

January 11, 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 (93<sup>rd</sup> Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered February 1, 2011.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.158 per dk since the last filing due to a decrease in the market price of gas and a higher cost of gas withdrawn from storage. Attachment B explains the reasons for the increase in the market price of gas. There has also been a change in pipeline rates, as shown on Attachment C, decreasing the cost of gas \$0.001 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 February 2011.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.157 per dk for residential and firm general service customers, an increase of \$0.147 per dk for small and large interruptible customers and an increase of \$0.146 per dk for Air Force interruptible customers from the currently effective rates.

Exhibit B shows the calculation of the current gas cost adjustment that will be applicable to Montana-Dakota's customers for the month of February 2011. The average cost of gas for firm customers, adjusted for losses, is \$5.299.

Exhibit C shows the calculation of the return on storage inventory balances and prepaid

demand and commodity balances using the calculation procedure set forth in Rate 88.

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

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

Exhibit A, page 2 summarizes the cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of February 2011. The net effect of this filing is an increase of \$2.196 per dk for all customers from the currently effective rates.

Exhibit D shows the calculation of the current cost of gas – propane that will be applicable to Montana-Dakota's customers for the month of February 2011. The average cost of propane for all customers, adjusted for losses, is \$15.919 per dk.

These proposed adjustments, calculated in accordance with Rates 88 and 99, will amount to an increase of approximately \$340,000 for natural gas customers and an increase of approximately \$13,200 for propane customers during the month of February 2011. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 93,916 natural gas customers and 332 propane customers in North Dakota as of December 31, 2010.

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 \$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 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  
 93rd Revised Sheet No. 3  
 Canceling 92nd 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	\$5.268	\$6.080
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$5.268	\$5.406
Interruptible Service - PAR			\$0.120	\$4.327	\$4.447
Interruptible Service - MAFB			\$0.120	\$4.348	\$4.468
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	\$5.268	\$5.865
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$4.327	(Maximum) \$5.198
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	\$5.363	\$5.960
Summer Gas Usage			\$0.597	\$4.399	\$4.996
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.020	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.020	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$4.327	(Maximum) \$5.046
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$15.245	\$16.057
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$15.245	\$15.842

Date Filed: January 11, 2011

Effective Date:

Issued By: Tamie A. Aberle  
 Pricing & Tariff Manager

Case No.:

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

**February 2011**

The established monthly price for the Rocky Mountain CIG Index decreased slightly 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 reflective of natural gas prices in the Rocky Mountain region and indicative of the supplies Montana-Dakota purchases for its requirements.

Despite the normal seasonal increase in natural gas consumption to meet the demand for space heating, near record levels of natural gas in storage and strong domestic supply likely caused the price of natural gas to decrease. The Energy Information Administration (EIA) reported storage levels nationwide as of December 31, 2010 were 6.5 percent above the five-year average and 1.5 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 January Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 16.

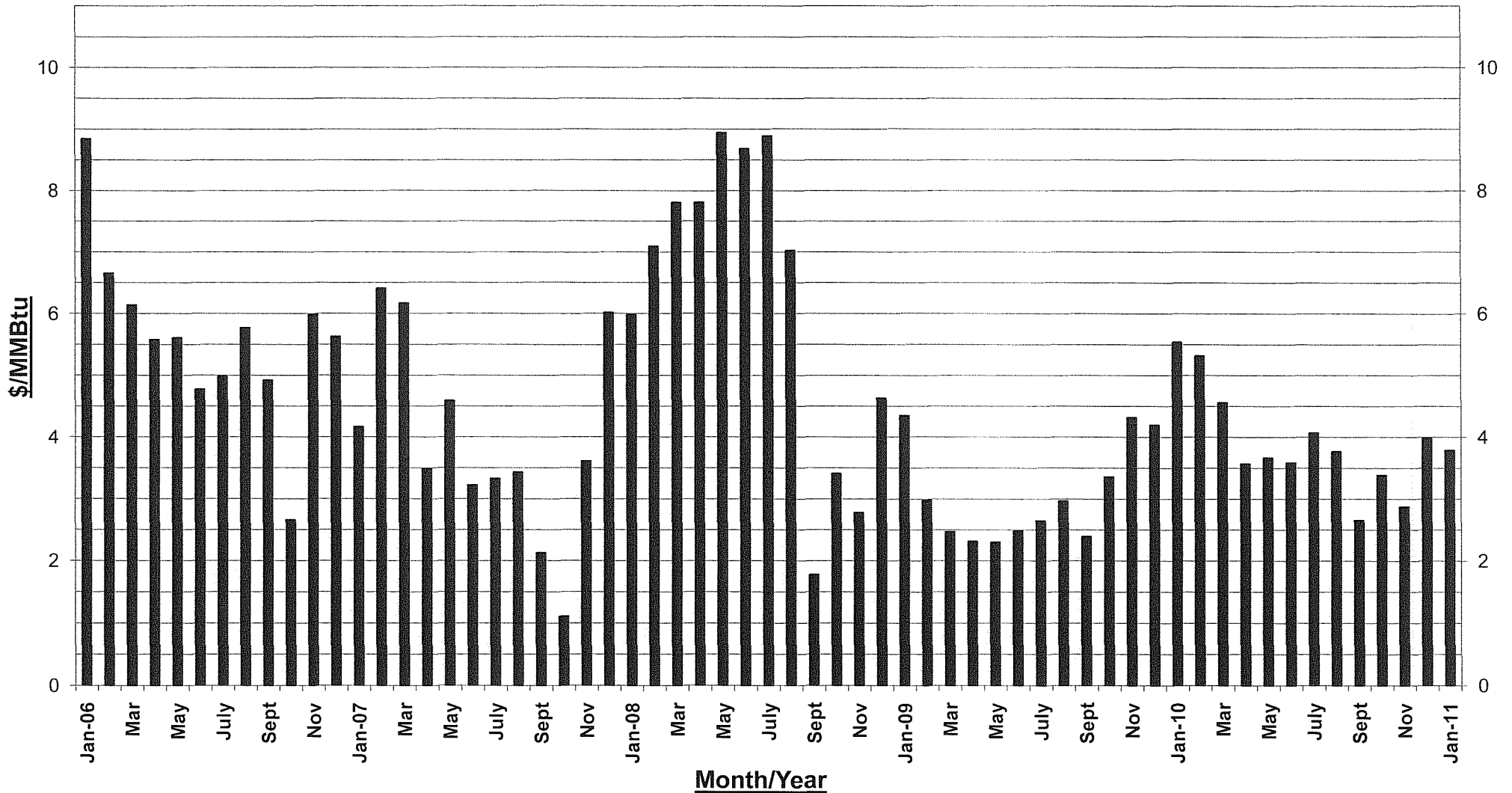
**Montana-Dakota Utilities Co.  
Market Conditions for Regional Propane  
February 2011**

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

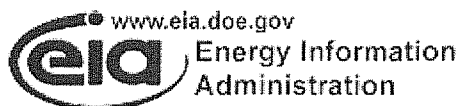
The January prices for propane have increased from the previous level. A change in the price of propane is generally driven by a combination of crude oil prices, weather, demand and inventory levels. As seasonal usage increases, this has resulted in a increase in the price of propane.

