

October 8, 2010

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

Re: Cost of Gas Adjustment  
(COG) Rate 88 and Rate 99  
Case No. PU-10-\_\_\_\_

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 Rates 88 and 99.

Attachment A is the Rate Summary Sheet (90<sup>th</sup> Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered November 1, 2010.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.643 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 page 1, 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 November 2010.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.643 per dk for residential and firm general service customers, an increase of \$0.642 per dk for small and large interruptible customers and an increase of \$0.639 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 November 2010. The average cost of gas for firm customers, adjusted for losses, is \$4.964.

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 purchases propane supplies from various wholesale suppliers. The cost of propane has increased since the last COG filing due to an increase in the market price of propane. Attachment B page 2 explains the reasons for the increase in the market price of propane.

Exhibit A, page 2 summarizes the cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of November, 2010. The net effect of this filing is an increase of \$2.198 per dk for all customers from the currently effective rates.

Exhibit D shows the calculation of the current cost of gas – propane that will be applicable to Montana-Dakota's customers for the month of November 2010. The average cost of propane for all customers, adjusted for losses, is \$13.173 per dk.

These proposed adjustments, calculated in accordance with Rates 88 and 99, will amount to an increase of approximately \$1,175,700 for natural gas customers and an increase of approximately \$7,900 for propane customers during the month of November 2010. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 92,689 natural gas customers and 332 propane customers in North Dakota as of August 31, 2010.

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 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

**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  
 90th Revised Sheet No. 3  
 Canceling 89th Revised Sheet No. 3

### RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	\$0.30 per day	\$0.812	\$4.933	\$5.745
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$4.933	\$5.071
Interruptible Service - PAR			\$0.120	\$4.018	\$4.138
Interruptible Service - MAFB			\$0.120	\$4.041	\$4.161
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	\$4.933	\$5.530
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$4.018	(Maximum) \$4.889
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	\$5.028	\$5.625
Summer Gas Usage			\$0.597	\$4.077	\$4.674
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.018	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.018	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$4.018	(Maximum) \$4.737
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$13.626	\$14.438
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$13.626	\$14.223

Date Filed: October 8, 2010

Effective Date:

Issued By: Tamie A. Aberle  
 Pricing & Tariff Manager

Case No.:

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

**November 2010**

The established 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 reflective of natural gas prices in the Rocky Mountain region and indicative of the supplies Montana-Dakota purchases for its requirements.

The threat of hurricanes and potential storms throughout the month of September, along with warm temperatures in the lower 48 which lead to increased natural gas fired electric generation, likely contributed to the increase in the price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of October 1, 2010 were 6.7 percent above the five-year average and 4.1 percent below last year's record storage balance.

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

The September 2010 Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 15. The October Outlook is to be published October 13, 2010.

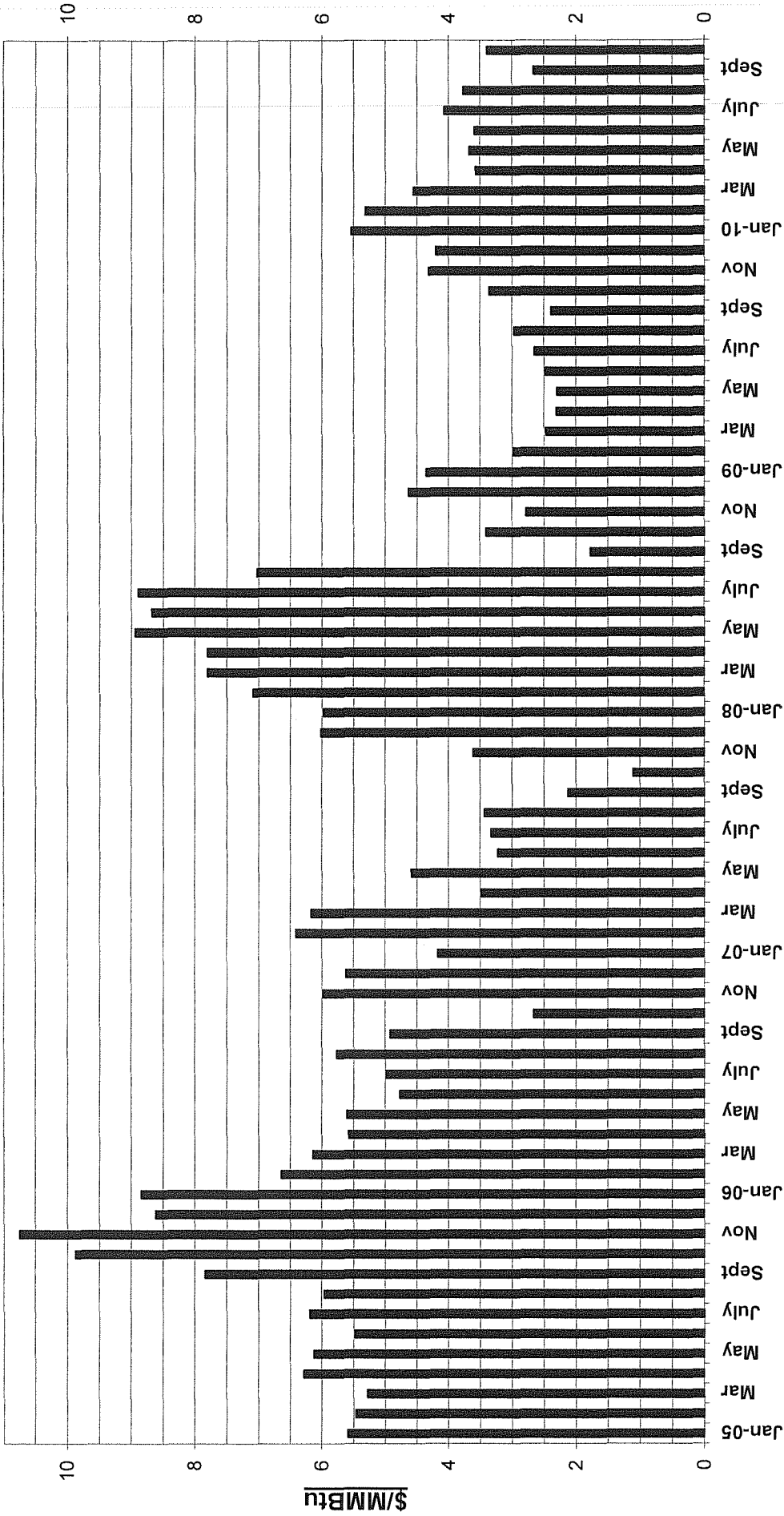
**Montana-Dakota Utilities Co.  
Market Conditions for Regional Propane  
November 2010**

