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

705 West Fir Ave.
PO Box 176
Fergus Falls, MN 56538-0176
1-877-267-4764

January 2, 2013

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

Re: Cost of Gas Adjustment (COG)
January 2013

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and two (2) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (82nd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (82nd Revised Sheet No. 8), showing the January 2013 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.4305 per mcf for all customers.

Attachment B shows the calculations supporting the gas costs for January 2013, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.4305 since the last COG filing.

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

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

Great Plains also submits herewith its check for $600.00 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment will cover the filing fee associated with the monthly COG filings.

Great Plains respectfully requests this filing be accepted as being in full compliance with the filing requirements of this Commission.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Rita A. Mulkern
Director of Regulatory Affairs

Attachments

Attachment A

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
82nd Revised Sheet No. 1.1
Canceling 81st Revised Sheet No.1.1

RATE SUMMARY SHEET

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	$6.1010	$7.3750
			Over 10 MCF	1.0540		7.1550
Firm Gas Service - General Highway 13	2.5	$3.50 per month	First 10 MCF	$2.1740	$6.1010	$8.2750
			Over 10 MCF	1.9540		8.0550
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.2697	$4.4088
			Next 2,600 MCF	0.8931		4.1628
			Over 3,000 MCF	0.7411		4.0108
Interruptible Gas Service - Highway 13	3.5	$3.50 per month	First 400 MCF	$2.0391	$3.2697	$5.3088
			Next 2,600 MCF	1.7931		5.0628
			Over 3,000 MCF	1.6411		4.9108
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.2697	$4.5088
Transportation Service	5	$3.50 per month	First 400 MCF	$1.1391		$1.1391
			Next 2,600 MCF	0.8931		0.8931
			Over 3,000 MCF	0.7411		0.7411

Date Filed: January 2, 2013

Effective Date: Service rendered on and after January 1, 2013

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
82nd Revised Sheet No. 8
Canceling 81st Revised Sheet No. 8

COST OF GAS

Summary:	Firm				Interruptible		
	Est. Wtd. Demand Costs	Average Commodity	GCR Adj.	Est. Wtd. Total Firm	Average Commodity	GCR Adj.	Total Int.
Base Rate	$0.0658	$5.1191	$0.0000	$5.1849	$5.1191	$0.0000	$5.1191
Accumulated Adj.	1.4751	(1.1422)	1.0137	1.3466	(1.1274)	(0.2915)	(1.4189)
Current Adj.	0.0000	(0.4305)	0.0000	(0.4305)	(0.4305)	0.0000	(0.4305)
Total Adj.	1.4751	(1.5727)	1.0137	0.9161	(1.5579)	(0.2915)	(1.8494)
Total Rate:	$1.5409	$3.5464	$1.0137	$6.1010	$3.5612	($0.2915)	$3.2697

Date Filed: January 2, 2013

Effective Date: Service rendered on and after January 1, 2013

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JANUARY 2013

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A	8,000		$3.4671	12	$332,842	$0.2378
FT-A - Zone 1-1	500		3.4671	5	8,668	0.0062
FT-A - Zone 1-2	4,500		4.5871	5	103,210	0.0737
FT-A Seasonal	2,000		3.7671	5	37,671	0.0269
TFX Seasonal	2,000		15.1530	5	151,530	0.1083
TFX - Winter	13,000		15.1530	5	984,945	0.7037
TFX - Summer	13,000		5.6830	7	517,153	0.3695
LMS Demand 2/						0.0148
Total Demand Charges					$2,136,019	1.5409
Estimated Weighted Average Commodity Cost	1,399,684	1/	3.5464		4,963,839	3.5464
Gas Cost Reconciliation Adjustment						1.0137
Total Current Firm Gas Cost					$7,099,858	6.1010
Base Cost of Gas						5.1849
Accumulated Adjustment						$0.9161

Interruptible	
Estimated Weighted Average Commodity Cost	$3.5464
Gas Cost Reconciliation Adjustment	(0.2915)
LMS Demand 2/	0.0148
Total Current Interruptible Gas Cost	3.2697
Base Cost of Gas	5.1191
Accumulated Adjustment	($1.8494)

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	$0.0148

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JANUARY 2013

Rates Effective November 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	15.1530	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	3.5464	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	$5.1849	Per Mcf

Interruptible:		
Commodity	$5.1191	Per Mcf

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

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

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

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

2/ Fuel and Losses Retention Percentages shall be applicable to all transportation rate schedules.

Transportation Fuel and Loss Retention Percentages are inclusive of the following percentages for Gas Lost and Unaccounted For: 0.15% for Zone 1-1, 0.17 % for Zone 1-2, and 0.02% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted for percentages.

Rate Schedule	Base Tariff Rate	Adjustment Under Section 27 1/	Rate After Current Adjustment
LMS – Monthly Demand Rate	$1.0000		$1.0000
LMS – Daily Overrun Rate	$0.1737		$0.1737
LMS – Load Management Cost Reconciliation Adjustment		($0.0022)	

1/ Pursuant to Section 27 of the General Terms and Conditions of this Tariff, a mechanism is established to reconcile through surcharges or credits to the Rate Schedule LMS rate, as appropriate, differences between the cost to maintain Company's line pack gas and the amounts Company receives or pays for such gas arising out of the purchase and sale of such gas.

Rate Schedule	Maximum Rate Per Dekatherm	Minimum Rate Per Dekatherm
PAL		
NPL, OPL, and APL Service:		
Daily Commodity Rate	$0.1737	$0.0000
RPL Service:		
Daily Reservation Rate	$0.1737	$0.0000

RATE SCHEDULE TF

	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
		TF12		
RESERVATION RATES	TF12 Base	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/ TF12 Base, TF12 Var., TF5 & TFF		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

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 Apr-Oct	MARKET-TO-MARKET Nov-Mar	FIELD-TO-FIELD Apr-Oct	FIELD-TO-FIELD 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/ Maximum	Reservation 1/ Minimum	Commodity 6/ Maximum	Commodity 6/ Minimum	Out-of-Balance 6/ Maximum	Out-of-Balance 6/ Minimum
MOPS Gathering	1.0514	0.0000	0.0018	0.0018	0.0018	0.0018
MOPS Transmission	1.5337	0.0000	0.0018	0.0018	0.0018	0.0018
Tivoli - Downstream	0.6827	0.0000	0.0018	0.0018	0.0018	0.0018
Other Gulf Coast	4.8169	0.0000	0.0018	0.0018	0.0018	0.0018

1/ The minimum reservation rate is equal to zero.
2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
3/ Maximum and Minimum rates include ACA of $0.0018 and the Market Area Electric Compression charge of $0.0001 where applicable.
4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
5/ Where applicable, Field Area Compression charge of $0.0000 and ACA will be added to the mileage based rates.
6/ Maximum and Minimum rates include ACA of $0.0018.

