



A Division of MDU Resources Group, Inc.

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December 1, 2009

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

Re: Cost of Gas Adjustment (COG)  
December 2009

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 (45<sup>th</sup> Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (45<sup>th</sup> Revised Sheet No. 8), showing the December 2009 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.1254 per mcf for residential and firm general service customers and \$0.1813 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for December 2009, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.1813 per mcf since the last COG filing due to a decrease in the market price of gas. There has been an increase in pipeline charges of \$0.0559 per mcf due to changes in pipeline charges. The net effect of these changes is a decrease of \$0.1254 per mcf for residential and firm general service customers.

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

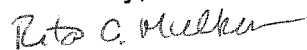
Attachment D shows the calculation of the balancing account since April 30, 2009.

Great Plains submitted a check for \$600.00 on December 30, 2008 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment covers the \$50.00 filing fee associated with this month's COG filing.

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

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

Sincerely,



Rita A. Mulkern  
Regulatory Analysis 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

45th Revised Sheet No. 1.1

Canceling 44th Revised Sheet No.1.1

### RATE SUMMARY SHEET

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/MCF
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF \$1.2740 Over 10 MCF 1.0540	\$7.4207	\$8.6947 8.4747
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411	\$3.9275	\$5.0666 4.8206 4.6686
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$3.9275	\$5.1666
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: December 1, 2009

Effective Date: December 1, 2009

Issued By: Donald R. Ball  
Vice President - 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  
 45<sup>th</sup> Revised Sheet No. 8  
 Canceling 44<sup>th</sup> 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.	2.3953	(0.2684)	0.2343	2.3612	(0.2684)	(0.7419)	(1.0103)
Current Adj.	0.0559	(0.1813)	0.0000	(0.1254)	(0.1813)	0.0000	(0.1813)
Total Adj.	2.4512	(0.4497)	0.2343	2.2358	(0.4497)	(0.7419)	(1.1916)
Total Rate:	\$2.5170	\$4.6694	\$0.2343	\$7.4207	\$4.6694	(\$0.7419)	\$3.9275

**Date Filed:** December 1, 2009

**Effective Date:** December 1, 2009

**Issued By:** Donald R. Ball  
 Vice President – Regulatory Affairs

**Case No.:**

**GREAT PLAINS NATURAL GAS CO.  
WAHPETON  
COST OF GAS ADJUSTMENT  
DECEMBER 2009**

<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	\$0.2084
FT-A - Zone 1-1	500	3.4671	5	8,668	0.0055
FT-A - Zone 1-2	4,500	4.5871	5	103,210	0.0659
FT-A Seasonal	3,000	3.7671	5	56,507	0.0361
TFX Seasonal	3,000	15.1530	5	227,295	0.1452
NOVA - Demand Charge	7,947	13.1434	12	1,253,407	0.8006
Trans Canada - Demand Charge	7,947	11.6733	12	1,113,213	0.7111
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068	13.1434	5	333,054	0.2127
Trans Canada - Seasonal	5,068	11.6733	5	295,801	0.1889
BP Canada - Seasonal	5,068	0.9612	5	24,357	0.0156
BP Canada Winter Surcharge	5,068	3.0417	5	77,077	0.0492
LMS Demand	2,500	1.0000	12	30,000	0.0192
Total Demand Charges				<u>\$3,940,479</u>	<u>2.5170</u>
Estimated Weighted Average Commodity Cost	1,565,565	1/ 4.6694		<u>7,310,249</u>	<u>4.6694</u>
Gas Cost Reconciliation Adjustment					<u>0.2343</u>
Total Current Firm Gas Cost				<u>\$11,250,728</u>	<u>7.4207</u>
Base Cost of Gas					<u>5.1849</u>
Accumulated Adjustment					<u>\$2.2358</u>
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$4.6694
Gas Cost Reconciliation Adjustment					<u>(0.7419)</u>
Total Current Interruptible Gas Cost					<u>3.9275</u>
Base Cost of Gas					<u>5.1191</u>
Accumulated Adjustment					<u>(\$1.1916)</u>

1/ Authorized in MN Docket No. G004/GR-04-1487 plus Wahpeton volumes.

**GREAT PLAINS NATURAL GAS CO.  
WAHPETON  
COST OF GAS ADJUSTMENT  
DECEMBER 2009**

<b>Rates Effective December 1, 2009</b>	<u>\$/Dk</u>	
FT-A - Zone 1-1	\$3.4671	Per dk/Mo.
FT-A - Zone 1-2	4.5871	Per dk/Mo.
FT-A - Seasonal	3.7671	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
NOVA - Demand Charge	13.1434	Per dk/Mo.
Trans Canada Pipeline Demand Charge	11.6733	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	13.1434	Per dk/Day
Trans Canada - Seasonal	11.6733	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:	4.6694	Per dk
<b>Base Rate Effective September 1, 1981</b>		
Demand Charge	\$0.8100	Per Mcf/Mo.
Commodity Charge	5.1191	Per Mcf
<b>Base Rate Calculation</b>		
<u>Firm</u>		
Demand 1/	\$0.0658	Per Mcf
Commodity	5.1191	Per Mcf
Total Firm Base Cost	<u>\$5.1849</u>	Per Mcf
<u>Interruptible:</u>		
Commodity	\$5.1191	Per Mcf

