MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

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

February 10, 2009

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

Re: Cost of Gas Adjustment
(COG) Rate 88
Case No. PU-09-___

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

Attachment A is the Rate Summary Sheet (72nd Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered March 1, 2009.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased $1.219 per dk since the last filing due to a decrease in the overall market price of gas. Attachment B explains the reasons for the decrease in the market price of gas. There also has been a change in pipeline rates, as shown on Attachment C, that has no effect on the cost of gas.

The COG tariff sheet, Exhibit A, 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 March 2009.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of $1.219 per dk for residential and firm general service customers, a decrease of $1.216 per dk for small and large interruptible customers and a decrease of $1.211 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 March 2009. The average cost of gas for firm customers, adjusted for losses, is $5.288.

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 will amount to a decrease of approximately $2,258,900 during the month of March 2009. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 91,043 customers in North Dakota as of January 31, 2009.

Please refer all inquiries regarding this filing to:

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

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

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

Montana-Dakota submitted a check for the amount of $600 in accordance with North Dakota Century Code Section 49-05-05 on January 9, 2009. This payment will cover the filing fee associated with the monthly COG filings for January through December, 2009.

Montana-Dakota respectfully requests that this filing be accepted as being in full compliance with the filing requirements of this Commission.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed stamped envelope.

Sincerely,

Donald R. Ball

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 10th day of February 2009.

Donald R. Ball

Donald R. Ball

Subscribed and sworn to before me this 10th day of February 2009.

SARA J GRAF
Notary Public
State of North Dakota
My Commission Expires September 18, 2013

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
72nd Revised Sheet No. 3
Canceling 71st Revised Sheet No. 3

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	$0.30 per day	$0.812	$6.125	$6.937
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$6.125	$6.263
Interruptible Service - PAR			$0.120	$4.733	$4.853
Interruptible Service - MAFB			$0.120	$4.531	$4.651
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		$0.52 per day			
Meters rated > 500 cubic feet		$1.75 per day	$0.597	$6.125	$6.722
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	14	$100.00 per month	$0.871	$4.733	$5.604
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		$0.52 per day			
Meters rated > 500 cubic feet		$1.75 per day			
Winter Gas Usage			$0.597	$6.207	$6.804
Summer Gas Usage			$0.597	$5.283	$5.880
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	
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	27	$675.00 per month	$0.719	$4.733	$5.452
Residential Propane Rate 90	32	$0.30 per day	$0.812	$13.571	$14.383
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	$13.571	$14.168

Date Filed: February 10, 2009 **Effective Date:**

Issued By: Donald R. Ball
Vice President - Regulatory Affairs **Case No.:**

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

March 2009

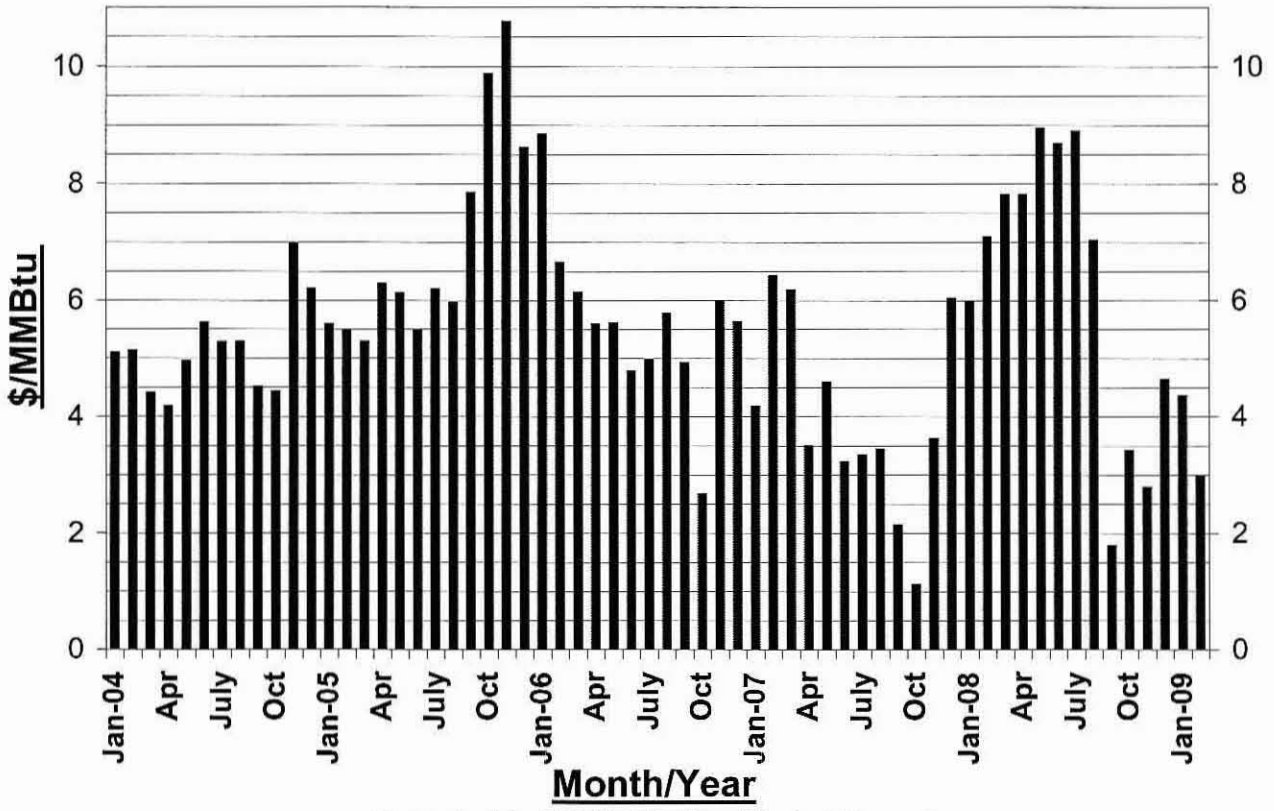
The established February monthly price for the Rocky Mountain CIG Index decreased from the previous month. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices 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.

