

November 30, 2011

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

Re: Cost of Gas Adjustment (COG)
December 2011

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 (69th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (69th Revised Sheet No. 8), showing the December 2011 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.4014 per mcf for residential and firm general service customers and a decrease of \$0.3492 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for December 2011, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.3492 since the last COG filing. There has been a decrease in pipeline charges of \$0.0522 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of \$0.4014 per mcf for residential and firm general service customers.

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

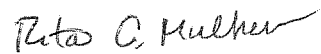
Attachment D shows the calculation of the balancing account since April 30, 2011.

Great Plains submitted a check for \$600.00 on January 10, 2011 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
69th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 68th 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	\$7.6476	\$8.9216 8.7016
Firm Gas Service - General Highway 13	2.5	\$3.50 per month	First 10 MCF \$2.1740 Over 10 MCF 1.9540	\$7.6476	\$9.8216 9.6016
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	\$3.1130	\$4.2521 4.0061 3.8541
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	\$3.1130	\$5.1521 4.9061 4.7541
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$3.1130	\$4.3521
Transportation Service	5	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411		\$1.1391 0.8931 0.7411

Date Filed: November 30, 2011

Effective Date: December 1, 2011

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
69th Revised Sheet No. 8
Canceling 68th 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.	4.0075	(1.6536)	0.5102	2.8641	(1.6391)	(0.0178)	(1.6569)
Current Adj.	(0.0522)	(0.3492)	0.0000	(0.4014)	(0.3492)	0.0000	(0.3492)
Total Adj.	3.9553	(2.0028)	0.5102	2.4627	(1.9883)	(0.0178)	(2.0061)
Total Rate:	\$4.0211	\$3.1163	\$0.5102	\$7.6476	\$3.1308	(\$0.0178)	\$3.1130

Date Filed: November 30, 2011

Effective Date: December 1, 2011

Issued By: Tamie A. Aberle
Regulatory Affairs Manager

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
DECEMBER 2011**

Firm	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
FT-A	7,841	\$3.4671	12	\$326,226	\$0.2325
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	0.0736
FT-A Seasonal	2,000	3.7671	5	37,671	0.0268
TFX Seasonal	2,000	15.1530	5	151,530	0.1080
NOVA - Demand Charge	7,947	16.7914	12	1,601,295	1.1413
Trans Canada - Demand Charge	7,947	22.9850	12	2,191,942	1.5622
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0653
NOVA - Seasonal	5,068	16.7914	5	425,494	0.3033
Trans Canada - Seasonal	5,068	22.9850	5	582,440	0.4151
BP Canada - Seasonal	5,068	0.9612	5	24,357	0.0174
BP Canada Winter Surcharge	5,068	3.0417	5	77,077	0.0549
LMS Demand 2/				0.0145	0.0145
Total Demand Charges				\$5,621,574	4.0211
Estimated Weighted Average Commodity Cost	1,403,100	1/ 3.1163		4,372,481	3.1163
Gas Cost Reconciliation Adjustment					0.5102
Total Current Firm Gas Cost				\$9,994,055	7.6476
Base Cost of Gas					5.1849
Accumulated Adjustment					\$2.4627
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$3.1163
Gas Cost Reconciliation Adjustment					(0.0178)
LMS Demand 2/					0.0145
Total Current Interruptible Gas Cost					3.1130
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$2.0061)

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.

	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
LMS Demand	2,500	\$1.0000	12	\$30,000	\$0.0145

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
DECEMBER 2011**

Rates Effective December 1, 2011	<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	16.7914	Per dk/Mo.
Trans Canada Pipeline Demand Charge	22.9850	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	16.7914	Per dk/Day
Trans Canada - Seasonal	22.9850	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:	3.1163	Per dk

Base Rate Effective September 1, 1981

Demand Charge	\$0.8100	Per Mcf/Mo.
Commodity Charge	5.1191	Per Mcf

Base Rate Calculation

Firm

Demand 1/	\$0.0658	Per Mcf
Commodity	5.1191	Per Mcf
Total Firm Base Cost	<u>\$5.1849</u>	Per Mcf

Interruptible:

Commodity	\$5.1191	Per Mcf
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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	1.66%
Zone 1-2	\$0.0130	\$0.0018	\$0.0148	1.91%
Zone 2-2	\$0.0130	\$0.0018	\$0.0148	0.25%
Minimum Rate	\$0.0130	\$0.0018	\$0.0148	
IT and AOT				
Zone 1-1	\$0.1368	\$0.0018	\$0.1386	1.66%
Zone 1-2	\$0.1737	\$0.0018	\$0.1755	1.91%
Zone 2-2	\$0.0834	\$0.0018	\$0.0852	0.25%
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: 0.08% for Zone 1-1, 0.09 % for Zone 1-2, and 0.01% 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		\$0.0265	

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 Commodity Rate Per Dekatherm, Per Day	Minimum Commodity Rate Per Dekatherm, Per Day
PAL	\$0.1737	\$0.0000

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

Third Revised Sheet No. 50
Superseding
Second Revised Sheet No. 50

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/ 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	0.0382	0.0213			0.0175	0.0000	0.0382	0.0213
Field	Market	0.0382	0.0213	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 \$0.0005 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	0.0382	0.0213			0.0175	0.0000	0.0382	0.0213
Field	Market	0.0382	0.0213	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 \$0.0005 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.

