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April 30, 2012

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

Re: Cost of Gas Adjustment (COG)
May 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 (74th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (74th Revised Sheet No. 8), showing the May 2012 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.1940 per mcf for residential and firm general service customers and a decrease of \$0.2121 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for May 2012, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.2124 since the last COG filing. There has been an increase in pipeline charges of \$0.0184 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of \$0.1940 per mcf for residential and firm general service customers.

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

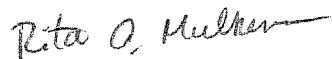
Attachment D shows the calculation of the balancing account since April 30, 2011.

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

A handwritten signature in cursive script that reads "Rita A. Mulkern".

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
74th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 73rd Revised Sheet No.1.1

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/MCF
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF \$1.2740 Over 10 MCF 1.0540	\$6.2281	\$7.5021 7.2821
Firm Gas Service - General Highway 13	2.5	\$3.50 per month	First 10 MCF \$2.1740 Over 10 MCF 1.9540	\$6.2281	\$8.4021 8.1821
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	\$1.7823	\$2.9214 2.6754 2.5234
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	\$1.7823	\$3.8214 3.5754 3.4234
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$1.7823	\$3.0214
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: April 30, 2012

Effective Date: May 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
74th Revised Sheet No. 8
Canceling 73rd 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.	3.8484	(3.1214)	0.5102	1.2372	(3.1069)	(0.0178)	(3.1247)
Current Adj.	0.0184	(0.2124)	0.0000	(0.1940)	(0.2121)	0.0000	(0.2121)
Total Adj.	3.8668	(3.3338)	0.5102	1.0432	(3.3190)	(0.0178)	(3.3368)
Total Rate:	\$3.9326	\$1.7853	\$0.5102	\$6.2281	\$1.8001	(\$0.0178)	\$1.7823

Date Filed: April 30, 2012

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

Issued By: Tamie A. Aberle
Regulatory Affairs Manager

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WHPETON
COST OF GAS ADJUSTMENT
MAY 2012**

<u>Firm</u>	<u>Billing</u> <u>Determinants</u>	<u>Rate</u>	<u>Demand</u> <u>Months</u>	<u>Amount</u>	<u>Amount</u> <u>Per dk</u>
FT-A	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	15.0486	12	1,435,095	1.0253
Trans Canada - Demand Charge	7,947	23.5856	12	2,249,217	1.6069
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0655
NOVA - Seasonal	5,068	15.0486	5	381,332	0.2724
Trans Canada - Seasonal	5,068	23.5856	5	597,659	0.4270
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
Total Demand Charges				<u>\$5,483,706</u>	<u>3.9326</u>
Estimated Weighted Average Commodity Cost	1,399,684	1/ 1.7853		<u>2,498,856</u>	1.7853
Gas Cost Reconciliation Adjustment					0.5102
Total Current Firm Gas Cost				<u><u>\$7,982,562</u></u>	<u><u>6.2281</u></u>
Base Cost of Gas					<u>5.1849</u>
Accumulated Adjustment					<u><u>\$1.0432</u></u>
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$1.7853
Gas Cost Reconciliation Adjustment					(0.0178)
LMS Demand 2/					0.0148
Total Current Interruptible Gas Cost					<u>1.7823</u>
Base Cost of Gas					<u>5.1191</u>
Accumulated Adjustment					<u><u>(\$3.3368)</u></u>

1/ Three year normalized average Dk sales.

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

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

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

Rates Effective May 1, 2012	\$/Dk	
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	15.0486	Per dk/Mo.
Trans Canada Pipeline Demand Charge	23.5856	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	15.0486	Per dk/Day
Trans Canada - Seasonal	23.5856	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:	1.7853	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	\$5.1849	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
Category 1 (Contract Term of Less than 3 Years)	
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
Category 2 (Contract Term of 3 Years to less than 5 Years)	
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
Category 3 (Contract Term of 5 or more Years)	
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 DEMARICATION
	TF12			TFF
	TF12 Base	Variable	TF5	
Base Tariff Rates 1/				
Summer (Apr-Oct)	5.683	5.683	-0-	5.473
Winter (Nov-Mar)	10.230	13.866	15.153	9.853

COMMODITY RATES 2/		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
TF12 Base,	TF12 Var.,	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.

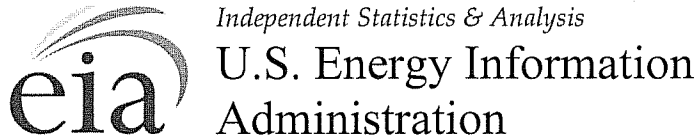
**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
May 2012**

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

Seasonal record storage levels resulting from warm winter temperatures nationwide likely contributed to the expected decrease in the index price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of April 20, 2012 were 55.4 percent above the five-year average and 52.0 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 19.