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 2006-2011YTD



From Inside F.E.R.C.'s Gas Market Report  
Annual Averages: - 2009-\$3.07; 2010-\$3.92; 2011YTD - \$3.79



January 2011

## Short-Term Energy Outlook

January 11, 2011 Release

### Highlights

- This edition of the *Short-Term Energy Outlook* is the first to include forecasts (monthly, quarterly and annual) through December 2012.
- EIA expects the price of West Texas Intermediate (WTI) crude oil to average about \$93 per barrel in 2011, \$14 higher than the average price last year. For 2012, EIA expects WTI prices to continue to rise, with a forecast average price of \$99 per barrel in the fourth quarter 2012. EIA's forecast assumes U.S. real gross domestic product (GDP) grows 2.2 percent in 2011 and 2.9 percent in 2012, while world real GDP (weighted by oil consumption) grows by 3.3 percent and 3.7 percent in 2011 and 2012, respectively.
- EIA expects regular-grade motor gasoline retail prices to average \$3.17 per gallon this year, 39 cents per gallon higher than last year and 3.29 per gallon in 2012, with prices forecast to average about 5 cents per gallon higher in each year during the April through September peak driving season. There is regional variation in the forecast, with average expected prices on the West Coast about 25 cents per gallon above the national average during the April through September period. There is also significant uncertainty surrounding the forecast, with the current market prices of futures and options contracts for gasoline suggesting more than a 25 percent probability that the national average retail price for regular gasoline could exceed \$3.50 per gallon in the June through September period in 2011 and an 8 to 10 percent probability that it could exceed \$4.00 per gallon in August and September 2011.
- Natural gas working inventories ended 2010 at 3.1 trillion cubic feet (Tcf), about 1 percent below the 2009 record-setting end-of-December level. Inventories are expected to remain at or near record-high levels through most of 2011. The projected Henry Hub natural gas spot price averages \$4.02 per million Btu (MMBtu) for 2011, \$0.37 per MMBtu lower than the 2010 average.

EIA expects the natural gas market to begin to tighten in 2012, with the Henry Hub spot price increasing to an average \$4.50 per MMBtu.

- EIA expects average household expenditures for space-heating fuels to total \$990 this winter, about \$22 higher than last year. EIA projects higher expenditures for heating oil and propane, flat expenditures for natural gas, but lower expenditures for electricity. A forecast of milder weather than last winter in the South and the West leads to lower fuel consumption in those areas.
- EIA projects that U.S. carbon dioxide (CO<sub>2</sub>) emissions from fossil fuels, which increased by 3.8 percent in 2010, will decline by 0.6 percent in 2011. EIA expects that CO<sub>2</sub> emissions will increase by 2.4 percent in 2012 as consumption grows for all the fossil fuels. Projected fossil-fuel CO<sub>2</sub> emissions in 2012 remain below the levels seen in any year from 2000 through 2008.

## Global Crude Oil and Liquid Fuels

*Crude Oil and Liquid Fuels Overview.* EIA expects a continued tightening of world oil markets over the next 2 years. World oil consumption grows by an annual average of 1.5 million barrels per day (bbl/d) through 2012 while the growth in supply from non-Organization of the Petroleum Exporting Countries (non-OPEC) countries averages less than 0.1 million bbl/d each year. Consequently, EIA expects the market will rely on both inventories and significant increases in production of crude oil and non-crude liquids in OPEC member countries to meet world demand growth. While on-shore commercial oil inventories in the Organization for Economic Cooperation and Development (OECD) countries remained high last year, floating oil storage fell sharply in 2010, and EIA expects OECD oil inventories will decline over the forecast period.

There are many significant uncertainties that could push oil prices higher or lower than expected. Should OPEC not increase production as global consumption recovers, oil prices could be significantly higher than the central forecast. The rate of economic recovery, both domestically and globally, also remains uncertain due to a variety of factors including fiscal issues facing national and sub-national governments, China's efforts to address concerns regarding its growth and inflation rates, and unforeseen production issues.

*Global Crude Oil and Liquid Fuels Consumption.* World oil consumption grew by an estimated 2.2 million bbl/d in 2010, to 86.6 million bbl/d. This growth more than offset the losses of the previous 2 years and surpassed the 2007 level of 86.3 million bbl/d

reached prior to the economic downturn. EIA expects average global consumption growth over the next 2 years to return to rates seen before the onset of the global downturn in 2008. Forecast global consumption growth averages 1.4 million bbl/d in 2011 and 1.6 million bbl/d in 2012, compared with an average of 1.3 million bbl/d per year from 2000 through 2007. From 2000 through 2007 the non-OECD countries as a group accounted for about three-fourths of total world consumption growth. The non-OECD countries are expected to account for all of the world's growth over the next 2 years, with the largest contributions coming from China, the Middle East, and Brazil ([World Liquid Fuels Consumption Chart](#)). Among the OECD regions, EIA expects that only North America will show oil consumption growth over the next 2 years, but it will be offset by continued declines in OECD Europe and Asia.

***Non-OPEC Supply.*** EIA expects non-OPEC crude oil and liquid fuels production to rise by 160,000 bbl/d in 2011 and a further 20,000 bbl/d in 2012. Increases in non-OPEC oil production will be concentrated in a few countries, particularly in China, Brazil, and Canada, where EIA expects each to show annual average production growth of 120,000 to 150,000 bbl/d in 2011 and 2012. Ghana became a new non-OPEC oil producer with the startup of the Jubilee field in December of 2010. Other non-OPEC production is expected to decline. EIA expects Mexico's production will fall by about 200,000 bbl/d in 2011, followed by another production decline of 80,000 bbl/d in 2012. Similarly, the United Kingdom is expected to see production declines of an average 120,000 bbl/d in both 2011 and 2012 since oil production and the discovery of new reserves have not kept pace with the maturation of existing fields.

***OPEC Supply.*** OPEC is not scheduled to meet again until June 2011 to discuss its production targets. Nonetheless, EIA expects that OPEC members' crude oil production will continue to rise over the next 2 years to accommodate increasing world oil consumption, especially with non-OPEC supplies expected to show limited growth. Projected OPEC crude oil production increases by 0.5 and 1.1 million bbl/d in 2011 and 2012, respectively. OPEC non-crude petroleum liquids, which are not subject to production targets, increase by 0.7 million bbl/d in 2011 and by 0.4 million bbl/d in 2012. EIA expects OPEC surplus production capacity will fall from about 4.7 million bbl/d at the end of 2010 to 4.3 million bbl/d at the end of 2012 ([OPEC Surplus Crude Oil Production Capacity Chart](#)).