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

Third Revised Sheet No. 54
Superseding
Second Revised Sheet No. 54

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

Fuel Percentages/Electric Compression Rates

	Percentages -----
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	1.12%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.20% 4/ 5/
FDD Storage Fuel	1.21%
	Electric Compression -----
COMMODITY RATES:	1/
Market Area	\$0.0005
Field Area	\$0.0000

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

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

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

4/ The Unaccounted For percentage utilizes the most recent twelve-month period ending December 31, 2010.

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

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

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

RATE SCHEDULES FDD, PDD, IDD & SMS

Rate Schedule FDD

Maximum Reservation Fee	1.7140	1/	
Maximum Capacity Fee	0.3567	1/	
Injection Charge - Firm	0.0149		
Withdrawal Charge - Firm	0.0149		
Annual Rollover Fee	0.3567	1/	

Rate Schedule PDD

Maximum Capacity Fee	0.3567	1/	
Maximum Monthly Inventory Charge	0.0887	1/	
Injection Charge	0.0149		
Withdrawal Charge	0.0149		
Annual Rollover Fee	0.3567	1/	

Rate Schedule IDD

Maximum Monthly Inventory Charge	0.0887	1/	
Injection Charge	0.0149		
Withdrawal Charge	0.0149		
Annual Rollover Fee	0.3567	1/	

Rate Schedule SMS

Reservation Fee	2.1800		
Commodity Rate	0.0208		

1/ Minimum Rate is zero.

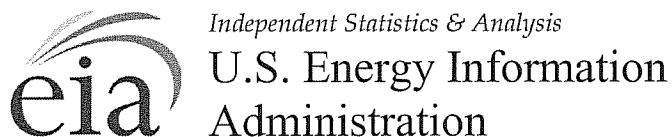
**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
December 2011**

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 December monthly price for the AECO Index is expected to decrease 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).

The continuation of mild fall weather, record levels of natural gas in storage and strong domestic supply likely contributed to the decline in the index price. The Energy Information Administration (EIA) reported storage levels nationwide as of November 18, 2011 were 6.4 percent above the five-year average and 0.6 percent above last year's record 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 14.



November 2011

Short-Term Energy Outlook

November 8, 2011 Release

Highlights

- EIA expects the U.S. average refiner acquisition cost of crude oil to remain relatively flat, averaging about \$100 per barrel in 2011 and 2012. The value of West Texas Intermediate (WTI) benchmark crude oil was about \$11 per barrel below the U.S. refiner acquisition cost of crude oil in the third quarter of this year. The forecast WTI price discount narrows to \$8 per barrel by the fourth quarter of 2012, as rail and truck capacity is added to the region.
- EIA's U.S. and world economic growth assumptions have been lowered from last month's *Outlook*. World oil-consumption-weighted real GDP grows by 3.1 percent in 2012, compared with 3.5 percent in the previous *Outlook*.
- EIA projects that average household heating expenditures for heating oil and propane will increase by 10 percent and 9 percent, respectively, this winter (October 1 to March 31) compared with last winter. Average expenditures for households that heat with oil or propane are forecast to be higher than in any previous winter. In contrast, natural gas and electricity expenditures are projected to remain close to last year's levels.
- Regular-grade gasoline retail prices have fallen by 46 cents per gallon from their peak monthly average this year of \$3.91 per gallon for May to \$3.45 per gallon for October. This drop in prices results from falling crude oil prices as well as the normal seasonal decline in consumption and the switch in production from summer-grade gasoline to lower-cost winter-grade gasoline. EIA projects gasoline retail prices to continue to decline, albeit slightly, through the end of the year.
- Natural gas working inventories ended October 2011 at an estimated 3.8 trillion cubic feet (Tcf), about 1 percent below the same time last year. The projected Henry Hub natural gas spot price averages \$4.09 per million British thermal units (MMBtu) in 2011, \$0.30 per MMBtu lower than the 2010 average, and \$4.13 per MMBtu in 2012.

Global Crude Oil and Liquid Fuels

Errata

There were two errors in the 3rd quarter 2011 international balance that affected STEO Tables 3a and 3b and Figures 8 and 12 that were originally published. Non-OPEC Central & S. America crude oil and liquid fuels production was overstated by an average 1.5 million barrels per day during July and August 2011. OECD commercial stocks were overstated by 24 million barrels in August 2011 and all subsequent months through the end of the forecast. These errors were corrected and new text, tables, and charts were made available on the STEO website on November 8, 2011, at 4:00 pm

Crude Oil and Liquid Fuels Overview. Oil prices continue to face upward price pressure because of supply uncertainty resulting from ongoing unrest in the oil-producing regions of the Middle East and North Africa. However, there may be downward price pressure if Libya is able to ramp up oil production and exports sooner than anticipated. At the same time, downside demand risks continue as fears persist about weakening global economic growth, contagion effects of the debt crisis in the European Union, and other fiscal issues facing national governments.

Given expected rates of global oil consumption growth, the engine for which will be emerging markets outside of the Organization for Economic Cooperation and Development (OECD), a combination of increased oil output from members of the Organization of the Petroleum Exporting Countries (OPEC) and inventory withdrawals will need to supplement non-OPEC supply growth in order for the oil market to balance at the prices projected in this Outlook.

Global Crude Oil and Liquid Fuels Consumption. EIA expects that world crude oil and liquid fuels consumption will grow from its record-high level of 87.1 million barrels per day (bbl/d) in 2010 to 88.2 million bbl/d in 2011 and 89.6 million bbl/d in 2012 (World Liquid Fuels Consumption Chart). China and other emerging economies account for all of the projected crude oil and liquid fuels consumption growth through 2012. Consumption in member countries of the OECD is projected to decline by 0.4 million bbl/d in 2011 and to remain relatively flat in 2012.

