

January 8, 2010

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

Re: Cost of Gas Adjustment
(COG) Rate 88 and Rate 99
Case No. PU-10-____

In accordance with North Dakota Century Code Section 49-05-05, Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., respectfully submits an original and seven (7) copies of a Cost of Gas (COG) change pursuant to the terms of Rates 88 and 99.

Attachment A is the Rate Summary Sheet (83rd Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered February 1, 2010.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$1.334 per dk since the last filing due to an increase in the overall market price of gas. Attachment B explains the reasons for the increase in the market price of gas. There has also been a change in pipeline rates, as shown on Attachment C, that has no effect on the cost of gas.

The COG tariff sheet, Exhibit A page 1, summarizes the gas cost adjustment, calculated pursuant to the terms of Rate 88, and the surcharge adjustment and market based pricing differential provision that will apply during the month of February 2010.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$1.334 per dk for residential and firm general service customers, an increase of \$1.343 per dk for small and large interruptible customers and an increase of \$1.337 per dk for Air Force interruptible customers from the currently effective rates.

Exhibit B shows the calculation of the current gas cost adjustment that will be applicable to Montana-Dakota's customers for the month of February 2010. The average cost of gas for firm customers, adjusted for losses, is \$6.601.

Exhibit C shows the calculation of the return on storage inventory balances and prepaid demand and commodity balances using the calculation procedure set forth in Rate 88.

The overall rate of return of 8.791% was authorized by the Commission in Case No. PU-04-97.

Montana-Dakota purchases propane supplies from various wholesale suppliers. The cost of propane has increased since the last COG filing due to an increase in the market price of propane. Attachment B page 2 explains the reasons for the increase in the market price of propane.

Exhibit A, page 2 summarizes the cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of February, 2010. The net effect of this filing is an increase of \$3.842 per dk for all customers from the currently effective rates.

Exhibit D shows the calculation of the current cost of gas – propane that will be applicable to Montana-Dakota's customers for the month of February 2010. The average cost of propane for all customers, adjusted for losses, is \$16.467 per dk.

These proposed adjustments, calculated in accordance with Rates 88 and 99, will amount to an increase of approximately \$2,906,600 for natural gas customers and an increase of approximately \$23,000 for propane customers during the month of February 2010. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 92,102 natural gas customers and 333 propane customers in North Dakota as of December 31, 2009.

Please refer all inquiries regarding this filing to:

Ms. Rita A. Mulkern
Regulatory Analysis Manager
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501

Also, please send copies of all written inquiries, correspondence and pleadings to:

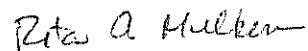
Mr. Daniel S. Kuntz
Associate General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

Montana-Dakota submitted a check for the amount of \$1,200 in accordance with North Dakota Century Code Section 49-05-05 on January 9, 2009. This payment will cover the filing fee associated with this monthly COG.

Montana-Dakota respectfully requests that 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

Attachment

Attachment A

**Rate Summary Sheet
(Proposed)**



Montana-Dakota Utilities Co.

A Division of MDU Resources Group, Inc.
 400 N 4th Street
 Bismarck, ND 58501

State of North Dakota Gas Rate Schedule

NDPSC Volume 7
 83rd Revised Sheet No. 3
 Canceling 82nd Revised Sheet No. 3

RATE SUMMARY SHEET

Page 1 of 2

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	\$0.30 per day	\$0.812	\$6.075	\$6.887
Air Force Rate 64	7	\$1,000.00 per month \$135.00 per month			
Minot Air Force Base					
PAR Site					
Firm Service			\$0.138	\$6.075	\$6.213
Interruptible Service - PAR			\$0.120	\$5.495	\$5.615
Interruptible Service - MAFB			\$0.120	\$5.646	\$5.766
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$6.075	\$6.672
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$5.495	(Maximum) \$6.366
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day			
Winter Gas Usage			\$0.597	\$6.165	\$6.762
Summer Gas Usage			\$0.597	\$5.212	\$5.809
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.025	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.025	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$5.495	(Maximum) \$6.214
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$15.909	\$16.721
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$15.909	\$16.506

Date Filed: January 8, 2010

Effective Date:

Issued By: Donald R. Ball
 Vice President - Regulatory Affairs

Case No.:

**Montana-Dakota Utilities Co.
Market Conditions for Regional Natural Gas**

February 2010

The established monthly price for the Rocky Mountain CIG Index increased from the previous PGA rate change effective January 2010. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid by willing sellers and buyers of quantities of gas in that region. That price is most reflective of natural gas prices in the Rocky Mountain region and indicative of a majority of the supplies Montana-Dakota purchases for its requirements.

The major factor contributing to the price increase was the below normal temperatures across much of the nation during the month of December resulting in high demand for space heating and subsequent large withdrawals from storage. The Energy Information Administration (EIA) reported storage levels nationwide as of January 1, 2010 are 11.3 percent above the five-year average and 10.1 percent above last year's balance.

The EIA provides various publications on energy issues. The information is available on their website: <http://www.eia.doe.gov>.

The December Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 15.

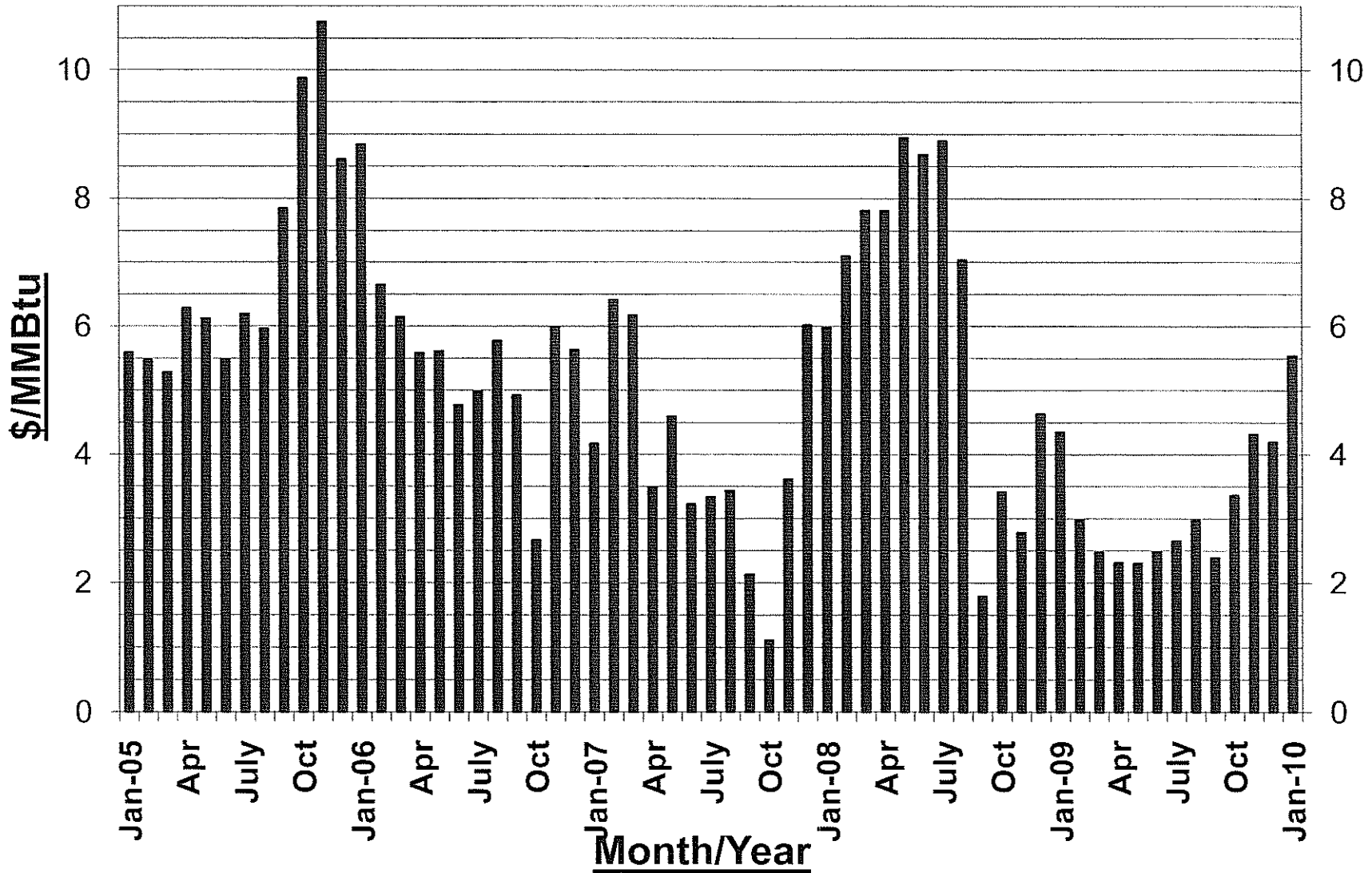
**Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
February 2010**

