

June 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 (76th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered July 1, 2009.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.231 per dk since the last filing due to an increase in the overall market price of gas. Attachment B explains the reasons for the increase in the market price of gas.

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 July 2009.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.231 per dk for residential and firm general service customers, an increase of \$0.224 per dk for small and large interruptible customers and an increase of \$0.223 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 July 2009. The average cost of gas for firm customers, adjusted for losses, is \$4.383.

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 an increase of approximately \$67,700 during the month of July 2009. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 90,936 customers in North Dakota as of May 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
Vice President – Regulatory Affairs

Attachment

Attachment A

**Rate Summary Sheet
(Proposed)**



Montana-Dakota Utilities Co.

A Division of MDU Resources Group, Inc.
 400 N 4th Street
 Bismarck, ND 58501

State of North Dakota Gas Rate Schedule

NDPSC Volume 7
 76th Revised Sheet No. 3
 Canceling 75th Revised Sheet No. 3

RATE SUMMARY SHEET

Page 1 of 2

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	\$0.30 per day	\$0.812	\$5.220	\$6.032
Air Force Rate 64	7	\$1,000.00 per month \$135.00 per month			
Minot Air Force Base					
PAR Site					
Firm Service			\$0.138	\$5.220	\$5.358
Interruptible Service - PAR			\$0.120	\$3.797	\$3.917
Interruptible Service - MAFB			\$0.120	\$3.599	\$3.719
Firm General Service Rate 70	13	\$0.52 per day \$1.75 per day			
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet			\$0.597	\$5.220	\$5.817
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$3.797	(Maximum) \$4.668
Optional Seasonal Gas Service Rate 72	15	\$0.52 per day \$1.75 per day			
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet					
Winter Gas Usage			\$0.597	\$5.309	\$5.906
Summer Gas Usage			\$0.597	\$4.358	\$4.955
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.016	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.016	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$3.797	(Maximum) \$4.516
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$7.350	\$8.162
Firm General Propane Rate 92	34	\$0.52 per day \$1.75 per day			
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet			\$0.597	\$7.350	\$7.947

Date Filed: June 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**

July 2009

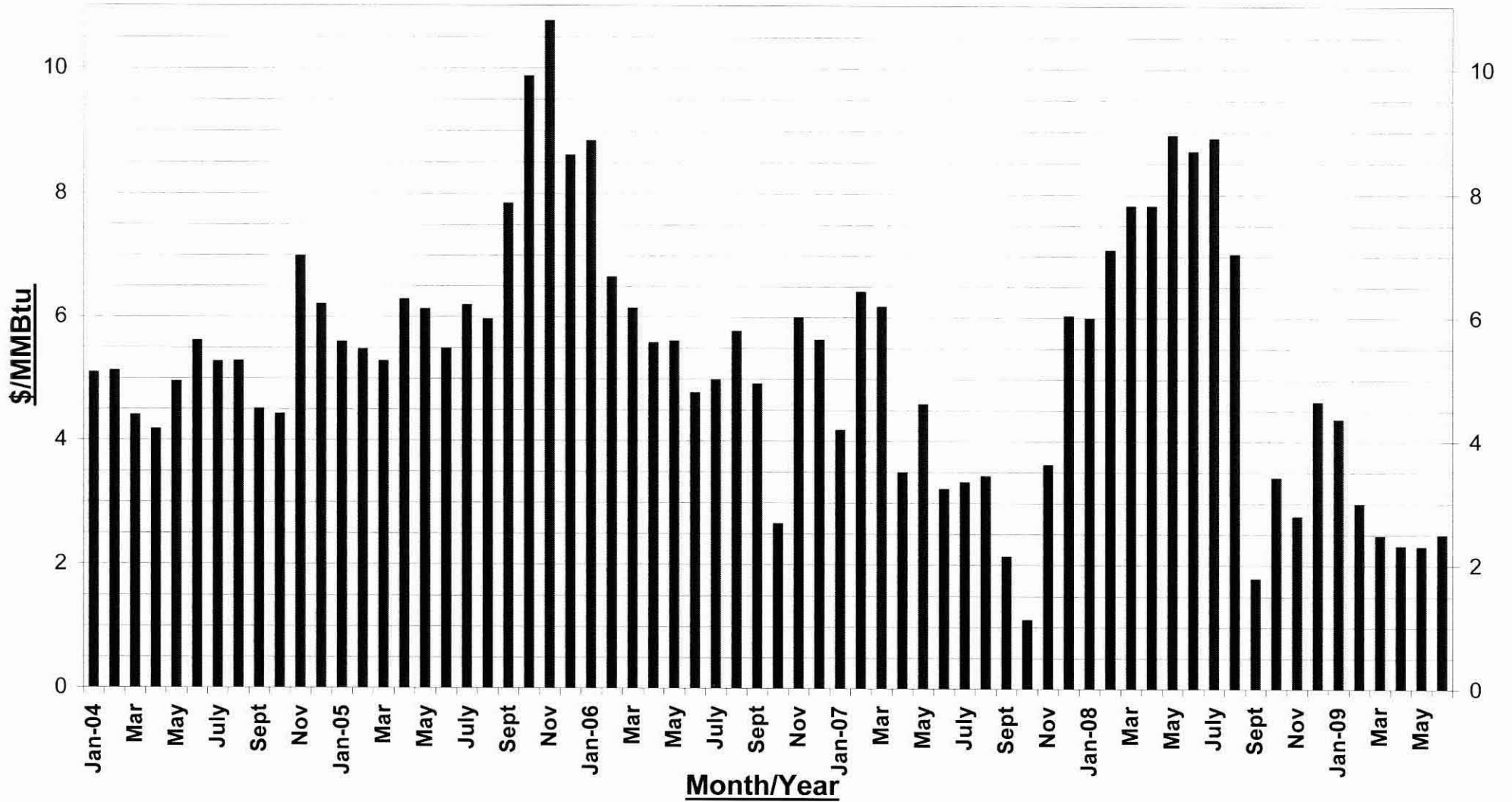
The established June monthly price for the Rocky Mountain CIG Index increased from the previous month. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid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