***OECD Petroleum Inventories.*** EIA estimates commercial oil inventories held in the OECD ended 2010 at 2.71 billion barrels, equivalent to about 58 days of forward-cover, and roughly 75 million barrels more than the 5-year average for the corresponding time of year. Projected OECD oil inventories decline over the forecast with days of forward-cover falling from current high levels to closer to the 5-year average by the end of 2012 ([Days of Supply of OECD Commercial Stocks Chart](#)).

**Crude Oil Prices.** WTI crude oil spot prices averaged over \$89 per barrel in December, about \$5 per barrel higher than the November average, as expectations of higher oil demand, combined with unusually cold weather in both Europe and the U.S. Northeast, lifted prices. EIA has raised the first-quarter 2011 WTI spot price forecast by over \$7 per barrel from the last month's *Outlook*, to about \$92 per barrel. WTI spot prices rise to an average \$99 per barrel in the fourth quarter of 2012. Projected WTI spot prices average \$93 per barrel in 2011 and \$98 per barrel in 2012.

Energy price forecasts are uncertain ([Energy Price Volatility and Forecast Uncertainty](#)). WTI futures for March 2011 delivery for the 5-day period ending January 6 averaged \$91 per barrel, and implied volatility averaged 28 percent. This makes the lower and upper limits of the 95-percent confidence interval \$76 per barrel and \$109 per barrel, respectively, for WTI delivered in March 2011. Last year at this time, WTI for March 2010 delivery averaged \$82 per barrel and implied volatility averaged 40 percent, with the limits of the 95-percent confidence interval at \$66 per barrel and \$102 per barrel. Based on futures and options prices over the first week in January, the probability that the monthly average price of WTI crude oil will exceed \$100 per barrel in December 2011 is about 36 percent. Conversely, the probability that the monthly average December 2011 WTI price will fall below \$80 per barrel is about 31 percent.

## U.S. Crude Oil and Liquid Fuels

**U.S. Liquid Fuels Consumption.** Preliminary data indicate that total consumption of petroleum and non-petroleum liquid fuels increased by 350,000 bbl/d (1.9 percent) in 2010 ([U.S. Liquid Fuels Consumption Growth Chart](#)). The major sources of consumption growth were distillate fuel oil (diesel fuel and heating oil), which grew by 130,000 bbl/d (3.7 percent), and motor gasoline, which increased by 60,000 bbl/d (0.7 percent). Reflecting the ongoing economic recovery, projected total U.S. liquid fuels consumption in 2011 increases by 160,000 bbl/d (0.8 percent) in 2011 and a further 170,000 bbl/d (0.9 percent), to 19.4 million bbl/d, in 2012. Motor gasoline and distillate fuel account for much of the growth in consumption over the next 2 years.

**U.S. Liquid Fuels Supply and Imports.** Domestic crude oil production, which increased by 150,000 bbl/d in 2010 to 5.51 million bbl/d, declines by 20,000 bbl/d in 2011 and by a further 130,000 bbl/d in 2012 ([U.S. Crude Oil Production Chart](#)). The 2011 forecast includes declines of 50,000 bbl/d in Alaska and 220,000 bbl/d in Federal Gulf of Mexico (GOM) production, which are almost offset by a projected 250,000-bbl/d increase in lower-48 non-GOM production. In 2012, lower-48 non-GOM output increases by 70,000 bbl/d, Alaskan production declines by 20,000 bbl/d, and GOM output decreases by 180,000 bbl/d.

Liquid fuel net imports (including both crude oil and refined products) fell from 57 percent of total U.S. consumption in 2008 to 49.4 percent in 2010, primarily because of the decline in consumption during the recession and rising exports. EIA forecasts that liquid fuel net imports will average 9.6 million bbl/d in 2011 and 9.9 million bbl/d in 2012, about 50 percent and 51 percent of total consumption, respectively.

EIA expects slow growth in fuel ethanol production over the next 2 years. EIA projects that ethanol production will increase by 6 percent (50,000 bbl/d) in 2011, reflecting the startup of several new plants and the restart of some plants that were idled during the recession. EIA projects that ethanol production growth will slow to 1 percent in 2012. Forecast ethanol blending into gasoline exceeds the conventional biofuels component of the Renewable Fuels Standard (RFS) in both 2011 and 2012.

***U.S. Petroleum Product Prices.*** Projected regular-grade gasoline retail prices rise from an average of \$2.78 per gallon in 2010 to \$3.17 per gallon in 2011 and \$3.29 per gallon in 2012. On-highway diesel fuel retail prices, which averaged \$2.99 per gallon in 2010, average \$3.40 per gallon and \$3.52 per gallon in 2011 and 2012, respectively. Rising crude oil prices are the primary reason for higher retail prices, but higher gasoline and distillate refining margins are also expected to contribute to higher retail prices.

The projected monthly average regular gasoline price peaks this year at \$3.27 per gallon in July. New York Harbor RBOB (Reformulated Blendstock for Oxygenate Blending) futures contracts for July 2011 delivery for the 5-day period ending January 6 averaged \$2.52 per gallon and implied volatility averaged 29 percent. The probability the RBOB futures price will exceed \$2.80 per gallon (and the retail price exceed \$3.50 per gallon) in July 2011 is about 26 percent. The probability the RBOB futures price will exceed \$3.30 per gallon (and the retail price exceed \$4.00 per gallon) in July 2011 is about 7 percent.

## Natural Gas

***U.S. Natural Gas Consumption.*** EIA expects total natural gas consumption to decline by 0.9 percent in 2011. Projected residential and commercial consumption fall by about 2.7 percent in 2011 partly because of the forecast of 1.3 percent fewer heating degree-days during the winter months this year compared with last year, but also because of recent changes in the way EIA collects and reports natural gas consumption data (see [\*Changes in Natural Gas Monthly Consumption Data Collection and the Short-Term Energy Outlook\*](#)). Forecast natural gas consumption in the electric power sector falls by 1.0 percent in 2011 because of the forecast return to near-normal summer weather compared with the very warm summer last year. Forecast cooling

degree-days fall by 16 percent, from 1,468 in 2010 to 1,234 in 2011. Only industrial sector natural gas consumption rises in 2011, by 1.1 percent, because of the 1.2 percent increase in the natural-gas-weighted industrial production index.

Total natural gas consumption grows by 1.6 percent in 2012 to 66.5 billion cubic feet per day (Bcf/d). While projected commercial and residential consumption decline by a slight 0.2 percent from 2011 to 2012, the electric power and industrial sectors drive growth with projected increases of 3.6 and 1.6 percent, respectively.

