projected to decline by 2.3 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 2.4 percent in 2013 as hydropower continues to decline (2.3 percent) but non-hydropower renewables grow by an average of 4.8 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 26 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.

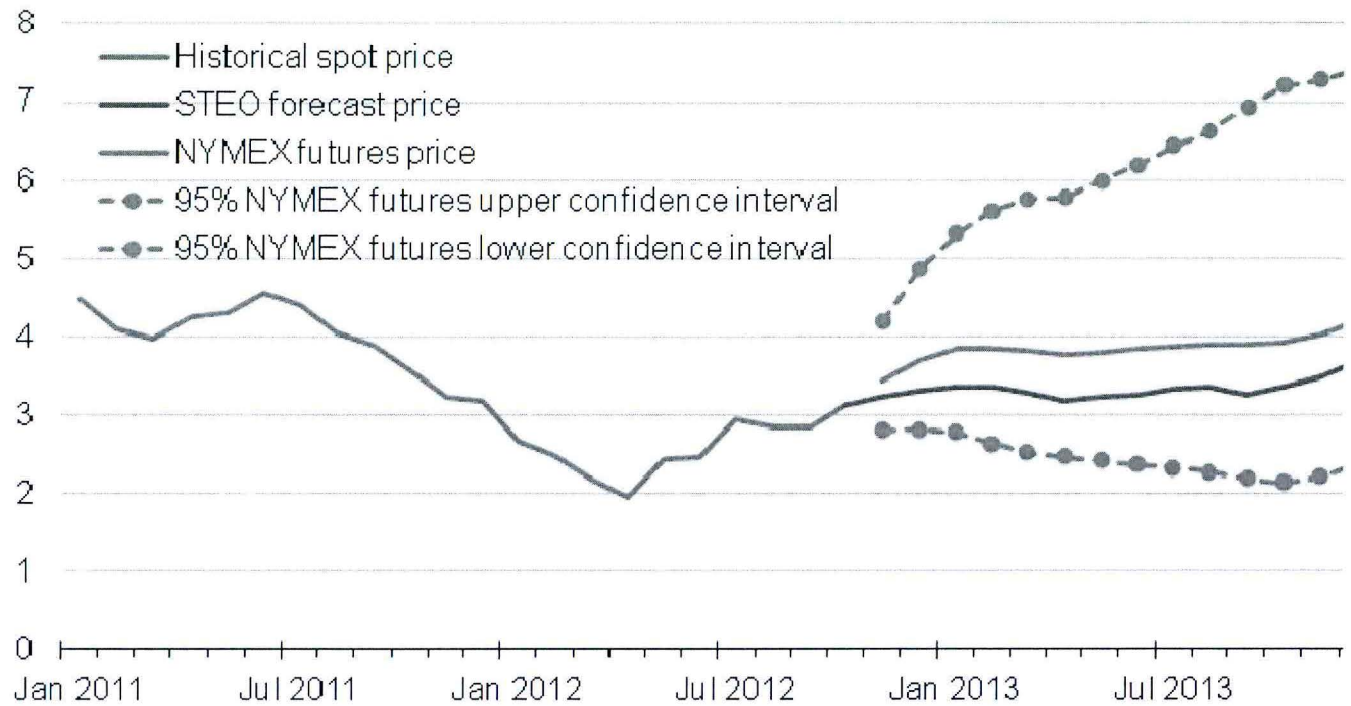
As a result of drought conditions depressing corn harvests throughout the Midwest, fuel ethanol production fell from an average of 890 thousand bbl/d during the second quarter of 2012 to an average of 820 thousand bbl/d in the third quarter 2012. EIA expects ethanol production will remain near current levels through the first half of 2013 and recover in the second half of 2013, averaging 850 thousand bbl/d (13.03 billion gallons) for the year. The projected lower ethanol production is generally matched by 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 83 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 2.3 percent in 2011, fossil fuel emissions are projected to further decline by 2.7 percent in 2012. This decline is followed by an increase of 1.9 percent in 2013. Petroleum emissions fall by 1.4 percent in 2012 and grow 0.2 percent in 2013. Natural gas emissions rise by 5.2 percent in 2012 and fall by 0.4 percent in 2013. Coal emissions decline 9.7 percent in 2012, but are projected to rise by 6.0 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



