



# **MONTANA-DAKOTA**

**UTILITIES CO.**

*A Division of MDU Resources Group, Inc.*

400 North Fourth Street  
Bismarck, ND 58501  
(701) 222-7900

April 10, 2008

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

Re: Cost of Gas Adjustment  
(COG) Case No. PU-08-\_\_\_\_

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 Rate 88.

Attachment A is the Rate Summary Sheet (62<sup>nd</sup> Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered May 1, 2008, pursuant to the Order in Docket No. PU-08-132.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.424 per dk since the last filing because Montana-Dakota is using more flowing gas and less of the lower cost storage gas. The market cost of gas has remained unchanged and Attachment B discusses the market conditions for the cost of gas.

The COG tariff sheet, Exhibit A, summarizes the gas cost adjustment, calculated pursuant to the terms of Rate 88, and the surcharge adjustment and margin sharing provision that will apply during the month of May 2008.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.424 per dk for residential and firm general service customers, an increase of \$0.446 per dk for small and large interruptible customers and an increase of \$0.444 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 May 2008. The average cost of gas for firm customers, adjusted for losses, is \$9.523.

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.

The proposed adjustment, calculated in accordance with Rate 88, will amount to an increase of approximately \$261,000 during the month of May 2008. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 89,877 customers in North Dakota as of March 31, 2008.

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 \$300.00 in accordance with North Dakota Century Code Section 49-05-05 on December 12, 2007. This payment will cover the filing fee associated with the monthly COG filings for January through June, 2008.

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,



Donald R. Ball  
Vice President – Regulatory Affairs

Attachments

STATE OF NORTH DAKOTA )

: ss.

COUNTY OF BURLEIGH )

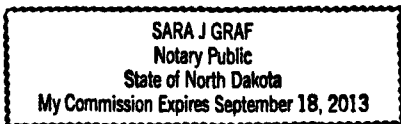
Donald R. Ball, being first duly sworn, deposes and says; that he is the Vice President – Regulatory Affairs of Montana-Dakota Utilities Co., the Applicant herein; that he has read the foregoing Application, knows the contents thereof, and that the same is true and correct to the best of his knowledge, information and belief.

Dated this 10<sup>th</sup> day of April 2008.



Donald R. Ball

Subscribed and sworn to before me this 10<sup>th</sup> day of April 2008.



Sara J. Graf, Notary Public  
Burleigh County, North Dakota  
My Commission Expires: 09/18/2013

OF COUNSEL:

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

**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  
 62nd Revised Sheet No. 3  
 Canceling 61st 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	\$9.281	\$10.093
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$9.281	\$9.419
Interruptible Service - PAR			\$0.120	\$8.212	\$8.332
Interruptible Service - MAFB			\$0.120	\$8.454	\$8.574
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	\$9.281	\$9.878
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$8.212	(Maximum) \$9.083
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	\$9.360	\$9.957
Summer Gas Usage			\$0.597	\$8.457	\$9.054
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.039	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.039	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$8.212	(Maximum) \$8.931
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$16.864	\$17.676
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	\$16.864	\$17.461

Date Filed: April 10, 2008

Effective Date:

Issued By: Donald R. Ball

Vice President - Regulatory Affairs

Case No.:

