

January 3, 2011

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

Re: Cost of Gas Adjustment (COG)  
January 2011

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and seven (7) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (58<sup>th</sup> Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (58<sup>th</sup> Revised Sheet No. 8), showing the January 2011 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.0728 per mcf for residential and firm general service customers and \$0.0510 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for January 2011, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.0510 per mcf since the last COG filing due to an increase in the market price of gas. There has been an increase in pipeline charges of \$0.0218 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of \$0.0728 per mcf for residential and firm general service customers.

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

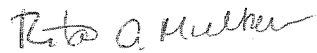
Attachment D shows the calculation of the balancing account since April 30, 2010.

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 for January through December, 2011.

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  
58th Revised Sheet No. 1.1

**RATE SUMMARY SHEET**

Canceling 57th 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	\$8.1207	\$9.3947 9.1747
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	\$3.8922	\$5.0313 4.7853 4.6333
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$3.8922	\$5.1313
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:** January 3, 2011

**Effective Date:** January 1, 2011

**Issued By:** Tamie A. Aberle  
Pricing & Tariff 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  
58<sup>th</sup> Revised Sheet No. 8  
Canceling 57<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.	3.6477	(1.1788)	0.3941	2.8630	(1.1643)	(0.1136)	(1.2779)
Current Adj.	0.0218	0.0510	0.0000	0.0728	0.0510	0.0000	0.0510
Total Adj.	3.6695	(1.1278)	0.3941	2.9358	(1.1133)	(0.1136)	(1.2269)
Total Rate:	\$3.7353	\$3.9913	\$0.3941	\$8.1207	\$4.0058	(\$0.1136)	\$3.8922

**Date Filed:** January 3, 2011

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**Issued By:** Tamie A. Aberle  
Pricing & Tariff Manager

**Case No.:**

GREAT PLAINS NATURAL GAS CO.  
WAHPETON  
COST OF GAS ADJUSTMENT  
JANUARY 2011

<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	\$0.2329
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	3,000	3.7671	5	56,507	0.0403
TFX Seasonal	3,000	15.1530	5	227,295	0.1623
NOVA - Demand Charge	7,947	18.4570	12	1,760,133	1.2565
Trans Canada - Demand Charge	7,947	17.1431	12	1,634,835	1.1671
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0654
NOVA - Seasonal	5,068	18.4570	5	467,700	0.3339
Trans Canada - Seasonal	5,068	17.1431	5	434,406	0.3101
BP Canada - Seasonal	5,068	0.9612	5	24,357	0.0174
BP Canada Winter Surcharge	5,068	3.0417	5	77,077	0.0550
LMS Demand 2/					0.0145
Total Demand Charges				\$5,212,078	3.7353
Estimated Weighted Average Commodity Cost	1,400,774	1/ 3.9913		5,590,909	3.9913
Gas Cost Reconciliation Adjustment					0.3941
Total Current Firm Gas Cost				\$10,802,987	8.1207
Base Cost of Gas					5.1849
Accumulated Adjustment					\$2.9358
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$3.9913
Gas Cost Reconciliation Adjustment					(0.1136)
LMS Demand 2/					0.0145
Total Current Interruptible Gas Cost					3.8922
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$1.2269)

1/ Three year normalized average Dk sales.

2/ Amount divided by 2009 interruptibles sales volumes plus three year normalized firm Dk Sales.

	<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	\$0.0145

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

<b>Rates Effective January 1, 2011</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	18.4570	Per dk/Mo.
Trans Canada Pipeline Demand Charge	17.1431	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	18.4570	Per dk/Day
Trans Canada - Seasonal	17.1431	Per dk/Mo.
BP Canada - Seasonal	0.9612	Per dk/Mo.
BP Canada Winter Surcharge	3.0417	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	3.9913	Per dk

**Base Rate Effective September 1, 1981**

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

**Base Rate Calculation**

Firm

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

Interruptible:

Commodity	\$5.1191	Per Mcf
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1/ Demand base rate calculation:  $4,768 \times 12 \times \$0.8100 / 707,222$

STATEMENT OF RATES  
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

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

Viking Gas Transmission Company  
FERC Gas Tariff  
Volume No. 1

Part 5.0  
Statement of Rates  
v. 1.0.0

Rate Schedule	Base Tariff Rate	Adjustment Under Section 19 1/	Rate After Current Adjustment	Fuel and Loss Retention Percentages 2/
<b>Commodity Rates</b>				
FT-A – Maximum Rates				
Zone 1-1	\$0.0130	\$0.0019	\$0.0149	1.92%
Zone 1-2	\$0.0130	\$0.0019	\$0.0149	2.23%
Zone 2-2	\$0.0130	\$0.0019	\$0.0149	0.31%
Minimum Rate	\$0.0130	\$0.0019	\$0.0149	
IT and AOT				
Zone 1-1	\$0.1368	\$0.0019	\$0.1387	1.92%
Zone 1-2	\$0.1737	\$0.0019	\$0.1756	2.23%
Zone 2-2	\$0.0834	\$0.0019	\$0.0853	0.31%
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: 0.16% for Zone 1-1, 0.18% 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		\$0.0453	