April 2012

Short-Term Energy and Summer Fuels Outlook

April 10, 2012 Release

Highlights

- EIA has lowered the forecast 2012 average U.S. refiner acquisition cost of crude oil by \$2 per barrel from last month's *Outlook* to \$112 per barrel, still \$10 per barrel higher than last year's average price. EIA expects the price of West Texas Intermediate (WTI) crude oil to average about \$106 per barrel in 2012, the same as in last month's *Outlook* but \$11 per barrel higher than the average price last year. Constraints in transporting crude oil from the U.S. midcontinent region contribute to the expected discount for WTI relative to other world crude oil prices. EIA expects WTI prices to remain relatively flat in 2013, averaging about \$106 per barrel, while the average U.S. refiner acquisition cost of crude oil averages \$110 per barrel.
- During the April-through-September summer driving season this year, regular gasoline retail prices are forecast to average about \$3.95 per gallon, peaking in May at a monthly average price of \$4.01 per gallon. EIA expects regular gasoline retail prices to average \$3.81 per gallon in 2012 and \$3.73 per gallon in 2013, compared with \$3.53 per gallon in 2011. The June 2012 New York Harbor Reformulated Blendstock for Oxygenate Blending (RBOB) futures contract averaged \$3.28 per gallon for the five trading days ending April 5. Based on the market value of futures and options contracts, there is a 40 percent probability that its price at expiration will exceed \$3.35 per gallon, consistent with a monthly average regular-grade gasoline retail price exceeding \$4.00 per gallon in June.
- The warmer-than-normal weather this past winter contributed to high natural gas working inventories that continue to set new record seasonal highs, with March 2012 ending at an estimated 2.48 trillion cubic feet (Tcf), about 57 percent above the same time last year. EIA's average 2012 Henry Hub natural gas spot price forecast is \$2.51 per million British thermal units (MMBtu), a decline of \$1.49 per MMBtu from the 2011 average spot price. EIA expects that Henry Hub spot prices will average \$3.40 per MMBtu in 2013.

- EIA expects electricity generation from coal to decline by about 10 percent in 2012 as generation from natural gas increases by about 17 percent. EIA forecasts that electricity generation from coal will increase by about 7 percent and generation from natural gas fall by 3 percent in 2013 as projected coal prices to the power sector fall slightly while natural gas prices increase, allowing coal to regain some of its power sector generation share.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA expects global liquid fuels consumption will increase by 0.89 million barrels per day (bbl/d) in 2012, while total liquids supply increases by 1.81 million bbl/d, 0.85 million bbl/d from countries outside of the Organization of the Petroleum Exporting Countries (OPEC) and 0.97 million bbl/d of crude oil and non-crude liquids from OPEC-member countries. The larger increase in total supply compared with consumption growth is misleading, however, as the 2011 balance between supply and consumption resulted in a supply shortfall of 0.77 million bbl/d that contributed to a decline in world inventories, including the coordinated drawdown in government-held stocks in countries belonging to the Organization for Economic Cooperation and Development (OECD) last summer. Consequently, the change in the supply-demand balance for 2012 reflects the increase in supply over last year that is forecast to maintain stocks near current levels.

Several uncertainties could push oil prices higher or lower than projected. A number of non-OPEC countries are currently undergoing supply disruptions. Oil prices could be higher than projected in this *Outlook* if their recoveries from the 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 Iranian crude oil imports are still uncertain, heightened market anxiety surrounding a potentially significant supply disruption could further bolster oil prices. On the demand side, if the pace of global economic growth fails to recover in countries belonging to the OECD, or if economic growth slows in non-OECD countries, prices could be lower.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by an estimated 0.79 million bbl/d to 87.9 million bbl/d in 2011. EIA expects that this growth will accelerate over the next two years, with consumption reaching 88.8 million bbl/d in 2012 and 90.1 million bbl/d in 2013. Non-OECD countries will account for essentially all of the world's consumption growth over the next two years, with the largest contributions coming from China, the Middle East, and Central and South America (World Liquid Fuels Consumption Chart). OECD liquid fuels consumption is projected to decline by about 400 thousand bbl/d in 2012, with Europe

and the United States accounting for almost all the decline. In 2013, forecast OECD liquid fuels consumption is expected to recover slightly by 100 thousand bbl/d, driven by higher consumption in the United States.

Non-OPEC Supply. EIA expects non-OPEC crude oil and liquid fuels production to rise by 850 thousand bbl/d in 2012 and by a further 840 thousand bbl/d in 2013. The largest area of non-OPEC growth will be North America, where production increases by 560 thousand bbl/d and 180 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. EIA expects that Kazakhstan, which will commence commercial production in the Kashagan field in the next year, will increase its total production annually by an average of 170 thousand bbl/d in both 2012 and 2013. In Brazil, output rises annually by an average of 130 thousand bbl/d over the next two years, with increased output from its offshore, pre-salt oil fields. Production also rises in China and Colombia over the next two years, while production declines in Russia, Mexico, and the North Sea.

Several notable disruptions to non-OPEC production commenced or intensified since the beginning of this year. In the former Sudan, an unresolved dispute between Sudan and the newly independent South Sudan over transit fees and other issues caused the latter to shut in all of its production at the end of January. EIA projects that total production from Sudan and South Sudan, which averaged about 430 thousand bbl/d in 2011, will average 190 thousand bbl/d in 2012 and recover to 440 thousand bbl/d in 2013 (Sudan and South Sudan Country Analysis Brief).

In Yemen and Syria, civil conflict continues to compromise a considerable portion of each country's oil output. Yemen's production is already impaired by an ongoing outage to the Marib pipeline. EIA projects that Yemen's production will average 180 thousand bbl/d in 2012, and 200 thousand bbl/d in 2013, down from the country's pre-crisis production level of around 260 thousand bbl/d (Yemen Country Analysis Brief). Due to heightened unrest, EIA expects Syria to produce 260 thousand bbl/d in 2012 and 360 thousand bbl/d in 2013, still below the country's pre-crisis production level of 400 thousand bbl/d.

Moderate disruptions stemming from technical issues have temporarily curbed production at some oil fields in Canada, Brazil, and China, but production is expected to recover in the near future.

OPEC Supply. EIA expects that OPEC members' crude oil production will continue to rise 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 720 thousand bbl/d in 2012 and then falls by 150 thousand bbl/d in 2013. 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 240 thousand bbl/d in 2012, and by 70 thousand bbl/d in 2013.