Montana-Dakota uses three regional bulk wholesale propane suppliers for obtaining the lowest prices for Hettinger customers. Each time Montana-Dakota purchases propane, it requests a price quote from each supplier for a specific delivery date and quantity in truckloads, delivering 8,000 to 12,000 gallons. Montana-Dakota selects the lowest price, all other things being equal.

The October prices for propane have increased from the previous level. A change in the price of propane is generally driven by a combination of crude oil prices, weather, demand and inventory levels. As seasonal usage increases, this has resulted in an increase in the price of propane.

The Department of Energy's (DOE) Energy Information Administration (EIA) provides various publications on Energy issues. The information is available on their website:  
<http://www.eia.doe.gov>

**CIG Rocky Mountains Index  
Monthly Gas Prices 2005-2010YTD**



**Month/Year**  
From Inside F.E.R.C.'s Gas Market Report  
Annual Averages: - 2008-\$6.24; 2009-\$3.07; 2010YTD - \$4.01



September 2010

## Short-Term Energy Outlook

September 8, 2010 Release

### Highlights

- These projections reflect updated expectations for economic activity, with forecasted U.S. real gross domestic product (GDP) growth of 2.8 percent in 2010 and 2.3 percent in 2011, down from the previous *Outlook's* growth projections of 3.1 and 2.7 percent for 2010 and 2011, respectively. The 2011 world oil-consumption-weighted real GDP growth rate is also lowered, to 3.3 percent from the 3.6 percent level in last month's *Outlook*.
- EIA projects that the West Texas Intermediate (WTI) spot price, which averaged \$77 per barrel in August, will average \$77 per barrel in the fourth quarter of 2010 and \$82 per barrel in 2011, slightly below the forecasts in last month's *Outlook*.
- EIA expects that regular-grade motor gasoline retail prices, which averaged \$2.35 per gallon last year, will average \$2.69 per gallon over the second half of 2010, down 7 cents per gallon from the average for the first half of the year. In 2011, higher projected crude oil prices combined with strengthening refiner margins are expected to boost annual average motor gasoline prices to \$2.90 per gallon.
- The projected Henry Hub natural gas spot price averages \$4.54 per million Btu (MMBtu) for 2010, a \$0.60-per-MMBtu increase over the 2009 average, but down \$0.15 per MMBtu from the forecast in last month's *Outlook*. EIA expects the Henry Hub spot price will average \$4.76 per MMBtu in 2011, down \$0.22 per MMBtu from last month's *Outlook*.
- The annual average residential electricity price increases only moderately over the forecast period, averaging 11.6 cents per kilowatthour (kWh) in 2010, compared with 11.5 cents per kWh in 2009, and rising to 11.9 cents per kWh in 2011. These projections are virtually unchanged from the previous *Outlook*.

- Estimated U.S. carbon dioxide (CO<sub>2</sub>) emissions from fossil fuels, which declined by 6.9 percent in 2009, are expected to increase by 3.6 percent in 2010. In 2011, projected CO<sub>2</sub> emissions increase by a further 0.4 percent as the expected milder summer reduces electricity use. However, even with these increases, CO<sub>2</sub> emissions remain below their level in any year from 1999 through 2008.

## Global Crude Oil and Liquid Fuels

**Crude Oil and Liquid Fuels Overview.** For the third month in a row, EIA's view of the world oil market remains largely unchanged. Despite a slight reduction in forecast global demand growth and the drop in world oil prices in recent weeks, the projected gradual reduction in global oil inventories over the forecast period should lend support to firming oil prices. World oil prices are expected to rise slowly as global economic growth leads to higher global oil demand, growth in non-OPEC oil supply slows in 2011, and members of the Organization of the Petroleum Exporting Countries (OPEC) continue to support world oil prices.

**Global Crude Oil and Liquid Fuels Consumption.** EIA projects world oil consumption growth of 1.6 million barrels per day (bbl/d) in 2010. Countries outside of the Organization for Economic Cooperation and Development (OECD), especially China, the Middle East countries, and Brazil, represent most of the expected growth in world oil consumption ([World Liquid Fuels Consumption Chart](#)). Projected global oil consumption growth in 2011 is 1.4 million bbl/d, down slightly from the previous *Outlook* due to lower GDP forecast growth.

**Non-OPEC Supply.** EIA projects non-OPEC oil supply will increase by 0.7 million bbl/d in 2010 with the growth coming mainly from the United States, Brazil, and the former Soviet Union. Forecasted non-OPEC supply falls by 160,000 bbl/d in 2011, primarily because of declining total North Sea production and lower supply originating in the former Soviet Union, particularly Russia. This would be only the third time in the last 15 years that non-OPEC supplies fail to grow year-over-year, following non-OPEC production declines in 2005 and 2008, which were primarily the result of supply disruptions in the Gulf of Mexico.

**OPEC Supply.** EIA expects OPEC crude oil production to rise slightly through 2011 to accommodate increasing world oil demand and to maintain OPEC market objectives. OPEC crude oil production is projected to increase by 0.3 and 0.5 million bbl/d in 2010 and 2011, respectively, with non-crude petroleum liquids expected to increase by 0.6 million bbl/d in 2010 and 0.7 million bbl/d in 2011. OPEC surplus capacity should

remain near 5 million bbl/d compared with 4.3 million in 2009 and 1.5 million in 2008 (OPEC Surplus Crude Oil Production Capacity Chart).