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

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

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			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/		Carlton Surcharge 4/		Out-of Balance 3/	
TF12 Base, TF12 Var., TF5 & TFF		Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Receipt Point	Delivery Point								
Market	Market	0.0384	0.0215			0.0175	0.0000	0.0384	0.0215
Field	Market	0.0384	0.0215	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	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 \$0.0006 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.

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	0.0384	0.0215			0.0175	0.0000	0.0384	0.0215
Field	Market	0.0384	0.0215	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.
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- 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.

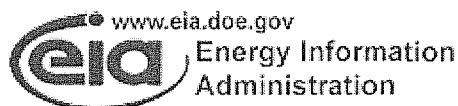
**Great Plains Natural Gas Co.  
Market Conditions for Wahpeton's Natural Gas  
January 2011**

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

Cold weather over much of the U.S. and the corresponding increase in demand is the reason for the anticipated increase in the index price. However, anticipated January 2011 AECO prices will be approximately 25 percent less than the previous year. The Energy Information Administration (EIA) reported storage levels nationwide as of December 17, 2010 were 8.5 percent above the five-year average and 1.6 percent below 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 14.



December 2010

## Short-Term Energy Outlook

December 7, 2010 Release

### Highlights

- EIA expects the price of West Texas Intermediate (WTI) crude oil to average about \$84 per barrel this winter (October 1 to March 31), more than \$6 higher than the average price last winter. Projected WTI prices rise to \$89 per barrel by the end of 2011, a \$2 per barrel increase from last month's *Outlook*, as U.S. and global economic conditions improve. EIA's forecast assumes U.S. real gross domestic product (GDP) grows 2.7 percent in 2010 and 2.1 percent in 2011, while world real GDP (weighted by oil consumption) grows by 4.0 percent and 3.2 percent, in 2010 and 2011, respectively.
- EIA expects regular-grade motor gasoline retail prices to average \$2.88 per gallon this winter, 22 cents per gallon higher than last winter. Projected retail diesel fuel prices average \$3.14 per gallon this winter, an increase of 35 cents per gallon over last winter, while residential heating oil prices average \$3.17 per gallon this winter. In 2011, higher crude oil prices combined with higher refiner margins push annual average prices for motor gasoline and diesel fuel to \$3.00 and \$3.23 per gallon, respectively.
- Natural gas working inventories end November 2010 at 3.8 trillion cubic feet (Tcf), slightly less than last year's record-setting end-of-November level. The projected Henry Hub natural gas spot price averages \$4.37 per million Btu (MMBtu) for 2010, a \$0.42-per-MMBtu increase over the 2009 average. EIA expects the Henry Hub spot price to average \$4.33 per MMBtu in 2011.
- EIA expects average household expenditures for space-heating fuels to total \$962 this winter, about the same as last year's expenditures. EIA projects higher expenditures for heating oil and propane, but lower expenditures for natural gas and electricity. This forecast reflects higher prices for all the fuels, although electricity prices increase by only 1 percent. However, a forecast of milder weather than last winter in all the regions, except the Northeast, leads to lower fuel consumption in those areas.

- EIA projects that U.S. carbon dioxide (CO<sub>2</sub>) emissions from fossil fuels, which fell by 7.0 percent in 2009, will increase by 3.9 percent in 2010. In 2011, projected CO<sub>2</sub> emissions remain relatively flat as the increase in emissions from growth in petroleum consumption is offset by a decline in emissions from natural gas and coal because of reduced summer electricity use based on a projected milder summer.

## Global Crude Oil and Liquid Fuels

*Crude Oil and Liquid Fuels Overview.* Gradual tightening in global oil markets continues to support world oil prices. Projected liquid fuels consumption growth of 2 million barrels per day (bbl/d) in 2010 is almost double the growth in supply from countries outside of the Organization of the Petroleum Exporting Countries (OPEC), which has led to rising demand for OPEC crude oil production and declining global oil inventories. While overall commercial oil inventories in the Organization for Economic Cooperation and Development (OECD) countries remain high, stock levels are unevenly distributed with some regions experiencing tightness in recent months. Both floating and reported on-shore inventories have been declining, and EIA believes that the projected continued reduction in OECD stocks over the forecast period should lend support to firming oil prices.

