

October 9, 2009

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-09-____

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 (80th Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered November 1, 2009.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.937 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. In addition, firm transportation capacity was changed in certain areas of the system, resulting in a system wide change in demand allocation and an increase of approximately \$0.010 per dk.

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 November 2009.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.947 per dk for residential and firm general service customers, an increase of \$0.929 per dk for small and large interruptible customers and an increase of \$0.924 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 November 2009. The average cost of gas for firm customers, adjusted for losses, is \$5.087.

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 November 2009. The net effect of this filing is an increase of \$1.097 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 November 2009. The average cost of propane for all customers, adjusted for losses, is \$9.331 per dk.

These proposed adjustments, calculated in accordance with Rates 88 and 99, will amount to an increase of approximately \$1,740,100 for natural gas customers and an increase of approximately \$4,800 for propane customers during the month of November 2009. All of Montana-Dakota's retail gas and propane customers in North Dakota may be affected by this proposal. There were 90,974 natural gas customers and 334 propane customers in North Dakota as of September 30, 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:

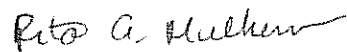
Mr. Daniel S. Kuntz
Associate General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

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 the monthly COG filings for January through December, 2009.

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
 80th Revised Sheet No. 3
 Canceling 79th 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	\$4.561	\$5.373
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$4.561	\$4.699
Interruptible Service - PAR			\$0.120	\$3.983	\$4.103
Interruptible Service - MAFB			\$0.120	\$4.140	\$4.260
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	\$4.561	\$5.158
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$3.983	(Maximum) \$4.854
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	\$4.652	\$5.249
Summer Gas Usage			\$0.597	\$3.697	\$4.294
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.019	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.019	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$3.983	(Maximum) \$4.702
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$8.773	\$9.585
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	\$8.773	\$9.370

Date Filed: October 9, 2009

Effective Date:

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

Case No.:

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

November 2009

The established October monthly price for the Rocky Mountain CIG Index increased from the previous month. 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.

Factors contributing to the increase in natural gas prices are reports from the U.S. Department of Commerce showing improved retail sales and a report from the Federal Reserve showing improved levels of industrial production. The Energy Information Administration (EIA) reported storage levels nationwide as of September 25, 2009 were 15.5 percent above the five-year average and 15.8 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 September Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 17.

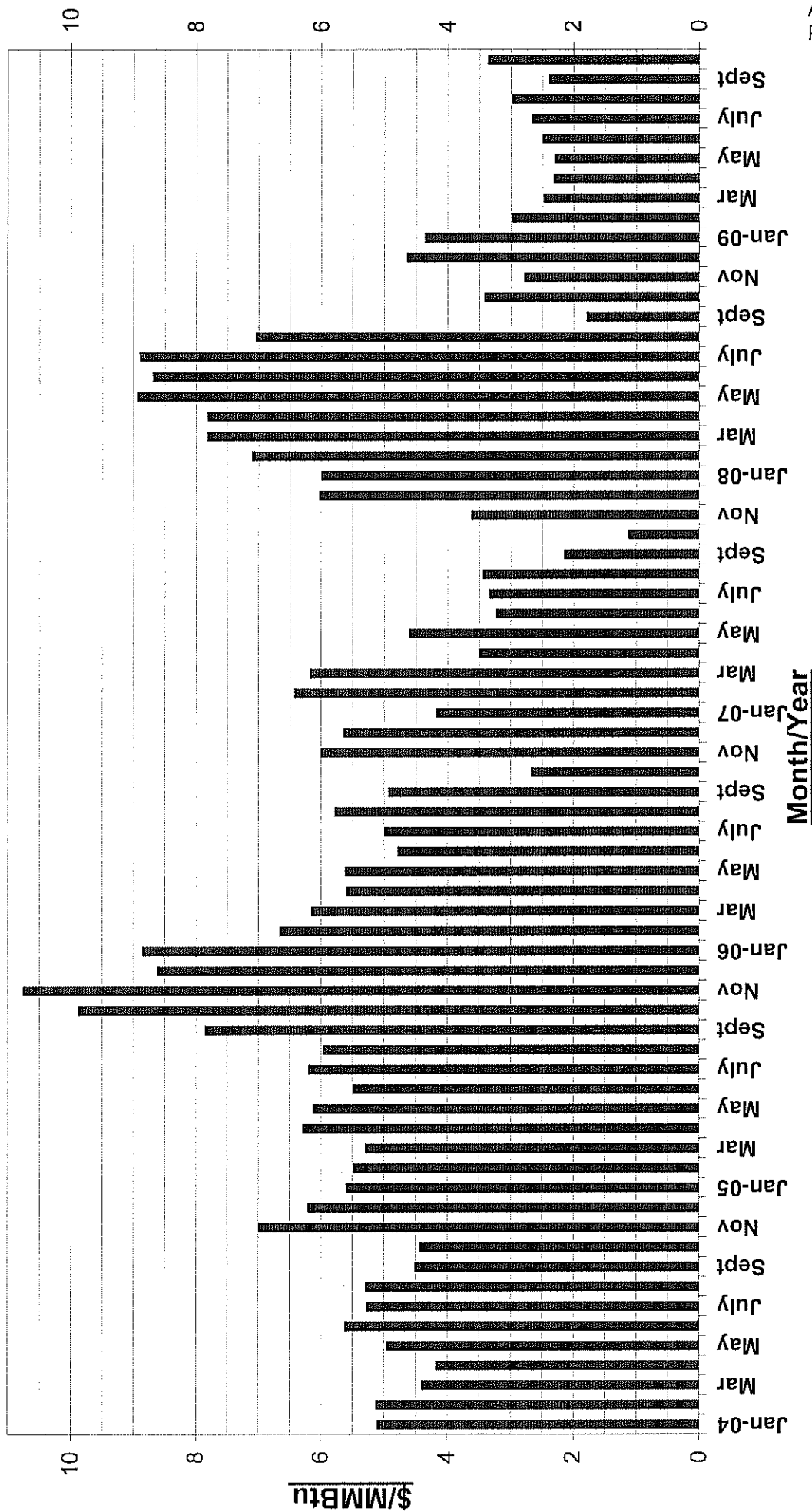
**Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
November 2009**

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.

