



A Division of MDU Resources Group, Inc.

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May 31, 2012

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

Re: Cost of Gas Adjustment (COG)
June 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 (75th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (75th Revised Sheet No. 8), showing the June 2012 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.9598 per mcf for residential and firm general service customers and \$0.1816 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for June 2012, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.4553 per mcf since the last COG filing due to an increase in the market price of gas. There has been an increase in pipeline charges of \$0.0010 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of \$0.4563 per mcf for residential and firm general service customers.

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

Attachment D shows the calculation of the gas cost reconciliation (GCR) adjustment that will apply during the period of June 1, 2012 through May 31, 2013. The total GCR is \$1.0137 per mcf for residential and general service customers and a negative \$0.2915 per mcf for interruptible customers. The effect of this change is an increase of \$0.5035 for residential and general service customers and a decrease of \$0.2737 for interruptible customers. The increase for residential and general service customers is due to warmer than normal weather during the 2011-2012 winter heating season.


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
Regulatory Affairs Manager

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
 75th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 74th 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	\$7.1879	\$8.4619 8.2419
Firm Gas Service - General Highway 13	2.5	\$3.50 per month	First 10 MCF \$2.1740 Over 10 MCF 1.9540	\$7.1879	\$9.3619 9.1419
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	\$1.9639	\$3.1030 2.8570 2.7050
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	\$1.9639	\$4.0030 3.7570 3.6050
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$1.9639	\$3.2030
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: May 31, 2012

Effective Date: June 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
75th Revised Sheet No. 8
Canceling 74th 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.	3.8668	(3.3338)	0.5102	1.0432	(3.3190)	(0.0178)	(3.3368)
Current Adj.	0.0010	0.4553	0.5035	0.9598	0.4553	(0.2737)	0.1816
Total Adj.	3.8678	(2.8785)	1.0137	2.0030	(2.8637)	(0.2915)	(3.1552)
Total Rate:	\$3.9336	\$2.2406	\$1.0137	\$7.1879	\$2.2554	(\$0.2915)	\$1.9639

Date Filed: May 31, 2012

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

Issued By: Tamie A. Aberle
Regulatory Affairs Manager

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JUNE 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	7,841	\$3.4671	12	\$326,226	\$0.2331
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
NOVA - Demand Charge	7,947	15.0310	12	1,433,416	1.0241
Trans Canada - Demand Charge	7,947	23.6147	12	2,251,992	1.6089
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0655
NOVA - Seasonal	5,068	15.0310	5	380,886	0.2721
Trans Canada - Seasonal	5,068	23.6147	5	598,396	0.4275
BP Canada - Seasonal	5,068	0.9612	5	24,357	0.0174
BP Canada Winter Surcharge	5,068	3.0417	5	77,077	0.0551
LMS Demand 2/				0.0148	0.0148
Total Demand Charges				\$5,485,093	3.9336
Estimated Weighted Average Commodity Cost	1,399,684	1/ 2.2406		3,136,132	2.2406
Gas Cost Reconciliation Adjustment					1.0137
Total Current Firm Gas Cost				\$8,621,225	7.1879
Base Cost of Gas					5.1849
Accumulated Adjustment					\$2.0030
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$2.2406
Gas Cost Reconciliation Adjustment					(0.2915)
LMS Demand 2/					0.0148
Total Current Interruptible Gas Cost					1.9639
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$3.1552)

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
JUNE 2012**

Rates Effective June 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 Seasonal	15.1530	Per dk/Mo.
NOVA - Demand Charge	15.0310	Per dk/Mo.
Trans Canada Pipeline Demand Charge	23.6147	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	15.0310	Per dk/Day
Trans Canada - Seasonal	23.6147	Per dk/Mo.
BP Canada - Seasonal	0.9612	Per dk/Mo.
BP Canada Winter Surcharge	3.0417	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	2.2406	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: $4,768 \times 12 \times \$0.8100 / 707,222$

STATEMENT OF RATES
 (Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
<u>Category 1 (Contract Term of Less than 3 Years)</u>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$3.7671
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$4.8871
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$2.1400
Zone 2-2 Minimum Rate	\$0.0000
<u>Category 2 (Contract Term of 3 Years to less than 5 Years)</u>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$3.6171
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$4.7371
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$1.9900
Zone 2-2 Minimum Rate	\$0.0000
<u>Category 3 (Contract Term of 5 or more Years)</u>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$3.4671
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$4.5871
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$1.8400
Zone 2-2 Minimum Rate	\$0.0000

Rate Schedule	Base Tariff Rate	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		TF5	TF5	TFF
	TF12 Base	Variable			
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 Surcharges 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)	0.67%
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
June 2012**

The principal gas sources of natural gas for Wahpeton, North Dakota are from the large Western Canadian Sedimentary Basin (WCSB). The pricing point for much of this gas is the Alberta Energy Company (AECO-C), one of the largest and most liquid volume points in North America. The June monthly price for the AECO Index is expected to increase from the previous month index. The AECO Index is based on the weighted average one month spot price at AECO-C and Nova Inventory Transfer (N.I.T.) as reported by Natural Gas Exchange (NGX).

Warmer weather and increased use of air conditioning along with inventory levels that seemed to be moderating compared to the five-year average likely contributed to the increase in the index price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of May 18, 2012 were 37.8 percent above the five-year average and 37.6 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 17.



Independent Statistics & Analysis

U.S. Energy Information
Administration

May 2012

Short-Term Energy Outlook

Highlights

- EIA's current forecast of the average U.S. refiner acquisition cost of crude oil in 2012 is \$110 per barrel, which is \$2.50 per barrel lower than in last month's *Outlook*, but still about \$8 per barrel higher than last year's average price. EIA expects the price of West Texas Intermediate (WTI) crude oil to average about \$104 per barrel in 2012, about \$2 per barrel lower than the forecast in last month's *Outlook*, but \$9 per barrel higher than the 2011 average price. EIA expects crude oil prices to remain relatively flat in 2013.
- With falling global crude oil prices over the past month, EIA has lowered the average regular gasoline retail price forecast for the current April-through-September summer driving season to \$3.79 per gallon, 16 cents per gallon below the level in the previous *Outlook*. EIA expects regular gasoline retail prices to average \$3.71 per gallon in 2012 and \$3.67 per gallon in 2013, compared with \$3.53 per gallon in 2011. The September 2012 New York Harbor Reformulated Blendstock for Oxygenate Blending (RBOB) futures contract averaged \$2.99 per gallon for the five trading days ending May 3. Based on the market value of futures and options contracts, there is a 22 percent probability that the RBOB contract price at expiration will exceed \$3.30 per gallon, consistent with an average regular-grade gasoline retail price exceeding \$4.00 per gallon in September.
- EIA expects U.S. total crude oil production to average 6.2 million barrels per day (bbl/d) in 2012, an increase of 0.5 million bbl/d from last year, and the highest level of production since 1998. Forecast lower-48 onshore crude oil production in 2012 averages over 4.3 million bbl/d, reaching its highest level since 1993. Projected U.S. domestic crude oil production increases to 6.4 million bbl/d in 2013, driven primarily by growth in lower-48 onshore production.
- Very mild weather over the past winter contributed to natural gas working inventories that continue to set new record seasonal highs, with April 2012 ending at an estimated 2.61 trillion cubic feet (Tcf), about 46 percent more than the same time last year. EIA's average 2012 Henry Hub natural gas spot price forecast is \$2.45 per million British thermal units (MMBtu), a decline of \$1.55 per MMBtu from the 2011 average spot price. EIA expects that Henry Hub spot prices will average \$3.17 per MMBtu in 2013.

- EIA expects electricity generation from coal to decline by about 15 percent in 2012 as generation from natural gas increases by about 24 percent. EIA forecasts that electricity generation from coal will increase by about 4 percent in 2013, as projected coal prices fall slightly while natural gas prices increase, allowing coal to regain some of its power generation share.