*Global Crude Oil and Liquid Fuels Consumption.* Projected world liquid fuels consumption increases by 2 million bbl/d in 2010, following declines in 2008 and 2009. As a result, total global consumption in 2010 should be close to the 2007 level. Global oil consumption growth slows to 1.4 million bbl/d in 2011. Non-OECD regions, especially China, the Middle East, and Brazil, represent most of the expected growth in world oil consumption next year ([World Liquid Fuels Consumption Chart](#)). Among the countries of the OECD, only the United States is expected to show any significant growth in consumption volume in 2011 at about 0.2 million bbl/d.

*Non-OPEC Supply.* EIA projects the total non-OPEC supply of crude oil will grow by just over 1.0 million bbl/d to an average 51.5 million bbl/d in 2010 - the largest year-over-year increase since 2002. The increase in total non-OPEC supply for the year is the result of higher production in the United States, Brazil, China, and Russia. However, non-OPEC supply falls by 280,000 bbl/d in 2011. The decline in non-OPEC supply in 2011 would be only the third time in the last 15 years that non-OPEC supplies fall year-over-year. Previous declines in 2005 and 2008 were primarily the result of supply disruptions in the Gulf of Mexico related to hurricanes.

**OPEC Supply.** EIA expects that OPEC crude oil production will increase by 0.3 and 0.4 million bbl/d in 2010 and 2011, respectively, similar to last month's *Outlook*, to accommodate increasing world oil consumption. Projected non-crude liquids increase by 0.7 million bbl/d in both 2010 and 2011. OPEC surplus capacity should remain close to 5 million bbl/d, compared with 4.3 million in 2009 and 1.5 million in 2008 (OPEC Surplus Crude Oil Production Capacity Chart).

**OECD Petroleum Inventories.** Commercial oil inventories held by OECD countries at the end of 2010 are an estimated 2.73 billion barrels, equivalent to about 58 days of forward cover and roughly 94 million barrels more than the 5-year average for the corresponding time of year (Days of Supply of OECD Commercial Stocks Chart). OECD oil inventories decline through the forecast period, though days of forward cover should remain high by historical standards.

**Crude Oil Prices.** WTI crude oil spot prices averaged over \$84 per barrel in November, more than \$2 per barrel higher than the October average, as expectations of higher oil demand pushed up prices. EIA has raised the average winter 2010-2011 WTI spot price forecast by \$1 per barrel from the last month's *Outlook* to \$84 per barrel. WTI spot prices rise to \$89 per barrel by the end of next year, \$2 per barrel higher than in the last *Outlook*. Projected WTI prices average \$79 per barrel in 2010 and \$86 per barrel in 2011.

Energy price forecasts are uncertain (Energy Price Volatility and Forecast Uncertainty). WTI futures for February 2011 delivery for the 5-day period ending December 2 averaged \$86 per barrel, and implied volatility averaged 30 percent. This made the lower and upper limits of the 95-percent confidence interval \$70 per barrel and \$106 per barrel, respectively, for WTI delivered in February 2011. Last year at this time, WTI for February 2010 delivery averaged \$78 per barrel and implied volatility averaged 40 percent, with the limits of the 95-percent confidence interval at \$61 per barrel and \$102 per barrel.

## U.S. Crude Oil and Liquid Fuels

**U.S. Liquid Fuels Consumption.** Projected total U.S. liquid fuels consumption increases by 320,000 bbl/d (1.7 percent) to 19.09 million bbl/d in 2010, which is about 60,000 bbl/d higher than forecast in last month's *Outlook*. A year-over-year decline in total liquid fuels consumption averaging 40,000 bbl/d in the first quarter of 2010 was followed by a year-over-year rise averaging 610,000 bbl/d in the second and third quarters, led by increases in motor gasoline and distillate fuel oil consumption. During 2010 as a whole, projected gasoline consumption increases by 0.4 percent and distillate consumption increases by 4.0 percent. Total liquid fuels consumption

increases by a further 160,000 bbl/d (0.8 percent) in 2011, as all of the major petroleum products register consumption growth ([U.S. Liquid Fuels Consumption Growth Chart](#)). Gasoline consumption grows by 0.8 percent, and distillate fuel consumption increases by 1.7 percent in 2011.

***U.S. Liquid Fuels Supply and Imports.*** Domestic crude oil production, which increased by 410,000 bbl/d in 2009, increases by 140,000 bbl/d in 2010 ([U.S. Crude Oil Production Chart](#)) and then falls by 30,000 bbl/d to 5.47 million bbl/d in 2011. The 2011 forecast includes declines of 50,000 bbl/d and 180,000 bbl/d in Alaska and the Federal Gulf of Mexico (GOM), respectively, and a 190,000-bbl/d increase in lower-48 non-GOM production. Ethanol production, which averaged 710,000 bbl/d in 2009, increases to an average of 860,000 bbl/d in 2010 and 890,000 bbl/d in 2011.