Likely key factors contributing to the decline and softness of natural gas prices include a lower level of industrial demand for natural gas, as a result of the ongoing economic downturn, and relatively low crude oil prices. The Energy Information Administration (EIA) reported storage levels nationwide as of January 30, 2009 were 0.8 percent above the five-year average and 2.8 percent above last year's balance.

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

The December Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 11.

CIG Rocky Mountains Index
Monthly Gas Prices 2004-2009 YTD



From Inside F.E.R.C.'s Gas Market Report

Annual Averages: - 2007-$3.97; 2008-$6.24; 2009YTD-$3.67

www.eia.doe.gov
Energy Information Administration

January 2009

Short-Term Energy Outlook

January 13, 2009 Release

Highlights

- This edition of the *Short-Term Energy Outlook* is the first to include monthly forecasts through December 2010.

- The energy forecast is sensitive to economic conditions. In this forecast, U.S. real gross domestic product (GDP) is expected to decline by 2 percent in 2009, leading to decreases in domestic energy consumption for all major fuels. Economic recovery is projected to begin in 2010, with 2 percent year-over-year growth in GDP.

- In the past 6 months, the monthly average price of West Texas Intermediate (WTI) crude oil has fallen from $133 per barrel in July to $41 in December. WTI prices are projected to average $43 per barrel in 2009 and $55 in 2010.

- Average monthly U.S. prices for regular gasoline and diesel fuel were $1.69 and $2.45 per gallon, respectively, in December 2008, more than $2.25 per gallon below their monthly peaks last July. Economic contraction in 2009 and lower projected crude oil prices are expected to reduce annual average retail gasoline and diesel fuel prices in 2009 to $1.87 and $2.27 per gallon, respectively.

- Residential heating oil prices during the current (2008-09) heating season are projected to average $2.48 per gallon, a reduction of 25 percent from the 2007-2008 heating season. Residential propane prices are projected to average $2.14 this winter, a decrease of 13 percent from last winter. Residential natural gas prices are projected to average $12.17 per thousand cubic feet (Mcf), a decrease of 4 percent from last winter.

- The U.S. economic downturn is also contributing to lower natural gas prices. The Henry Hub natural gas spot price is projected to decline from an average of $9.13 per Mcf in 2008 to $5.78 per Mcf in 2009, but then increase in 2010 to an average of $6.63 per Mcf.

Global Petroleum

Overview. The downward trend in oil prices continued in December as the worsening global economy weakened oil demand and the second Organization of Petroleum Exporting Countries (OPEC) agreement for substantial production cuts within a month has failed, thus far, to support substantially higher prices. The outlook for supply and demand fundamentals indicates a fairly loose oil market balance over the next 2 years. The global economic downturn points to declining oil consumption in 2009, while additional production capacity from both OPEC and non-OPEC nations should boost surplus production capacity, reducing the likelihood of a renewed strong upward pressure on prices. Global real GDP growth (weighted according to shares of world oil consumption) is assumed to be 0.6 percent in 2009 and 3.0 percent in 2010. These projections compare with 4.6 percent real GDP growth in 2007 and 3.2 percent in 2008. The oil price path going forward will be driven mainly by the depth and duration of the global economic downturn, the pace and timing of the recovery, and actual OPEC production.