*OECD Petroleum Inventories.* Commercial inventories held by OECD countries stood at an estimated 2.75 billion barrels at the end of the second quarter of 2010, equivalent to about 61 days of forward cover, and roughly 95 million barrels more than the 5-year average for the corresponding time of year (Days of Supply of OECD Commercial Stocks Chart). OECD oil inventories decline throughout the forecast period, although days-forward-cover should remain high by historical standards.

*Crude Oil Prices.* WTI crude oil spot prices averaged about \$77 per barrel in August 2010, very close to the July average, but \$3 per barrel lower than projected in last month's *Outlook*. WTI spot prices averaged almost \$82 per barrel over the first 10 days of August but then fell by \$9 per barrel over the next 2 weeks as the market reacted to a series of reports of a stumbling economic recovery. EIA has lowered the average fourth quarter 2010 forecasted WTI spot price to \$77 per barrel, compared with \$81 per barrel in last month's *Outlook*. WTI spot prices are projected to rise to \$84 per barrel by the end of next year (West Texas Intermediate Crude Oil Price Chart).

Energy price forecasts are highly uncertain, as history has shown (Energy Price Volatility and Forecast Uncertainty). WTI futures for November 2010 delivery for the 5-day period ending September 2 averaged \$75 per barrel, and implied volatility averaged 32 percent. This made the lower and upper limits of the 95-percent confidence interval \$61 and \$94 per barrel, respectively, for WTI delivered November 2010. Last year at this time, WTI for November 2009 delivery averaged \$70 per barrel, and implied volatility averaged 47 percent, with the limits of the 95-percent confidence interval at \$51 and \$96 per barrel.

## U.S. Crude Oil and Liquid Fuels

*U.S. Liquid Fuels Consumption.* Projected total liquid fuels consumption grows by 160,000 bbl/d (0.8 percent) in 2010, and 130,000 bbl/d (0.7 percent) in 2011 as all of the major petroleum products register consumption growth (U.S. Liquid Fuels Consumption Growth Chart). This reverses the trend of falling consumption during 2006-2009. A year-over-year decline in total liquid fuels consumption averaging 40,000 bbl/d in the first quarter of 2010 was followed by a year-over-year rise averaging 440,000 bbl/d in the second quarter of 2010, led by increases in motor gasoline and distillate fuel oil consumption. During 2010 as a whole, gasoline consumption is projected to increase by 0.3 percent and distillate consumption is projected to grow by 2.0 percent. Projected gasoline consumption growth increases to

0.8 percent in 2011 while distillate fuel consumption growth moderates to 0.7 percent. Jet fuel consumption grows at an average annual rate of about 0.7 percent through 2011.

***U.S. Liquid Fuels Supply and Imports.*** Domestic crude oil production, which increased by 410,000 bbl/d in 2009, is projected to increase by 70,000 bbl/d in 2010 ([U.S. Crude Oil Production Chart](#)). Crude oil production shut in by hurricanes during June, July, and August averaged 47,000 bbl/d, about half of EIA's original forecast of 96,000 bbl/d for those 3 months. Forecast total domestic crude oil production rises by 10,000 bbl/d to 5.44 million bbl/d in 2011. That projection includes a 120,000 bbl/d decline in the federal Gulf of Mexico (GOM) and a 150,000 bbl/d increase in lower-48 non-GOM production next year. These projections reflect EIA's estimates of an average reduction in crude oil output of about 82,000 bbl/d in 2011 resulting from the current 6-month moratorium on deepwater drilling. Projected ethanol production, which averaged 710,000 bbl/d in 2009, increases to an average of 850,000 bbl/d in 2010 and 880,000 bbl/d in 2011.

EIA forecasts that liquid fuel net imports (including both crude oil and refined products), which fell from 57 percent to 51 percent of total U.S. consumption between 2008 and 2009, will average about 50 percent of total consumption in 2010 and 2011.

***U.S. Petroleum Product Prices.*** Projected regular-grade gasoline retail prices rise from an average \$2.35 per gallon in 2009 to an average \$2.72 per gallon in 2010 and \$2.90 per gallon in 2011. Forecast regular-grade pump prices average \$2.76 per gallon this summer, an increase of 33 cents from last summer. On-highway diesel fuel retail prices, which averaged \$2.46 per gallon in 2009, average \$2.93 per gallon in 2010 and \$3.10 in 2011 in this forecast. Refining margins, which have been at their lowest levels since 2003, are projected to average about \$2 per barrel higher next year because of growing global product demand and shutdowns of excess global refining capacity.

## **Natural Gas**

***U.S. Natural Gas Consumption.*** EIA expects total natural gas consumption will increase by 4.0 percent from 2009 levels to 65.0 billion cubic feet per day (Bcf/d) in 2010 and then remain relatively flat in 2011 ([Total U.S. Natural Gas Consumption Growth Chart](#)). The power generation and industrial sectors account for the bulk of the projected increase in consumption in 2010 over 2009.

Projected consumption of natural gas for power generation grows by nearly 1.3 Bcf/d to 20.2 Bcf/d in 2010. The use of natural gas for electric power generation surged this year because of the 23 percent increase in U.S. cooling degree- days, resulting in an

over 300 Bcf (11 percent) increase in natural gas consumption in the power generation sector over the last 4 months compared with the same period last year. Projected natural gas consumption in the power generation sector falls by 0.4 Bcf/d (2.0 percent) next year because of the expected return to near-normal summer temperatures.

Projected use of natural gas in the industrial sector also grows significantly in 2010, increasing by 6.4 percent, from 16.8 Bcf/d in 2009 to 17.9 Bcf/d in 2010. Forecasted industrial-sector consumption growth slows to 1.2 percent in 2011 as the projected increase in the natural-gas-weighted industrial production index slows from 7.0 percent in 2010 to 2.1 percent in 2011.