Montana-Dakota uses three regional bulk wholesale propane suppliers for obtaining the lowest prices for Hettinger customers. Each time Montana-Dakota purchases propane, it requests a price quote from each supplier for a specific delivery date and quantity in truckloads, delivering 8,000 to 12,000 gallons. Montana-Dakota selects the lowest price, all other things being equal.

The January prices for propane have increased from the previous level. A change in the price of propane is generally driven by a combination of crude oil prices, weather, demand and inventory levels. An increase in energy prices, including crude oil, has resulted in an increase in the price of propane.

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

CIG Rocky Mountains Index Monthly Gas Prices 2004-2010YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2008-\$6.24; 2009-\$3.07; 2010YTD -



December 2009

Short-Term Energy Outlook

December 8, 2009 Release

Highlights

- EIA expects the price of West Texas Intermediate (WTI) crude oil will average about \$76 per barrel this winter (October-March). The forecast for the monthly average WTI price dips to \$75 early next year then rises to \$82 per barrel by December 2010, assuming U.S. and world economic conditions continue to improve. EIA's forecast assumes that 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.
- Rising crude oil prices contribute to an increase in the annual average regular-grade gasoline retail price from \$2.35 per gallon in 2009 to \$2.83 in 2010, as pump prices approach \$3 per gallon during next year's driving season. Projected annual average diesel fuel retail prices are \$2.46 and \$2.96 per gallon, respectively, in 2009 and 2010. Average household expenditures on heating oil this winter are expected to increase to \$1,911 from \$1,864 last winter. Projected average household expenditures for propane of \$1,700 this winter are almost 13 percent lower than last winter's \$1,950.
- EIA expects the annual average natural gas Henry Hub spot price for 2010 to be \$4.62 per thousand cubic feet (Mcf). This represents a \$0.67-per-Mcf increase from the estimated 2009 price of \$3.95 per Mcf. Natural gas working inventories reached a new record-high level of 3.837 trillion cubic feet (Tcf) on November 27 as mild weather throughout much of the country contributed to uncommon storage builds for most of that month. Projected average household expenditures on natural gas total \$778 this winter, compared with \$889 last winter.

Global Crude Oil and Liquid Fuels

Global Petroleum Overview. As 2009 draws to a close and the Organization of the Petroleum Exporting Countries (OPEC) prepares to meet again at the end of the month, it faces a global oil market that has firmed up in response to production cuts that began to take effect in January 2009. Although OPEC compliance with the cuts has weakened and global oil inventories remain very high by historical standards, WTI oil prices averaged \$78 per barrel in November, continuing their generally upward trend since February. Expectations of a continued global economic turnaround have buttressed oil markets, and this *Outlook* assumes world oil-consumption-weighted real GDP grows by 2.6 percent in 2010, following a decline of 0.7 percent in 2009. EIA's expectation is that OPEC crude oil output in 2010 will hold at roughly fourth-quarter 2009 levels of under 30 million barrels per day.

Global Petroleum Consumption. EIA forecasts that world oil consumption will grow in 2010 by 1.1 million barrels per day (bbl/d) to 85.2 million bbl/d ([World Liquid Fuels Consumption Chart](#)), down slightly from last month's *Outlook*. Countries outside of the Organization for Economic Cooperation and Development (OECD) are likely to account for almost all of this growth. Projected OECD oil consumption grows by only 0.1 million bbl/d in 2010, despite a projected 0.27 million bbl/d increase in the United States after a very weak 2009.

Non-OPEC Supply. EIA expects non-OPEC oil production to average 50.3 million bbl/d in 2009, about 0.6 million bbl/d higher than year-earlier levels. Non-OPEC oil production increases have been largely the result of higher production from the United States, Brazil, and the Former Soviet Union (FSU). Oil production in Colombia has also been surprisingly strong. According to preliminary data, the country's crude oil output exceeded 0.7 million bbl/d in October for the first time since 2000. Projected non-OPEC supply growth slows to 0.2 million bbl/d in 2010, largely the result of lower growth in the United States and FSU ([Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart](#)).

OPEC Supply. OPEC crude oil production is expected to average 29.1 million bbl/d in 2009, down more than 2 million bbl/d from year-earlier levels. Projected OPEC crude oil production increases to an average of 29.6 million bbl/d in 2010, a response to an anticipated rebound in global oil demand ([World Crude Oil and Liquid Fuels Production Growth Chart](#)). EIA expects OPEC non-crude petroleum liquids, which are not subject to OPEC production targets, to grow by 0.6 million bbl/d in 2010. OPEC is scheduled to meet in Angola on December 22 to reassess the market situation. Through the forecast period, OPEC surplus crude oil 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](#)).

OECD Petroleum Inventories. OECD commercial oil inventories stood at 2.77 billion barrels at the end of the third quarter of 2009, 115 million barrels more than the 5-year average. Inventories are projected to be at 58 days of forward cover at the end of 2009, 5 days above the 5-year average for that time of year ([Days of Supply of OECD Commercial Stocks Chart](#)). EIA expects OECD oil inventories to remain above average historical levels throughout the forecast period.

Crude Oil Prices. WTI crude oil spot prices averaged \$78 per barrel in November, more than \$2 per barrel above than the prior month's average. This increase reflected improving expectations of a global economic recovery and higher oil consumption offsetting concerns about the high current level of oil inventories. EIA forecasts that WTI spot prices will weaken over the next few months, falling to about \$75 per barrel in February, and then rising to about \$82 per barrel by the end of next year ([West Texas Intermediate \(WTI\) Crude Oil Price Chart](#)).

Crude oil prices were less volatile in November than during October. During November, the WTI spot price traded within a \$5-per-barrel range, between roughly \$75 and \$80 per barrel. This contrasts with October, when the WTI spot price averaged just under \$76 per barrel and traded in an \$11-per-barrel range, between roughly \$70 and \$81 per barrel.