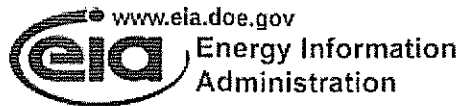
The October prices for propane have increased from the previous level. A change in the price of propane is generally driven by a combination of crude oil prices, weather, demand and inventory levels. An increase in energy prices, including crude oil, has resulted in an increase in the price of propane.

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 2004-2009 YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2007-\$3.97; 2008-\$6.24; 2009YTD-\$2.83



October 2009

Short-Term Energy and Winter Fuels Outlook

October 6, 2009 Release

Highlights

- EIA projects average household expenditures for space-heating fuels to be \$960 this winter (October 1 to March 31), a decrease of \$84, or 8 percent, from last winter. This forecast principally reflects lower fuel prices, although expected slightly milder weather than last winter will also contribute to lower fuel use in many areas. The largest expenditure decreases are in households using natural gas and propane, projected at 12 and 14 percent, respectively. Projected electricity and heating oil expenditures decline by 2 percent (see [EIA Short Term and Winter Fuels Outlook](#) slideshow).
- According to the [National Oceanic and Atmospheric Administration's \(NOAA\)](#) most recent projection of heating degree-days, the Lower-48 States are forecast to be 1 percent warmer this winter compared with last winter and 1 percent milder than the 30-year average (1971-2000). However, heating degree-day projections vary widely between regions. For example, the Midwest, a major market for propane and natural gas, is projected to be about 4 percent warmer than last winter, while the West is projected to be about 4 percent colder.
- EIA expects the price of West Texas Intermediate (WTI) crude oil to average about \$70 per barrel this winter (October-March), a \$19 increase over last winter. The forecast for average WTI prices rises gradually to about \$75 per barrel by December 2010 as U.S. and world economic conditions improve. EIA's forecast assumes U.S. GDP grows by 1.8 percent in 2010 and world oil-consumption-weighted GDP grows by 2.6 percent.
- Energy prices remain volatile, reflecting uncertainty, or risk, in the market. To measure this uncertainty, EIA is tracking futures prices and the market's assessment of the range in which those futures prices might trade (see [STEO Supplement: Energy Price Volatility and Forecast Uncertainty](#)). The *Outlook* will now report confidence intervals around the New York Mercantile Exchange

(NYMEX) crude oil and natural gas futures prices using a measure of risk derived from the NYMEX options markets known as “implied volatility.”

- Natural gas inventories are expected to set a new record high at the end of this year’s injection season (October 31), reaching more than 3.8 trillion cubic feet (Tcf). The projected Henry Hub annual average spot price increases from \$3.85 per thousand cubic feet (Mcf) in 2009 to \$5.02 in 2010.

Projected Winter Fuel Expenditures by Fuel and Region

The average household winter heating fuel expenditures discussed in this *Outlook* provide a broad guide to changes compared with last winter, but fuel expenditures for individual households are highly dependent on local weather conditions, market size, the size and energy efficiency of individual homes and their heating equipment, and thermostat settings.

Natural Gas. EIA expects households heating primarily with natural gas to spend an average of \$105 (12 percent) less this winter. About 52 percent of all households depend on natural gas as their primary heating fuel. The 12-percent decline in natural gas expenditures reflects an 11-percent decrease in prices and a 1-percent decrease in consumption. In the Midwest, where more than 70 percent of all households rely on natural gas, a projected 15-percent decrease in average household expenditures results from an 11-percent decrease in prices and a decline in consumption of 4 percent based on the forecast of warmer weather than last winter.

Heating Oil. EIA expects households heating primarily with heating oil to spend an average of \$40 (2 percent) less this winter. About 7 percent of U.S. households depend on heating oil for winter fuel. The Northeast accounts for 80 percent of heating fuel consumption. In that region, the average household is projected to spend 3 percent less (\$60) than last winter as a result of a 2-percent decrease in consumption, with regional prices about 1 percent less than last winter. EIA projects residential heating oil prices in the Northeast to average about \$2.64 per gallon during the winter season, 2 cents less than last winter. For comparison, prices averaged \$3.31 in the winter of 2007-08.

Propane. EIA expects households heating primarily with propane to spend an average of \$280 (14 percent) less this winter but that decrease varies broadly by region. EIA expects Midwestern households to see an average reduction in expenditures of 21 percent, and homes in the West 5 percent less this winter. One-half of the difference in the change in fuel bills between the two regions is due to weather with the Midwest about 4 percent warmer and the West about 4 percent colder than

last winter. Propane-heated households represent about 6 percent of total U.S. households.

Electricity. Households heating primarily with electricity can expect to spend an average of \$20 (2 percent) less than last winter. The 2-percent decline in electricity expenditures reflects a 2-percent decrease in prices and very little change in consumption. Thirty-five percent of all U.S. households rely on electricity as their primary heating fuel, ranging from 13 percent in the Northeast to 59 percent in the South. The number of households heating with electricity is growing faster, at an estimated annual rate of 2.5 percent, than all the other major heating fuels.

Global Crude Oil and Liquid Fuels

Global Petroleum Overview. Sustained economic growth in China and signs of a turnaround in other Asian countries continue to fuel expectations of a global recovery in world oil consumption. EIA has revised its expectations for world oil consumption upwards by 0.2 million barrels per day (bbl/d) for the remainder of 2009 and for 2010, in large part because of the revision to Asian growth. However, EIA has not revised its WTI oil price projections upward because ample oil supplies remain on the market. Oil inventories remain high and EIA expects oil production by the Organization of the Petroleum Exporting Countries (OPEC) to increase as well.