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

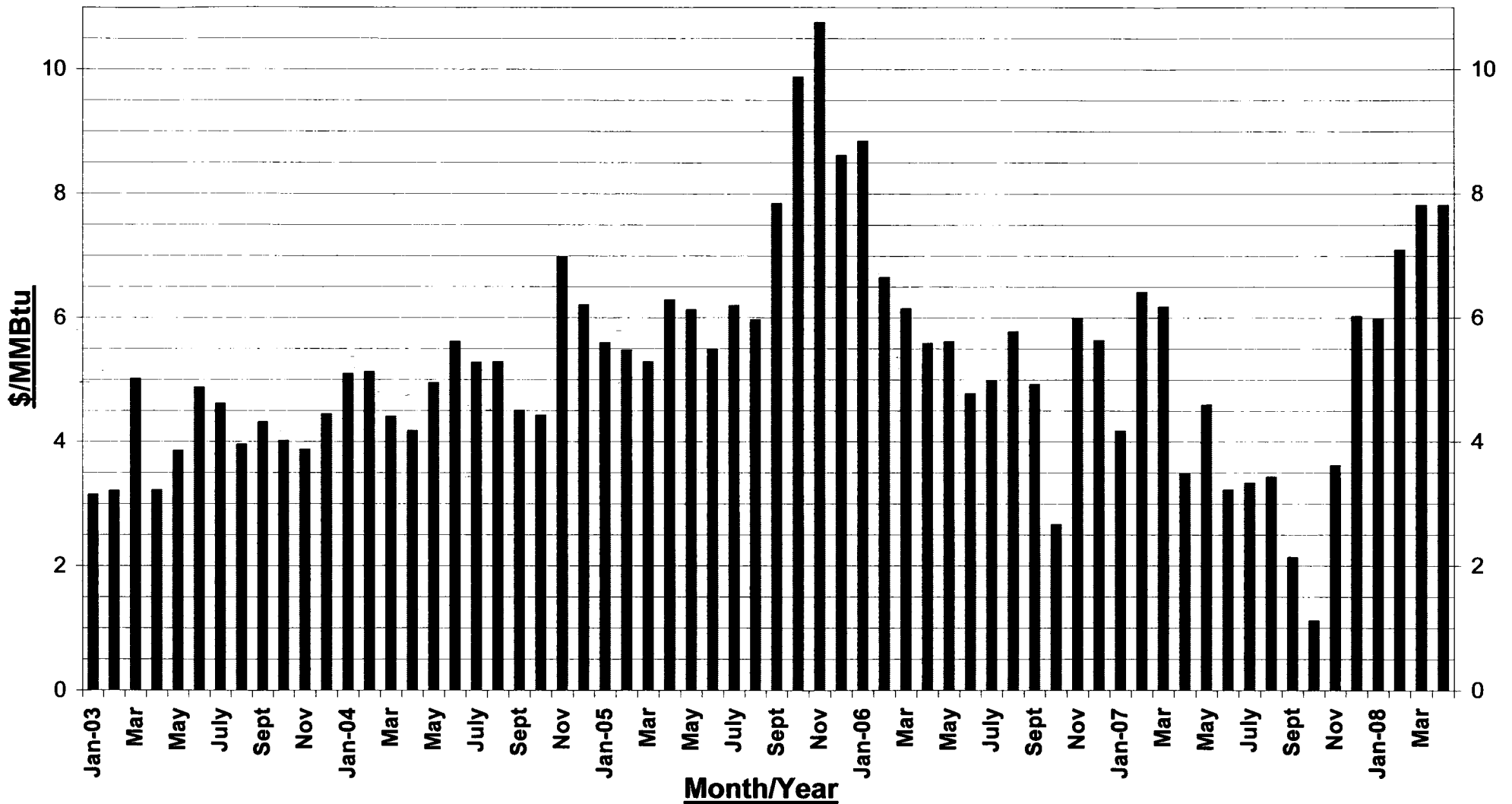
**May 2008**

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

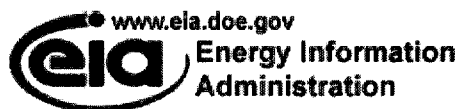
Continued cold weather throughout much of the nation resulted in a winter heating season approximately 6.3% colder than last year and near record high crude oil prices provided upward pressure on all energy commodities. Volumes of natural gas in storage were 0.5 percent above the five year average and approximately 20 percent below the prior year balance as of March 28, 2008 as reported by the Department of Energy's (DOE) Energy Information Administration (EIA). NYMEX futures prices remain high reflecting that the mindset of persisting tight supply in the natural gas market is expected to continue. The EIA provides various publications on energy issues. The information is available on their website: <http://www.eia.doe.gov>.

The April Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 14.

# CIG Rocky Mountains Index Monthly Gas Prices 2003-2008 YTD



From Inside F.E.R.C.'s Gas Market Report  
Annual Averages: - 2006-\$5.63; 2007-\$3.97; 2008YTD-\$7.17



April 2008

## Short-Term Energy and Summer Fuels Outlook

April 8, 2008 Release

### *Highlights*

- West Texas Intermediate (WTI) crude oil prices, which averaged \$72.32 per barrel in 2007, are projected to average \$101 per barrel in 2008 and \$92.50 per barrel in 2009.
- The projected higher costs for crude oil will contribute to higher petroleum product prices. Motor gasoline prices are projected to average \$3.36 per gallon in 2008, up 55 cents from last year. Diesel prices are projected to show even larger increases in 2008, averaging \$3.62 per gallon, or 74 cents above the 2007 average price. The monthly average gasoline price is projected to peak at about \$3.60 per gallon this spring, while monthly diesel prices are expected to average about \$3.90 per gallon in March and April. Weekly diesel prices have already crossed the \$4.00-per-gallon threshold in many regions of the country.
- U.S. consumption of liquid fuels and other petroleum is expected to decline in 2008 by about 85,000 barrels per day (bbl/d) as a result of the economic slowdown and high petroleum prices. After accounting for increased ethanol use, U.S. petroleum consumption is projected to fall by 210,000 bbl/d in 2008.
- U.S. real gross domestic product (GDP) is expected to decline in the first half of the year and then start growing again, with annual growth in 2008 at 1.2 percent, the slowest annual rate since 2001. An expected modest economic recovery in 2009, combined with lower petroleum prices, is projected to boost total U.S. liquid fuels and other petroleum consumption by about 200,000 bbl/d.
- The Henry Hub natural gas spot price averaged \$7.17 per thousand cubic feet (Mcf) in 2007 and is expected to average \$8.59 per Mcf in 2008 and \$8.32 per Mcf in 2009. Higher prices this year and next reflect continued strong demand, high oil prices, and the need to replenish more stocks this year than last year.

## *Global Petroleum*

The global oil market remains fundamentally tight entering the second quarter, despite a slowdown in U.S. oil consumption and growing risks to global economic growth. The combination of rising world oil consumption and low surplus production capacity is putting upward pressure on oil prices. The flow of investment money into commodities has contributed to crude oil price volatility. Inventories are improving in the Organization for Economic Cooperation and Development (OECD) countries, but given the lack of surplus capacity and geopolitical concerns in Nigeria, Venezuela, and Iraq, a higher level of commercial inventories is desirable. The magnitude, breadth, and duration of any global economic slowdown will certainly influence market conditions over the near term. The increase in non-Organization of the Petroleum Exporting Countries (OPEC) production in the second half of the year, however, is expected to contribute to increases in OPEC surplus crude oil production capacity and ease upward price pressures toward the end of the year (discussed further below).

**Consumption.** World oil consumption is expected to grow by 1.2 million bbl/d in 2008. Non-OECD countries are expected to account for over 1 million bbl/d of world consumption growth, while OECD consumption is expected to climb by 90,000 bbl/d. Higher oil prices and slower economic growth have dampened consumption in the United States, but available partial data indicate global oil consumption is still increasing because of continued growth in China, India, Russia, and the Middle East oil-exporting countries. In March, China's oil majors were reportedly rationing diesel fuel in parts of the country (World Oil Consumption).

**Non-OPEC Supply.** Growth in non-OPEC supply is projected to be 0.6 million bbl/d in 2008, lower than last month's assessment, because of revisions to recent historical data and delays in new oil projects. Brazil, Azerbaijan, and Sudan are expected to account for most of the net additions to capacity, while the United Kingdom, Mexico, and Norway are among countries expected to experience declines (Non-OPEC Oil Production Growth). The bulk of the supply growth is weighted toward the second half of the year, with non-OPEC supply growth projected to rise by 1.1 million bbl/d in the second half of 2008 (compared with year-earlier levels), versus growth of 80,000 bbl/d in the first half of the year. Given recent history, EIA recognizes that the pace and timing of non-OPEC supply growth will continue to be subject to possible delays in key projects, thus, production increases could be less than the current forecast.

**OPEC Supply.** OPEC crude oil production is expected to average 32.3 million bbl/d during the first quarter of 2008, or about 700,000 bbl/d above fourth quarter 2007 levels. The increase since the end of 2007 mainly reflects higher production from

Saudi Arabia, Angola, and the United Arab Emirates. Based on EIA projections of consumption and non-OPEC supply, OPEC crude oil production is expected to increase during the summer and then dip in the second half of the year. If consumption rises more slowly than expected and OECD inventories climb substantially relative to historic levels, OPEC members would likely consider holding their output below the projected level. Based on country capacity expansion plans and projected production, EIA expects that OPEC surplus production capacity will increase slightly in 2008 but remain concentrated in Saudi Arabia (OPEC Surplus Oil Production Capacity).