Consumption. World oil consumption continues to be revised downward in response to the global economic downturn. Global consumption is estimated to have been largely unchanged in 2008 and is projected to fall by 800,000 barrels per day (bbl/d) in 2009. Total world oil consumption is expected to record a modest rebound in 2010, rising by 880,000 bbl/d from year-earlier levels, on the assumption of the beginning of an expected recovery in global economic growth. Oil consumption growth is concentrated in countries outside of the Organization for Economic Cooperation and Development (OECD), particularly China, the Middle East, and Latin America. However, projected declines in oil consumption in OECD countries more than offset any non-OECD oil consumption growth in 2009 (World Oil Consumption). If the world economic recovery happens sooner or is stronger than EIA now anticipates, oil consumption could decline at a slower rate or potentially increase at a faster rate than expected, putting upward pressure on oil prices.

Non-OPEC Supply. Non-OPEC supply is projected to rise modestly over the next 2 years. After falling by 340,000 bbl/d in 2008 because of project delays and disruptions in Central Asia and the Gulf of Mexico, non-OPEC supply is projected to grow by about 180,000 bbl/d in 2009 and 90,000 bbl/d in 2010. These projections assume that unexpected delays to new non-OPEC supply that have occurred in the past will continue through the forecast period. Supply growth in countries such as the United States, Brazil, and Azerbaijan is expected to more than compensate for continued declines in many non-OPEC nations, particularly Mexico, the North Sea, and Russia. The global economic slowdown and falling oil prices bring additional risk to the usual

uncertainties concerning non-OPEC supply growth, such as unexpected disruptions, project delays, and underestimation of decline rates. Lower oil prices bring into doubt the viability of some high-cost non-OPEC projects, especially those utilizing nonconventional technology or those seeking to exploit frontier oil basins. The credit crunch associated with the global economic crisis can also make it difficult to acquire financing for new projects or even finance the investment required to prevent accelerated declines at producing fields. If conditions in global financial markets lead to delayed investment in existing and new oil fields, then even a short-lived economic downturn could have longer-term ramifications for world oil supply. This would heighten the risk of a return to a tight supply situation once the world economy and oil demand growth recover.

OPEC Supply. OPEC's December announcement that it would cut crude oil production again, following its earlier cut in November, has not yet led to a substantial increase in oil prices. Together, the two announced cuts imply a new overall target for production (excluding Iraq) of 24.845 million bbl/d , 4.2 million bbl/d below actual September production. However, the market is not presently convinced that OPEC members will willingly curtail output enough to lead to much higher prices. Adherence to the announced cuts will be challenging, as several individual countries are motivated to maintain production at higher levels to to generate revenue needed to finance their government programs amid falling prices. The lack of transparency in the new agreement, highlighted by the failure to publicize individual country production cuts, is one indicator of the reluctance of countries to cut production consistent with the group's new overall production target. OPEC plans to meet again on March 15 in Vienna to evaluate the effectiveness of its recent actions.

EIA projects that total OPEC crude oil production (including Iraq) will fall by more than 2 million bbl/d, from 31.4 million bbl/d in September 2008 to 29.3 million bbl/d in the first quarter of 2009, implying a compliance rate of a little more than 50 percent. Because of Indonesia's exit from OPEC, EIA has revised its historic and forecasted values for OPEC oil production to be consistent with the current membership. OPEC crude oil production is expected to average 30.0 million bbl/d in 2009 and 30.7 million bbl/d in 2010. In addition, EIA expects that OPEC production of non-crude liquids will rise substantially next year, growing by 600,000 bbl/d in 2009 and by 850,000 bbl/d in 2010. The combination of lower demand for OPEC crude oil and the capacity expansions expected in several OPEC countries means that surplus production capacity could increase to roughly 4.0 million bbl/d in 2009 and 4.7 million bbl/d by the end of 2010, compared with the 1 to 2 million bbl/d of surplus capacity available over the past several years (OPEC Surplus Oil Production Capacity).

Inventories. Revised data indicate that OECD commercial inventories rose by 330,000 bbl/d in the third quarter of 2008, lower than historic rates for inventory builds during that time of year. OECD commercial inventories stood at 2.63 billion barrels at the end of the third quarter, equivalent to 57 days of forward consumption cover. On the basis of days of forward cover, OECD commercial inventories are well above average historic levels, and EIA projects that they will remain there through the end of 2010 (Days of Supply of OECD Commercial Stocks). The combination of substantial surplus capacity and above-average inventories should dampen price pressure over the period. In any event, a sustained rebound in prices is not likely until the economic recovery causes a sustained rebound in demand for OPEC crude oil.

