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

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

July 9, 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 (77th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered August 1, 2009.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased $0.141 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 August 2009.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of $0.141 per dk for residential and firm general service customers, an increase of $0.140 per dk for small and large interruptible customers and an increase of $0.140 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 August 2009. The average cost of gas for firm customers, adjusted for losses, is $4.524.

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 $45,500 during the month of August 2009. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 90,904 customers in North Dakota as of June 30, 2009.

Please refer all inquiries regarding this filing to:

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

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

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

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

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

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

Sincerely,

Donald R. Ball

Donald R. Ball
Vice President – Regulatory Affairs

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

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	$0.30 per day	$0.812	$5.361	$6.173
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$5.361	$5.499
Interruptible Service - PAR			$0.120	$3.937	$4.057
Interruptible Service - MAFB			$0.120	$3.739	$3.859
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	$5.361	$5.958
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	14	$100.00 per month	$0.871	$3.937	$4.808
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	$5.452	$6.049
Summer Gas Usage			$0.597	$4.499	$5.096
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	
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	27	$675.00 per month	$0.719	$3.937	$4.656
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

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

August 2009

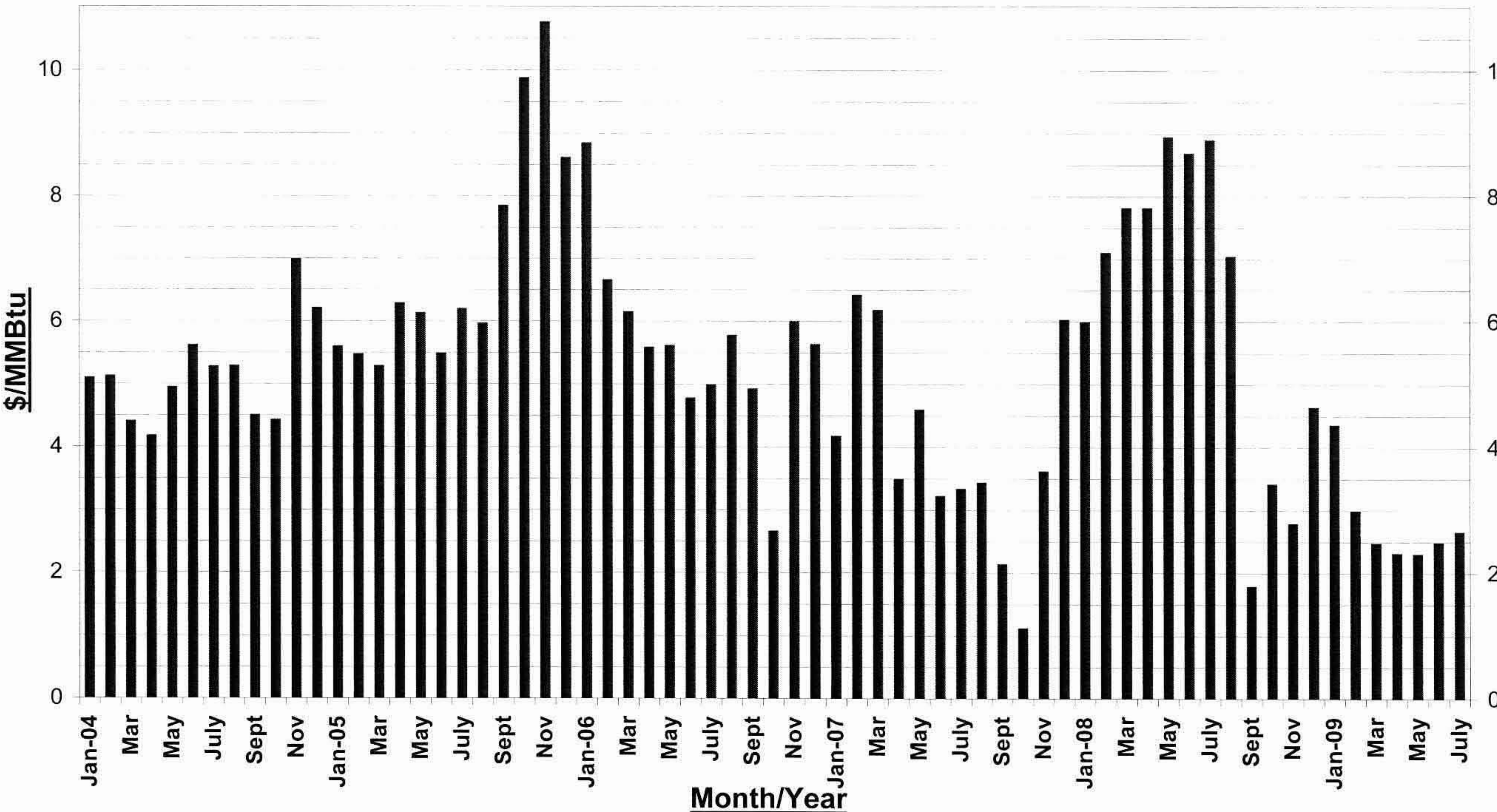
The established July monthly price for the Rocky Mountain CIG Index increased from the previous month. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid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