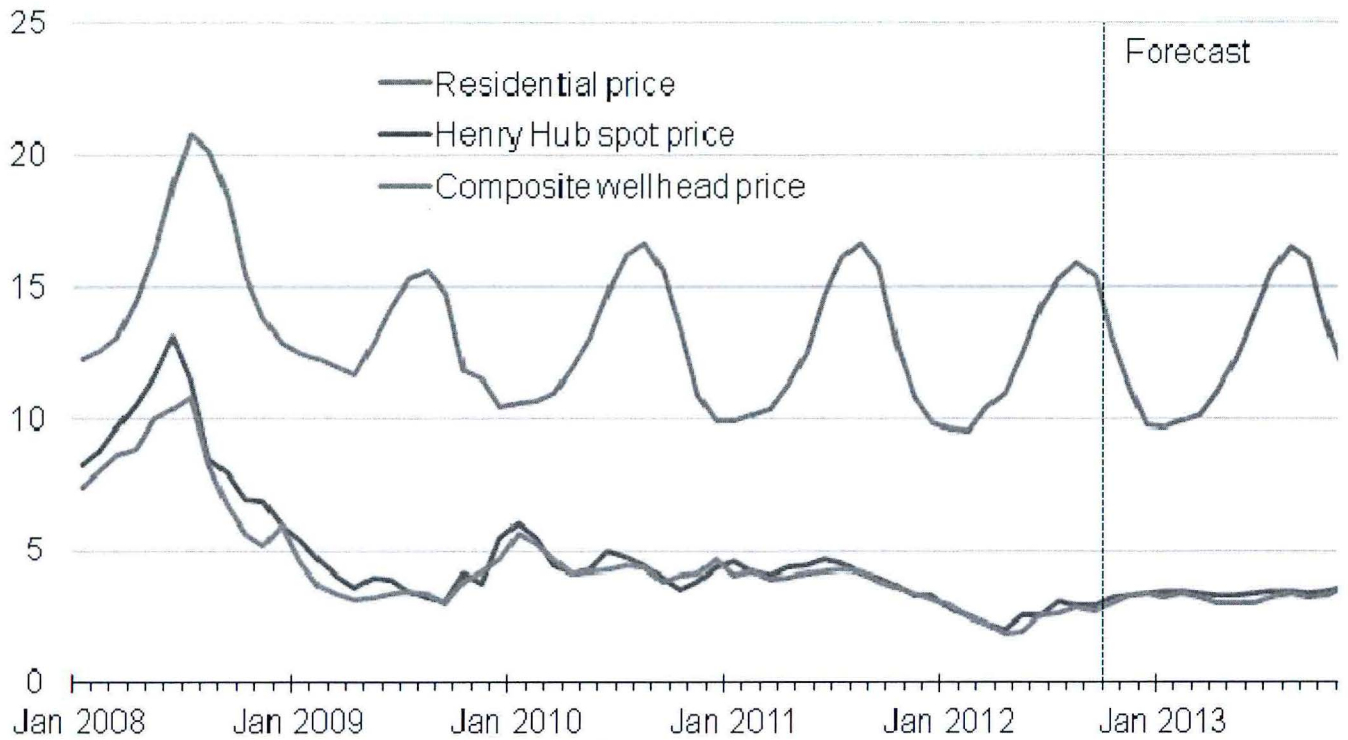
Note: Confidence interval derived from options market information for the 5 trading days ending October 4, 2012. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, October 2012