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

Viking Gas Transmission Company  
FERC Gas Tariff  
First Revised Volume No. 1

Twelfth Revised Sheet No. 5  
Superseding  
Eleventh Revised Sheet No. 5

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

Issued by: Raymond D. Neppel, Vice President  
 Issued on: November 29, 2005  
 Effective on: January 1, 2006  
 Filed to comply with order of the Federal Energy Regulatory Commission, Docket  
 No. RP02-132-002, issued November 8, 2002, 01 FERC ¶ 61,170

Viking Gas Transmission Company  
FERC Gas Tariff  
First Revised Volume No. 1

Twenty-Seventh Revised Sheet No. 5B  
Superseding  
Twenty-Sixth Revised Sheet No. 5B

STATEMENT OF RATES (Rates Per Dekatherm)				
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	\$0.0019	\$0.0149	0.74%
Zone 1 - 2	\$0.0130	\$0.0019	\$0.0149	0.87%
Zone 2 - 2	\$0.0130	\$0.0019	\$0.0149	0.13%
Minimum Rate	\$0.0130	\$0.0019	\$0.0149	
IT and AOT				
Zone 1 - 1	\$0.1368	\$0.0019	\$0.1387	0.74%
Zone 1 - 2	\$0.1737	\$0.0019	\$0.1756	0.87%
Zone 2 - 2	\$0.0834	\$0.0019	\$0.0853	0.13%
Minimum Rate	\$0.0130	\$0.0019	\$0.0149	
1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of \$0.0019 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: .05% for Zone 1-1, .06% for Zone 1-2, and .01% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted For percentages.				

Issued by: Ron Mucci, Vice President of Regulatory

Issued on: September 25, 2009

Effective on: November 1, 2009

Viking Gas Transmission Company  
FERC Gas Tariff  
First Revised Volume No. 1

Fourteenth Revised Sheet No. 5C  
Superseding  
Thirteenth Revised Sheet No. 5C

STATEMENT OF RATES  
(Rates Per Dekatherm)

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		\$0.0080	

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.

Issued by: J. Phill May, Vice President Commercial

Issued on: February 20, 2009

Effective on: April 1, 2009

R A T E S C H E D U L E T F

RESERVATION RATES	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
	TF12 Base	TF12 Variable	TF5	TFF
Base Tariff Rates 1/				
Summer (Apr-Oct)	5.683	5.683	-0-	5.473
Winter (Nov-Mar)	10.230	13.866	15.153	9.853

COMMODITY RATES 2/		Market Area 3/		Field Mileage 5/		Carlton Surcharge 4/		Out-of Balance 3/		
TF12 Base, TF12 Var., TF5 & TFF	Receipt Point	Maximum	Minimum	Rate per 100 miles	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
	Market	0.0381	0.0212				0.0175	0.0000	0.0381	0.0212
	Field	0.0381	0.0212	0.0122	0.0040		0.0175	0.0000		
	Market			0.0122	0.0040					
	Field			0.0122	0.0040				0.0295	0.0109

- 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.
- 3/ Maximum and Minimum rates include ACA of \$0.0019 and the Market Area Electric Compression charge of \$0.0003 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.

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

79 Revised Sheet No. 51  
Superseding  
78 Revised Sheet No. 51

R A T E S C H E D U L E S T F X a n d L F T

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	0.0381	0.0212			0.0175	0.0000	0.0381	0.0212
Field	Market	0.0381	0.0212	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0295	0.0109

GULF COAST	Reservation 1/		Commodity 6/		Out-of-Balance 6/	
	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
MOPS Gathering	1.0514	0.0000	0.0019	0.0019	0.0019	0.0019
MOPS Transmission	1.5337	0.0000	0.0019	0.0019	0.0019	0.0019
Tivoli - Downstream	0.6827	0.0000	0.0019	0.0019	0.0019	0.0019
Other Gulf Coast	4.8169	0.0000	0.0019	0.0019	0.0019	0.0019

- 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.
- 3/ Maximum and Minimum rates include ACA of \$0.0019 and the Market Area Electric Compression charge of \$0.0003 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 \$0.0019.

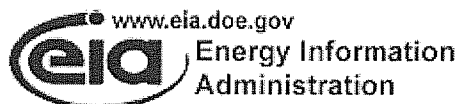
**Great Plains Natural Gas Co.  
Market Conditions for Wahpeton's Natural Gas  
December 2009**

The principal gas sources of natural gas for Wahpeton, North Dakota are from the large Western Canadian Sedimentary Basin (WCSB). The pricing point for much of this gas is the Alberta Energy Company (AECO-C), one of the largest and most liquid volume points in North America. The December monthly price for the AECO Index is expected to decrease 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).

Factors likely contributing to the expected decrease in the index price are high levels of gas in storage and unseasonably mild temperatures across much of the U.S. resulting in less demand for space heating. The Energy Information Administration (EIA) reported storage levels nationwide as of November 20, 2009 were 13.0 percent above the five-year average and 11.8 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 12.