***U.S. Natural Gas Production and Imports.*** Total marketed natural gas production increased significantly in 2010, by an estimated 2.4 Bcf/d, or 4.1 percent. Declines in production of 0.07 Bcf/d and 0.46 Bcf/d in Alaska and the GOM, respectively, were offset by a 2.9 Bcf/d increase in lower-48 onshore production. EIA expects average total production to fall by 0.3 percent in 2011. The latest EIA data for monthly natural gas production, which are for October 2010, showed a slight decline in the lower-48 states from the previous month. EIA expects this gradual decline to continue throughout 2011 because of a falling drilling rig count in response to lower prices. The number of rigs drilling for natural gas reported by Baker Hughes Inc. increased from a low of 665 in July 2009 to 973 in April 2010. Over the following 6 months the natural gas rig count stayed relatively unchanged, but in the last several weeks the rig count has fallen and ended December 2010 at 919 rigs, a level not seen since February 2010. The large price difference between petroleum liquids and natural gas on an energy-equivalent basis contributes to an expected shift towards drilling for liquids.

The December 2010 *Natural Gas Monthly* contains extensive revisions to estimated production in 2008, 2009, and much of 2010. These changes have reduced the annualized balancing items for those years. EIA's forecast has been updated to reflect these new estimates. EIA has adjusted the forecast for natural gas production in last month's *Outlook* downward by about 0.5 Bcf/d to reflect the revised estimates.

The projected decline in production in 2011 and increase in natural gas consumption in 2012 contribute to a strengthening of natural gas prices late in this year and next. As natural gas prices begin to rise, forecast production rebounds in 2012, growing by 2.2 percent. Projected total marketed production averages 64.2 Bcf/d in December 2012 compared with 62.3 Bcf/d and 60.6 Bcf/d in December 2010 and December 2011, respectively.

EIA expects gross pipeline imports of 8.6 Bcf/d in 2011 and 8.2 Bcf/d in 2012, year-over-year decreases of 4.3 and 4.4 percent, respectively. Canadian gas will become less competitive as new U.S. pipelines and increased lower-48 production with lower transport costs displace imports. Projected liquefied natural gas (LNG) imports

average 1.1 Bcf/d in 2011, a 4.7-percent decrease from 2010 levels. Imports in 2012 grow modestly to 1.2 Bcf/d. High domestic production, high inventories, and low U.S. prices relative to European and Asian markets should continue to discourage LNG imports into North America.

***U.S. Natural Gas Inventories.*** On January 6, 2011, working natural gas in storage stood at 3,097 Bcf, slightly below last year's level at this time ([U.S. Working Natural Gas in Storage Chart](#)). At the end of the winter heating season (March 31, 2011), EIA expects about 1,774 Bcf of working natural gas will remain in storage, a record high and well above last year's level of 1,662 Bcf. The forecast higher inventory is primarily the result of both the current high natural gas production rates and about 4 percent fewer heating degree-days during the first quarter 2011 compared with the same period last year. EIA expects record high inventories to continue through most of 2011, with falling production to bring inventories back into their historical range next year.

***U.S. Natural Gas Prices.*** The Henry Hub spot price averaged \$4.25 per MMBtu during December, an increase of about 54 cents from November's price of \$3.71 per MMBtu ([Henry Hub Natural Gas Price Chart](#)). EIA expects the higher forecast production during the first half of 2011 compared with the same period last year, combined with a decline in consumption, to moderate natural gas spot prices. The projected spot price falls to a low of \$3.73 per MMBtu in June then rises to \$4.61 in December, averaging \$4.02 per MMBtu for all of 2011, which is \$0.37 per MMBtu lower than the 2010 average and \$0.31 per MMBtu lower than in last month's *Outlook*. In 2012, the spot price rises to an average of \$4.50 per MMBtu.

Uncertainty over future natural gas prices is slightly lower this year compared with last year at this time. Natural gas futures for March 2011 delivery (for the 5-day period ending January 6) averaged \$4.39 per MMBtu, and the average implied volatility over the same period was 43 percent. This produced lower and upper bounds for the 95-percent confidence interval for March 2011 contracts of \$3.21 per MMBtu and \$6.02 per MMBtu, respectively. At this time last year, the natural gas March 2010 futures contract averaged \$5.73 per MMBtu and implied volatility averaged 57 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.88 per MMBtu and \$8.47 per MMBtu.

## Electricity

***U.S. Electricity Consumption.*** EIA expects total U.S. consumption of electricity to fall slightly during 2011 and then grow by 2.6 percent in 2012 ([U.S. Total Electricity Consumption Chart](#)). EIA estimates that retail sales of electricity to the residential

sector rose by 6.1 percent in 2010 as a result of a relatively cold winter in the Southeast and a very warm summer east of the Rocky Mountains. Based on the forecast return to more normal temperatures, residential electricity sales fall by 2.1 percent during 2011. Forecast growth in manufacturing output should lead to increases in industrial sector electricity sales of 1.5 percent this year and 2.2 percent in 2012.

***U.S. Electricity Generation.*** Projected total electricity generation decreases by 0.3 percent in 2011, following a 4.0 percent increase in 2010. A forecast 6.0-percent increase in conventional hydropower generation during 2011 (due to an assumed return to near-normal precipitation levels) and a 13-percent increase in generation from other renewable sources, mostly wind, lead to a 2.4-percent reduction in coal-fired generation and a 1.0-percent decline in natural gas generation. During 2012, EIA expects a 2.6-percent increase in total electric power sector generation, which will be fueled primarily by increased generation from coal, natural gas, and non-hydropower renewables ([U.S. Electric Power Sector Generation Growth Chart](#)).

***U.S. Electricity Retail Prices.*** EIA expects the U.S. retail price for electricity distributed to the residential sector during 2010 to average 11.6 cents per kilowatt-hour, about the same level as in 2009. EIA expects the U.S. residential price to increase only slightly over the forecast period--by 0.6 percent in 2011 and by 1.0 percent in 2012 ([U.S. Residential Electricity Prices Chart](#)).

## Coal

***U.S. Coal Consumption.*** EIA estimates that coal consumption in the electric power sector grew by nearly 5.0 percent in 2010, primarily the result of higher electricity consumption because of the very warm summer. EIA projects that coal consumption in the electric power sector will decrease by 1.1 percent in 2011 as increases in generation from hydropower and other renewable energy sources back out coal. In 2012, projected electricity generation increases by 2.7 percent and coal consumption in the electric power sector grows by 3.6 percent ([U.S. Coal Consumption Growth Chart](#)).

***U.S. Coal Supply.*** Coal production for the first 6 months of 2010 fell by 2.5 percent despite a 5.5-percent increase in U.S. coal consumption. A drawdown in stocks, particularly in the electric power sector, met the demand increase ([U.S. Electric Power Sector Coal Stocks Chart](#)). Estimated coal production increases in the second half of 2010 contribute to 2010 annual growth of 1.0 percent. EIA projects coal production in 2011 will remain relatively flat as coal consumption shows little change ([U.S. Annual Coal Production Chart](#)). The projected increase in coal consumption in 2012 leads to a forecast 4.1 percent increase in coal production.