In the crude oil futures options market, WTI implied volatility trended lower over the second half of October and most of November 2009, following the downtrend in spot price volatility. Implied volatility from the February 2010 futures options contracts averaged 40 percent for the 5 days ending December 3, with the lower and upper limits of the 95-percent confidence interval for the February 2010 futures price at about \$60 per barrel and \$112 per barrel respectively (see [Energy Price Volatility and Forecast Uncertainty](#)). The February 2010 WTI futures contract averaged \$78.43 per barrel for the 5 days ending December 3.

Last year at this time, market participants were pricing WTI crude oil in February 2009 at \$50 per barrel, about \$28 below the level currently trading for February 2010 delivery. The implied volatility last year for the February 2009 contract was double the current level, at 82 percent per year, with lower and upper limits of \$29 and \$84 per barrel, respectively, for the 95-percent confidence interval. The higher implied volatility reflected continued market uncertainty following a price collapse from all-time highs for the WTI futures of more than \$145 per barrel in July 2008.

U.S. Crude Oil and Liquid Fuels

U.S. Petroleum Consumption. Total consumption of liquid fuels and other petroleum products is projected to average 18.7 million bbl/d, or about 800,000 bbl/d (4.1 percent) lower in 2009 compared with 2008 ([U.S. Liquid Fuels Consumption Growth Chart](#)). During the first half of 2009, total consumption fell 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 slowed to 280,000 bbl/d (1.5 percent) in the third quarter 2009, although this is in large part due to a 220,000-bbl/d increase in motor gasoline consumption as high prices and Hurricanes Gustav and Ike depressed gasoline consumption last year. Year-over-year total petroleum consumption is 430,000 bbl/d (2.2 percent) lower in the fourth quarter of 2009 as the gains in gasoline consumption return to near zero and warmer weather in the eastern United States reduces heating fuel demand. The modest economic recovery assumed for 2010 partly contributes to an increase in total liquid fuels consumption of 270,000 bbl/d (1.4 percent).

U.S. Petroleum Supply. EIA expects U.S. crude oil production will average 5.34 million bbl/d in 2009, the first production increase since 1991. Production is forecast to increase to an average of 5.44 million bbl/d in 2010 ([U.S. Crude Oil Production Chart](#)). The growth in production comes primarily from the Federal Offshore Gulf of Mexico. Crude oil production from the Thunder Horse, Tahiti, Shenzi, and Atlantis Federal offshore fields is expected to account for 12 percent of total U.S. crude oil production by the fourth quarter of 2010.

U.S. Petroleum Product Prices. Regular grade motor gasoline prices are expected to average \$2.65 per gallon in December, unchanged from the November average but almost \$1 per gallon higher than last December. In 2010 the refiner cost for crude oil averages about \$77 per barrel, or over \$17 per barrel (41 cents per gallon) higher than the 2009 average, contributing to an expected \$0.48-per-gallon increase in regular-grade gasoline prices to an average of \$2.83 per gallon next year. Diesel fuel retail prices, which averaged \$2.79 per gallon in November, are expected to average \$2.96 per gallon in 2010. Residential heating oil prices this winter (October through March) are projected to average \$2.77 per gallon, compared with \$2.63 per gallon last winter.

Natural Gas

U.S. Natural Gas Consumption. EIA expects total natural gas consumption will decrease by 1.9 percent in 2009 and by an additional 0.4 percent in 2010 ([Total U.S. Natural Gas Consumption Growth Chart](#)). A steep decline in demand by the industrial sector, and smaller but significant declines in the residential and

commercial sectors, have been partially offset by consumption growth in the electric power sector this year. Low natural gas prices relative to coal caused substantial switching to natural gas for baseload electric power generation throughout most of 2009. However, in recent weeks, natural-gas-fired generation has been closer to year-ago levels because of the seasonal increase in natural gas prices and the decrease in coal prices driven by historically high coal stocks. In addition, warmer-than-normal weather over the eastern United States during November depressed seasonal space-heating demand in the residential and commercial sectors. This weaker consumption is evident in natural gas working inventories, which increased by an estimated 9 billion cubic feet (Bcf) during November compared with the previous 5-year average decline of about 57 Bcf over the month.

A return to normal weather and expectations for economic growth are the primary drivers in EIA's forecast for consumption increases in the residential, commercial, and industrial sectors in 2010. However, EIA still expects total consumption to fall as higher natural gas prices contribute to some reversal of the coal-to-natural-gas switching that took place in the electric power sector during 2009.

U.S. Natural Gas Production and Imports. EIA expects total marketed natural gas production will increase by 3.7 percent in 2009, followed by a decline of 3.1 percent in 2010. Minimal hurricane disruptions and significant growth in production from onshore shale basins have contributed to the increase in domestic supply this year, despite a nearly 60-percent decline in the working natural gas rig count from September 2008 to July 2009. According to Baker Hughes, the working natural gas rig count is currently 748, up 83 from the low of 665 this past July. Although marketed production in the Lower-48 non-Federal Gulf of Mexico has declined since peaking in February 2009, the recent dip in September production appears to be the result of shut-ins, maintenance, and pipeline constraints, as opposed to declining field productivity. Production volumes are expected to have recovered in October and November. Shorter completion times and enhanced well productivity in shale basins contributed to sustained higher production levels amidst a dramatically lower rig count in 2009.

U.S. pipeline imports averaged about 9 Bcf/d through the first 9 months of 2009, compared with 9.9 Bcf/d during the same period last year. Lower drilling activity and natural gas production in Canada have contributed to reduced pipeline import flows this year. EIA expects pipeline imports to fall by 12 percent for the year. The persistence of low rig counts in Canada leads to lower expected Canadian natural gas production and lower U.S. pipeline imports next year. Offsetting a portion of the decline in pipeline imports, U.S. liquefied natural gas (LNG) imports increased in 2009, averaging about 1.3 Bcf/d through September compared with almost 1.0 Bcf/d

during the same period last year. Imports rose, albeit from very low levels in 2008, as new global liquefaction capacity added to supply while global LNG demand suffered under the economic crisis. EIA expects that U.S. LNG imports will increase to 1.7 Bcf/d in 2010 with the expected completion of additional global LNG supply projects, although the start-up dates for supply additions have historically been subject to delay.

U.S. Natural Gas Inventories. On November 27, 2009, working natural gas in storage was 3,837 Bcf ([U.S. Working Natural Gas in Storage Chart](#)), 487 Bcf above the 5-year average (2004–2008) and 470 Bcf above the level during the corresponding week last year. Assuming a storage withdrawal between the end of November and the end of March about 6.1 percent (113 Bcf) greater than the previous 5-year average for that period, end-of-winter (March 31, 2010) stocks will be about 1,845 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 \$3.77 per Mcf in November, \$0.35 per Mcf lower than the average spot price in October ([Henry Hub Natural Gas Price Chart](#)). Prices were depressed as warmer-than-normal weather in November reduced seasonal residential and commercial space-heating consumption by about 1.7 Bcf/d, or about 7 percent, below the projected 22.85 Bcf/d consumption in last month's *Outlook*. EIA expects prices to increase as space-heating demand rises in the coming months. However, strong domestic production, a retrenchment of electric-power-sector natural gas demand, and uncertainty about the extent of recovery in the industrial sector, should limit sustained upward price movements through the winter and well into next year. The projected Henry Hub spot price averages \$3.95 per Mcf in 2009 and \$4.62 per Mcf in 2010.

