



MONTANA-DAKOTA

UTILITIES CO.

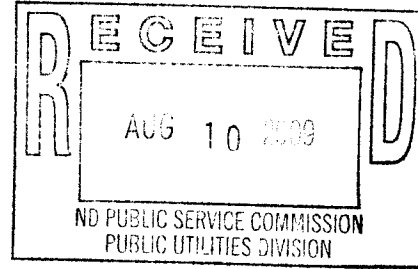
A Division of MDU Resources Group, Inc.

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

ORIGINAL

August 11, 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 (78th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered September 1, 2009.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.128 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 September 2009.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.128 per dk for residential and firm general service customers, an increase of \$0.131 per dk for small and large interruptible customers and an increase of \$0.130 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 September 2009. The average cost of gas for firm customers, adjusted for losses, is \$4.652.

Exhibit C shows the calculation of the return on storage inventory balances and prepaid demand and commodity balances using the calculation procedure set forth in Rate 88. The overall rate of return of 8.791% was authorized by the Commission in Case No. PU-04-97. Montana-Dakota has refined the calculation of the revenue requirement to

reflect an adjustment for income taxes only on the equity portion of the rate of return rather than the entire return component effective with this COG filing.

The proposed adjustment will amount to an increase of approximately \$65,000 during the month of September 2009. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 90,825 customers in North Dakota as of July 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:

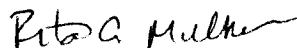
Mr. Daniel S. Kuntz
Associate General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

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,



Rita A. Mulkern
Regulatory Analysis Manager

Attachment
Cc: D. Ball

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
78th Revised Sheet No. 3
Canceling 77th 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	\$5.489	\$6.301
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$5.489	\$5.627
Interruptible Service - PAR			\$0.120	\$4.068	\$4.188
Interruptible Service - MAFB			\$0.120	\$3.869	\$3.989
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$5.489	\$6.086
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$4.068	(Maximum) \$4.939
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day			
Winter Gas Usage			\$0.597	\$5.579	\$6.176
Summer Gas Usage			\$0.597	\$4.627	\$5.224
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.017	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.017	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$4.068	(Maximum) \$4.787
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$7.350	\$8.162
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	\$7.350	\$7.947

Date Filed: August 10, 2009

Effective Date:

Issued By: Donald R. Bail

Vice President - Regulatory Affairs

Case No.:

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

September 2009

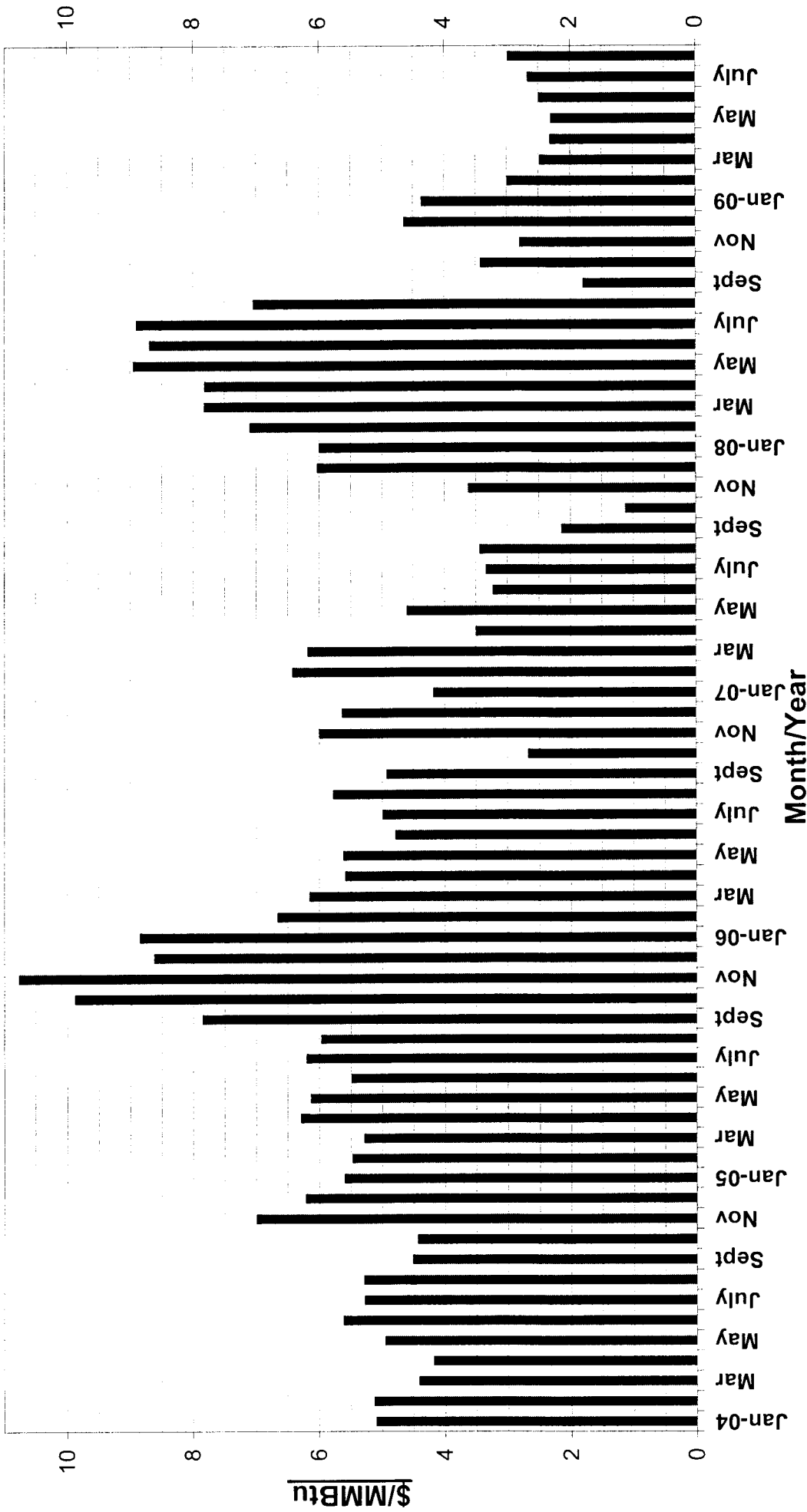
The established August monthly price for the Rocky Mountain CIG Index increased from the previous month. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices 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 the completion and start up of the Rocky Mountain Express East Pipeline segment, 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 July 31, 2009 were 19.1 percent above the five-year average and 23.1 percent above last year's balance.