Despite ample supplies of natural gas, factors contributing to rising natural gas prices include increased cooling demand for natural gas and rising crude oil prices. The CIG index price for July 2009 is approximately 70 percent less that the July 2008 price of $8.89. The Energy Information Administration (EIA) reported storage levels nationwide as of June 26, 2009 were 20.7 percent above the five-year average and 29.2 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.

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-$2.79

www.eia.doe.gov
Energy Information Administration

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).

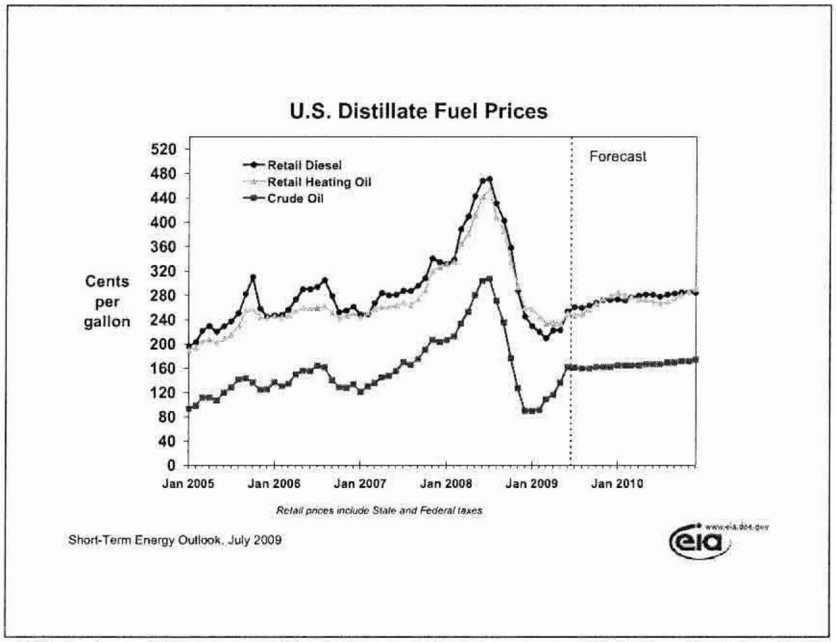
Prices. Residential electricity prices rose by 8 percent during the first quarter of 2009 compared with the first quarter of 2008 (U.S. Residential Electricity Prices Chart). Lower generation fuel costs are expected to be passed through to retail consumers later this year, keeping the annual average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