Market participants were pricing gas delivered to Henry Hub in January 2010 through futures contracts at \$4.76 per million Btu (MMBtu) (\$4.90 per Mcf) during the 5 days ended December 3. Implied price volatility for the January 2010 natural gas futures contract averaged just over 56 percent (see [Energy Price Volatility and Forecast Uncertainty](#)). This translates into a 95-percent confidence interval with a lower limit of \$3.60 and an upper limit of approximately \$6.30 per MMBtu for the January 2010 contract. The implied price volatility reflects market participants' uncertainty over how production, demand, and high inventories will be balanced in the upcoming winter heating season.

At this time last year, natural gas for delivery in January 2009 to the Henry Hub was trading at \$6.38 per MMBtu, and the implied volatility was almost 68 percent. This

translated into a lower and upper limit of \$4.65 and \$8.75 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 September 2009 were down by about 12 percent compared with the same period last year, similar to the decline in the U.S. manufacturing production index. EIA's assumption of 3.6 percent growth in manufacturing during 2010 translates to an expected growth in electricity sales to the industrial sector of about 1.1 percent. EIA forecasts electricity sales to the residential and commercial sectors to increase by 2.4 percent and 1.2 percent, respectively, in 2010 with total electricity consumption increasing by 1.6 percent ([U.S. Total Electricity Consumption Chart](#)).

U.S. Electricity Generation. The projected share of electricity generated by natural gas in the electric power sector falls from 22 percent in 2009 to 21 percent next year. This reduction will be offset by expected increases in generation from coal-fired plants, as a result of switching away from higher-priced natural gas generation and from renewable sources, especially as a result of increased windpower capacity.

U.S. Electricity Retail Prices. EIA expects delivered natural gas fuel costs for generating electricity to rise by 10 percent next year. However, lower delivered coal costs combined with comparatively more generation from coal should reduce residential electricity prices by about 0.9 percent next year ([U.S. Residential Electricity Prices Chart](#)).

Coal

U.S. Coal Consumption. Coal consumption by the electric power sector fell nearly 12 percent for the first 9 months of 2009 in response to lower total electricity generation coupled with increases in generation from other sources, natural gas, hydropower, and wind. An expected continuation of these trends for the rest of the year leads to an annual decline in electric-power-sector coal consumption of almost 10 percent. Projected increases in electricity demand and higher natural gas prices will contribute to growth in coal-fired generation in 2010. Forecast coal consumption in the electric power sector increases by nearly 4 percent in 2010 but remains below 1 billion short tons for the second consecutive year. Coal consumed for coke production declined by 30 percent in the first half of 2009 compared with the first half of 2008. Consumption of coal at coke plants rises in 2010 as economic conditions improve, with an increase of more than 3 million short tons (21 percent). EIA projects 3-percent growth in 2010

for coal consumption in the retail and general industry sectors, following a 17-percent decline in 2009 ([U.S. Coal Consumption Growth Chart](#)).

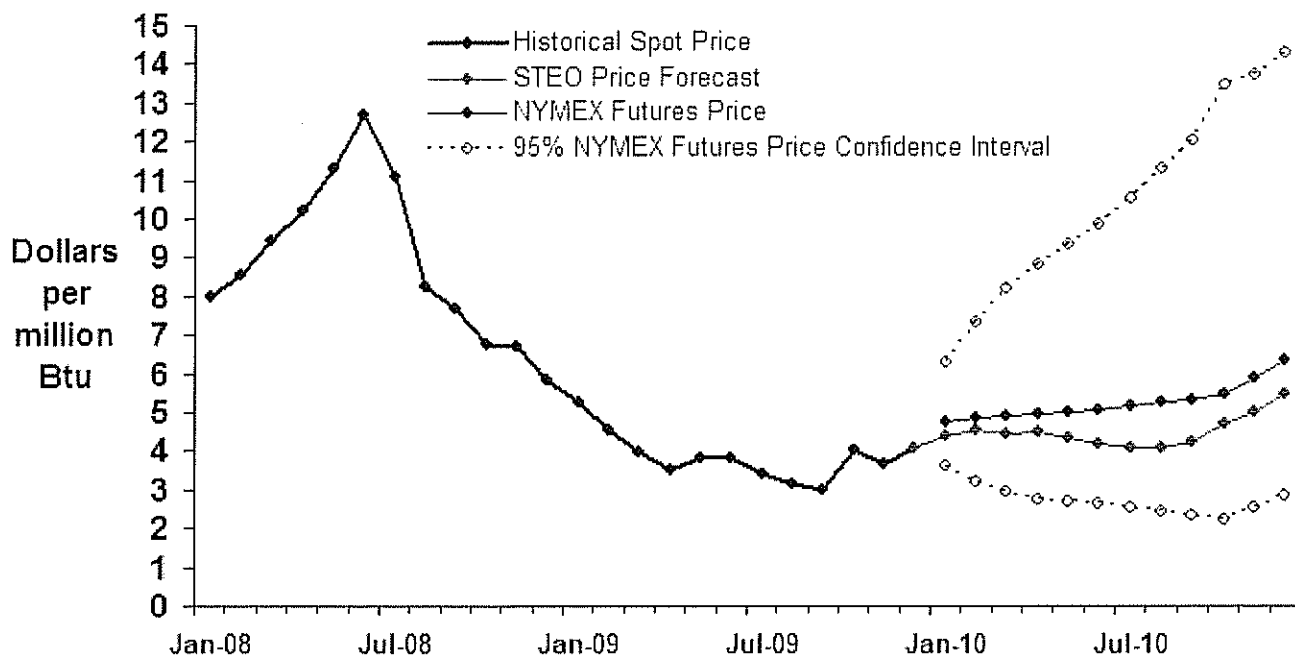
U.S. Coal Supply. Coal production for the first 3 quarters of 2009 fell by 6 percent in response to lower U.S. coal consumption, fewer exports, and higher coal inventories. These conditions are expected to persist for the remainder of 2009, with an annual decline in coal production of nearly 7 percent. Production declines by an additional 2.5 percent in 2010 in this forecast despite increases in domestic consumption and exports. Balance is maintained through a reduction in coal inventories and increased imports ([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, EIA expects the delivered electric-power-sector coal price to average about \$2.22 per MMBtu for 2009, a 7-percent increase. This higher cost of delivered coal is due to the significant portion of power-sector coal contracts initiated during a period of high prices for all fuels. The projected electric-power-sector delivered coal price falls by 8 percent to average \$2.03 per MMBtu in 2010.