Global Crude Oil and Liquid Fuels

Global Crude Oil and Liquid Fuels Overview. EIA expects that global oil markets will continue to remain tight in 2012, although markets have eased somewhat since mid-March. Year-over-year supply growth in 2012 should significantly exceed the projected 1.0 million bbl/d rise in consumption, and we expect global commercial stocks to build following the significant draws during 2011. The oil production gains contributed to a counter-seasonal stock build during the 1st quarter of 2012 and a moderate reduction in backwardation in crude oil prices. However, EIA does not expect these large counter-seasonal stock builds to continue throughout the year, and both global oil inventory and spare production capacity levels are projected to be tight enough to support higher average crude oil prices in 2012 than in the previous year. The projected oil market balance reflects the impacts from previous sanctions against Iran, but the potential impacts of the more recent sanctions set to take effect this year are not accounted for in the current *Outlook*.

Crude oil prices have declined after increasing through mid-March, as global liquids supply outpaced consumption by 0.6 million bbl/d in first quarter 2012, which led to global inventory builds. The easing in the backwardation of waterborne light crude prices noted in EIA's April 27th report, *The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran*, has also continued in recent days. While price trends and reduced backwardation signal some market easing, the continuing premium on contracts for near-term delivery and a price level that remains elevated relative to the fourth quarter of 2011 is still indicative of tightness in world oil markets.

There are several uncertainties that could push oil prices higher or lower than projected. A number of countries outside of the Organization of the Petroleum Exporting Countries (OPEC) are currently undergoing supply disruptions, as discussed in EIA's April 27th report *The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran* and the April 18 edition of *This Week in Petroleum*. Oil prices could be higher than projected in this *Outlook* if recoveries from supply disruptions are slower than forecast, additional disruptions occur, or supply growth is lower than expected. Additionally, although the effects of the impending European Union embargo and other sanctions targeting exports of Iranian crude oil and their associated payments are still uncertain, heightened market anxiety surrounding a potentially significant supply disruption could bolster oil prices. On the demand side, economic growth below current expectations could result in reduced oil demand and lower prices.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by an estimated 0.8 million bbl/d in 2011. EIA expects consumption growth of 1.0 million bbl/d in 2012 and 1.2 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 (World Liquid Fuels Consumption Chart). OECD liquid fuels consumption is projected to decline by 0.4 million bbl/d in 2012, with Europe and, to a lesser extent, the United States accounting for almost all of the decline. In 2013, forecast OECD liquid fuels consumption is expected to remain essentially flat.

Non-OPEC Supply. EIA expects non-OPEC crude oil and liquid fuels production to rise by 0.7 million bbl/d in 2012 and by a further 1.1 million bbl/d in 2013. The largest area of non-OPEC growth will be North America, where production increases by 680 thousand bbl/d and 260 thousand bbl/d in 2012 and 2013, respectively, resulting from continued production growth from U.S. onshore shale and other tight oil formations and Canadian oil sands. In Brazil, output is projected to rise annually by an average of 130 thousand bbl/d over the next two years, with increased output from its offshore, pre-salt oil fields. EIA expects that Kazakhstan, which will commence commercial production in the Kashagan field next year, will increase its total production by 160 thousand bbl/d in 2013. Production also rises in China and Colombia over the next two years, while production declines in Mexico and the North Sea.

Several notable disruptions to non-OPEC production commenced or intensified since the beginning of this year, as discussed in both the April 27th report *The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran* and in the April 18 edition of *This Week in Petroleum*. Unplanned outages to non-OPEC production totaled over 1.2 million bbl/d in March and are estimated to remain at an elevated level.

OPEC Supply. EIA expects that OPEC members will continue to produce slightly over 30 million bbl/d of crude oil over the next two years to accommodate the projected increase in world oil demand and to counterbalance supply disruptions. Projected OPEC crude oil production increases by about 1.0 million bbl/d in 2012 and then falls by 0.3 million bbl/d in 2013 as non-OPEC supply growth increases and stocks remain flat. OPEC non-crude petroleum liquids (condensates, natural gas liquids, coal-to-liquids, and gas-to-liquids), which are not covered by OPEC's production quotas, are forecast to increase by 0.2 million bbl/d in 2012, and by 0.1 million bbl/d in 2013.

EIA expects Iran's crude production to fall by about 500 thousand bbl/d by the end of 2012 and by an additional 200 thousand bbl/d in 2013, from its previous output level of 3.55 million bbl/d at the end of 2011. Iran's output decline began to accelerate during the last quarter of 2011 and has continued. EIA believes that this acceleration reflects a lack of investment, which is needed to offset natural production declines. A number of foreign companies that were investing in Iran's upstream have halted their activities as a result of previous sanctions against Iran that have made it difficult to do business with the country. EIA expects that the forecast decline in Iran's output will be offset by increased production in other OPEC member countries.

EIA's forecast of market balances does not factor in any potential effects of the more recent sanctions targeting Iran's central bank and the impending European Union embargo on Iran's crude oil production, or their possible impact on the production, spare capacity, or inventories of Iran and other OPEC member countries. As noted in EIA's April 27th report, there are indications that the U.S. and EU sanctions are already affecting sales of Iranian crude oil. Current and continuing difficulties in placing export volumes from Iran could result in a buildup of Iranian oil in storage, whether onshore or offshore. An increase in Iranian crude oil storage would drive an increase in global oil inventories. However, insofar as inventories held by Iran are building due to the effect of sanctions on its ability to sell oil, those volumes would not be available to consumers in the same way as traditional inventories.

Moreover, if Iran's difficulties in finding markets for its oil persist or intensify, or outstrip available storage capacity, Iran may have to shut in production. EIA expects that any volumes that are shut-in could be replaced by increased production from spare capacity held by other OPEC member countries. In such a scenario, the shut-in production capacity in Iran may technically be counted as new spare capacity, but—like inventories that accumulate for similar reasons—would not be readily available to alleviate market tightness in the same manner that regular spare capacity not forced by sanctions typically would be.

OPEC members serve as the swing producers in the world market because only OPEC producers possess surplus or spare oil production capacity. EIA projects that OPEC surplus production capacity will average 2.8 million bbl/d in 2012 and rise to an average 3.5 million bbl/d in 2013 (OPEC Surplus Crude Oil Production Capacity Chart). However, as discussed above, markets may be closely watching the composition of OPEC spare capacity, as well as its aggregate level, as the situation with respect to Iran evolves. Under plausible circumstances, the market may discount a portion of OPEC members' aggregate spare capacity.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories ended 2011 at 2.59 billion barrels, equivalent to 56.1 days of forward-cover (Days of Supply of OECD Commercial Stocks Chart). Projected OECD oil inventories increase to 2.64 billion barrels and 57.3 days of forward-cover by the end of 2012. Although the forecast December 2012 inventory is slightly lower than the 2.66-billion-barrel level at the end of December 2010, the days of forward-cover are still among the highest end-of-year levels since 1991 because of the decline in OECD consumption.

Crude Oil Prices. EIA has lowered the forecast 2012 average U.S. refiner acquisition cost of crude oil by \$2.50 per barrel from last month's *Outlook* to \$110 per barrel, still about \$8 per barrel higher than last year's average price. EIA expects the price of WTI crude oil to average about \$104 per barrel in 2012, about \$2 per barrel lower than last month's *Outlook*, but \$9 per barrel higher than the 2011 average price. EIA expects crude oil prices to remain relatively flat in 2013, with WTI and the U.S. refiner acquisition cost of crude oil averaging about \$104 per barrel and \$108 per barrel, respectively (West Texas Intermediate Crude Oil Price Chart). The

projected WTI price discount to the average U.S. refiner acquisition cost of crude oil narrows over the forecast from about \$6 per barrel in the second quarter of 2012 to \$4 per barrel by the fourth quarter of 2013, as transportation bottlenecks diminish.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for July 2012 delivery during the 5-day period ending May 3, 2012 averaged \$105 per barrel. Implied volatility averaged 23 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in July 2012 at \$90 per barrel and \$123 per barrel, respectively. Last year at this time, WTI for July 2011 delivery averaged \$110 per barrel and implied volatility averaged 29 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$91 per barrel and \$133 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total consumption fell 340 thousand bbl/d (1.8 percent) last year. Motor gasoline consumption accounted for the bulk of that decline, shrinking by 260 thousand bbl/d (2.9 percent). In the first quarter of 2012, total consumption continued to display weakness, falling by 670 thousand bbl/d (3.5 percent) from the same period last year (U.S. Liquid Fuels Consumption Chart). Higher retail gasoline prices contributed to the 150-thousand-bbl/d (1.7-percent) decline in motor gasoline consumption during the first quarter 2012 from the year before. Distillate fuel consumption also shrank by 150 thousand bbl/d (3.7 percent), largely due to unusually warm weather. For the rest of 2012, EIA expects more moderate year-over-year declines in motor gasoline consumption, averaging about 30 thousand bbl/d. In contrast, projected distillate fuel oil consumption recovers from the very warm winter with year-over-year growth averaging about 80 thousand bbl/d, boosted by continued growth in manufacturing production.

