

November 10, 2011

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-11-____

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 (99th Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered December 1, 2011.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.219 per dk since the last filing due to a decrease in the overall market price of gas. Attachment B explains the reasons for the decrease in the market price of gas. There has also been a change in pipeline rates, as shown on Attachment C, increasing the cost of gas \$0.025 per dk. In addition, Montana-Dakota has increased its overall firm transportation capacity, resulting in a system wide change in demand allocation and an increase of approximately \$0.035 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 December 2011.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.159 per dk for residential and firm general service customers, a decrease of \$0.199 per dk for small and large interruptible customers and a decrease of \$0.198 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 December 2011. The average cost of gas for firm customers, adjusted for losses, is \$5.017.

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 will not seek a Cost of Gas – Propane (COG) adjustment change for the month of December 2011. The Purchased Propane Cost Adjustment tariff (Rate 99), Section 2(b) provides that “Montana-Dakota shall file an adjustment to reflect changes in its average cost of propane supply only when the amount of such adjustment is at least 10 (ten) cents per dk.” The COG adjustment for the month of December 2011 results in a change of less than 10 cents per dk, and therefore, in accordance with the authorized tariff, Montana-Dakota will not seek a purchased propane cost adjustment change.

These proposed adjustments, calculated in accordance with Rate 88, will amount to a decrease of approximately \$412,500 for natural gas customers during the month of December 2011. All of Montana-Dakota's retail natural gas customers in North Dakota may be affected by this proposal. There were 91,997 natural gas customers in North Dakota as of October 31, 2011.

Please refer all inquiries regarding this filing to:

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

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

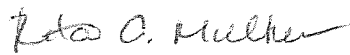
Mr. Daniel S. Kuntz
Associate General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

Montana-Dakota submitted a check for the amount of \$600 in accordance with North Dakota Century Code Section 49-05-05 on December 9, 2010. 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 Affairs 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
 99th Revised Sheet No. 3
 Canceling 98th 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	\$4.976	\$5.788
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$4.976	\$5.114
Interruptible Service - PAR			\$0.120	\$4.122	\$4.242
Interruptible Service - MAFB			\$0.120	\$4.081	\$4.201
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	\$4.976	\$5.573
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$4.122	(Maximum) \$4.993
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	\$5.066	\$5.663
Summer Gas Usage			\$0.597	\$4.101	\$4.698
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.018	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.018	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$4.122	(Maximum) \$4.841
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$16.969	\$17.781
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	\$16.969	\$17.566

Date Filed: November 10, 2011

Effective Date:

Issued By: Tamie A. Aberle
 Regulatory Affairs Manager

Case No.:

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

December 2011

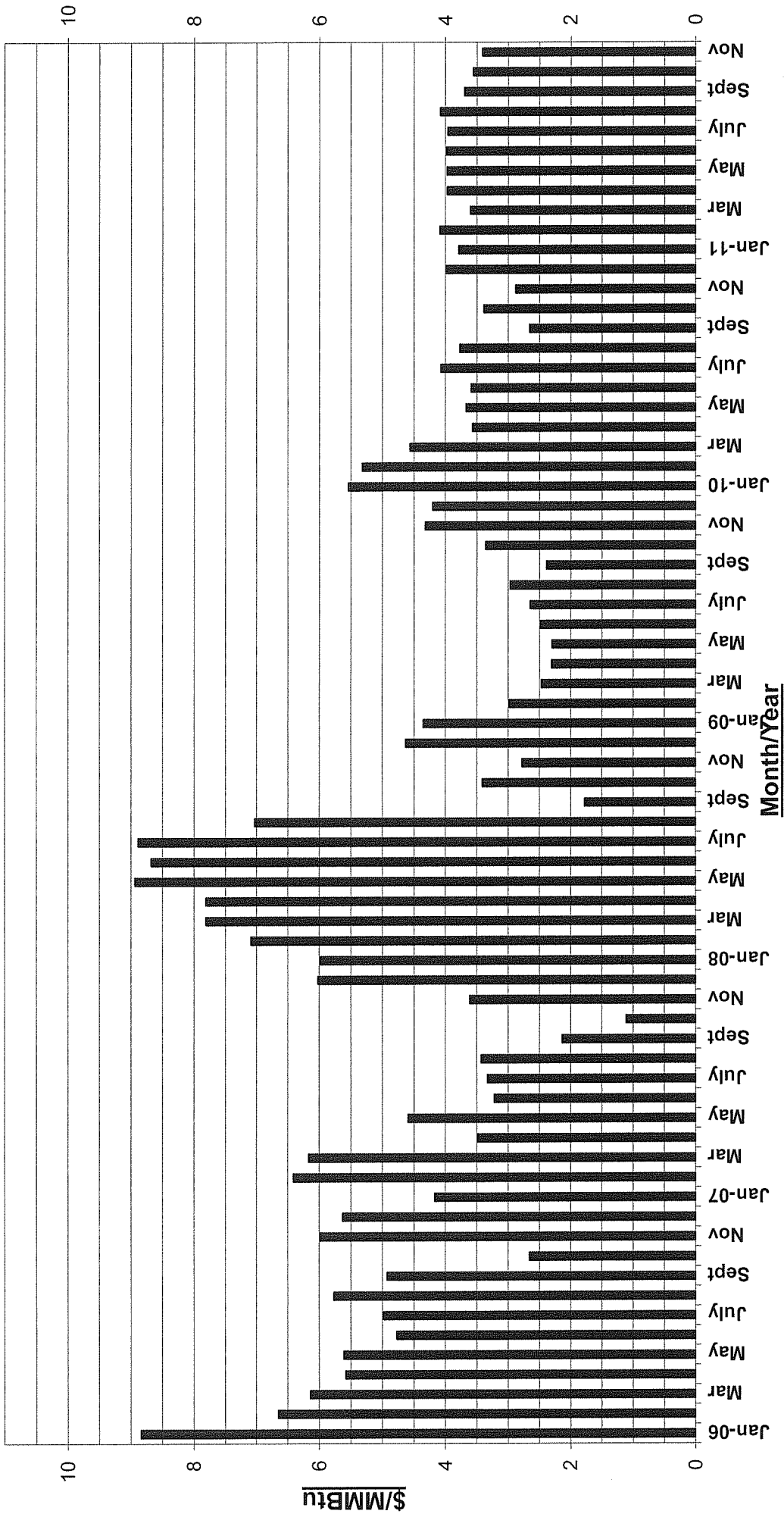
The established monthly price for the Rocky Mountain CIG Index has decreased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid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

Mild temperatures across much of the US during the transition into the heating season and the abundance of domestic shale gas production resulting in storage levels near the record storage balance were the likely reasons for the decrease in the price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of October 28, 2011 were 5.6 percent above the five-year average and 0.4 percent below last year's record storage balance.

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

The November Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 15.