U.S. Carbon Dioxide Emissions

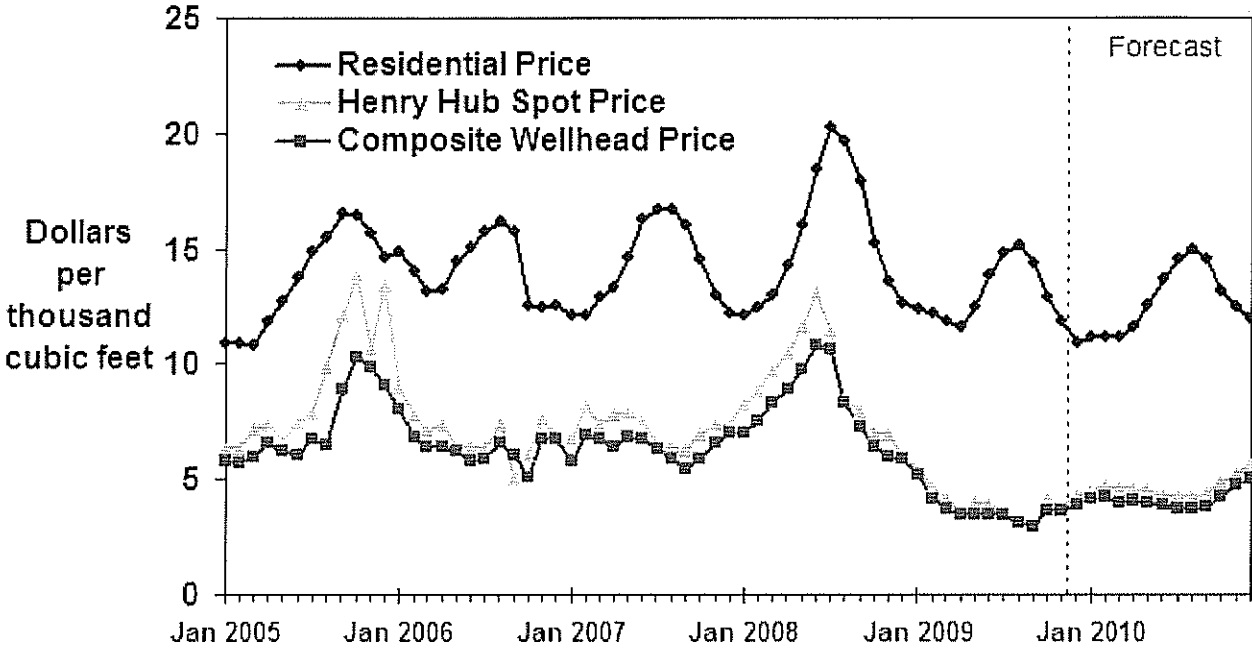
Projected carbon dioxide (CO₂) emissions from fossil fuels fall by an estimated 6.1 percent in 2009. Emissions from coal leads the drop in 2009 CO₂ emissions, falling by more than 10 percent. Changes in energy consumption in the industrial sector, a result of the weak economy, and changes in electricity generation sources are the primary reasons for the decline in CO₂ emissions ([U.S. Carbon Dioxide Emissions Growth Chart](#)). Projected improvements in the economy contribute to an expected 1.5-percent increase in CO₂ emissions in 2010.

Henry Hub Natural Gas Price

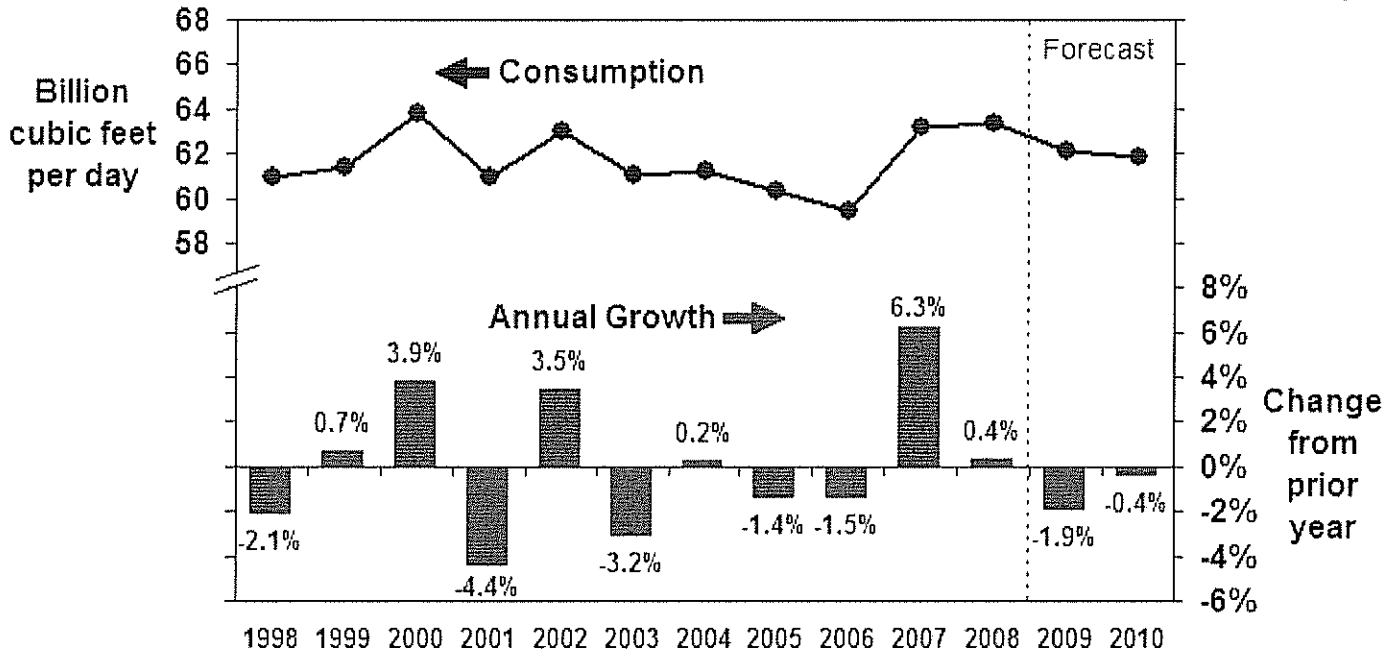


Note: Confidence interval derived from options market information on December 3, 2009

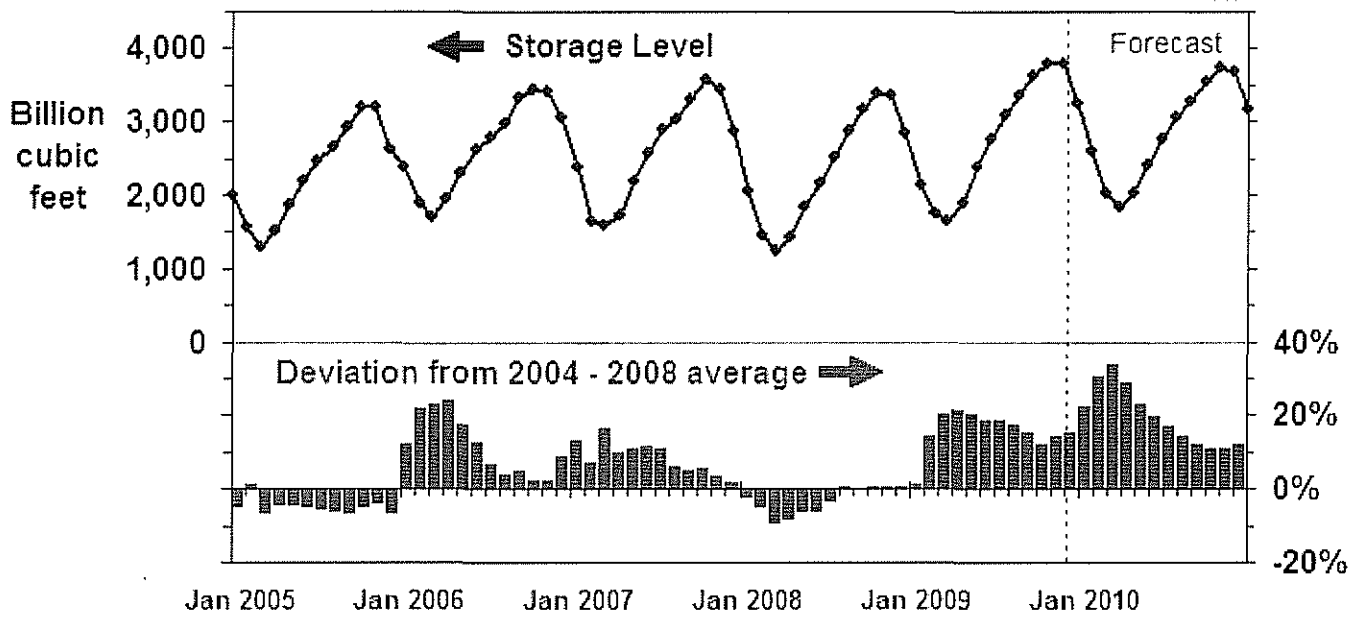
Natural Gas Prices



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

**Montana-Dakota Utilities Co.
Pipeline Rate Changes Since Last COG
North Dakota**

NorthWestern Energy – Docket No. D2009.12.155

On December 11, 2009, NorthWestern Energy filed with the Montana Public Service Commission (Commission) to change its rates to reflect changes in state and local taxes and fees and to track these changes such that the actual level of taxes and fees is recovered. On December 24, 2009, the Commission approved the increase in rates to be effective with service rendered on or after January 1, 2010 in Order No. 7057.