Global Petroleum Consumption. Global oil consumption declined by 3.2 million bbl/d in the first half of 2009 compared with year-earlier levels. Members of the Organization for Economic Cooperation and Development (OECD) accounted for most of the decline, as non-OECD oil consumption was down by about 0.4 million bbl/d during that period. Preliminary data indicate that oil consumption in the third quarter of 2009 was 1.2 million bbl/d below year-earlier levels. EIA's current macroeconomic outlook assumes that the world economy begins to recover at the end of 2009, led by non-OECD Asia. As a result, EIA expects world oil consumption to grow in the fourth quarter of 2009 compared with year-earlier levels, which would be the first such growth in five quarters. EIA projects world oil consumption growth of 1.1 million bbl/d in 2010, with almost all of the growth occurring in the non-OECD countries ([World Liquid Fuels Consumption Chart](#)).

Non-OPEC Supply. Total non-OPEC supply averaged 50.1 million bbl/d in the first half of 2009, about 0.2 million bbl/d higher than in the first half of 2008. The largest amount of growth came from South America and the former Soviet Union, which was offset in part by a decline in European production. Non-OPEC supply is expected to increase by 0.6 million bbl/d in the second half of 2009 and by 0.2 million bbl/d in 2010, compared with year-earlier levels. Over the forecast period, higher output from

Brazil, the United States, Azerbaijan, Kazakhstan, and Canada should offset falling production in Mexico and the North Sea (Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart).

OPEC Supply. OPEC crude oil production was 28.7 million bbl/d in the first half of 2009, down 2.6 million bbl/d from year-earlier levels. EIA expects OPEC production to rise gradually over the second half of the year in response to an anticipated rebound in demand, unless prices fall sharply from current levels. OPEC is scheduled to meet in Angola on December 22 to reassess the market situation. EIA projects OPEC crude oil production to climb to 29.3 million bbl/d in the second half of 2009, and then average 29.2 million bbl/d in 2010 (World Crude Oil and Liquid Fuels Production Growth Chart).

Global Petroleum Inventories. Based on revised data, OECD commercial oil inventories stood at 2.76 billion barrels at the end of the second quarter of 2009. At 61 days of forward cover, OECD commercial inventories were well above average levels for that time of year (Days of Supply of OECD Commercial Stocks Chart). EIA expects OECD oil inventories to remain higher than average historical levels throughout the forecast period.

Crude Oil Prices. WTI oil prices averaged \$69 per barrel in September, about \$2 per barrel below the August average, as expectations of an economic recovery and higher oil consumption were weighed down by currently weak demand and high inventories. With prices near \$70 per barrel, OPEC agreed to maintain its existing production targets, as expected, at its meeting in September.

Energy prices are volatile, primarily reflecting market participants' adjustments to new information from physical energy markets and/or energy-related financial derivatives. EIA quantifies this uncertainty, or risk, in the market by using "implied volatilities" derived from the NYMEX options markets to construct confidence intervals around the NYMEX crude oil futures prices. Implied volatility is calculated from traded option prices using the Black commodity option pricing model (see STEO Supplement: Energy Price Volatility and Forecast Uncertainty). The confidence intervals reflect the range in which those prices are likely to trade.

A confidence level determines the range of prices within the confidence interval. The confidence level represents the probability that the final market price for a particular futures contract, e.g., December 2009 crude oil, will fall somewhere within the lower and upper limits of the range of prices. For example, if a confidence level of 95 percent is specified, then a range of prices can be estimated within which there is a 95-percent probability the delivered price for the commodity in the contract's delivery

month will fall within that range. The higher the specified confidence level, the wider the range between the lower and upper limits.

Confidence intervals tend to be wide, in part because even small imbalances in oil markets can trigger large movements in prices given that both the production and use of oil tend to be relatively insensitive to price changes in the short-run. Increased uncertainty in consumption, production, or many other factors influencing oil prices would tend to induce an increase in implied volatility and a widening of the confidence intervals.

During the 5 days ending October 1, 2009, NYMEX futures market participants were pricing WTI delivered to Cushing, Oklahoma, in December 2009 at an average of \$69 per barrel. The 95-percent confidence interval for the December 2009 futures contract is \$49 per barrel and \$96 per barrel for the lower and upper limits of the confidence interval, respectively; a \$47 per barrel range (West Texas Intermediate (WTI) Crude Oil Price Chart). The low and high confidence limits correspond to a 48-percent implied volatility derived from the NYMEX options market. Confidence intervals also tend to widen as markets look further into the future. For example, the 95-percent lower and upper confidence limits for the December 2010 futures contract are \$32 per barrel and \$168 per barrel, respectively; a \$136 per barrel range.

While near-term implied volatilities are now lower, and confidence intervals narrower, than they were at this time last year, the current confidence intervals highlight the fact that there continues to be significant uncertainty in the outlook for oil prices. EIA's crude oil price forecast reflects all available data and our expert judgment, nonetheless there is a substantial likelihood that prices will diverge significantly from the forecast.

U.S. Crude Oil and Liquid Fuels

U.S. Petroleum Consumption. EIA forecasts total consumption of liquid fuels and other petroleum products decreasing by about 730,000 bbl/d (3.7 percent) in 2009 compared with 2008 (U.S. Petroleum Products Consumption Growth Chart). During the first half of the year, consumption declined by almost 1.25 million bbl/d (6.3 percent) from the same period last year, one of the steepest declines on record. The year-over-year projected decline in petroleum consumption slows to 210,000 bbl/d (1.1 percent) in the second half of 2009 as economic recovery begins to take hold. Monthly average motor gasoline consumption since June has shown year-over-year increases for the first time since September 2007 and continues to grow over year-ago levels throughout the forecast. The modest economic recovery projected for 2010

contributes to a 320,000-bbl/d (1.7 percent) increase in total liquid fuels consumption, led by an increase of 110,000 bbl/d (3.0 percent) in distillate consumption.