November 2009

## Short-Term Energy Outlook

November 10, 2009 Release

### Highlights

- EIA is raising the forecast price of West Texas Intermediate (WTI) crude oil by \$7 per barrel compared with the last *Outlook*, to average about \$77 per barrel this winter (October-March). The forecast for monthly average WTI prices rises to about \$81 per barrel by December 2010, assuming U.S. and world economic conditions continue to improve, particularly in Asia, where current growth has been stronger than expected. EIA's forecast assumes U.S. real gross domestic product (GDP) grows by 1.9 percent in 2010 and world oil-consumption-weighted real GDP grows by 2.6 percent.
- EIA projects the monthly average regular-grade gasoline retail price to rise from \$2.55 per gallon in October to \$2.70 per gallon this month. Generally higher crude oil prices through the forecast period contribute to an increase in the annual average gasoline retail price from \$2.36 per gallon in 2009 to \$2.81 in 2010, with prices near \$3.00 per gallon during next year's driving season. Projected annual average diesel fuel retail prices are \$2.48 and \$2.94 per gallon, respectively, in 2009 and 2010. Higher forecast crude oil prices also raise the projected average household expenditures on heating oil this winter to \$1,940 in this forecast, compared with \$1,864 last winter.
- EIA projects the monthly Henry Hub natural gas spot price to average \$4.22 per thousand cubic feet (Mcf) in November, more than \$2.60 per Mcf lower than the November 2008 price. Natural gas inventories at the end of this year's injection season (October 31) were about 3.8 trillion cubic feet (Tcf), a record level for this time of the year. With a growing economy and expected decrease in natural gas production, the projected Henry Hub annual average spot price increases from \$4.03 per Mcf in 2009 to \$5.01 in 2010.

## Global Crude Oil and Liquid Fuels

**Global Petroleum Overview.** Sustained economic growth in China and other Asian countries is contributing to the beginnings of a rebound in world oil consumption, leading EIA to revise its expectations for world oil consumption upwards for the second consecutive month, with consumption growth increased by 0.15 million barrels per day (bbl/d) for both 2009 and 2010 compared with the last *Outlook*. Although Organization for Economic Cooperation and Development (OECD) oil inventories (as measured in days-of-supply) remain high, optimism for a continued economic turnaround combined with the impact of Organization of the Petroleum Exporting Countries' (OPEC) production cuts have driven oil prices higher. However, if the economic recovery stalls and oil consumption does not rebound, oil prices could weaken given the high level of inventories.

**Global Petroleum Consumption.** China and other Asian countries outside of the OECD continue to lead a global economic and oil market turnaround. Although EIA expects oil consumption by OECD members to continue to show year-over-year declines for the fourth quarter of 2009, oil demand growth in the non-OECD countries during this period is expected to more than offset these losses, leading to the first growth in global oil consumption in 5 quarters. EIA projects world oil consumption to grow in 2010 by 1.26 million bbl/d (World Liquid Fuels Consumption Chart). Non-OECD countries are expected to represent the largest share of this growth. Projected OECD oil consumption grows by only 0.1 million bbl/d in 2010, largely because of the projected turnaround in the United States, which would mark the reversal of a downward trend in U.S. oil consumption that began in 2005.

**Non-OPEC Supply.** Total oil production by countries outside of OPEC averaged 50.1 million bbl/d during the first 3 quarters of 2009, about 0.5 million bbl/d higher than year-earlier levels. Non-OPEC oil production has been surprisingly strong in 2009, largely the result of higher-than-expected production from Russia. Russian oil production exceeded 10 million bbl/d in August, setting a new record for the post-Soviet era. Projected non-OPEC supply increases by 0.25 million bbl/d in 2010. Over the forecast period, higher output from the Former Soviet Union, Brazil, and the United States should offset falling production in Mexico and the North Sea (Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart).

**OPEC Supply.** OPEC crude oil production averaged 29.0 million bbl/d during the first 3 quarters of 2009, down 2.4 million bbl/d from year-earlier levels. EIA expects OPEC crude oil production to rise gradually in 2010 to an average of 29.4 million bbl/d in response to an anticipated rebound in demand (World Crude Oil and Liquid Fuels Production Growth Chart). Through the forecast period, OPEC surplus

production capacity should remain in excess of 4 million bbl/d, versus an average of 2.8 million bbl/d seen over the 1998-2008 period ([OPEC Surplus Crude Oil Production Capacity Chart](#)). EIA expects OPEC non-crude petroleum liquids, which are not subject to OPEC production targets, to grow by 0.7 million bbl/d in 2010, following a projected gain of 0.4 million bbl/d in 2009. OPEC is scheduled to meet in Angola on December 22 to reassess the market situation.

**OECD Petroleum Inventories.** Based on preliminary estimates, OECD commercial oil inventories stood at 2.75 billion barrels at the end of the third quarter of 2009. At 61 days of forward cover, OECD commercial inventories were well above average levels for that time of year ([Days of Supply of OECD Commercial Stocks Chart](#)). EIA expects OECD oil inventories to decline toward average historical levels throughout the forecast period.