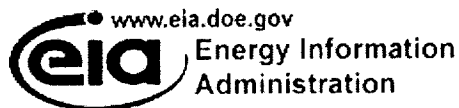
The EIA provides various publications on energy issues. The information is available on their website: <http://www.eia.doe.gov>.

The July Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 11. The August Outlook is to be published August 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-\$2.81



July 2009

Short-Term Energy Outlook

July 7, 2009 Release

Highlights

- After climbing for much of the year, the spot price of West Texas Intermediate (WTI) crude oil hovered around \$70 per barrel through most of June. The price of WTI crude oil is expected to average near \$70 per barrel through the second half of 2009, an increase of about \$18 compared with the average for the first half of the year. The WTI spot price is projected to rise slowly as economic conditions improve, and to average about \$72 per barrel in 2010.
- U.S. average prices for regular-grade gasoline, which reached \$2.69 per gallon in EIA's June 22 weekly survey, have fallen back slightly. Gasoline prices are expected to stay near current levels but will be strongly influenced by any changes in crude oil prices. The annual average regular-grade gasoline retail price in 2009 is expected to be \$2.36 per gallon. Higher projected crude oil prices next year are expected to boost the average price to \$2.69 per gallon in 2010. Annual average diesel fuel retail prices are expected to be \$2.46 and \$2.79 per gallon in 2009 and 2010, respectively.
- The monthly average Henry Hub natural gas spot price is expected to remain below \$4 per thousand cubic feet (Mcf) until late in the year given plentiful U.S. natural gas supplies and weak demand, particularly in the industrial sector. The Henry Hub price is projected to increase from an average of \$4.22 per Mcf in 2009 to an average of \$5.93 per Mcf in 2010 as expected economic growth increases industrial consumption of natural gas.

Global Petroleum

Overview. Crude oil prices rose in June for the fourth consecutive month, in part because of stronger-than-anticipated global economic activity, primarily in Asia. Market sentiment continues to reflect expectations of an economic recovery and a future rebound in oil demand that are outweighing weak current oil consumption and high inventory levels. Continued production restraint by members of the

Organization of the Petroleum Exporting Countries (OPEC) and unrest in Iran and Nigeria, respectively OPEC's second- and seventh-biggest oil producers, are also supporting prices. The downside price risks of this forecast are a delayed or weaker-than-expected global economic recovery, ample global surplus production capacity, and high commercial inventories.

Consumption. The global economic downturn curtailed world oil consumption during the second half of 2008 and the first half of 2009. Compared with the year prior, world oil consumption was down an average of 3.0 million barrels per day (bbl/d) from the fourth quarter of 2008 through the second quarter of 2009. However, the consumption decline rate is expected to moderate later this year because of comparison with a lower level of consumption last year and projected gradual global economic improvement. In particular, there has been stronger economic activity in Asia than was previously anticipated, and the current forecast reflects higher expected oil consumption in that region. As a result, a smaller decline in global oil consumption is expected in 2009, with oil consumption projected to fall by 1.6 million bbl/d compared with a decline of 1.7 million bbl/d in the June *Outlook*. Global consumption is projected to grow by 0.9 million bbl/d in 2010 in response to expected positive global economic growth ([World Liquid Fuels Consumption Chart](#)).