Factors contributing to rising natural gas prices include increased cooling demand for natural gas and rising crude oil prices. Additional factors include a weakening U.S. dollar and a potential incipient recovery in the U.S economy. The Energy Information Administration (EIA) reported storage levels nationwide as of May 29, 2009 were 22.1 percent above the five-year average and 30.5 percent above last year's balance.

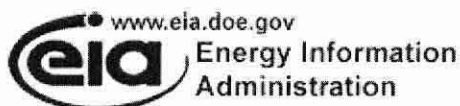
The EIA provides various publications on energy issues. The information is available on their website: <http://www.eia.doe.gov>.

The June 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-\$2.82



June 2009

Short-Term Energy Outlook

June 9, 2009 Release

Highlights

- Spot prices for crude oil and petroleum products have increased over the past month. The price of West Texas Intermediate (WTI) crude oil is expected to average \$67 per barrel for the second half of 2009, an increase of about \$16 compared with the first half of the year.
- The average U.S. price for regular-grade gasoline, at \$2.62 per gallon on June 8, was almost 60 cents per gallon higher than its price at the end of April. Regular-grade gasoline prices are expected to reach their summer seasonal peak in July, with a monthly average close to \$2.70 per gallon. The annual average regular-grade gasoline retail price in 2009 is expected to be \$2.33 per gallon, rising to \$2.56 in 2010. The annual average diesel fuel retail prices are expected to be \$2.40 and \$2.67 per gallon in 2009 and 2010, respectively.
- The monthly average Henry Hub natural gas spot price is expected to stay under \$4 per thousand cubic feet (Mcf) until late in the year as abundant natural gas supplies converge with weak demand driven by an 8-percent decline in industrial sector consumption. The price is projected to increase from an average of \$4.13 per Mcf in 2009 to an average \$5.49 per Mcf in 2010 as expected economic growth boosts industrial consumption of natural gas.
- Based on the current Atlantic hurricane season outlook from the National Oceanic and Atmospheric Administration (NOAA), EIA estimates expected production shut-ins on the U.S. Gulf Coast during the upcoming hurricane season (June through November) of about 4.5 million barrels for crude oil and 36 billion cubic feet for natural gas (see the [*2009 Outlook for Hurricane Production Outages in the Gulf of Mexico*](#)). Actual shut-ins are likely to differ significantly from this expectation depending on the number, track, and strength of hurricanes as the season progresses.

Global Petroleum

Overview. Oil prices rose for the third consecutive month in May, driven in part by expectations of a global economic recovery and future increases in oil consumption. In addition, a weaker dollar and increasing financial market activity are prompting higher prices for commodities, overshadowing weak oil supply and demand fundamentals. The weaker dollar may indicate that economic activity abroad, especially in Asia, is stronger than currently estimated, which would provide an upside risk to the oil price forecast. Downside risks, such as continuing weak demand as indicated by sluggish first quarter 2009 oil consumption data, high inventories, and increased surplus production capacity levels within the Organization of the Petroleum Exporting Countries (OPEC) could moderate the upward price pressure, especially if the global economic recovery is delayed and/or weaker than expected.

Consumption. World crude oil and liquid fuels consumption remains below year-ago levels. Total consumption during the fourth quarter of 2008 was 2.8 million barrels per day (bbl/d) below fourth quarter 2007 levels because of the global economic downturn. The year-over-year decline in total consumption increased in the first quarter of 2009 to an estimated 3.4 million bbl/d. Oil consumption in countries that are members of the Organization for Economic Cooperation and Development (OECD) fell by 2.4 million bbl/d in the first quarter of 2009, compared to the first quarter of 2008, accounting for more than 70 percent of the total decline. The rate of consumption decline is expected to moderate later in the year. After falling by an average 1.8 million bbl/d in 2009, global consumption is projected to grow by 0.7 million bbl/d in 2010 in response to expected positive global economic growth ([World Liquid Fuels Consumption Chart](#)).

Non-OPEC Supply. After falling by 270,000 bbl/d in 2008, total non-OPEC supply is projected to rise by 400,000 bbl/d in 2009 and remain almost flat at the 2009 level in 2010. Over the forecast period, higher output in a few countries, such as Brazil, the United States, and Azerbaijan, is expected to offset declining production in Mexico, the North Sea, and Russia ([Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart](#)).