Non-OPEC Supply. EIA projects that non-OPEC liquid fuels production will grow by 0.4 million bbl/d in 2011 and 1.1 million bbl/d in 2012, to an average of 53.3 million bbl/d next year (Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart). The largest sources of expected growth in non-OPEC oil production over the forecast period are Canada, China, Colombia, Kazakhstan, and the United States, with average annual growth in each country of over 100 thousand bbl/d. In contrast, forecast Russian and Mexican projected production is lower at the end of the forecast period.

Regional turmoil, particularly in Syria and Yemen, exerts additional pressure on the non-OPEC outlook and on global oil prices.

EIA revised Brazil's liquids fuels production forecast downward for both 2011 and 2012 by 140 thousand bbl/d and 90 thousand bbl/d, respectively. The revisions are due to the decrease in projected ethanol production resulting from a poor sugar cane harvest and reduced investment. However, EIA expects that Brazil's crude oil production will continue to increase through the forecast period.

OPEC Supply. While forecast OPEC non-crude liquids production, which is not subject to production targets, is expected to increase by 0.4 million bbl/d in 2011 and by 0.5 million bbl/d in 2012, EIA expects OPEC crude oil production to remain flat in both 2011 and in 2012, after having grown by 0.7 million bbl/d in 2010. Libyan oil exports resumed at the end of September, averaging about 0.2 million bbl/d. EIA expects Libyan crude oil exports to rise to 0.35 million bbl/d during the first quarter of 2012 and to 0.8 million bbl/d by the end of 2012, compared with pre-disruption exports of 1.5 million bbl/d. OPEC surplus crude oil production capacity falls from 3.5 million bbl/d in the fourth quarter of 2010 to a projected 3.0 million bbl/d in the fourth quarter of 2011, but then increases to 4.0 million bbl/d in the fourth quarter of 2012, as Libyan production capacity comes back on line, freeing up capacity in other OPEC countries (OPEC Surplus Crude Oil Production Capacity Chart).

OECD Petroleum Inventories. EIA expects that OECD commercial inventories will decline in both 2011 and 2012. However, because of declining consumption, days of supply (total inventories divided by average daily consumption) falls slightly, from 57.7 days to 57.4 days between the fourth quarters of 2011 and 2012 (Days of Supply of OECD Commercial Stocks Chart).

Crude Oil Prices. West Texas Intermediate (WTI) crude oil spot prices fell from an average of \$110 per barrel in April to \$86 per barrel in August, and remained near this level through October (West Texas Intermediate Crude Oil Price Chart). EIA has revised the projected oil price paths slightly upward from last month's *Outlook*. EIA expects that the U.S. refiner average crude oil acquisition cost will average \$100 per barrel in 2011 and 2012, slightly higher than the projections of \$99 per barrel and \$98 per barrel for 2011 and 2012, respectively, in the previous *Outlook*.

For most of the last 30 years, WTI has traded at a premium over the average U.S. refiner acquisition cost of crude oil. However, the growth in crude oil supply, particularly from Canada and North Dakota, to the midcontinent region where WTI is traded, has not yet been matched by increases in transportation capacity out of the Midwest to the refining centers, such as the Gulf Coast. This transportation bottleneck contributes to the large price discount for WTI relative to other U.S. and

world crude oils. After reaching a record price discount in the third quarter of this year, the discount for WTI is now expected to diminish modestly as the flow of crude oil out of the mid-continent region increases. Consequently, the projected U.S. refiner acquisition cost of crude oil, which averaged \$11 per barrel above WTI in the third quarter of this year, narrows to \$8 per barrel above WTI by the fourth quarter of 2012, as rail and truck capacity is added.

Energy price forecasts are highly uncertain (Market Prices and Uncertainty Report). WTI futures for January 2012 delivery during the 5-day period ending November 3 averaged \$93 per barrel. Implied volatility averaged 39 percent, establishing the lower and upper limits of a 95-percent confidence interval for the market's expectations of monthly average WTI prices in January of \$72 per barrel and \$121 per barrel, respectively. Last year at this time, WTI for January 2011 delivery averaged \$85 per barrel and implied volatility averaged 31 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$69 per barrel and \$103 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Projected total U.S. liquid fuels consumption in 2011 falls by 250 thousand bbl/d (1.3 percent) (U.S. Liquid Fuels Consumption Chart). Motor gasoline consumption accounts for most of the projected decline for the year, shrinking by 220 thousand bbl/d (2.4 percent). EIA expects total liquid fuels consumption to increase by 110 thousand bbl/d (0.6 percent) to 19.0 million bbl/d in 2012. Projected motor gasoline and distillate consumption rise by 40 thousand bbl/d (0.5 percent) and 30 thousand bbl/d (0.7 percent) in 2012, respectively, as highway travel and the U.S. economy show modest growth.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by 110 thousand bbl/d in 2010 to 5.5 million bbl/d. Production increases by a further 210 thousand bbl/d in 2011, and by 240 thousand bbl/d in 2012 (U.S. Crude Oil and Liquid Fuels Production Chart). This rising trend in production is driven by increased oil-directed drilling activity, particularly in on-shore shale formations.

Liquid fuel net imports (including both crude oil and refined products) fell from 57 percent of total U.S. consumption in 2008 to 49 percent in 2010 because of rising domestic production and the decline in consumption during the economic downturn. EIA forecasts that liquid fuel net imports' share of total consumption will decline to 45 percent in 2011.