U.S. Natural Gas Prices

dollars per thousand cubic feet



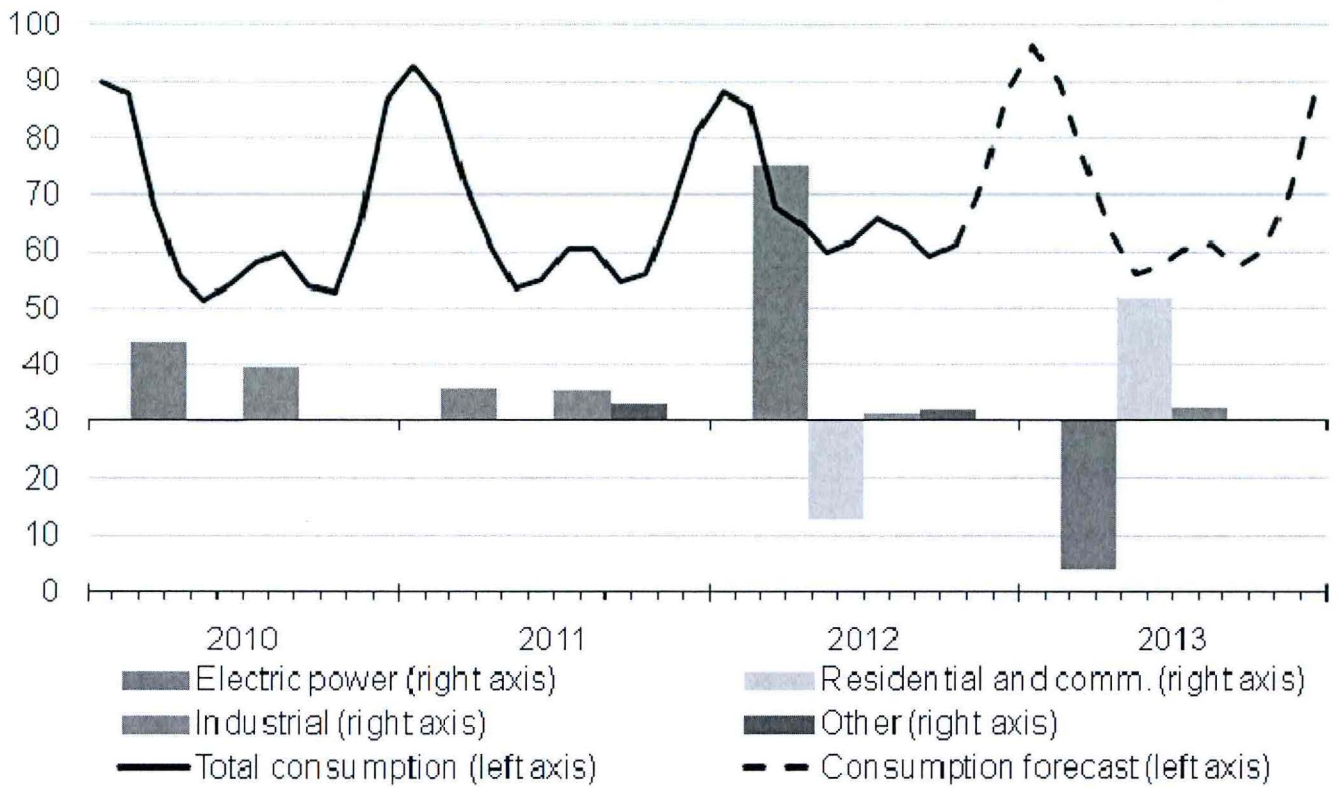
Source: Short-Term Energy Outlook, October 2012



U.S. Natural Gas Consumption

billion cubic feet per day (bcf/d)

annual change (bcf)



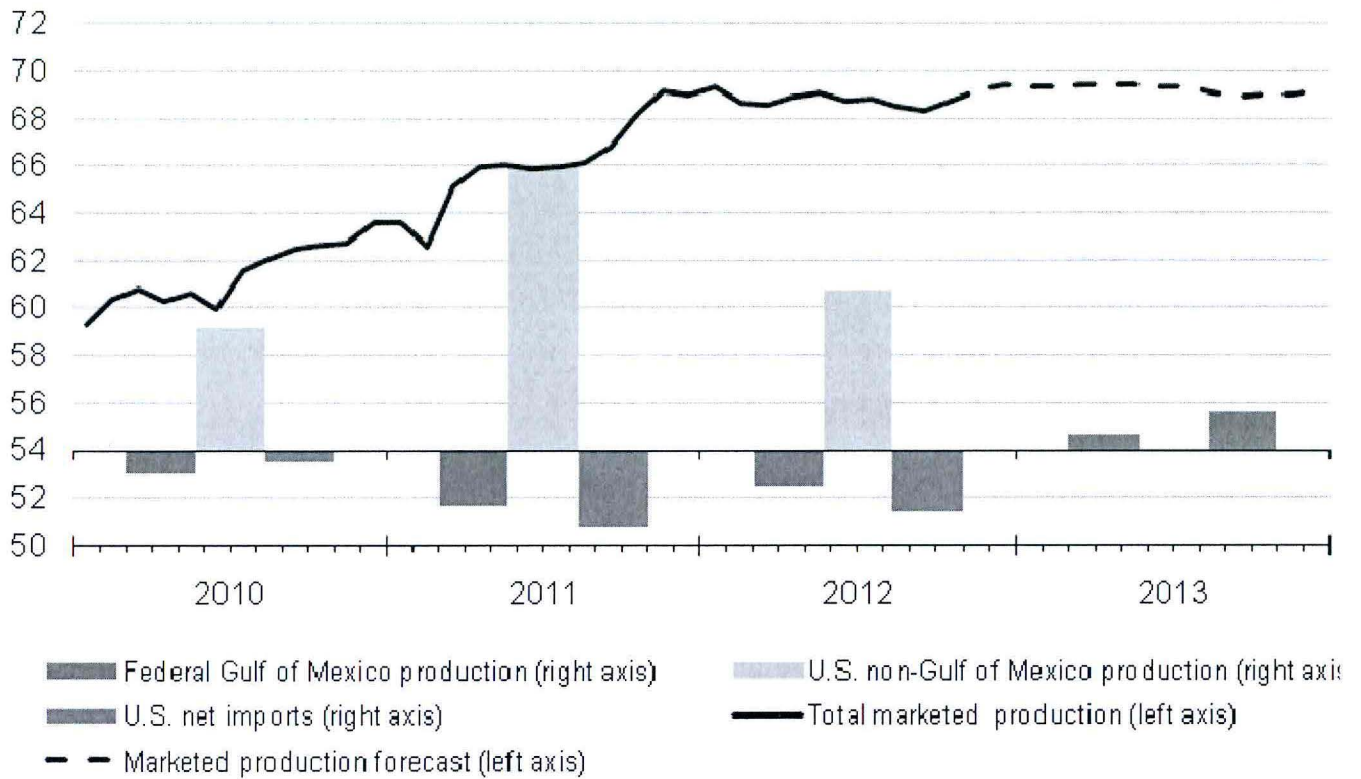
Source: Short-Term Energy Outlook, October 2012