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

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.97%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.43% 4/ 5/
FDD Storage Fuel	1.09%

	Electric Compression
COMMODITY RATES:	1/
Market Area	$0.0001
Field Area	$0.0000

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

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

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

4/ The Unaccounted For percentage utilizes the most recent twelve-month period ending December 31, 2011.

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

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

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

RATE SCHEDULES FDD, PDD, IDD & SMS

Rate Schedule FDD		
Maximum Reservation Fee	1.7140	1/
Maximum Capacity Fee	0.3567	1/
Injection Charge - Firm	0.0149	
Withdrawal Charge - Firm	0.0149	
Annual Rollover Fee	0.3567	1/
Rate Schedule PDD		
Maximum Capacity Fee	0.3567	1/
Maximum Monthly Inventory Charge	0.0887	1/
Injection Charge	0.0149	
Withdrawal Charge	0.0149	
Annual Rollover Fee	0.3567	1/
Rate Schedule IDD		
Maximum Monthly Inventory Charge	0.0887	1/
Injection Charge	0.0149	
Withdrawal Charge	0.0149	
Annual Rollover Fee	0.3567	1/
Rate Schedule SMS		
Reservation Fee	2.1800	
Commodity Rate	0.0208	

1/ Minimum Rate is zero.

Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
January 2013

The principal gas sources of natural gas for Wahpeton, North Dakota are from the mid-continent area of the United States. The pricing for much of this gas is the Northern Natural Gas Co. Ventura, Iowa point which is an actively traded market point in North America. The January monthly price for the NNG-Ventura Index is expected to decrease from the previous month index. The NNG-Ventura Index is based on negotiated trades during the last five business days of the month, commonly known as bid week and reported by Platt's Inside FERC's Gas Market Report published the beginning of each month.

Continued high levels of gas in storage, strong domestic natural gas production and periods of above normal temperatures in many locations likely contributed to the NNG-Ventura index price decrease. The Energy Information Administration (EIA) reported storage levels nationwide as of December 21, 2012 were 12.8 percent above the five-year average and 2.3 percent above last year's balance.

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

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 17.

Independent Statistics & Analysis
U.S. Energy Information Administration

December 2012

Short-Term Energy Outlook (STEO)

- EIA expects that the Brent crude oil spot price will average $110 per barrel in the fourth quarter of 2012, while the West Texas Intermediate (WTI) crude oil spot price will average $89 per barrel. The Brent and WTI crude oil spot prices are forecast to average $104 per barrel and $88 per barrel, respectively, in 2013. The projected WTI discount to Brent crude oil, which averaged $23 per barrel in November 2012, falls to an average of $11 per barrel by the fourth quarter of 2013. This forecast rests on the assumption that U.S. real gross domestic product (GDP) grows by 2.1 percent in 2012 and 1.8 percent in 2013, while world oil-consumption-weighted real GDP grows by 2.7 percent and 2.4 percent in 2012 and 2013, respectively.

- U.S. monthly average regular gasoline retail prices fell from $3.85 per gallon in September to $3.45 per gallon in November, as crude oil prices fell and the gasoline market transitioned from summer-grade to lower-cost winter-grade gasoline specifications. Projected national average regular gasoline retail prices average $3.63 per gallon in 2012 and $3.43 per gallon in 2013, compared with $3.53 per gallon in 2011. Forecast diesel fuel retail prices average $4.02 per gallon during the fourth quarter of 2012 before falling to an average of $3.84 per gallon in 2013.

- EIA's projections of average household fuel bills this winter have not changed significantly from last month's STEO. EIA expects household expenditures for space heating fuels will be higher this winter than last winter, primarily because of the return to roughly normal winter temperatures east of the Rocky Mountains compared with last winter's unusual warmth. Average expenditures for households that heat with heating oil are forecast to be higher than any previous winter on record.

- EIA expects U.S. total crude oil production to average 6.4 million barrels per day (bbl/d) in 2012, an increase of 0.8 million bbl/d from the previous year. Projected domestic crude oil production increases to 7.1 million bbl/d in 2013, 0.2 million bbl/d higher than projected in last month's STEO and the highest annual average rate of production since 1992.

- Natural gas working inventories, which reached an all-time weekly record in early November, ended the month at an estimated 3.8 trillion cubic feet (Tcf), almost equal to the level at the same time last year. EIA expects the Henry Hub natural gas spot price, which averaged $4.00 per million British thermal units (MMBtu) in 2011, will average $2.78 per MMBtu in 2012 and $3.68 per MMBtu in 2013.

Global Crude Oil and Liquid Fuels

Global Crude Oil and Liquid Fuels Overview. EIA estimates that global oil markets have loosened in the fourth quarter of 2012 relative to the same quarter last year. Projected world liquid fuels production increases by 0.1 million bbl/d from the third quarter to the fourth quarter of 2012 as members of the Organization of the Petroleum Exporting Countries (OPEC) continue to produce more than 30 million bbl/d of crude oil and non-OPEC countries recover from unplanned outages and scheduled maintenance. Total liquid fuels supply, which was 1.1 million bbl/d lower than world consumption in the fourth quarter of 2011, falls short of consumption by about 0.3 million bbl/d in the fourth quarter 2012. EIA expects global inventories to build during the first half of 2013, mostly due to continued growth in U.S. and other non-OPEC supply.

Global Crude Oil and Liquid Fuels Consumption. EIA expects world liquid fuels consumption growth of about 0.8 million bbl/d in 2012 and 1.0 million bbl/d in 2013, with countries outside of the Organization for Economic Cooperation and Development (OECD) driving future demand growth.

Projected OECD liquid fuels consumption declines by 0.5 million bbl/d in 2012 and by an additional 0.2 million bbl/d in 2013. EIA projections do not assume any significant deterioration of the economic situation in the United States or the European Union (EU) next year, but movements in oil prices could include changing market assessments about the downside risks to future consumption from the so-called fiscal cliff in the United States or concerns over eurozone economic stability.

China's economy has shown signs of improvement over the past two months as key manufacturing indexes, export volumes, and refining runs have increased; however, a sustained rebound is still tentative. EIA expects liquid fuels consumption growth in China, which slowed from 460,000 bbl/d in 2011 to 380,000 bbl/d in 2012, should rise to about 400,000 bbl/d in 2013.

South Korea shut down two nuclear reactors in early November 2012 after discovering the plants used parts supplied with forged quality certificates. EIA believes that the country's power sector will primarily rely on an increase in generation using imported liquefied natural gas rather than petroleum to compensate for the reactor outages.

Non-OPEC Supply. EIA estimates non-OPEC liquid fuels production in November 2012 to be 0.4 million bbl/d above the same month last year, primarily because of increased crude oil production from tight oil plays in the United States. Projected non-OPEC production increases by 1.3 million bbl/d in 2013, largely due to continued production growth from U.S. tight oil formations and Canadian oil sands.