U.S. Petroleum Supply. EIA projects total U.S. crude oil production to average 5.27 million bbl/d in 2009 and increase to an average of 5.34 million bbl/d in 2010 ([U.S. Crude Oil Production Chart](#)). The last year U.S. crude oil production increased was 1991. Crude oil production from the Thunder Horse, Tahiti, Shenzi, and Atlantis Federal offshore fields accounts for about 14 percent of Lower-48 crude oil production in the fourth quarter of 2010.

U.S. Distillate and Propane Inventories. As of September 30, the start of the winter heating season, total distillate fuel inventories were an estimated 170 million barrels, up about 43 million barrels from the previous year and 38 million barrels above the end-of-September average of the last 5 years. Total distillate inventories at the end of March 2010 are projected to be 132 million barrels, about 12 million barrels above the previous 5-year average.

U.S. propane inventories were an estimated 73 million barrels at the end of September, about 14 million barrels above last year's level and 8 million barrels above the end-of-September average over the last 5 years. Projected propane inventories will end the winter season at about 32 million barrels, 2 million barrels above the average of the last 5 years. Lower natural gas production over the coming months because of very high natural gas inventories in both the United States and Canada could reduce natural gas liquids and propane production and lead to lower-than-projected propane inventories next year.

U.S. Petroleum Product Prices. EIA expects the monthly average regular-grade gasoline retail price to fall from \$2.62 per gallon in August to an average of \$2.44 per gallon for the last 3 months of the year. Higher projected crude oil prices in 2010 (refiner average cost of crude oil about \$12 per barrel, or 29 cents per gallon, higher than the 2009 average) lead to an expected increase in regular-grade gasoline prices to an average of \$2.65 per gallon next year. Projected diesel fuel retail prices, which averaged \$2.63 per gallon in August and September, will average \$2.60 during the fourth quarter of 2009 in the forecast, as the winter heating fuel season begins.

Natural Gas

U.S. Natural Gas Consumption. Total natural gas consumption is projected to decline by 2.0 percent in 2009 and 0.2 percent in 2010 ([Total U.S. Natural Gas Consumption Growth Chart](#)). Weak economic conditions continue to hamper the industrial sector, where the most recent data show natural gas consumption is down by 12.4 percent

through July compared with the same period last year. With lower consumption in the residential and commercial sectors as well, natural gas use in the electric power sector continues to serve as the only demand outlet for increased natural gas supplies. EIA data indicate that electric-power-sector natural gas consumption increased by 0.4 percent in 2009 through July, compared with the same period in 2008, despite a 5.3-percent decline in total electricity generation over the same period. Sustained low natural gas prices are expected to prolong the preferred use of natural gas in place of coal for electricity generation in some regions until space-heating demand picks up this winter.

EIA expects natural gas consumption growth in the commercial and industrial sectors in 2010 to be offset by a decline in the electric power sector. In addition to the assumption of fewer cooling degree-days next year, higher relative natural gas prices and the start-up of new coal-fired generating capacity are all expected to contribute to a reduction in natural-gas-fired electric generation in 2010.

U.S. Natural Gas Production and Imports. EIA expects total U.S. marketed natural gas production to increase by 1.5 percent in 2009 and decline by 3.8 percent in 2010. Marketed natural gas production in the Lower-48 States rose by 2.9 percent this year through July, compared with the same interval in 2008, despite a more than 40-percent decline in the working rig count since the start of the year. While production has remained stronger than expected through much of this year, EIA expects the pullback in drilling to lead to a 3.6-percent decline in Lower-48 production from the first half to the second half of 2009. In addition to the natural rate of decline from producing wells, the current forecast assumes some additional production curtailments as natural gas inventories begin to swell toward capacity limits this month. Although the working rig count has begun to increase slightly in recent weeks, EIA expects domestic natural gas production to continue to fall, with marketed production during the first half of 2010 to average about 1.8 billion cubic feet (Bcf) per day lower than the second half of 2009. However, economic recovery and increasing demand next year are expected to push prices up and provide the incentive for increasing production later next year.

U.S. liquefied natural gas (LNG) imports increase to about 471 Bcf in 2009, from 352 Bcf in 2008, and rise to about 660 Bcf in 2010. Higher LNG import levels may occur on a temporary basis as cargoes are redirected from Europe, where storage is reaching capacity and prices have declined. EIA expects that the startup of several large LNG supply projects in 2010 will lead to an increase in U.S. LNG imports, although previous supply additions abroad have been slowed by construction delays and feedgas shortages that contribute to EIA's present uncertainty about the future of current projects.

U.S. Natural Gas Inventories. On September 25, 2009, working natural gas in storage was 3,589 billion cubic feet ([U.S. Working Natural Gas in Storage Chart](#)). Current inventories are now 481 Bcf above the 5-year average (2004–2008) and 491 Bcf above the level during the corresponding week last year. Working natural gas stocks are now expected to reach 3,850 Bcf at the end of the 2009 injection season (October 31), about 40 Bcf below the sum of historical non-coincident demonstrated peak working gas storage volumes at individual active natural gas storage sites, a conservative measure of capacity that may understate the amount that could actually be stored. (See [Estimates of Peak Underground Working Gas Storage Capacity in the United States, 2009 Update](#)). The projected working gas inventory is about 285 Bcf above the previous record of 3,565 Bcf reported for the end of October 2007.