EIA expects Iran's crude production to fall by about 500 thousand bbl/d by the end of 2012, from its previous level of 3.55 million bbl/d at the end of 2011. Iran's decline in output began to accelerate during the last quarter of 2011 and has continued. EIA believes that the 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's forecast 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, because it is too early to assess Iran's ability to place its supply elsewhere.

OPEC members serve as the "swing" producers in the world market because only OPEC producers possess surplus or "spare" oil production capacity. EIA expects that the forecast decline in Iran's output of 500 thousand bbl/d in 2012 and an additional 200 thousand bbl/d in 2013 will be offset by increased production in other OPEC member countries. EIA projects that OPEC surplus production capacity will average 2.9 million bbl/d in 2012 and rise to 3.6 million bbl/d in 2013 (OPEC Surplus Crude Oil Production Capacity Chart).

OECD Petroleum Inventories. EIA estimates that commercial oil inventories held in the OECD ended 2011 at 2.59 billion barrels, equivalent to about 56.0 days of forward-cover (days-of-supply) (Days of Supply of OECD Commercial Stocks Chart). Projected OECD oil inventories increase slightly, to 2.62 billion barrels and 56.8 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 at the highest end-of-year level since 1991 because of a decline in OECD consumption.

Crude Oil Prices. The projected U.S. refiner acquisition cost of crude oil averages \$112 per barrel in 2012 and \$110 per barrel in 2013. EIA's forecast of the WTI spot price is the same as in last month's *Outlook*, averaging about \$106 per barrel in both 2012 and 2013 (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 \$7 per barrel in the second quarter of 2012 to \$4 per barrel by the fourth quarter of 2013, as physical pipeline capacity constraints diminish.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for June 2012 delivery during the 5-day period ending April 5, 2012 averaged \$104 per barrel. Implied volatility averaged 26 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in June 2012 at \$88 per barrel and \$123 per barrel, respectively. Last year at this time, WTI for June 2011 delivery averaged \$109 per barrel and implied volatility averaged 30 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$90 per barrel and \$132 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total U.S. liquid fuels consumption fell by an estimated 850 thousand bbl/d (4.5 percent) in the first quarter of 2012 from the same period last year (U.S. Liquid Fuels Consumption Chart). Motor gasoline and distillate fuel consumption accounted for much of that decline, shrinking by 240 thousand bbl/d (2.8 percent) and 260 thousand bbl/d (6.7 percent), respectively. EIA expects more moderate year-over-year declines in motor gasoline consumption, averaging about 40 thousand bbl/d over the next 9 months. In contrast, projected distillate fuel oil consumption recovers from the very warm winter with year-over-year growth averaging about 80 thousand bbl/d.

Despite assumed growth in U.S. real disposable income of 1.7 percent in 2013, forecast motor gasoline consumption will continue to be constrained by high gasoline prices, slowing growth in the driving-age population, and the improving average fuel economy of new vehicles, and declines by a further 20 thousand bbl/d in 2013. Distillate fuel consumption increases by 130 thousand bbl/d (3.3 percent) in 2013, buoyed by an assumed near-normal winter and relatively strong growth in manufacturing output.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by an estimated 180 thousand bbl/d (3.2 percent) to 5.66 million bbl/d in 2011, an upward revision of about 60 thousand bbl/d from last month's *Outlook*. A 440-thousand bbl/d increase in lower-48 onshore production in 2011 was partly offset by a 40-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 6.02 million bbl/d in 2012, an upward revision of 190 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 450 thousand bbl/d in 2012 overshadows declines averaging about 30 thousand bbl/d

in Alaskan output and 50 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 1,329 on April 5, 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 be 43 percent in both 2012 and 2013.

Summer Transportation Fuels Outlook

U.S. Gasoline and Diesel Fuel Prices. EIA expects that regular-grade gasoline retail prices, which averaged \$3.71 per gallon last summer, will average \$3.95 per gallon during the current summer (April through September) driving season, a year-over-year increase of 6.3 percent. The projected monthly average regular retail gasoline price peaks this summer at \$4.01 per gallon in May. Diesel fuel prices, which averaged \$3.94 per gallon last summer, are projected to average \$4.21 per gallon this summer, with monthly prices peaking at \$4.25 per gallon in the middle of the driving season. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas exceeding the national average price by 25 cents per gallon or more.

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 about \$114 per barrel (\$2.71 per gallon) this summer compared with the \$104 per barrel (\$2.48 per gallon) average of last summer. Crude oil prices that differ from our forecast would be reflected in the price of motor fuels. Each dollar per barrel of sustained change in crude oil prices relative to the forecast translates into approximately a 2.4-cent-per-gallon change in product prices, absent the consideration of factors specific to the gasoline and diesel fuel markets.

EIA expects wholesale gasoline margins (the difference between the wholesale price of gasoline and the refiner acquisition cost of crude oil) will average 56 cents per gallon this summer, about the same as last summer, but 8 cents per gallon higher than the previous 5-summer average of 48 cents per gallon (U.S. Gasoline and Crude Oil Prices Chart). Forecast wholesale diesel margins are 1 cent per gallon above last

summer's level and 10 cents per gallon higher than the previous 5-summer average of 54 cents per gallon (U.S. Diesel Fuel and Crude Oil Prices Chart).