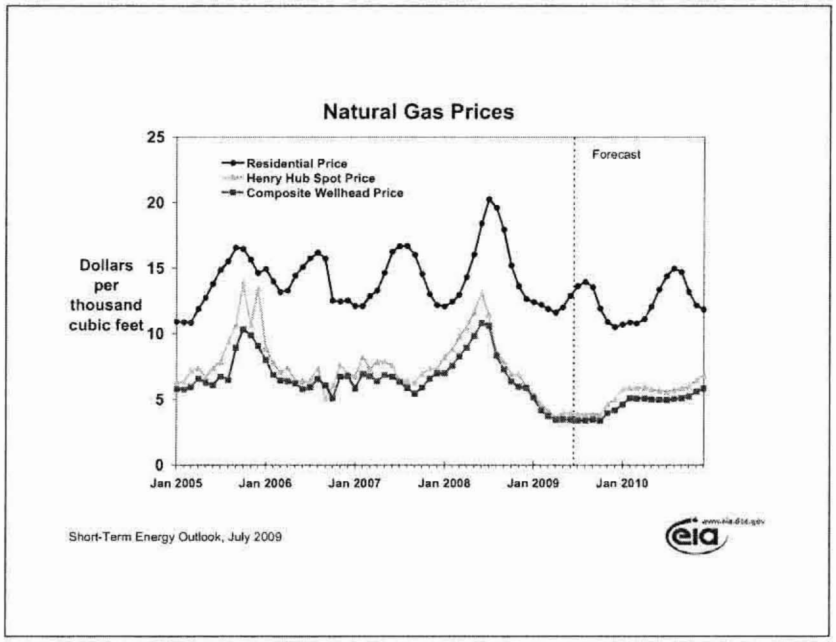
Coal

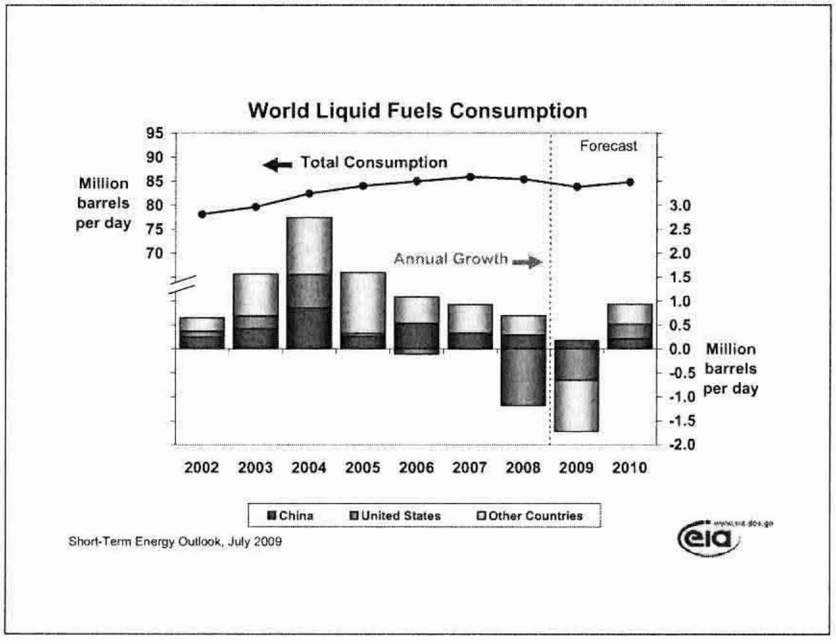
Consumption. The projected electric-power-sector consumption of about 990 million short tons of coal in 2009 would be the first time since 2002 that annual consumption would be below the billion-short-ton level. The 5.2-percent decline in coal consumption in the electric power sector is the result of 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).

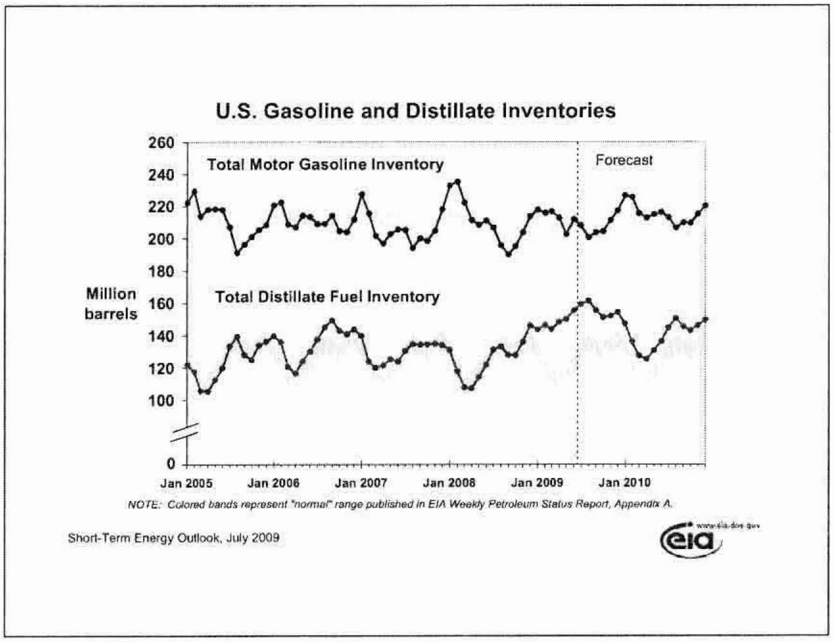
Production. Coal production is expected to fall by about 8 percent in 2009 in response to lower domestic coal consumption, fewer exports, and higher coal inventories. The May 2009 production estimate is the lowest monthly coal production figure since December 2000. Production is projected to increase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