***U.S. Natural Gas Production and Imports.*** EIA predicts total marketed natural gas production will increase by 1.2 Bcf/d (2.1 percent) to 61.2 Bcf/d in 2010. Projected production declines gradually in 2011, falling by 1.2 Bcf/d (1.9 percent) as relatively low prices depress drilling activity.

A total of 7.9 Bcf of natural gas production was shut in because of hurricanes during June, July, and August, compared with EIA's original projection of 57.4 Bcf for those 3 months. Nevertheless, the next 2 months are typically the height of the hurricane season and additional outages are included in this forecast. Based on the latest NOAA hurricane forecast, during the final 3 months of the hurricane season this forecast includes 66.3 Bcf in outages with almost two-thirds of that total occurring in September.

EIA forecasts gross pipeline imports of 9.2 Bcf/d in 2010, an increase of 1.3 percent from 2009. Forecasted imports of liquefied natural gas (LNG) average 1.25 Bcf/d in 2010 and 1.32 Bcf/d in 2011. Low U.S. prices have discouraged imports, and ample domestic natural gas production has reduced the need for large quantities of LNG despite significantly higher consumption.

***U.S. Natural Gas Inventories.*** On August 27, working natural gas in storage was 3,106 Bcf ([U.S. Working Natural Gas in Storage Chart](#)), which is 208 Bcf less than the previous year's level and 169 Bcf greater than the 5-year (2005-2009) average. Weekly U.S. natural gas inventory builds this year have fallen below last year's builds in 16 of the last 18 weeks. This was primarily the result of the very warm summer and the resulting increase in natural gas consumption in the power generation sector. EIA expects working gas inventories in the United States to total 3,687 Bcf at the end of the injection season, about 3 percent below the record level reached at the end of the injection season last year.

**U.S. Natural Gas Prices.** The Henry Hub spot price averaged \$4.32 per MMBtu in August, \$0.31 per MMBtu lower than the average spot price in July ([Henry Hub Natural Gas Price Chart](#)). EIA expects prices will fall below \$4 per MMBtu in September and October before rebounding at the onset of colder weather. EIA now expects prices will average \$4.76 per MMBtu in 2011; this is a downward revision from the \$4.98 per MMBtu forecast in last month's *Outlook*.

Uncertainty over future natural gas prices is lower this year compared with last year at this time. Natural gas futures for November 2010 delivery for the 5-day period ending September 2 averaged \$4.07 per MMBtu, and the average implied volatility over the same period was 48 percent. This produced lower and upper bounds for the 95-percent confidence interval of \$2.84 and \$5.83 per MMBtu, respectively. At this time last year, the natural gas November 2009 futures contract averaged \$3.89 per MMBtu and implied volatility averaged 75 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$2.22 and \$6.81 per MMBtu.

## Electricity

**U.S. Electricity Consumption.** During the first half of 2010, total consumption of electricity rose an estimated 4.2 percent compared with the first half of last year. Growth during the second half is projected to be slightly higher, rising 5.2 percent compared with the same period in 2009. High temperatures during July and August have pushed up sales of electricity in the residential and commercial sectors, especially in the Midwest and Northeast. Projected electricity sales to the industrial sector increase by 6 percent in 2010, but growth slows to 0.2 percent next year as expected growth in industrial output moderates. Total forecast consumption of electricity falls slightly in 2011 since summer temperatures are forecast to return to near-normal levels ([U.S. Total Electricity Consumption Chart](#)).

**U.S. Electricity Generation.** Total U.S. electric-power-sector generation grew by about 3 percent during the first half of this year compared with the same period in 2009. Generation from coal increased by 6.1 percent, and natural gas generation increased by 4.7 percent. Hydropower output declined by nearly 8 percent as water runoff in the Pacific Northwest was low this spring compared with last year. Some areas of the United States set hourly peak load records during July and August and much of this peak demand was fueled by natural gas, boosting projected year-over-year growth in natural gas generation during the second half of 2010 to over 8 percent.

**U.S. Electricity Retail Prices.** Overall, the average U.S. residential electricity price was down slightly during the first half of 2010 compared with the first half of 2009 in response to lower fuel costs for generating power. The largest price declines occurred

in New England (-7.7 percent) and the West South Central region (-5.3 percent). In contrast, residential prices in the Middle Atlantic region were up 6.2 percent during the first half of the year as some of the price caps in Pennsylvania began to expire. Generation fuel costs have increased this year, which is expected to boost U.S. residential electricity prices by about 2.1 percent in the second half of 2010 compared with the same period last year, and by 2.4 percent during 2011 ([U.S. Residential Electricity Prices Chart](#)).

## Coal

**U.S. Coal Consumption.** Projected coal consumption in the electric power sector increases by 6.2 percent in 2010 because of the warm summer weather and associated increase in electricity generation. With a small projected decline (0.4 percent) in electricity consumption in 2011, coal-fired electricity generation and related coal consumption are projected to decline at a slightly higher rate (0.8 percent), primarily because of forecasted increases in nuclear and renewable-based electricity generation ([U.S. Coal Consumption Growth Chart](#)).

**U.S. Coal Supply.** Drawdowns in both producer and end-user inventories ([U.S. Electric Power Sector Coal Stocks Chart](#)) are forecasted to meet the increased coal consumption in 2010. Consequently, projected coal production falls by 0.3 percent in 2010. EIA forecasts a 1.8-percent increase in coal production in 2011 ([U.S. Annual Coal Production Chart](#)).

**U.S. Coal Trade.** U.S. coal gross imports and gross exports fell by 34 percent and 28 percent in 2009, respectively. Forecast coal exports will grow by 25 percent in 2010, driven in part by rising demand for metallurgical coal. Forecast coal exports in 2011 are relatively unchanged from 2010 levels. Metallurgical coal currently constitutes a larger share of the U.S. coal export market than steam coal.