Liquid fuel net imports (including both crude oil and refined products) fell from 57 percent of total U.S. consumption in 2008 to 51 percent in 2009, primarily because of the decline in consumption during the recession. EIA forecasts that liquid fuel net imports will average 9.48 million bbl/d in 2010 and 9.62 million bbl/d in 2011, about 50 percent of total consumption in both years.

***U.S. Petroleum Product Prices.*** Projected regular-grade gasoline retail prices rise from an average of \$2.35 per gallon in 2009 to an average of \$2.77 per gallon in 2010 and \$3.00 per gallon in 2011. On-highway diesel fuel retail prices, which averaged \$2.46 per gallon in 2009, average \$2.98 per gallon in 2010 and \$3.23 in 2011 in the current forecast. Refining margins, which had been at their lowest levels since 2003, average about \$2 per barrel higher next year because of growing global product demand.

## Natural Gas

***U.S. Natural Gas Consumption.*** This month's *Outlook*, for the first time, reflects recent changes in the Form EIA-857 monthly natural gas survey methodology in the forecasts for residential and commercial natural gas consumption (see [Changes in Natural Gas Monthly Consumption Data Collection and the Short-Term Energy Outlook](#)). The new survey methodology should not significantly change reported total annual consumption volumes. However, EIA expects significant changes in the seasonality of reported residential and commercial sector natural gas consumption from historical reporting norms as the improved reporting on the EIA-857 leads to more accurate monthly reports. For example, first quarter 2011 forecast residential plus commercial consumption is 1.7 billion cubic feet per day (Bcf/d) lower in this forecast compared with last month's *Outlook*, while fourth quarter 2011 consumption is 3.8 Bcf/d higher.

**U.S. Natural Gas Production and Imports.** Forecast marketed natural gas production increases by 3.5 percent in 2010, up from 2.5 percent in last month's *Outlook*. The revision is largely due to unexpectedly high production during the month of September as reported in the EIA *Natural Gas Monthly*. Natural gas production in 2011 has also been revised upwards, but EIA still predicts a total year-over-year decline of 0.1 percent in 2011. An expected 14.3-percent decline in GOM production is mostly offset by a 1.4 percent increase in the lower 48 non-GOM production.

The increase in the natural-gas-directed drilling rig count since mid-2009, combined with a growing share of horizontal drilling rigs in the lower-48 States, contributed to natural gas production growth in 2010. The number of rigs drilling for natural gas reported by Baker Hughes Incorporated increased from a low of 665 in July 2009 to 973 in April 2010. Over the last 6 months the natural gas rig count has stayed relatively unchanged, but in the last several weeks it has appeared to show the beginning of an expected decline, ending November with 953 rigs. EIA expects drilling activity to decline in 2011 because of relatively lower natural gas prices. The large price difference between petroleum liquids and natural gas prices on an energy-equivalent basis contributes to an expected shift towards drilling in shale formations that contain a higher proportion of liquids.

EIA expects gross pipeline imports of 8.4 Bcf/d in 2011, a decrease of 6.3 percent compared with 2010 pipeline imports. This is a significant revision of last month's forecast of a 1.4-percent increase. EIA expects that Canadian gas will become less competitive as new U.S. pipelines and increased lower-48 production with lower transport costs displace imports. Projected liquefied natural gas (LNG) imports average 1.25 Bcf/d in 2010, a 1.0-percent increase from 2009 levels. Imports in 2011 fall to 1.21 Bcf/d, a decline of 2.9 percent. High domestic production, high inventories, and low U.S. prices relative to European and Asian markets should continue to discourage LNG imports into North America.

**U.S. Natural Gas Inventories.** On November 26, 2010, working natural gas in storage stood at 3,814 Bcf, slightly below last year's level at this time ([U.S. Working Natural Gas in Storage Chart](#)). At the end of the winter heating season (March 31, 2011), EIA expects 1,833 Bcf of working natural gas will remain in storage, about 171 Bcf higher than at the end of March 2010. The forecast higher inventory is primarily the result of both the projected 3.1 Bcf/d increase in natural gas production and 5 percent fewer heating degree-days over the next 4 months compared with the year before.

**U.S. Natural Gas Prices.** The Henry Hub spot price averaged \$3.71 per million Btu (MMBtu) during November, an increase of about 28 cents from October's price of \$3.43 per MMBtu ([Henry Hub Natural Gas Price Chart](#)). Over the winter heating

season, the projected monthly average spot price peaks at \$4.29 per MMBtu in January 2011, before dropping back down to close to \$4.00 per MMBtu in June 2011. This month's *Outlook* slightly raises the average 2011 Henry Hub spot price to \$4.33 per MMBtu from last month's forecast of \$4.31 per MMBtu.