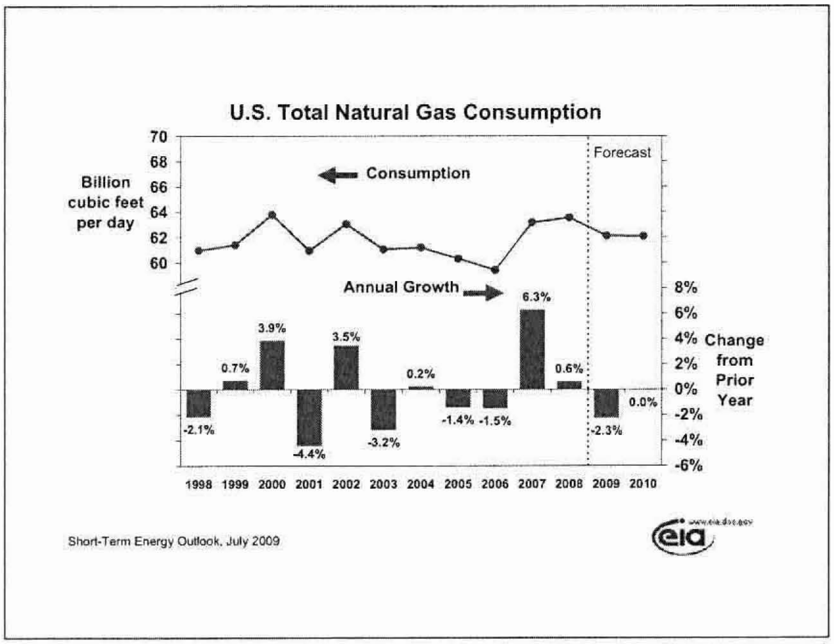
Prices. Despite declines in electricity demand, decreases in spot coal prices, and lower costs for other fossil fuels, the average delivered electric-power-sector coal price is projected to increase from an average of $2.07 per million Btu in 2008 to $2.15 per million Btu in 2009. A significant portion 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.

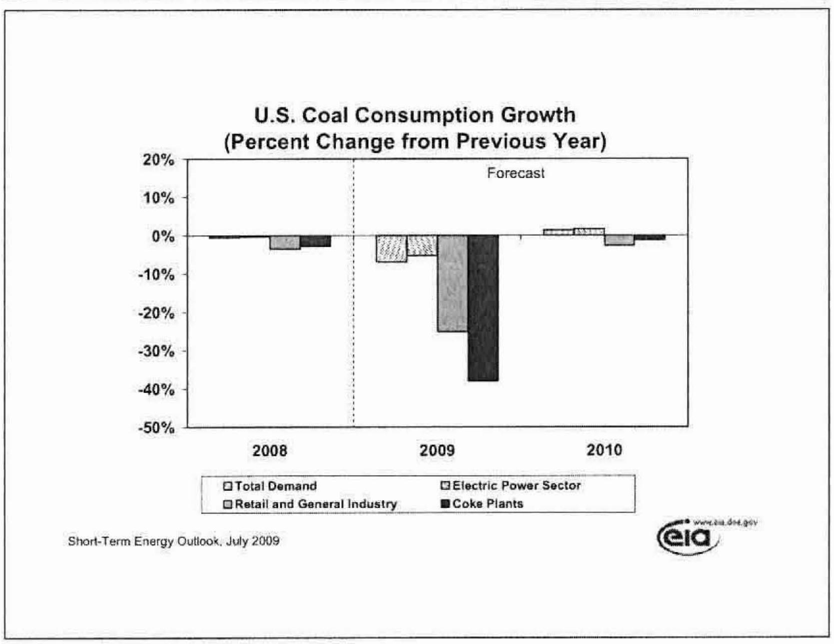

U.S. Distillate Fuel Prices
Retail Diesel
Retail Heating Oil
Crude Oil
Forecast
Cents per gallon
520
480
440
400
360
320
280
240
200
160
120
80
40
0
Jan 2005
Jan 2006
Jan 2007
Jan 2008
Jan 2009
Jan 2010
Retail prices include State and Federal taxes
Short-Term Energy Outlook, July 2009