U.S. Natural Gas Prices. The Henry Hub spot price averaged \$3.06 per Mcf in September, \$0.17 per Mcf below the average spot price in August. Spot prices fell early in September then moved higher as pipeline maintenance reduced available supply and natural-gas-fired electric generators increased demand. A slight tightening of the year-over-year supply and demand balance was evident in the weekly storage injections, which averaged 67 Bcf this September compared with 72 Bcf last September. EIA expects prices to remain low through October then begin to increase as space-heating demand picks up this winter and economic conditions improve. Prices are expected to increase in 2010 but, even with a projected winter storage withdrawal greater than the 5-year average, end-of-March inventories still will be the highest recorded since March of 1991. Furthermore, lower breakeven costs for domestic production and growing global LNG supply should limit sustained price increases throughout the forecast period. EIA expects the Henry Hub spot price to average \$3.85 per Mcf in 2009 and \$5.02 per Mcf in 2010.

For the 5 days ending October 1, 2009, natural gas futures on the NYMEX were trading at \$5.59 per MMBtu for gas delivered to Henry Hub, Louisiana, during December 2009 (approximately equal to \$5.76 per Mcf assuming a natural gas heat content of 1,030 Btu per Mcf). The 95-percent confidence interval around this price has a lower limit of \$3.70 and an upper limit of \$8.50, a difference of \$4.80 per MMBtu, which corresponds to a 56-percent implied volatility ([Henry Hub Natural Gas Price Chart](#)).

Last year at this time, NYMEX natural gas to be delivered to Henry Hub in December 2008 was trading at \$7.80 per MMBtu. The lower and upper limits of the 95-percent confidence interval were \$5.40 and \$11.40, respectively. This \$6.00-per-MMBtu range corresponded to an implied volatility of 51 percent. The current implied volatility is

slightly higher than last year, but because the natural gas price is almost \$2 per MMBtu lower, the price range of the 95-percent confidence interval is smaller.

Forecast Henry Hub natural gas spot prices in this *Outlook* are about \$1 per MMBtu lower than the NYMEX futures prices. While considerable uncertainty in the market persists, this difference reflects EIA's expectation that a significant volume of natural gas production remains economic at prices below the current NYMEX 2010 futures prices. Furthermore, EIA expects that natural gas demand in the electric power sector, which served as a crucial outlet for high natural gas supplies this year, will be limited in 2010 as prices move slightly higher and new coal-fired electric generation capacity becomes available.

Electricity

U.S. Electricity Consumption. During the first half of 2009, the largest declines in residential electricity sales occurred in the western United States, while industrial sales declined most dramatically in the eastern United States. The rate of decline in electricity consumption is expected to slow during the second half of 2009, especially in the southwestern United States, where warm temperatures increased summer air conditioning usage. EIA projects total U.S. electricity consumption will decline by 3.3 percent in 2009 and then grow by 1.3 percent in 2010 as the improving economy leads to slowly recovering industrial sector electricity sales ([U.S. Total Electricity Consumption Chart](#)).

U.S. Electricity Generation. According to the September *Electric Power Monthly*, more than 50 percent of the decline in coal generation during the first half of 2009 occurred in the Appalachian States, where spot coal prices spiked late last year. Conversely, natural gas generation in those same States was up by 80 percent during the first half of 2009, compared with the same period last year. EIA expects this fuel-switching trend to reverse during 2010, with generation from U.S. coal-fired plants increasing by 1.8 percent while natural gas generation falls by 1.3 percent. This reversal is mainly the result of a number of coal-fired plants expected to begin generation in 2010.

U.S. Electricity Retail Prices. Although increased capital construction costs for generation and transmission upgrades have resulted in higher residential electricity rates over the past year, recent steep declines in utilities' cost of fuel for power generation and the cost of purchased power are likely to push those rates lower by about 1.6 percent in 2010 ([U.S. Residential Electricity Prices Chart](#)).

Coal

U.S. Coal Consumption. Coal consumption in the electric power sector fell by 11 percent in the first half of this year compared to the first half of last year, the result of lower total electricity generation combined with increases in generation from natural gas, nuclear, hydropower, and wind. Lower electric power sector coal consumption is expected to continue for the remainder of the year with the total annual decline projected at more than 9 percent. Coal is expected to regain a larger share of the baseload generation mix beginning in 2010, as demand for electricity grows and natural gas prices rise at the same time new coal-fired plants come online. Projected coal consumption in the electric power sector increases by more than 2 percent in 2010 but it remains below 1 billion short-tons for the second consecutive year. Coal consumed for steam (retail and general industry) and coke production declined by 21 percent in the first half of 2009 compared with the first half of last year. In the forecast, lower consumption of coal in both sectors continues for the remainder of the year, followed by an increase of 5 percent in the coke sector. EIA projects 4 percent growth in 2010 for coal use in the retail and general industry sector ([U.S. Coal Consumption Growth Chart](#)).

U.S. Coal Supply. Coal production for the first 6 months of 2009 fell by more than 5 percent in response to lower U.S. coal consumption, fewer exports, and higher coal inventories. These conditions persist and increase in the forecast for the remainder of 2009. Projected production declines by 2.3 percent in 2010, despite increases in domestic consumption and exports. Reductions in coal inventories and increased imports offset the increase in U.S. coal consumption ([U.S. Annual Coal Production Chart](#)).

U.S. Coal Prices. Despite decreases in spot coal prices, lower prices for other fossil fuels, and declines in demand for coal for electricity generation, the monthly average delivered electric-power-sector coal price reached a record high of \$2.29 per MMBtu in March 2009. The delivered cost of coal to the electric power sector had continued to rise because a significant portion of power-sector coal contracts were initiated during a period of high prices for all fuels. Projected power-sector coal prices fall over the forecast, averaging about \$2.20 per MMBtu for 2009 and just over \$2.00 per MMBtu in 2010.