OPEC Supply. OPEC crude oil production is estimated to have averaged approximately 28.7 million bbl/d in the first quarter of 2009 and is projected to average 28.6 million bbl/d in the second quarter. This represents a roughly two-thirds compliance rate with announced production cuts. OPEC, which held production targets steady at its May 28 meeting, plans to meet again on September 9 in Vienna to review market conditions. Over the forecast period, prospects for an economic recovery and a rebound in oil consumption signal higher demand for OPEC oil.

OPEC crude oil production is projected to average 28.5 million bbl/d in 2009, before rising slightly to 28.8 million bbl/d in 2010. However, OPEC production capacity is expected to rise by 1.2 million bbl/d by the end of next year, relative to the end of 2008, which will increase surplus production capacity and help mitigate upward price pressure.

Inventories. Revised data indicate that OECD commercial inventories at year-end 2008 stood at 2.7 billion barrels. At 57 days of forward cover, OECD commercial inventories were well above average levels for that time of year (Days of Supply of OECD Commercial Stocks Chart). Preliminary estimates suggest that OECD commercial inventories increased by 46 million barrels during the first quarter of 2009, rather than declining seasonally, reaching 60 days of forward cover. The United States was responsible for this counter-seasonal build in OECD commercial inventories, with other OECD-member commercial stocks declining slightly. However, with the expected global demand increase in 2010 not forecast to be fully matched by increased supply, global inventories are expected to fall slightly over the forecast period.

U.S. Crude Oil and Liquid Fuels

Consumption. Based on the weak economy, total consumption of liquid fuels and other petroleum products is projected to contract by 550,000 bbl/d (2.9 percent) in 2009 (U.S. Petroleum Products Consumption Growth Chart), including a decline of 220,000 bbl/d (5.5 percent) in distillate fuel consumption and about 100,000 bbl/d (6.9 percent) in jet fuel consumption. Motor gasoline, however, is projected to increase by 30,000 bbl/d (0.3 percent) as a result of the substantial declines in retail prices from last summer and the stabilization of real disposable income. The gradual economic recovery in 2010 is expected to contribute to a 300,000-bbl/d (1.6 percent) increase in total liquid fuels consumption.

Production. Total domestic crude oil production averaged 4.96 million bbl/d in 2008, down from 5.06 million bbl/d in 2007 (U.S. Crude Oil Production Chart). Production is expected to increase to an average of 5.27 million bbl/d in 2009 and 5.32 million bbl/d in 2010, including an estimated expectation, with a wide range of uncertainty, of hurricane-induced outage of about 4.5 million barrels for the offshore region in 2009 (see the 2009 Outlook for Hurricane Production Outages in the Gulf of Mexico).

Prices. WTI crude oil prices, which averaged \$99.57 per barrel in 2008 (Crude Oil Prices Chart), are projected to average \$58.70 per barrel in 2009 and \$67.42 per barrel in 2010. As always, energy price forecasts are highly uncertain. One measure of how the market reflects this uncertainty is the sizable participation in near-term options on

crude oil futures contracts at strike prices that are significantly different from current futures market prices. This reflects the tendency for crude oil prices to fluctuate within a wide range in a relatively short period.

EIA projects that regular-grade motor gasoline retail prices, which averaged \$3.26 per gallon in 2008, will average \$2.33 per gallon this year, up 21 cents per gallon from last month's *Outlook* projection. These prices are projected to rise to \$2.56 per gallon in 2010, 26 cents above that projected in the previous *Outlook*. Diesel fuel retail prices, which averaged \$3.80 per gallon in 2008, are projected to average \$2.40 per gallon in 2009, up 14 cents from the previous *Outlook*. Diesel fuel retail prices are projected to average \$2.67 per gallon in 2010, up 19 cents per gallon from the previous *Outlook*.

Natural Gas

Consumption. Total natural gas consumption is projected to decline by 2.2 percent in 2009 and then increase slightly in 2010 (Total U.S. Natural Gas Consumption Growth Chart). While total natural gas consumption remains hampered by the broad economic downturn, the persistence of low natural gas prices into the fourth quarter of 2009 is expected to lead to a 2.7-percent increase in electric power sector consumption in 2009, offsetting a portion of the 8-percent decline expected in industrial sector consumption. Additional declines expected in the residential and commercial sectors this year also contribute to the lower 2009 consumption estimate. The anticipation of some economic recovery in 2010 is the basis for slight consumption increases in the commercial and industrial sectors next year, with little change expected in the residential sector. Furthermore, if the dollar remains weak and natural gas prices remain relatively low, consumption in the industrial sector may be bolstered by increased exports of natural-gas-intensive products. Finally, consumption in the electric power sector is expected to remain flat in 2010 as natural gas prices rise relative to coal prices.