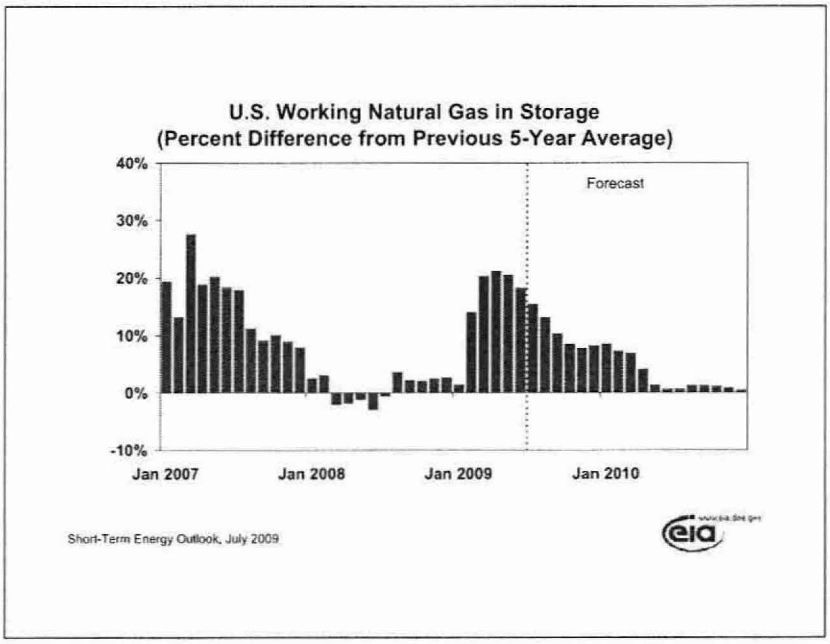

Natural Gas Prices
Residential Price
Henry Hub Spot Price
Composite Wellhead Price
Forecast
Dollars per thousand cubic feet
25
20
15
10
5
0
Jan 2005
Jan 2006
Jan 2007
Jan 2008
Jan 2009
Jan 2010
Short-Term Energy Outlook, July 2009

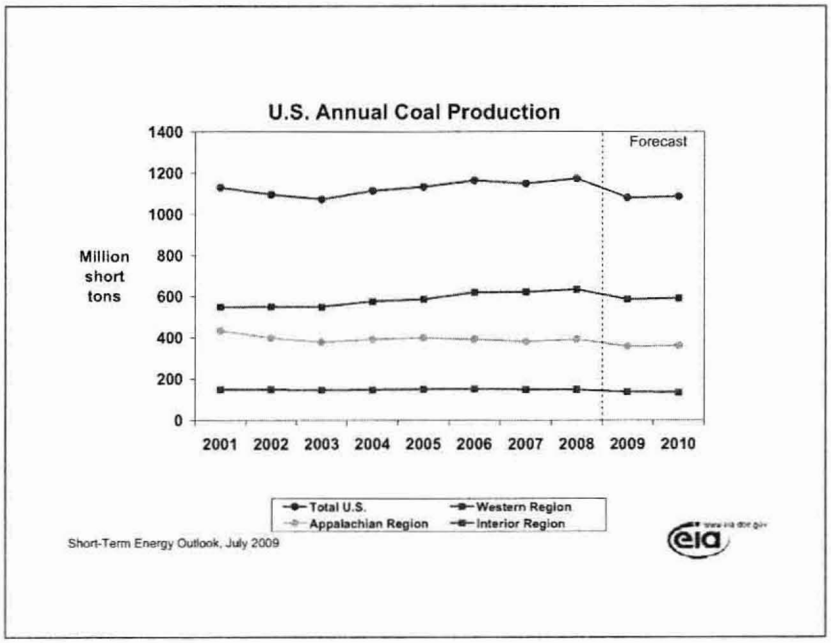

World Liquid Fuels Consumption
Forecast
Total Consumption
Annual Growth
Million barrels per day
95
90
85
80
75
70
3.0
2.5
2.0
1.5
1.0
0.5
0.0
-0.5
-1.0
-1.5
-2.0
Million barrels per day
2002
2003
2004
2005
2006
2007
2008
2009
2010
China
United States
Other Countries
Short-Term Energy Outlook, July 2009