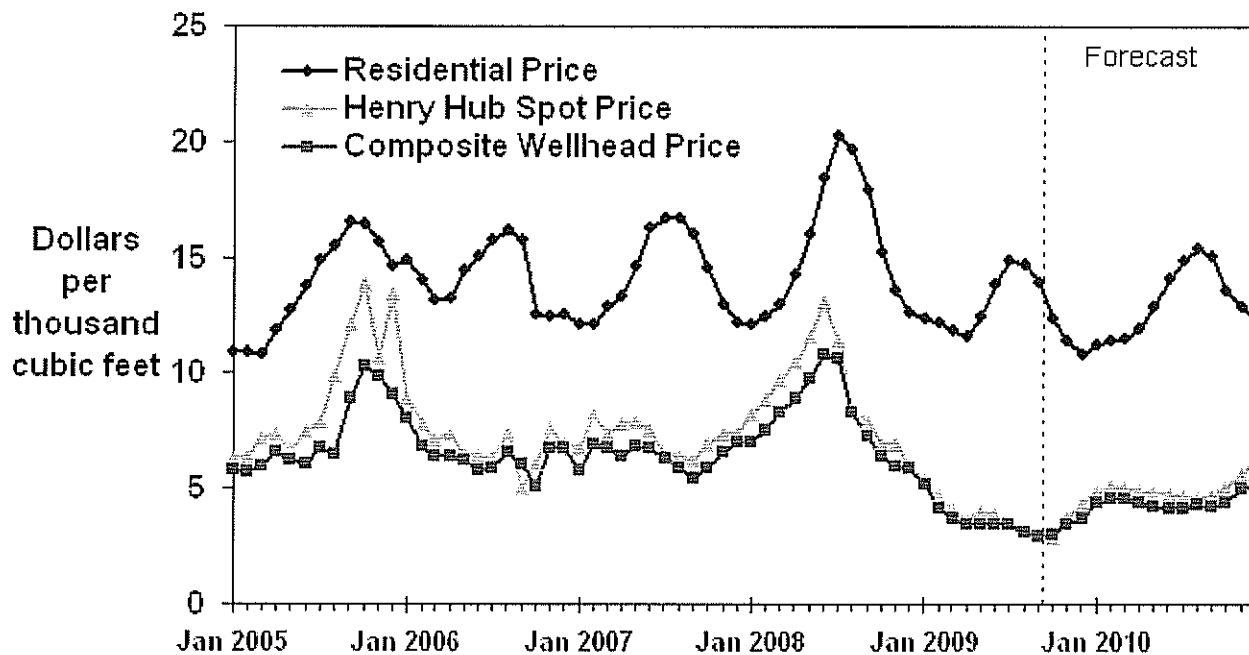
U.S. Carbon Dioxide Emissions

Projected carbon dioxide (CO₂) emissions from fossil fuels fall by 5.9 percent in 2009. Coal leads the drop in 2009 CO₂ emissions, falling by 10.1 percent. Changes in energy consumption in the industrial sector, a result of the weak economy, and changes in

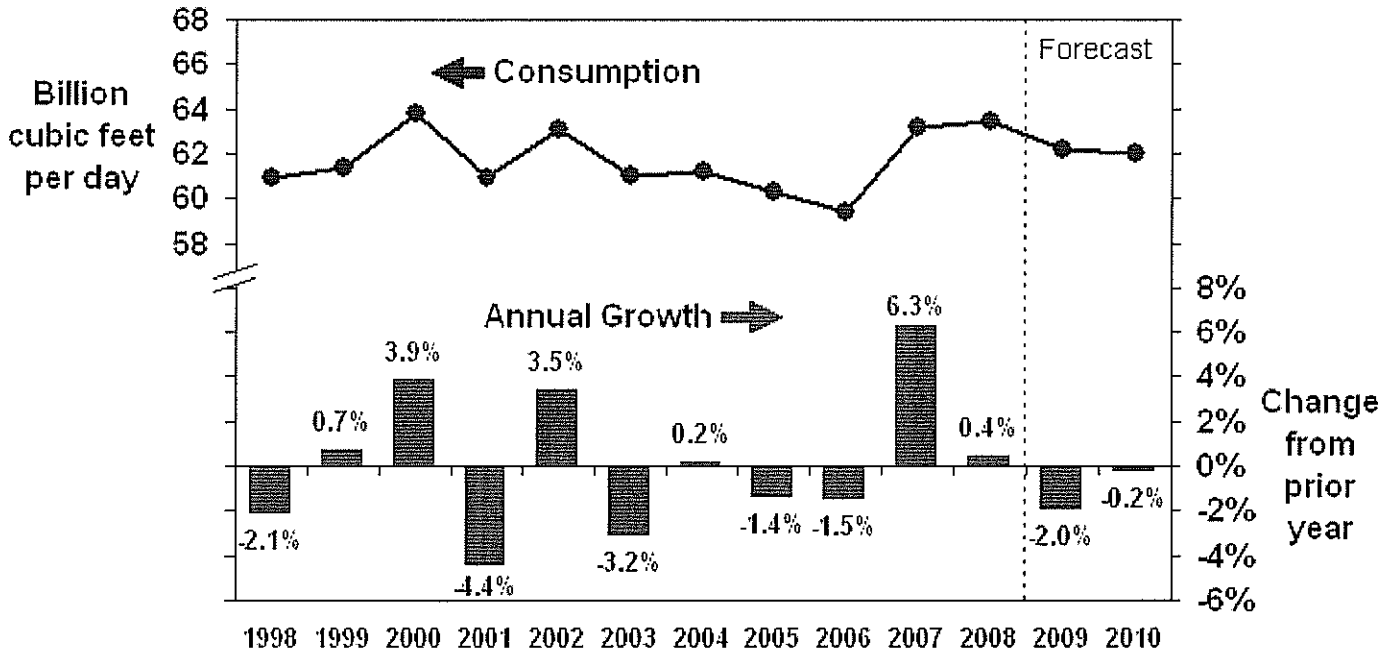
electricity generation sources are the primary factors for the decline in CO₂ emissions (U.S. Carbon Dioxide Emissions Growth Chart). The projected recovery in the economy contributes to an expected 1.1-percent increase in CO₂ emissions in 2010.