Production and Imports. Total U.S. marketed natural gas production is expected to decline by 1.1 percent in 2009 and by 2.6 percent in 2010. Low natural gas prices brought about by the current economic slump have had a dramatic impact on recent drilling activity. According to Baker Hughes, total working natural gas rigs are now down 56 percent from the September 2008 peak. Although a corresponding decline in production has yet to appear in data through March 2009, total U.S. marketed production is expected to drop by nearly 5 billion cubic feet (Bcf) per day between the first and fourth quarters of 2009. The decline in annual production is expected to occur almost exclusively in the Lower-48 non-Gulf of Mexico (GOM) this year, more than offsetting the small expected increase in GOM output. This projection includes an estimated expectation of hurricane-induced outage of about 36 Bcf for the offshore

region in 2009 (see the [2009 Outlook for Hurricane Production Outages in the Gulf of Mexico](#))

The lagged effect of this year's drilling pullback is also expected to result in lower natural gas production in 2010. However, EIA does not anticipate that working rigs and natural gas prices need to return to 2008 levels for production to increase. Recent improvements in technology have reduced finding and development costs, lowered completion times, and greatly enhanced well productivity, increasing the production potential from domestic sources. As a result, production is expected to respond adequately, with a shorter lag, to sustained increases in demand.

U.S. liquefied natural gas (LNG) imports are expected to increase to about 495 Bcf in 2009, from 352 Bcf in 2008, due to weakness in demand for LNG in the global market. The severe economic contractions in the LNG-consuming countries of Asia have increased the amount of available LNG in the global market, elevating LNG purchases in Europe, where natural gas prices remain slightly above those in the United States. In the coming months, as storage facilities in Europe are replenished and new liquefaction capacity comes online, available LNG cargoes are expected to be directed to U.S. terminals. While there is still a degree of uncertainty associated with the start-up of new liquefaction capacity and the availability of shipments, higher than expected LNG imports would almost certainly have a dampening effect on prices and cause lower domestic natural gas production or pipeline imports.

Inventories. On May 29, 2009, working natural gas in storage was 2,337 Bcf ([U.S. Working Natural Gas in Storage Chart](#)). Current inventories are now 423 Bcf above the 5-year average (2003–2007) and 546 Bcf above the level during the corresponding week last year. The estimated inventory build in May was 465 Bcf, the largest increase for this particular month since at least 1976, when records were first kept. Working natural gas stocks are now expected to reach 3,659 Bcf at the end of the 2009 injection season (October 31), roughly 94 Bcf above the previous record of 3,565 Bcf reported for the end of October 2007.

Prices. The Henry Hub spot price averaged \$3.96 per Mcf in May, \$0.33 per Mcf above the average spot price in April. Prices remain low as natural gas supplies continue to seep into a weak market. As working natural gas inventory nears storage capacity limits, prices may need to decline further to induce necessary adjustments in supply or stimulate demand. Anticipated economic recovery and seasonal space-heating demand are expected to contribute to some price strength in early 2010, and enhanced production capability from domestic supply sources is expected to limit sustained upward price movements throughout the forecast period. The Henry Hub spot price is expected to average \$4.13 per Mcf in 2009 and \$5.49 per Mcf in 2010.

Electricity

Consumption. During the first quarter of 2009, total consumption of electricity fell by an estimated 3 percent compared to the same period last year primarily because of weak industrial consumption. Growth in residential retail sales during the second half of this year is expected to slightly offset continued declines in industrial electricity sales. Total consumption is projected to fall by 1.8 percent for the entire year of 2009 and then rise by 1.2 percent in 2010 (U.S. Total Electricity Consumption Chart).

Prices. Retail residential electricity prices increased an estimated 8 percent during the first quarter of 2009 compared to the first quarter of 2008 (U.S. Residential Electricity Prices Chart) because of regulatory lags in the pass-through of fuel costs. However, lower fuel costs for generation are expected to be passed through to retail consumers later this year, keeping the annual 2009 growth in prices around 5.0 percent. Residential prices are expected to grow by just 2.4 percent during 2010.