EIA projects coal imports to decline an additional 15 percent in 2010 as increased consumption is met by draws on domestic inventories. Projected coal imports grow by 35 percent in 2011, but the annual tonnage (26 million short tons) remains significantly below the 2005-through-2008 average of 34 million short tons.

**U.S. Coal Prices.** The 2009 delivered electric-power-sector coal price increased by 6.7 percent despite decreases in spot coal prices, lower prices for other fossil fuels, and declines in coal-fired electricity generation. This higher cost of delivered coal reflected the impacts of longer-term power-sector coal contracts initiated during a period of high prices and rising transportation costs. The projected electric-power-

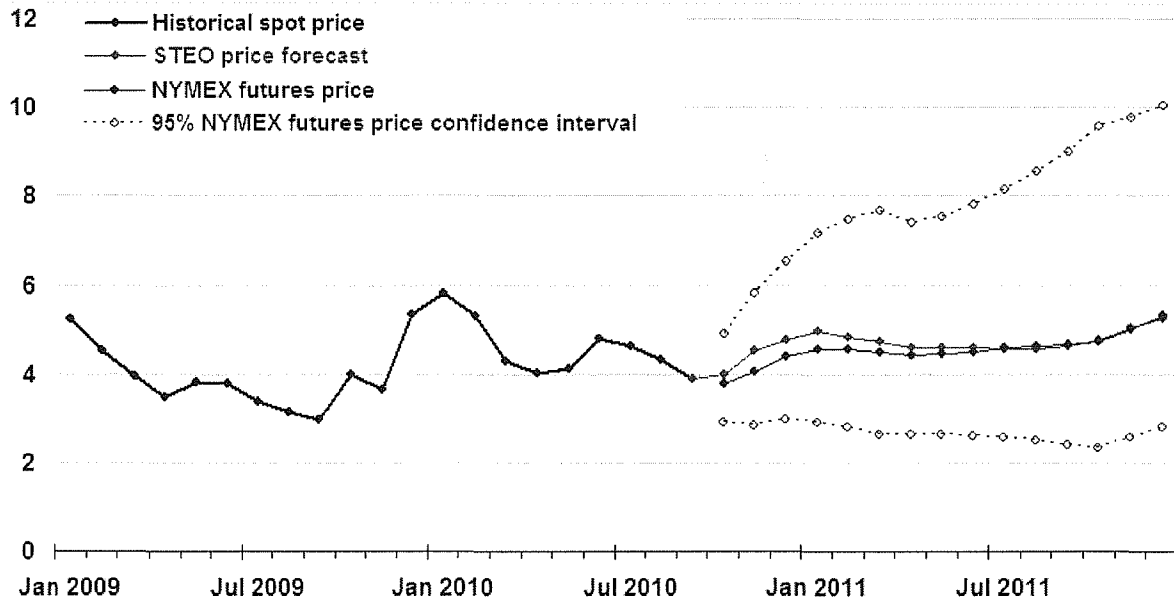
sector delivered coal price increases by 1.7 percent to average \$2.25 per MMBtu in 2010, and then declines to an average of \$2.19 per MMBtu in 2011.

### **U.S. Carbon Dioxide Emissions**

Forecasted economic growth combined with increased use of coal and natural gas is expected to contribute to increases in fossil-fuel CO<sub>2</sub> emissions of 3.6 percent in 2010 ([U.S. Carbon Dioxide Emissions Growth Chart](#)). Projected coal-related CO<sub>2</sub> emissions increase by 6.8 percent in 2010 primarily because of increased electricity sector coal usage. Higher natural gas consumption in the industrial and electric power sectors is expected to lead to a 4.3-percent increase in CO<sub>2</sub> emissions from natural gas. Demand for petroleum in the transportation sector (motor gasoline, diesel fuel, and jet fuel) combined with continued industrial sector fossil fuel demand growth contribute to the projected 0.4-percent increase in fossil-fuel CO<sub>2</sub> emissions in 2011. However, even with these increases, projected CO<sub>2</sub> emissions in 2010 and 2011 remain below their level in any year from 1999 through 2008.

## Henry Hub Natural Gas Price

dollars per million btu

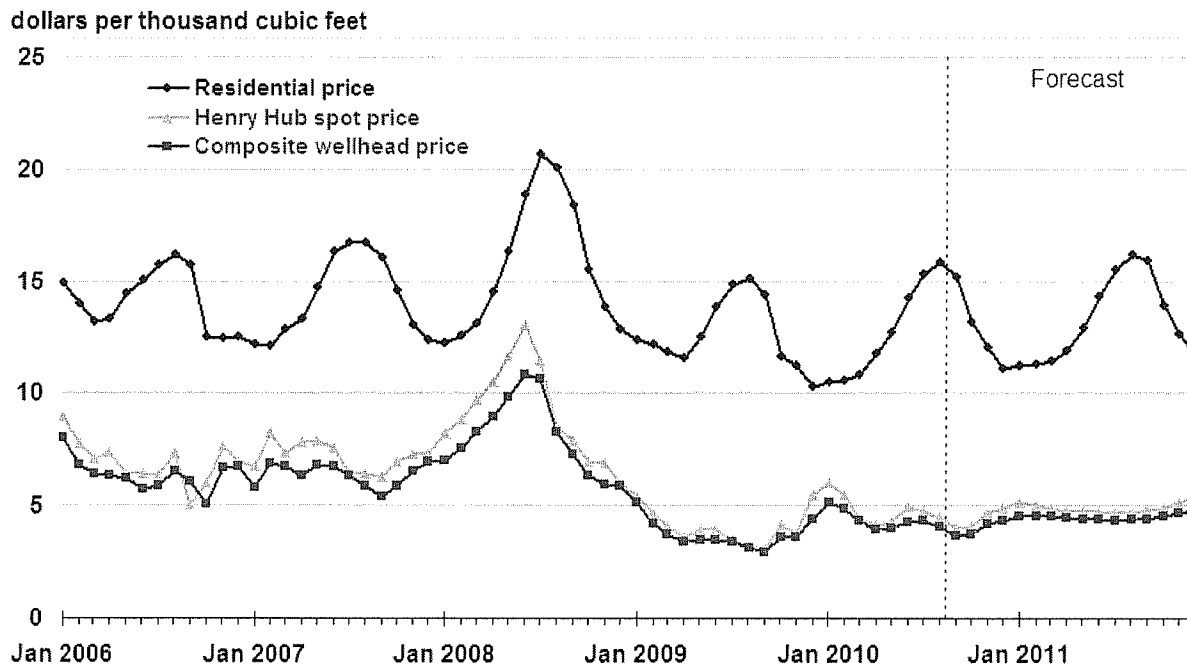


*Note: Confidence interval derived from options market information for the 5 trading days ending September 2, 2010  
Intervals not calculated for months with sparse trading in "near-the-money" options contracts*