U.S. Crude Oil and Petroleum Product Inventories. Distillate fuel oil stocks ended October 2011 at an estimated 143 million barrels, down 19 million barrels from the

same time last year and 5 million barrels below the average for that month between 2006 and 2010 (see *This Week In Petroleum*, Nov. 2, 2011). Total motor gasoline stocks at the end of October 2011 were an estimated 209 million barrels, down 1 million barrels from last year but 5 million barrels higher than the previous 5-year average for that month. Projected total distillate and motor gasoline inventories at the end of 2012 will average about 3 million barrels and 4 million barrels higher, respectively, than their previous 5-year averages (U.S. Gasoline and Distillate Inventories Chart).

Commercial crude oil inventory levels ended October 2011 at an estimated 340 million barrels, 28 million barrels below last year but 8 million barrels higher than the previous 5-year average for that month. Projected commercial crude oil stocks are gradually drawn down to 317 million barrels by the end of 2012, close to their 5-year average (U.S. Crude Oil Stocks Chart).

U.S. Petroleum Product Prices. EIA forecasts that the annual average regular-grade gasoline retail price, which averaged \$2.78 per gallon in 2010, will increase to an average of \$3.54 per gallon in 2011, before declining to an average \$3.46 per gallon in 2012 (U.S. Gasoline and Crude Oil Prices Chart). The higher retail prices in 2011 reflect not only the higher cost of crude oil but also changes in the average U.S. refinery gasoline margin (the difference between refinery wholesale gasoline prices and the average cost of crude oil). The average U.S. refinery gasoline margin increases from \$0.34 per gallon in 2010 to \$0.48 per gallon in 2011, then declines to \$0.42 per gallon in 2012. The forecast narrowing of the WTI crude oil price discount to other crude oils should lower average refining margins next year.

EIA expects that on-highway diesel fuel retail prices, which averaged \$2.99 per gallon in 2010, will average \$3.84 per gallon in 2011 and \$3.79 per gallon in 2012 (U.S. Diesel Fuel and Crude Oil Prices Chart).

Natural Gas

U.S. Natural Gas Consumption. EIA expects that total natural gas consumption will grow by 1.7 percent to 67.1 billion cubic feet per day (Bcf/d) in 2011 (U.S. Total Natural Gas Consumption Chart). Rising use of natural gas in the industrial and electric power sectors accounts for most of the increase in total consumption this year, with projected growth rates of 2.0 percent and 1.5 percent, respectively. Projected total natural gas consumption increases by 1.1 percent in 2012 to 67.9 Bcf/d, compared with a projected level of 67.7 Bcf/d in last month's *Outlook*. Higher projections of residential and commercial consumption account for much of this change in the forecast, driven by the 1.1 percent increase in heating degree-days from 2011 to 2012.

U.S. Natural Gas Production and Imports. EIA expects U.S. marketed natural gas production to average 65.6 Bcf/d in 2011, a 3.8-Bcf/d (6.1 percent) increase over 2010. All of this growth comes from higher onshore production in the lower 48 States, which more than offsets a year-over-year decline of 1.0 Bcf/d (17 percent) in the Federal Gulf of Mexico (GOM). EIA expects that total marketed production will continue to grow in 2012, but at a slower pace, increasing 1.3 Bcf/d (2.0 percent) to an average of 66.9 Bcf/d (U.S. Total Natural Gas Production and Imports Chart).

Drilling activity has been resilient despite lower natural gas spot and futures prices. According to Baker Hughes, the October 28 rig count was 934 active drilling rigs targeting natural gas, higher than this year's low of 866 on May 20 and higher than last month. If drilling continues to increase, production could grow more than expected in 2012.

Growing domestic natural gas production has reduced reliance on natural gas imports and contributed to increased exports. EIA expects that pipeline gross imports of natural gas will fall by 6.7 percent to 8.5 Bcf/d during 2011 and by another 1.4 percent to 8.3 Bcf/d in 2012. Projected U.S. imports of liquefied natural gas (LNG) will fall from 1.2 Bcf/d in 2010 to 0.9 Bcf/d in 2011 and to 0.7 Bcf/d in 2012. Pipeline gross exports to Mexico and Canada are expected to average 4.1 Bcf/d in 2011 and 4.2 Bcf/d in 2012, compared with 3.1 Bcf/d in 2010.

U.S. Natural Gas Inventories. Working natural gas in storage ended October at an estimated 3.8 Tcf (U.S. Working Natural Gas in Storage Chart). EIA expects that working natural gas inventories will total about 1.8 Tcf at the end of March 2012, the end of the winter heating season. This would represent a withdrawal of 2.0 Tcf over the upcoming heating season, compared with a withdrawal of 2.3 Tcf last season.

U.S. Natural Gas Prices. The Henry Hub spot price averaged \$3.56 per MMBtu in October 2011, 34 cents lower than the September 2011 average and 49 cents lower than the August 2011 average (Henry Hub Natural Gas Price Chart). This month's *Outlook* lowers the 2011 forecast by 6 cents to \$4.09 per MMBtu and lowers the 2012 forecast by 19 cents to \$4.13 per MMBtu compared with last month's *Outlook*.

Natural gas futures prices for January 2012 delivery (for the 5-day period ending November 3, 2011) averaged \$3.96 per MMBtu, and the average implied volatility was 35 percent ([Market Prices and Uncertainty Report](#)). The lower and upper bounds for the 95-percent confidence interval for January 2012 contracts are \$3.06 per MMBtu and \$5.13 per MMBtu. At this time last year, the January 2011 natural gas futures contract averaged \$4.13 per MMBtu and implied volatility averaged 41 percent. The

corresponding lower and upper limits of the 95-percent confidence interval were \$3.06 per MMBtu and \$5.59 per MMBtu.