Despite assumed growth in U.S. real disposable income of 1.9 percent next year, forecast motor gasoline consumption continues to decline by 30 thousand bbl/d (0.3 percent) in 2013. This *Outlook* reflects high gasoline prices, slowing growth in the driving-age population, and the improving average fuel economy of new vehicles. Distillate fuel consumption, on the other hand, increases by 90 thousand bbl/d (2.4 percent), buoyed by an assumed near-normal winter and continuing growth in manufacturing output.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by an estimated 190 thousand bbl/d (3.4 percent) to 5.66 million bbl/d in 2011. An increase of 450 thousand bbl/d in lower-48 onshore production in 2011 was partly offset by a 30-thousand-bbl/d production decline in Alaska and a 230-thousand-bbl/d production decline in the Federal Gulf of Mexico (GOM).

Forecast U.S. total crude oil production increases to 6.17 million bbl/d in 2012, an upward revision of 150 thousand bbl/d from last month's *Outlook*, and the highest level of production

since 1998. Growth in lower-48 onshore crude oil production of 560 thousand bbl/d in 2012 overshadows declines averaging about 30 thousand bbl/d in Alaskan output and 20 thousand bbl/d in GOM production (U.S. Crude Oil and Liquid Fuels Production Chart). The rise in production is driven by increased oil-directed drilling activity, particularly in onshore tight oil formations. The number of onshore oil-directed drilling rigs reported by Baker Hughes increased from 777 at the beginning of 2011 to 1,355 on May 4, 2012.

The share of total U.S. consumption met by total liquid fuel net imports (including both crude oil and products) has been falling since 2005, and averaged 45 percent in 2011, down from 49 percent in 2010. EIA expects that the total net import share of consumption will continue to decline to 43 percent in 2012 and to 42 percent in 2013.

U.S. Petroleum Product Prices. Regular-grade gasoline retail prices averaged \$3.53 per gallon in 2011, \$0.74 per gallon (27 percent) higher than the 2010 average. The price increase in 2011 largely reflected higher crude oil costs (\$0.60 per gallon) and higher refinery gasoline margins (\$0.10 per gallon). EIA expects the regular-grade gasoline retail price to increase to an average of \$3.71 per gallon in 2012, primarily due to higher crude oil costs (U.S. Gasoline and Crude Oil Prices Chart). Regular-grade gasoline prices peaked at \$3.90 per gallon in April and are projected to average \$3.79 per gallon during the summer season (April through September) compared with last summer's average of \$3.71 per gallon. Forecast regular-grade gasoline prices decline to an average of \$3.67 per gallon in 2013.

EIA expects that on-highway diesel fuel retail prices, which averaged \$3.84 per gallon in 2011, will average \$4.06 per gallon in 2012, down 9 cents per gallon from last month's *Outlook*. In 2013, diesel fuel retail prices are projected to decline to \$4.03 per gallon, 8 cents per gallon lower than the previous *Outlook* (U.S. Diesel Fuel and Crude Oil Prices Chart).

Because taxes and retail distribution costs are generally stable, movements in gasoline and diesel prices are driven primarily by changes in both crude oil prices and wholesale margins. The retail price projections reflect higher prices for the average refiner acquisition cost of crude oil, which averages \$110 per barrel (\$2.61 per gallon) in 2012, compared with the \$102-per-barrel (\$2.43-per-gallon) average for 2011. EIA expects wholesale gasoline margins (the difference between the wholesale price of gasoline and the refiner acquisition cost of crude oil) will average 42 cents per gallon and 41 cents per gallon in 2012 and 2013, respectively, which are slightly higher than the previous 5-year average of 40 cents per gallon. In contrast, wholesale diesel margins are robust during the forecast interval due to strong world-wide demand for the fuel. In 2012, those margins average 60 cents per gallon, similar to the 2011 average and higher than the previous 5-year average of 52 cents per gallon. The diesel wholesale margin for 2013 remains wide, averaging 59 cents per gallon.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 70.2 billion cubic feet per day (Bcf/d) in 2012, an increase of 3.4 Bcf/d (5.1 percent) from 2011 and an upward revision of 0.6 Bcf/d from last month's *Outlook*. EIA expects that large gains in electric power use will offset declines in residential and commercial use. Because of the much-warmer-than-normal winter this year, EIA expects both residential and commercial consumption to fall by over 6 percent in 2012, reflecting a downward revision in projected consumption from last month's *Outlook*. The downward revisions in residential and commercial consumption reflect the decline in total projected 2012 heating degree-days as reported by the National Oceanic and Atmospheric Administration.

Projected consumption of natural gas in the electric power sector grows by almost 21 percent in 2012, primarily driven by the increasing relative cost advantages of natural gas over coal for power generation in some regions. Consumption in the electric power sector peaks in the third quarter of 2012, at 31.2 Bcf/d, when electricity demand for air conditioning is highest. This compares with 27.7 Bcf/d during the third quarter of 2011.

Growth in total natural gas consumption slows in 2013, with forecast consumption averaging 71.2 Bcf/d (U.S. Natural Gas Consumption Chart). However, unlike 2012, growth in 2013 is driven by consumption from the residential, commercial, and industrial sectors. A forecast of closer-to-normal winter temperatures drives increases in residential and commercial consumption in 2013 of 7.1 percent and 4.2 percent, respectively. The increase in consumption in these sectors, as well as a 1.4-percent increase in industrial consumption, more than offsets a 2.0-percent decline in power-sector natural gas burn.

U.S. Natural Gas Production and Imports. Total marketed production of natural gas grew by an estimated 4.8 Bcf/d (7.9 percent) in 2011. This strong growth was driven in large part by increases in shale gas production. While EIA expects year-over-year production growth to continue in 2012, the projected increases occur at a slower rate than in 2011 as low prices reduce new drilling plans. According to Baker Hughes, the natural gas rig count was 613 as of April 27, 2012, down from a 2011 high of 936 in mid-October, making it the lowest rig count since 2002. EIA's production survey indicates natural gas marketed production fell by 420 Bcf/d from January 2012 to February 2012. EIA expects growth in U.S. production during 2012 to average 4.4 percent. Declining production from less-profitable "dry" natural gas plays such as the Haynesville Shale are 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 0.3 Bcf/d (3.3 percent) in 2012 as domestic supply displaces Canadian sources. The warm winter in the United States also adds 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 pipeline gross imports will increase

by 2.3 percent in 2013, partially due to near-normal winter weather driving higher residential and commercial demand. Additionally, EIA expects increased pipeline imports to help meet continued high demand for natural gas for electric power generation. Pipeline gross exports grew by 1.0 Bcf/d in 2011, driven by increased exports to Mexico, and are expected to continue to grow at a slower rate in 2012 and 2013.

Liquefied natural gas (LNG) imports are expected to fall by 0.3 Bcf/d (32 percent) in 2012. EIA expects that an average of about 0.7 Bcf/d will arrive in the United States (mainly at the Everett LNG terminal in New England and the Elba Island terminal in Georgia) in both 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.