U.S. Petroleum

Consumption. The increase in prices to record levels in 2008 and the weakening economy drove total petroleum products consumption down by about 1.2 million bbl/d, or 5.7 percent, from the 2007 average (U.S. Petroleum Products Consumption Growth). Motor gasoline consumption declined by slightly more than 300,000 bbl/d, or 3.3 percent. Despite the cold weather that gripped much of the Nation in December, distillate fuel consumption in 2008 declined by 5.3 percent from the year before. In 2009, total petroleum products consumption is projected to fall by nearly 400,000 bbl/d, or 2 percent, due to continued economic weakness. Consumption for both motor gasoline and distillate fuel are forecasted to decline by about 100,000 bbl/d each. The expected economic recovery in 2010 is projected to boost total petroleum products consumption by 150,000 bbl/d, or 0.8 percent, and both motor gasoline and distillate consumption are each projected to rise by about 50,000 bbl/d.

Production. In 2008, domestic crude oil production averaged 4.9 million bbl/d, down by 140,000 bbl/d from 2007 (U.S. Crude Oil Production). However, in 2009, domestic output is projected to increase by over 300,000 bbl/d to an average of 5.25 million bbl/d. This would be the first increase in production since 1991. Output is projected to rise by a further 50,000 bbl/d in 2010. Contributing to the increases in output are the Gulf of Mexico Thunder Horse platform, which is coming on stream now, and the Tahiti platform, expected to come on stream late in 2009.

Prices. Having fallen from record highs to below $40 per barrel, WTI prices averaged near $100 per barrel in 2008. Under current economic assumptions and assuming no major crude oil supply disruptions, WTI prices are expected to average $43.25 per barrel in 2009 and $54.50 per barrel in 2010 (Crude Oil Prices).

Regular-grade gasoline prices averaged $1.68 per gallon on January 5, down substantially from their July 14 peak of $4.11 per gallon. These prices are projected to

average $1.87 per gallon in 2009 and $2.18 per gallon in 2010. Because of lower motor gasoline consumption, the difference between the retail gasoline price and the cost of crude oil is expected to remain narrow for much of 2009 but is expected to increase slightly in 2010.

On-highway diesel fuel retail prices, which averaged $3.79 per gallon in 2008, are projected to average $2.27 per gallon in 2009 and $2.54 in 2010. The projected continuation of the decline in the consumption of diesel fuel in the United States as well as a slowing of the growth in distillate fuel usage outside the United States are expected to result in a weakening of refining margins for distillate throughout the forecast.

Natural Gas

Consumption. Total natural gas consumption is estimated to have increased by 0.7 percent in 2008, primarily driven by a 5.8-percent increase in heating degree-days year-over-year. Natural gas consumption is projected to decline by 1.0 percent in 2009 and then increase by 0.7 percent in 2010 (Total U.S. Natural Gas Consumption Growth). The demand outlook for 2009 is largely driven by expectations of continued economic weakness. The slight consumption growth projected in the residential sector is expected to be more than offset by consumption declines in the commercial, industrial, and electric power sectors this year. With the natural-gas-weighted industrial production index projected to fall by 6.6 percent in 2009, industrial sector natural gas consumption is expected to decline by 3.0 percent. Consumption growth in 2010 is expected to be limited to the electric power sector, with all other sectors expected to decline slightly.

Production and Imports. Total U.S. marketed natural gas production is estimated to have increased by 5.9 percent in 2008 led by the development of unconventional reserves in the Lower-48 States. Total marketed production is expected to increase by 0.7 percent in 2009, and then decline by 0.9 percent in 2010. Producers have already begun to react to lower prices and the outlook for lower consumption as evidenced by the recent pullback in drilling activity. The number of rigs drilling for natural gas in the Lower-48 onshore region has fallen from about 1,540 in August 2008 to under 1,200 at the beginning of January 2009. Despite the cutback in drilling activity, the current outlook suggests that some production curtailments may be necessary during the latter part of 2009 in order to balance the market. Nevertheless, in 2009, Lower-48 production outside of the Gulf of Mexico (GOM) region is expected to increase by 1.0 percent. Although drilling activity is expected to begin recovery in 2010, production is projected to decline relative to 2009 by 4.7 percent in the Federal GOM and by 0.4 percent in the Lower-48 non-GOM.

U.S. imports of liquefied natural gas (LNG) are estimated to have totaled about 350 billion cubic feet (Bcf) in 2008. Shipments of LNG to the United States are currently expected to rise to about 420 Bcf in 2009. However, limits to natural gas storage capacity outside the United States could unexpectedly boost U.S. imports of LNG during the summer months if global demand for natural gas does not increase as expected. U.S. LNG imports in 2010 are projected to reach a little more than 500 Bcf.