**Inventories.** OECD commercial inventories stood at 2.58 billion barrels at the end of 2007, 53 million barrels higher than reported in the last *Outlook* due to revised historic data. The improved stock situation mostly reflects lower-than-expected fourth quarter oil consumption in OECD Europe and Asia. In the first quarter of 2008, OECD commercial inventories are expected to decline only slightly, in contrast to an average 400,000 bbl/d draw over the past 5 years. Total U.S. inventories, which represent about 40 percent of total OECD stocks, rose by 1 million barrels during the first quarter, compared with an average decline of 26 million barrels over the same period during the previous 5 years. The normal seasonal decline in U.S. stocks was held in check by the weak U.S. gasoline market, with gasoline inventories increasing by 9 million barrels during the first quarter compared with the previous 5-year average decline of 6 million barrels. As a result, OECD commercial stocks could enter the summer almost 50 million barrels above the 5-year average. If expected oil production and consumption levels in the second half of 2008 materialize, total OECD commercial inventories should remain above the 5-year average for the rest of the year (Days of Supply of OECD Commercial Stocks).

### ***U.S. Petroleum***

**Production.** In 2007, domestic crude oil output averaged 5.1 million bbl/d, unchanged from 2006 (U.S. Crude Oil Production), and is projected to decline only slightly in 2008. In 2009, however, production is projected to grow by 3.9 percent, or about 200,000 bbl/d, mainly because of the start-up of the Thunder Horse and Tahiti platforms in the Gulf of Mexico.

**Consumption.** Total petroleum consumption of liquid fuels and other petroleum products averaged 20.7 million bbl/d in 2007, essentially unchanged from 2006 (U.S. Petroleum Products Consumption Growth). Based on the projections of weak economic growth and record high crude oil and product prices, consumption of liquid fuels and other petroleum products is projected to decline by 90,000 bbl/d in 2008—a sharp reversal from the 40,000 bbl/d increase projected in the previous *Outlook*—then

increase by 200,000 bbl/d in 2009. After accounting for projected increases in domestic ethanol production, U.S. petroleum consumption is projected to fall by 210,000 bbl/d this year. Gasoline consumption is projected to decline by 0.3 percent this year but increase by 0.9 percent in 2009. Distillate fuel consumption projected to shrink by 0.2 percent in 2008 before rising by 1.5 percent in 2009.

**Crude Oil Prices.** WTI crude oil prices, which averaged \$72.32 per barrel in 2007, are projected to average \$101 per barrel in 2008 and \$92.50 per barrel in 2009 (Crude Oil Prices).

A significant uncertainty in this *Outlook* is the WTI crude oil price projection. Price sensitivity is a characteristic of the current tight petroleum markets. Any real or perceived disturbance to petroleum demand or supplies, such as unusual weather, unscheduled refinery disruptions, or geopolitical uncertainty in oil-exporting regions, can result in large price increases in a short period of time. Prices can fall as rapidly under a different set of circumstances, such as easing of geopolitical tensions or further weakening of U.S. and world economic growth.

The last few months provide a good example of oil price volatility. Between mid-November 2007 and early December, the spot price of WTI crude oil fell by almost \$12 per barrel from \$99.16 per barrel on November 20 to a low of \$87.45 per barrel on December 5, then rebounded by January 2 to \$99.64 per barrel. By early February the WTI price was back down to \$87.16, but then rose steadily to over \$110 per barrel on March 13. The monthly average WTI price for March 2008 was \$105.46 per barrel and is expected to average near \$100 per barrel through the rest of this year.

### ***Summer Fuels Outlook***

The current record high prices for both crude oil and product prices belie the weakness in U.S. product demand. This weakness is expected to be a prominent feature of the summer driving season, defined as the period from April 1 to September 30.

**Prices.** Regular grade gasoline retail prices, which averaged \$2.93 per gallon last summer, are projected to average \$3.54 per gallon during the current driving season. Diesel fuel prices, which averaged \$2.85 per gallon last summer, are projected to average \$3.73 this summer. The monthly average gasoline price is projected to peak at just over \$3.60 per gallon in June, while the monthly average diesel price is expected to peak at just over \$3.90 per gallon in April.

These retail price projections reflect higher prices for the refiner's average acquisition cost of crude oil, projected to average almost \$97 per barrel, up from about \$67 per barrel last summer. However, for motor gasoline these projections indicate a narrowing of the difference between the gasoline retail price and the average cost of crude oil, due largely to the weak gasoline demand, high inventories, and growth in ethanol production. While the average cost of crude oil is projected to increase by about 70 cents per gallon this summer over last, the average gasoline retail price is expected to increase by only 60 cents. In contrast, summer diesel fuel prices are projected to increase by 87 cents per gallon this summer over last, largely because of strong world distillate demand growth, especially in Europe and Asia.

It is important to note, however, that even if the national average monthly gasoline price peaks around \$3.60 per gallon this summer, it is possible that prices at some point will cross the \$4 per gallon threshold. There are several reasons why this may occur:

1. *Variations around the monthly average.* Daily or weekly national average prices will inevitably be both above and below the monthly average price, whatever it turns out to be. For example, in May 2007, the average monthly retail price for regular gasoline was nearly \$3.15 per gallon, but the weekly price within that month increased from \$3.05 per gallon at the beginning of the month to \$3.22 per gallon by the end.
2. *Variations across States.* There is also significant regional variation in gasoline retail prices because of different gasoline quality specifications, distribution costs, and taxes. For example, prices along the West Coast—and more specifically, California—are often well above the U.S. average price. On March 31, 2008, the U.S. average price was nearly \$3.29 per gallon, while the average price in California was \$3.61 per gallon, or 32 cents above the U.S. average. In other periods, it has been the Midwest that has seen prices well above the U.S. average.
3. *Variations within States.* Finally, there is significant variation in prices between stations and areas within any State. For example, during the first 3 months of 2008 the price of gasoline in San Francisco has been about 10 cents per gallon higher than the California average.

Because taxes and retail distribution costs are generally stable, movements in gasoline and diesel prices are driven primarily by the change in crude oil prices and wholesale margins. The projected average WTI crude oil price for May and June is about \$103 per barrel. Assuming no change in margins, an additional dollar in the oil price adds

about 2.4 cents to product prices. Crude oil prices have been highly volatile in recent months. Oil prices significantly above the projected level would greatly increase the prospects for \$4 per gallon gasoline in some parts of the country. Local supply conditions will also play a key role in determining prices in various regions and locations this spring and summer.