Approximate impact on Montana-Dakota's cost of gas – 0.0 cents per dk

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS TARIFF SHEET
NORTH DAKOTA GAS
EFFECTIVE FEBRUARY 2010

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$6.601	\$6.691	\$5.647	\$5.622
Prior Gas Cost	<u>5.267</u>	<u>5.357</u>	<u>4.304</u>	<u>4.285</u>
Current Gas Cost Adjustment	\$1.334	\$1.334	\$1.343	\$1.337
<u>Surcharge Adjustment:</u>				
Current Adjustment	(\$0.515)	(\$0.515)	(\$0.152)	\$0.024
Prior Adjustment	<u>(0.515)</u>	<u>(0.515)</u>	<u>(0.152)</u>	<u>0.024</u>
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<u>Market Based Pricing Differential</u>				
Current Adjustment	(\$0.011)	(\$0.011)	\$0.000	\$0.000
Prior Adjustment	<u>(0.011)</u>	<u>(0.011)</u>	<u>0.000</u>	<u>0.000</u>
Change in Margin Sharing Provision	\$0.000	\$0.000	\$0.000	\$0.000
Net Increase (Decrease) in Gas Costs	<u>\$1.334</u>	<u>\$1.334</u>	<u>\$1.343</u>	<u>\$1.337</u>
Gas Cost Level	\$6.601	\$6.691	\$5.647	\$5.622
Plus: Surcharge	<u>(0.515)</u>	<u>(0.515)</u>	<u>(0.152)</u>	<u>0.024</u>
Total Gas Cost Level in Tariff Rates	<u>\$6.086</u>	<u>\$6.176</u>	<u>\$5.495</u>	<u>\$5.646</u>

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE TARIFF SHEET
NORTH DAKOTA PROPANE
EFFECTIVE FEBRUARY 2010

<u>Cost of Gas - Propane:</u>	
Current Propane Cost (Exhibit D)	\$16.467
Prior Propane Cost	<u>12.625</u>
Current Propane Cost Adjustment	<u>\$3.842</u>
<u>Surcharge Adjustment:</u>	
Current Adjustment	(\$0.547)
Prior Adjustment	<u>(0.547)</u>
Change in Surcharge Adjustment	\$0.000
<u>Market Based Pricing Differential</u>	
Current Adjustment	(\$0.011)
Prior Adjustment	<u>(0.011)</u>
Change in Margin Sharing Provision	\$0.000
Net Increase (Decrease) in Gas Costs	<u>\$3.842</u>
Propane Cost Level	\$16.467
Plus: Surcharge	<u>(0.547)</u>
Total Propane Cost Level in Rates	<u>\$15.920</u>

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
RESIDENTIAL AND GENERAL SERVICE
EFFECTIVE FEBRUARY 2010**

	Amount
Total Gas Costs 1/	\$88,648,956
Residential and General Service dk Requirements 2/	13,490,818
Average Cost of Gas per dk	\$6.571
Average Cost of Gas as Adjusted for Losses @ 99.55%	6.601
Less: Gas Cost Level in Rates 3/	5.267
Current Gas Cost Adjustment	\$1.334

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -14 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C.

2/ Normalized dk sales for the twelve months ended November 30, 2009, adjusted for losses at .45%

3/ Gas Cost Level in Current Tariff Rates Case No. PU-09-738:

Cost of Purchased Gas	\$5.243
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.267

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
OPTIONAL SEASONAL - RATE 72
EFFECTIVE FEBRUARY 2010**

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$88,648,956
Less: Annual MDDQ Costs 1/	<u>11,587,067</u>
Total Gas Costs excluding MDDQ	\$77,061,889
Firm Service Requirements 1/	13,490,818
Other Gas Costs per Dk (excluding MDDQ)	\$5.712
Summer Seasonal Rate, adjusted for losses 2/	5.738
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,587,067
Winter Firm Service Requirements	12,213,749
MDDQ Costs per Winter Dk	\$0.949
Add: Other Gas Costs per Dk	<u>5.712</u>
Winter Seasonal Rate	6.661
Winter Seasonal Rate, adjusted for losses 2/	\$6.691
Less: Gas Cost Level in Rates 3/	<u>5.357</u>
Current Gas Cost Adjustment	<u><u>\$1.334</u></u>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-09-738:

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$4.382	\$5.333
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$4.402	\$5.357

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
INTERRUPTIBLE
EFFECTIVE FEBRUARY 2010**

	Amount
Total Gas Costs 1/	\$19,691,726
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$5.622
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.647
Less: Gas Cost Level in Rates 2/	4.304
Current Gas Cost Adjustment	\$1.343

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -14 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C.

2/ Gas Cost Level in Current Tariff Rates Case No. PU-09-738:

Cost of Purchased Gas	\$4.285
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.304

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
EFFECTIVE FEBRUARY 2010

	<u>Amount</u>
Total Gas Costs 1/	\$4,947,175
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$5.622
Less: Gas Cost Level in Rates 2/	<u>4.285</u>
Current Gas Cost Adjustment	<u><u>\$1.337</u></u>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -14 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C, allocated to Air Force interruptible on MDDQ.

2/ Gas Cost Level in Current Tariff Rates Case No. PU-09-738:
Cost of Purchased Gas \$4.285

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
February 2010 PGA**

Williston Basin Interstate Pipeline Company - Exhibit B, pages 6 - 8 for Schedules FT-1, FTN-1, and FS-1.

Northern Border Pipeline Company – Exhibit B, pages 9-10 for Schedule T-1.

Foothills Pipe Lines, Ltd. - Billed on a cost of service basis so there are no tariff sheets.

NOVA Gas Transmission – Exhibit B, page 11 for Schedule FT-D.

NorthWestern Energy – Exhibit B, page 12 for Schedule T-FTG-1.

South Dakota Intrastate Pipeline – Exhibit B, page 13 for Rate 1.

SourceGas Distribution LLC – Exhibit B, Page 14 for Schedule TC.

NOTICE OF CURRENTLY EFFECTIVE RATES

(ALL RATES ARE STATED IN CENTS PER DEKATHERM OR EQUIVALENT DEKATHERM AS INDICATED)

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES

RATE SCHEDULE FT-1						

RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	737.928	N.A.	N.A.	N.A.	737.928
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
COMMODITY CHARGE						
MAXIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
MINIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.190	N.A.	N.A.	31.074
MINIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310

-
- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 2.688%, CONSISTING OF 2.601% FOR THE CURRENT PERCENTAGE AND 0.087% FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR TRANSPORTATION. THE APPLICABLE RATE IS 0.506 CENTS, CONSISTING OF 0.506 CENTS FOR THE CURRENT RATE AND 0.000 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.