Non-OPEC Supply. Total non-OPEC supply is expected to rise by 360,000 bbl/d in 2009 and to remain fairly flat in 2010. Over the forecast period, higher output from Brazil, the United States, Azerbaijan, and Kazakhstan is expected to offset falling 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 be 28.6 million bbl/d in the second quarter of 2009, down slightly from first quarter levels, but down 3.1 million bbl/d from the third quarter of 2008. OPEC crude output is expected to remain near current levels through the end of the year, then trend upward moderately in 2010 in response to higher demand. Substantial surplus production capacity, located mostly in Saudi Arabia, should help moderate upward price pressure until higher demand begins to erode the global supply cushion.

Inventories. Preliminary data indicate that commercial inventories held by Organization for Economic Cooperation and Development (OECD) countries stood at 2.7 billion barrels at the end of the first quarter of 2009. At 60 days of forward cover, OECD commercial inventories were well above average levels at the end of March ([Days of Supply of OECD Commercial Stocks Chart](#)). Preliminary estimates suggest that OECD commercial inventories held fairly steady during the second quarter of 2009, rather than rising seasonally, but still remain well above the historic average.

Crude oil in floating storage, which is not included in the OECD stock totals, has reportedly declined from a high of more than 120 million barrels at the beginning of 2009 to about 80 million barrels.

U.S. Crude Oil and Liquid Fuels

Consumption. Total consumption of liquid fuels and other petroleum products is projected to decrease by 650,000 bbl/d (3.3 percent) in 2009 (U.S. Petroleum Products Consumption Growth Chart), including a decline of 280,000 bbl/d (7.0 percent) in distillate fuel consumption and 140,000 bbl/d (8.7 percent) in jet fuel consumption. Motor gasoline consumption is projected to remain virtually flat as the significant price decline from last summer offsets some of the impact of the economic downturn. Modest economic recovery in 2010 is expected to contribute to a 310,000-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 5.23 million bbl/d in 2009 and 5.36 million bbl/d in 2010. Oil production from the new Thunder Horse, Tahiti, Shenzi, and Atlantis Federal offshore fields is expected to account for about 14 percent of Lower-48 crude oil production by the fourth quarter of 2010.

Prices. WTI crude oil prices, which averaged \$99.57 per barrel in 2008, are projected to average \$60.35 per barrel in 2009 and \$72.42 per barrel in 2010 (Crude Oil Prices Chart). This projection represents a \$2-to-\$5-per-barrel increase over that of the previous *Outlook*.

Regular-grade motor gasoline retail prices, which averaged \$3.26 per gallon in 2008, are expected to average \$2.36 per gallon this year. Higher projected crude oil prices in 2010 (\$12 per barrel higher on average, or 29 cents per gallon) are expected to boost average motor gasoline prices to \$2.69 per gallon next year. Diesel fuel retail prices, which averaged \$3.80 per gallon in 2008, are projected to average \$2.46 per gallon in 2009 and \$2.79 in 2010.

Natural Gas

Consumption. Total natural gas consumption is projected to decline by 2.3 percent in 2009 and remain unchanged in 2010 (Total U.S. Natural Gas Consumption Growth). Poor economic conditions are expected to prolong the current slump in natural gas demand over the coming months, led by an 8.2-percent drop among industrial users

in 2009. While consumption is expected to fall in the residential and commercial sectors as well this year, competitive natural gas prices relative to coal are projected to lead to a 2.4-percent increase in electric power sector consumption in 2009. Slight consumption increases in the residential, commercial, and industrial sectors next year are expected to result from the projected economic recovery. Natural gas consumption in the electric power sector is expected to decline by 1 percent in 2010 as natural gas prices rise and coal regains a larger share of the baseload generation mix.

Production and Imports. Total U.S. marketed natural gas production is expected to decline by 0.6 percent in 2009 and by 2.9 percent in 2010. As both consumption and prices have waned amid the recent economic downturn, natural gas producers have responded with a dramatic reduction in drilling activities. According to Baker Hughes, total working natural gas rigs are now down 57 percent since September 2008. The resulting production decline from the drop in rigs is expected to occur almost exclusively in the Lower-48 non-Gulf of Mexico (GOM) region during the second half of this year. While the drop in natural gas drilling rigs is expected to result in lower natural gas production in 2010, recent improvements in drilling technology have lowered costs, reduced drilling time, and increased well productivity. These factors should improve the responsiveness of producers to changes in demand, limiting the extent of sustained upward price movements through the forecast period.

U.S. liquefied natural gas (LNG) imports are expected to increase to about 506 billion cubic feet (Bcf) in 2009 from 352 Bcf in 2008, because of a combination of weak demand and growing supply in the global LNG market. Lower demand for LNG in Japan and South Korea has increased the amount of available LNG in the global market, leading to larger LNG purchases in China and Europe. However, with limited natural gas storage capacity in Asia and Europe, lower global demand is expected to increase available LNG cargoes for import by the United States.