Uncertainty over future natural gas prices is slightly lower this year compared with last year at this time. Natural gas futures for February 2011 delivery (for the 5-day period ending December 2) averaged \$4.29 per MMBtu, and the average implied volatility over the same period was 45 percent. This produced lower and upper bounds for the 95-percent confidence interval for February 2011 contracts of \$3.06 per MMBtu and \$6.03 per MMBtu, respectively. At this time last year, the natural gas February 2010 futures contract averaged \$4.84 per MMBtu and implied volatility averaged 57 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.20 per MMBtu and \$7.34 per MMBtu.

## Electricity

***U.S. Electricity Consumption.*** EIA expects U.S. electricity consumption will rise slightly by 4.7 percent in 2010. Retail sales of electricity to the industrial sector from January through September 2010 were up by nearly 7 percent compared with the same period last year, about the same as the increase in the U.S. manufacturing production index. EIA's assumption of 3.6 percent growth in manufacturing output during 2011 translates to an expected growth in electricity sales to the industrial sector of about 1.7 percent. Improved economic conditions should also spur growth of 1.1 percent in retail electricity sales to the commercial sector. However, EIA expects residential electricity sales to fall by 2.1 percent next year as summer temperatures return to normal levels after the hot summer of 2010. Overall, growth in total U.S. consumption of electricity remains nearly flat during 2011 ([U.S. Total Electricity Consumption Chart](#)).

***U.S. Electricity Generation.*** EIA projects that total electric power sector generation will increase slightly (by 0.2 percent) during 2011. A 0.9-percent increase in nuclear power and a 7.2-percent increase in conventional hydropower generation (due to an assumed return to near-normal precipitation levels) will offset a 1.7-percent reduction in electric power sector generation fired by coal. EIA expects the share of total generation fueled by natural gas will fall slightly next year as cooler summer temperatures reduce the need for the peaking capacity required during the past year ([U.S. Electric Power Sector Generation Growth Chart](#)).

***U.S. Electricity Retail Prices.*** The average U.S. retail price for electricity distributed to the residential sector during the first three quarters of 2010 was about the same as

the retail price during the same period last year. However, residential electricity prices during the fourth quarter 2010 are expected to be 1.2 percent higher than last year. EIA expects the U.S. residential price to continue growing by 0.9 percent during 2011 as utilities pass through the higher fuel costs they incurred this past year to their retail customers ([U.S. Residential Electricity Prices Chart](#)).

## Coal

**U.S. Coal Consumption.** EIA forecasts that coal consumption in the electric power sector will grow by 5.7 percent in 2010, primarily the result of higher electricity consumption. EIA expects electricity consumption in 2011 to decline by 0.1 percent and generation from non-fossil-fuel-fired sources to increase. Although natural gas-fired generation also declines, EIA expects that lower electric power sector natural gas prices will keep natural gas competitive as a generation source and lessen its decline. EIA projects that 2011 coal consumption in the electric power sector will decline by 0.2 percent ([U.S. Coal Consumption Growth Chart](#)).

**U.S. Coal Supply.** Coal production for the first 6 months of 2010 fell by 3 percent despite a 5-percent increase in U.S. coal consumption. Drawdowns in stocks, particularly in the electric power sector, met the demand increase ([U.S. Electric Power Sector Coal Stocks Chart](#)). Projected coal production increases in the second half of 2010 contribute to 2010 annual growth of 1 percent. EIA projects coal production in 2011 will remain relatively flat as coal consumption shows little change ([U.S. Annual Coal Production Chart](#)).

**U.S. Coal Trade.** Strong global demand for coal, particularly metallurgical coal used to produce steel, has resulted in sharp increases in U.S. coal exports in 2010. Metallurgical coal exports nearly doubled in the first half of this year compared with the first half of 2009, and metallurgical coal's share of total coal exports has grown from 52 percent in 2008 to a projected 73 percent in 2010. EIA expects total coal exports to increase by 30 percent in 2010 but to decline in 2011 as other major coal-exporting countries increase their supply to the global coal market.