Unplanned production outages in non-OPEC countries averaged just under 0.9 million bbl/d in November 2012, roughly the same volume that was offline in the previous month. Syria and Sudan are currently the most significant sources of disruption to non-OPEC production. EIA forecasts Sudan and South Sudan's production to average 120,000 bbl/d in 2012 and recover to 270,000 bbl/d in 2013, still well below the pre-shut-in level of around 450,000 bbl/d.

After months of planned and unplanned maintenance, the United Kingdom's Buzzard Field, which was originally expected to return to operation in September, resumed operations in the second half of November. Buzzard is the largest of the fields that contribute to the Forties crude oil blend, which is the most important stream that makes up the Brent crude price benchmark.

OPEC Supply. EIA expects that OPEC members will continue to produce more than 30 million bbl/d of crude oil next year to accommodate the projected increase in world oil consumption and to counterbalance supply disruptions. Saudi Arabia in particular has continued to produce at high levels for most of 2012.

Protestors disrupted operations at Libya's second-largest refinery on two separate occasions in November, as energy infrastructure continues to act as a tempting target for groups that seek to apply pressure on the nascent government. Although fuel supplies in Tripoli were only temporarily strained and the effect on upstream production was minimal, these and other developments reinforce EIA's expectation that Libya will struggle to sustain production at full capacity until political and security conditions improve. At the very least, Libya poses a greater upside than downside risk to the oil price forecast, as the potential production loss from more significant disruptions exceeds the potential short-term production gains from a sector that has already significantly recovered.

Nigerian crude oil production declined for a third consecutive month in November to 1.9 million bbl/d. Pipeline sabotage, oil spills, and production delays have continued to compromise a significant portion of Nigeria's production in November, after the country's crude oil production suffered from maintenance-related outages in September and floods in October. As of the end of November, three of Nigeria's crude streams (Qua Iboe, Forcados, and Brass River) were under force majeure, and preliminary data showed an overall reduction in crude oil loadings that month.

Iran's crude oil production is estimated at 2.6 million bbl/d in November 2012, indicating at least a temporary bottoming out of Iranian production declines. Iranian production had been falling since at least the last quarter of 2011. The latest round of U.S. and EU sanctions contributed to declines in Iranian production during the second and third quarters of 2012. However, preliminary trade numbers show that exports rose to 1.3 million bbl/d in October, at least temporarily slowing down the production declines. The export numbers are based on commercial data on tanker liftings from Iran, press reports, and other relevant information. However, this tentative interpretation of a very fluid situation could change as EIA revises data,

industry sources issue independent estimates of Iranian production, and more details about Iranian storage levels, refinery utilization, and domestic consumption emerge.

EIA estimates that OPEC surplus capacity, which is overwhelmingly concentrated in Saudi Arabia, remained relatively tight by historical standards at 2.0 million bbl/d over the past three months. Projected OPEC surplus capacity increases to 3.3 million bbl/d by the second quarter of 2013. This estimate does not include additional capacity that may be available in Iran but which is currently offline due to the impacts of U.S. and EU sanctions on Iran's ability to sell its oil.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories ended 2011 at 2.61 billion barrels, equivalent to 56.1 days of supply. Projected OECD oil inventories increase to 2.68 billion barrels (58.2 days of supply) by the end of 2012, and remain flat through the end of 2013. Forecast days of supply are at the highest end-of-year levels since 1991.

Crude Oil Prices. EIA projects the spot price of Brent crude oil will average $112 per barrel in 2012 and $104 per barrel in 2013, both mostly unchanged from last month's STEO. EIA expects the WTI price to average $89 per barrel in the fourth quarter of 2012, $1 per barrel lower than in last month's STEO, and to average $88 per barrel in 2013. EIA projects the WTI crude oil spot price discount to the Brent crude oil spot price will average $21 per barrel in the fourth quarter of 2012 before falling to $11 per barrel by the end of 2013.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for March 2013 delivery during the five-day period ending December 6, 2012, averaged $89.37 per barrel. Implied volatility averaged 28 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in March 2013 at $71 per barrel and $113 per barrel, respectively. Last year at this time, WTI for March 2012 delivery averaged $99 per barrel and implied volatility averaged 41 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $69 per barrel and $142 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Having fallen 230,000 bbl/d (1.2 percent) in 2011, total liquid fuels consumption is projected to shrink a further 310,000 bbl/d (1.6 percent) in 2012. All of the major petroleum categories contribute to the slide in consumption this year despite the continued economic recovery and little change in inflation-adjusted retail fuel prices. Motor gasoline consumption declines 30,000 bbl/d (0.3 percent) in 2012, with a 0.2-percent projected growth in highway travel more than offset by a 0.5-percent increase in fleetwide fuel efficiency. Warm weather during the first half of the year contributes to a projected 130,000-bbl/d (3.2-percent) decline in distillate fuel oil consumption in 2012, but softness in transportation (including export-oriented) markets accounts for part of the midyear weakness. Competitive natural gas prices, warm winter weather, and a decline in vessel bunkering consumption

contributed to a sizable 80,000-bbl/d (17.8-percent) decline in residual oil consumption to record lows in 2012.

In 2013, total liquid fuels consumption increases by 90,000 bbl/d (0.5 percent), with all of the major product categories exhibiting growth. Most of that recovery comes from distillate fuel oil and natural gas liquids consumption, which rise because of continued growth in freight shipments and industrial use as well as the assumption of near-normal weather this coming winter compared with much warmer-than-normal weather last winter. Despite higher assumed growth in U.S. real disposable income and a projected decline in gasoline retail prices of 5.5 percent, forecast motor gasoline consumption remains almost unchanged from 2012 because of continued slow growth in the driving-age population, improvements in the average fuel economy of new vehicles, and increased rates of retirement of older, less-fuel-efficient vehicles.

U.S. Liquid Fuels Supply and Imports. Onshore crude oil production in the Lower 48 United States is being driven by drilling activity in tight oil formations in Texas, North Dakota, and Montana. Bakken, a formation in the Williston Basin in North Dakota and Montana, and Eagle Ford, a formation in the Western Gulf Basin in Texas, are frequently referenced as the key productive plays in the United States and contribute about two-thirds of U.S. tight oil production. (The term play refers to an oil or natural gas formation with active prospecting and development.)

The Permian Basin in East Texas, which includes plays such as Spraberry, Bonespring, and Wolfcamp, is a third key growth area. The Permian Basin consists of layers of tight and conventional oil formations. In order to capitalize on this, the majority of rigs in this region are drilling vertical wells that produce oil from a number of the overlapping formations. The Permian Basin has more than 400 active drilling rigs, by far the most of any U.S. basin, that are drilling a large number of wells very quickly. EIA estimates that crude oil production from the Permian Basin surpassed 1.25 million bbl/d in November 2012, 33 percent greater than the estimated 0.93 million bbl/d in the Western Gulf Basin and 45 percent greater than the 0.86 million bbl/d in the Williston Basin.