A convergence of several factors has contributed to the projected decline in CO₂ emissions in 2009 (see *STEO Supplement: Understanding the Decline in CO₂ Emissions in 2009*). EIA estimates that the combined effects of the decline in consumption of coal and natural gas in the industrial, commercial, and residential sectors, the substitution of natural gas for coal in the electric power sector, and the forecast increase in non-CO₂ emitting electricity generation (hydroelectric, nuclear, wind, solar, wood and wood waste) reduce CO₂ emissions by 242 million metric tons, or 70 percent of the total projected 2009 decline. The projected reduction in petroleum consumption accounts for the remaining 30 percent of the decline in CO₂ emissions. CO₂ emissions from petroleum are expected to fall by 102 million metric tons in 2009, with over two-thirds of the decline attributable to economy-related reductions in consumption of jet fuel and distillate fuel oil, including both diesel fuel and home heating oil. Reduced petroleum consumption in the industrial sector also contributes to the overall reduction in petroleum use.

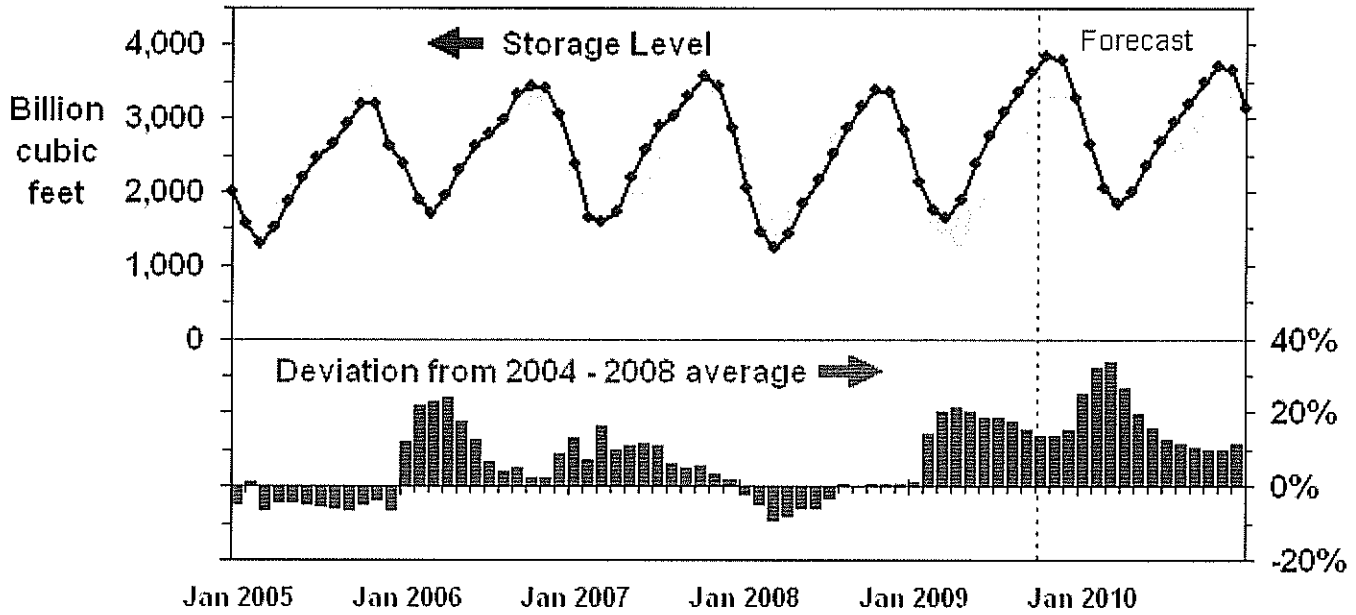
Natural Gas Prices



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.
COST OF GAS TARIFF SHEET
NORTH DAKOTA GAS
EFFECTIVE NOVEMBER 2009

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$5.087	\$5.178	\$4.135	\$4.116
Prior Gas Cost	4.140	4.230	3.206	3.192
Current Gas Cost Adjustment	\$0.947	\$0.948	\$0.929	\$0.924
<u>Surcharge Adjustment:</u>				
Current Adjustment	(\$0.515)	(\$0.515)	(\$0.152)	\$0.024
Prior Adjustment	(0.515)	(0.515)	(0.152)	0.024
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	(0.011)	(0.011)	0.000	0.000
Change in Margin Sharing Provision	\$0.000	\$0.000	\$0.000	\$0.000
Net Increase (Decrease) in Gas Costs	<u>\$0.947</u>	<u>\$0.948</u>	<u>\$0.929</u>	<u>\$0.924</u>
Gas Cost Level	\$5.087	\$5.178	\$4.135	\$4.116
Plus: Surcharge	(0.515)	(0.515)	(0.152)	0.024
Total Gas Cost Level in Tariff Rates	<u>\$4.572</u>	<u>\$4.663</u>	<u>\$3.983</u>	<u>\$4.140</u>

**MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE TARIFF SHEET
NORTH DAKOTA PROPANE
EFFECTIVE NOVEMBER 2009**

Cost of Gas - Propane:

Current Propane Cost (Exhibit D)	\$9.331
Prior Propane Cost	<u>8.234</u>
Current Propane Cost Adjustment	<u><u>\$1.097</u></u>

Surcharge Adjustment:

Current Adjustment	(\$0.547)
Prior Adjustment	<u>(0.547)</u>
Change in Surcharge Adjustment	\$0.000