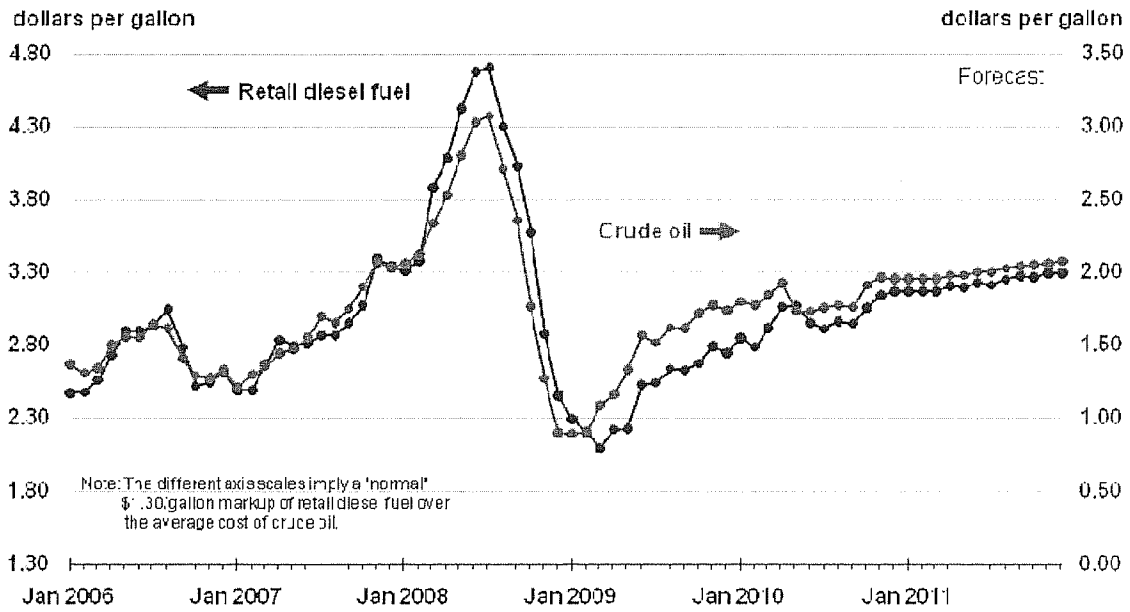
**U.S. Coal Prices.** The electric power sector coal price rose by 1.3 percent in the first half of 2010 compared with the first half of last year. This higher cost of delivered coal reflects the effect of longer-term power sector coal contracts initiated during a period of high prices, rising transportation costs, increased consumption, and increases in spot coal prices. The projected electric power sector delivered coal price averages \$2.27 per MMBtu in 2010, and then declines slightly to an average of \$2.26 per MMBtu in 2011.

## U.S. Carbon Dioxide Emissions

EIA expects fossil-fuel CO<sub>2</sub> emissions to increase by 3.9 percent in 2010 ([U.S. Carbon Dioxide Emissions Growth Chart](#)). Coal- and natural gas-related CO<sub>2</sub> emissions rise as a result of increased usage of both fuels for electricity generation and higher consumption of natural gas in the industrial sector.

Declines in electric power sector fossil fuel consumption in 2011 offset forecast increased consumption of petroleum in the transportation sector (i.e., motor gasoline, diesel fuel, and jet fuel). Consequently, fossil-fuel CO<sub>2</sub> emissions remain virtually unchanged in 2011. Projected fossil-fuel CO<sub>2</sub> emissions in 2010 and 2011 also remain below the levels seen in any year from 1999 through 2008.

### U.S. Diesel Fuel and Crude Oil Prices

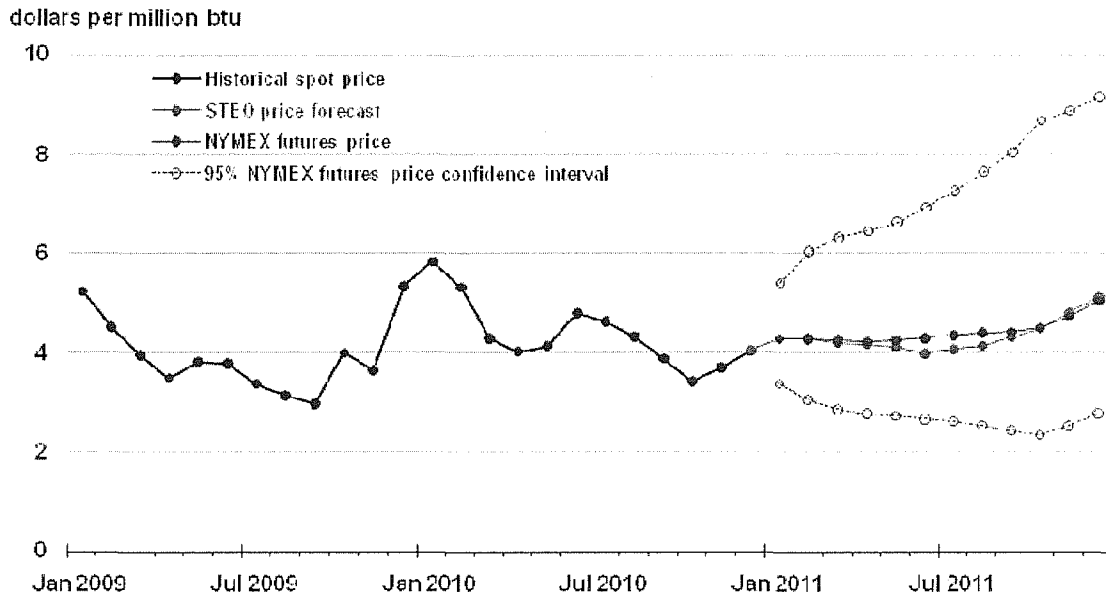


Note: Crude oil price is refiner average acquisition cost. Retail diesel fuel price includes State and Federal taxes.