Alaska crude oil production reached a seasonal low this year of 400,000 bbl/d in August, when summer maintenance typically decreases volumes, and has recovered to 560,000 bbl/d in November. EIA expects Alaskan crude oil production to average 530,000 bbl/d in 2012, about 6 percent lower than during 2011, and 520,000 bbl/d in 2013.

U.S. Federal Gulf of Mexico average daily oil production remained depressed at 1.17 million bbl/d in September 2012 due to outages early in the month related to Hurricane Isaac. Having recovered from the storm by the end of September, oil production is estimated to have increased to 1.37 million bbl/d in October and 1.39 million bbl/d in November. Average daily production for 2012 is projected to be 1.27 million bbl/d, approximately 40,000 bbl/d lower than during 2011.

The drought this year has raised concerns that barge traffic on the Mississippi River could be disrupted because of low water levels. Through the first 9 months of 2012, an average of 55,000 bbl/d of crude oil and 131,000 bbl/d of petroleum products were transported from the Midwest (PADD 2) to the Gulf Coast (PADD 3) by barge or tanker. From the Gulf Coast to the Midwest, 53,000 bbl/d of products were shipped, but there were no waterborne crude oil movements. This forecast assumes there are no disruptions to the waterborne transportation of liquid fuels on the Mississippi River.

The share of total U.S. consumption met by liquid fuel net imports, including crude oil, has been falling since peaking at over 60 percent in 2005. In 2011, it averaged 45 percent, down from 49 percent in 2010. EIA expects that the total net import share of consumption will continue to decline to 40 percent in 2012 as a result of continued substantial increases in oil production, an increase in net petroleum product exports, and an overall decline in liquid fuel consumption. The net import share of liquid fuel product consumption declines further to 37 percent in 2013 because of the projected increases in domestic crude oil production. It will be the first time since 1991 that the share of total U.S. consumption met by liquid fuel net imports is less than 40 percent. In EIA's *Annual Energy Outlook 2013* Reference case released last week, the import share continues to decline to 34 percent in 2019 with slow increases thereafter.

U.S. Petroleum Product Prices. U.S. regular gasoline retail prices fell from an average of $3.75 per gallon in October 2012 to an average of $3.45 per gallon in November, which was the lowest average since July of this year. The West Coast (PADD 5) experienced the largest decline in retail gasoline prices over the last two months, as multiple supply constraints were resolved and gasoline inventories recovered. PADD 5 regular gasoline retail prices fell by $0.79 per gallon, from $4.41 per gallon on October 8, 2012 to $3.62 per gallon on December 3, 2012. Regular gasoline prices in the Central Atlantic states (PADD 1B) fell by $0.32 per gallon over this same period despite the market disruptions caused by Hurricane Sandy. EIA expects regular-grade gasoline retail prices, which averaged $3.53 per gallon in 2011, to average $3.63 per gallon and $3.43 per gallon in 2012 and 2013, respectively.

On-highway diesel fuel retail prices averaged $4.09 per gallon in October 2012, and continued tight market conditions and strong global demand kept on-highway diesel fuel prices at an average of $4.00 per gallon in November. On November 23, 2012, U.S. week-ending stocks of distillate fuel oil fell to their lowest level since May 30, 2008, despite the higher expected demand during the upcoming winter heating oil season. EIA expects that on-highway diesel fuel retail prices will average $3.97 per gallon in 2012 and $3.84 per gallon in 2013. Wholesale diesel margins (the difference between the wholesale price of diesel and the U.S. average refiner acquisition cost of crude oil) averaged $0.60 per gallon in the first half of 2012, and then climbed to an average of $0.97 per gallon in October, the highest monthly average on record, surpassing the previous high of $0.96 per gallon in October 2005. EIA projects wholesale diesel margins will average $0.91 per gallon in the fourth quarter of 2012 and $0.76 per gallon in 2013, compared with the previous five-year (2007-2011) average of $0.52 per gallon.

Natural Gas

U.S. Natural Gas Consumption. Overall natural gas consumption in late October and early November showed little response to Hurricane Sandy, which hit the Northeast on October 29. Declines in natural gas-fired generation because of electric power outages may have been somewhat mitigated by power producers substituting natural gas for shut-down nuclear capacity resulting from the storm. Most of the effects of the storm on natural gas markets appear to have been short-lived, and EIA has not made substantial adjustments to its forecast as a result of Hurricane Sandy.

EIA expects that natural gas consumption will average 69.7 billion cubic feet per day (Bcf/d) in 2012, an increase of 4.8 percent from 2011. Large gains in electric power use in 2012 more than offset declines in residential and commercial use. EIA projects consumption of natural gas for power generation in 2012 will exceed the previous year's level by 21.3 percent. Consumption of natural gas for power generation was particularly high in 2012 because of an unusually hot summer combined with relatively low gas prices. While consumption of gas for power generation is expected to decline 10.4 percent in 2013 to 22.6 Bcf/d, natural gas for power generation remains high by historical standards and reflects a structural shift toward using more natural gas for power generation.

Projected consumption in 2013 declines slightly from 2012, as increases in residential and commercial consumption offset the declines in electric power use. The National Oceanic and Atmospheric Administration projects temperatures that are near normal this winter, but much colder than last year's mild winter. The weather forecasts imply large increases in use of natural gas for heating.

U.S. Natural Gas Production and Imports. This month's STEO revises upward the forecast for marketed production for 2012 by 0.4 Bcf/d to 69.2 Bcf/d. While the revision is relatively small, the cause of the revision is significant. EIA's production survey indicated a 9 percent increase in production between August and September 2012. Part of this increase is a recovery from Hurricane Isaac-related declines in August, but the increase also reverses several months of declines that had taken place earlier in 2012. At 69.4 Bcf/d, marketed production in September was slightly higher than January 2012 and the highest since February 1973 despite the decline in the natural gas rig count this year. According to Baker Hughes, the natural gas rig count was 417 as of December 7, 2012, compared with 811 at the start of 2012.

EIA forecasts that total marketed production will average 69.6 Bcf/d in 2013, slightly up from 2012. Even with the projected increases in the second half of 2012, production growth has slowed from its strong upward trajectory seen in 2009–11. EIA expects that growth in associated gas from crude oil production, as well as continued drilling in liquids-rich areas, will continue to offset the decline in drilling activity.