As in the case of crude oil, the market's expectation of uncertainty in monthly average gasoline prices is reflected in the pricing and implied volatility of futures and options contracts. New York Harbor reformulated gasoline blendstock for oxygenate blending (RBOB) futures contracts for June 2012 delivery over the 5-day period ending April 5, averaged \$3.28 per gallon. The probability the RBOB futures price will exceed \$3.35 per gallon (consistent with a U.S. average regular gasoline retail price above \$4.00 per gallon in June 2012) is about 40 percent, while the probability it will exceed \$3.85 per gallon (consistent with a U.S. average regular gasoline retail price above \$4.50 per gallon) in June 2012 is about 5 percent.

While retail gasoline prices have generally followed the rise in crude oil prices, refinery closures in the Philadelphia area and other parts of the Atlantic Basin may have a further impact on prices. This *Outlook* assumes the Sunoco Philadelphia refinery continues to operate. If the Sunoco Philadelphia refinery closes, price impacts are highly uncertain. If certain areas cannot be adequately supplied in the short term, prices can spike. For a more detailed analysis on Northeast refining issues, see EIA's "*Potential Impacts of Reductions in Refinery Activity on Northeast Petroleum Product Markets.*"

The projected increase in gasoline prices this year suggests that vehicle fueling costs for the average U.S. household will be about \$250 higher in 2012 than they were in 2011. According to the 2009 National Household Travel Survey (Transportation Energy Data Book, Tables 4.1 and 8.6), U.S. households drove an average 19,850 miles with an average passenger car fuel efficiency of 22.5 miles per gallon. Assuming no change in travel or average fuel economy, the increase in the average annual gasoline retail price (all grades) from \$2.83 per gallon in 2010 to \$3.58 per gallon in 2011 and a projected \$3.87 per gallon in 2012 implies an increase in average annual household expenditures on gasoline from \$2,501 in 2010 to \$3,159 in 2011 and to \$3,410 in 2012.

Motor Gasoline. During this summer season (April through September), projected motor gasoline consumption declines by 0.5 percent from last summer. Finished motor gasoline is supplied by four sources: domestic refinery output, fuel ethanol blending, net imports of gasoline and gasoline blending components, and primary inventories. EIA expects that domestic refinery production, including blending output, will decline 0.6 percent from last summer. Fuel ethanol blending into gasoline is projected to change little from last summer's level of about 850 thousand bbl/d, which is about 9.6 percent of total gasoline consumption. Forecast total gasoline net

imports are projected to average 340 thousand bbl/d, a decrease of 9 percent from the previous summer.

At the onset of the summer driving season (April 1) total gasoline stocks, at 221.3 million barrels, are 6.4 million barrels above the level of a year ago, and 5.1 million barrels more than the previous 5-year average for beginning-of-season stocks (U.S. Gasoline and Distillate Inventories Chart). Stock withdrawals have not been a significant motor gasoline supply source for the summer season in recent years, having averaged less than 50 thousand bbl/d during the previous 5 summer seasons. This summer, total gasoline stocks are projected to be drawn down by an average of 27 thousand bbl/d, compared with an average 7 thousand bbl/d build last summer.

Diesel Fuel. Projected consumption of distillate fuel, which includes diesel fuel and heating oil, will average 3.85 million bbl/d this summer, up 2.3 percent from last summer. That growth is buoyed by continued strength in manufacturing output and foreign trade.

Distillate fuel is supplied by four sources: domestic refinery output, biodiesel blending, primary inventories, and net imports. EIA expects refinery output of distillate fuel will average 4.52 million bbl/d this summer, up 1.0 percent from last summer. Biodiesel has been a small but growing part of the distillate pool. Biodiesel blending averaged 62 thousand bbl/d last summer and is forecast to average about 61 thousand bbl/d this summer. Projected distillate fuel net exports average 580 thousand bbl/d this summer, down from the record 680 thousand bbl/d last summer. In contrast, the United States was a net importer of distillate fuel, averaging 120 thousand bbl/d, during the summers of 2000 through 2007.

Distillate inventories are projected to start the summer at 135.4 million barrels, down from 148.5 million barrels last year. Distillate inventories typically build during the summer season in preparation for the heating season. This summer, the build is forecast to average 88 thousand bbl/d, far more than the 28 thousand bbl/d recorded last summer but similar to the previous 5-year average summer build of 90 thousand bbl/d. End-of-summer stocks are 151 million barrels, down slightly from the 154 million barrels recorded last summer, but unchanged from the previous 5-year end-of-summer average.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 69.6 billion cubic feet per day (Bcf/d) in 2012, an increase of 2.8 Bcf/d (4.2 percent) from 2011. 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 residential and commercial consumption to fall by 3.9 percent and 2.7 percent, respectively, in 2012, reflecting a downward revision in projected consumption from last month's *Outlook*. Currently, the National Oceanic and Atmospheric Administration (NOAA) expects heating degree-days to total 4,020 for 2012, 5.3 percent less than in last month's *Outlook*, and about 11 percent below the 30-year normal level.

Projected consumption of natural gas in the electric power sector grows by about 16 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 30.6 Bcf/d, when electricity demand for air conditioning is highest. This compares with 27.7 Bcf/d in the third quarter of 2011.

Growth in total natural gas consumption continues into 2013, with forecast consumption averaging 70.5 Bcf/d (U.S. Natural Gas Consumption Chart). A forecast of closer-to-normal winter temperatures drives increases in residential and commercial consumption of 7.3 percent and 4.7 percent, respectively. The increase in consumption in these sectors, as well as an increase in industrial consumption, more than offsets a 3.4-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, the largest year-over-year volumetric increase in history. 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 much lower rate than in 2011 as low prices reduce new drilling plans. According to Baker Hughes, the natural gas rig count was 647 as of April 5, 2012, down from a 2011 high of 936 in mid-October. So far, the lower rig count has not impacted production levels, partly reflecting improved drilling efficiency. While fewer horizontal natural gas rigs, particularly in areas of dry production such as the Haynesville Shale, probably indicate declines in these areas, these losses are more than offset in the short term by other production from wet plays.