*Motor Gasoline.* During the summer season, motor gasoline consumption is projected to decline by 0.4 percent to 9.4 million bbl/d as a result of the current economic slowdown and high retail prices. The economic stimulus payments, which are scheduled to start in May, are expected to boost real disposable income but are not expected to have a significant impact on motor gasoline consumption.

Motor gasoline is supplied by four sources: domestic production of ethanol and other oxygenates for gasoline blending, domestic refinery output, primary inventories, and net imports of motor fuel and blending components.

The methyl tertiary butyl ether (MTBE) phaseout in 2006, high oil prices, and new mandates requiring the use of renewable fuels, have all encouraged construction of new ethanol production capacity. During 2007, 36 new ethanol plants or plant expansions started production, and in 2008 an additional 64 new facilities are expected to begin production. Domestic ethanol production has increased from an average of 314,000 bbl/d during the summer of 2006, to 418,000 bbl/d during the summer of 2007, and is projected to average 550,000 bbl/d this summer.

This summer's domestic gasoline production is expected to be down by about 20,000 bbl/d from last summer's average. Because of the expected 130,000 bbl/d increase in ethanol production, production of gasoline at U.S. refineries is expected to decline by as much as 150,000 bbl/d this summer.

At the onset of the peak driving season (April 1), total gasoline stocks, at 224 million barrels, are estimated to be ample. That level is 23 million barrels above last year, 19 million barrels above the 5-year average, and the highest in 15 years (U.S. Gasoline and Distillate Inventories). Because of the high current inventory level, the average stock draw is projected to be about 88,000 bbl/d, compared with last summer's 14,000 bbl/d stock draw (and the average of 15,000 bbl/d over the last 15 years).

Imports are a significant source of motor gasoline on the East Coast, accounting for 87 percent of the U.S. total. The East Coast obtains almost 30 percent of its gasoline supply from imports compared with about 2 percent for the rest of the United States. Because of the expected growth in ethanol production, the current high gasoline inventory levels, and the decline in gasoline consumption, there should also be less

demand for gasoline imports this year. For the current summer season, net imports of motor gasoline and blending components are projected to average 1.1 million bbl/d, down almost 100,000 bbl/d from last summer's average of 1.2 million bbl/d.

**Diesel Fuel.** Distillate fuel consumption, which includes both diesel fuel and heating oil, is projected to be at about the same level as last summer. Distillate fuel is supplied by three sources: domestic refinery output, primary inventories, and net imports.

Refinery production this summer is projected to be close to last summer's average of 4.14 million bbl/d. Refinery production of distillate fuel both here and in Europe may be constrained by the potentially weak gasoline market. Without a growing outlet for gasoline, refiners may have to cut back on crude oil runs, resulting in lower distillate fuel output.

Distillate inventories are projected to start the summer season at 109 million barrels. Although 11 million barrels less than last year, inventories are only slightly less than the 5-year average. Consistent with seasonal patterns, distillate stocks are projected to rise to 132 million barrels at the end of third quarter, only 2 million barrels less than the year-earlier level. As a result, distillate stocks are projected to build at a daily average rate of 122,000 bbl/d over the summer compared to 76,000 bbl/d last summer.

Because of the demand for building inventories during the summer to meet next winter's heating fuel demand, net imports are projected to average 115,000 bbl/d, up from 55,000 bbl/d last summer. However, strong growth in world demand for distillate fuels and constrained supplies could limit the availability of imports and leave inventories lower than desired at the beginning of next winter.

### **Natural Gas**

**Consumption.** Total natural gas consumption is expected to increase by 1.0 percent in 2008 and by 0.8 percent in 2009 (U.S. Total Natural Gas Consumption). The assumption of normal weather is expected to lead to limited growth in residential and commercial demand in 2008, while economic conditions are expected to limit industrial sector growth for the year. In 2009, consumption is projected to decrease slightly in the residential and commercial sectors, with a small increase expected in the industrial sector. Finally, milder summer temperatures are expected to leave natural gas consumption for electricity generation unchanged in 2008, after an increase of more than 10 percent in 2007. Consumption growth of 2.9 percent is expected in the electric power sector in 2009.

**Production and Imports.** Total U.S. marketed natural gas production is expected to increase by 2.9 percent in 2008 and by 0.2 percent in 2009. In 2008, the development of deepwater supplies is expected to drive production growth of 4.8 percent in the Gulf of Mexico. Production from the Lower-48 onshore region is expected to continue the upward trend of recent years, increasing by 2.7 percent, led by growth in unconventional production basins. In 2009, production growth will be offset partially by the absence of further increases in rigs drilling natural gas prospects; the natural decline in production from current wells, particularly in the offshore fields; and rising production costs. In 2009, natural gas production in the Gulf of Mexico is projected to decline by 0.7 percent while production in the Lower-48 onshore region is expected to increase by 0.3 percent.

Imports of liquefied natural gas (LNG) are projected to reach about 680 billion cubic feet (Bcf) for 2008, representing a 12-percent decline from the record volume received in 2007. Strong demand in Asia and Western Europe, which compete with the United States for LNG supplies, has greatly reduced the number of U.S.-bound LNG cargoes so far this year. Although current import volumes are low, EIA expects U.S. LNG imports to rebound slightly this summer as global demand wanes. An increase in global LNG supplies, particularly expansions in Nigeria and Norway, are expected to boost shipments of LNG to the United States in 2009, when import volumes are projected to total about 950 Bcf.

**Inventories.** On March 28, 2008, working natural gas in storage was 1,248 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 6 Bcf above the 5-year average (2003-2007) and 304 Bcf below the level during the corresponding week last year.

**Prices.** The Henry Hub spot price averaged \$9.74 Mcf in March, nearly \$1.00 per Mcf more than the average spot price in February. This was the first month since December 2005 that Henry Hub spot prices averaged more than \$9 per Mcf. The recent upward price shift reflects a number of factors, including the dropoff in LNG imports compared to year-ago levels, high oil prices, and the drawdown in storage to the lowest levels in 4 years. As seasonal demand wanes, spot prices are expected to decline before they begin to rise again toward a winter peak. On an annual basis, the Henry Hub spot price is expected to average about \$8.59 per Mcf in 2008 and \$8.32 per Mcf in 2009.