**Crude Oil Prices.** WTI oil futures prices for the December 2009 contract averaged \$76 per barrel in October on the New York Mercantile Exchange (NYMEX), almost \$6 per barrel above the prior month's average for that contract. This was an increase of just over 8 percent for the month, with expectations of an economic recovery and higher oil consumption offsetting concerns about current high oil inventories.

Expected price volatility in the crude oil markets has declined since last month's *Outlook*, indicating the markets were slightly more comfortable with news of an economic turnaround led by Asia. For the 5 days ending November 5, the January 2010 WTI futures contract prices averaged just under \$80 per barrel ([West Texas Intermediate \(WTI\) Crude Oil Price Chart](#)), and the implied volatility for options on that contract averaged just over 41 percent, down more than 7 percentage points from the 49-percent level prevailing the month prior. The 95-percent confidence interval for the January 2010 WTI futures contract consistent with this volatility was \$61 per barrel at the lower limit and \$104 per barrel at the upper limit, a range of \$43 per barrel.

A year ago, NYMEX market participants were pricing WTI delivered to Cushing, Oklahoma, in January 2009 at just over \$66 per barrel. The implied volatility at that time for the January 2009 contract was double the current level, at 82 percent per annum. This implied lower and upper limits of \$39 and \$113 per barrel, respectively, for the 95-percent confidence interval. This reflected significant market uncertainty following a price collapse from all-time highs of more than \$145 per barrel for WTI in July 2008.

## U.S. Crude Oil and Liquid Fuels

**U.S. Petroleum Consumption.** EIA forecasts total consumption of liquid fuels and other petroleum products to decline by about 780,000 bbl/d (4.0 percent) in 2009 compared with 2008 ([U.S. Liquid Fuels Consumption Growth Chart](#)). During the first half of the year, consumption declined by almost 1.25 million bbl/d (6.3 percent) from the same period last year, one of the steepest declines on record. The year-over-year projected decline in petroleum consumption slows to 310,000 bbl/d (1.6 percent) in the second half of 2009 as economic recovery begins to take hold. Monthly average motor gasoline consumption since June has shown year-over-year increases for the first time since September 2007 and continues to grow over year-ago levels throughout the forecast. The modest economic recovery projected for 2010 contributes to a 290,000-bbl/d (1.6-percent) increase in total liquid fuels consumption, led by an increase of 110,000 bbl/d (3.0 percent) in distillate consumption. Except for residual fuel oil, consumption of all the major products grows in 2010.

**U.S. Petroleum Supply.** EIA projects total U.S. crude oil production to average 5.33 million bbl/d in 2009, the first production increase since 1991. EIA expects production to increase to an average of 5.46 million bbl/d in 2010 ([U.S. Crude Oil Production Chart](#)). Crude oil production from the Thunder Horse, Tahiti, Shenzi, and Atlantis Federal offshore fields accounts for 12.2 percent of total U.S. crude oil production in the fourth quarter of 2010.

**U.S. Petroleum Product Prices.** EIA projects regular grade motor gasoline prices to average \$2.66 per gallon during the current quarter, up from September and October's average of \$2.55 per gallon. Higher projected crude oil prices in 2010 (refiner average cost of crude oil almost \$17 per barrel, or 40 cents per gallon, higher than the 2009 average) contribute to an expected \$0.45-per-gallon increase in regular-grade gasoline prices, to an average of \$2.81 per gallon next year. Expected diesel fuel retail prices, which averaged \$2.63 per gallon in August and September, average \$2.79 during the fourth quarter of 2009 and \$2.94 per gallon in 2010. The projected year-over-year increases in motor gasoline and diesel prices include a small increase in refining margins as a result of the economy-related increases in product demand. Heating oil residential prices this winter (October through March) are projected to average \$2.80 per gallon, compared with \$2.63 per gallon last winter.

## Natural Gas

**U.S. Natural Gas Consumption.** EIA projects total natural gas consumption to decline by 1.9 percent in 2009 to 62.2 billion cubic feet (Bcf) per day and by another 1.1 percent in 2010 ([Total U.S. Natural Gas Consumption Growth Chart](#)). While the broad

economic downturn led to a drop in total consumption in 2009, low prices have contributed to a 2-percent increase in natural gas use in the electric power sector from January through August of this year compared with the same period in 2008. The recent increase in natural gas prices has contributed to a return to normal seasonal levels of natural gas consumption for electric power generation. EIA expects natural gas use in the electric power sector to remain near normal in the coming months as the onset of winter weather and the corresponding increase in space-heating demand lead to higher prices.

A large decline in electric power sector consumption of natural gas in 2010 is projected to more than offset natural gas consumption growth in the residential, commercial, and industrial sectors. The anticipated addition of new coal-fired generating capacity combined with higher natural gas prices should reverse the coal-to-natural-gas switching trend that accounted for the large increase in electric-power-sector natural gas consumption this year.

***U.S. Natural Gas Production and Imports.*** EIA expects total U.S. marketed natural gas production to increase by 2.8 percent in 2009 and decline by 3.8 percent in 2010. While working natural gas rigs have declined by more than 54 percent since cresting at 1,600 late in August 2008, marketed natural gas production in the Lower-48 non-Federal Gulf of Mexico has only declined by 0.6 percent between January and August. The natural gas rig count is on the rise again after bottoming out in mid-July 2009, according to Baker Hughes. Nonetheless, EIA still expects that the reduced drilling rates and steeper decline rates from new wells brought on stream in 2009 will lead to lower levels of production during 2010.