Coal

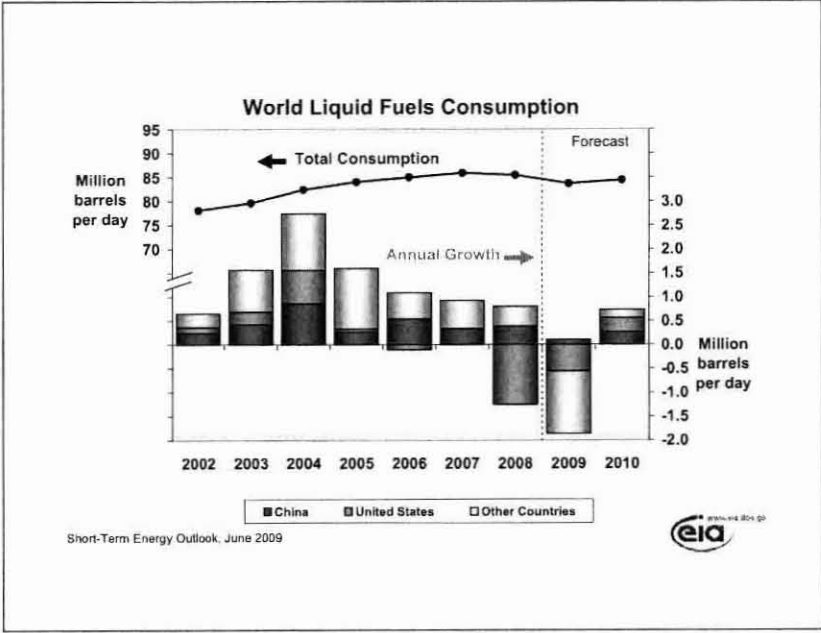
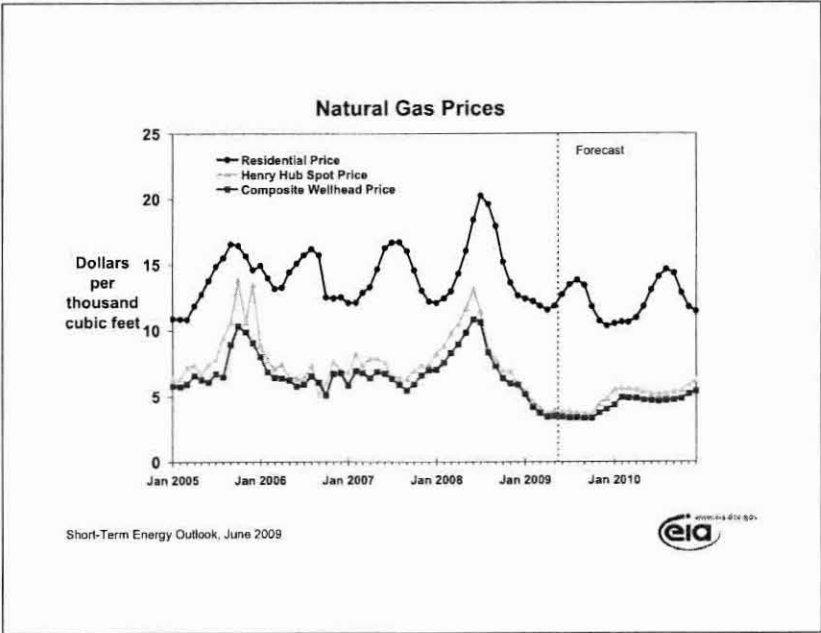
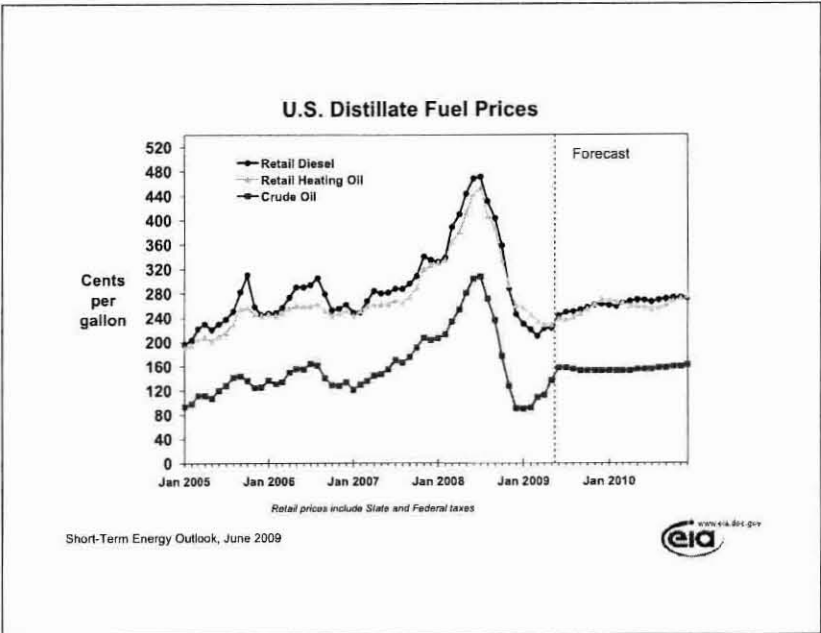
Consumption. A decline in overall electricity generation, combined with projected increases from natural gas, nuclear, and renewable (hydroelectric and wind) generation sources, are projected to lead to a 4.6-percent decline in coal consumption in the electric power sector this year. The projected electric power sector consumption of 994 million short tons (MMst) in 2009 is the first time since 2002 that annual consumption would be below the billion short ton level. An expected increase in total electricity generation of 1.5 percent in 2010 is expected to lead to a 1.7-percent increase in electric-power-sector coal consumption. Non-power-sector coal consumption, for both steam and coke production, is projected to decline by 33 percent in 2009, reflecting very weak industrial activity (U.S. Coal Consumption Growth Chart).