Inventories. On June 26, 2009, working natural gas in storage was 2,721 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 467 Bcf above the 5-year average (2003–2007) and 615 Bcf above the level during the corresponding week last year. Through the first 3 months of the injection season (March 27 through June 26) the estimated inventory build was 1,067 Bcf, the largest increase for this period since 2001, and 157 Bcf more than the average build during this period since 2001. Working natural gas stocks are now expected to reach 3,670 Bcf at the end of the 2009 injection season (October 31), about 105 Bcf above the previous record of 3,565 Bcf reported for the end of October 2007.

Prices. The Henry Hub spot price averaged \$3.91 per Mcf in June, which was 5 cents below the average spot price in May. Prices continue to reflect the disparity between weak demand and strong supply. Despite low prices, natural gas marketed production in the Lower-48 non-GOM increased by 1.9 Bcf/d (3.7 percent) on a year-over-year basis in April, the most current available monthly data. Although U.S. natural gas production is projected to decline over the coming months, historically high storage levels and limits to storage capacity may cause prices to decline further this fall. Prices are expected to recover in early 2010 as the market balance tightens. However, rising prices are expected to be tempered by improvements in the productive capacity of domestic onshore supply sources throughout the forecast period. The Henry Hub spot price is expected to average \$4.22 per Mcf in 2009 and \$5.93 per Mcf in 2010.

Electricity

Consumption. Retail sales of electricity in the industrial sector continue to decline, having fallen by 12 percent during the first quarter of 2009 compared with year-ago levels. Total consumption of electricity is projected to fall by 2.0 percent for the entire year of 2009 and then rise by 0.8 percent in 2010 ([U.S. Total Electricity Consumption Chart](#)).

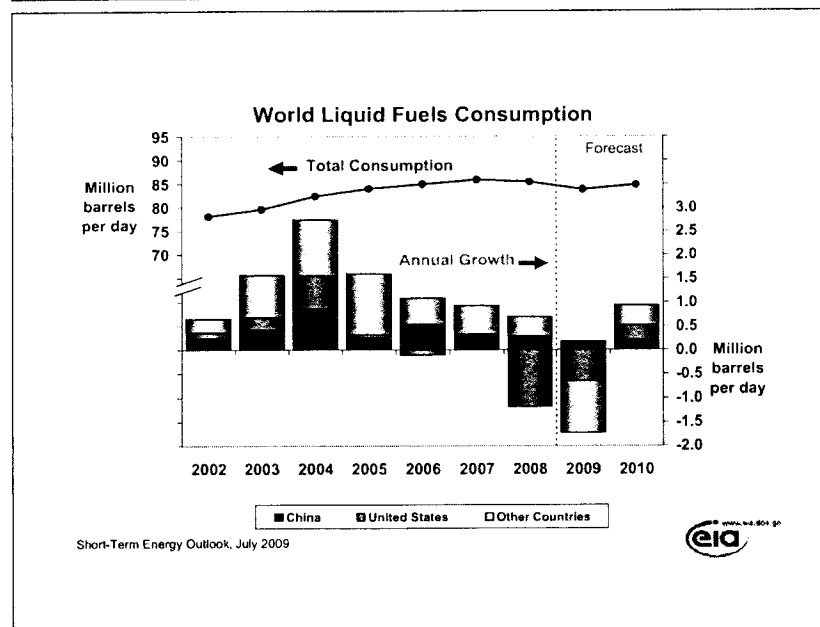
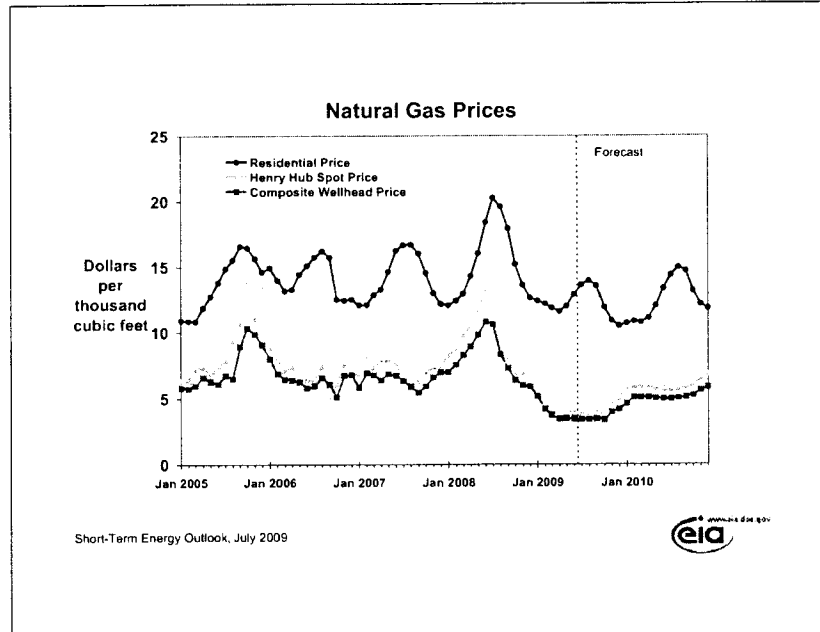
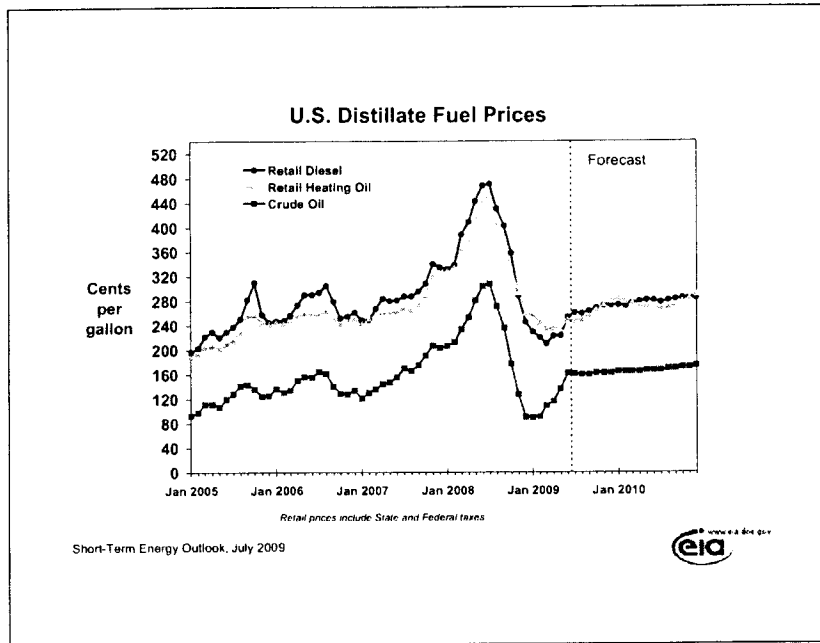
Prices. Residential electricity prices rose by 8 percent during the first quarter of 2009 compared with the first quarter of 2008 ([U.S. Residential Electricity Prices Chart](#)). Lower generation fuel costs are expected to be passed through to retail consumers later this year, keeping the annual average growth in prices at around 4.7 percent and 3.3 percent in 2009 and 2010, respectively.