U.S. Natural Gas Production and Imports

billion cubic feet per day (bcf/d)

annual change (bcf/d)



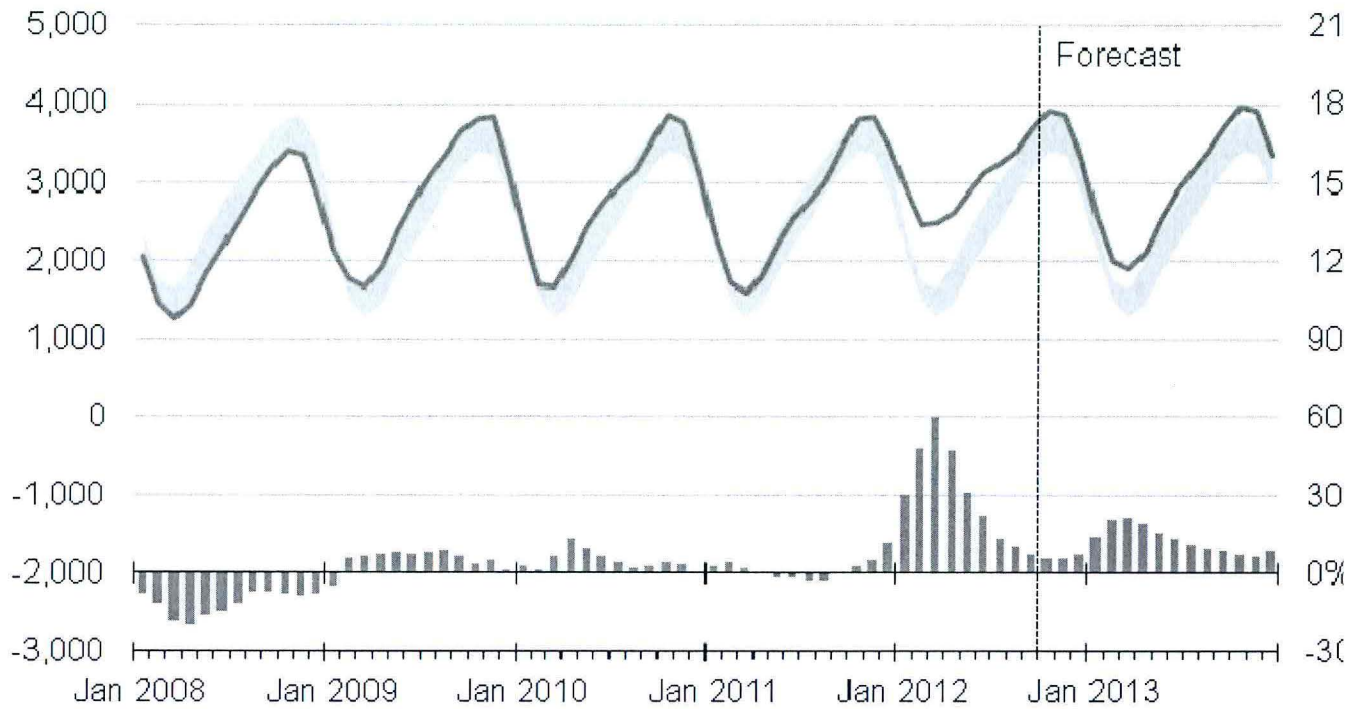
Source: Short-Term Energy Outlook, October 2012



U.S. Working Natural Gas in Storage

billion cubic feet

deviation from average



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

Source: Short-Term Energy Outlook, October 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
Balance @ September 30, 2012									<u><u>\$521,530</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**

	<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>(\$72,396)</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)
Balance @ September 30, 2012									<u>(\$116,406)</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).