Source: Short Term Energy Outlook, December 2010

### Henry Hub Natural Gas Price

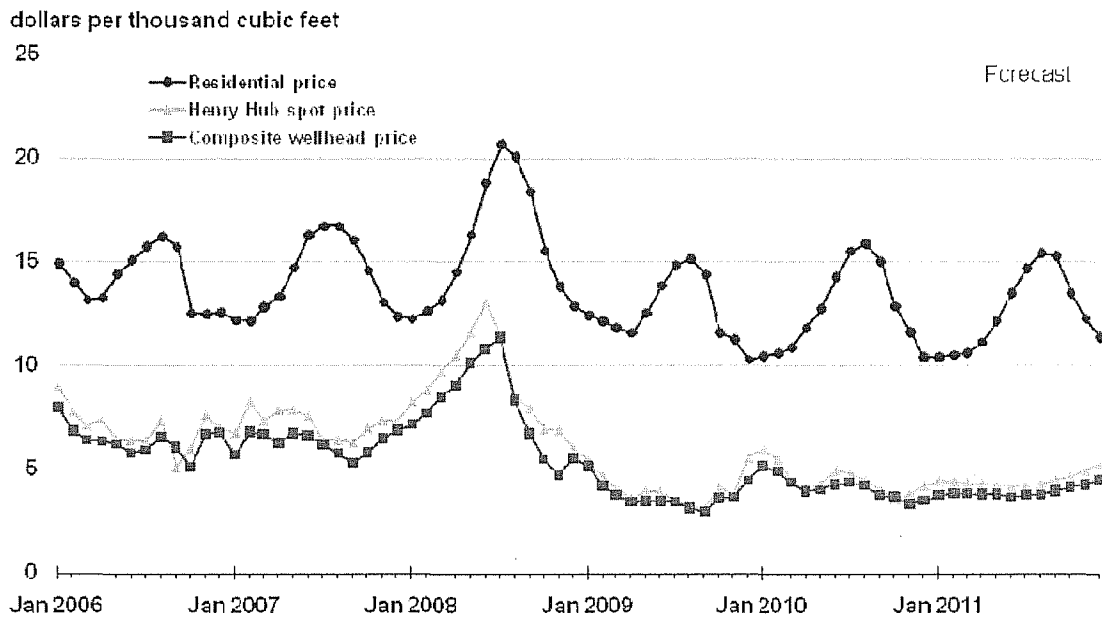


Note: Confidence interval derived from options market information for the 5 trading days ending December 2, 2010  
Intervals not calculated for months with sparse trading in "near-the-money" options contracts



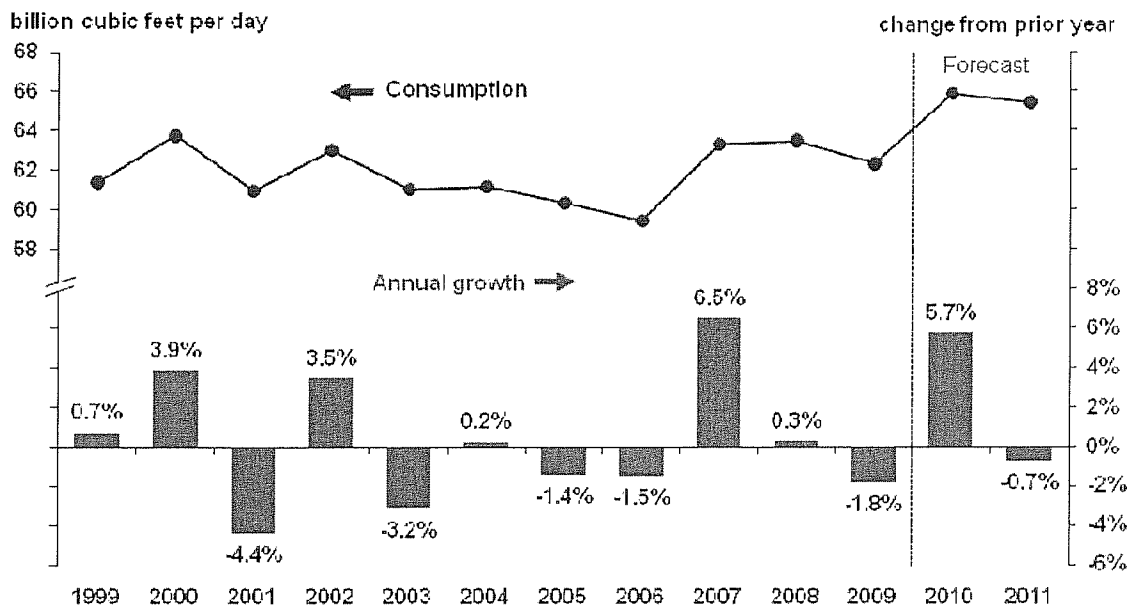
Source: Short-Term Energy Outlook, December 2010; Reuters News Service; and CME Group