CIG Rocky Mountains Index Monthly Gas Prices 2006-2011YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2009-\$3.07; 2010-\$3.92; 2011YTD - \$3.83



Independent Statistics & Analysis
U.S. Energy Information
Administration

November 2011

Short-Term Energy Outlook

November 8, 2011 Release

Highlights

- EIA expects the U.S. average refiner acquisition cost of crude oil to remain relatively flat, averaging about \$100 per barrel in 2011 and 2012. The value of West Texas Intermediate (WTI) benchmark crude oil was about \$11 per barrel below the U.S. refiner acquisition cost of crude oil in the third quarter of this year. The forecast WTI price discount narrows to \$8 per barrel by the fourth quarter of 2012, as rail and truck capacity is added to the region.
- EIA's U.S. and world economic growth assumptions have been lowered from last month's *Outlook*. World oil-consumption-weighted real GDP grows by 3.1 percent in 2012, compared with 3.5 percent in the previous *Outlook*.
- EIA projects that average household heating expenditures for heating oil and propane will increase by 10 percent and 9 percent, respectively, this winter (October 1 to March 31) compared with last winter. Average expenditures for households that heat with oil or propane are forecast to be higher than in any previous winter. In contrast, natural gas and electricity expenditures are projected to remain close to last year's levels.
- Regular-grade gasoline retail prices have fallen by 46 cents per gallon from their peak monthly average this year of \$3.91 per gallon for May to \$3.45 per gallon for October. This drop in prices results from falling crude oil prices as well as the normal seasonal decline in consumption and the switch in production from summer-grade gasoline to lower-cost winter-grade gasoline. EIA projects gasoline retail prices to continue to decline, albeit slightly, through the end of the year.
- Natural gas working inventories ended October 2011 at an estimated 3.8 trillion cubic feet (Tcf), about 1 percent below the same time last year. The projected Henry Hub natural gas spot price averages \$4.09 per million British thermal units (MMBtu) in 2011, \$0.30 per MMBtu lower than the 2010 average, and \$4.13 per MMBtu in 2012.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. Oil prices continue to face upward price pressure because of supply uncertainty resulting from ongoing unrest in the oil-producing regions of the Middle East and North Africa. However, there may be downward price pressure if Libya is able to ramp up oil production and exports sooner than anticipated. At the same time, downside demand risks continue as fears persist about weakening global economic growth, contagion effects of the debt crisis in the European Union, and other fiscal issues facing national governments.

Given expected rates of global oil consumption growth, the engine for which will be emerging markets outside of the Organization for Economic Cooperation and Development (OECD), a combination of increased oil output from members of the Organization of the Petroleum Exporting Countries (OPEC) and inventory withdrawals will need to supplement non-OPEC supply growth in order for the oil market to balance at the prices projected in this Outlook.

Global Crude Oil and Liquid Fuels Consumption. EIA expects that world crude oil and liquid fuels consumption will grow from its record-high level of 87.1 million barrels per day (bbl/d) in 2010 to 88.2 million bbl/d in 2011 and 89.6 million bbl/d in 2012 (World Liquid Fuels Consumption Chart). China and other emerging economies account for all of the projected crude oil and liquid fuels consumption growth through 2012. Consumption in member countries of the OECD is projected to decline by 0.4 million bbl/d in 2011 and to remain relatively flat in 2012.

Non-OPEC Supply. EIA projects that non-OPEC liquid fuels production will grow by 0.7 million bbl/d in 2011 and 0.8 million bbl/d in 2012, to an average of 53.3 million bbl/d next year (Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart). The largest sources of expected growth in non-OPEC oil production over the forecast period are Canada, China, Colombia, Kazakhstan, and the United States, with average annual growth in each country of over 100 thousand bbl/d. In contrast, forecast Russian and Mexican projected production is lower at the end of the forecast period. Regional turmoil, particularly in Syria and Yemen, exerts additional pressure on the non-OPEC outlook and on global oil prices.

EIA revised Brazil's liquids fuels production forecast downward for both 2011 and 2012 by 140 thousand bbl/d and 90 thousand bbl/d, respectively. The revisions are due to the decrease in projected ethanol production resulting from a poor sugar cane harvest and reduced investment. However, EIA expects that Brazil's crude oil production will continue to increase through the forecast period.

OPEC Supply. While forecast OPEC non-crude liquids production, which is not subject to production targets, is expected to increase by 0.4 million bbl/d in 2011 and by 0.5 million bbl/d in 2012, EIA expects OPEC crude oil production to remain flat in both 2011 and in 2012, after having grown by 0.7 million bbl/d in 2010. Libyan oil exports resumed at the end of September, averaging about 0.2 million bbl/d. EIA expects Libyan crude oil exports to rise to 0.35 million bbl/d during the first quarter of 2012 and to 0.8 million bbl/d by the end of 2012, compared with pre-disruption exports of 1.5 million bbl/d. OPEC surplus crude oil production capacity falls from 3.5 million bbl/d in the fourth quarter of 2010 to a projected 3.0 million bbl/d in the fourth quarter of 2011, but then increases to 4.0 million bbl/d in the fourth quarter of 2012, as Libyan production capacity comes back on line, freeing up capacity in other OPEC countries (OPEC Surplus Crude Oil Production Capacity Chart).

OECD Petroleum Inventories. EIA expects that OECD commercial inventories will decline in both 2011 and 2012. However, because of declining consumption, days of supply (total inventories divided by average daily consumption) remain relatively high at 57 days during the fourth quarters of both 2011 and 2012 (Days of Supply of OECD Commercial Stocks Chart).

Crude Oil Prices. West Texas Intermediate (WTI) crude oil spot prices fell from an average of \$110 per barrel in April to \$86 per barrel in August, and remained near this level through October (West Texas Intermediate Crude Oil Price Chart). EIA has revised the projected oil price paths slightly upward from last month's *Outlook*. EIA expects that the U.S. refiner average crude oil acquisition cost will average \$100 per barrel in 2011 and 2012, slightly higher than the projections of \$99 per barrel and \$98 per barrel for 2011 and 2012, respectively, in the previous *Outlook*.

For most of the last 30 years, WTI has traded at a premium over the average U.S. refiner acquisition cost of crude oil. However, the growth in crude oil supply, particularly from Canada and North Dakota, to the midcontinent region where WTI is traded, has not yet been matched by increases in transportation capacity out of the Midwest to the refining centers, such as the Gulf Coast. This transportation bottleneck contributes to the large price discount for WTI relative to other U.S. and world crude oils. After reaching a record price discount in the third quarter of this year, the discount for WTI is now expected to diminish modestly as the flow of crude oil out of the mid-continent region increases. Consequently, the projected U.S. refiner acquisition cost of crude oil, which averaged \$11 per barrel above WTI in the third quarter of this year, narrows to \$8 per barrel above WTI by the fourth quarter of 2012, as rail and truck capacity is added.