EIA expects pipeline imports of natural gas to decline by 13 percent in 2009 and 7 percent in 2010 based on lower expected production and higher consumption in Canada. Pipeline imports have averaged about 1 Bcf per day below year-ago levels all year, dropping considerably in the most recent months.

U.S. liquefied natural gas (LNG) imports increase to about 470 Bcf in 2009 from 350 Bcf in 2008 and rise to about 660 Bcf in 2010 in this forecast. Although winter weather in the Northern Hemisphere tends to increase global LNG demand and limit cargoes available for the United States, the recent start-up of new liquefaction projects in Qatar and Yemen may lead to higher U.S. LNG import flows before the year is out. The increased supply of LNG brought about by the start-up of several large LNG supply projects in late-2009 and in 2010 contributes to an increase in the outlook for U.S. LNG imports next year. However, the timing of these new liquefaction additions is extremely difficult to judge. In the past, projects have been delayed and postponed

for significant lengths of time as a result of feedgas shortage and construction problems.

***U.S. Natural Gas Inventories.*** On October 30, 2009, working natural gas in storage was 3,788 Bcf ([U.S. Working Natural Gas in Storage Chart](#)), 414 Bcf above the 5-year average (2004–2008), 379 Bcf above the level during the corresponding week last year, and 223 Bcf above the previous record of 3,565 Bcf reported for the end of October 2007. Assuming a winter storage withdrawal about 14 percent (240 Bcf) greater than the previous 5-year average (October 2004 – March 2009), end-of-winter (March 31, 2010) stocks will be about 1,739 Bcf. This would be the highest end-of-winter storage level since 1991, when inventories measured 1,912 Bcf.

***U.S. Natural Gas Prices.*** The Henry Hub spot price averaged \$4.12 per Mcf in October, \$1.06 per Mcf higher than the average spot price in September ([Henry Hub Natural Gas Price Chart](#)). Smaller-than-expected weekly storage injections, due to colder weather in the Midwest and pipeline maintenance, contributed to stronger prices this past month. Although prices have more than doubled since reaching a low of \$1.83 per Mcf on September 4, EIA expects any further price run-up to be limited through the remainder of the year. High storage levels and resilient domestic production are expected to keep prices around \$5 per Mcf in the coming months, even as space-heating demand increases and economic conditions improve. Beyond the winter, limited demand growth constrains price increases through the forecast. The projected Henry Hub spot price averages \$4.03 per Mcf in 2009 and \$5.01 per Mcf in 2010.

Implied price volatility for the December 2009 Henry Hub, Louisiana, futures contract moved higher as prices rose during October. Market participants were pricing gas delivered to Henry Hub in December against the futures contract at \$4.86 per million Btu (MMBtu) (\$5.01 per Mcf, assuming a natural gas heat content of 1,030 Btu per Mcf). This corresponded to an implied volatility of 60 percent for the December 2009 contract. The lower limit of the 95-percent confidence interval for the natural gas December 2009 futures contract was \$3.76 per MMBtu and the upper limit was \$6.28 per MMBtu, for a range of \$2.52 per MMBtu.

At this time last year, market participants were pricing pipeline-quality natural gas into Henry Hub at \$7.01 per MMBtu. Implied volatility was roughly at the same level it is now, approximately 62 percent, which, given the higher futures price at the time, translated into a lower and upper limit of \$6.17 and \$7.98 per MMBtu, respectively, for the 95-percent confidence interval.

## Electricity

**U.S. Electricity Consumption.** Retail sales of electricity to the industrial sector from January through August 2009 were down by an average of 0.34 billion kilowatthours per day (Bkwh/d) compared with the same period last year, with about 35 percent of that decline occurring in the Midwest region. While projected industrial sales begin to recover only very slowly next year, quicker growth in residential and commercial sector electricity sales should push total electricity consumption up by 1.6 percent in 2010 ([U.S. Total Electricity Consumption Chart](#)).

**U.S. Electricity Generation.** The projected price of natural gas used for electric power generation rises above \$5 per MMBtu by the end of this year, motivating electric power generators who have recently switched away from coal to natural gas to meet baseload generation requirements to increase their reliance on coal-fired generation. Coal-fired generation grows by 0.20 Bkwh/d during 2010, while natural-gas-fired generation falls by 0.10 Bkwh/d.

**U.S. Electricity Retail Prices.** EIA now expects residential electricity prices to decline only slightly in 2010 in contrast to the expected 1.6-percent decline in last month's *Outlook* ([U.S. Residential Electricity Prices Chart](#)). This revision in the forecast is due primarily to higher projections for natural gas fuel costs and a slower decline in the price of coal delivered to the electric power sector.