**U.S. Coal Trade.** Strong global demand for coal, particularly metallurgical coal used to produce steel, has resulted in sharp increases in U.S. coal exports in 2010 to an average 7.3 percent of production. Metallurgical coal exports nearly doubled in the first half of 2010 compared with the first half of 2009, and metallurgical coal's share of total coal exports has grown from 52 percent in 2008 to about 70 percent in 2010. Metallurgical coal exports to Asia and Europe accounted for nearly 90 percent of the increase, with significant increases to China, the Netherlands, Turkey, Japan and South Korea. EIA expects total U.S. coal exports to stay near current levels in 2011 and 2012 as other major coal-exporting countries increase their supply to the global coal market.

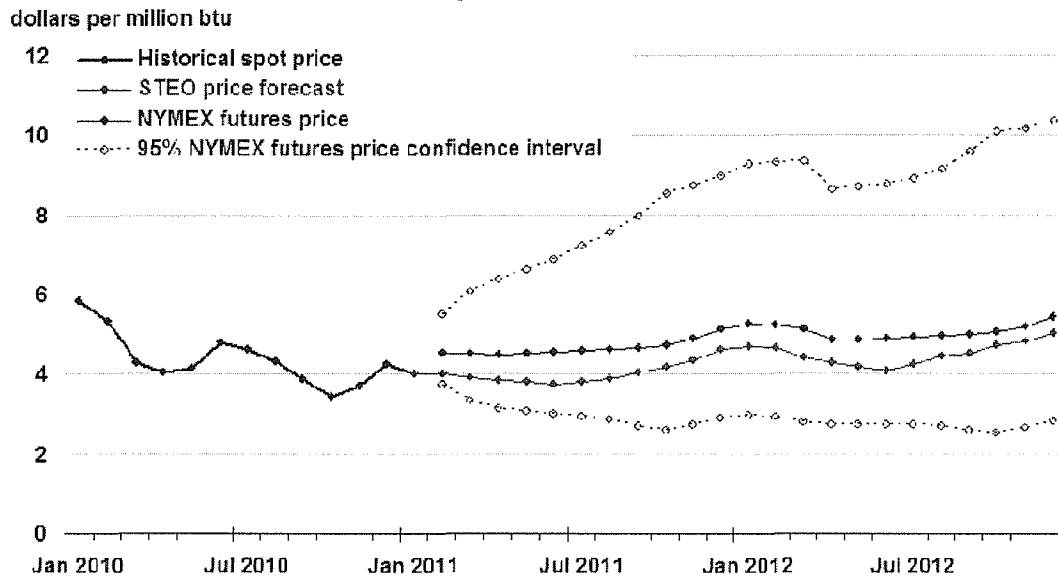
**U.S. Coal Prices.** Coal prices have been rising relatively steadily over the last 10 years reflecting longer-term power sector coal contracts initiated during a period of high energy prices, rising transportation costs, increased consumption, and increases in spot coal prices. However, EIA expects that the power sector coal price will show little change over 2011 and 2012 as coal competes with natural gas for market share in the power sector. The projected power sector delivered coal price, which averaged \$2.26 per MMBtu in 2010, averages \$2.24 per MMBtu in both 2011 and 2012.

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

EIA estimates fossil-fuel CO<sub>2</sub> emissions increased by 3.8 percent in 2010 ([U.S. Carbon Dioxide Emissions Growth Chart](#)). Coal- and natural gas-related CO<sub>2</sub> emissions rose as a result of increased usage of both fuels for electricity generation and higher consumption of natural gas in the industrial sector.

Projected declines in fossil fuel consumption in the electric power sector in 2011 more than offset increased consumption of petroleum in the transportation sector (i.e., motor gasoline, diesel fuel, and jet fuel). Consequently, forecast fossil-fuel CO<sub>2</sub> emissions fall by 0.6 percent in 2011. The forecast resumption of growth in electricity generation and improvement in economic growth in 2012 contribute to a 2.4-percent increase in fossil-fuel CO<sub>2</sub> emissions. Projected fossil-fuel CO<sub>2</sub> emissions in 2012 remain below the levels seen since 1999 and 4.4 percent below 2005 emissions.

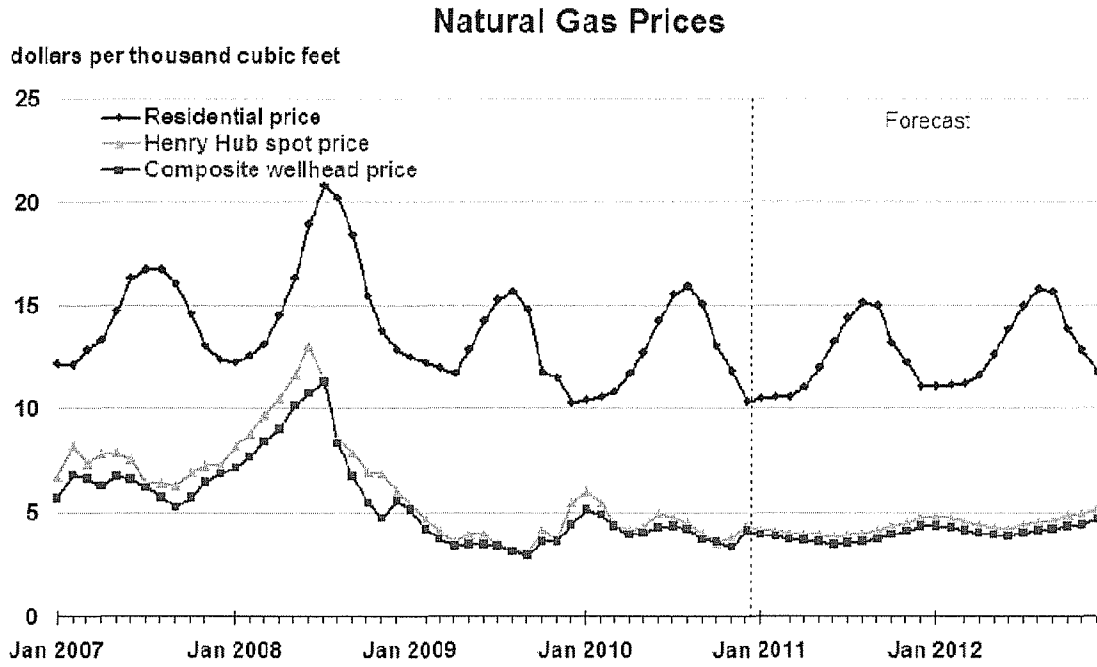
### Henry Hub Natural Gas Price



*Note: Confidence interval derived from options market information for 5 trading days ending January 6, 2011  
Intervals not calculated for months with sparse trading in "near-the-money" options contracts*