Coal

U.S. Coal Consumption. EIA expects that coal consumption for electricity generation will decline by 16 million short tons (MMst) (1.6 percent) in 2011, as the modest growth in total electricity generation is more than satisfied by increases in generation from natural gas, hydropower, and renewables other than hydropower. Projected increases in generation from natural gas, nuclear and non-hydro renewables, combined with lower electricity consumption, contribute to an additional 4.6 percent decline in electric power sector coal consumption in 2012.

U.S. Coal Supply. EIA forecasts that coal production will fall slightly (by 0.2 percent) in 2011 despite a significant increase in coal exports (U.S. Annual Coal Production Chart). Coal production in the Western region is projected to decline, while production in the Appalachian and Interior regions increases slightly. EIA expects coal production to decline by 3.6 percent in 2012 as domestic consumption and exports fall and inventories at electric power plants decline (U.S. Electric Power Sector Coal Stocks Chart).

U.S. Coal Trade. U.S. coal exports rose to 54 MMst during the first half of 2011, the highest since 1982, representing about a 35 percent increase during the first half of 2011 compared with the same period in 2010. EIA expects U.S. coal exports to remain elevated over the second half of 2011, reaching an annual total of 102 MMst. Forecast U.S. coal exports fall back to 91 MMst in 2012, as supply from other major coal-exporting countries recovers from disruptions.

U.S. Coal Prices. Average delivered coal prices to the electric power sector have increased steadily over the last 10 years by an average of 6.7 percent each year. EIA expects that this trend will continue in 2011, largely because of a rise in transportation costs. The projected average delivered coal price to the electric power sector, which was \$2.26 per MMBtu in 2010, rises to \$2.41 per MMBtu in 2011 and \$2.44 per MMBtu in 2012.

Electricity

U.S. Electricity Consumption. Total U.S. consumption of electricity across all sectors is forecast to fall by 0.6 percent during 2012 after having grown by an estimated 0.3 percent this year (U.S. Total Electricity Consumption Chart). Despite the recent cold snap and snowstorm in the Northeast, NOAA expects overall temperatures this

winter to be milder than last year. In the South Atlantic region, where a majority of households heat with electricity, heating degree-days between October 2011 and March 2012 are expected to be 5.9 percent lower than in the same period last year. This implies a drop of 2.6 percent in winter electricity sales to the residential sector in the South Atlantic.

U.S. Electricity Generation. EIA projects total U.S. generation by the electric power sector will average 10.9 terawatt hours per day during 2011. Coal is expected to fuel about 44.9 percent of this generation, down from a 46.1 percent share last year. During 2012, EIA expects coal to supply about 43.5 percent of total generation. In contrast, the share of generation fueled by natural gas is forecast to rise, growing from 22.6 percent in 2010 to 22.8 percent in 2011, and 23.7 percent in 2012 (U.S. Electric Power Sector Generation Chart).

U.S. Electricity Retail Prices. The cost of coal delivered to electric generators is expected to increase by 6.4 percent during 2011, while the delivered cost of natural gas continues to decline. The net effect will be relatively modest growth in retail electricity prices over the forecast horizon. EIA expects average U.S. residential electricity prices to increase by 1.7 percent in 2011 and by 1.2 percent in 2012 (U.S. Residential Electricity Prices Chart).

Renewables and Carbon Dioxide Emissions

U.S. Renewables. Led by a 23-percent increase in conventional hydropower, the total supply of renewables is projected to grow by about 12 percent from 2010 to 2011. EIA expects total renewable energy supply to decline by 1.1 percent in 2012 as a 12-percent decline in hydropower offsets growth in other renewable energy supplies.

U.S. hydropower generation during 2011 is expected to reach the highest level since 1999, primarily because of high levels of precipitation in regions such as the Pacific Northwest. EIA assumes a return to normal snow and rainfall levels in 2012, with hydropower generation falling by 0.36 quadrillion Btu (12 percent).

Wood and wood waste is second only to hydropower in terms of the total energy supplied by renewable sources. Because much of the wood supply is subject to industrial market conditions, especially in the pulp and paper industry, a decline of 2.4 percent is projected between 2010 and 2011 as output from the paper industry is projected to decline more than 1 percent. Wood supply growth picks up in 2012 to a projected rate of 1.8 percent.

Wind energy is estimated to have grown by 23 percent from 2010 to 2011. Growth in wind energy in 2012 is projected to slow to 15 percent as the expiration of the production tax credit nears. The solar energy supply is projected to grow by 4.5 percent and 4.9 percent in 2011 and 2012, respectively, reaching a total of 0.12 quadrillion Btu.