Energy price forecasts are highly uncertain ([Market Prices and Uncertainty Report](#)). WTI futures for January 2012 delivery during the 5-day period ending November 3 averaged \$93 per barrel. Implied volatility averaged 39 percent, establishing the lower and upper limits of a 95-percent confidence interval for the market's expectations of monthly average WTI prices in January of \$72 per barrel and \$121 per barrel, respectively. Last year at this time, WTI for January 2011 delivery averaged \$85 per barrel and implied volatility averaged 31 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$69 per barrel and \$103 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Projected total U.S. liquid fuels consumption in 2011 falls by 250 thousand bbl/d (1.3 percent) (U.S. Liquid Fuels Consumption Chart). Motor gasoline consumption accounts for most of the projected decline for the year, shrinking by 220 thousand bbl/d (2.4 percent). EIA expects total liquid fuels consumption to increase by 110 thousand bbl/d (0.6 percent) to 19.0 million bbl/d in 2012. Projected motor gasoline and distillate consumption rise by 40 thousand bbl/d (0.5 percent) and 30 thousand bbl/d (0.7 percent) in 2012, respectively, as highway travel and the U.S. economy show modest growth.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by 110 thousand bbl/d in 2010 to 5.5 million bbl/d. Production increases by a further 210 thousand bbl/d in 2011, and by 240 thousand bbl/d in 2012 (U.S. Crude Oil and Liquid Fuels Production Chart). This rising trend in production is driven by increased oil-directed drilling activity, particularly in on-shore shale formations.

Liquid fuel net imports (including both crude oil and refined products) fell from 57 percent of total U.S. consumption in 2008 to 49 percent in 2010 because of rising domestic production and the decline in consumption during the economic downturn. EIA forecasts that liquid fuel net imports' share of total consumption will decline to 45 percent in 2011.

U.S. Crude Oil and Petroleum Product Inventories. Distillate fuel oil stocks ended October 2011 at an estimated 143 million barrels, down 19 million barrels from the same time last year and 5 million barrels below the average for that month between 2006 and 2010 (see [This Week In Petroleum](#), Nov. 2, 2011). Total motor gasoline stocks at the end of October 2011 were an estimated 209 million barrels, down 1 million barrels from last year but 5 million barrels higher than the previous 5-year average for that month. Projected total distillate and motor gasoline inventories at the end of 2012 will average about 3 million barrels and 4 million barrels higher, respectively, than their previous 5-year averages (U.S. Gasoline and Distillate Inventories Chart).

Commercial crude oil inventory levels ended October 2011 at an estimated 340 million barrels, 28 million barrels below last year but 8 million barrels higher than the previous 5-year average for that month. Projected commercial crude oil stocks are gradually drawn down to 317 million barrels by the end of 2012, close to their 5-year average (U.S. Crude Oil Stocks Chart).

U.S. Petroleum Product Prices. EIA forecasts that the annual average regular-grade gasoline retail price, which averaged \$2.78 per gallon in 2010, will increase to an average of \$3.54 per gallon in 2011, before declining to an average \$3.46 per gallon in 2012 (U.S. Gasoline and Crude Oil Prices Chart). The higher retail prices in 2011 reflect not only the higher cost of crude oil but also changes in the average U.S. refinery gasoline margin (the difference between refinery wholesale gasoline prices and the average cost of crude oil). The average U.S. refinery gasoline margin increases from \$0.34 per gallon in 2010 to \$0.48 per gallon in 2011, then declines to \$0.42 per gallon in 2012. The forecast narrowing of the WTI crude oil price discount to other crude oils should lower average refining margins next year.

EIA expects that on-highway diesel fuel retail prices, which averaged \$2.99 per gallon in 2010, will average \$3.84 per gallon in 2011 and \$3.79 per gallon in 2012 (U.S. Diesel Fuel and Crude Oil Prices Chart).

Natural Gas

U.S. Natural Gas Consumption. EIA expects that total natural gas consumption will grow by 1.7 percent to 67.1 billion cubic feet per day (Bcf/d) in 2011 (U.S. Total Natural Gas Consumption Chart). Rising use of natural gas in the industrial and electric power sectors accounts for most of the increase in total consumption this year, with projected growth rates of 2.0 percent and 1.5 percent, respectively. Projected total natural gas consumption increases by 1.1 percent in 2012 to 67.9 Bcf/d, compared with a projected level of 67.7 Bcf/d in last month's *Outlook*. Higher projections of residential and commercial consumption account for much of this change in the forecast, driven by the 1.1 percent increase in heating degree-days from 2011 to 2012.

U.S. Natural Gas Production and Imports. EIA expects U.S. marketed natural gas production to average 65.6 Bcf/d in 2011, a 3.8-Bcf/d (6.1 percent) increase over 2010. All of this growth comes from higher onshore production in the lower 48 States, which more than offsets a year-over-year decline of 1.0 Bcf/d (17 percent) in the Federal Gulf of Mexico (GOM). EIA expects that total marketed production will continue to grow in 2012, but at a slower pace, increasing 1.3 Bcf/d (2.0 percent) to an average of 66.9 Bcf/d (U.S. Total Natural Gas Production and Imports Chart).

Drilling activity has been resilient despite lower natural gas spot and futures prices. According to Baker Hughes, the October 28 rig count was 934 active drilling rigs targeting natural gas, higher than this year's low of 866 on May 20 and higher than last month. If drilling continues to increase, production could grow more than expected in 2012.

Growing domestic natural gas production has reduced reliance on natural gas imports and contributed to increased exports. EIA expects that pipeline gross imports of natural gas will fall by 6.7 percent to 8.5 Bcf/d during 2011 and by another 1.4 percent to 8.3 Bcf/d in 2012. Projected U.S. imports of liquefied natural gas (LNG) will fall from 1.2 Bcf/d in 2010 to 0.9 Bcf/d in 2011 and to 0.7 Bcf/d in 2012. Pipeline gross exports to Mexico and Canada are expected to average 4.1 Bcf/d in 2011 and 4.2 Bcf/d in 2012, compared with 3.1 Bcf/d in 2010.

U.S. Natural Gas Inventories. Working natural gas in storage ended October at an estimated 3.8 Tcf (U.S. Working Natural Gas in Storage Chart). EIA expects that working natural gas inventories will total about 1.8 Tcf at the end of March 2012, the end of the winter heating season. This would represent a withdrawal of 2.0 Tcf over the upcoming heating season, compared with a withdrawal of 2.3 Tcf last season.

U.S. Natural Gas Prices. The Henry Hub spot price averaged \$3.56 per MMBtu in October 2011, 34 cents lower than the September 2011 average and 49 cents lower than the August 2011 average (Henry Hub Natural Gas Price Chart). This month's *Outlook* lowers the 2011 forecast by 6 cents to \$4.09 per MMBtu and lowers the 2012 forecast by 19 cents to \$4.13 per MMBtu compared with last month's *Outlook*.

Natural gas futures prices for January 2012 delivery (for the 5-day period ending November 3, 2011) averaged \$3.96 per MMBtu, and the average implied volatility was 35 percent ([Market Prices and Uncertainty Report](#)). The lower and upper bounds for the 95-percent confidence interval for January 2012 contracts are \$3.06 per MMBtu and \$5.13 per MMBtu. At this time last year, the January 2011 natural gas futures contract averaged \$4.13 per MMBtu and implied volatility averaged 41 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.06 per MMBtu and \$5.59 per MMBtu.

Coal

U.S. Coal Consumption. EIA expects that coal consumption for electricity generation will decline by 16 million short tons (MMst) (1.6 percent) in 2011, as the modest growth in total electricity generation is more than satisfied by increases in generation from natural gas, hydropower, and renewables other than hydropower. Projected increases in generation from natural gas, nuclear and non-hydro renewables, combined with lower electricity consumption, contribute to an additional 4.6 percent decline in electric power sector coal consumption in 2012.