Inventories. On January 2, 2009, working natural gas in storage was 2,830 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 87 Bcf above the 5-year average (2004-2008), and 31 Bcf above the level during the corresponding week last year. Storage inventories are expected to finish the 2009 winter season (March 31, 2009) at over 1.5 trillion cubic feet (Tcf), about 270 Bcf above the corresponding period last year, but below the 1.7 Tcf mark recorded in 2006. The expected supply overhang throughout the 2009 injection season (April 1 to October 31) is projected to send the resulting working gas inventories near the previous high reported on November 2, 2007.

Prices. The Henry Hub spot price averaged $9.13 per Mcf in 2008 but ended the year averaging $5.99 per Mcf in December. Weak natural gas demand associated with poor economic conditions together with strong domestic production growth contributed to the recent decrease in prices that is expected to persist in 2009. On an annual basis, the Henry Hub spot price is expected to average $5.78 per Mcf in 2009 and $6.63 per Mcf in 2010. As consumption reacts to worsening economic factors, natural gas prices may need to fall further than currently forecast in order to restrain production activities and balance the market during the second half of 2009, particularly as inventory nears storage capacity. Prices are expected to begin to increase in 2010 as the economy improves.

Electricity

Consumption. Total electricity consumption is projected to decline by 0.5 percent in 2009 (U.S. Total Electricity Consumption), with an expected 3.6-percent decline in electricity sales to the industrial sector during due to economic conditions partially offset by slight growth in residential electricity sales. Total electricity consumption is expected to rebound in 2010 by 1.5 percent, driven by growth in the commercial and residential sectors.

Prices. A number of utilities that increased electricity rates last summer have begun reducing prices in response to fuel costs which have fallen from last year's peak levels.

Other utilities are pursuing slight increases to cover the cost of upgrades to generation and transmission facilities. Overall, U.S. residential electricity prices are forecast to grow by 2.3 percent in 2009 and by 2.0 percent in 2010 (U.S. Residential Electricity Prices).

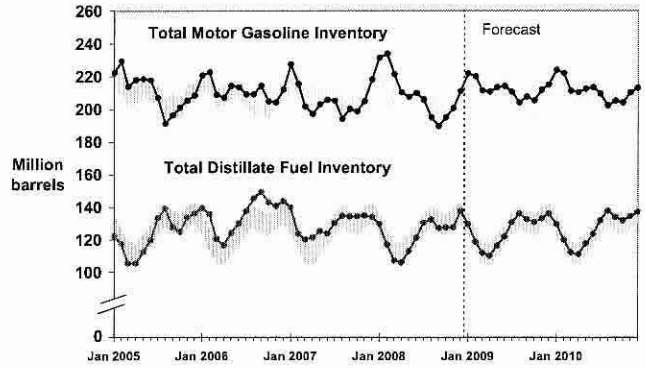
Coal

Consumption. The projected decline in electricity consumption, combined with projected increases from other generation sources (nuclear, petroleum, and wind) will lead to a 0.7-percent decline in electric-power-sector coal consumption, which accounts for more than 90 percent of total coal consumption. An expected increase in electricity consumption in 2010 of 1.5 percent will lead to a 1.9-percent increase in electric-power-sector coal consumption. Consumption growth in the coke plant sector is estimated to have been flat in 2008 but is expected to fall by 8.2 percent in 2009 and by 5 percent in 2010 due to the economic slowdown. Retail and other industrial sector coal consumption is expected to decline by 9.0 percent in 2009 but increase by 0.7 percent in 2010 as economic conditions improve (U.S. Coal Consumption Growth).

Production. A significant increase in coal exports in 2008 contributed to a 2.8-percent increase in coal production. Production is expected to fall in 2009 by 4.0 percent as lower total domestic coal consumption is combined with declines in exports and a small increase in imports. Production is projected to increase by 2.4 percent in 2010 as domestic consumption and exports increase with an improving economy (U.S. Annual Coal Production).

Exports. Reductions in global coal demand, coupled with the return to normal supply conditions in major coal-producing and exporting countries that experienced disruptions during 2008, are expected to reduce U.S. coal exports, which grew by nearly 40 percent in 2008, by 10 million short tons in 2009, a 12-percent decrease. The improving global economy in 2010 will spur global coal demand and this will lead to a projected 12-percent increase in exports.