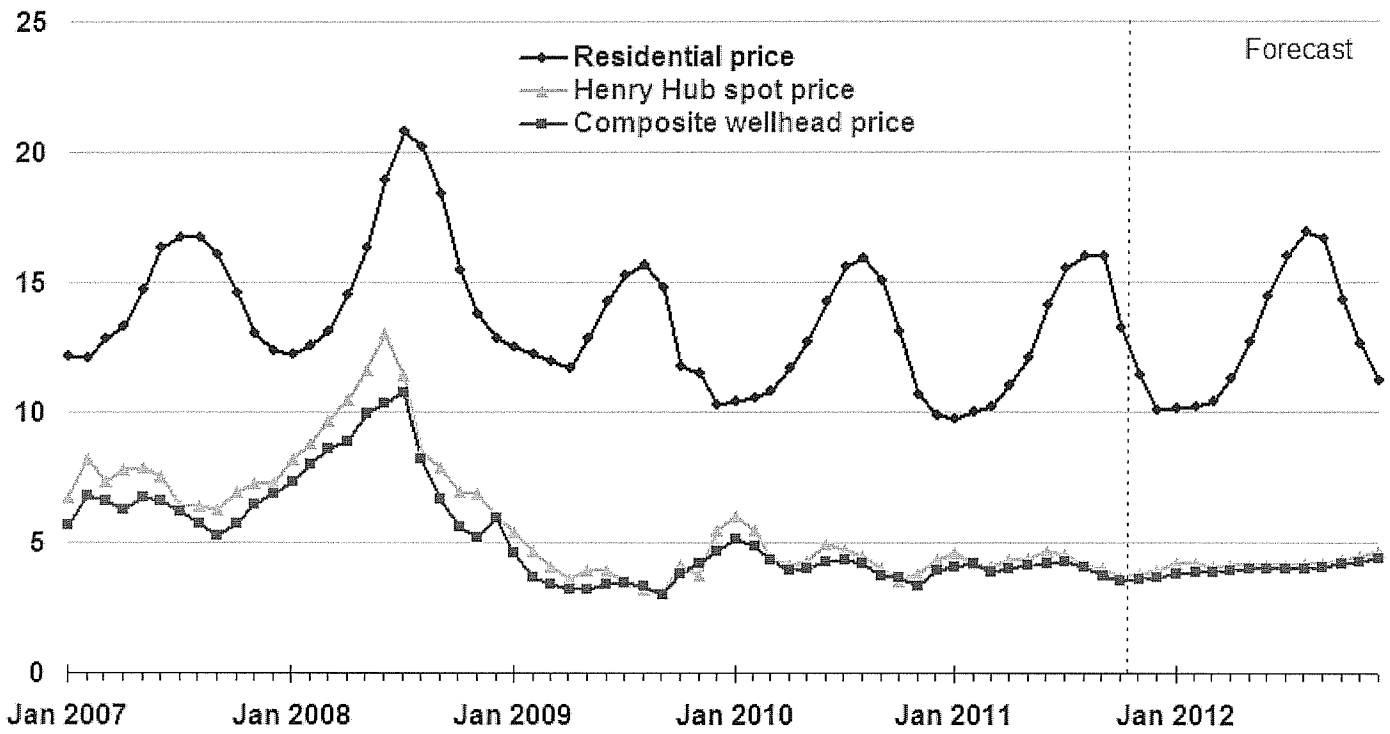
In terms of liquid renewable fuels, EIA estimates that biodiesel production in 2011 averaged about 56 thousand bbl/d (860 million gallons total annual production). This volume surpasses the 2011 Renewable Fuel Standard (RFS) Biomass-Based Diesel mandate of 800 million gallons. RFS credits generated above the current mandate can be banked and used for compliance in the following year for up to 20 percent of the requirement. The \$1 per gallon biodiesel tax credit expires at the end of 2011. In 2012, biodiesel production is forecast to grow slightly higher to 61 thousand bbl/d (940 million gallons), just reaching the proposed 2012 RFS mandate of 1.0 billion gallons after accounting for 60 million gallons of 2011 credits.

Ethanol production growth, which averaged 120 thousand bbl/d annually between 2005 and 2010, is expected to slow to 30 thousand bbl/d in 2011 and 20 thousand bbl/d in 2012, reaching an average of 920 thousand bbl/d in 2012. Ethanol exports reduce the volume of ethanol blended into gasoline. Assuming ethanol net exports average about 40 thousand bbl/d next year, EIA expects that 880 thousand bbl/d of ethanol will be blended into gasoline in 2012. The expiration of the Federal motor fuels excise tax credit for ethanol blending is expected to have little effect on blending levels, as ethanol producers do not currently appear to be capturing much of the value of the credit.

U.S. CO₂ Emissions. EIA estimates that CO₂ emissions from fossil fuels increased by 3.9 percent in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). Forecast fossil-fuel CO₂ emissions fall by 0.6 percent in 2011, as increasing emissions from higher natural gas consumption are offset by declines in coal and petroleum consumption. Increases in hydroelectric generation and other renewable energy sources in 2011 also help to mitigate emissions growth. Fossil-fuel CO₂ emissions in 2012 are expected to decline by about 1 percent as emissions from coal decline by 4.1 percent. That decline more than offsets expected increases in emissions from petroleum (0.4 percent) and natural gas (1.3 percent).