Source: Short-Term Energy Outlook, January 2011

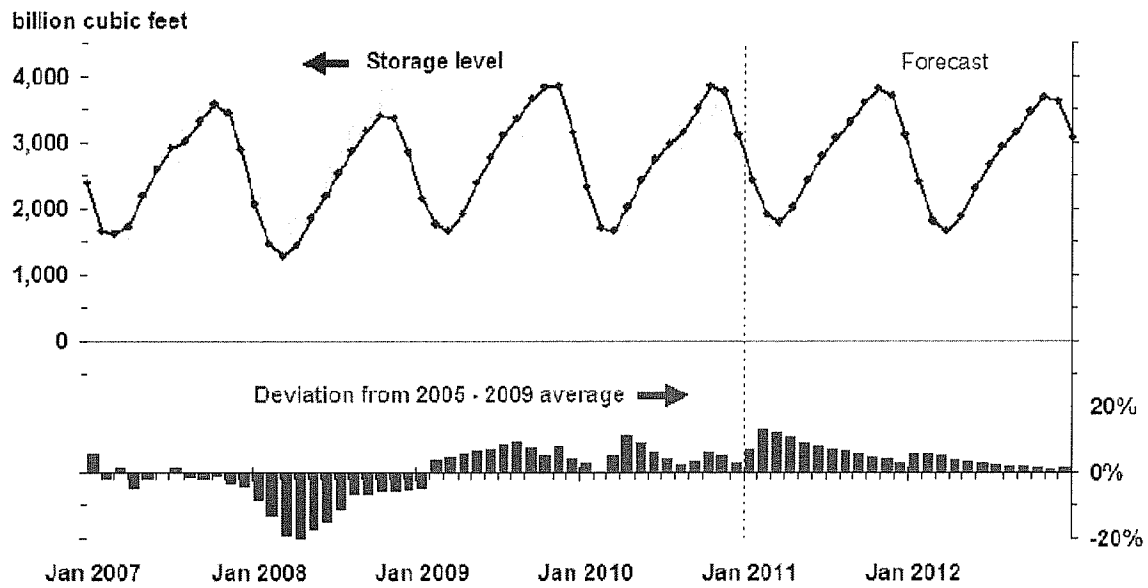




Source: Short-Term Energy Outlook, January 2011



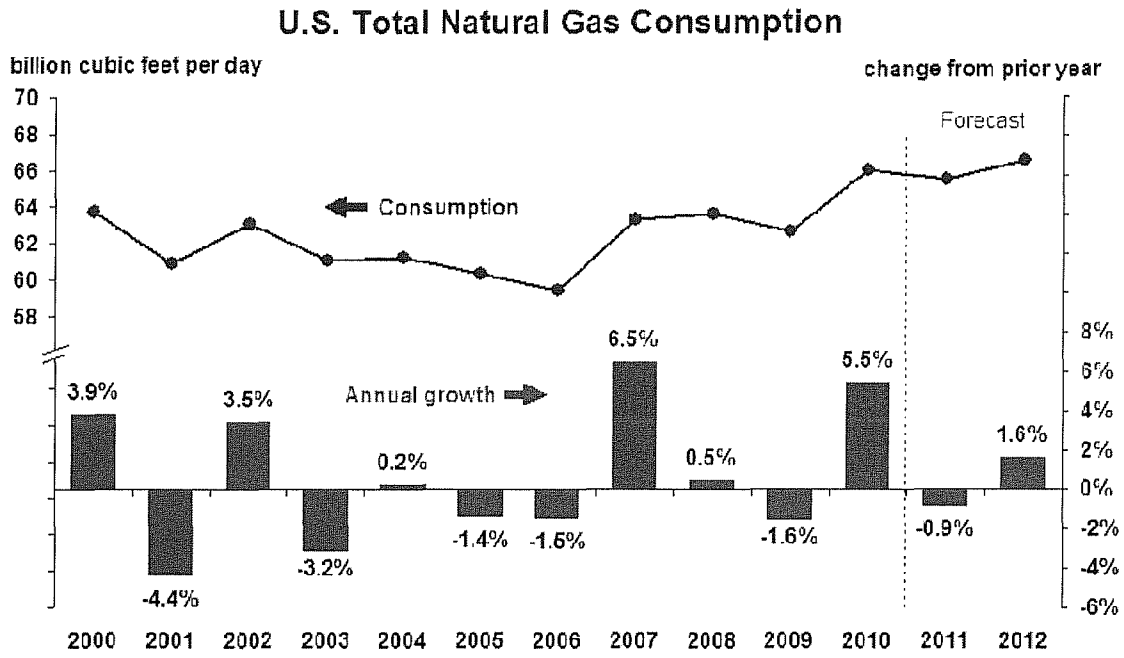
### U.S. Working Natural Gas in Storage



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

Source: Short-Term Energy Outlook, January 2011





Source: Short-Term Energy Outlook, January 2011



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

**NorthWestern Energy**

On December 23, 2010, NorthWestern Energy filed its 2011 Electric and Natural Gas State and Local Tax and Fee tracking filing in Docket No. D2010.12.116. On December 28, 2010, the Montana Public Service Commission approved rates on an interim basis effective January 1, 2011.

Approximate impact on Montana-Dakota's cost of gas – (0.001) cents per dk

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

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<b><u>Gas Cost Adjustment:</u></b>				
Gas Cost Level (Exhibit B)	\$5.299	\$5.394	\$4.337	\$4.317
Prior Gas Cost	5.142	5.238	4.190	4.171
Current Gas Cost Adjustment	\$0.157	\$0.156	\$0.147	\$0.146
<b><u>Surcharge Adjustment:</u></b>				
Current Adjustment	(\$0.023)	(\$0.023)	(\$0.010)	\$0.031
Prior Adjustment	(0.023)	(0.023)	(0.010)	0.031
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<b><u>Market Based Pricing Differential</u></b>				
Current Adjustment	(\$0.008)	(\$0.008)	\$0.000	\$0.000
Prior Adjustment	(0.008)	(0.008)	0.000	0.000
Change in Margin Sharing Provision	\$0.000	\$0.000	\$0.000	\$0.000
<b>Net Increase (Decrease) in Gas Costs</b>	<b>\$0.157</b>	<b>\$0.156</b>	<b>\$0.147</b>	<b>\$0.146</b>
Gas Cost Level	\$5.299	\$5.394	\$4.337	\$4.317
Plus: Surcharge	(0.023)	(0.023)	(0.010)	0.031
Total Gas Cost Level in Tariff Rates	\$5.276	\$5.371	\$4.327	\$4.348

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

**Cost of Gas - Propane:**

Current Propane Cost (Exhibit D)	\$15.919
Prior Propane Cost	<u>13.723</u>
Current Propane Cost Adjustment	<u>\$2.196</u>

**Surcharge Adjustment:**

Current Adjustment	(\$0.666)
Prior Adjustment	<u>(0.666)</u>
Change in Surcharge Adjustment	\$0.000

**Market Based Pricing Differential**

Current Adjustment	(\$0.008)
Prior Adjustment	<u>(0.008)</u>
Change in Margin Sharing Provision	\$0.000

**Net Increase (Decrease) in Gas Costs**

\$2.196

Propane Cost Level	\$15.919
Plus: Surcharge	<u>(0.666)</u>
Total Propane Cost Level in Rates	<u><u>\$15.253</u></u>

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

	Amount
Total Gas Costs 1/	\$71,256,809
Residential and General Service dk Requirements 2/	13,507,441
Average Cost of Gas per dk	\$5.275
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.299
Less: Gas Cost Level in Rates 3/	5.142
<b>Current Gas Cost Adjustment</b>	<b>\$0.157</b>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -15 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C.