Pipeline gross imports are expected to fall by 0.7 Bcf/d (7.2 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. 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 (28 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 a very warm winter has contributed to much-lower-than-normal inventory draws. As of March 30, 2012, according to EIA's *Weekly Natural Gas Storage Report*, working inventories totaled 2,479 Bcf, 887 Bcf greater than last year's level and 934 Bcf above the 5-year (2007-2011) average. In the last 20 years, end-of-March inventories have not risen over 1,700 Bcf, and prior to that, rose above 2,100 Bcf just once, in 1983. With only a few exceptions, weekly inventory withdrawals have been smaller than the previous 5-year average during this year's winter heating season, and though the end of March is technically the end of the heating season, net inventory injections began the week ending March 16. EIA expects that inventory levels at the end of October 2012 will set a new record high as well (U.S. Working Natural Gas in Storage Chart).

U.S. Natural Gas Prices. Natural gas spot prices averaged \$2.18 per MMBtu at the Henry Hub in March 2012, down \$0.32 per MMBtu from the February 2012 average and the lowest average monthly price since April 1999. Abundant storage levels, as well as ample production, have contributed to the recent low prices. EIA expects natural gas prices will average \$2.51 per MMBtu in 2012, a downward revision from \$3.17 per MMBtu expected in last month's *Outlook*. EIA revised its forecast for 2013 down to \$3.40 per MMBtu, from \$3.96 per MMBtu in last month's *Outlook*. Prices remain low as production and supplies remain robust (U.S. Natural Gas Prices Chart).

Natural gas futures prices for June 2012 delivery (for the 5-day period ending April 5, 2012) averaged \$2.27 per MMBtu, and the average implied volatility based on options and futures prices was 48 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 June 2012 contracts at \$1.60 per MMBtu and \$3.21 per MMBtu, respectively. At this time last year, the June 2011 natural gas futures contract averaged \$4.29 per MMBtu and implied volatility averaged 34 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.37 per MMBtu and \$5.47 per MMBtu.

Coal

U.S. Coal Consumption. EIA forecasts that electric power sector coal consumption will be well below 900 million short tons (MMst) in both 2012 and 2013. Power sector natural gas prices have fallen significantly, leading generators in several regions to increase the share of natural gas-fired generation. EIA expects this trend to continue in 2012 with power sector coal consumption falling by 10 percent (U.S. Coal Consumption Chart). Projected power sector coal prices fall slightly next year while natural gas prices increase. In response, EIA expects that electric power sector coal consumption will increase by 5 percent in 2013 as the economic competitiveness of coal-fired generation improves.

U.S. Coal Supply. EIA forecasts coal production to decline by 7.6 percent in 2012 as domestic consumption and exports fall (U.S. Coal Production Chart). Production declines greater than 20 MMst are expected in each of the three coal-producing regions (Appalachia, Interior and Western). EIA projects that secondary inventories will increase in 2012, with electric power sector stocks exceeding 200 MMst, and inventories will remain at these 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 be below the 107 MMst exported in 2011. Forecast U.S. coal exports are 100 MMst in 2012 and 98 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 sector have increased steadily over the last 10 years and this trend continued in 2011, with an average delivered coal price of \$2.40 per MMBtu (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 about 1.0 percent lower than the 2011 average price. EIA predicts the 2013 average delivered coal price to be \$2.30 per MMBtu, or 3.2 percent lower than the previous year's price.

Electricity

U.S. Electricity Consumption. EIA expects total U.S. consumption of electricity will fall slightly during 2012, and then grow by 2.3 percent during 2013 (U.S. Total Electricity Consumption Chart). Growth in retail sales of electricity to the commercial and industrial sectors during 2012 will be offset by a 3.2-percent decline in residential

sector consumption. Residential consumption falls this year as a result of milder weather compared with last year. EIA estimates that U.S. residential electricity consumption during the first quarter of this year was about 8 percent lower than during the same period in 2011, primarily because of the 22-percent decline in heating degree-days nationwide. Similarly, the projected 17-percent year-over-year decline in U.S. cooling degree-days during the second and third quarters this year is expected to reduce residential electricity consumption by 5 percent this summer.

U.S. Electricity Generation. The price of natural gas delivered to electric generators averaged \$3.67 per million Btu in January, which is the lowest price since 2002. These low prices continue to drive substantial displacement of coal by natural gas for fueling electricity generation. Furthermore, a projected year-over-year decline in hydroelectric generation in the western U.S. contributes to higher levels of generation from natural gas this year. EIA projects that the share of total generation fueled by natural gas will rise from an average 24.8 percent in 2011 to an average of 29.2 percent in 2012. The 4.4 percentage point increase is the largest annual change in natural gas's fuel share since record-keeping began in 1949. The share of total generation produced using coal falls from 42.2 percent in 2011 to 38.3 percent in 2012 (U.S. Electricity Generation Chart).

U.S. Electricity Retail Prices. EIA forecasts average U.S. residential electricity prices to rise by 0.9 percent in 2012, and then fall by 1.4 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. In addition, some of the increase in electricity prices this year is due to the forecast of a milder summer, which lowers average household consumption and raises the contribution of fixed electricity costs to the per kilowatt-hour average price.