U.S. Gasoline and Distillate Inventories
Total Motor Gasoline Inventory
Forecast
Total Distillate Fuel Inventory
Million barrels
260
240
220
200
180
160
140
120
100
0
Jan 2005
Jan 2006
Jan 2007
Jan 2008
Jan 2009
Jan 2010
NOTE: Colored bands represent "normal" range published in EIA Weekly Petroleum Status Report, Appendix A.
Short-Term Energy Outlook, July 2009


U.S. Total Natural Gas Consumption
Forecast
Consumption
Billion cubic feet per day
70
68
66
64
62
60
Annual Growth
8%
6%
4%
2%
0%
-2%
-4%
-6%
Change from Prior Year
-2.1%
0.7%
3.9%
-4.4%
3.5%
-3.2%
0.2%
-1.4%
-1.5%
6.3%
0.6%
-2.3%
0.0%
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
Short-Term Energy Outlook, July 2009


U.S. Coal Consumption Growth
(Percent Change from Previous Year)
Forecast
20%
10%
0%
-10%
-20%
-30%
-40%
-50%
2008
2009
2010
Total Demand
Electric Power Sector
Retail and General Industry
Coke Plants
Short-Term Energy Outlook, July 2009


U.S. Working Natural Gas in Storage
(Percent Difference from Previous 5-Year Average)
Forecast
40%
30%
20%
10%
0%
-10%
Jan 2007
Jan 2008
Jan 2009
Jan 2010
Short-Term Energy Outlook, July 2009
eia


U.S. Annual Coal Production
Forecast
Million short tons
1400
1200
1000
800
600
400
200
0
2001 2002 2003 2004 2005 2006 2007 2008 2009 2010
Total U.S.
Western Region
Appalachian Region
Interior Region
Short-Term Energy Outlook, July 2009
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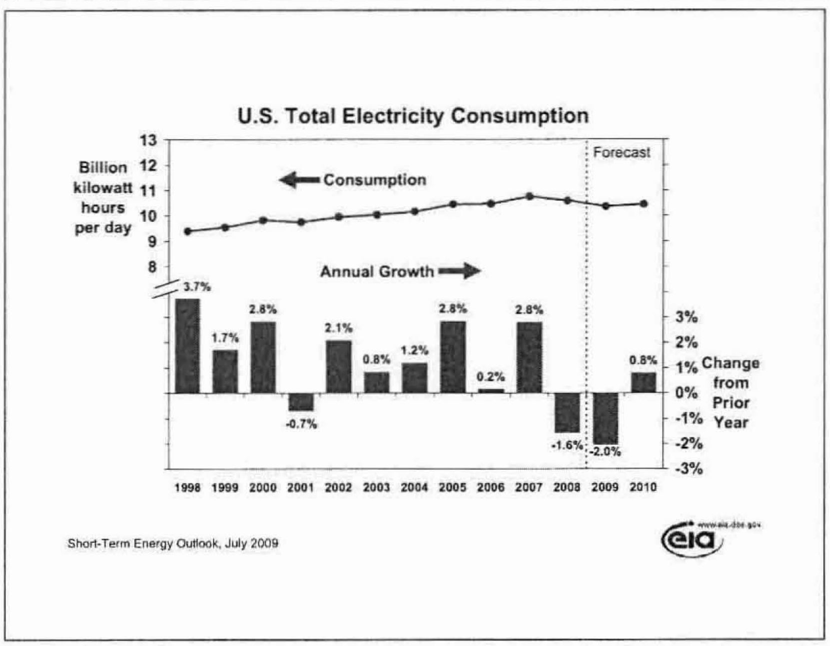
U.S. Total Electricity Consumption
Forecast
Billion kilowatt hours per day
13
12
11
10
9
8
Consumption
Annual Growth
3.7%
1.7%
2.8%
-0.7%
2.1%
0.8%
1.2%
2.8%
0.2%
2.8%
-1.6%
-2.0%
0.8%
3%
2%
1%
0%
-1%
-2%
-3%
Change from Prior Year
1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010
Short-Term Energy Outlook, July 2009
eia