U.S. Coal Supply. EIA forecasts that coal production will fall slightly (by 0.2 percent) in 2011 despite a significant increase in coal exports (U.S. Annual Coal Production Chart). Coal production in the Western region is projected to decline, while production in the Appalachian and Interior regions increases slightly. EIA expects coal production to decline by 3.6 percent in 2012 as domestic consumption and exports fall and inventories at electric power plants decline (U.S. Electric Power Sector Coal Stocks Chart).

U.S. Coal Trade. U.S. coal exports rose to 54 MMst during the first half of 2011, the highest since 1982, representing about a 35 percent increase during the first half of 2011 compared with the same period in 2010. EIA expects U.S. coal exports to remain elevated over the second half of 2011, reaching an annual total of 102 MMst. Forecast U.S. coal exports fall back to 91 MMst in 2012, as supply from other major coal-exporting countries recovers from disruptions.

U.S. Coal Prices. Average delivered coal prices to the electric power sector have increased steadily over the last 10 years by an average of 6.7 percent each year. EIA expects that this trend will continue in 2011, largely because of a rise in transportation costs. The projected average delivered coal price to the electric power sector, which was \$2.26 per MMBtu in 2010, rises to \$2.41 per MMBtu in 2011 and \$2.44 per MMBtu in 2012.

Electricity

U.S. Electricity Consumption. Total U.S. consumption of electricity across all sectors is forecast to fall by 0.6 percent during 2012 after having grown by an estimated 0.3 percent this year (U.S. Total Electricity Consumption Chart). Despite the recent cold snap and snowstorm in the Northeast, NOAA expects overall temperatures this winter to be milder than last year. In the South Atlantic region, where a majority of households heat with electricity, heating degree-days between October 2011 and March 2012 are expected to be 5.9 percent lower than in the same period last year.

This implies a drop of 2.6 percent in winter electricity sales to the residential sector in the South Atlantic.

U.S. Electricity Generation. EIA projects total U.S. generation by the electric power sector will average 10.9 terawatt hours per day during 2011. Coal is expected to fuel about 44.9 percent of this generation, down from a 46.1 percent share last year. During 2012, EIA expects coal to supply about 43.5 percent of total generation. In contrast, the share of generation fueled by natural gas is forecast to rise, growing from 22.6 percent in 2010 to 22.8 percent in 2011, and 23.7 percent in 2012 (U.S. Electric Power Sector Generation Chart).

U.S. Electricity Retail Prices. The cost of coal delivered to electric generators is expected to increase by 6.4 percent during 2011, while the delivered cost of natural gas continues to decline. The net effect will be relatively modest growth in retail electricity prices over the forecast horizon. EIA expects average U.S. residential electricity prices to increase by 1.7 percent in 2011 and by 1.2 percent in 2012 (U.S. Residential Electricity Prices Chart).

Renewables and Carbon Dioxide Emissions

U.S. Renewables. Led by a 23-percent increase in conventional hydropower, the total supply of renewables is projected to grow by about 12 percent from 2010 to 2011. EIA expects total renewable energy supply to decline by 1.1 percent in 2012 as a 12-percent decline in hydropower offsets growth in other renewable energy supplies.

U.S. hydropower generation during 2011 is expected to reach the highest level since 1999, primarily because of high levels of precipitation in regions such as the Pacific Northwest. EIA assumes a return to normal snow and rainfall levels in 2012, with hydropower generation falling by 0.36 quadrillion Btu (12 percent).

Wood and wood waste is second only to hydropower in terms of the total energy supplied by renewable sources. Because much of the wood supply is subject to industrial market conditions, especially in the pulp and paper industry, a decline of 2.4 percent is projected between 2010 and 2011 as output from the paper industry is projected to decline more than 1 percent. Wood supply growth picks up in 2012 to a projected rate of 1.8 percent.

Wind energy is estimated to have grown by 23 percent from 2010 to 2011. Growth in wind energy in 2012 is projected to slow to 15 percent as the expiration of the production tax credit nears. The solar energy supply is projected to grow by 4.5

percent and 4.9 percent in 2011 and 2012, respectively, reaching a total of 0.12 quadrillion Btu.

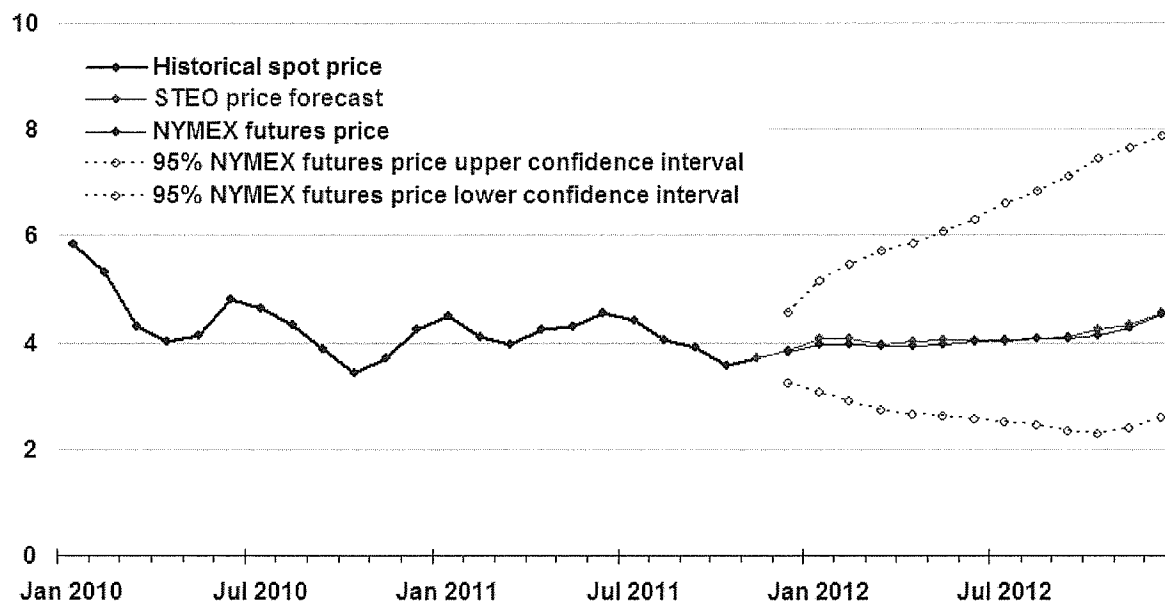
In terms of liquid renewable fuels, EIA estimates that biodiesel production in 2011 averaged about 56 thousand bbl/d (860 million gallons total annual production). This volume surpasses the 2011 Renewable Fuel Standard (RFS) Biomass-Based Diesel mandate of 800 million gallons. RFS credits generated above the current mandate can be banked and used for compliance in the following year for up to 20 percent of the requirement. The \$1 per gallon biodiesel tax credit expires at the end of 2011. In 2012, biodiesel production is forecast to grow slightly higher to 61 thousand bbl/d (940 million gallons), just reaching the proposed 2012 RFS mandate of 1.0 billion gallons after accounting for 60 million gallons of 2011 credits.