## *Electricity*

**Consumption.** Cooling degree-days in the summers of 2006 and 2007 were 12 percent and 10 percent higher than normal, respectively (U.S. Summer Cooling Degree-Days). Given the assumption that summer temperatures this year will be close to normal, total annual electricity consumption is expected to grow at a relatively slow rate of 0.7 percent in 2008 and return to a more normal rate of 1.3 percent in 2009 (U.S. Total Electricity Consumption).

**Prices.** Spot prices for coal, especially in the Appalachian region, have rapidly increased in recent months. However, due to the lagged effect of purchase contracts and rate regulation, these fuel cost increases are not expected to have a significant impact on retail electricity prices in the near-term. Residential electricity prices are projected to increase at a rate of 2.7 percent in 2008 and a slightly higher rate of 3.1 percent in 2009 (U.S. Residential Electricity Prices).

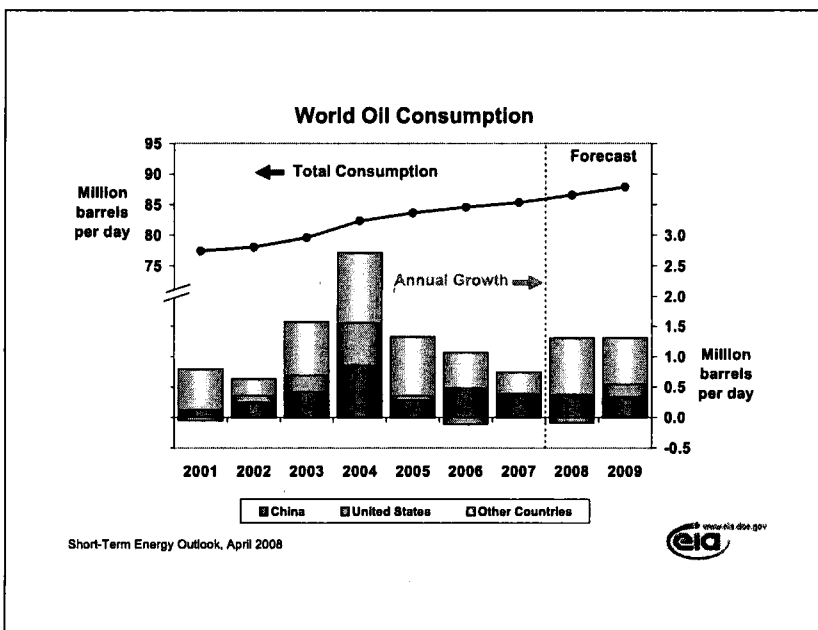
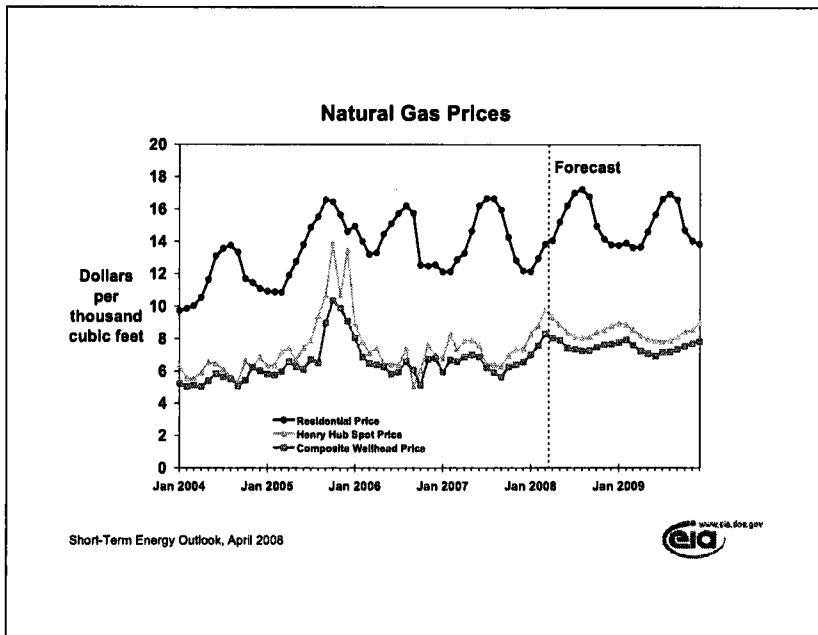
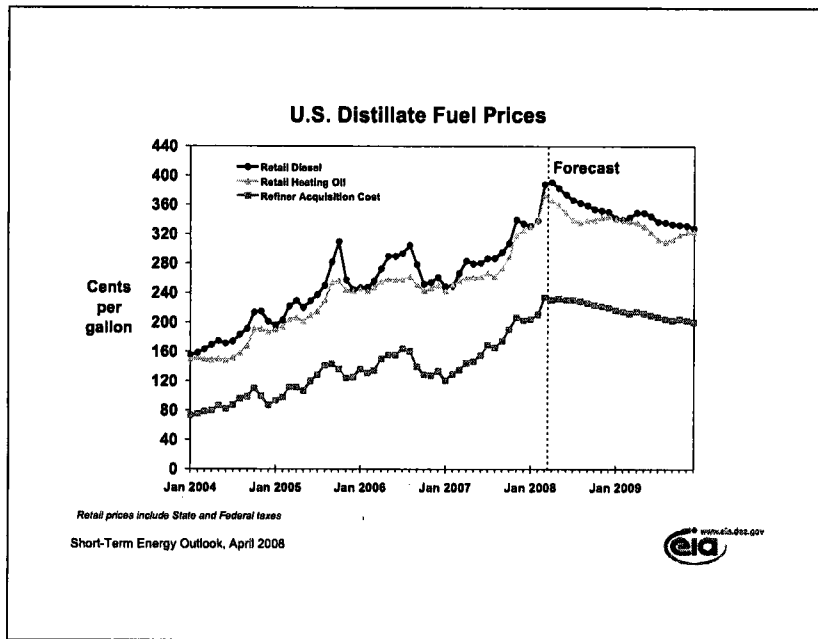
## *Coal*

**Consumption.** Projected increases in renewable generation, particularly hydropower and wind, combined with modest growth in electricity consumption, are expected to keep growth of coal consumption in the electric power sector to about 0.5 percent and 0.3 percent in 2008 and 2009, respectively (U.S. Coal Consumption Growth).