Renewables and Carbon Dioxide Emissions

U.S. Renewables. After growing 14 percent in 2011, total renewable energy supply is projected to decline by 2.7 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 0.4 quadrillion Btu (12 percent). The decline in hydropower from the 2011 level offsets growth in other renewable energy supplies. Renewables supply increases slightly in 2013 as hydropower continues to decline (4.3 percent) and non-hydropower renewables grow by 2.8 percent, which is modest compared with recent experience.

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-

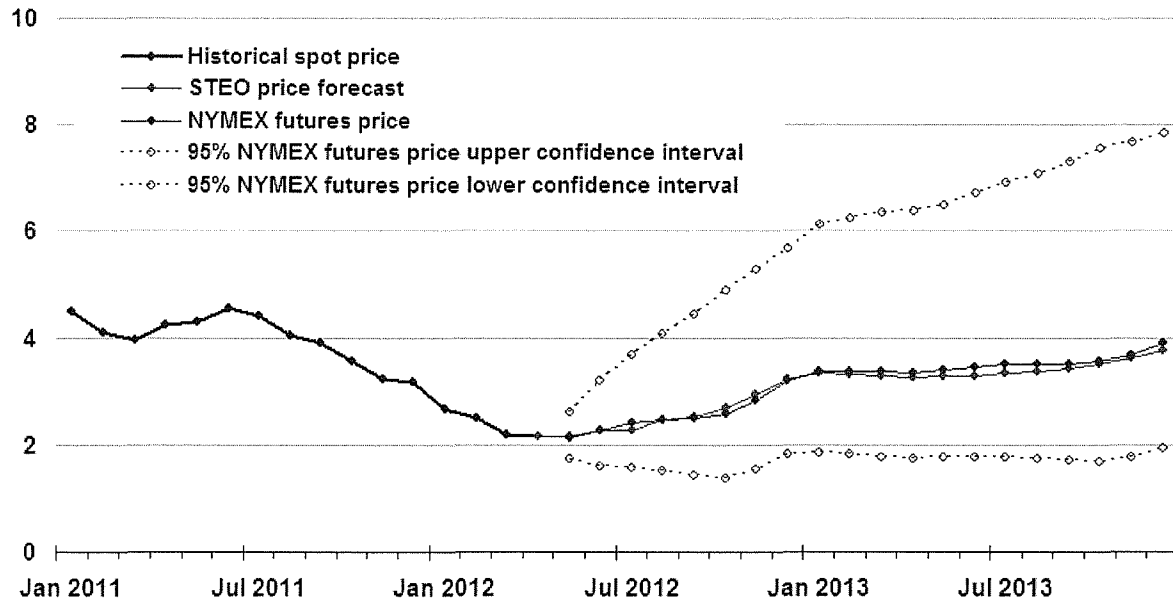
powered generation, which grew by 26 percent in 2011, is forecast to grow an additional 14 percent in 2012 and 5 percent in 2013. Of the 1,739 megawatts (MW) of capacity that has been reported to EIA as possibly coming on line in 2013 only 49 MW is currently under construction. The project under construction is in Ohio, where there is a renewable portfolio standard (RPS) that requires 2.4 percent of covered energy to come from renewable sources by 2014, up from 0.2 percent in 2009. Most of the States with approved, pending, or planned projects also have RPS requirements. Production credits for other eligible renewables, such as closed-loop biomass and geothermal generation, expire at the end of 2013. Solar energy (at both the corporate and residential level) is eligible for investment tax credits that will remain at 30 percent throughout the forecast period.

In terms of liquid renewable fuels, EIA expects fuel ethanol production to fall slightly, from an average of 910 thousand bbl/d in 2011 to an average of 900 thousand bbl/d in both 2012 and 2013. 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 61 thousand bbl/d (939 million gallons of total annual production). Forecast biodiesel production averages 56 thousand bbl/d in 2012, and 65 thousand bbl/d in 2013.

U.S. CO₂ Emissions. After declining by 1.9 percent in 2011, fossil fuel emissions are projected to further decline by 1.9 percent in 2012, but increase by 2.1 percent in 2013. Petroleum emissions decline slightly in 2012 (0.5 percent) and then rise by 0.6 percent in 2013, while natural gas emissions rise by 4.6 percent and 1.1 percent in 2012 and 2013, respectively. Coal emissions decline in 2012 by 8.2 percent, but rise by 4.8 percent in 2013 (U.S. Carbon Dioxide Emissions Growth Chart).