### Natural Gas Prices



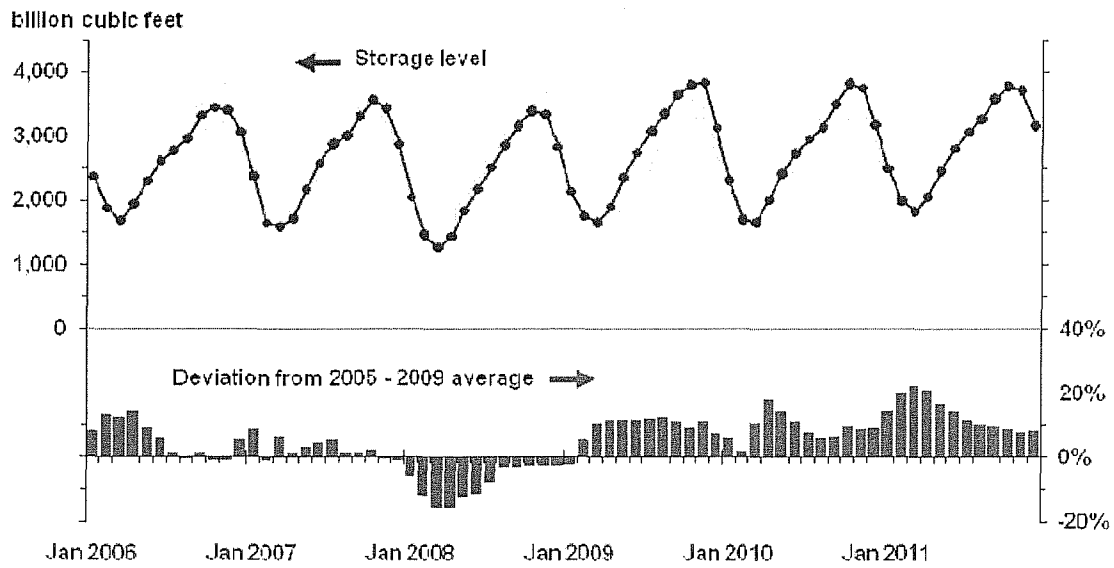
Source: Short-Term Energy Outlook, December 2010; Reuters News Service

### U.S. Total Natural Gas Consumption



Source: Short Term Energy Outlook, December 2010

### U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2005 - Dec. 2009.



Source: Short-Term Energy Outlook, December 2010

**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, 2010</b>									<b><u>\$114,988</u></b>
May	\$29,734	\$0	\$723	\$30,457	12,466	\$0.2343	\$2,921	\$27,536	142,524
June	11,277	0	917	12,194	8,311	0.3941	2,356 2/	9,838	152,362
July	20,585	0	982	21,567	6,200	0.3941	2,444	19,123	171,485
August	86,747	0	1,115	87,862	5,953	0.3941	2,347	85,515	257,000
September	92,220	0	1,725	93,945	6,368	0.3941	2,509	91,436	348,436
October	34,666	0	2,373	37,039	8,070	0.3941	3,181	33,858	382,294
November	23,805	0	2,602	26,407	17,808	0.3941	7,018	19,389	401,683
<b>Balance @ November 30, 2010</b>									<b><u>\$401,683</u></b>

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

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

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

	<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, 2010</b>									<b><u>(\$30,590)</u></b>
May	\$576	\$0	(\$199)	\$377	10,944	(\$0.7419)	(\$8,120)	\$8,497	(22,093)
June	(8,617)	0	(146)	(8,763)	11,808	(0.1136)	(6,678) 2/	(2,085)	(24,178)
July	(8,501)	0	(169)	(8,670)	10,612	(0.1136)	(1,205)	(7,465)	(31,643)
August	(1,507)	0	(224)	(1,731)	9,466	(0.1136)	(1,075)	(656)	(32,299)
September	422	0	(230)	192	13,953	(0.1136)	(1,585)	1,777	(30,522)
October	4,873	0	(219)	4,654	26,958	(0.1136)	(3,062)	7,716	(22,806)
November	4,335	0	(170)	4,165	36,122	(0.1136)	(4,104)	8,269	(14,537)
<b>Balance @ November 30, 2010</b>									<b><u>(\$14,537)</u></b>

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

2/ Reflects 8,493.0 dk @ (\$0.7419) and 3,315.3 dk @ (\$0.1136).