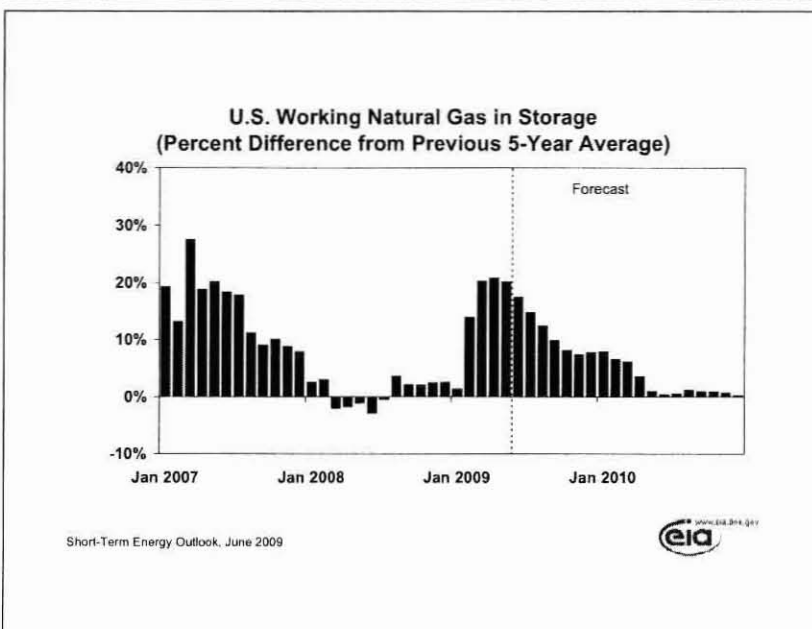
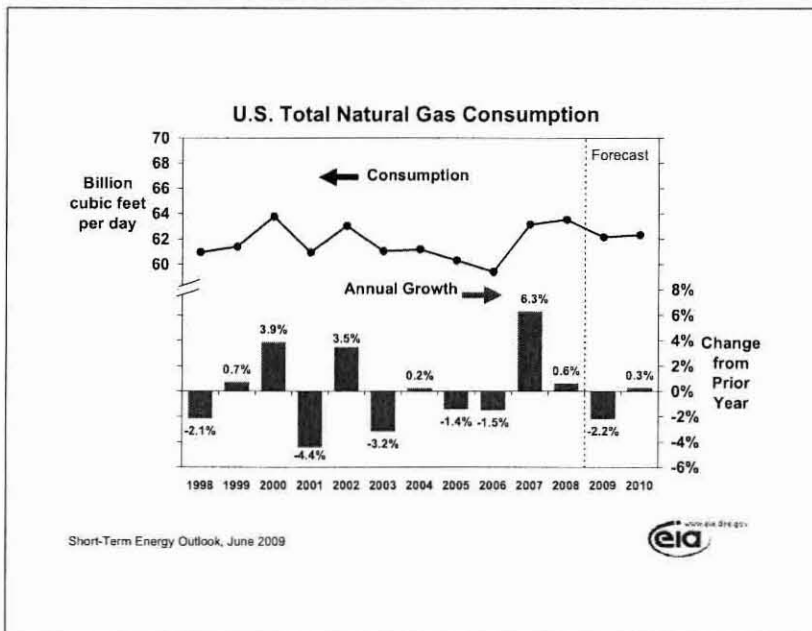
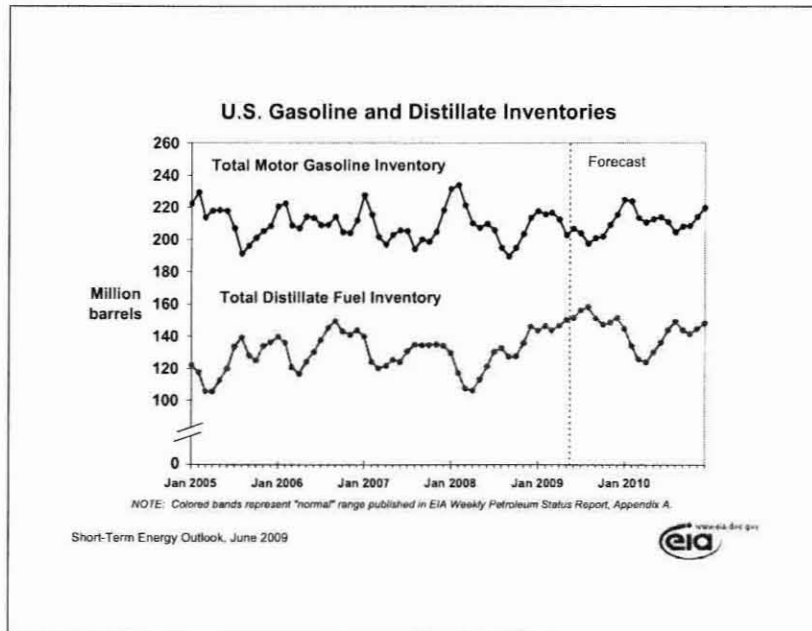
Production. Production is expected to fall by about 7 percent in 2009 in response to lower total domestic coal consumption, export declines, and high coal inventories. The April 2009 production estimate of 88.3 MMst is the lowest monthly coal production figure since May 2004. Conversely, the estimated March 2009 secondary coal inventories of 183.9 MMst is the highest in over 20 years (secondary inventories were 185.5 MMst in December 1987). Production is projected to increase slightly (0.6 percent) in 2010 as domestic consumption and exports increase with an improving economy (U.S. Annual Coal Production Chart).

Exports. Reductions in global coal demand are expected to reduce U.S. coal exports by about 16.5 million short tons, a 20-percent decrease, in 2009. The projected

rebound in global economic activity is expected to increase global coal demand and lead to a 24-percent increase in exports in 2010.

Prices. Despite declines in electricity demand and lower fuel costs, the annual average delivered coal price is projected to increase to \$2.16 per million Btu (MMBtu) in 2009 due to a pricing lag between mine-mouth and delivered coal prices caused by long-term coal contracts. Current delivered prices were set when contracts were entered into during a period of high prices for all fuels one year or more ago. Although record increases in spot prices (some well over 100 percent) for several types of coal contributed to the increase in the cost of coal, spot market purchases make up only a small portion of total coal consumed. The average delivered coal price is expected to decline to \$1.98 per MMBtu in 2010, as expiring high-priced contracts are replaced.