EIA expects pipeline gross imports will fall by 0.2 Bcf/d (2.8 percent) in 2012, as domestic supply continues to displace Canadian sources. The warm winter in the United States early this year also added to the year-over-year decline in imports, particularly to the Northeast where imported natural gas can serve as additional supply in times of very cold weather. EIA expects a slight increase in pipeline gross imports in 2013. Gross exports to Mexico have grown substantially since 2010, but EIA expects this growth will taper off in 2013 and exports will remain at their 2012 level of 4.4 Bcf/d.

Liquefied natural gas (LNG) imports are expected to remain at minimal levels of less than 0.5 Bcf/d in both 2012 and 2013. Exports mainly arrive at the Elba Island terminal in Georgia and the Everett terminal in New England, either to fulfill long-term contract obligations or to take advantage of temporarily high local prices due to cold snaps and disruptions. Higher prices for LNG, particularly in Asian markets, have made the United States a market of last resort for LNG suppliers.

U.S. Natural Gas Inventories. At the end of October, inventories heading into the winter were very strong at 3,923 Bcf, and injections continued a few weeks into November. On November 2, 2012, inventories hit a record high level of 3,929 Bcf, surpassing the previous record set the week before, according to EIA's *Weekly Natural Gas Storage Report*. An injection of 4 Bcf for the week ending November 23 surprised many analysts, who had been expecting a net withdrawal for the week. Unsurprisingly, the Nymex January 2013 Henry Hub futures contract dropped 15.3 cents on November 29 (the day the November 23 report was released).

While inventories ended the injection season at a record high, it was due mainly to a high level of gas going into the injection season, rather than strong injection levels. The increase of 1,446 Bcf in working gas inventory during the 2012 injection season (from the beginning of April through the end of October) is small by historical standards. Last year's inventory build from April through October, for comparison, was 2,224 Bcf.

U.S. Natural Gas Prices. Natural gas spot prices averaged $3.54 per MMBtu at the Henry Hub in November 2012, up $0.23 per MMBtu from the October 2012 average and $0.30 per MMBtu more than the November 2011 average. EIA expects the Henry Hub natural gas price will average $2.78 per MMBtu in 2012 and $3.68 per MMBtu in 2013; these are increases of $0.01 per MMBtu in 2012 and $0.19 per MMBtu in 2013 from projections in last month's STEO.

Natural gas futures prices for March 2013 delivery (for the five-day period ending December 6, 2012) averaged $3.62 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for March 2013 contracts at $2.62 per MMBtu and $5.00 per MMBtu, respectively. At this time last year, the March 2012 natural gas futures contract averaged $3.63 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were $2.62 per MMBtu and $5.05 per MMBtu.

Coal

U.S. Coal Consumption. EIA forecasts coal consumption in the electric power sector to total 829 million short tons (MMst) in 2012, the lowest amount since 1992. Lower natural gas prices to electric generators have led to a significant increase in the share of natural gas-fired generation. EIA projects power sector coal consumption to grow by 5 percent in 2013, as higher natural gas prices lead to a reduction in natural gas-fired generation.

U.S. Coal Supply. EIA forecasts that coal production will decline by 6 percent in 2012 as domestic consumption falls. EIA expects production to increase slightly by 1 percent in 2013 as inventory draws and lower exports offset an increase in domestic consumption in the forecast. Electric power sector stocks, which ended 2011 at 172 MMst, are forecast to total 183 MMst at the end of the 2012 and 179 MMst in 2013.

U.S. Coal Trade. EIA expects coal exports to total a record 124 MMst in 2012. EIA projects that coal exports will decline in 2013 but remain above 100 MMst for the third straight year. Continuing economic weakness in Europe and lower international coal prices are primary reasons for the expected decline in coal exports. U.S. exports could be higher if there are significant supply disruptions from any of the major coal-exporting countries.

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

Electricity

U.S. Electricity Consumption. Variations in winter weather can have a significant effect on residential electricity consumption, especially in the southeastern United States where nearly two-thirds of households use electricity as their primary heating source. Last winter, heating degree days in the South Atlantic Census division during the months of December, January, and February totaled about 21 percent below the 30-year normal. As a consequence, residential electricity consumption during those three months reached the lowest level since the winter of 2005-06.

Forecast heating degree days nationwide during the next three months (December-February) total about 15 percent more than last winter, which would lead to a year-over-year increase in U.S. residential electricity consumption of 8.6 percent during that period. For all of 2013, EIA projects flat growth in U.S. residential electricity sales as cooler summer weather and the

associated reduction in electricity consumption for space cooling offsets the projected increase in winter electricity consumption.

U.S. Electricity Generation. The most important trend in electricity generation over the past few years has been the industry's price-driven substitution of coal-fired generation with generation fueled by natural gas. Through September this year, the price of natural gas delivered to electric generators has averaged 35 percent less than the cost during the same period last year, while the delivered price of coal is unchanged. In response, the share of total generation fueled by natural gas during the first three quarters of the year has risen from 24 percent in 2011 to 31 percent this year.

By January 2013, EIA expects the delivered price of natural gas will be 31 percent higher than the price during January 2012, which should begin to lower the use of natural gas for power generation. EIA projects the share of generation fueled by natural gas in 2013 to average 27.2 percent compared with an annual average share of 30.4 percent in 2012.

U.S. Electricity Retail Prices. EIA expects the nominal U.S. residential electricity price will rise by 1.2 percent during 2012, compared with an increase of 1.6 percent last year and an average annual increase of 2.4 percent during the previous five years. Residential prices during 2013 are projected to rise by 1.6 percent to an average of 12.0 cents per kilowatthour.

Renewables and Carbon Dioxide Emissions

U.S. Renewables. After growing by 13.1 percent in 2011, total renewable energy consumption is projected to decline by 2.0 percent in 2012. This decrease is the result of hydropower production falling by 0.4 quadrillion Btu (13.1 percent), as precipitation patterns in the Pacific Northwest fall from the unusually high levels seen in 2011. The decline in hydropower from 2011 to 2012 more than offsets the projected growth in the consumption of other renewable energy forms. Renewable energy consumption increases 3.7 percent in 2013 as hydropower is projected to grow by 1.1 percent and nonhydropower renewables grow by an average of 5.0 percent.

Under current law, the federal production tax credit (PTC) for wind-powered generation will not be available for turbines that begin commercial operations after the end of 2012. Wind-powered generation, which grew by 27 percent in 2011, is forecast to grow an additional 15 percent in 2012. Based on current reporting to EIA, 6 gigawatts of wind capacity is scheduled to come on line in the last two months of 2012, in addition to the approximately 6 gigawatts that entered service from January 2012 through October of 2012. This is projected to lead to an additional 15-percent increase in wind generation in 2013 as compared to 2012, as this new capacity would be operating for the entire year. Absent the PTC, very little new capacity is projected to come on line in 2013.