Ethanol production growth, which averaged 120 thousand bbl/d annually between 2005 and 2010, is expected to slow to 30 thousand bbl/d in 2011 and 20 thousand bbl/d in 2012, reaching an average of 920 thousand bbl/d in 2012. Ethanol exports reduce the volume of ethanol blended into gasoline. Assuming ethanol net exports average about 40 thousand bbl/d next year, EIA expects that 880 thousand bbl/d of ethanol will be blended into gasoline in 2012. The expiration of the Federal motor fuels excise tax credit for ethanol blending is expected to have little effect on blending levels, as ethanol producers do not currently appear to be capturing much of the value of the credit.

U.S. CO₂ Emissions. EIA estimates that CO₂ emissions from fossil fuels increased by 3.9 percent in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). Forecast fossil-fuel CO₂ emissions fall by 0.6 percent in 2011, as increasing emissions from higher natural gas consumption are offset by declines in coal and petroleum consumption. Increases in hydroelectric generation and other renewable energy sources in 2011 also help to mitigate emissions growth. Fossil-fuel CO₂ emissions in 2012 are expected to decline by about 1 percent as emissions from coal decline by 4.1 percent. That decline more than offsets expected increases in emissions from petroleum (0.4 percent) and natural gas (1.3 percent).

Henry Hub Natural Gas Price

dollars per million Btu



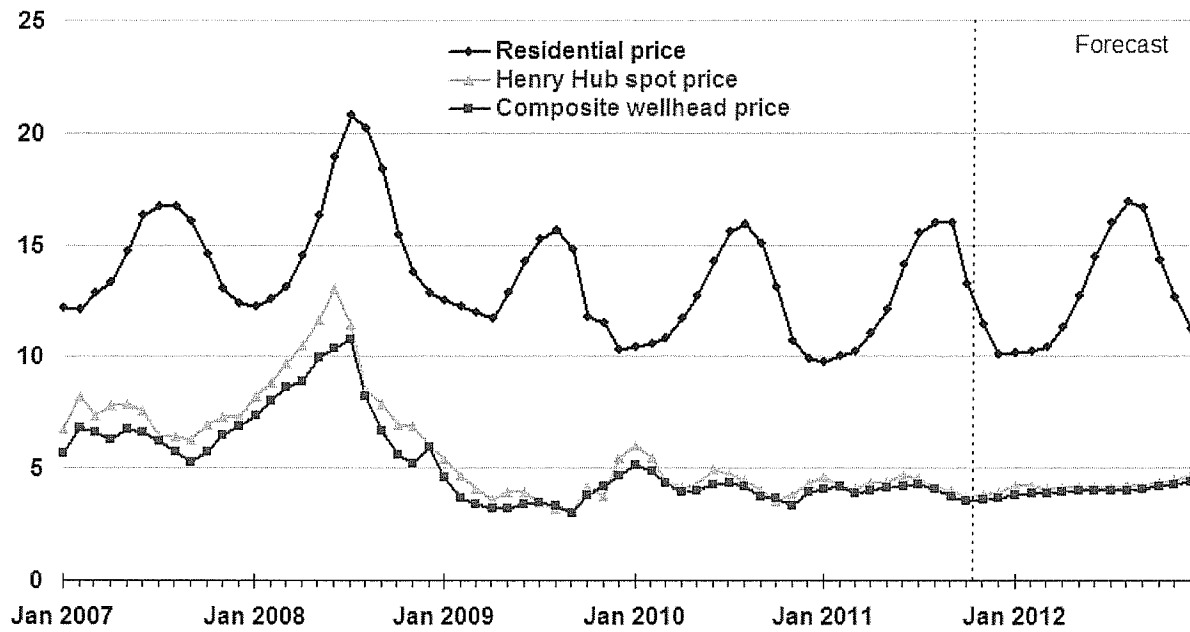
*Note: Confidence interval derived from options market information for the 5 trading days ending November 3, 2011
Intervals not calculated for months with sparse trading in "near-the-money" options contracts*