2/ Normalized dk sales for the twelve months ended November 30, 2010, adjusted for losses at .45%

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

Cost of Purchased Gas	\$5.119
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.142

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

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$71,256,809
Less: Annual MDDQ Costs 1/	<u>11,685,993</u>
Total Gas Costs excluding MDDQ	\$59,570,816
Firm Service Requirements 1/	13,507,441
Other Gas Costs per Dk (excluding MDDQ)	\$4.410
Summer Seasonal Rate, adjusted for losses 2/	4.430
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,685,993
Winter Firm Service Requirements	12,168,379
MDDQ Costs per Winter Dk	\$0.960
Add: Other Gas Costs per Dk	<u>4.410</u>
Winter Seasonal Rate	5.370
Winter Seasonal Rate, adjusted for losses 2/	\$5.394
Less: Gas Cost Level in Rates 3/	<u>5.238</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.156</u></u></b>

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	\$4.260	\$5.214
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$4.279	\$5.238

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

	Amount
Total Gas Costs 1/	\$15,120,068
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$4.317
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.337
Less: Gas Cost Level in Rates 2/	4.190
<b>Current Gas Cost Adjustment</b>	<b>\$0.147</b>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -15 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	\$4.171
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.190

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

	<u>Amount</u>
Total Gas Costs 1/	\$3,798,643
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$4.317
Less: Gas Cost Level in Rates 2/	<u>4.171</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.146</u></u></b>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -15 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 \$4.171

**Montana-Dakota Utilities Co.  
Schedule of Applicable Effective Pipeline Rates  
February 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, 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, pages 11-12 for Schedule FT-D.

NorthWestern Energy – Exhibit B, page 13 for Schedule T-FTG-1.

South Dakota Intrastate Pipeline – Exhibit B, page 14 for Rate 1.

SourceGas Distribution LLC – Exhibit B, Page 15 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
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 2.153%, CONSISTING OF 2.614% FOR THE CURRENT PERCENTAGE AND (0.461%) 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 0.818 CENTS, CONSISTING OF 0.830 CENTS FOR THE CURRENT RATE AND (0.012) 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: October 1, 2010  
 Docket Number: RP11-29-000  
 FERC Order Date: November 2, 2010

Effective On: October 1, 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 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						
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 0.402%, CONSISTING OF 0.568% FOR THE CURRENT PERCENTAGE AND (0.166%) 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 0.182 CENTS, CONSISTING OF 0.346 CENTS FOR THE CURRENT RATE AND (0.164) 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: October 1, 2010  
 Docket Number: RP11-29-000  
 FERC Order Date: November 2, 2010

Effective On: October 1, 2010

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

PART 4.1  
Statement of Rates  
T-1 and T-1B - Long Term Base Tariff Rates  
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.

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

PART 4.7  
Statement of Rates  
ACA and Compressor Usage Surcharge  
v.0.0.0

STATEMENT OF RATES

	Commodity Rate -----
Annual Charge Adjustment (ACA) Rate (per Dekatherm) 1/	\$0.0019
Compressor Usage Surcharge (per 100 Dekatherm-miles) 2/	\$0.0020

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 6.16 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 6.44 of the General Terms and Conditions.

**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 based on a three year term (Price Point "B") & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) \$207.61/10 <sup>3</sup> m <sup>3</sup>		
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	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 \$6.01/GJ FT-D Demand Rate for Group 2 Delivery Points <sup>1</sup> \$0.98/GJ FT-D Demand Rate for Group 3 Delivery Points <sup>2</sup> N/A		
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	Refer to Attachment "3" for applicable FT-P Demand Rate per month		
7. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10<sup>3</sup>m<sup>3</sup>/day)</u>	
	1-5 years	10.43	
	6-10 years	8.72	
	15 years	7.82	
	20 years	6.94	
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 <sup>3</sup> m <sup>3</sup>	
10. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
11. Rate Schedule IT-D	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 <sup>3</sup> m <sup>3</sup> /d
	9009-01001-1	\$ 660.00/d	50.0 10 <sup>3</sup> m <sup>3</sup> /d
14. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2010416547	\$ 24.00 / month	
	2010416543	\$ 7.00 / month	
	2010416549	\$ 63.00 / month	
	2010416546	\$ 5.00 / month	
	2010416548	\$ 1.00 / month	
	2010416540	\$ 42.00 / month	
	2010416550	\$ 96.00 / month	
	2010416545	\$ 1,688.00 / month	
	2010418000	\$ 151.00 / month	
	2010416551	\$ 46.00 / month	
	2010417322	\$ 153.00 / month	
	2010416544	\$ 79.00 / month	
	2010416541	\$ 209.00 / month	
	2010418777	\$ 209.00 / month	
	2010418778	\$ 350.00 / month	
	2003004522	\$ 83,333.00 / month	
15. Rate Schedule CO <sub>2</sub>	<u>Tier</u>	<u>CO<sub>2</sub> Rate (\$/10<sup>3</sup>m<sup>3</sup>)</u>	
	1	520.03	
	2	411.79	
	3	272.12	

1. Rate for all Group 2 Delivery Points with the exception of Alberta-Montana, Cold Lake and Unity.

2. FT-D Service at Group 3 Delivery Points not available until the Integration Effective Date.

NOVA Gas Transmission Ltd.

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	6.00	0.2170
3002	BOUNDARY LAKE BORDER	5.37	0.1941
1958	EMPRESS BORDER	6.03	0.2179
3886	GORDONDALE BORDER	5.37	0.1941
6404	MCNEILL BORDER	6.03	0.2179