NOTICE OF CURRENTLY EFFECTIVE RATES

(ALL RATES ARE STATED IN CENTS PER DEKATHERM OR EQUIVALENT DEKATHERM AS INDICATED)

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES

RATE SCHEDULE FTN-1						

RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	47.491	N.A.	N.A.	N.A.	47.491
MINIMUM	RATE PER EQV. DKT PER MO.	1.589	N.A.	N.A.	N.A.	1.589

Issued by: Keith A. Tiggelaar - Director of Regulatory Affairs
 Issued on: May 19, 2005
 Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP00-107, et al., issued April 19, 2005

Effective on: April 19, 2005

NOTICE OF CURRENTLY EFFECTIVE RATES

(ALL RATES ARE STATED IN CENTS PER DEKATHERM OR EQUIVALENT DEKATHERM AS INDICATED)

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES

RATE SCHEDULE FS-1						

CAPACITY RESERVATION						
MAXIMUM	RATE PER EQV. DKT PER MO.	2.102	N.A.	N.A.	N.A.	2.102
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
CAPACITY DELIVERABILITY						
MAXIMUM	RATE PER EQV. DKT PER MO.	190.602	N.A.	N.A.	N.A.	190.602
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
INJECTION						
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
WITHDRAWAL						
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
SCHEDULED OVERRUN CHARGE						
INJECTION						
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
WITHDRAWAL						
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888

A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 0.492%, CONSISTING OF 0.595% FOR THE CURRENT PERCENTAGE AND (0.103%) FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR STORAGE. THE APPLICABLE RATE IS 0.608 CENTS, CONSISTING OF 0.515 CENTS FOR THE CURRENT RATE AND 0.093 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

Northern Border Pipeline Company
FERC Gas Tariff
First Revised Volume No. 1

Seventh Revised Sheet No. 98
Superseding
Sixth Revised Sheet No. 98

STATEMENT OF RATES

2/ 3/

Rate Schedule -----	Long-Term Base Tariff Rate (per 100 Dth-Miles) 1/ -----
T-1 and T-1B	
Daily Reservation Rate - Port of Morgan, MT to Ventura, IA	
Maximum	\$0.0321
Minimum	\$0.0000
Daily Reservation Rate - Ventura, IA to North Hayden, IN	
Maximum	\$0.0345
Minimum	\$0.0000
Commodity Rate - Port of Morgan, MT to North Hayden, IN	
Maximum	\$0.0004
Minimum	\$0.0004

- 1/ Applicable to any Rate Schedule T-1 U.S. Shippers Service Agreement or any Rate Schedule T-1B Service Agreement with a primary term of at least twelve consecutive months.
- 2/ The Settlement Base Rates, pursuant to the Stipulation at Docket No. RP06-72-000, et al., remain in effect until such rates are superseded by new base rates placed into effect consistent with the provisions of the Stipulation.
- 3/ Rates on this sheet are subject to the revenue retrieval provision pursuant to Article X of the Stipulation at Docket No. RP06-72-000, et al.

Issued by: Raymond D. Neppl, Vice President

Issued on: November 21, 2006

Effective on: January 1, 2007

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP06-72-000, issued November 21, 2006, 17 FERC ¶ 61,217

Northern Border Pipeline Company
FERC Gas Tariff
First Revised Volume No. 1

Fourteenth Revised Sheet No. 99
Superseding
Thirteenth Revised Sheet No. 99

STATEMENT OF RATES

	Commodity Rate -----
Annual Charge Adjustment (ACA) Rate (per Dekatherm) 1/	\$0.0019
Compressor Usage Surcharge (per 100 Dekatherm-miles) 2/	\$0.0026

1/ In accordance with the Commission's regulations, the authorized FERC unit charge per dekatherm is applied to physical transportation deliveries and is applicable to all transportation rate schedules. Pursuant to Section 16 of the General Terms and Conditions herein, the ACA is effectively charged at a rate of \$0.0002 per 100 Dekatherm-miles.

2/ Rate is charged in accordance with Section 45 of the General Terms and Conditions.

Issued by: Bambi L. Heckerman, Manager, Regulatory Affairs
Issued on: August 21, 2009

Effective on: October 1, 2009

NOVA Gas Transmission Ltd.

TABLE OF RATES, TOLLS & CHARGES

Service	Rates, Tolls and Charges		
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) \$213.83/10 ³ m ³		
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D	FT-D Demand Rate per month \$ 5.66/GJ		
4. Rate Schedule STFT	STFT Bid Price. Minimum bid of 100% of FT-D Demand Rate		
5. Rate Schedule FT-DW	FT-DW Bid Price. Minimum bid of 125% of FT-D Demand Rate		
6. Rate Schedule FT-A	FT-A Commodity Rate \$ 0.55/10 ³ m ³		
7. Rate Schedule FT-P	Refer to Attachment "2" for applicable FT-P Demand Rate per month		
8. Rate Schedule LRS	<u>Contract Term</u>		<u>Effective LRS Rate (\$/10³m³/day)</u>
	1-5 years		10.43
	6-10 years		8.72
	15 years		7.82
	20 years		6.94
9. Rate Schedule LRS-2	LRS-2 Rate per month \$50,000		
10. Rate Schedule LRS-3	LRS-3 Demand Rate per month \$129.55/10 ³ m ³		
11. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate & Surcharge for each Receipt Point		
12. Rate Schedule IT-D	IT-D Rate \$ 0.2045/GJ		
13. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
14. Rate Schedule PT	<u>Schedule No</u>	<u>PT Rate</u>	<u>PT Gas Rate</u>
	9006-01000-0	\$ 60.50/d	1.0 10 ³ m ³ /d
	9009-01001-1	\$660.00/d	50.0 10 ³ m ³ /d
15. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2008333534	\$ 212.00	/ month
	2009367515	\$ 45.00	/ month
	2009367513	\$ 90.00	/ month
	2009376392	\$ 9.00	/ month
	2009367511	\$ 6.00	/ month
	2009367517	\$ 5.00	/ month
	2009367518	\$ 48.00	/ month
	2009367514	\$ 146.00	/ month
	2009369554	\$ 350.00	/ month
	2009367512	\$ 1,671.00	/ month
	2009367516	\$ 18.00	/ month
	2009367441	\$ 43.00	/ month
	2009367265	\$ 169.00	/ month
	2009367442	\$ 88.00	/ month
	2009376113	\$ 185.00	/ month
2009367266	\$ 9.00	/ month	
2003004522	\$ 83,333.00	/ month	
16. Rate Schedule CO ₂	<u>Tier</u>	<u>CO₂ Rate (\$/10³m³)</u>	
	1	520.03	
	2	411.79	
	3	272.12	

Effective Date: January 1, 2010

NATURAL GAS TARIFF



Canceling $\frac{17^{\text{th}}}{16^{\text{th}}}$ Revised Revised Sheet No. 80.1
Sheet No. 80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

APPLICABILITY: Applicable to Shippers for firm transportation service on the Utility Transmission System under the terms of a Firm Gas Transportation Service Agreement (Agreement) between the Utility Transportation Business Unit (Utility) and Shipper and as subject to Rate Schedule General Terms and Operating Conditions (Rate Schedule GTC-1).