Source: Short-Term Energy Outlook, November 2011



U.S. Natural Gas Prices

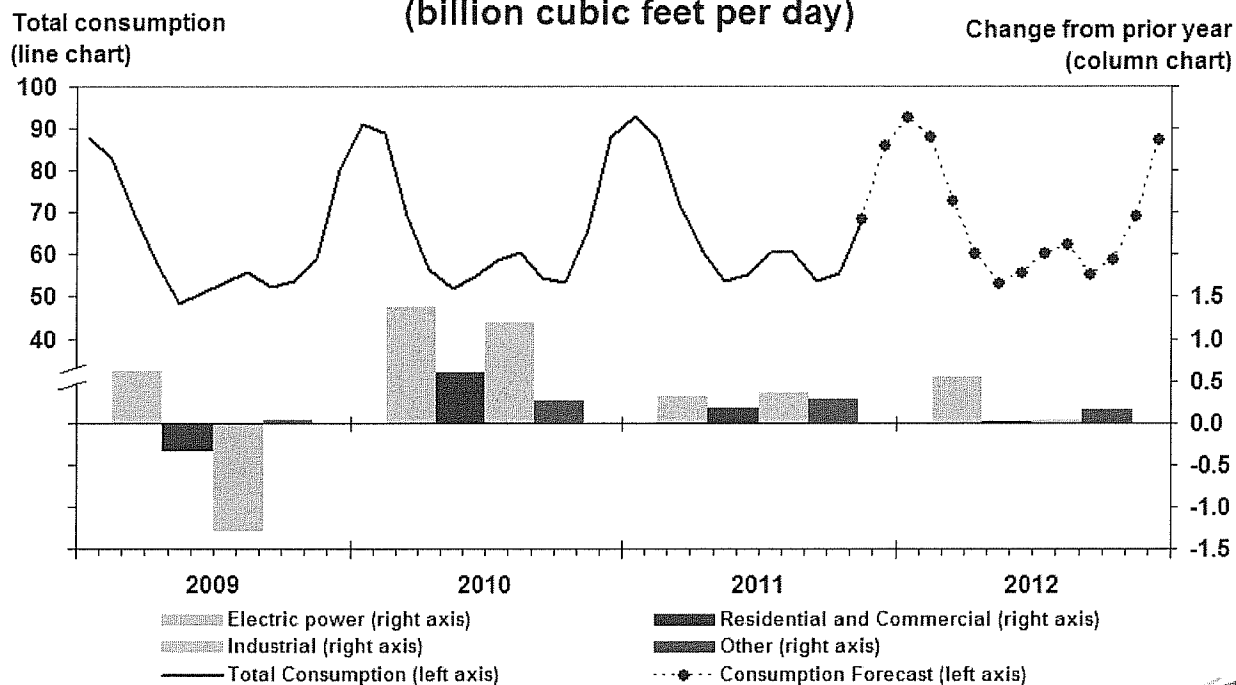
dollars per thousand cubic feet



Source: Short-Term Energy Outlook, November 2011



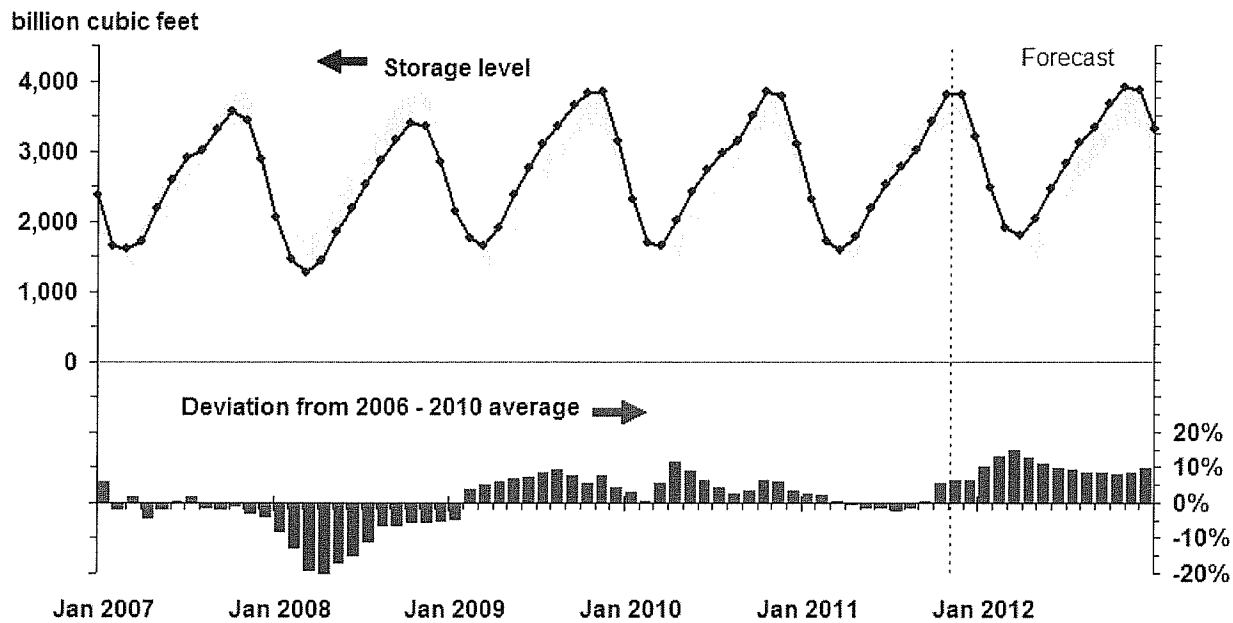
U.S. Natural Gas Consumption (billion cubic feet per day)



Source: Short-Term Energy Outlook, November 2011



U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2006 - Dec. 2010.

Source: Short-Term Energy Outlook, November 2011



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

NOVA Gas Transmission LTD.

On May 16, 2011, TransCanada filed for approval of final rates, tolls and charges for the Alberta System services for 2011 with the National Energy Board to be effective October 1, 2011. On August 19, 2011, the Board issued an order approving these rates effective October 1, 2011.

Approximate impact on Montana-Dakota's cost of gas – 0.000 cents per dk

Williston Basin Interstate Pipeline Company Docket No. RP11-2476-001

On August 31, 2011, Williston Basin filed with the FERC its semi-annual fuel and electric power reimbursement adjustment reflecting revisions to the fuel and electric power components of Williston Basin's transportation and storage rates to be effective October 1, 2011. On September 28, 2011, the Federal Energy Regulatory Commission issued a letter order approving these rates effective October 1, 2011.

Approximate impact on Montana-Dakota's cost of gas – 0.025 cents per dk

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS TARIFF SHEET
NORTH DAKOTA GAS
EFFECTIVE DECEMBER 2011

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$5.017	\$5.107	\$4.058	\$4.040
Prior Gas Cost	<u>5.176</u>	<u>5.265</u>	<u>4.257</u>	<u>4.238</u>
Current Gas Cost Adjustment	(\$0.159)	(\$0.158)	(\$0.199)	(\$0.198)
<u>Surcharge Adjustment:</u>				
Current Adjustment	(\$0.032)	(\$0.032)	\$0.064	\$0.041
Prior Adjustment	<u>(0.032)</u>	<u>(0.032)</u>	<u>0.064</u>	<u>0.041</u>
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<u>Market Based Pricing Differential</u>				
Current Adjustment	(\$0.009)	(\$0.009)	\$0.000	\$0.000
Prior Adjustment	<u>(0.009)</u>	<u>(0.009)</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>(\$0.159)</u>	<u>(\$0.158)</u>	<u>(\$0.199)</u>	<u>(\$0.198)</u>
Gas Cost Level	\$5.017	\$5.107	\$4.058	\$4.040
Plus: Surcharge	<u>(0.032)</u>	<u>(0.032)</u>	<u>0.064</u>	<u>0.041</u>
Total Gas Cost Level in Tariff Rates	<u>\$4.985</u>	<u>\$5.075</u>	<u>\$4.122</u>	<u>\$4.081</u>

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
RESIDENTIAL AND GENERAL SERVICE
EFFECTIVE DECEMBER 2011

	<u>Amount</u>
Total Gas Costs 1/	\$69,318,836
Residential and General Service dk Requirements 2/	13,880,953
Average Cost of Gas per dk	\$4.994
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.017
Less: Gas Cost Level in Rates 3/	<u>5.176</u>
Current Gas Cost Adjustment	<u><u>(\$0.159)</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/ Normalized dk sales for the twelve months ended September 30, 2011, adjusted for losses at .45%

3/ Gas Cost Level in Current Tariff Rates Case No. PU-11-8:

Cost of Purchased Gas	\$5.153
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.176

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
OPTIONAL SEASONAL - RATE 72
EFFECTIVE DECEMBER 2011**

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$69,318,836
Less: Annual MDDQ Costs 1/	<u>12,090,157</u>
Total Gas Costs excluding MDDQ	\$57,228,679
Firm Service Requirements 1/	13,880,953
Other Gas Costs per Dk (excluding MDDQ)	\$4.123
Summer Seasonal Rate, adjusted for losses 2/	4.142
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$12,090,157
Winter Firm Service Requirements	12,574,304
MDDQ Costs per Winter Dk	\$0.961
Add: Other Gas Costs per Dk	<u>4.123</u>
Winter Seasonal Rate	\$5.084
Winter Seasonal Rate, adjusted for losses 2/	\$5.107
Less: Gas Cost Level in Rates 3/	<u>5.265</u>
Current Gas Cost Adjustment	<u><u>(\$0.158)</u></u>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-11-8:

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$4.310	\$5.241
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$4.329	\$5.265

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
INTERRUPTIBLE
EFFECTIVE DECEMBER 2011**

	Amount
Total Gas Costs 1/	\$14,152,119
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$4.040
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.058
Less: Gas Cost Level in Rates 2/	4.257
Current Gas Cost Adjustment	(\$0.199)

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-11-8:

Cost of Purchased Gas	\$4.238
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.257

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
EFFECTIVE DECEMBER 2011

	<u>Amount</u>
Total Gas Costs 1/	\$3,555,469
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$4.040
Less: Gas Cost Level in Rates 2/	<u>4.238</u>
Current Gas Cost Adjustment	<u><u>(\$0.198)</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-11-8:
Cost of Purchased Gas \$4.238

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
December 2011 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, page 9 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, pages 10-11 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	0.180	N.A.	N.A.	3.300
MINIMUM A/B/	RATE PER DKT	3.120	0.180	N.A.	N.A.	3.300
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.180	N.A.	N.A.	31.064
MINIMUM A/B/	RATE PER DKT	3.120	0.180	N.A.	N.A.	3.300
VOLUMETRIC CAPACITY RELEASE CHARGE						
MAXIMUM	RATE PER DKT	24.261	N.A.	N.A.	N.A.	24.261
MINIMUM	RATE PER DKT	0.000	N.A.	N.A.	N.A.	0.000

-
- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 3.261%, CONSISTING OF 3.450% FOR THE CURRENT PERCENTAGE AND (0.189%) 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 1.098 CENTS, CONSISTING OF 0.962 CENTS FOR THE CURRENT RATE AND 0.136 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.