Henry Hub Natural Gas Price

dollars per million Btu

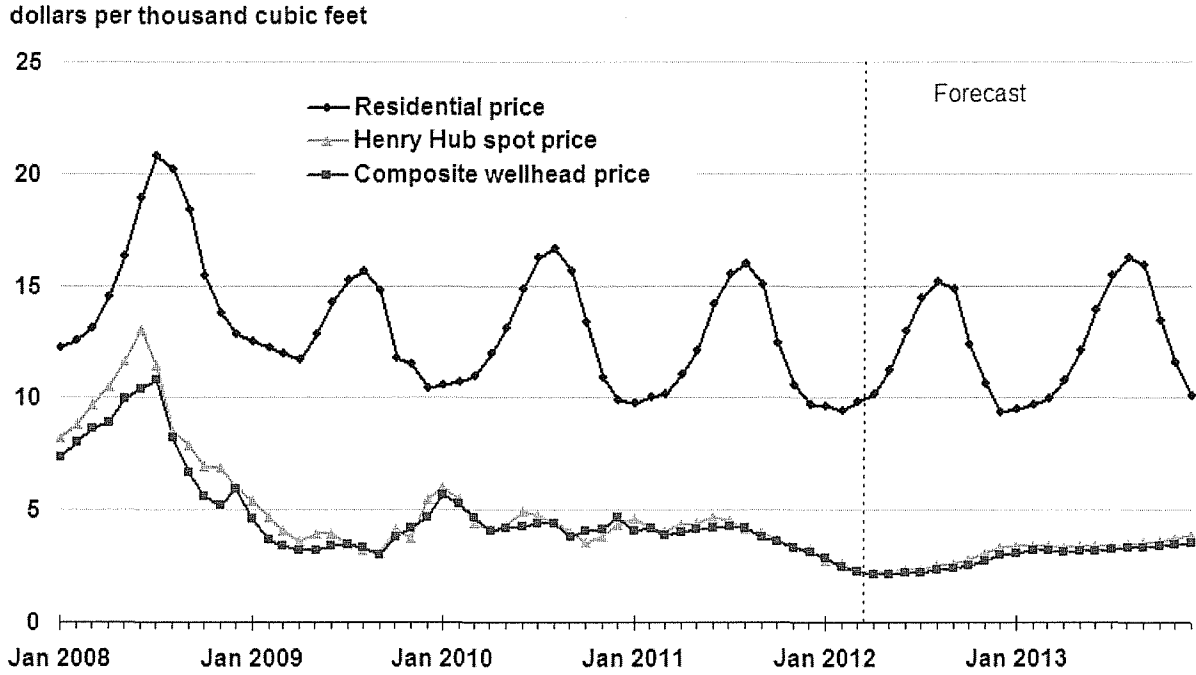


Note: Confidence interval derived from options market information for the 5 trading days ending April 5, 2012
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: Short-Term Energy Outlook, April 2012