Exhibit A

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

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
Gas Cost Adjustment:				
Gas Cost Level (Exhibit B)	$4.524	$3.662	$3.588	$3.572
Prior Gas Cost	4.383	3.521	3.448	3.432
Current Gas Cost Adjustment	$0.141	$0.141	$0.140	$0.140
Surcharge Adjustment:				
Current Adjustment	$0.845	$0.845	$0.349	$0.167
Prior Adjustment	0.845	0.845	0.349	0.167
Change in Surcharge Adjustment	$0.000	$0.000	$0.000	$0.000
Market Based Pricing Differential				
Current Adjustment	($0.008)	($0.008)	$0.000	$0.000
Prior Adjustment	(0.008)	(0.008)	0.000	0.000
Change in Margin Sharing Provision	$0.000	$0.000	$0.000	$0.000
Net Increase (Decrease) in Gas Costs	**$0.141**	**$0.141**	**$0.140**	**$0.140**
Gas Cost Level	$4.524	$3.662	$3.588	$3.572
Plus: Surcharge	0.845	0.845	0.349	0.167
Total Gas Cost Level in Tariff Rates	$5.369	$4.507	$3.937	$3.739

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

	Amount
Total Gas Costs 1/	$60,352,345
Residential and General Service dk Requirements 2/	13,398,640
Average Cost of Gas per dk	$4.504
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.524
Less: Gas Cost Level in Rates 3/	4.383
Current Gas Cost Adjustment	**$0.141**

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 May 31, 2009, adjusted for losses at .45%
3/ Gas Cost Level in Current Tariff Rates Case No. PU-09-289:

Cost of Purchased Gas	$4.363
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$4.383

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

Summer - June - September	
Total Gas Costs 1/	$60,352,345
Less: Annual MDDQ Costs 1/	11,501,344
Total Gas Costs excluding MDDQ	$48,851,001
Firm Service Requirements 1/	13,398,640
Other Gas Costs per Dk (excluding MDDQ)	$3.646
Summer Seasonal Rate, adjusted for losses 2/	3.662
Less: Gas Cost Level in Rates 3/	3.521
Current Gas Cost Adjustment	**$0.141**
Winter - October - May	
Annual MDDQ Costs 1/	$11,501,344
Winter Firm Service Requirements	12,130,297
MDDQ Costs per Winter Dk	$0.948
Add: Other Gas Costs per Dk	3.646
Winter Seasonal Rate	4.594
Winter Seasonal Rate, adjusted for losses 2/	$4.615

1/ Exhibit B, page 1.
2/ Loss factor of .45%.
3/ Gas Cost Level in Current Tariff Rates Case No. PU-09-289:

	Summer	Winter
Cost of Purchased Gas	$3.505	$4.452
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	$3.521	$4.472

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

	Amount
Total Gas Costs 1/	$12,512,369
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	$3.572
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.588
Less: Gas Cost Level in Rates 2/	3.448
Current Gas Cost Adjustment	**$0.140**

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-09-289:

Cost of Purchased Gas	$3.432
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$3.448

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

	Amount
Total Gas Costs 1/	$3,143,490
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	$3.572
Less: Gas Cost Level in Rates 2/	3.432
Current Gas Cost Adjustment	**$0.140**

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-09-289:
Cost of Purchased Gas $3.432

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

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.

STATEMENT OF RATES
2/ 3/

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

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

STATEMENT OF RATES

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

1/ In accordance with the Commission's regulations, the authorized FERC unit charge per dekatherm is applied to physical transportation deliveries and is applicable to all transportation rate schedules. Pursuant to Section 16 of the General Terms and Conditions herein, the ACA is effectively charged at a rate of $0.0002 per 100 Dekatherm-miles.