Issued On: September 1, 2011
 Docket Number: RP11-2476-001
 FERC Order Date: September 28, 2011

Effective On: October 1, 2011

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
VOLUMETRIC CAPACITY RELEASE CHARGE						
MAXIMUM	RATE PER DKT	1.561	N.A.	N.A.	N.A.	1.561
MINIMUM	RATE PER DKT	0.052	N.A.	N.A.	N.A.	0.052

Issued On: September 30, 2010
 Docket Number: RP10-1378-000
 FERC Order Date: November 1, 2010

Effective On: September 30, 2010

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 CHARGE						
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 CHARGE						
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 CHARGE						
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 CHARGE						
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 0.998%, CONSISTING OF 1.264% FOR THE CURRENT PERCENTAGE AND (0.266%) 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 0.491 CENTS, CONSISTING OF 0.673 CENTS FOR THE CURRENT RATE AND (0.182) 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.

Issued On: August 31, 2011
 Docket Number: RP11-2477-000
 FERC Order Date: September 23, 2011

Effective On: October 1, 2011

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

PART 4.1
4.1 - Statement of Rates
T-1 and T-1B - Long Term Base Tariff Rates
v.1.0.0 Superseding v.0.0.0

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 in this section are subject to the revenue retrieval provision pursuant to Article X of the Stipulation at Docket No. RP06-72-000, et al.

Issued: December 13, 2010
Effective: July 28, 2010

Docket No. RP10-1004-001
Accepted: August 16, 2011

NOVA Gas Transmission Ltd.

Table of Rates, Tolls and Charges
Page 1 of 2

Service	Rates, Tolls and Charges		
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month based on a three year term (Price Point "B") & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) \$ 182.52/10 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 ³	Refer to Attachment "2" for applicable FT-D Demand Rate per month based on a one year term (Price Point "Z") & Surcharge for each Group 1 or Group 2 Delivery Point. Average FT-D Demand Rate for Group 1 Delivery Points \$ 5.81/GJ FT-D Demand Rate for Group 2 Delivery Points ¹ \$ 1.66/GJ FT-D Demand Rate for Group 3 Delivery Points ² \$ 1.99/GJ		
4. Rate Schedule STFT	STFT Bid Price = Minimum of 100% of the applicable FT-D Demand Rate based on a one year term (Price Point "Z") for each Group 1 Delivery Point		
5. Rate Schedule FT-DW	FT-DW Bid Price = Minimum of 125% of the applicable FT-D Demand Rate based on a three year term (Price Point "Y") for each Group 1 Delivery Point		
6. Rate Schedule FT-P ³	Refer to Attachment "3" for applicable FT-P Demand Rate per month		
7. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10³m³/day)</u>	
	1-5 years	10.64	
	6-10 years	8.89	
	15 years	7.97	
	20 years	7.08	
8. Rate Schedule LRS-2	LRS-2 Rate per month	\$ 50,000	
9. Rate Schedule LRS-3	LRS-3 Demand Rate per month	\$ 129.55/10 ³ m ³	
10. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
11. Rate Schedule IT-D ³	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point		
12. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
13. 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
14. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2011462247	\$ 27.00	/ month
	2011462241	\$ 7.00	/ month
	2011462238	\$ 20.00	/ month
	2011462242	\$ 3.00	/ month
	2011462243	\$ 1.00	/ month
	2011462244	\$ 32.00	/ month
	2011462240	\$ 1.00	/ month
	2011462245	\$ 1,985.00	/ month
	2011462252	\$ 3.00	/ month
	2011462239	\$ 56.00	/ month
	2011462248	\$ 135.00	/ month
	2011462249	\$ 75.00	/ month
	2011462246	\$ 11.00	/ month
	2011462250	\$ 207.00	/ month
	2011462251	\$ 204.00	/ month
	2011463220	\$ 392.00	/ month
	2003004522	\$ 83,333.00	/ month
	2011476052 / 2011476054	\$ 0.0546	/ GJ subject to
		\$ 717,000.00	Minimum Annual Charge
	2011475772	\$ 9,250.00	/ month
	2011475056	\$ 0.095	/ GJ and
		\$ 1,000.00	/ month
	2011476092	\$ 0.095	/ GJ and
		\$ 1,000.00	/ month
	2011494569	\$ 0.095	/ GJ and
		\$ 1,000.00	/ month

NOVA Gas Transmission Ltd.

Attachment 2
Table of Rates , Tolls and Charges
Page 1 of 5

Group 1 Delivery Point Number	Group 1 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" (\$/GJ)	IT-D Rate per Day (\$/GJ)
2000	ALBERTA-B.C. BORDER	5.79	0.2093
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	1.66	0.0601
31110	ALLIANCE EDSON INTERCONNECT APN	1.66	0.0601
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	1.66	0.0601
3002	BOUNDARY LAKE BORDER	4.30	0.1554
1958	EMPRESS BORDER	5.87	0.2123
3886	GORDONDALE BORDER	4.30	0.1554
6404	MCNEILL BORDER	5.87	0.2123