U.S. Natural Gas Inventories. Working natural gas inventories continue to set new seasonal record highs as the very mild winter contributed to much-lower-than-normal inventory draws. As of April 27, 2012, according to EIA's *Weekly Natural Gas Storage Report*, working inventories totaled 2,576 Bcf, 840 Bcf greater than last year's level and 857 Bcf above the 5-year (2007-2011) average. EIA expects that inventory levels at the end of October 2012 will set a new record high at 4,096 Bcf (U.S. Working Natural Gas in Storage Chart), although the record will largely be due to high levels already present at the start of the injection season. The projected increase of 1,623 Bcf in working gas inventory during the 2012 injection season (from the end of March to the end of October) is the smallest build since 2002. Limits on storage capacity, as well as high demand from the electric power sector this summer, will limit the overall level of injections. In 2013, working inventory levels recede from record highs, although they will still remain robust compared with recent history.

U.S. Natural Gas Prices. Natural gas spot prices averaged \$1.95 per MMBtu at the Henry Hub in April 2012, down \$0.23 per MMBtu from the March 2012 average and the lowest average monthly price since March 1999, which also was the last time the Henry Hub price averaged less than \$2 per MMBtu. Abundant supplies and lower winter heating demand this year have contributed to the recent low prices. EIA expects the Henry Hub natural gas price will average \$2.45 per MMBtu in 2012, a small downward revision from \$2.51 per MMBtu expected in last month's *Outlook*. EIA revised its forecast for 2013 down to \$3.17 per MMBtu, from \$3.40 per MMBtu in last month's *Outlook* (U.S. Natural Gas Prices Chart).

Natural gas futures prices for July 2012 delivery (for the 5-day period ending May 3, 2012) averaged \$2.39 per MMBtu, and the average implied volatility based on options and futures prices was 51 percent (*Market Prices and Uncertainty Report*). Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for July 2012 contracts at \$1.63 per MMBtu and \$3.50 per MMBtu, respectively. At this time last year, the July 2011 natural gas futures contract averaged \$4.65 per MMBtu and implied volatility averaged 34 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.61 per MMBtu and \$5.98 per MMBtu.

Coal

U.S. Coal Consumption. EIA forecasts that electric power sector coal consumption will be about 800 million short tons (MMst) in both 2012 and 2013. Prices for natural gas delivered to the electric power industry fell by 7.5 percent in 2011, which contributed to a significant increase in the share of natural-gas-fired generation. EIA expects this trend to continue in 2012, with electric power sector coal consumption falling by 14 percent (U.S. Coal Consumption Chart). EIA expects that electric power sector coal consumption will increase by 1.2 percent in 2013, as projected power industry coal prices fall (4 percent) and natural gas prices increase.

U.S. Coal Supply. EIA forecasts that coal production will decline by 10.2 percent in 2012 as domestic consumption and exports fall (U.S. Coal Production Chart). Production for the first three months of 2012 was 22 MMst below last year's value for the same period. Annual production declines greater than 25 MMst are expected in each of the three coal-producing regions (Appalachia, Interior and Western). Despite declines in production, EIA projects that secondary inventories will increase in 2012, with electric power sector stocks exceeding 200 MMst, and inventories will remain at elevated levels in 2013 (U.S. Electric Power Sector Coal Stocks Chart).

U.S. Coal Trade. EIA expects U.S. coal exports to remain strong but fall below the 107 MMst exported in 2011. Forecast U.S. coal exports are 100 MMst in 2012 and 97 MMst in 2013. U.S. coal exports averaged 56 MMst in the decade preceding 2011.

U.S. Coal Prices. Delivered coal prices to the electric power industry had increased steadily over the last 10 years and this trend continued in 2011, with an average delivered coal price of \$2.40 per MMBtu (a 5.8 percent increase from 2010). However, EIA expects the decline in demand for coal to generate electricity will put downward pressure on coal prices and contribute to the shut-in of higher-cost production. Several companies have recently announced the curtailment of operations, particularly in Appalachia, where production costs at some older mines are high. EIA forecasts the average delivered coal price in 2012 will be 2.8 percent lower than the 2011 average price. EIA predicts the 2013 average delivered coal price to be \$2.24 per MMBtu, or 3.8 percent lower than the previous year's price.

Electricity

U.S. Electricity Consumption. Heating degree-days nationwide during the first quarter of 2012 were at the lowest level since record keeping began in 1895. Winter temperatures were particularly mild in the South, where a majority of homes use electric heat pumps. The mild weather contributed to an 11-percent decline in U.S. residential electricity sales compared with the same period last year. For the summer months, EIA expects U.S. cooling degree-days to average 16 percent lower than last summer. Overall, residential electricity sales fall about 4

percent during 2012. EIA expects total consumption of electricity to decline by 0.8 percent during 2012 and then grow by 1.9 percent in 2013.

U.S. Electricity Generation. Natural-gas-fired generation continues to expand its share of total generation at the expense of coal-fired generation. During the first quarter of 2012, natural gas accounted for 28.7 percent of total generation compared with 20.7 percent during the same quarter last year. In contrast, coal's share of total generation declined from 44.6 percent to 36.0 percent over the same period. Much of the recent increase in natural gas generation has stemmed from increased utilization of combined cycle capacity, which typically does not exhibit as much seasonal fluctuation as other types of natural gas plants used primarily for peaking generation. This trend in capacity utilization, along with summer weather that is projected to be milder than last year, should dampen year-over-year growth in natural gas generation during the third quarter (U.S. Electricity Generation Chart).

U.S. Electricity Retail Prices. EIA forecasts average U.S. residential electricity prices to rise by 0.6 percent in 2012, and then fall by 2.1 percent in 2013 (U.S. Residential Electricity Prices Chart). The rising costs of transmitting and distributing electricity to retail customers offset some of the declining fuel costs.

Renewables and Carbon Dioxide Emissions

U.S. Renewables. After growing by 14 percent in 2011, total renewable energy supply is projected to decline by 1.5 percent in 2012 (U.S. Renewable Energy Supply Chart). This decrease is the result of hydropower resource levels beginning a return to the long-term average, with supply falling by 0.3 quadrillion Btu (10 percent). The decline in hydropower from the 2011 level more than offsets growth in other renewable energy supplies. Renewables supply decreases further in 2013 as hydropower continues to decline (6.7 percent) and non-hydropower renewables growth of 2.2 percent is not enough to offset the decline.

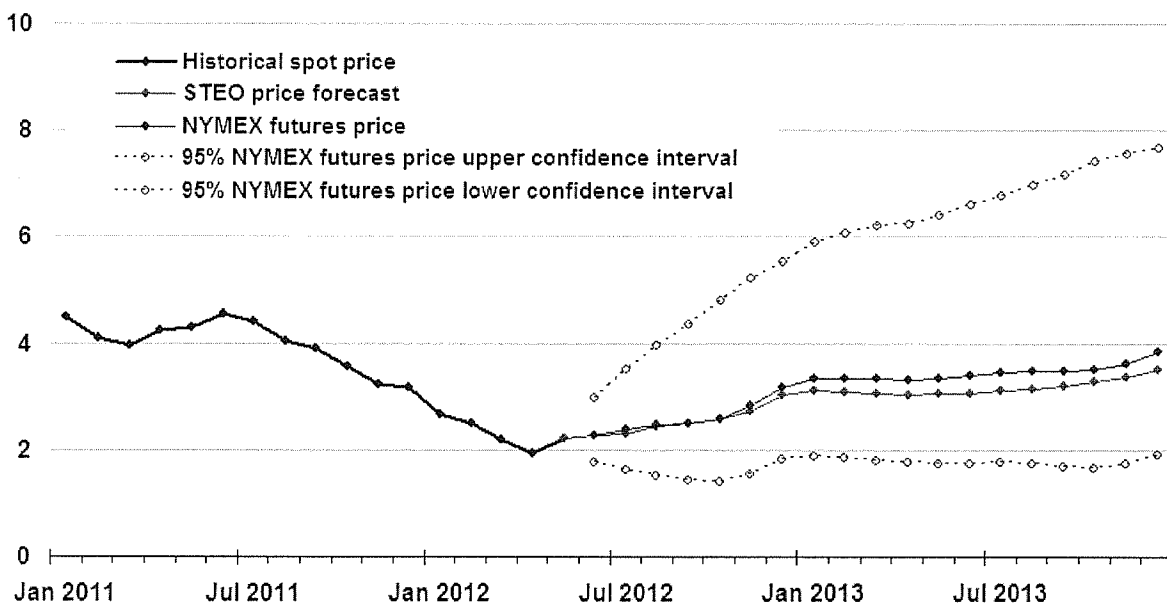
Under current law, federal production tax credits for wind-powered generation will not be available for turbines that begin operating after the end of 2012. Wind-powered generation, which grew by 26 percent in 2011, is forecast to grow an additional 13 percent in 2012 and 5 percent in 2013. Since the last *Outlook*, the amount of new wind capacity reported to EIA as possibly coming on line in 2013 has fallen by 26 percent.