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

Service	Rates, Tolls and Charges
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) $168.24/$10^3m^3$
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point
3. Rate Schedule FT-D	FT-D Demand Rate per month $ 4.45/GJ
4. Rate Schedule STFT	STFT Bid Price. Minimum bid of 100% of FT-D Demand Rate
5. Rate Schedule FT-DW	FT-DW Bid Price. Minimum bid of 125% of FT-D Demand Rate
6. Rate Schedule FT-A	FT-A Commodity Rate $ 0.48/10^3m^3
7. Rate Schedule FT-P	Refer to Attachment "2" for applicable FT-P Demand Rate per month
8. Rate Schedule LRS	Contract Term — Effective LRS Rate ($/$10^3m^3$/day) 1-5 years — 10.08 6-10 years — 8.42 15 years — 7.55 20 years — 6.71
9. Rate Schedule LRS-2	LRS-2 Rate per month $50,000
10. Rate Schedule LRS-3	LRS-3 Demand Rate per month $129.55/$10^3m^3$
11. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate & Surcharge for each Receipt Point
12. Rate Schedule IT-D	IT-D Rate $ 0.1606/GJ
13. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service
14. Rate Schedule PT	Schedule No: 9006-01000-0 — PT Rate: $ 67.22/d — PT Gas Rate: 1.0 10^3m^3/d
15. Rate Schedule OS	Schedule No. — Charge 2003034359-2 — $ 899.00 / month 2007262666-1 — $ 434.00 / month 2006253651-1 — $ 11.00 / month 2007262711-1 — $ 6.00 / month 2007262709-1 — $ 303.00 / month 2007262728-1 — $ 859.00 / month 2007262705-1 — $ 1,220.00 / month 2007263949-1 — $ 46.00 / month 2007262175-1 — $ 438.00 / month 2007262669-1 — $ 95.00 / month 2007262602-1 — $ 4.00 / month 2007262701-1 — $ 9.00 / month 2007262727-1 — $ 17.00 / month 2007262698-1 — $ 43.00 / month 2007262609-1 — $ 7.00 / month 2007262668-1 — $ 19.00 / month 2007262697-1 — $ 1,760.00 / month 2007263948-1 — $ 90.00 / month 2003004522-2 — $ 83,333.00 / month
16. Rate Schedule CO_2	Tier — CO_2 Rate ($/$10^3m^3$) 1 — 630.10 2 — 503.07 3 — 349.65

NATURAL GAS TARIFF

NorthWestern Energy

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

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

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

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

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

Transmission Commodity Rate (Monthly Rate per Dkt):

Maximum	$ 0.062431	(R)
Minimum	$ 0.017935	
GTAC Amortization	$ 0.019020	
Balancing Penalty Rate	Higher of $25.00 / Dkt. Or 150% of Market Price	

PLUS:

OTHER APPLICABLE CHARGES: All charges contained on other applicable rate schedules approved by the Public Service Commission of Montana.

GAS TRANSPORTATION ADJUSTMENT CLAUSE: Pursuant to MPSC Order the above GTAC Amortization shall be in effect until the balance is extinguished.

MINIMUM BILL: Per respective contracts.

(continued)

GAS RATE SCHEDULE

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

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

Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is $2.398 per dekatherm.

Issued By: Lisa A. Murphy, Vice President-Chief Financial Officer

STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company SD P.U.C. Section No. 4

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

Division	Receipt Point	Delivery Point	Monthly Customer Charge	Maximum Transportation Charge 2/	Minimum Transportation Charge 2/	Fuel Reimbursement Quantity Percentage 3/
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 AUGUST 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	2,290,031	61,997	(41,169)
July	5,800,231	186,713	990,341
August	7,949,219	268,713	2,001,584
September	9,543,793	559,213	2,802,277
October	10,267,240	568,702	3,062,520
13 month average	$3,400,979	$320,827	$699,000
Rate of Return	8.791%	8.791%	8.791%
Return	$298,980	$28,204	$61,449
Return Requirement - Revenue	$495,082	$46,703	$101,754

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

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

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2008									**$11,725,941**
August	$891,059	$0	$11,188	$902,247	229,458	($0.233)	($33,640) 2/	$935,887	12,661,828
September	(334,878)	0	7,928	(326,950)	286,271	0.000	0	(326,950)	12,334,878
October	(838,712)	0	4,631	(834,081)	479,761	0.845	183,238 3/	(1,017,319)	11,317,559
November	469,987	0	1,170	471,157	969,656	0.845	819,360	(348,203)	10,969,356
December	449,232	4,160 4/	179	453,571	1,894,641	0.845	1,600,972	(1,147,401)	9,821,955
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)
Balance @ May 31, 2009									**($3,693,766)**

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
Balance @ May 31, 2009									**$13,954**

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
Balance @ May 31, 2009									**$101,688**

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.