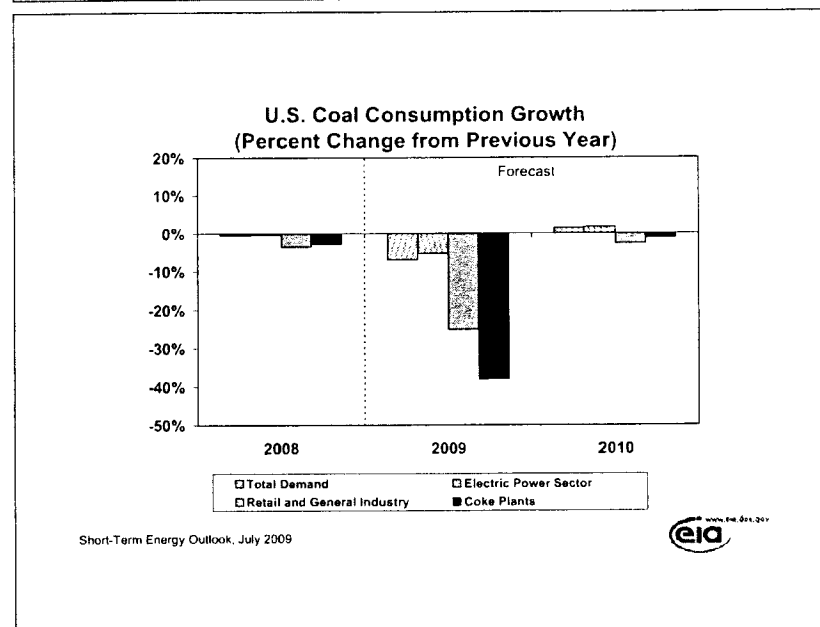
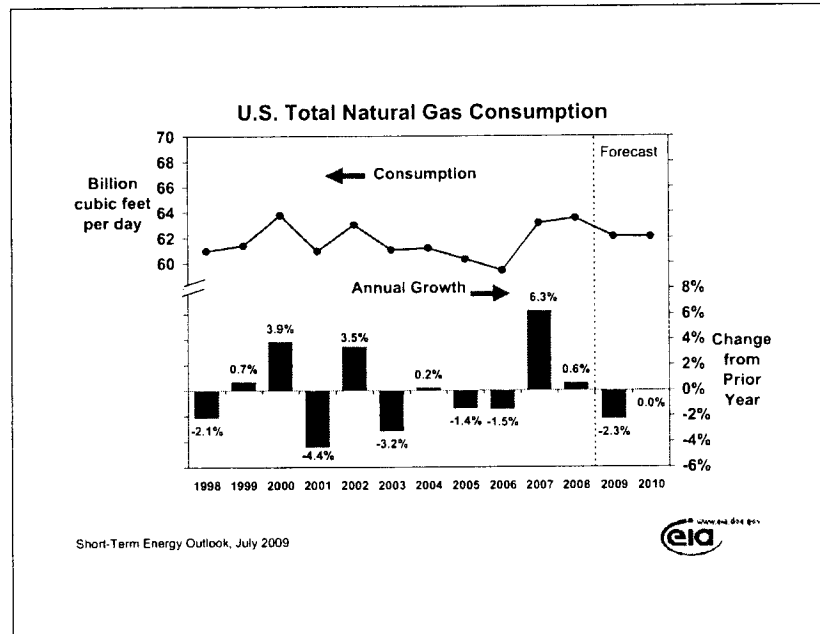
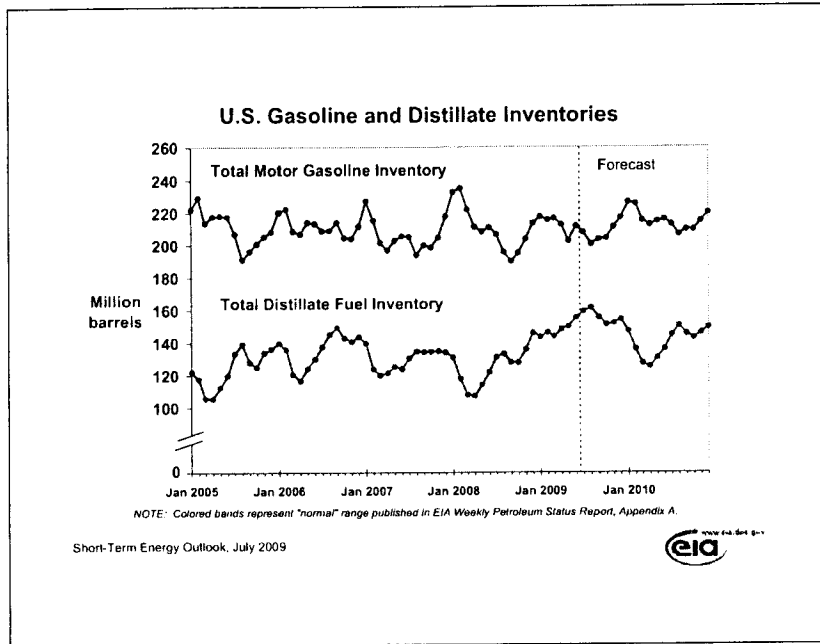
Coal