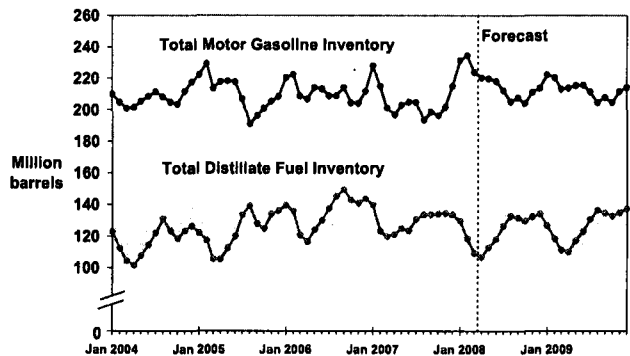
**Production and Inventories.** U.S. coal production (U.S. Annual Coal Production) fell in 2007 (1.5 percent) for the first time since 2003. Projected weak demand for coal is expected to result in small growth (0.6 percent) in coal production for 2008 and no growth for 2009. Total coal stocks are estimated to have grown by 1.3 percent in 2007 despite a nearly 16-percent decline in primary stocks (held by producers and coal distributors). This trend is expected to continue in 2008, as total coal stocks are forecast to rise by 3.6 percent and primary stocks are projected to decline by 11.2 percent.

**Imports and Exports.** Growth of coal imports into the United States slowed in 2007 to only 0.3 percent. Coal imports had experienced double-digit growth previously (19 percent in 2006 and 12 percent in 2005) but modest growth of 0.9 percent is expected in 2008. Increases in coal demand, coupled with the need for lower-sulfur coals, will see imports grow by 6.2 percent in 2009. U.S. coal exports are estimated to have increased by nearly 10 million short tons, or 19.2 percent, in 2007. In 2008, strong global demand for coal, coupled with supply issues in other major coal-exporting countries, is expected to result in a 15-percent increase in U.S. coal exports. Slower

global coal demand growth in 2009 is projected to lead to a 7.4-percent decline, about 5 million short tons, in exports.



**U.S. Gasoline and Distillate Inventories**

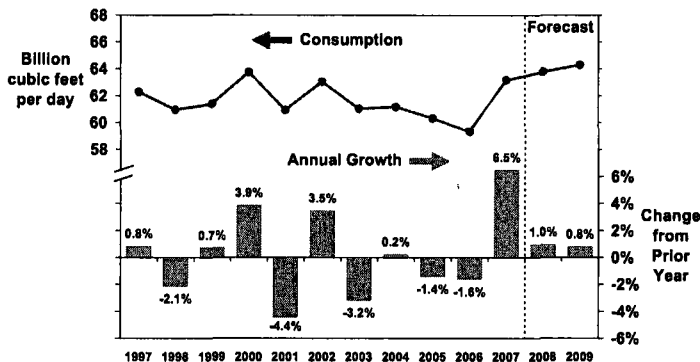


NOTE: Colored bands represent "normal" range published in EIA Weekly Petroleum Status Report, Appendix A.

Short-Term Energy Outlook, April 2008



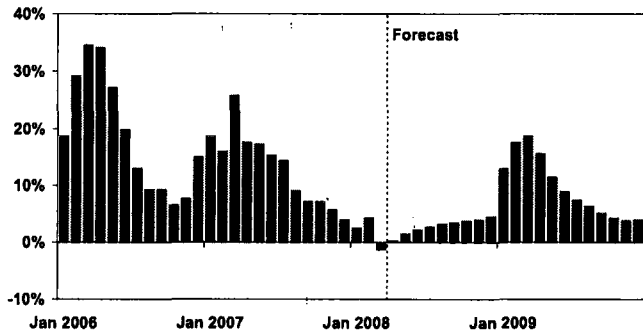
**U.S. Total Natural Gas Consumption**



Short-Term Energy Outlook, April 2008



**U.S. Working Natural Gas in Storage  
(Percent Difference from Previous 5-Year Average)**



Short-Term Energy Outlook, April 2008



**MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS TARIFF SHEET  
NORTH DAKOTA GAS  
EFFECTIVE MAY 2008**

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<b><u>Gas Cost Adjustment:</u></b>				
Gas Cost Level (Exhibit B)	\$9.523	\$9.602	\$8.628	\$8.589
Prior Gas Cost	<u>9.099</u>	<u>9.176</u>	<u>8.182</u>	<u>8.145</u>
Current Gas Cost Adjustment	\$0.424	\$0.426	\$0.446	\$0.444
<b><u>Surcharge Adjustment:</u></b>				
Current Adjustment	(\$0.233)	(\$0.233)	(\$0.416)	(\$0.135)
Prior Adjustment	<u>(0.233)</u>	<u>(0.233)</u>	<u>(0.416)</u>	<u>(0.135)</u>
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<b><u>Margin Sharing Provision</u></b>				
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
<b>Net Increase (Decrease) in Gas Costs</b>	<b><u><u>\$0.424</u></u></b>	<b><u><u>\$0.426</u></u></b>	<b><u><u>\$0.446</u></u></b>	<b><u><u>\$0.444</u></u></b>
Gas Cost Level	\$9.523	\$9.602	\$8.628	\$8.589
Plus: Surcharge	<u>(0.233)</u>	<u>(0.233)</u>	<u>(0.416)</u>	<u>(0.135)</u>
Total Gas Cost Level in Tariff Rates	<b><u><u>\$9.290</u></u></b>	<b><u><u>\$9.369</u></u></b>	<b><u><u>\$8.212</u></u></b>	<b><u><u>\$8.454</u></u></b>

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
RESIDENTIAL AND GENERAL SERVICE  
EFFECTIVE MAY 2008**

	<u>Amount</u>
Total Gas Costs 1/	\$131,682,327
Residential and General Service dk Requirements 2/	13,891,132
Average Cost of Gas per dk	\$9.480
Average Cost of Gas as Adjusted for Losses @ 99.55%	9.523
Less: Gas Cost Level in Rates 3/	<u>9.099</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.424</u></u></b>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -13 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 February 29, 2008, adjusted for losses at .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-08-120:

Cost of Purchased Gas	\$9.058
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$9.099

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
OPTIONAL SEASONAL - RATE 72  
EFFECTIVE MAY 2008**