U.S. Natural Gas Prices

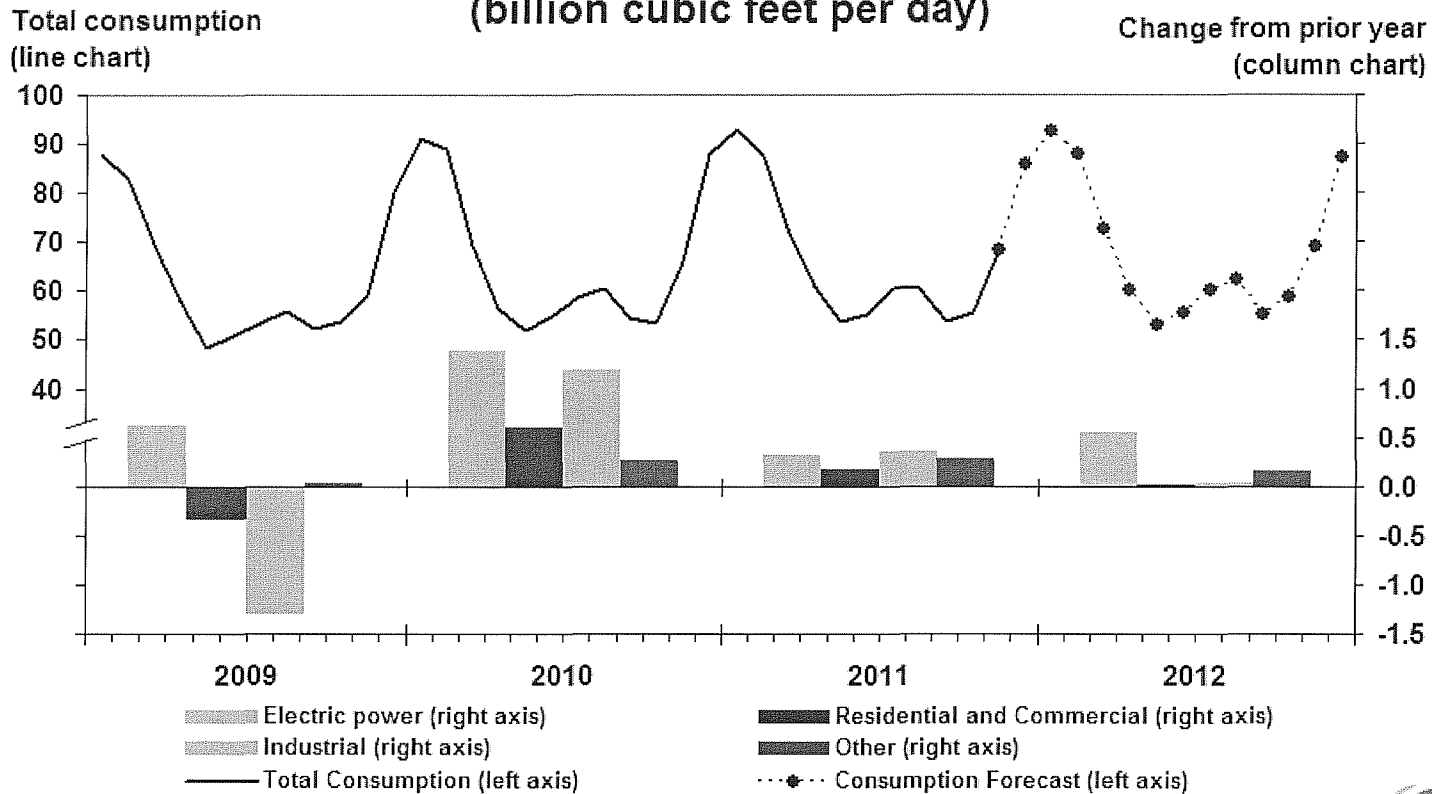
dollars per thousand cubic feet



Source: Short-Term Energy Outlook, November 2011



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



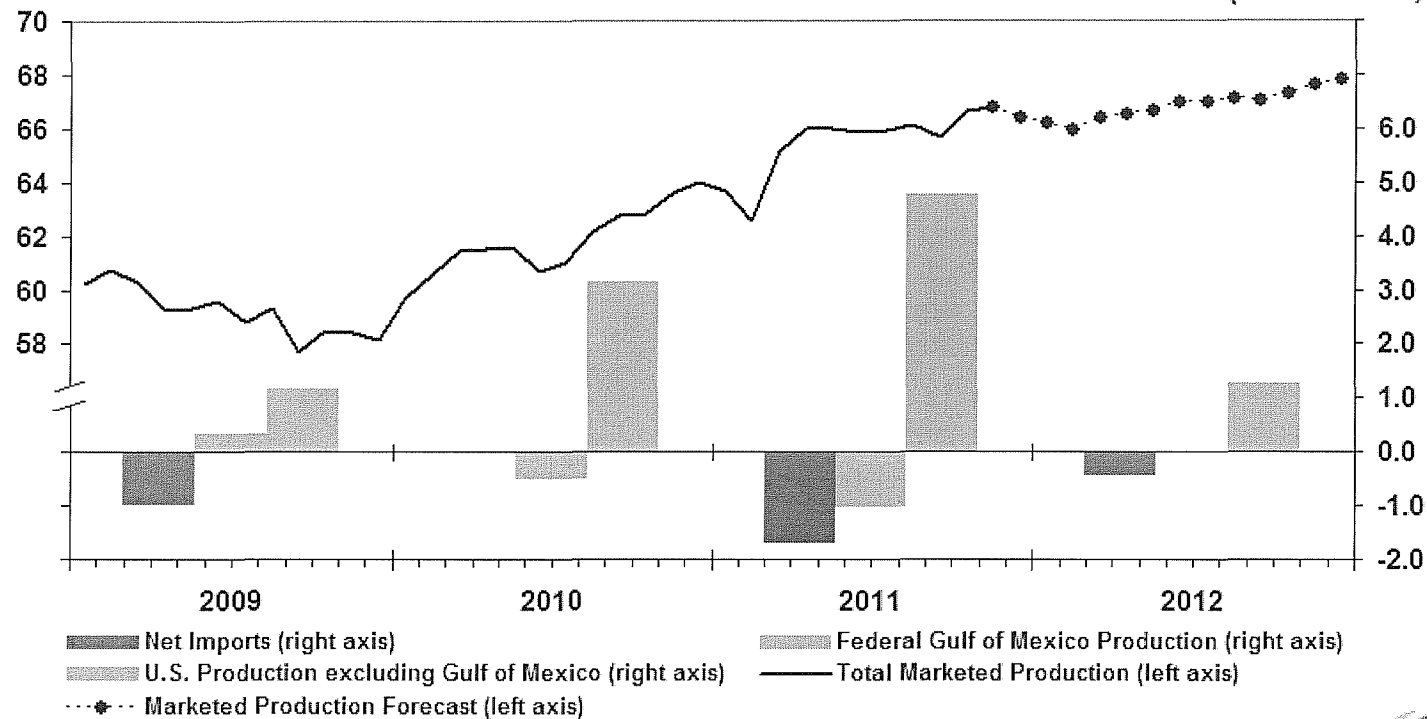
Source: Short-Term Energy Outlook, November 2011