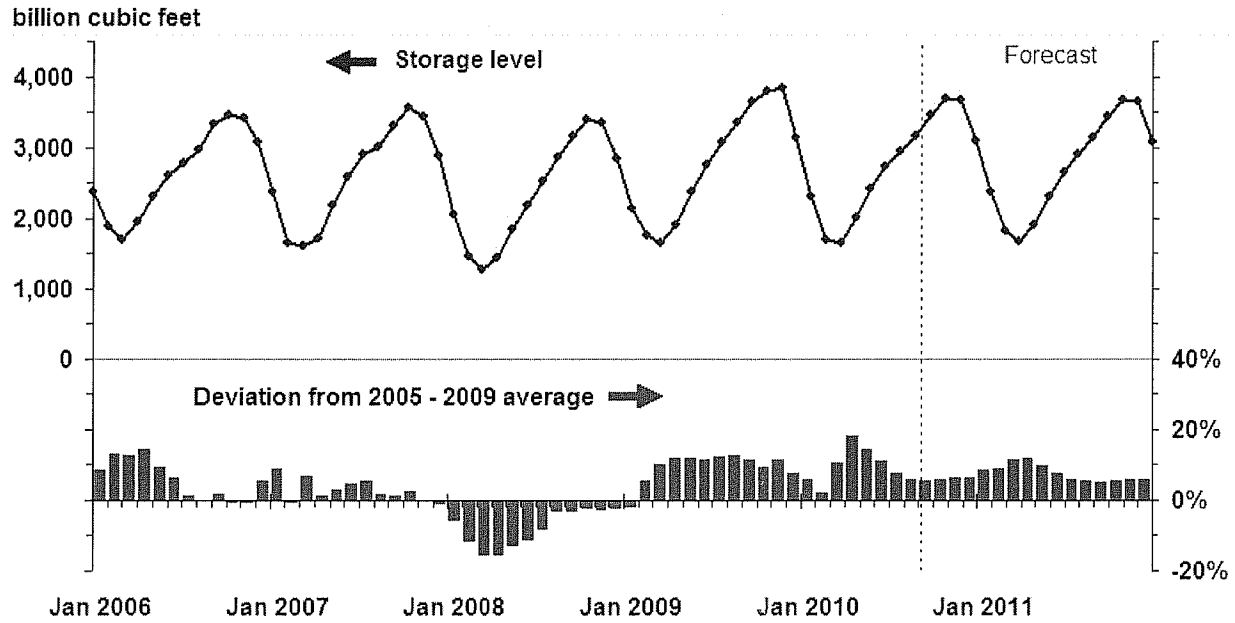
Source: Short-Term Energy Outlook, September 2010; Reuters News Service; and CME Group