Group 2 Delivery Point Number	Group 2 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" (\$/GJ)	IT-D Rate per Day (\$/GJ)	Subject to ATCO Pipelines Franchise Fees ¹
31000	A.T. PLASTICS SALES APN	3.39	0.1226	Yes
31001	ADM AGRI INDUSTRIES SALES APN	3.39	0.1226	Yes
3880	AECO INTERCONNECTION	1.66	0.0601	
31003	AGRIUM CARSELAND SALES APS	1.99	0.0718	
31002	AGRIUM FT. SASK SALES APN	1.66	0.0601	Yes
31004	AGRIUM REDWATER SALES APN	1.66	0.0601	
31005	AINSWORTH SALES APGP	3.39	0.1226	
31006	AIR LIQUIDE SALES APN	3.39	0.1226	
31007	ALBERTA ENVIROFUELS SALES APN	3.39	0.1226	Yes ²
31008	ALBERTA HOSPITAL SALES APN	3.39	0.1226	Yes
3868	ALBERTA-MONTANA	4.30	0.1554	
3059	ALLISON CREEK SALES	1.66	0.0601	
31009	ALTASTEEL SALES APN	3.39	0.1226	Yes ²
3562	AMOCO SALES (BP SALES TAP)	1.66	0.0601	
31012	APL JASPER SALES APN	3.39	0.1226	Yes
3488	ARDLEY SALES	1.66	0.0601	
3135	AURORA SALES	1.66	0.0601	
3423	BASHAW WEST SALES	1.66	0.0601	
31013	BAYMAG SALES APS	1.99	0.0718	
31014	BEAR CREEK COGEN SALES APGP	3.39	0.1226	
3068	BEAVER HILLS SALES	1.66	0.0601	
3933	BIG EDDY INTERCONNECTION	1.66	0.0601	
3067	BIGSTONE SALES	1.66	0.0601	
3446	BITTERN LAKE SALES	1.66	0.0601	
3468	BLEAK LAKE SALES	1.66	0.0601	
3164	BRAINARD LAKE SALES	1.66	0.0601	
3918	BUFFALO CREEK INTERCONNECTION	1.66	0.0601	
31015	BURDETT COGEN SALES APS	1.99	0.0718	
3109	CALDWELL SALES	1.66	0.0601	
31016	CALGARY ENERGY CENTRE SALES APS	1.66	0.0601	Yes
3634	CANOE LAKE SALES	1.66	0.0601	
3165	CANOE LK SLS #2	1.66	0.0601	
3866	CARBON INTERCONNECTION	1.66	0.0601	
3484	CARIBOU LAKE SALES	1.66	0.0601	
3157	CARIBOU LK SOUTH SL	1.66	0.0601	
3106	CARMON CREEK SALES	1.66	0.0601	
3101	CAROLINE SALES	1.66	0.0601	
31017	CARSELAND COGEN SALES APS	1.99	0.0718	
3495	CAVALIER SALES	1.66	0.0601	
31018	CHAIN LAKES COOP SALES APS	1.99	0.0718	
3907	CHANCELLOR INTERCONNECTION	1.66	0.0601	
3151	CHEECHAM W. #2 SALES	1.66	0.0601	
3622	CHEECHAM WEST SALES	1.66	0.0601	
6014	CHEVRON AURORA SALES	1.66	0.0601	

NATURAL GAS TARIFF

NorthWestern
Energy

Canceling	<u>26th</u>	Revised	Sheet No.	<u>80.1</u>
	<u>25th</u>	Revised	Sheet No.	<u>80.1</u>

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	\$ 103.60
10,001 to 30,000	\$ 148.95
>30,000	\$ 330.50

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	\$ 0.8469517
--	--------------

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	\$ 0.0064180
Minimum	\$ 0.0017935
GTAC Amortization	\$ (0.0011145)
Balancing Penalty Rate	Higher of \$25.00/ Dekatherm 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)

Staff Approved: July 27, 2011
Accepted as filed. No Commission action required.
Tariff Letter No. 194-G

Effective for service rendered on or after
August 1, 2011

PUBLIC SERVICE COMMISSION
Aleisha Salim Secretary

GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company
1415 N. Airport Rd
Pierre, SD 57501

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

Date Filed: January 24, 2001

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

NG-00-001

STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5
Third Revised Sheet No. 12
Cancels Second Revised 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	\$0.1040	\$0.0010	0.885%
	MLI	MLE	\$145.00	\$0.1040	\$0.0010	0.885%
	MLI	DSE	\$225.00	\$0.1978	\$0.0020	2.425%
Interruptible						
Transportation 4/	MLI	MLI	\$0.00	\$0.0844	\$0.0010	0.885%
	MLI	MLE	\$145.00	\$0.0844	\$0.0010	0.885%
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 therm.
- 3/ For fuel, lost and unaccounted for gas, the Company shall be entitled to retain the stated percentage of all therms received for transportation, unless otherwise agreed in writing. On or before March 1 of each year, the Company shall file with the Commission an application to revise the stated percentage to be effective June 1 of that year through May 31 of the following year. The Company shall calculate the stated percentage using not less than twelve (12) consecutive months of actual data.
- 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: March 1, 2011
By: William N. Cantrell

Date Effective: June 1, 2011
Title: President and CEO

**MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS
EFFECTIVE DECEMBER 2011**

	General Service		
	Storage Balance 1/	Commodity Balance 2/	Prepaid Demand
October 2011	\$15,494,686	\$738,322	\$3,073,007
November	12,933,780	616,217	2,527,668
December	8,196,534	413,481	1,217,760
January 2012	1,888,404	178,069	(398,096)
February	(2,491,690)	11,799	(1,423,291)
March	(3,306,466)	(36,142)	(2,016,099)
April	(3,095,261)	(36,469)	(1,824,418)
May	(698,958)	95,176	(1,074,189)
June	2,689,633	286,803	(49,844)
July	6,439,883	499,221	1,024,572
August	10,153,571	709,349	2,079,385
September	12,859,621	1,049,308	2,910,499
October	13,602,618	1,082,655	3,176,598
13 month average	<u>\$5,743,566</u>	<u>\$431,368</u>	<u>\$709,504</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$504,917	\$37,922	\$62,372
Return Requirement	<u>\$688,539</u>	<u>\$51,713</u>	<u>\$85,055</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.
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, 2011									<u>(\$589,074)</u>
August	\$229,854	\$119,111 2/	(\$5) 3/	\$348,960	257,122	(\$0.023)	(\$5,914)	\$354,874	(234,200)
September	153,237	(52,739) 4/	(70) 5/	100,428	263,383	(0.023)	(6,058)	106,486	(127,714)
Balance @ September 30, 2011									<u>(\$127,714)</u>

1/ Interest calculated at the 90 day Treasury Note rate.

2/ Reflects correction to restate June gas costs to include correct dk volumes.

3/ Includes interest associated with June gas cost adjustment.

4/ Adjustment to correct gas costs for the period July 2009 - August 2011 due to incorrect pipeline border station metered volumes and adjustment for the period December 2010 - June 2011 to reflect the correct allocation of the volumes associated with the Billings Landfill.

5/ Includes interest associated with the September gas cost adjustments.

**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, 2011									<u><u>\$48,803</u></u>
August	\$10,522	\$0	\$1	\$10,523	30,906	(\$0.010)	(\$309)	\$10,832	59,635
September	14,424	20,058 2/	32 3/	34,514	33,439	(0.010)	(334)	34,848	94,483
Balance @ September 30, 2011									<u><u>\$94,483</u></u>

1/ Interest calculated at the 90 day Treasury Note rate.

2/ Adjustment to correct gas costs for the period July 2009 - August 2011 due to incorrect pipeline border station metered volumes and adjustment for the period December 2010 - June 2011 to reflect the correct allocation of the volumes associated with the Billings Landfill.

3/ Includes interest associated with the September gas cost adjustments.

**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, 2011									<u><u>\$82,096</u></u>
August	\$7,880	(\$62,107) 2/	\$0	(\$54,227)	4,781	\$0.031	\$148	(\$54,375)	27,721
September	11,054	(72,081) 3/	(7) 4/	(61,034)	4,781	0.031	148	(61,182)	(33,461)
Balance @ September 30, 2011									<u><u>(\$33,461)</u></u>

1/ Interest calculated at the 90 day Treasury Note rate.

2/ Reflects correction to restate June gas costs to include correct dk volumes.

3/ Adjustment to correct gas costs for the period July 2009 - August 2011 due to incorrect pipeline border station metered volumes and adjustment for the period December 2010 - June 2011 to reflect the correct allocation of the volumes associated with the Billings Landfill.

4/ Includes interest associated with the September gas cost adjustments.