In terms of liquid renewable fuels, EIA expects fuel ethanol production to remain steady from 2011 through 2013 averaging about 900 thousand bbl/d for all 3 years. This forecast assumes that E15 (gasoline blended with 15 percent ethanol by volume) does not yet reach the market. Consequently, U.S. ethanol production is projected to exceed the volume that can easily be used in the U.S. liquid fuels pool, so the Nation will continue to be a net exporter of ethanol over the next two years. EIA estimates that biodiesel production in 2011 averaged about 63 thousand bbl/d (971 million gallons of total annual production). Forecast biodiesel production averages 63 thousand bbl/d in 2012, and 71 thousand bbl/d in 2013.

U.S. Energy-Related Carbon Dioxide Emissions. After declining by 1.9 percent in 2011, fossil fuel emissions are projected to further decline by 2.9 percent in 2012, but increase by 1.2 percent in 2013. Petroleum emissions decline slightly in 2012 (0.3 percent) and then rise by 0.6 percent in 2013, while natural gas emissions rise by 5.5 percent and 1.2 percent in 2012 and 2013, respectively. Coal emissions decline in 2012 by 11.9 percent, but rise by 2.1 percent in 2013 (U.S. Carbon Dioxide Emissions Growth Chart).

Henry Hub Natural Gas Price

dollars per million Btu



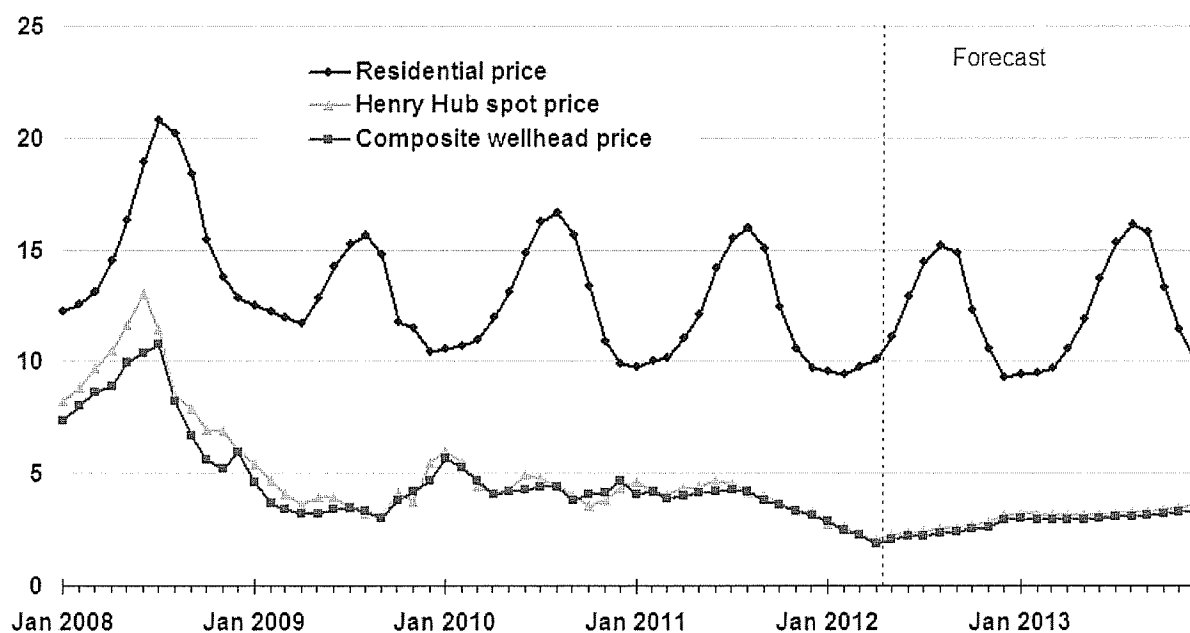
*Note: Confidence interval derived from options market information for the 5 trading days ending May 3, 2012
Intervals not calculated for months with sparse trading in "near-the-money" options contracts*