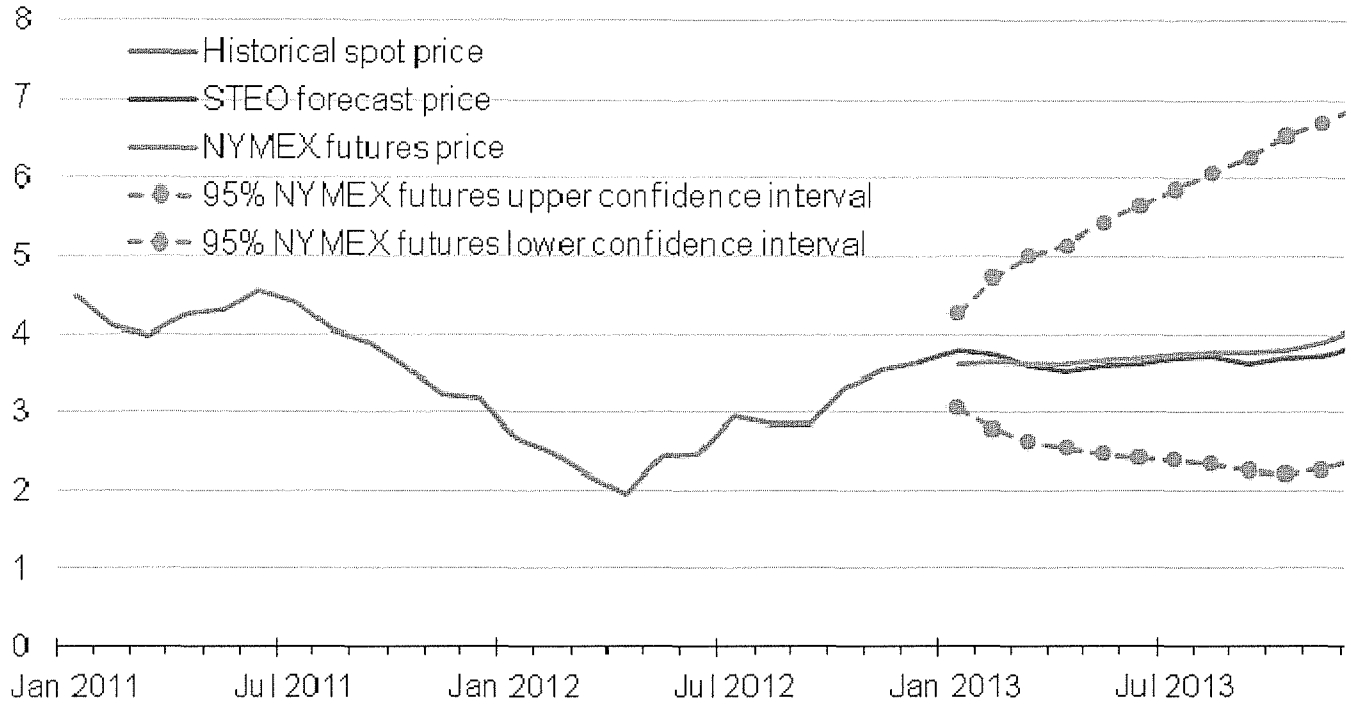
Solar energy continues robust growth, although the total amount remains small compared to total U.S. generation. Consumption is projected to grow by 31 percent in 2012 and 28 percent in 2013.

As a result of drought conditions depressing corn harvests throughout the Midwest, fuel ethanol production fell from an average of 900,000 bbl/d during the first half of 2012 to an average of 820,000 bbl/d in the second half of the year. EIA expects ethanol production will remain near current levels through mid-2013 before recovering to pre-drought production levels, averaging 861,000 bbl/d (13.2 billion gallons) for the year. The projected lower ethanol production is generally matched by higher ethanol imports and lower ethanol exports. Biodiesel production averaged about 63,000 bbl/d (0.97 billion gallons) in 2011. Forecast biodiesel production averages 66,000 bbl/d in 2012 and 80,000 bbl/d in 2013, with biodiesel blending meeting the Renewable Fuels Standard requirements of 1.0 billion gallons and 1.28 billion gallons, respectively, in those years.

U.S. Energy-Related Carbon Dioxide Emissions. After declining by 2.2 percent in 2011, fossil fuel emissions are projected to further decline by 3.2 percent in 2012. This decline is followed by an increase of 1.8 percent in 2013.

Henry Hub Natural Gas Price

dollars per million btu



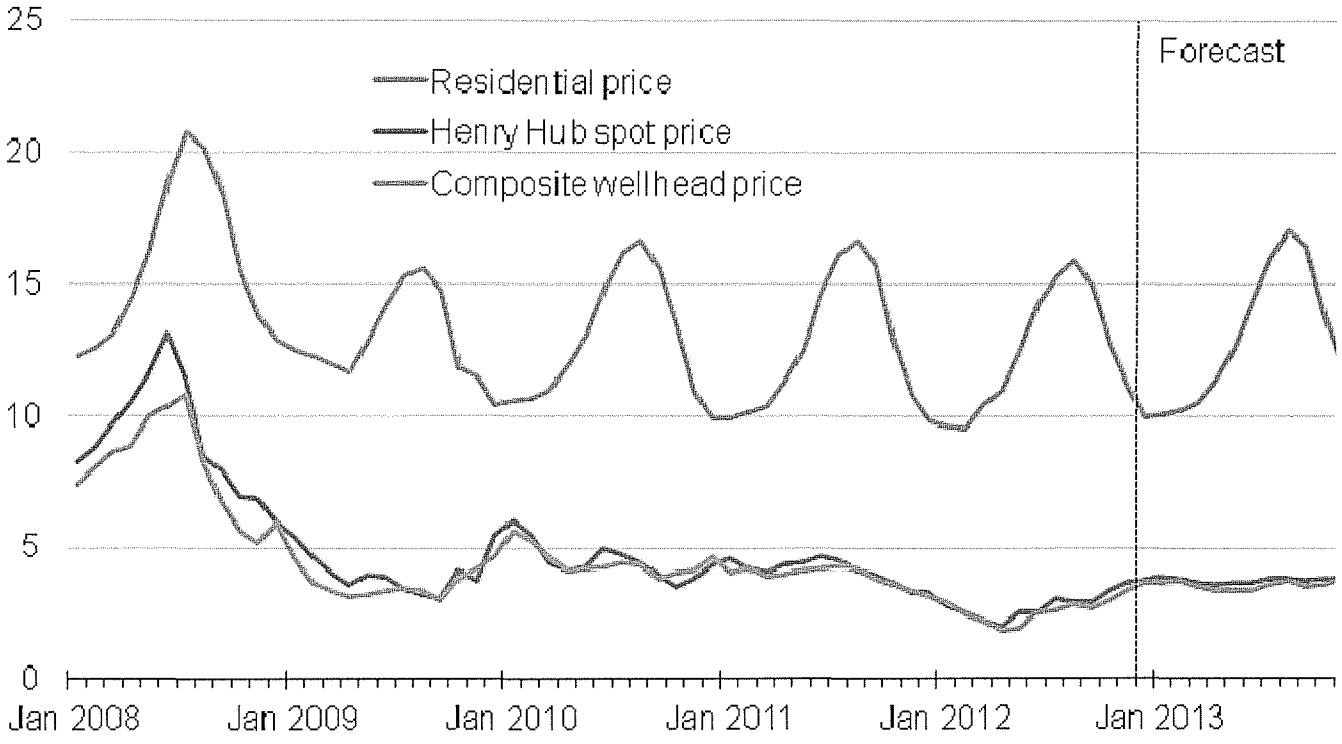
Note: Confidence interval derived from options market information for the 5 trading days ending December 6, 2012. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, December 2012