Market Based Pricing Differential

Current Adjustment	(\$0.011)
Prior Adjustment	<u>(0.011)</u>
Change in Margin Sharing Provision	\$0.000

Net Increase (Decrease) in Gas Costs	<u><u>\$1.097</u></u>
---	------------------------------

Propane Cost Level	\$9.331
Plus: Surcharge	<u>(0.547)</u>
Total Propane Cost Level in Rates	<u><u>\$8.784</u></u>

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
RESIDENTIAL AND GENERAL SERVICE
EFFECTIVE NOVEMBER 2009**

	Amount
Total Gas Costs 1/	\$68,162,774
Residential and General Service dk Requirements 2/	13,459,055
Average Cost of Gas per dk	\$5.064
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.087
Less: Gas Cost Level in Rates 3/	4.140
Current Gas Cost Adjustment	\$0.947

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 August 31, 2009, adjusted for losses at .45%

3/ Gas Cost Level in Current Tariff Rates Case No. PU-09-650:

Cost of Purchased Gas	\$4.121
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.140

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
OPTIONAL SEASONAL - RATE 72
EFFECTIVE NOVEMBER 2009**

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$68,162,774
Less: Annual MDDQ Costs 1/	<u>11,586,107</u>
Total Gas Costs excluding MDDQ	\$56,576,667
Firm Service Requirements 1/	13,459,055
Other Gas Costs per Dk (excluding MDDQ)	\$4.204
Summer Seasonal Rate, adjusted for losses 2/	4.223
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,586,107
Winter Firm Service Requirements	12,184,993
MDDQ Costs per Winter Dk	\$0.951
Add: Other Gas Costs per Dk	<u>4.204</u>
Winter Seasonal Rate	5.155
Winter Seasonal Rate, adjusted for losses 2/	\$5.178
Less: Gas Cost Level in Rates 3/	<u>4.230</u>
Current Gas Cost Adjustment	<u><u>\$0.948</u></u>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-09-650:

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$3.263	\$4.211
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$3.278	\$4.230

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
INTERRUPTIBLE
EFFECTIVE NOVEMBER 2009

	<u>Amount</u>
Total Gas Costs 1/	\$14,417,861
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$4.116
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.135
Less: Gas Cost Level in Rates 2/	<u>3.206</u>
Current Gas Cost Adjustment	<u><u>\$0.929</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.

2/ Gas Cost Level in Current Tariff Rates Case No. PU-09-650:

Cost of Purchased Gas	\$3.192
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.206

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
EFFECTIVE NOVEMBER 2009

	<u>Amount</u>
Total Gas Costs 1/	\$3,622,201
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$4.116
Less: Gas Cost Level in Rates 2/	<u>3.192</u>
Current Gas Cost Adjustment	<u><u>\$0.924</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-09-650:
Cost of Purchased Gas \$3.192

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
November 2009 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. Neppi, 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 and Charges

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) \$183.99/10 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 \$ 4.87/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 \$ 0.50/10 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	10.28	
	6-10 years	8.59	
	15 years	7.71	
	20 years	6.84	
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 \$ 0.1759/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	
	2009227545	\$ 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	553.44	
	2	438.58	
	3	294.62	

Effective Date: April 29, 2009 revised pursuant to NEB Order AO-I-TGI-01-2009

NATURAL GAS TARIFF

NorthWestern
Energy

Canceling $\frac{16^{th}}{15^{th}}$ 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	\$ 100.75
10,001 to 30,000	\$ 144.90
>30,000	\$ 321.50

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for
Maximum Daily Delivery Quantity (MDDQ) \$ 8.238700

Transmission Commodity Rate (Monthly Rate per Dkt):

Maximum	\$ 0.062431
Minimum	\$ 0.017935
GTAC Amortization	\$ (0.001275) (R)
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: June 23, 2009
Docket No.: D2009.5.63, Interim Order No. 7004
Tariff Letter No. 155-G

Effective for service rendered on or after
July 1, 2009

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
Rate Schedule TC 1/
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 NOVEMBER 2009**

	General Service		
	Storage Balance 1/	Commodity Balance 2/	Prepaid Demand
October 2009	\$12,811,042	\$643,769	\$3,064,452
November	11,716,519	559,880	2,473,154
December	11,020,956	367,965	1,169,375
January 2010	4,626,340	142,509	(407,717)
February	210,308	(17,296)	(1,350,496)
March	(2,222,301)	(119,036)	(1,947,800)
April	(2,234,001)	(141,412)	(1,761,274)
May	(1,219,394)	(107,202)	(1,042,377)
June	2,121,170	35,768	(49,367)
July	5,946,552	201,269	990,704
August	9,742,113	365,436	2,010,347
September	12,567,851	801,465	2,814,371
October	13,773,923	836,105	3,067,999
13 month average	<u>\$6,066,237</u>	<u>\$274,555</u>	<u>\$694,721</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$533,283	\$24,136	\$61,073
Return Requirement	<u>\$737,776</u>	<u>\$33,391</u>	<u>\$84,492</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 NOVEMBER 2009**

Cost of Purchased Propane	\$40,502
Gallons Purchased	47,649
Projected dk Sales	4,360
Propane Cost per Dk	\$9.289
Average Cost of Propane as Adjusted for Losses @ 99.55%	9.331
Less: Propane Cost Level in Rates 1/	<u>8.234</u>
Current Propane Cost Adjustment	<u><u>\$1.097</u></u>

1/ Propane Cost Level in Current Rates - Case No. PU-09-650

**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)
Balance @ August 31, 2009									<u>(\$7,027,087)</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
 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)
Balance @ August 31, 2009									<u>(\$116,971)</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)
Balance @ August 31, 2009									<u>(\$1,105)</u>

1/ Interest calculated at 90 day Treasury Note rate.

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