Source: Short-Term Energy Outlook, May 2012



U.S. Natural Gas Prices

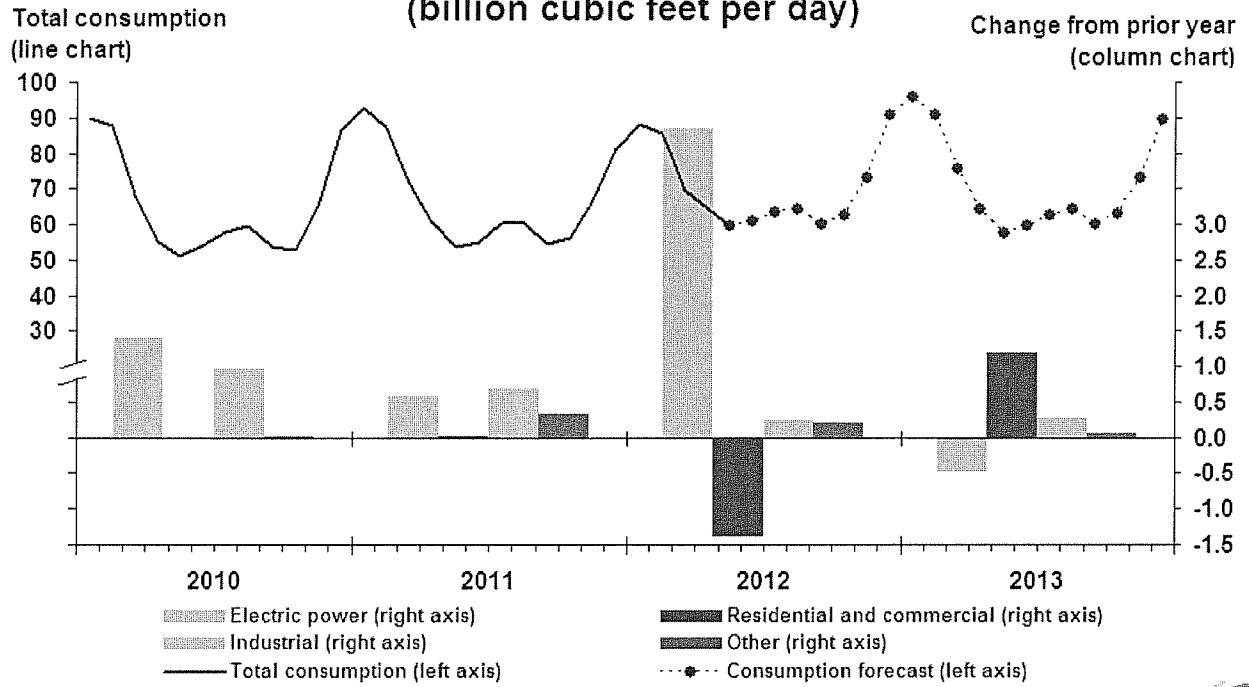
dollars per thousand cubic feet



Source: Short-Term Energy Outlook, May 2012



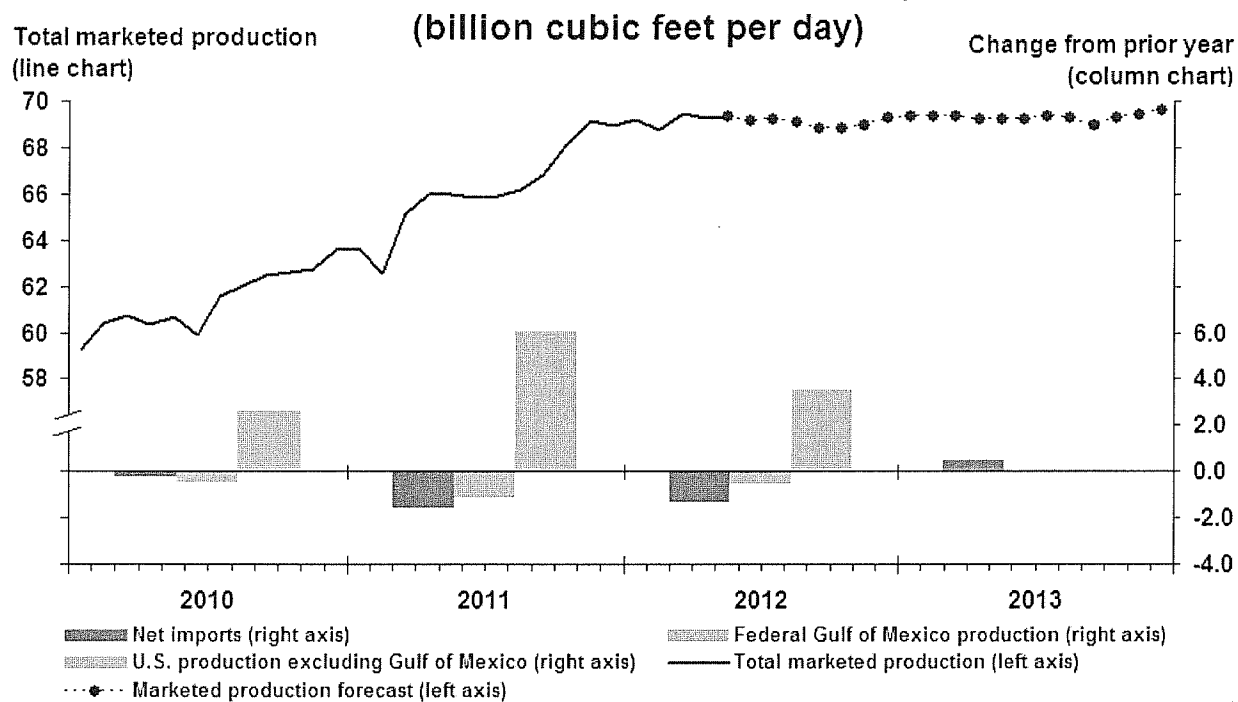
U.S. Natural Gas Consumption (billion cubic feet per day)



Source: Short-Term Energy Outlook, May 2012



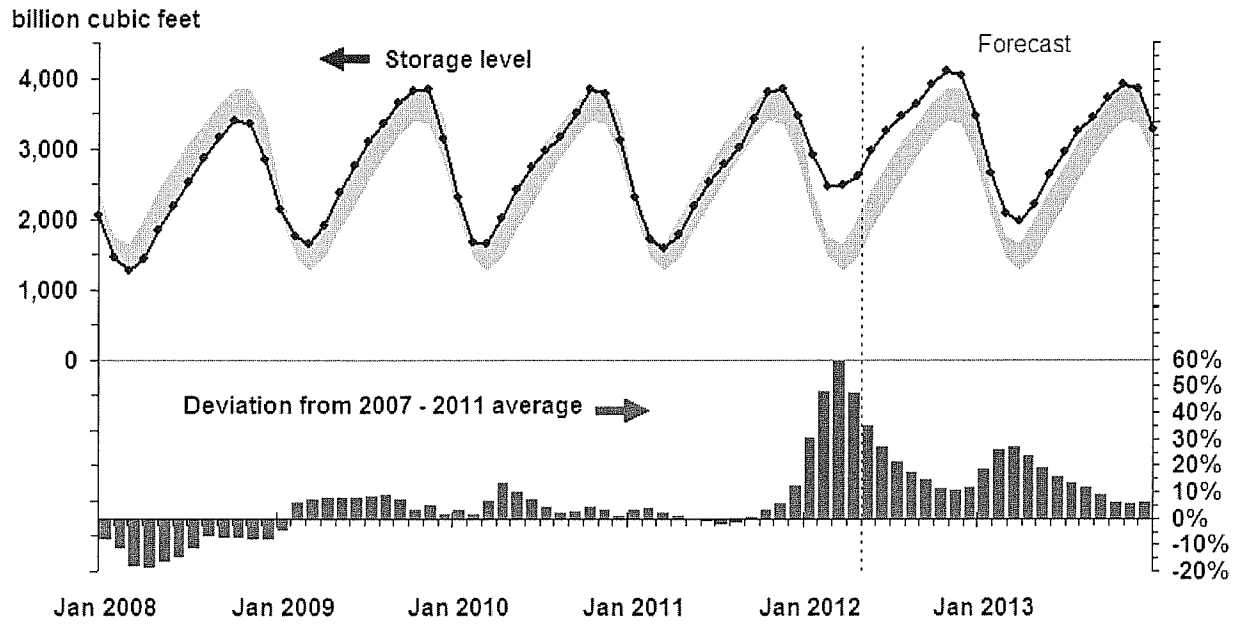
U.S. Natural Gas Production and Imports



Source: Short-Term Energy Outlook, May 2012



U.S. Working Natural Gas in Storage



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

Source: Short-Term Energy Outlook, May 2012



**GREAT PLAINS NATURAL GAS CO.
GAS COST RECONCILIATION ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
FIRM
TO BE EFFECTIVE JUNE 1, 2012 THROUGH MAY 31, 2013**

(Over)/under recovered gas costs @ April 30, 2012: \$311,764

Less projected recovery from rates already established:

	Volume	Rate	Amount
May	13,000	\$0.5102	\$6,633

Additional recovery required \$305,131

Projected sales volumes (mcf)

June 2012	9,000		
July	8,000		
August	8,000		
September	11,000		
October	20,000		
November	33,000		
December	47,000		
January 2013	52,000		
February	42,000		
March	36,000		
April	22,000		
May	13,000		
Total			<u>301,000</u>

Total gas cost reconciliation adjustment
to be effective June 1, 2012 through May 31, 2013 \$1.0137

**GREAT PLAINS NATURAL GAS CO.
GAS COST RECONCILIATION ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE
TO BE EFFECTIVE JUNE 1, 2012 THROUGH MAY 31, 2013**

(Over)/under recovered gas costs @ April 30, 2012: (\$72,396)

Less projected recovery from rates already established:

	Volume	Rate	Amount
May	22,000	(\$0.0178)	(\$392)

Additional recovery required (\$72,004)

Projected sales volumes (mcf)

June 2012	8,000		
July	9,000		
August	10,000		
September	11,000		
October	13,000		
November	25,000		
December	34,000		
January 2013	33,000		
February	23,000		
March	26,000		
April	33,000		
May	22,000		
Total			<u>247,000</u>

Total gas cost reconciliation adjustment
to be effective June 1, 2012 through May 31, 2013 (\$0.2915)

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change 2/	Cumulative Balance
Balance @ April 30, 2011									<u>\$148,188</u>
May	(\$1,396)	\$0	\$892	(\$504)	17,596	\$0.3941	\$6,935	(\$7,439)	140,749
June	33,915	0	837	34,752	9,855	0.5102	4,258 3/	30,494	171,243
July	68,988	0	1,054	70,042	6,564	0.5102	3,349	66,693	237,936
August	76,995	0	1,531	78,526	5,973	0.5102	3,047	75,478	313,414
September	25,141	0	2,066	27,207	6,611	0.5102	3,373	23,834	337,248
October	54,573	0	2,227	56,799	8,236	0.5102	4,202	52,597	389,846
November	18,005	0	2,594	20,599	17,707	0.5102	9,034	11,565	401,411
December	12,176	0	2,668	14,844	29,901	0.5102	15,255	(412)	400,999
January 2012	(8,290)	0	2,661	(5,629)	35,493	0.5102	18,108	(23,737)	377,262
February	(33,507)	0	2,489	(31,018)	39,715	0.5102	20,262	(51,280)	325,982
March	(2,694)	0	2,123	(571)	32,685	0.5102	16,676	(17,247)	308,735
April	9,737	0	2,000	11,737	17,067	0.5102	8,707	3,030	311,764
	<u>\$253,643</u>	<u>\$0</u>	<u>\$23,141</u>	<u>\$276,784</u>	<u>227,401</u>		<u>\$113,207</u>	<u>\$163,577</u>	
Balance @ April 30, 2012									<u>\$311,764</u>

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

2/ Total net additions less total adjustment amount.