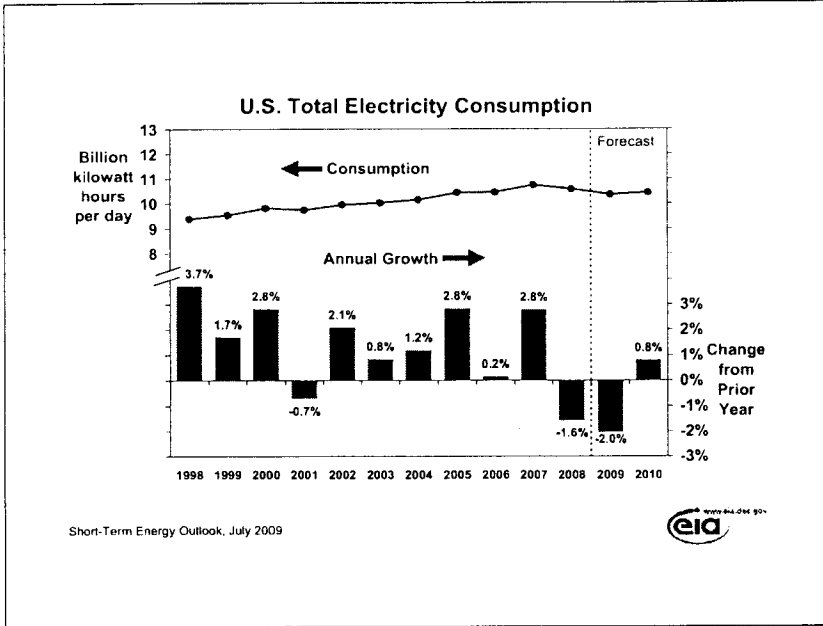
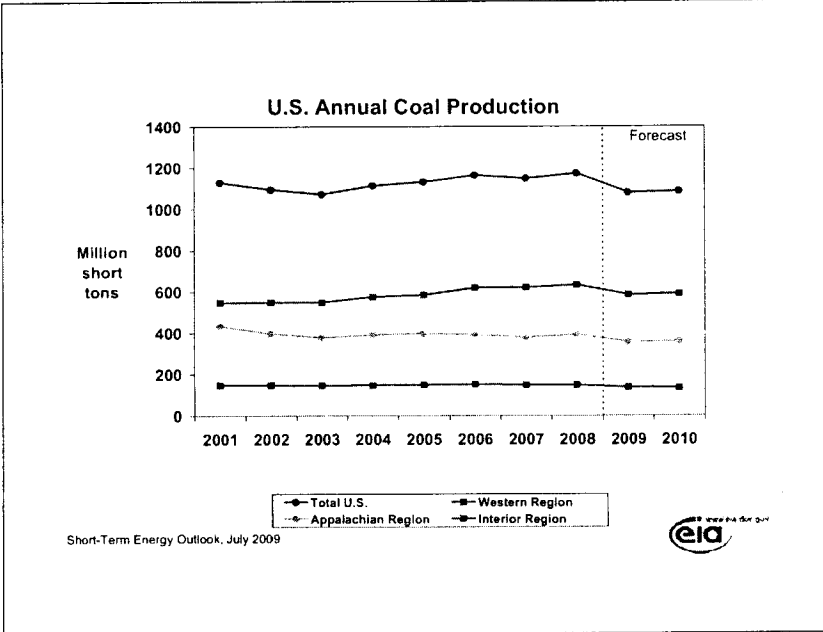
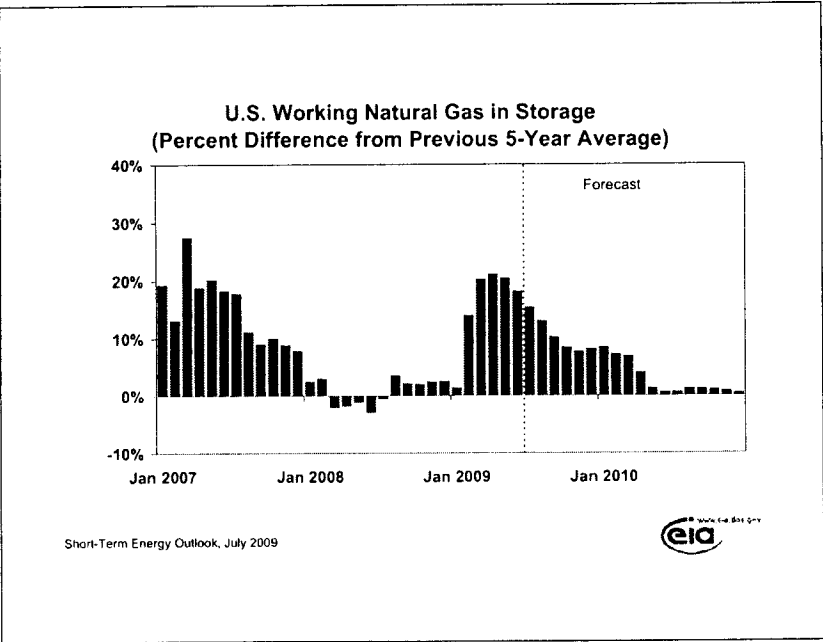
Consumption. The projected electric-power-sector consumption of about 990 million short tons of coal in 2009 would be the first time since 2002 that annual consumption would be below the billion-short-ton level. The 5.2-percent decline in coal consumption in the electric power sector is the result of lower total electricity generation coupled with projected increases from other generating sources, including natural gas, nuclear, hydroelectric, and wind. Coal consumption in the electric power sector is expected to increase by 1.6 percent in 2010 as natural gas prices rise and coal regains a larger share of the baseload generation mix. Coal consumption for both steam and coke production is projected to decline by 29 percent in 2009, reflecting very weak industrial activity ([U.S. Coal Consumption Growth Chart](#)).