## Coal

**U.S. Coal Consumption.** Lower total electricity generation combined with increases in generation from natural gas, nuclear, hydropower, and wind led to an 11-percent decline in coal consumption by the electric power sector in the first half of 2009. A projected continuation of these trends for the remainder of the year leads to an annual decline in electric power sector coal consumption of more than 9 percent. Projected increases in electricity demand and natural gas prices will contribute to coal regaining a larger share of baseload generation in 2010. Nearly 4,300 megawatts of new coal-fired generation, online by the end of 2010, will add to the demand for coal. Projected coal consumption in the electric power sector increases by almost 5 percent in 2010 but it remains below 1 billion short tons for the second consecutive year. Coal consumed for steam (retail and general industry) and coke production declined by 21 percent in the first half of 2009 compared with the first half of last year. In the forecast, consumption of coal for coke plants rises in the second half of 2009. Improved economic conditions in 2010 are forecast to lead to an increase of almost 3 million short tons (17 percent) of coal consumed in the coke sector. EIA projects 6-

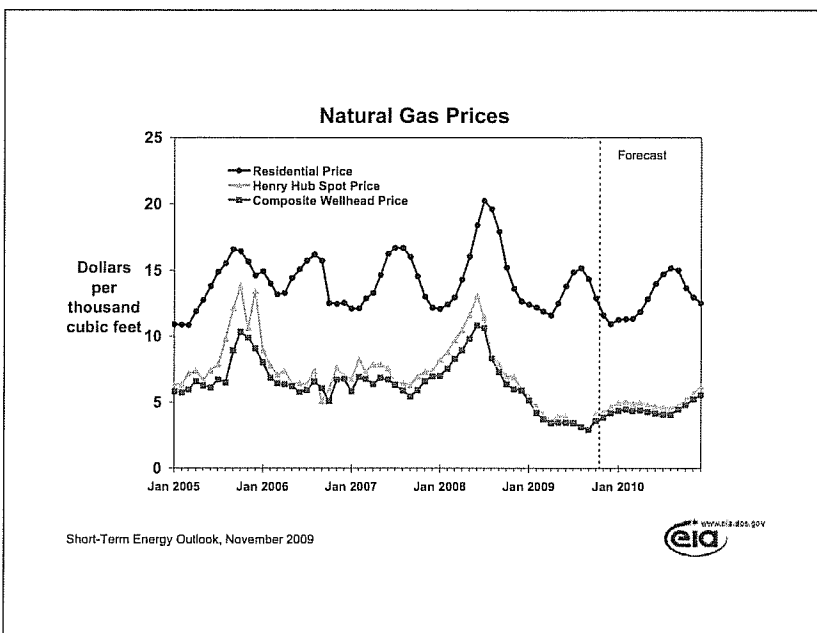
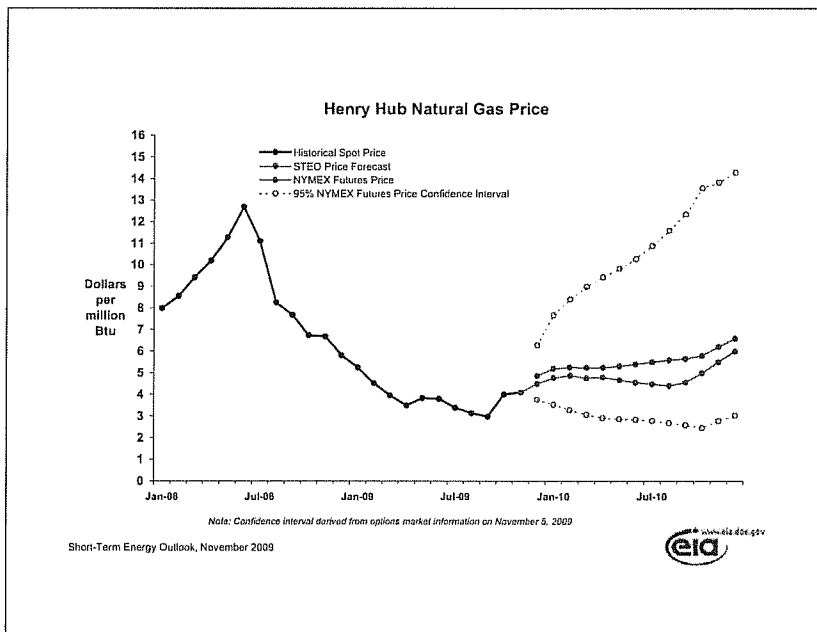
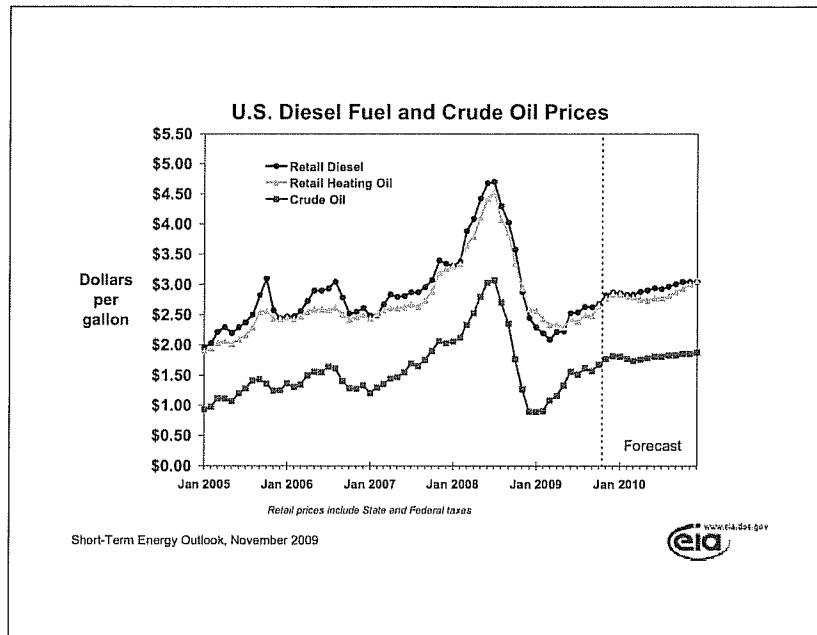
percent growth in 2010 for coal consumption in the retail and general industry sectors ([U.S. Coal Consumption Growth Chart](#)).