eia

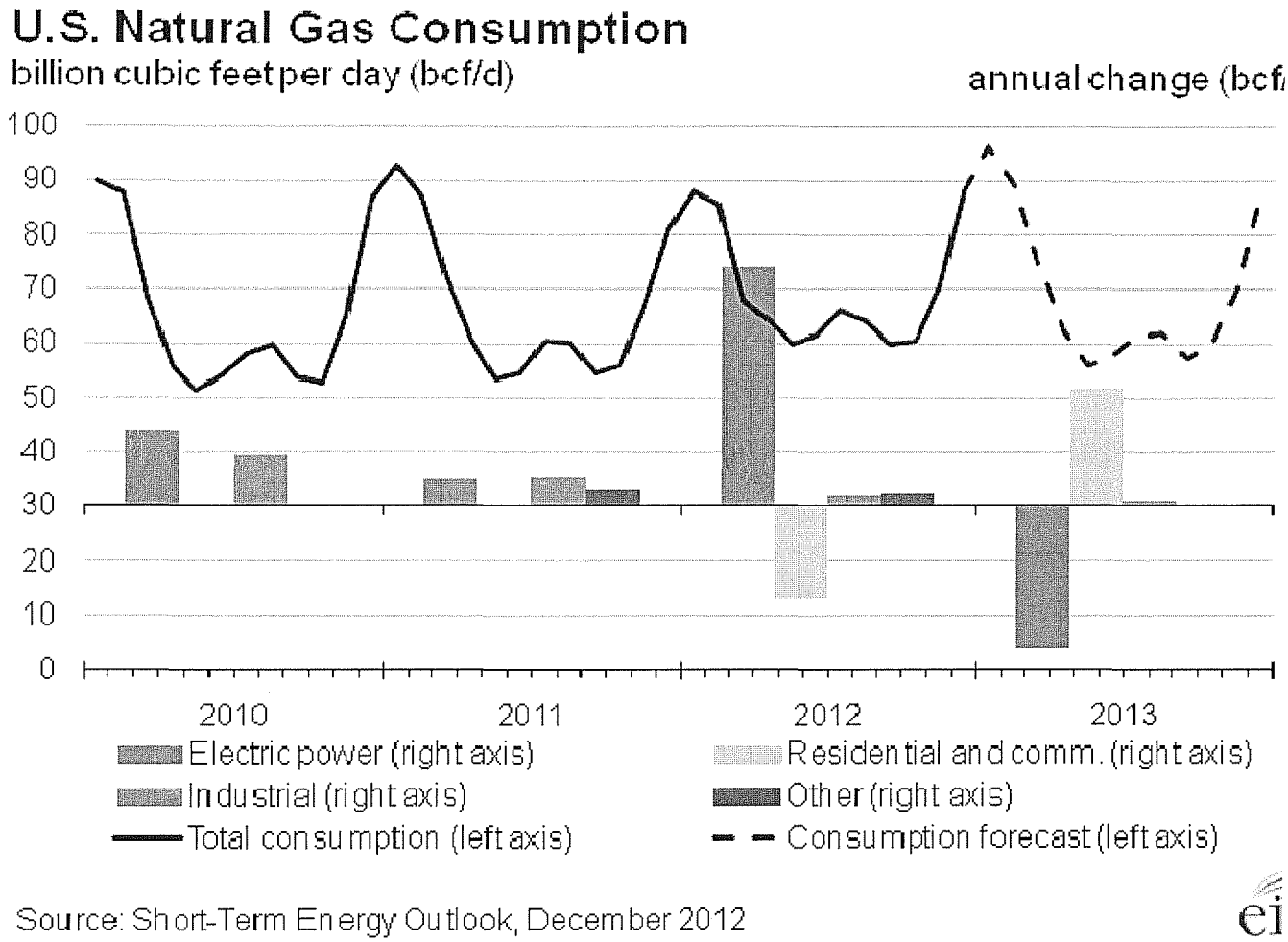
U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, December 2012