Production. Coal production is expected to fall by about 8 percent in 2009 in response to lower domestic coal consumption, fewer exports, and higher coal inventories. The May 2009 production estimate is the lowest monthly coal production figure since December 2000. Production is projected to increase slightly (0.5 percent) in 2010 as domestic consumption and exports increase with an improving economy (U.S. Annual Coal Production Chart).

Prices. Despite declines in electricity demand, decreases in spot coal prices, and lower costs for other fossil fuels, the average delivered electric-power-sector coal price is projected to increase from an average of \$2.07 per million Btu in 2008 to \$2.15 per million Btu in 2009. A significant portion of power-sector coal contracts were entered into during a period of high prices for all fuels. Although record increases in spot prices last year (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 coal consumed in the power sector. The average delivered power-sector coal price is expected to decline to \$2.02 per million Btu in 2010 as expiring high-priced contracts are replaced.







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

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$4.652	\$3.790	\$3.719	\$3.702
Prior Gas Cost	<u>4.524</u>	<u>3.662</u>	<u>3.588</u>	<u>3.572</u>
Current Gas Cost Adjustment	\$0.128	\$0.128	\$0.131	\$0.130
<u>Surcharge Adjustment:</u>				
Current Adjustment	\$0.845	\$0.845	\$0.349	\$0.167
Prior Adjustment	<u>0.845</u>	<u>0.845</u>	<u>0.349</u>	<u>0.167</u>
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	<u>(0.008)</u>	<u>(0.008)</u>	<u>0.000</u>	<u>0.000</u>
Change in Margin Sharing Provision	\$0.000	\$0.000	\$0.000	\$0.000
Net Increase (Decrease) in Gas Costs	<u>\$0.128</u>	<u>\$0.128</u>	<u>\$0.131</u>	<u>\$0.130</u>
Gas Cost Level	\$4.652	\$3.790	\$3.719	\$3.702
Plus: Surcharge	<u>0.845</u>	<u>0.845</u>	<u>0.349</u>	<u>0.167</u>
Total Gas Cost Level in Tariff Rates	<u>\$5.497</u>	<u>\$4.635</u>	<u>\$4.068</u>	<u>\$3.869</u>

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

	Amount
Total Gas Costs 1/	\$62,092,943
Residential and General Service dk Requirements 2/	13,407,475
Average Cost of Gas per dk	\$4.631
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.652
Less: Gas Cost Level in Rates 3/	4.524
Current Gas Cost Adjustment	\$0.128

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 June 30, 2009, adjusted for losses at .45%

3/ Gas Cost Level in Current Tariff Rates Case No. PU-09-530:

Cost of Purchased Gas	\$4.504
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.524

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

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$62,092,943
Less: Annual MDDQ Costs 1/	<u>11,501,344</u>
Total Gas Costs excluding MDDQ	\$50,591,599
Firm Service Requirements 1/	13,407,475
Other Gas Costs per Dk (excluding MDDQ)	\$3.773
Summer Seasonal Rate, adjusted for losses 2/	3.790
Less: Gas Cost Level in Rates 3/	<u>3.662</u>
Current Gas Cost Adjustment	<u><u>\$0.128</u></u>

<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,501,344
Winter Firm Service Requirements	12,138,295
MDDQ Costs per Winter Dk	\$0.948
Add: Other Gas Costs per Dk	<u>3.773</u>
Winter Seasonal Rate	4.721
Winter Seasonal Rate, adjusted for losses 2/	\$4.742

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-09-530:

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$3.646	\$4.594
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$3.662	\$4.615

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

	Amount
Total Gas Costs 1/	\$12,967,175
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$3.702
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.719
Less: Gas Cost Level in Rates 2/	3.588
Current Gas Cost Adjustment	\$0.131

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-09-530:

Cost of Purchased Gas	\$3.572
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.588

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

	<u>Amount</u>
Total Gas Costs 1/	\$3,257,752
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$3.702
Less: Gas Cost Level in Rates 2/	<u>3.572</u>
Current Gas Cost Adjustment	<u><u>\$0.130</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-09-530:
Cost of Purchased Gas \$3.572

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
September 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

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

Effective on: 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

NorthWestern
Energy

Canceling	<u>15th</u>	Revised	Sheet No.	<u>80.1</u>
	<u>14th</u>	Revised	Sheet No.	<u>80.1</u>

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

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

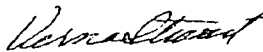
MINIMUM BILL: Per respective contracts.

(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
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 SEPTEMBER 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	(2,569,203)	(92,142)	(1,023,608)
June	2,213,143	47,984	(39,684)
July	6,809,084	217,239	993,561
August	9,562,691	323,297	2,006,491
September	10,575,100	584,178	2,808,367
October	10,378,421	547,447	3,068,499
13 month average	<u>\$3,684,666</u>	<u>\$326,582</u>	<u>\$700,668</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$323,919	\$28,710	\$61,596
Return Requirement	<u>\$448,129</u>	<u>\$39,719</u>	<u>\$85,216</u>

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

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

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

	(Over) Under Recovery	Refunds & Other	Interest 1/ Additions	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
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)
May	(799,213)	0	(339)	(799,552)	779,790	0.845	658,923	(1,458,475)	(3,693,766)
June	(1,191,853)	0	(558)	(1,192,411)	500,265	0.845	422,724	(1,615,135)	(5,308,901)
Balance @ June 30, 2009									(\$5,308,901)

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
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
May	(34,533)	0	10	(34,523)	53,654	0.349	18,725	(53,248)	13,954
June	(41,377)	0	2	(41,375)	37,946	0.349	13,243	(54,618)	(40,664)
Balance @ June 30, 2009									(\$40,664)

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) 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
May	(24,668)	0	20	(24,648)	39,854	0.167	6,656	(31,304)	101,688
June	(34,614)	0	16	(34,598)	21,457	0.167	3,583	(38,181)	63,507
Balance @ June 30, 2009									\$63,507

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.