U.S. Natural Gas Production and Imports (billion cubic feet per day)

Total marketed production
(line chart)

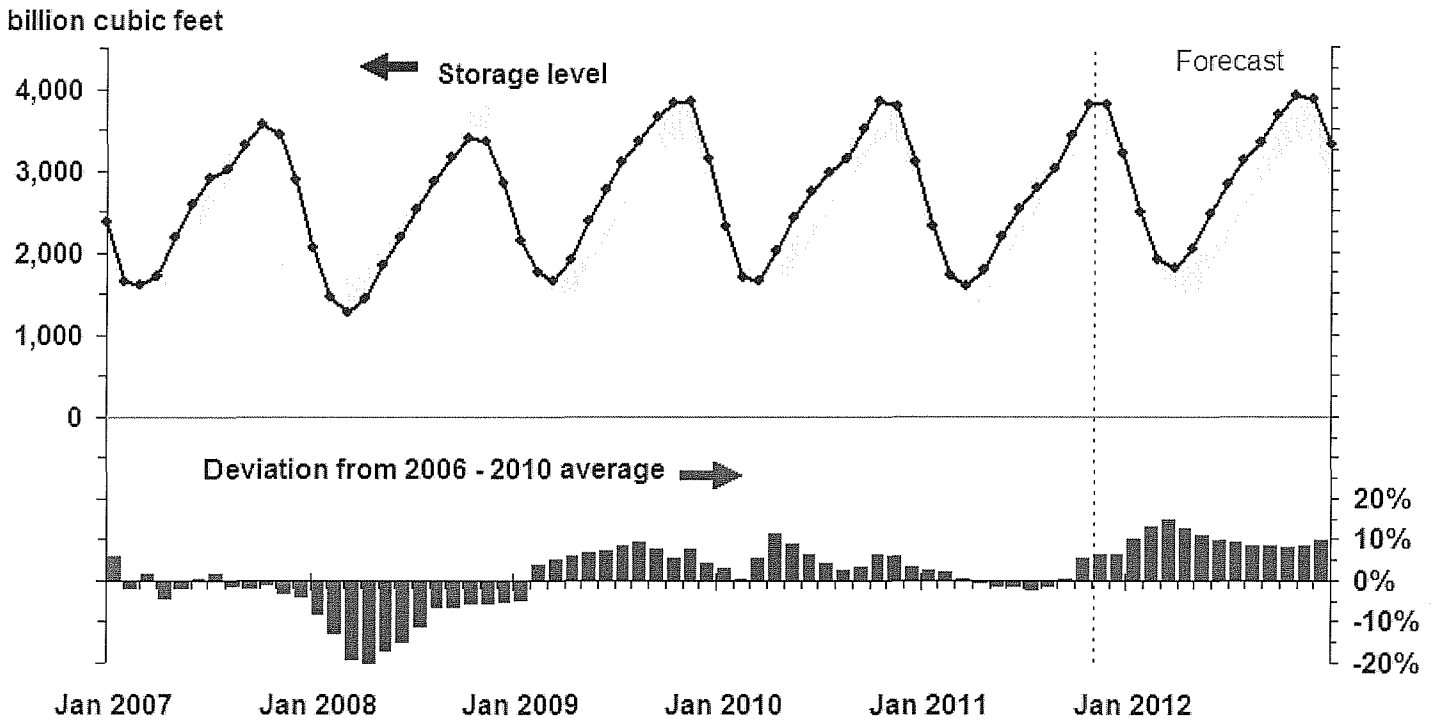
Change from prior year
(column chart)



Source: Short-Term Energy Outlook, November 2011



U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2006 - Dec. 2010.

Source: Short-Term Energy Outlook, November 2011



**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, 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 2/	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	1,530	78,525	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	54,572	0	2,227	56,799	8,236	0.5102	4,202	52,597	389,845
Balance @ October 31, 2011									<u>\$389,845</u>

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

2/ Reflects 6,634.4 dk @ \$0.3941 and 3,220.6 dk @ \$0.5102.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
Balance @ April 30, 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) 2/	(11,043)	(31,913)
July	(4,652)	0	(288)	(4,940)	9,020	(0.0178)	(161)	(4,779)	(36,692)
August	(3,906)	0	(320)	(4,226)	9,676	(0.0178)	(172)	(4,054)	(40,746)
September	(25,158)	0	(348)	(25,506)	10,802	(0.0178)	(192)	(25,314)	(66,060)
October	(1,098)	0	(529)	(1,627)	13,245	(0.0178)	(236)	(1,391)	(67,451)
Balance @ October 31, 2011									<u>(\$67,451)</u>

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

2/ Reflects 5,327.7 dk @ (\$0.1136) and 2,683 dk @ (\$0.0178).