**U.S. Coal Supply.** Coal production for the first 6 months of 2009 fell by 5 percent in response to lower U.S. coal consumption, fewer exports, and higher coal inventories. These conditions are expected to persist over the second half of 2009, with an annual decline in coal production of more than 7 percent. Projected production declines by an additional 1.4 percent in 2010 despite increases in domestic consumption and exports. Reductions in coal inventories and increased imports offset the increase in U.S. coal consumption ([U.S. Annual Coal Production Chart](#)).

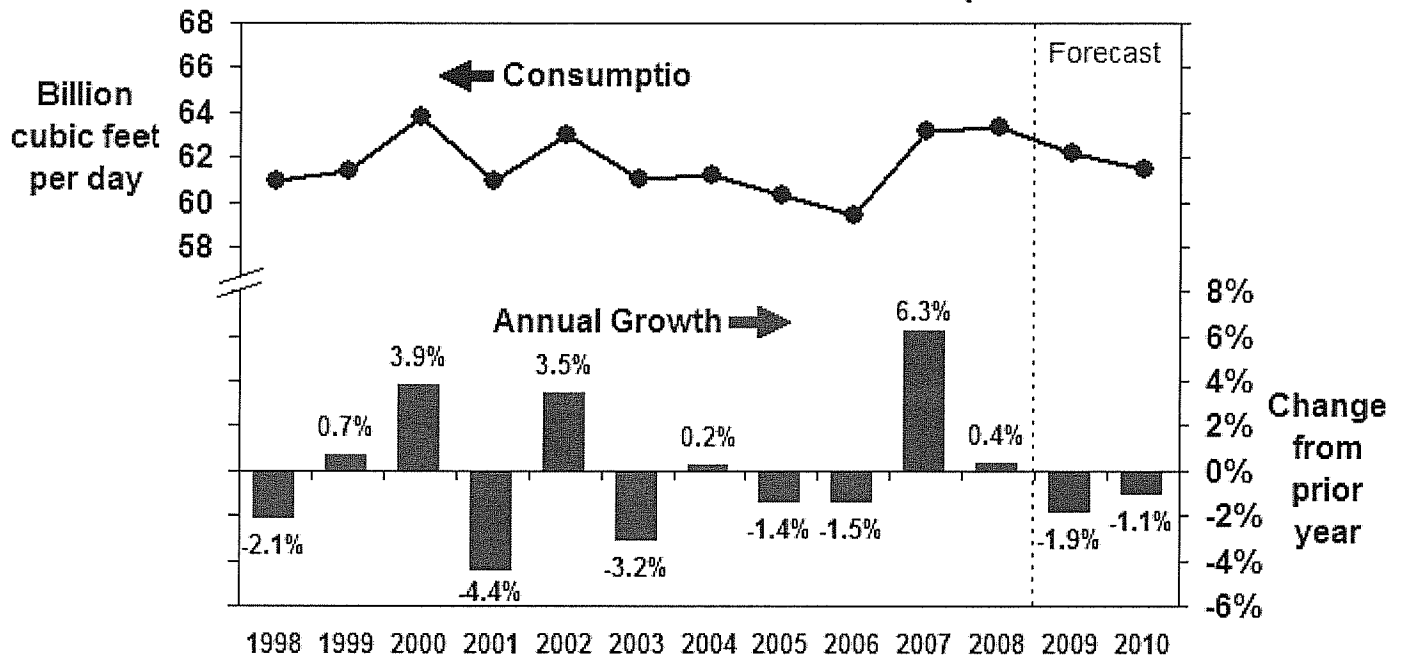
**U.S. Coal Prices.** Despite decreases in spot coal prices, lower prices for other fossil fuels, and declines in demand for coal for electricity generation, the monthly average delivered electric-power-sector coal price reached a record high of \$2.29 per MMBtu in March 2009. The price stood at \$2.24 per MMBtu in July 2009 and declines further over the forecast period, averaging about \$2.22 per MMBtu for 2009 and \$2.05 per MMBtu in 2010.