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

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$4.383	\$3.521	\$3.448	\$3.432
Prior Gas Cost	4.152	3.292	3.224	3.209
Current Gas Cost Adjustment	\$0.231	\$0.229	\$0.224	\$0.223
<u>Surcharge Adjustment:</u>				
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
<u>Market Based Pricing Differential</u>				
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	<u>\$0.231</u>	<u>\$0.229</u>	<u>\$0.224</u>	<u>\$0.223</u>
Gas Cost Level	\$4.383	\$3.521	\$3.448	\$3.432
Plus: Surcharge	0.845	0.845	0.349	0.167
Total Gas Cost Level in Tariff Rates	<u>\$5.228</u>	<u>\$4.366</u>	<u>\$3.797</u>	<u>\$3.599</u>

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

	Amount
Total Gas Costs 1/	\$58,507,277
Residential and General Service dk Requirements 2/	13,410,923
Average Cost of Gas per dk	\$4.363
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.383
Less: Gas Cost Level in Rates 3/	4.152
Current Gas Cost Adjustment	\$0.231

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -14 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C.

2/ Normalized dk sales for the twelve months ended April 30, 2009, adjusted for losses at .45%

3/ Gas Cost Level in Current Tariff Rates Case No. PU-09-194:

Cost of Purchased Gas	\$4.133
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.152

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

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$58,507,277
Less: Annual MDDQ Costs 1/	<u>11,501,344</u>
Total Gas Costs excluding MDDQ	\$47,005,933
Firm Service Requirements 1/	13,410,923
Other Gas Costs per Dk (excluding MDDQ)	\$3.505
Summer Seasonal Rate, adjusted for losses 2/	3.521
Less: Gas Cost Level in Rates 3/	<u>3.292</u>
Current Gas Cost Adjustment	<u><u>\$0.229</u></u>

<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,501,344
Winter Firm Service Requirements	12,141,417
MDDQ Costs per Winter Dk	\$0.947
Add: Other Gas Costs per Dk	<u>3.505</u>
Winter Seasonal Rate	4.452
Winter Seasonal Rate, adjusted for losses 2/	\$4.472

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-09-194:

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$3.277	\$4.222
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$3.292	\$4.241

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

	Amount
Total Gas Costs 1/	\$12,022,166
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$3.432
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.448
Less: Gas Cost Level in Rates 2/	3.224
Current Gas Cost Adjustment	\$0.224

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -14 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C.

2/ Gas Cost Level in Current Tariff Rates Case No. PU-09-194:

Cost of Purchased Gas	\$3.209
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.224

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

	<u>Amount</u>
Total Gas Costs 1/	\$3,020,337
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$3.432
Less: Gas Cost Level in Rates 2/	<u>3.209</u>
Current Gas Cost Adjustment	<u><u>\$0.223</u></u>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -14 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C, allocated to Air Force interruptible on MDDQ.

2/ Gas Cost Level in Current Tariff Rates Case No. PU-09-194:
Cost of Purchased Gas \$3.209

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

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

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

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

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

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

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

SourceGas Distribution LLC – Exhibit B, Page 14 for Schedule TC.

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FT-1						
RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	737.928	N.A.	N.A.	N.A.	737.928
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
COMMODITY CHARGE						
MAXIMUM A/B/	RATE PER DKT	3.120	0.170	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 2.262%, CONSISTING OF 2.175% FOR THE CURRENT PERCENTAGE AND 0.087% FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR TRANSPORTATION. THE APPLICABLE RATE IS 0.241 CENTS, CONSISTING OF 0.241 CENTS FOR THE CURRENT RATE AND 0.000 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES

RATE SCHEDULE FTN-1						

RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	47.491	N.A.	N.A.	N.A.	47.491
MINIMUM	RATE PER EQV. DKT PER MO.	1.589	N.A.	N.A.	N.A.	1.589

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

Issued on: May 19, 2005

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 0.266%, CONSISTING OF 0.369% FOR THE CURRENT PERCENTAGE AND (0.103%) FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR STORAGE. THE APPLICABLE RATE IS 0.093 CENTS, CONSISTING OF 0.000 CENTS FOR THE CURRENT RATE AND 0.093 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

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

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.

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

Issued on: August 26, 2008

Effective on: October 1, 2008

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 ³ m ³		
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D	FT-D Demand Rate per month \$ 4.45/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 ³ m ³		
7. Rate Schedule FT-P	Refer to Attachment "2" for applicable FT-P Demand Rate per month		
8. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10³m³/day)</u>	
	1-5 years	10.08	
	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 ³ m ³	
11. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate & Surcharge for each Receipt Point		
12. Rate Schedule IT-D	IT-D Rate \$ 0.1606/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 ³ m ³ /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 ₂	<u>Tier</u>	<u>CO₂ Rate (\$/10³m³)</u>	
	1	630.10	
	2	503.07	
	3	349.65	

NATURAL GAS TARIFF



Canceling $\frac{15^{th}}{14^{th}}$ Revised Revised Sheet No. 80.1
Sheet No. 80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge	
5,001 to 10,000	\$ 100.75	(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.

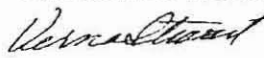
MINIMUM BILL: Per respective contracts.