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$131,682,327
Less: Annual MDDQ Costs 1/	<u>11,383,621</u>
Total Gas Costs excluding MDDQ	\$120,298,706
Firm Service Requirements 1/	13,891,132
Other Gas Costs per Dk (excluding MDDQ)	\$8.660
Summer Seasonal Rate, adjusted for losses 2/	8.699
 <u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,383,621
Winter Firm Service Requirements	12,664,696
MDDQ Costs per Winter Dk	\$0.899
Add: Other Gas Costs per Dk	<u>8.660</u>
Winter Seasonal Rate	9.559
Winter Seasonal Rate, adjusted for losses 2/	\$9.602
Less: Gas Cost Level in Rates 3/	<u>9.176</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.426</u></u></b>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-08-120:

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$8.226	\$9.135
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$8.263	\$9.176

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
INTERRUPTIBLE  
EFFECTIVE MAY 2008**

	Amount
Total Gas Costs 1/	\$30,084,013
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$8.589
Average Cost of Gas as Adjusted for Losses @ 99.55%	8.628
Less: Gas Cost Level in Rates 2/	8.182
<b>Current Gas Cost Adjustment</b>	<b>\$0.446</b>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -13 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C, allocated to interruptible on MDDQ.

2/ Gas Cost Level in Current Tariff Rates Case No. PU-08-120:

Cost of Purchased Gas	\$8.145
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$8.182

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
AIR FORCE INTERRUPTIBLE  
EFFECTIVE MAY 2008**

	<u>Amount</u>
Total Gas Costs 1/	\$7,558,038
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$8.589
Less: Gas Cost Level in Rates 2/	<u>8.145</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.444</u></u></b>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -13 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-08-120:  
Cost of Purchased Gas \$8.145

**Montana-Dakota Utilities Co.  
Schedule of Applicable Effective Pipeline Rates  
May 2008 PGA**

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

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

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

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

Kinder Morgan, Inc. (f/k/a Northern Gas Company) – Contract rate so there are no tariff sheets.

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

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

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FT-1						
RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	737.928	N.A.	N.A.	N.A.	737.928
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
COMMODITY CHARGE						
MAXIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
MINIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.190	N.A.	N.A.	31.074
MINIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 2.594%, CONSISTING OF 2.467 % FOR THE CURRENT PERCENTAGE AND 0.127% 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 0.224 CENTS, CONSISTING OF 0.299 CENTS FOR THE CURRENT RATE AND (0.075) CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
-----						
RATE SCHEDULE FTN-1						
-----						
RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	47.491	N.A.	N.A.	N.A.	47.491
MINIMUM	RATE PER EQV. DKT PER MO.	1.589	N.A.	N.A.	N.A.	1.589

Issued by: Keith A. Tiggelaar - Director of Regulatory Affairs

Issued on: May 19, 2005

Effective on: April 19, 2005

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP00-107, et al., issued April 19, 2005

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FS-1						
CAPACITY RESERVATION						
MAXIMUM	RATE PER EQV. DKT PER MO.	2.102	N.A.	N.A.	N.A.	2.102
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
CAPACITY DELIVERABILITY						
MAXIMUM	RATE PER EQV. DKT PER MO.	190.602	N.A.	N.A.	N.A.	190.602
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
INJECTION						
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
WITHDRAWAL						
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
SCHEDULED OVERRUN CHARGE						
INJECTION						
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
WITHDRAWAL						
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 0.372%, CONSISTING OF 0.507% FOR THE CURRENT PERCENTAGE AND (0.135%) 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 0.079 CENTS, CONSISTING OF 0.031 CENTS FOR THE CURRENT RATE AND 0.048 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

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

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

STATEMENT OF RATES

2/ 3/

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

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

Issued by: Raymond D. Neppl, Vice President

Issued on: November 21, 2006

Effective on: January 1, 2007

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

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

Substitute Tenth Revised Sheet No. 99  
Superseding  
Ninth Revised Sheet No. 99

---

STATEMENT OF RATES

Commodity

Rate

----

Annual Charge Adjustment (ACA) Rate (per Dekatherm) 1/  
\$0.0019

Compressor Usage Surcharge (per 100 Dekatherm-miles) 2/  
\$0.0020

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 16 of the General Terms and Conditions herein,  
the ACA is effectively charged at a rate of \$0.0002 per 100 Dekatherm-  
miles.

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

---

Issued by: Bambi L. Heckerman, Manager, Regulatory Affairs

Issued on: August 14, 2007

Effective on: October 1, 2007

NOVA Gas Transmission Ltd.

Table of Rates, Tolls and Charges

Service	Rates, Tolls and Charges		
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) \$168.24/10 <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	FT-D Demand Rate per month \$ 4.45/GJ		
4. Rate Schedule STFT	STFT Bid Price. Minimum bid of 100% of FT-D Demand Rate		
5. Rate Schedule FT-DW	FT-DW Bid Price. Minimum bid of 125% of FT-D Demand Rate		
6. Rate Schedule FT-A	FT-A Commodity Rate \$ 0.48/10 <sup>3</sup> m <sup>3</sup>		
7. Rate Schedule FT-P	Refer to Attachment "2" for applicable FT-P Demand Rate per month		
8. Rate Schedule LRS	<u>Contract Term</u>		<u>Effective LRS Rate (\$/10<sup>3</sup>m<sup>3</sup>/day)</u>
	1-5 years		10.08
	6-10 years		8.42
	15 years		7.55
	20 years		6.71
9. Rate Schedule LRS-2	LRS-2 Rate per month \$50,000		
10. Rate Schedule LRS-3	LRS-3 Demand Rate per month \$129.55/10 <sup>3</sup> m <sup>3</sup>		
11. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate & Surcharge for each Receipt Point		
12. Rate Schedule IT-D	IT-D Rate \$ 0.1606/GJ		
13. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
14. Rate Schedule PT	<u>Schedule No</u>	<u>PT Rate</u>	<u>PT Gas Rate</u>
	9006-01000-0	\$ 67.22/d	1.0 10 <sup>3</sup> m <sup>3</sup> /d
15. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2003034359-2	\$ 899.00 / month	
	2007262666-1	\$ 434.00 / month	
	2006253651-1	\$ 11.00 / month	
	2007262711-1	\$ 6.00 / month	
	2007262709-1	\$ 303.00 / month	
	2007262728-1	\$ 859.00 / month	
	2007262705-1	\$ 1,220.00 / month	
	2007263949-1	\$ 46.00 / month	
	2007262175-1	\$ 438.00 / month	
	2007262669-1	\$ 95.00 / month	
	2007262602-1	\$ 4.00 / month	
	2007262701-1	\$ 9.00 / month	
	2007262727-1	\$ 17.00 / month	
	2007262698-1	\$ 43.00 / month	
	2007262609-1	\$ 7.00 / month	
	2007262668-1	\$ 19.00 / month	
	2007262697-1	\$ 1,760.00 / month	
	2007263948-1	\$ 90.00 / month	
	2003004522-2	\$ 83,333.00 / month	
16. 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	630.10	
	2	503.07	
	3	349.65	