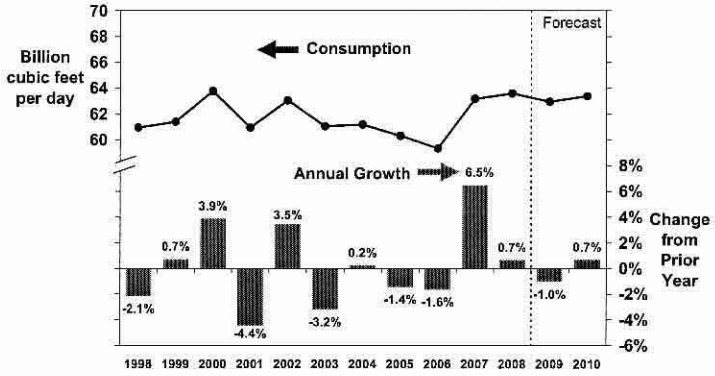
U.S. Gasoline and Distillate Inventories



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

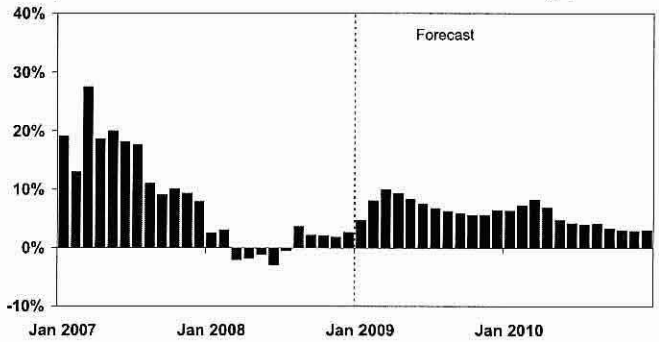
Short-Term Energy Outlook, January 2009

U.S. Total Natural Gas Consumption



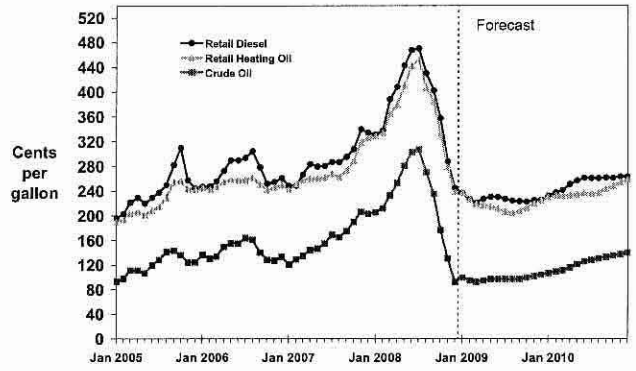
Short-Term Energy Outlook, January 2009

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



Short-Term Energy Outlook, January 2009

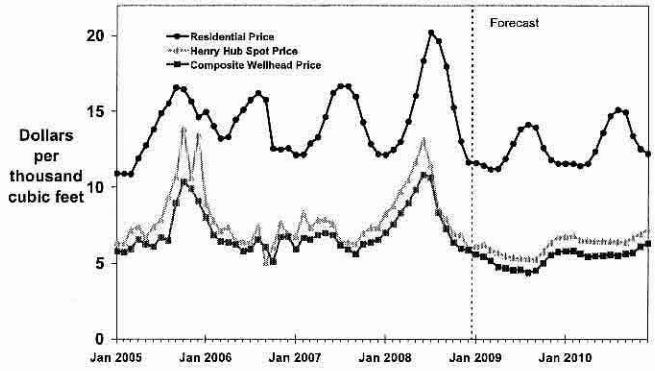
U.S. Distillate Fuel Prices



Retail prices include State and Federal taxes

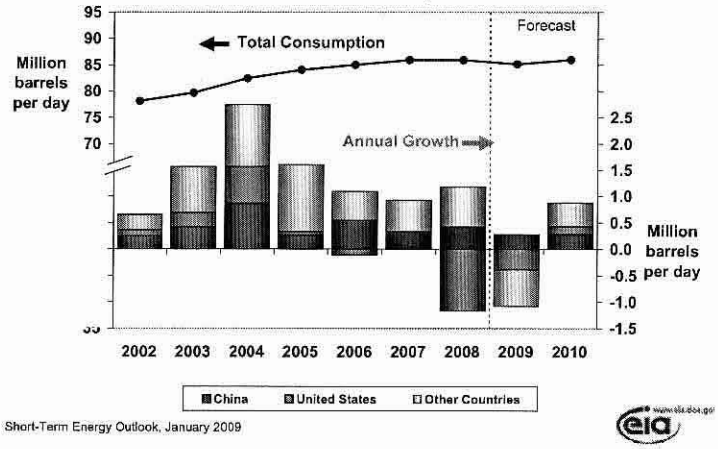
Short-Term Energy Outlook, January 2009

Natural Gas Prices



Short-Term Energy Outlook, January 2009

World Oil Consumption



Short-Term Energy Outlook, January 2009

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

NorthWestern Energy – Docket No. D2008.12.143

On December 12, 2008, NorthWestern Energy filed with the Montana Public Service Commission (Commission) to change its rates to reflect changes in state and local taxes and fees and to track these changes such that the actual level of taxes and fees is recovered. On December 23, 2008, the Commission approved the decrease in rates to be effective with service rendered on or after January 1, 2009.