### Natural Gas Prices



Source: Short-Term Energy Outlook, September 2010; Reuters News Service

### U.S. Working Natural Gas in Storage

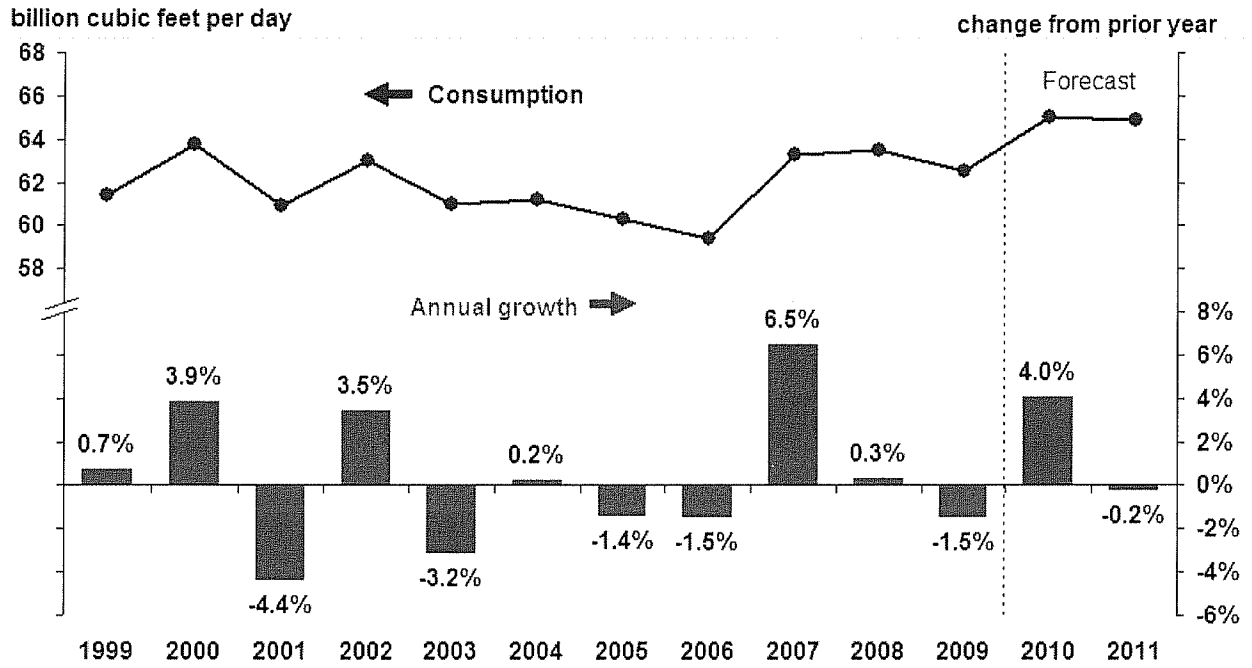


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2005 - Dec. 2009

Source: Short-Term Energy Outlook, September 2010



### U.S. Total Natural Gas Consumption



Source: Short-Term Energy Outlook, September 2010

MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS TARIFF SHEET  
NORTH DAKOTA GAS  
EFFECTIVE NOVEMBER 2010

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<b><u>Gas Cost Adjustment:</u></b>				
Gas Cost Level (Exhibit B)	\$4.964	\$5.059	\$4.028	\$4.010
Prior Gas Cost	<u>4.321</u>	<u>4.416</u>	<u>3.386</u>	<u>3.371</u>
Current Gas Cost Adjustment	\$0.643	\$0.643	\$0.642	\$0.639
<b><u>Surcharge Adjustment:</u></b>				
Current Adjustment	(\$0.023)	(\$0.023)	(\$0.010)	\$0.031
Prior Adjustment	<u>(0.023)</u>	<u>(0.023)</u>	<u>(0.010)</u>	<u>0.031</u>
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<b><u>Market Based Pricing Differential</u></b>				
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
<b>Net Increase (Decrease) in Gas Costs</b>	<b><u>\$0.643</u></b>	<b><u>\$0.643</u></b>	<b><u>\$0.642</u></b>	<b><u>\$0.639</u></b>
Gas Cost Level	\$4.964	\$5.059	\$4.028	\$4.010
Plus: Surcharge	<u>(0.023)</u>	<u>(0.023)</u>	<u>(0.010)</u>	<u>0.031</u>
Total Gas Cost Level in Tariff Rates	<b><u>\$4.941</u></b>	<b><u>\$5.036</u></b>	<b><u>\$4.018</u></b>	<b><u>\$4.041</u></b>

MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS - PROPANE TARIFF SHEET  
NORTH DAKOTA PROPANE  
EFFECTIVE NOVEMBER 2010

**Cost of Gas - Propane:**

Current Propane Cost (Exhibit D)	\$13.173
Prior Propane Cost	<u>10.978</u>
Current Propane Cost Adjustment	<u><u>\$2.195</u></u>

**Surcharge Adjustment:**

Current Adjustment	\$0.461
Prior Adjustment	<u>0.461</u>
Change in Surcharge Adjustment	\$0.000

**Market Based Pricing Differential**

Current Adjustment	(\$0.008)
Prior Adjustment	<u>(0.011)</u>
Change in Margin Sharing Provision	\$0.003

**Net Increase (Decrease) in Gas Costs**

\$2.198

Propane Cost Level	\$13.173
Plus: Surcharge	<u>0.461</u>
Total Propane Cost Level in Rates	<u><u>\$13.634</u></u>

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
RESIDENTIAL AND GENERAL SERVICE  
EFFECTIVE NOVEMBER 2010**

	Amount
Total Gas Costs 1/	\$67,247,626
Residential and General Service dk Requirements 2/	13,608,074
Average Cost of Gas per dk	\$4.942
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.964
Less: Gas Cost Level in Rates 3/	4.321
<b>Current Gas Cost Adjustment</b>	<b>\$0.643</b>

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 August 31, 2010, adjusted for losses at .45%

3/ Gas Cost Level in Current Tariff Rates Case No. PU-10-8:

Cost of Purchased Gas	\$4.302
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.321

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
OPTIONAL SEASONAL - RATE 72  
EFFECTIVE NOVEMBER 2010**

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$67,247,626
Less: Annual MDDQ Costs 1/	<u>11,592,671</u>
Total Gas Costs excluding MDDQ	\$55,654,955
Firm Service Requirements 1/	13,608,074
Other Gas Costs per Dk (excluding MDDQ)	\$4.090
Summer Seasonal Rate, adjusted for losses 2/	4.108
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,592,671
Winter Firm Service Requirements	12,259,036
MDDQ Costs per Winter Dk	\$0.946
Add: Other Gas Costs per Dk	<u>4.090</u>
Winter Seasonal Rate	5.036
Winter Seasonal Rate, adjusted for losses 2/	\$5.059
Less: Gas Cost Level in Rates 3/	<u>4.416</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.643</u></u></b>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-10-8:

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$3.450	\$4.396
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$3.466	\$4.416

**MONTANA-DAKOTA UTILITIES CO.**  
**CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA**  
**INTERRUPTIBLE**  
**EFFECTIVE NOVEMBER 2010**

	Amount
Total Gas Costs 1/	\$14,047,574
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$4.010
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.028
Less: Gas Cost Level in Rates 2/	3.386
<b>Current Gas Cost Adjustment</b>	<b>\$0.642</b>

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-10-8:

Cost of Purchased Gas	\$3.371
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.386

MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
AIR FORCE INTERRUPTIBLE  
EFFECTIVE NOVEMBER 2010

	<u>Amount</u>
Total Gas Costs 1/	\$3,529,182
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$4.010
Less: Gas Cost Level in Rates 2/	<u>3.371</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.639</u></u></b>

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-10-8:  
Cost of Purchased Gas \$3.371

**Montana-Dakota Utilities Co.  
Schedule of Applicable Effective Pipeline Rates  
November 2010 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	0.190	N.A.	N.A.	3.310
MINIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.190	N.A.	N.A.	31.074
MINIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
VOLUMETRIC CAPACITY RELEASE CHARGE						
MAXIMUM	RATE PER DKT	24.261	N.A.	N.A.	N.A.	24.261
MINIMUM	RATE PER DKT	0.000	N.A.	N.A.	N.A.	0.000

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 2.153%, CONSISTING OF 2.614% FOR THE CURRENT PERCENTAGE AND (0.461%) 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 0.818 CENTS, CONSISTING OF 0.830 CENTS FOR THE CURRENT RATE AND (0.012) 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.