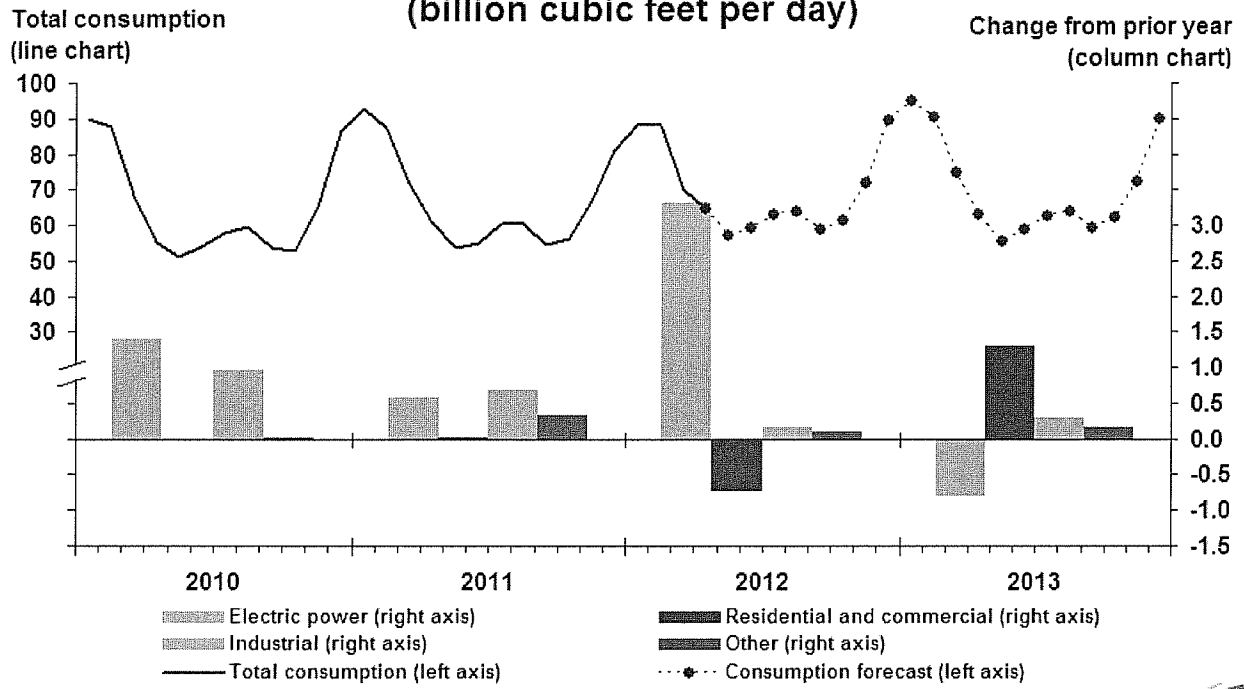
U.S. Natural Gas Prices



Source: Short-Term Energy Outlook, April 2012



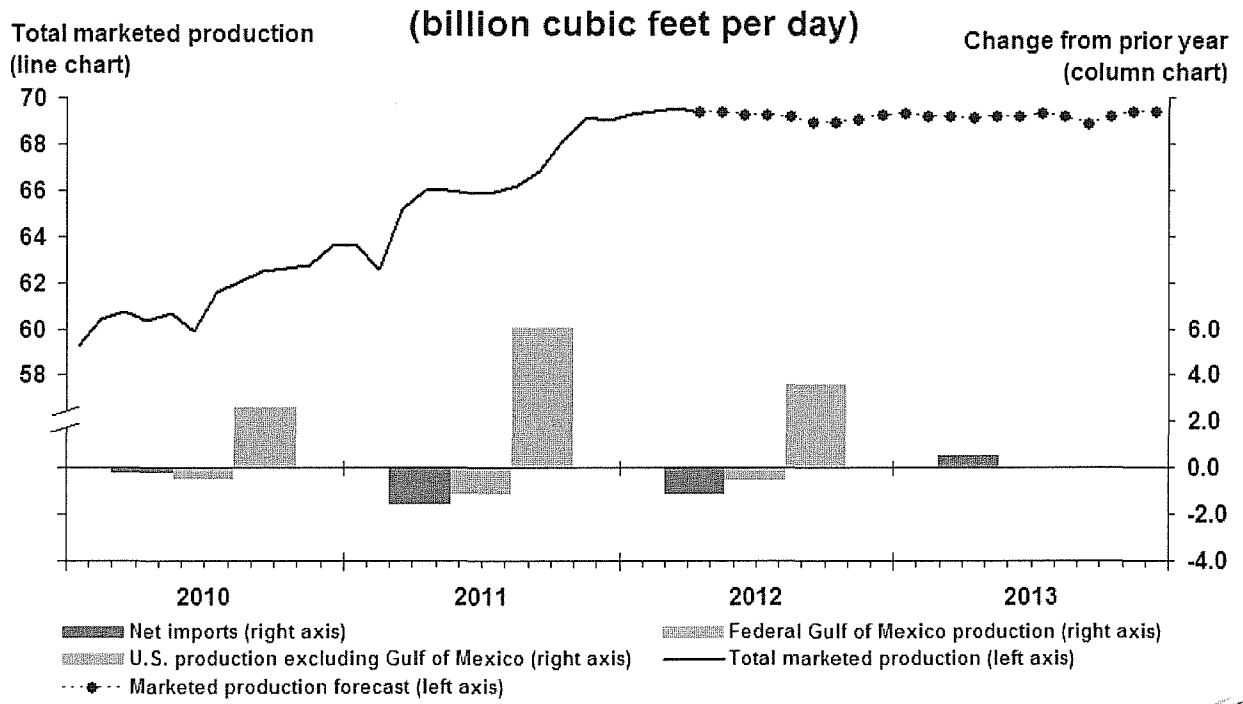
U.S. Natural Gas Consumption (billion cubic feet per day)



Source: Short-Term Energy Outlook, April 2012



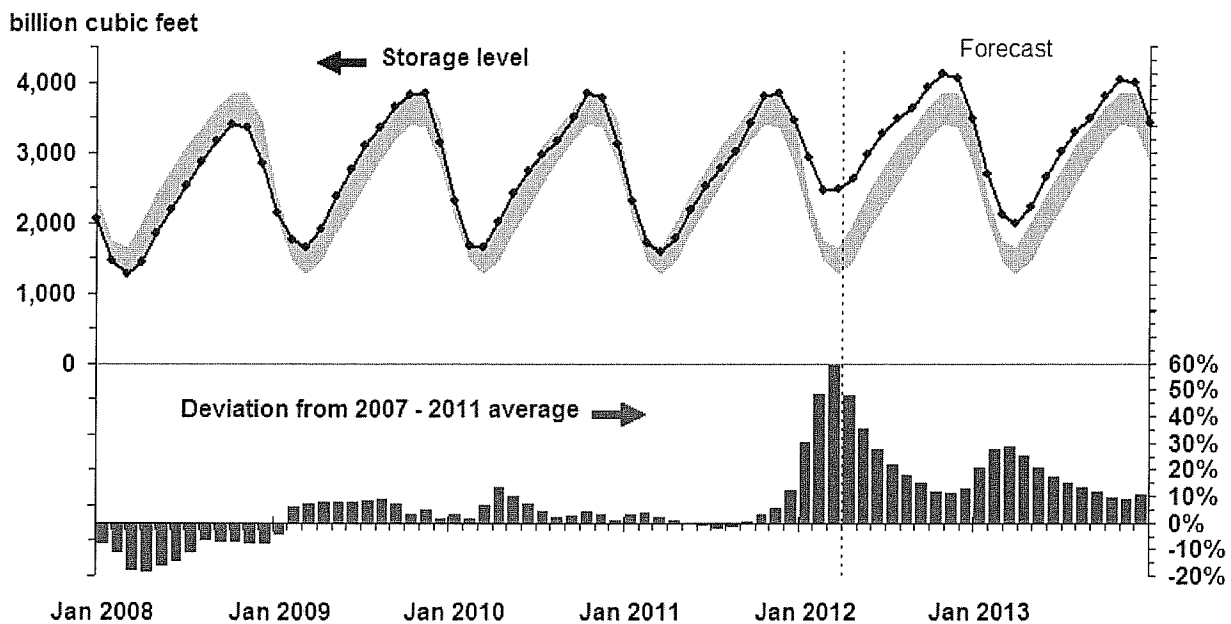
U.S. Natural Gas Production and Imports



Source: Short-Term Energy Outlook, April 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, April 2012



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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ April 30, 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
November	18,005	0	2,594	20,599	17,707	0.5102	9,034	11,565	401,410
December	12,176	0	2,668	14,844	29,901	0.5102	15,255	(411)	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	20,263	(51,281)	325,981
March	(2,694)	0	2,123	(571)	32,685	0.5102	16,676	(17,247)	308,734
Balance @ March 31, 2012									<u>\$308,734</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**

	<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><u>(\$5,922)</u></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)
November	(4,349)	0	(535)	(4,884)	24,583	(0.0178)	(438)	(4,446)	(71,897)
December	6,776	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	(440)	(818)	23,400	(0.0178)	(417)	(401)	(55,609)
March	(6,986)	0	(440)	(7,426)	26,397	(0.0178)	(470)	(6,956)	(62,565)
Balance @ March 31, 2012									<u><u>(\$62,565)</u></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).