3/ Reflects 5,750.5 dk @ \$0.2343 and 2,560.2 dk @ \$0.3941.

**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 2/	Cumulative Balance
Balance @ April 30, 2011									<u>(\$5,922)</u>
May	(\$17,358)	\$0	(\$95)	(\$17,453)	22,049	(\$0.1136)	(\$2,505)	(\$14,948)	(20,870)
June	(11,488)	0	(208)	(11,696)	8,011	(0.0178)	(653) 3/	(11,043)	(31,913)
July	(4,652)	0	(288)	(4,940)	9,020	(0.0178)	(161)	(4,779)	(36,692)
August	(3,906)	0	(321)	(4,227)	9,676	(0.0178)	(172)	(4,055)	(40,746)
September	(25,158)	0	(348)	(25,506)	10,802	(0.0178)	(192)	(25,313)	(66,060)
October	(1,098)	0	(528)	(1,627)	13,245	(0.0178)	(236)	(1,391)	(67,451)
November	(4,349)	0	(535)	(4,884)	24,583	(0.0178)	(438)	(4,447)	(71,897)
December	6,777	0	(564)	6,212	34,308	(0.0178)	(611)	6,823	(65,074)
January 2012	9,788	0	(513)	9,275	33,208	(0.0178)	(591)	9,866	(55,208)
February	(378)	0	(439)	(817)	23,400	(0.0178)	(417)	(401)	(55,608)
March	(6,986)	0	(440)	(7,427)	26,397	(0.0178)	(470)	(6,957)	(62,565)
April	(9,925)	0	(488)	(10,413)	32,735	(0.0178)	(583)	(9,831)	(72,396)
	<u>(\$68,733)</u>	<u>\$0</u>	<u>(\$4,768)</u>	<u>(\$73,501)</u>	<u>247,433</u>		<u>(\$7,027)</u>	<u>(\$66,474)</u>	
Balance @ April 30, 2012									<u>(\$72,396)</u>

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

2/ Total net additions less total adjustment amount.

3/ Reflects 5,327.7 dk @ (\$0.1136) and 2,683.0 dk @ (\$0.0178).

**GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
FIRM**

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>May 2011</u>				
Cost of Gas - Actual	\$8.90090	\$7.70180	\$8.90090	
Cost of Gas - Recovered	8.26460	8.23410	8.23410	
(Over) Under recovery per dk	\$0.63630	(\$0.53230)	\$0.66680	
dk billed	5,434	10,811	1,352	17,597
(Over) Under recovery	<u>\$3,457</u>	<u>(\$5,755)</u>	<u>\$901</u>	<u>(\$1,396)</u>
<u>June 2011</u>				
Cost of Gas - Actual	\$11.86830	\$8.90090	\$11.86830	
Cost of Gas - Recovered	8.48110	8.26460	8.26460	
(Over) Under recovery per dk	\$3.38720	\$0.63630	\$3.60370	
dk billed	3,221	304	6,330	9,855
(Over) Under recovery	<u>\$10,909</u>	<u>\$194</u>	<u>\$22,812</u>	<u>\$33,915</u>
<u>July 2011</u>				
Cost of Gas - Actual	\$19.20930	\$11.86830	\$19.20930	
Cost of Gas - Recovered	8.66590	8.48110	8.48110	
(Over) Under recovery per dk	\$10.54340	\$3.38720	\$10.72820	
dk billed	2,551	131	3,883	6,565
(Over) Under recovery	<u>\$26,893</u>	<u>\$442</u>	<u>\$41,652</u>	<u>\$68,988</u>
<u>August 2011</u>				
Cost of Gas - Actual	\$21.46680	\$19.20930	\$21.46680	
Cost of Gas - Recovered	8.30870	8.66590	8.66590	
(Over) Under recovery per dk	\$13.15810	\$10.54340	\$12.80090	
dk billed	2,322	130	3,520	5,972
(Over) Under recovery	<u>\$30,557</u>	<u>\$1,374</u>	<u>\$45,064</u>	<u>\$76,995</u>
<u>September 2011</u>				
Cost of Gas - Actual	\$19.03070	\$21.46680	\$19.03070	
Cost of Gas - Recovered	8.18100	8.30870	8.30870	
(Over) Under recovery per dk	\$10.84970	\$13.15810	\$10.72200	
dk billed	2,615	2,652	1,344	6,611
(Over) Under recovery	<u>\$28,371</u>	<u>(\$17,639)</u>	<u>\$14,409</u>	<u>\$25,141</u>
<u>October 2011</u>				
Cost of Gas - Actual	\$9.88760	\$19.03070	\$9.88760	
Cost of Gas - Recovered	8.07830	8.18100	8.18100	
(Over) Under recovery per dk	\$1.80930	\$10.84970	\$1.70660	
dk billed	3,519	4,392	325	8,236
(Over) Under recovery	<u>\$6,367</u>	<u>\$47,651</u>	<u>\$555</u>	<u>\$54,573</u>

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
FIRM

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>November 2011</u>				
Cost of Gas - Actual	\$8.60180	\$9.88760	\$8.60180	
Cost of Gas - Recovered	<u>7.53880</u>	<u>8.07830</u>	<u>8.07830</u>	
(Over) Under recovery per dk	\$1.06300	\$1.80930	\$0.52350	
dk billed	<u>7,176</u>	<u>3,783</u>	<u>6,748</u>	17,707
(Over) Under recovery	<u>\$7,629</u>	<u>\$6,844</u>	<u>\$3,532</u>	<u>\$18,005</u>
<u>December 2011</u>				
Cost of Gas - Actual	\$7.23810	\$8.60180	\$7.23810	
Cost of Gas - Recovered	<u>7.13740</u>	<u>7.53880</u>	<u>7.53880</u>	
(Over) Under recovery per dk	\$0.10070	\$1.06300	(\$0.30070)	
dk billed	<u>11,010</u>	<u>12,281</u>	<u>6,610</u>	29,901
(Over) Under recovery	<u>\$1,109</u>	<u>\$13,055</u>	<u>(\$1,988)</u>	<u>\$12,176</u>
<u>January 2012</u>				
Cost of Gas - Actual	\$6.26430	\$7.23810	\$6.26430	
Cost of Gas - Recovered	<u>7.07790</u>	<u>7.13740</u>	<u>7.13740</u>	
(Over) Under recovery per dk	(\$0.81360)	\$0.10070	(\$0.87310)	
dk billed	<u>10,171</u>	<u>22,688</u>	<u>2,634</u>	35,493
(Over) Under recovery	<u>(\$8,275)</u>	<u>\$2,285</u>	<u>(\$2,300)</u>	<u>(\$8,290)</u>
<u>February 2012</u>				
Cost of Gas - Actual	\$5.91960	\$6.26430	\$5.91960	
Cost of Gas - Recovered	<u>6.65400</u>	<u>7.07790</u>	<u>7.07790</u>	
(Over) Under recovery per dk	(\$0.73440)	(\$0.81360)	(\$1.15830)	
dk billed	<u>13,100</u>	<u>20,137</u>	<u>6,478</u>	39,715
(Over) Under recovery	<u>(\$9,621)</u>	<u>(\$16,383)</u>	<u>(\$7,503)</u>	<u>(\$33,507)</u>
<u>March 2012</u>				
Cost of Gas - Actual	\$6.82340	\$5.91960	\$6.82340	
Cost of Gas - Recovered	<u>6.33830</u>	<u>6.65400</u>	<u>6.65400</u>	
(Over) Under recovery per dk	\$0.48510	(\$0.73440)	\$0.16940	
dk billed	<u>10,883</u>	<u>12,908</u>	<u>8,893</u>	32,684
(Over) Under recovery	<u>\$5,280</u>	<u>(\$9,480)</u>	<u>\$1,506</u>	<u>(\$2,694)</u>
<u>April 2012</u>				
Cost of Gas - Actual	\$6.65610	\$6.82340	\$6.65610	
Cost of Gas - Recovered	<u>5.91190</u>	<u>6.33830</u>	<u>6.33830</u>	
(Over) Under recovery per dk	\$0.74420	\$0.48510	\$0.31780	
dk billed	<u>5,546</u>	<u>11,649</u>	<u>(128)</u>	17,067
(Over) Under recovery	<u>\$4,127</u>	<u>\$5,651</u>	<u>(\$41)</u>	<u>\$9,737</u>