(continued)

Commission Approved: December 23, 2008
Docket No.: D2008.12.143
Tariff Letter No. 148-G

Effective for service rendered on or after
January 1, 2009

PUBLIC SERVICE COMMISSION

 Secretary

GAS RATE SCHEDULE

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

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

Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is \$2.398 per dekatherm.

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

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5
First Revised Sheet No. 12
Cancels Original Sheet No. 12

Statement of Firm and Interruptible Transportation Service Rates
Applicable to Shippers Not Receiving
Choice Gas Service
Rate Schedule TC 1/
Casper Division

<u>Division</u>	<u>Receipt Point</u>	<u>Delivery Point</u>	<u>Monthly Customer Charge</u>	<u>Maximum Transportation Charge 2/</u>	<u>Minimum Transportation Charge 2/</u>	<u>Fuel Reimbursement Quantity Percentage 3/</u>
TC (Casper)						
Firm						
Transportation	MLI	MLI	\$0.00	\$1.0551	\$0.0100	0.781%
	MLI	MLE	\$163.00	\$1.0551	\$0.0100	0.781%
	MLI	DSE	\$163.00	\$2.0988	\$0.0200	3.425%
Interruptible						
Transportation 4/	MLI	MLI	\$0.00	\$0.8439	\$0.0100	0.781%
	MLI	MLE	\$163.00	\$0.8439	\$0.0100	0.781%
Administrative Fee 5/			\$325.00			

1/ Casper Division service area is defined on Sheet Nos. 3 and 4 of this Tariff.

2/ All charges are per Dekatherm.

3/ For fuel, lost and unaccounted for gas, SourceGas shall be entitled to retain the stated percentage of all Dekatherms received for transportation, unless otherwise agreed in writing.

4/ Interruptible Transportation Service is not available to DSE customers. The Customer Charge will be charged only for those months gas actually flows.

5/ In addition to the transportation charges stated above, Shippers are responsible for the monthly administrative fee as stated, applicable to each meter located at the customer location. For Interruptible Transportation Shippers, the Administrative Fee will be charged only for those months gas actually flows. Firm Transportation Shippers will be charged each month, regardless of gas flow.

Abbreviations (as defined in the General Terms and Conditions of this Tariff):

MLI Mainline System Interconnect
MLE Mainline System End-user
DSE Distribution System End-user

Date Issued: June 8, 2007
By: Bentley W. Breland

Date Effective: June 15, 2007
Title: Senior Vice President

**MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS
EFFECTIVE JULY 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	(535,124)	246,050	(397,864)
February	(3,569,219)	(7,421)	(1,320,609)
March	(5,566,203)	(172,337)	(1,909,458)
April	(5,393,708)	(168,880)	(1,736,211)
May	(2,575,788)	(83,528)	(1,025,129)
June	1,194,518	29,069	(40,366)
July	4,305,319	130,069	992,719
August	7,215,509	241,847	2,005,496
September	9,440,067	556,161	2,807,288
October	10,512,495	579,662	3,067,514
13 month average	<u>\$3,155,657</u>	<u>\$313,142</u>	<u>\$700,198</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$277,414	\$27,528	\$61,554
Return Requirement - Revenue	<u>\$459,371</u>	<u>\$45,584</u>	<u>\$101,927</u>

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

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

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2008									<u>\$11,725,941</u>
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
January 2009	635,716	0	694	636,410	2,891,983	0.845	2,443,726	(1,807,316)	8,014,639
February	(1,836,624)	0	1,305	(1,835,319)	2,176,867	0.845	1,839,453	(3,674,772)	4,339,867
March	(2,301,822)	0	517	(2,301,305)	2,207,860	0.845	1,865,642	(4,166,947)	172,920
April	(1,080,379)	0	14	(1,080,365)	1,571,415	0.845	1,327,846	(2,408,211)	(2,235,291)
Balance @ April 30, 2009									<u>(\$2,235,291)</u>

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**

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2008									<u>\$291,680</u>
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
January 2009	154,837	0	17	154,854	157,399	0.349	54,932	99,922	337,835
February	(61,289)	0	55	(61,234)	112,404	0.349	39,228	(100,462)	237,373
March	(70,155)	0	29	(70,126)	68,683	0.349	23,971	(94,097)	143,276
April	(44,509)	0	13	(44,496)	90,480	0.349	31,578	(76,074)	67,202
Balance @ April 30, 2009									<u>\$67,202</u>

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**

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2008									<u>\$121,188</u>
August	\$164,522	\$0	\$121	\$164,643	6,154	(\$0.135)	(\$831) 2/	\$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 3/	(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) 4/	5	(20,978)	56,147	0.167	9,377	(30,355)	281,063
January 2009	85,231	0	20	85,251	90,482	0.167	15,110	70,140	351,203
February	(49,634)	0	58	(49,576)	95,984	0.167	16,029	(65,605)	285,598
March	(92,358)	0	34	(92,324)	80,958	0.167	13,520	(105,844)	179,754
April	(34,462)	0	16	(34,446)	73,750	0.167	12,316	(46,762)	132,992
Balance @ April 30, 2009									<u>\$132,992</u>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Reflects 6,154 Dk @ (\$0.135).

3/ Reflects 0 Dk @ \$0.167

4/ Prior period adjustment related to Minot Air Force Base account switch from firm to interruptible Service.