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge	
5,001 to 10,000	\$ 100.85	(1)
10,001 to 30,000	\$ 145.05	(1)
>30,000	\$ 321.90	(1)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for
Maximum Daily Delivery Quantity (MDDQ) \$ 8.248586 (1)

Transmission Commodity Rate (Monthly Rate per Dkt):

Maximum \$ 0.062506 (1)
Minimum \$ 0.017935
GTAC Amortization \$ (0.001275)
Balancing Penalty Rate Higher of \$25.00 / Dkt. Or
150% of Market Price

PLUS:

OTHER APPLICABLE CHARGES: All charges contained on other applicable rate schedules approved by the Public Service Commission of Montana.

GAS TRANSPORTATION ADJUSTMENT CLAUSE: Pursuant to MPSC Order the above GTAC Amortization shall be in effect until the balance is extinguished.

MINIMUM BILL: Per respective contracts.

(continued)

Commission Approved: December 22, 2009
Docket No.: D2009.12.155, Interim Order No. 7057
Tariff Letter No. 163-G

Effective for service rendered on or after
January 1, 2010

PUBLIC SERVICE COMMISSION
 Secretary

GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company
1415 N. Airport Rd
Pierre, SD 57501
e Filed: January 24, 2001

SD P.U.C. Section No. 3
Original Sheet No. 1

Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is \$2.398 per dekatherm.

Issued By: Lisa A. Murphy, Vice President-Chief Financial Officer
STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5
First Revised Sheet No. 12
Cancels Original Sheet No. 12

Statement of Firm and Interruptible Transportation Service Rates Applicable to Shippers Not Receiving Choice Gas Service <u>Rate Schedule TC 1/</u> Casper Division						
<u>Division</u>	<u>Receipt Point</u>	<u>Delivery Point</u>	<u>Monthly Customer Charge</u>	<u>Maximum Transportation Charge 2/</u>	<u>Minimum Transportation Charge 2/</u>	<u>Fuel Reimbursement Quantity Percentage 3/</u>
TC (Casper)						
Firm						
Transportation	MLI	MLI	\$0.00	\$1.0551	\$0.0100	0.781%
	MLI	MLE	\$163.00	\$1.0551	\$0.0100	0.781%
	MLI	DSE	\$163.00	\$2.0988	\$0.0200	3.425%
Interruptible						
Transportation 4/	MLI	MLI	\$0.00	\$0.8439	\$0.0100	0.781%
	MLI	MLE	\$163.00	\$0.8439	\$0.0100	0.781%
Administrative Fee 5/			\$325.00			

1/ Casper Division service area is defined on Sheet Nos. 3 and 4 of this Tariff.

2/ All charges are per Dekatherm.

3/ For fuel, lost and unaccounted for gas, SourceGas shall be entitled to retain the stated percentage of all Dekatherms received for transportation, unless otherwise agreed in writing.

4/ Interruptible Transportation Service is not available to DSE customers. The Customer Charge will be charged only for those months gas actually flows.

5/ In addition to the transportation charges stated above, Shippers are responsible for the monthly administrative fee as stated, applicable to each meter located at the customer location. For Interruptible Transportation Shippers, the Administrative Fee will be charged only for those months gas actually flows. Firm Transportation Shippers will be charged each month, regardless of gas flow.

Abbreviations (as defined in the General Terms and Conditions of this Tariff):

MLI Mainline System Interconnect
MLE Mainline System End-user
DSE Distribution System End-user

Date Issued: June 8, 2007
By: Bentley W. Breland

Date Effective: June 15, 2007
Title: Senior Vice President

**MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS
EFFECTIVE FEBRUARY 2010**

	General Service		
	Storage Balance 1/	Commodity Balance 2/	Prepaid Demand
October 2009	\$12,185,122	\$676,026	\$3,129,297
November	11,254,366	597,205	2,522,196
December	9,665,823	361,847	1,206,173
January 2010	4,312,847	154,872	(385,414)
February	254,105	(2,087)	(1,339,027)
March	(831,337)	(70,610)	(1,945,172)
April	(731,209)	(88,010)	(1,762,962)
May	650,673	(36,297)	(1,045,310)
June	3,033,293	65,137	(51,962)
July	6,052,425	196,513	989,842
August	9,469,225	346,341	2,011,185
September	12,471,492	762,405	2,816,551
October	13,585,829	793,797	3,070,610
13 month average	<u>\$6,259,435</u>	<u>\$289,011</u>	<u>\$708,924</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$550,267	\$25,407	\$62,322
Return Requirement	<u>\$757,955</u>	<u>\$34,996</u>	<u>\$85,844</u>

1/ Monthly balance from SENDOUT Model, allocated to North Dakota on ratio of storage capacity MDDQ.

2/ Monthly balance allocated to North Dakota on sales volumes.

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE
NORTH DAKOTA
EFFECTIVE FEBRUARY 2010

Cost of Purchased Propane	\$98,031
Gallons Purchased	65,354
Projected dk Sales	5,980
Propane Cost per Dk	\$16.393
Average Cost of Propane as Adjusted for Losses @ 99.55%	16.467
Less: Propane Cost Level in Rates 1/	<u>12.625</u>
Current Propane Cost Adjustment	<u><u>\$3.842</u></u>

1/ Propane Cost Level in Current Rates - Case No. PU-09-715

**MONTANA-DAKOTA UTILITIES CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
APPLICABLE TO NORTH DAKOTA
FIRM**

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2009									<u>(\$6,530,761)</u>
August	(\$284,184)	\$9,408 2/	(\$929)	(\$275,705)	261,090	\$0.845	\$220,621	(\$496,326)	(7,027,087)
September	1,597	0	(706)	891	256,293	0.845	216,567	(215,676)	(7,242,763)
October	122,909	0	(424)	122,485	583,825	(0.515)	149,323 3/	(26,838)	(7,269,601)
November	671,644	0	(304)	671,340	1,022,685	(0.515)	(526,683)	1,198,023	(6,071,578)
Balance @ November 30, 2009									<u>(\$6,071,578)</u>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Prior period adjustment to correct the allocation between jurisdictions.

3/ Reflects 330,877 Dk @ \$0.845 and 252,948 Dk @ (\$0.515).

**MONTANA-DAKOTA UTILITIES CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE**

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2009									<u>(\$92,116)</u>
August	(\$16,499)	\$522 2/	(\$13)	(\$15,990)	25,403	\$0.349	\$8,865	(\$24,855)	(116,971)
September	3,789	0	(12)	3,777	27,818	0.349	9,709	(5,932)	(122,903)
October	(20,599)	0	(7)	(20,606)	32,507	0.349	11,344	(31,950)	(154,853)
November	55,639	0	(7)	55,632	70,459	(0.152)	(10,710)	66,342	(88,511)
Balance @ November 30, 2009									<u>(\$88,511)</u>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Prior period adjustment to correct the allocation between jurisdictions.

**MONTANA-DAKOTA UTILITIES CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
APPLICABLE TO NORTH DAKOTA
AIR FORCE**

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2009									<u>\$14,785</u>
August	(\$15,035)	\$336 2/	\$2	(\$14,697)	7,141	\$0.167	\$1,193	(\$15,890)	(1,105)
September	877	0	0	877	6,410	0.167	1,070	(193)	(1,298)
October	(4,862)	0	0	(4,862)	7,589	0.167	1,267	(6,129)	(7,427)
November	23,780	0	0	23,780	37,871	0.024	909	22,871	15,444
Balance @ November 30, 2009									<u>\$15,444</u>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Prior period adjustment to correct the allocation between jurisdictions.