1/ Consumed in current month.

2/ Consumed in prior month.

3/ True-up of prior month volumes.

**GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE**

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>May 2011</u>				
Cost of Gas - Actual	\$3.15180	\$3.45160	\$3.15180	
Cost of Gas - Recovered	4.03830	4.03830	4.03830	
(Over) Under recovery per dk	<u>(\$0.88650)</u>	<u>(\$0.58670)</u>	<u>(\$0.88650)</u>	
dk billed	7,361	7,301	7,387	22,049
(Over) Under recovery	<u>(\$6,526)</u>	<u>(\$4,283)</u>	<u>(\$6,548)</u>	<u>(\$17,358)</u>
<u>June 2011</u>				
Cost of Gas - Actual	\$2.63650	\$3.15180	\$2.63650	
Cost of Gas - Recovered	4.19060	4.03830	4.03830	
(Over) Under recovery per dk	<u>(\$1.55410)</u>	<u>(\$0.88650)</u>	<u>(\$1.40180)</u>	
dk billed	2,683	292	5,036	8,011
(Over) Under recovery	<u>(\$4,170)</u>	<u>(\$259)</u>	<u>(\$7,060)</u>	<u>(\$11,488)</u>
<u>July 2011</u>				
Cost of Gas - Actual	\$3.78320	\$2.63650	\$3.78320	
Cost of Gas - Recovered	4.41390	4.19060	4.19060	
(Over) Under recovery per dk	<u>(\$0.63070)</u>	<u>(\$1.55410)</u>	<u>(\$0.40740)</u>	
dk billed	3,359	198	5,463	9,020
(Over) Under recovery	<u>(\$2,119)</u>	<u>(\$308)</u>	<u>(\$2,226)</u>	<u>(\$4,652)</u>
<u>August 2011</u>				
Cost of Gas - Actual	\$3.92170	\$3.78320	\$3.92170	
Cost of Gas - Recovered	4.08910	4.41390	4.41390	
(Over) Under recovery per dk	<u>(\$0.16740)</u>	<u>(\$0.63070)</u>	<u>(\$0.49220)</u>	
dk billed	2,743	249	6,685	9,677
(Over) Under recovery	<u>(\$459)</u>	<u>(\$157)</u>	<u>(\$3,290)</u>	<u>(\$3,906)</u>
<u>September 2011</u>				
Cost of Gas - Actual	\$3.85940	\$3.92170	\$3.85940	
Cost of Gas - Recovered	3.88610	4.08910	4.08910	
(Over) Under recovery per dk	<u>(\$0.02670)</u>	<u>(\$0.16740)</u>	<u>(\$0.22970)</u>	
dk billed	3,017	6,549	1,237	10,803
(Over) Under recovery	<u>(\$81)</u>	<u>(\$24,793) 4/</u>	<u>(\$284)</u>	<u>(\$25,158)</u>
<u>October 2011</u>				
Cost of Gas - Actual	\$3.50050	\$3.85940	\$3.50050	
Cost of Gas - Recovered	3.88600	3.88610	3.88610	
(Over) Under recovery per dk	<u>(\$0.38550)</u>	<u>(\$0.02670)</u>	<u>(\$0.38560)</u>	
dk billed	7,240	11,168	(5,163)	13,245
(Over) Under recovery	<u>(\$2,791)</u>	<u>(\$298)</u>	<u>\$1,991</u>	<u>(\$1,098)</u>

**GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE**

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>November 2011</u>				
Cost of Gas - Actual	\$3.44660	\$3.50050	\$3.44660	
Cost of Gas - Recovered	3.48000	3.88600	3.88600	
(Over) Under recovery per dk	<u>(\$0.03340)</u>	<u>(\$0.38550)</u>	<u>(\$0.43940)</u>	
dk billed	14,761	8,527	1,295	24,583
(Over) Under recovery	<u>(\$493)</u>	<u>(\$3,287)</u>	<u>(\$569)</u>	<u>(\$4,349)</u>
<u>December 2011</u>				
Cost of Gas - Actual	\$3.52290	\$3.44660	\$3.52290	
Cost of Gas - Recovered	3.13080	3.48000	3.48000	
(Over) Under recovery per dk	<u>\$0.39210</u>	<u>(\$0.03340)</u>	<u>\$0.04290</u>	
dk billed	18,416	14,757	1,135	34,308
(Over) Under recovery	<u>\$7,221</u>	<u>(\$493)</u>	<u>\$49</u>	<u>\$6,777</u>
<u>January 2012</u>				
Cost of Gas - Actual	\$3.20120	\$3.52290	\$3.20120	
Cost of Gas - Recovered	3.12470	3.13080	3.13080	
(Over) Under recovery per dk	<u>\$0.07650</u>	<u>\$0.39210</u>	<u>\$0.07040</u>	
dk billed	12,604	22,920	(2,316)	33,208
(Over) Under recovery	<u>\$964</u>	<u>\$8,987</u>	<u>(\$163)</u>	<u>\$9,788</u>
<u>February 2012</u>				
Cost of Gas - Actual	\$2.61860	\$3.20120	\$2.61860	
Cost of Gas - Recovered	2.69350	3.12470	3.12470	
(Over) Under recovery per dk	<u>(\$0.07490)</u>	<u>\$0.07650</u>	<u>(\$0.50610)</u>	
dk billed	7,414	14,191	1,794	23,399
(Over) Under recovery	<u>(\$555)</u>	<u>\$1,086</u>	<u>(\$908)</u>	<u>(\$376)</u>
<u>March 2012</u>				
Cost of Gas - Actual	\$2.04680	\$2.61860	\$2.04680	
Cost of Gas - Recovered	2.49010	2.69350	2.69350	
(Over) Under recovery per dk	<u>(\$0.44330)</u>	<u>(\$0.07490)</u>	<u>(\$0.64670)</u>	
dk billed	12,196	13,298	903	26,397
(Over) Under recovery	<u>(\$5,407)</u>	<u>(\$996)</u>	<u>(\$584)</u>	<u>(\$6,986)</u>
<u>April 2012</u>				
Cost of Gas - Actual	\$1.95470	\$2.04680	\$1.95470	
Cost of Gas - Recovered	2.01220	2.49010	2.49010	
(Over) Under recovery per dk	<u>(\$0.05750)</u>	<u>(\$0.44330)</u>	<u>(\$0.53540)</u>	
dk billed	13,712	11,385	7,638	32,735
(Over) Under recovery	<u>(\$788)</u>	<u>(\$5,047)</u>	<u>(\$4,089)</u>	<u>(\$9,925)</u>

1/ Consumed in current month.

2/ Consumed in prior month.

3/ True-up of prior month volumes.

4/ Includes annual unbilled adjustment of \$24,708.