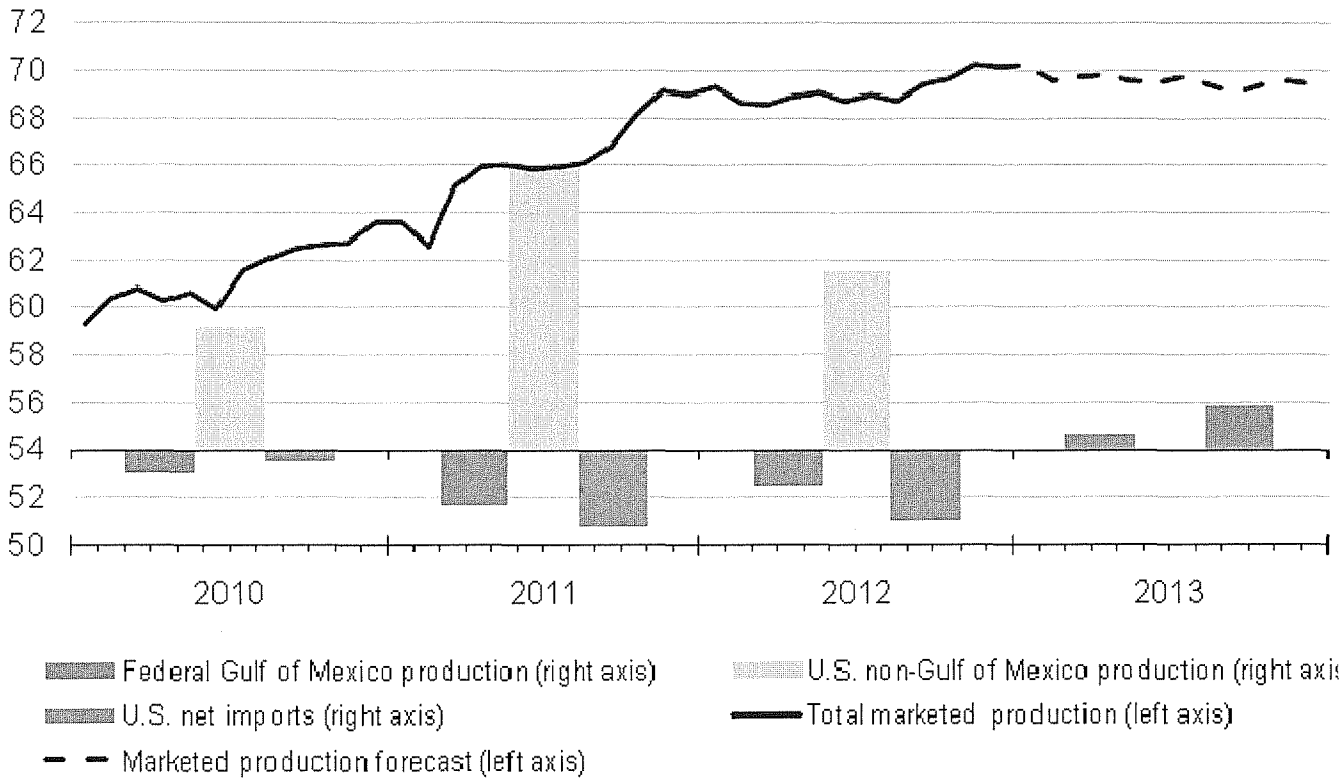
ei



Source: Short-Term Energy Outlook, December 2012

U.S. Natural Gas Production and Imports

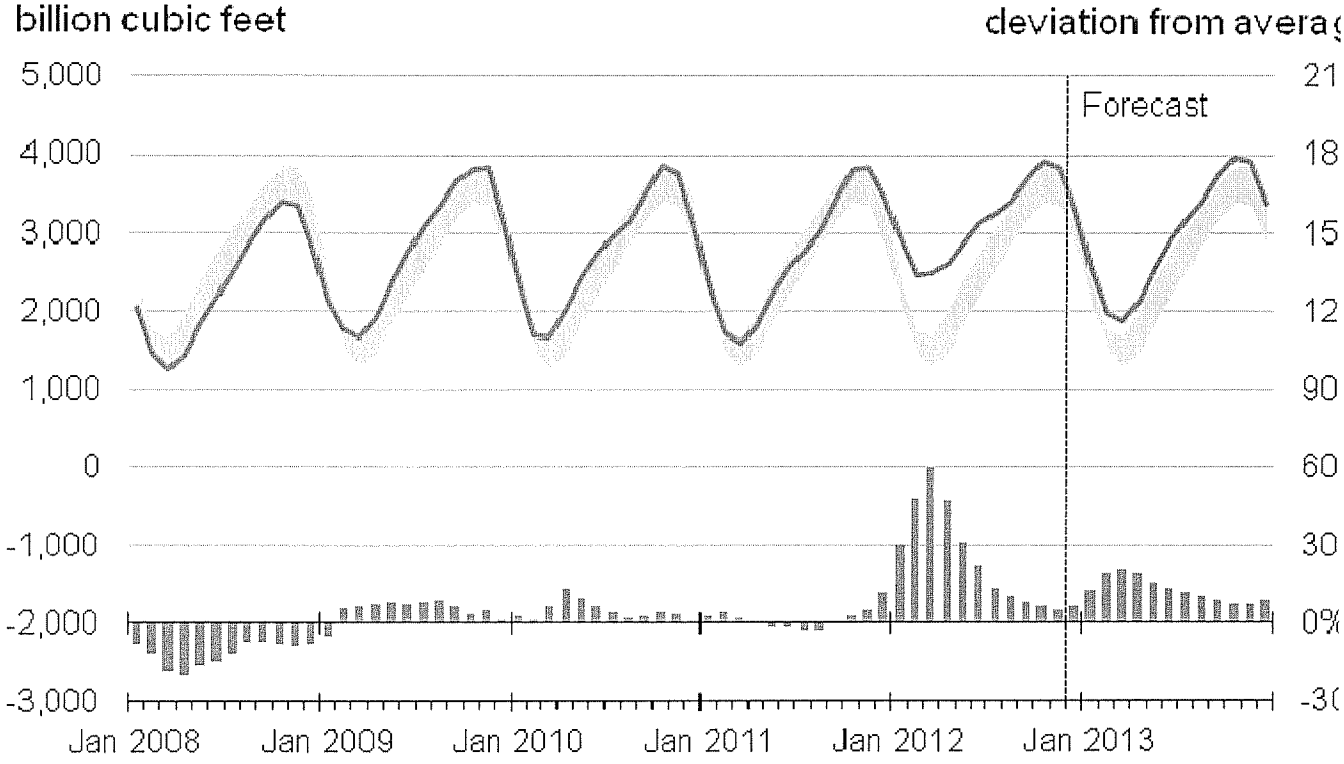
billion cubic feet per day (bcf/d) annual change (bcf



Source: Short-Term Energy Outlook, December 2012

ei

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, December 2012

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount		Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2012										**$311,764**
May	$30,099	$0	$2,016	$32,115	13,138	$0.5102	$6,702		$25,413	337,177
June	52,819	0	2,192	55,011	6,558	1.0137	4,625	2/	50,386	387,563
July	57,568	0	2,542	60,110	5,776	1.0137	5,855		54,255	441,818
August	58,888	0	2,918	61,806	5,143	1.0137	5,213		56,593	498,411
September	26,138	0	3,308	29,446	6,241	1.0137	6,327		23,119	521,530
October	36,902	0	3,454	40,356	10,185	1.0137	10,325		30,031	551,561
November	8,143	0	3,651	11,794	20,404	1.0137	20,684		(8,890)	542,671
Balance @ November 30, 2012										**$542,671**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 4,017.3 dk @ $0.5102 and 2,540.6 dk @ $1.0137.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2012									**($72,396)**
May	($11,426)	$0	($557)	($11,983)	23,670	($0.0178)	($422)	($11,561)	(83,957)
June	(6,055)	0	(637)	(6,692)	13,697	(0.2915)	(1,509) 2/	(5,183)	(89,140)
July	(16,584)	0	(671)	(17,255)	13,108	(0.2915)	(3,821)	(13,434)	(102,574)
August	(2,356)	0	(765)	(3,121)	14,195	(0.2915)	(4,138)	1,017	(101,557)
September	(20,241)	0	(754)	(20,995)	21,085	(0.2915)	(6,146)	(14,849)	(116,406)
October	325	0	(859)	(534)	37,029	(0.2915)	(10,794)	10,260	(106,146)
November	6,923	0	(784)	6,139	41,796	(0.2915)	(12,184)	18,323	(87,823)
Balance @ November 30, 2012									**($87,823)**

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