#### **U.S. Carbon Dioxide Emissions**

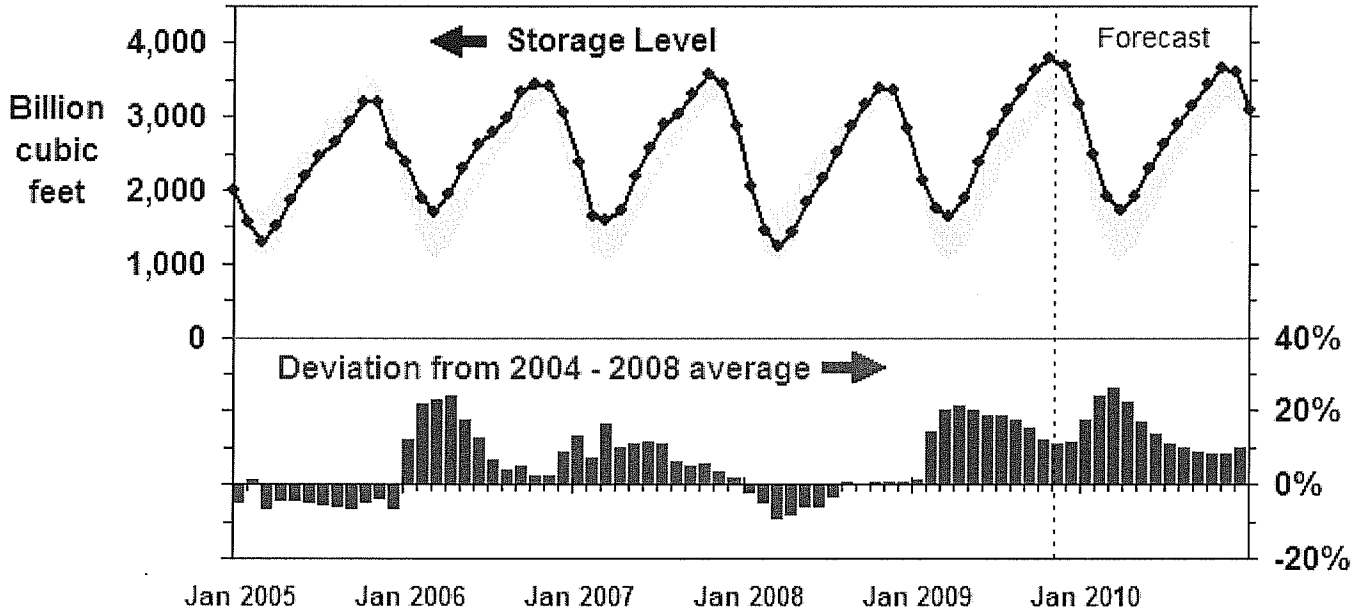
Projected carbon dioxide (CO<sub>2</sub>) emissions from fossil fuels fall by an estimated 5.6 percent in 2009. Coal leads the drop in 2009 CO<sub>2</sub> emissions, falling by slightly more than 10 percent. Changes in energy consumption in the industrial sector, a result of the weak economy, and changes in electricity generation sources are the primary reasons for the decline in CO<sub>2</sub> emissions ([U.S. Carbon Dioxide Emissions Growth Chart](#)). Projected improvements in the economy contribute to an expected 1.5-percent increase in CO<sub>2</sub> emissions in 2010.



## U.S. Total Natural Gas Consumption



## U.S. Working Natural Gas in Storage



NOTE: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2004 - Dec. 2008

**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 &amp; 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>
<b>Balance @ April 30, 2009</b>									<b><u>\$65,941</u></b>
May	(\$2,105)	\$0	\$671	(\$1,434)	16,822	(\$0.1857)	(\$3,124)	\$1,690	67,631
June	24,415	0	690	25,105	9,107	0.2343	(427) 2/	25,532	93,163
July	39,344	0	629	39,973	6,447	0.2343	1,511	38,462	131,625
August	39,771	0	902	40,673	5,943	0.2343	1,392	39,281	170,906
September	(2,165)	0	1,179	(986)	5,775	0.2343	1,353	(2,339)	168,567
October	35,022	0	1,154	36,176	11,535	0.2343	2,703	33,473	202,040
<b>Balance @ October 31, 2009.</b>									<b><u>\$202,040</u></b>

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

2/ Reflects 6,097.5 dk @ (\$0.1857) and 3,009.9 dk @ \$0.2343.

**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 &amp; 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>
<b>Balance @ April 30, 2009</b>									<b><u>(\$110,191)</u></b>
May	(\$5,411)	\$0	(\$1,024)	(\$6,435)	15,426	(\$0.7309)	(\$11,275)	\$4,840	(105,351)
June	(2,099)	0	(967)	(3,066)	10,879	(0.7419)	(7,985) 2/	4,919	(100,432)
July	(3,038)	0	(592)	(3,630)	7,435	(0.7419)	(5,516)	1,886	(98,546)
August	(4,584)	0	(581)	(5,165)	9,775	(0.7419)	(7,252)	2,087	(96,459)
September	(14,605)	0	(571)	(15,176)	9,230	(0.7419)	(6,848)	(8,328)	(104,787)
October	(9,999)	0	(634)	(10,633)	16,552	(0.7419)	(12,280)	1,647	(103,140)
<b>Balance @ October 31, 2009.</b>									<b><u>(\$103,140)</u></b>

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

2/ Reflects 7,849.5 dk @ (\$0.7309) and 3,029.9 dk @ (\$0.7419).