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

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS TARIFF SHEET
NORTH DAKOTA GAS
EFFECTIVE MARCH 2009

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
Gas Cost Adjustment:				
Gas Cost Level (Exhibit B)	$5.288	$5.370	$4.384	$4.364
Prior Gas Cost	6.507	6.589	5.600	5.575
Current Gas Cost Adjustment	($1.219)	($1.219)	($1.216)	($1.211)
Surcharge Adjustment:				
Current Adjustment	$0.845	$0.845	$0.349	$0.167
Prior Adjustment	0.845	0.845	0.349	0.167
Change in Surcharge Adjustment	$0.000	$0.000	$0.000	$0.000
Market Based Pricing Differential				
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
Net Increase (Decrease) in Gas Costs	**($1.219)**	**($1.219)**	**($1.216)**	**($1.211)**
Gas Cost Level	$5.288	$5.370	$4.384	$4.364
Plus: Surcharge	0.845	0.845	0.349	0.167
Total Gas Cost Level in Tariff Rates	$6.133	$6.215	$4.733	$4.531

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

	Amount
Total Gas Costs 1/	$72,364,390
Residential and General Service dk Requirements 2/	13,745,731
Average Cost of Gas per dk	$5.264
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.288
Less: Gas Cost Level in Rates 3/	6.507
Current Gas Cost Adjustment	**($1.219)**

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 December 31, 2008, adjusted for losses at .45%

3/ Gas Cost Level in Current Tariff Rates Case No. PU-08-924:

Cost of Purchased Gas	$6.478
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$6.507

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

Summer - June - September	
Total Gas Costs 1/	$72,364,390
Less: Annual MDDQ Costs 1/	11,530,215
Total Gas Costs excluding MDDQ	$60,834,175
Firm Service Requirements 1/	13,745,731
Other Gas Costs per Dk (excluding MDDQ)	$4.426
Summer Seasonal Rate, adjusted for losses 2/	4.446
Winter - October - May	
Annual MDDQ Costs 1/	$11,530,215
Winter Firm Service Requirements	12,532,133
MDDQ Costs per Winter Dk	$0.920
Add: Other Gas Costs per Dk	4.426
Winter Seasonal Rate	5.346
Winter Seasonal Rate, adjusted for losses 2/	$5.370
Less: Gas Cost Level in Rates 3/	6.589
Current Gas Cost Adjustment	**($1.219)**

1/ Exhibit B, page 1.
2/ Loss factor of .45%.
3/ Gas Cost Level in Current Tariff Rates Case No. PU-08-924:

	Summer	Winter
Cost of Purchased Gas	$5.639	$6.559
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	$5.664	$6.589

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

	Amount
Total Gas Costs 1/	$15,284,978
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	$4.364
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.384
Less: Gas Cost Level in Rates 2/	5.600
Current Gas Cost Adjustment	**($1.216)**

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/ Gas Cost Level in Current Tariff Rates Case No. PU-08-924:

Cost of Purchased Gas	$5.575
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$5.600

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

	Amount
Total Gas Costs 1/	$3,840,054
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	$4.364
Less: Gas Cost Level in Rates 2/	5.575
Current Gas Cost Adjustment	**($1.211)**

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-08-924:
Cost of Purchased Gas $5.575

Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
March 2009 PGA

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

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

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

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

Source Gas (f/k/a Kinder Morgan, Inc. and 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	0.170	N.A.	N.A.	3.290
MINIMUM A/B/	RATE PER DKT	3.120	0.170	N.A.	N.A.	3.290
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.170	N.A.	N.A.	31.054
MINIMUM A/B/	RATE PER DKT	3.120	0.170	N.A.	N.A.	3.290

A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 2.978%, CONSISTING OF 2.851% 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 0.646 CENTS, CONSISTING OF 0.721 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 0.535%, CONSISTING OF 0.670% 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 0.476 CENTS, CONSISTING OF 0.428 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.

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.

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

Twelfth Revised Sheet No. 99
Superseding
Eleventh Revised Sheet No. 99

STATEMENT OF RATES

	Commodity Rate
Annual Charge Adjustment (ACA) Rate (per Dekatherm) 1/	$0.0017
Compressor Usage Surcharge (per 100 Dekatherm-miles) 2/	$0.0023

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.