NATURAL GAS TARIFF



Canceling  $\frac{13^{\text{th}}}{12^{\text{th}}}$  Revised Revised Sheet No. 80.1  
Sheet No. 80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT  
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

**RATES:** Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge	
5,001 to 10,000	\$ 102.65	(I)
10,001 to 30,000	\$ 147.60	(I)
>30,000	\$ 327.50	(I)

**PLUS:**

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	\$ 8.392279	(I)
--	-------------	-----

Transmission Commodity Rate (Monthly Rate per Dkt):

Maximum	\$ 0.063595	(I)
Minimum	\$ 0.017935	(I)
GTAC Amortization	\$ 0.028297	
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 27, 2007  
Docket No.: D2007.7.82, Interim Order No. 6852h  
Tariff Letter No. 133-G

Effective for service rendered on or after  
January 1, 2008

PUBLIC SERVICE COMMISSION  
Secretary

**GAS RATE SCHEDULE**

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

SD P.U.C. Section No. 3  
Original Sheet No. 1  
Effective Date: January 10, 2001

---

**TRANSPORTATION SERVICE Rate 1**

Transportation rate is \$2.398 per dekatherm.

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

**MONTANA-DAKOTA UTILITIES CO.  
RETURN ON CYCLE STORAGE BALANCES  
AND PREPAID DEMAND AND COMMODITY BALANCES  
NORTH DAKOTA GAS  
EFFECTIVE MAY 2008**

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2007	\$15,582,989	\$652,377	\$3,076,642
November	14,327,247	529,819	2,499,237
December	8,196,719	340,577	1,203,224
January 2008	936,990	99,099	(353,779)
February	(4,803,619)	(96,346)	(1,345,417)
March	(9,683,961)	(195,911)	(1,918,937)
April	(10,071,971)	(229,774)	(1,742,141)
May	(7,427,452)	(142,643)	(1,031,957)
June	(2,295,319)	44,136	(49,791)
July	3,416,933	253,214	971,913
August	9,039,060	458,437	1,974,252
September	13,849,685	990,601	2,767,284
October	17,335,194	1,099,319	3,024,929
13 month average	\$3,723,269	\$292,531	\$698,112
Rate of Return	8.791%	8.791%	8.791%
Return	\$327,313	\$25,716	\$61,371
Return Requirement - Revenue	<u>\$541,999</u>	<u>\$42,583</u>	<u>\$101,624</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**

	(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, 2007</b>									<b><u>(\$3,168,783)</u></b>
August	(\$1,558,884)	\$0	(\$11,057)	(\$1,569,941)	259,098	\$0.111	\$28,760	(\$1,598,701)	(4,767,484)
September	(892,843)	0	(15,499)	(908,342)	279,608	0.111	31,037	(939,379)	(5,706,863)
October	(119,804)	0	(18,626)	(138,430)	482,413	(0.233)	(112,360) 2/	(26,070)	(5,732,933)
November	1,062,491	0	(15,628)	1,046,863	950,041	(0.233)	(221,360)	1,268,223	(4,464,710)
December	2,940,869	(840,039) 3/	(11,052)	2,089,778	1,836,296	(0.233)	(427,857)	2,517,635	(1,947,075)
January 2008	2,832,820	0	(4,210)	2,828,610	2,394,593	(0.233)	(557,940)	3,386,550	1,439,475
February	492,452	0	1,863	494,315	2,526,168	(0.233)	(588,597)	1,082,912	2,522,387
<b>Balance @ February 29, 2008</b>									<b><u>\$2,522,387</u></b>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Reflects 121.6 Dk @ \$0.111 and 482,290.1 @ (\$0.233).

3/ Reflects reallocation of gas commodity to correct allocation of storage gas.

**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, 2007</b>									<b><u>(\$383,071)</u></b>
August	(\$226,040)	\$0	(\$1,348)	(\$227,388)	27,533	(\$0.279)	(\$7,682)	(\$219,706)	(602,777)
September	(269,369)	0	(1,972)	(271,341)	42,600	(0.279)	(11,885)	(259,456)	(862,233)
October	(5,122)	0	(2,836)	(7,958)	31,574	(0.416)	(13,135)	5,177	(857,056)
November	(9,945)	0	(2,354)	(12,299)	55,502	(0.416)	(23,088)	10,789	(846,267)
December	(3,497)	570,270 2/	(2,125)	564,648	70,922	(0.416)	(29,504)	594,152	(252,115)
January 2008	123,903	0	(564)	123,339	94,656	(0.416)	(39,377)	162,716	(89,399)
February	2,879	0	(92)	2,787	110,067	(0.416)	(45,788)	48,575	(40,824)
<b>Balance @ February 29, 2008</b>									<b><u>(\$40,824)</u></b>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Reflects reallocation of gas commodity to correct allocation of storage gas.

**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, 2007</b>									<b><u>(\$114,724)</u></b>
August	(\$121,440)	\$0	(\$397)	(\$121,837)	14,865	(\$0.123)	(\$1,828)	(\$120,009)	(234,733)
September	(98,822)	0	(765)	(99,587)	15,725	(0.123)	(1,934)	(97,653)	(332,386)
October	(1,386)	0	(1,090)	(2,476)	9,269	(0.135)	(1,251)	(1,225)	(333,611)
November	(26,111)	0	(913)	(27,024)	43,334	(0.135)	(5,850)	(21,174)	(354,785)
December	5,119	23,573 2/	(890)	27,802	73,394	(0.135)	(9,908)	37,710	(317,075)
January 2008	122,482	0	(728)	121,754	103,171	(0.135)	(13,928)	135,682	(181,393)
February	(5,543)	0	(204)	(5,747)	103,790	(0.135)	(14,012)	8,265	(173,128)
<b>Balance @ February 29, 2008</b>									<b><u>(\$173,128)</u></b>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Reflects reallocation of gas commodity to correct allocation of storage gas.