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)
3880	AECO INTERCONNECTION	0.98	0.0353
3868	ALBERTA-MONTANA	5.37	0.1941
3059	ALLISON CREEK SALES	0.98	0.0353
3562	AMOCO SALES (BP SALES TAP)	0.98	0.0353
3488	ARDLEY SALES	0.98	0.0353
3943	ATUSIS CREEK INTERCONNECTION	0.98	0.0353
3135	AURORA SALES	0.98	0.0353
3423	BASHAW WEST SALES	0.98	0.0353
3068	BEAVER HILLS SALES	0.98	0.0353
3933	BIG EDDY INTERCONNECTION	0.98	0.0353
3067	BIGSTONE SALES	0.98	0.0353
3887	BITTERN LAKE INTERCONNECTION	0.98	0.0353
3468	BLEAK LAKE SALES	0.98	0.0353
3471	BLUE RIDGE EAST SALES	0.98	0.0353
3164	BRAINARD LAKE SALES	0.98	0.0353
2364	BROWNVALE SALES	0.98	0.0353
3918	BUFFALO CREEK INTERCONNECTION	0.98	0.0353
3109	CALDWELL SALES	0.98	0.0353
3634	CANOE LAKE SALES	0.98	0.0353
3165	CANOE LK SLS #2	0.98	0.0353
3866	CARBON INTERCONNECTION	0.98	0.0353
3484	CARIBOU LAKE SALES	0.98	0.0353
3157	CARIBOU LK SOUTH SL	0.98	0.0353
3106	CARMON CREEK SALES	0.98	0.0353
3101	CAROLINE SALES	0.98	0.0353
3893	CARROT CREEK INTERCONNECTION	0.98	0.0353
3495	CAVALIER SALES	0.98	0.0353
3907	CHANCELLOR INTERCONNECTION	0.98	0.0353
3151	CHEECHAM W. #2 SALES	0.98	0.0353
3622	CHEECHAM WEST SALES	0.98	0.0353
6014	CHEVRON AURORA SALES	0.98	0.0353
3097	CHICKADEE CREEK SALES	0.98	0.0353
3305	CHIGWELL NORTH SALES	0.98	0.0353
3496	CHIPEWYAN RIVER SALES	0.98	0.0353
3163	CHRISTINA LAKE NORTH SALES	0.98	0.0353
3158	CLYDE N SALES	0.98	0.0353
1417	COLD LAKE BDR	5.37	0.1941
3052	COLEMAN SALES	0.98	0.0353
3168	COLLICUTT SALES	0.98	0.0353
3904	CONKLIN WEST INTERCONNECTION	0.98	0.0353
3416	COUSINS A SALES	0.98	0.0353
1963	COUSINS B & C SALES	0.98	0.0353
3483	CRAMMOND SALES	0.98	0.0353

NATURAL GAS TARIFF

**NorthWestern**  
Energy

Canceling 22<sup>nd</sup> Revised  
21<sup>st</sup> 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	\$ 101.80	(I)
10,001 to 30,000	\$ 146.35	(I)
>30,000	\$ 324.70	(I)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	\$ 8.321131 (I)
--	-----------------

Transmission Commodity Rate (Monthly Rate per Dkt):

Maximum	\$ 0.063056 (I)
---------	-----------------

Minimum	\$ 0.017935
---------	-------------

GTAC Amortization	\$ 0.000962
-------------------	-------------

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)

Staff Approved: December 29, 2010  
Docket No.: D2010.12.116, Interim Order No. 7131  
Tariff Letter No. 182-G

Effective for service rendered on or after  
January 1, 2011

PUBLIC SERVICE COMMISSION

*Vernell Thomas*  
Secretary

**GAS RATE SCHEDULE**

Exhibit B  
Page 14 of 15

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

SD P.U.C. Section No.  
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**

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 FEBRUARY 2011**

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2010	\$13,431,294	\$653,606	\$3,048,451
November	11,876,668	567,703	2,461,969
December	9,321,762	392,208	1,200,498
January 2011	4,792,859	189,101	(396,037)
February	1,882,118	53,551	(1,340,046)
March	1,585,358	14,280	(1,936,798)
April	1,933,704	11,764	(1,764,137)
May	3,762,427	77,881	(1,042,219)
June	5,750,327	153,914	(49,078)
July	8,344,855	254,654	988,958
August	10,573,095	340,141	2,007,590
September	12,412,469	650,801	2,809,358
October	12,984,220	664,495	3,054,128
13 month average	<u>\$7,588,550</u>	<u>\$309,546</u>	<u>\$695,587</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$667,109	\$27,212	\$61,149
Return Requirement	<u>\$918,214</u>	<u>\$37,455</u>	<u>\$84,166</u>

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

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

MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS - PROPANE  
NORTH DAKOTA  
EFFECTIVE FEBRUARY 2011

Cost of Purchased Propane	\$95,079
Gallons Purchased	65,572
Projected dk Sales	6,000
Propane Cost per Dk	\$15.847
Average Cost of Propane as Adjusted for Losses @ 99.55%	15.919
Less: Propane Cost Level in Rates 1/	<u>13.723</u>
Current Propane Cost Adjustment	<u><u>\$2.196</u></u>

1/ Propane Cost Level in Current Rates - Case No. PU-10-8.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
<b>Balance @ July 31, 2010</b>									<b><u>(\$695,379)</u></b>
August	(\$305,149)	\$0	(\$94)	(\$305,243)	253,885	(\$0.515)	(\$130,750)	(\$174,493)	(869,872)
September	(418,566)	29,770 2/	(108)	(388,904)	283,887	(0.515)	(146,202)	(242,702)	(1,112,574)
October	(107,579)	0	(121)	(107,700)	428,232	(0.023)	(146,040) 3/	38,340	(1,074,234)
November	369,998	0	(126)	369,872	828,788	(0.023)	(19,062)	388,934	(685,300)
<b>Balance @ November 30, 2010</b>									<b><u>(\$685,300)</u></b>

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

2/ True-up related to August gas costs.

3/ Reflects 276,812.1 Dk @ (\$0.515) and 151,420 Dk @ (\$0.023).

**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 &amp; 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>
<b>Balance @ July 31, 2010</b>									<b><u><u>(\$18,649)</u></u></b>
August	\$9,163	\$0	(\$3)	\$9,160	29,023	(\$0.152)	(\$4,411)	\$13,571	(5,078)
September	(15,678)	(11,373) 2/	(1)	(27,052)	37,408	(0.152)	(5,686)	(21,366)	(26,444)
October	(34,715)	0	(3)	(34,718)	37,752	(0.010)	(5,698) 3/	(29,020)	(55,464)
November	30,228	0	(6)	30,222	50,009	(0.010)	(500)	30,722	(24,742)
<b>Balance @ November 30, 2010</b>									<b><u><u>(\$24,742)</u></u></b>

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

2/ True-up related to August gas costs.

3/ Reflects 37,464.9 Dk @ (\$0.152) and 287.3 Dk @ (\$0.010).

**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 &amp; 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>
<b>Balance @ July 31, 2010</b>									<b><u><u>\$14,139</u></u></b>
August	(\$14,595)	\$0	\$2	(\$14,593)	3,296	\$0.024	\$79	(\$14,672)	(533)
September	(16,382)	2,449 2/	0	(13,933)	5,317	0.024	128	(14,061)	(14,594)
October	(12,118)	0	(2)	(12,120)	12,771	0.031	306 3/	(12,426)	(27,020)
November	10,050	0	(3)	10,047	27,693	0.031	859	9,188	(17,832)
<b>Balance @ November 30, 2010</b>									<b><u><u>(\$17,832)</u></u></b>

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

2/ True-up related to August gas costs.

3/ Reflects 12,770.8 Dk @ \$0.024.