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) $168.24/10^3m^3$
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point
3. Rate Schedule FT-D	FT-D Demand Rate per month $ 4.45/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 $ $0.48/10^3m^3$
7. Rate Schedule FT-P	Refer to Attachment "2" for applicable FT-P Demand Rate per month
8. Rate Schedule LRS	Contract Term — Effective LRS Rate ($/10^3m^3$/day) 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 $129.55/10^3m^3$
11. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate & Surcharge for each Receipt Point
12. Rate Schedule IT-D	IT-D Rate $ 0.1606/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	Schedule No — PT Rate — PT Gas Rate 9006-01000-0 — $ 67.22/d — 1.0 10^3m^3/d
15. Rate Schedule OS	Schedule No. — Charge 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_2	Tier — CO_2 Rate ($/10^3m^3$) 1 630.10 2 503.07 3 349.65

NATURAL GAS TARIFF

NorthWestern Energy

	15th	Revised	Sheet No.	80.1
Canceling	14th	Revised	Sheet No.	80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour			Per Meter Charge	
5,001	to	10,000	$ 100.75	(R)
10,001	to	30,000	$ 144.90	(R)
>30,000			$ 321.50	(R)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

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

Transmission Commodity Rate (Monthly Rate per Dkt):

Maximum	$ 0.062431	(R)
Minimum	$ 0.017935	
GTAC Amortization	$ 0.019020	
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)

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

MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS
EFFECTIVE MARCH 2009

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2008	$11,590,437	$1,100,150	$3,040,391
November	10,346,230	998,226	2,461,118
December	4,059,007	621,772	1,157,690
January 2009	(285,129)	244,598	(399,869)
February	(3,511,512)	(26,038)	(1,326,411)
March	(4,065,188)	(108,512)	(1,912,590)
April	(4,055,341)	(133,509)	(1,740,961)
May	(2,013,212)	(40,985)	(1,030,489)
June	986,561	106,420	(45,248)
July	4,273,797	269,577	980,307
August	7,542,441	431,247	1,986,311
September	9,994,649	843,147	2,781,123
October	11,068,918	876,422	3,035,817
13 month average	$3,533,204	$398,655	$691,322
Rate of Return	8.791%	8.791%	8.791%
Return	$310,604	$35,046	$60,774
Return Requirement - Revenue	$514,330	$58,033	$100,636

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
Balance @ July 31, 2008									**$11,725,941**
August	$891,059	$0	$11,188	$902,247	229,458	($0.233)	($33,640) 2/	$935,887	12,661,828
September	(334,878)	0	7,928	(326,950)	286,271	0.000	0	(326,950)	12,334,878
October	(838,712)	0	4,631	(834,081)	479,761	0.845	183,238 3/	(1,017,319)	11,317,559
November	469,987	0	1,170	471,157	969,656	0.845	819,360	(348,203)	10,969,356
December	449,232	4,160 4/	179	453,571	1,894,641	0.845	1,600,972	(1,147,401)	9,821,955
Balance @ December 31, 2008									**$9,821,955**

1/ Interest calculated at 90 day Treasury Note rate.
2/ Reflects 144,378.1 Dk @ ($0.233).
3/ Reflects 216,850.3 Dk @ $0.845.
4/ Prior period adjustment related to Minot Air Force Base account switch from firm to interruptible service.

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

	(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
Balance @ July 31, 2008									**$291,680**
August	$155,690	$0	$284	$155,974	35,230	($0.416)	($14,655) 2/	$170,629	462,309
September	(28,185)	0	292	(27,893)	37,026	0.000	0	(27,893)	434,416
October	(163,211)	0	165	(163,046)	34,765	0.349	1 3/	(163,047)	271,369
November	59,141	0	28	59,169	64,484	0.349	22,505	36,664	308,033
December	(30,525)	0	5	(30,520)	113,467	0.349	39,600	(70,120)	237,913
Balance @ December 31, 2008									**$237,913**

1/ Interest calculated at 90 day Treasury Note rate.
2/ Reflects 35,229 Dk @ ($0.416).
3/ Reflects 2 Dk @ $0.349.

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

	(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
Balance @ July 31, 2008									**$121,188**
August	$164,522	$0	$121	$164,643	6,154	($0.135)	($831)	$165,474	286,662
September	50,064	0	182	50,246	6,042	0.000	0	50,246	336,908
October	(44,176)	0	128	(44,048)	10,916	0.167	0 2/	(44,048)	292,860
November	24,159	0	31	24,190	33,725	0.167	5,632	18,558	311,418
December	(15,997)	(4,986) 3/	5	(20,978)	56,147	0.167	9,377	(30,355)	281,063
Balance @ December 31, 2008									**$281,063**

1/ Interest calculated at 90 day Treasury Note rate.
2/ Reflects 0 Dk @ $0.167
3/ Prior period adjustment related to Minot Air Force Base account switch from firm to interruptible Service.