Issued On: October 1, 2010  
 Docket Number:  
 FERC Order Date:

Effective On: October 1, 2010

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
VOLUMETRIC CAPACITY RELEASE CHARGE						
MAXIMUM	RATE PER DKT	1.561	N.A.	N.A.	N.A.	1.561
MINIMUM	RATE PER DKT	0.052	N.A.	N.A.	N.A.	0.052

Issued On: September 30, 2010  
 Docket Number: RP10-1378-000  
 FERC Order Date:

Effective On: September 30, 2010

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 0.402%, CONSISTING OF 0.568% FOR THE CURRENT PERCENTAGE AND (0.166%) 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 0.182 CENTS, CONSISTING OF 0.346 CENTS FOR THE CURRENT RATE AND (0.164) 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.

Issued On: October 1, 2010  
 Docket Number:  
 FERC Order Date:

Effective On: October 1, 2010

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

PART 4.1  
Statement of Rates  
T-1 and T-1B - Long Term Base Tariff Rates  
v.0.0.0

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 in this section are subject to the revenue retrieval provision pursuant to Article X of the Stipulation at Docket No. RP06-72-000, et al.

Issued: July 28, 2010  
Effective: July 28, 2010

Docket No. RP10-1004-000  
Accepted:

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

PART 4.7  
Statement of Rates  
ACA and Compressor Usage Surcharge  
v.0.0.0

STATEMENT OF RATES

	Commodity Rate -----
Annual Charge Adjustment (ACA) Rate (per Dekatherm) 1/	\$0.0019
Compressor Usage Surcharge (per 100 Dekatherm-miles) 2/	\$0.0020

1/ In accordance with the Commission's regulations, the authorized FERC unit charge per dekatherm is applied to physical transportation deliveries and is applicable to all transportation rate schedules. Pursuant to Section 6.16 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 6.44 of the General Terms and Conditions.

Issued: July 28, 2010  
Effective: July 28, 2010

Docket No. RP10-1004-000  
Accepted:

**TABLE OF RATES, TOLLS & 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) \$213.83/10 <sup>3</sup> m <sup>3</sup>		
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D	FT-D Demand Rate per month \$ 5.66/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 \$ 0.55/10 <sup>3</sup> m <sup>3</sup>		
7. Rate Schedule FT-P	Refer to Attachment "2" for applicable FT-P Demand Rate per month		
8. Rate Schedule LRS	<u>Contract Term</u>		<u>Effective LRS Rate (\$/10<sup>3</sup>m<sup>3</sup>/day)</u>
	1-5 years		10.43
	6-10 years		8.72
	15 years		7.82
	20 years		6.94
9. Rate Schedule LRS-2	LRS-2 Rate per month \$50,000		
10. Rate Schedule LRS-3	LRS-3 Demand Rate per month \$129.55/10 <sup>3</sup> m <sup>3</sup>		
11. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate & Surcharge for each Receipt Point		
12. Rate Schedule IT-D	IT-D Rate \$ 0.2045/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	\$ 60.50/d	1.0 10 <sup>3</sup> m <sup>3</sup> /d
	9009-01001-1	\$660.00/d	50.0 10 <sup>3</sup> m <sup>3</sup> /d
15. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2010418777	\$ 209.00 / month	
	2010416547	\$ 24.00 / month	
	2010416549	\$ 63.00 / month	
	2010416543	\$ 7.00 / month	
	2010416546	\$ 5.00 / month	
	2010416548	\$ 1.00 / month	
	2010416540	\$ 42.00 / month	
	2010416550	\$ 96.00 / month	
	2010418778	\$ 350.00 / month	
	2010416545	\$ 1,688.00 / month	
	2010418000	\$ 151.00 / month	
	2010416551	\$ 46.00 / month	
	2010417322	\$ 153.00 / month	
	2010416544	\$ 79.00 / month	
	2010416541	\$ 209.00 / month	
2003004522	\$ 83,333.00 / month		
16. Rate Schedule CO <sub>2</sub>	<u>Tier</u>	<u>CO<sub>2</sub> Rate (\$/10<sup>3</sup>m<sup>3</sup>)</u>	
	1	520.03	
	2	411.79	
	3	272.12	

NATURAL GAS TARIFF



Canceling	<u>20<sup>th</sup></u>	Revised	Sheet No.	<u>80.1</u>
	<u>19<sup>th</sup></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	\$ 102.95	(I)
10,001 to 30,000	\$ 148.05	(I)
>30,000	\$ 328.50	(I)

**PLUS:**

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	\$ 8.417686	(I)
--	-------------	-----

Transmission Commodity Rate (Monthly Rate per Dkt):

Maximum	\$ 0.063787	(I)
Minimum	\$ 0.017935	
GTAC Amortization	\$ 0.000962	
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.

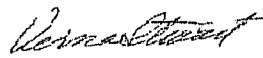
**MINIMUM BILL:** Per respective contracts.

(continued)

Commission Approved: July 8, 2010  
Docket No.: D2009.9.129, Interim Order 7046g  
Tariff Letter No. 173-G

Effective for service rendered on or after  
July 8, 2010

PUBLIC SERVICE COMMISSION

 Secretary

**GAS RATE SCHEDULE**

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

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

Effective Date: January 10, 2001

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**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**

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 NOVEMBER 2010**

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2010	\$12,490,454	\$628,710	\$3,092,339
November	11,058,525	540,535	2,526,144
December	7,643,535	373,607	1,239,721
January 2011	2,818,025	175,671	(365,755)
February	(252,367)	44,416	(1,317,870)
March	(1,312,202)	(18,079)	(1,922,284)
April	(1,236,674)	(31,858)	(1,756,301)
May	621,582	32,359	(1,040,358)
June	3,448,342	138,215	(52,841)
July	6,548,379	254,621	981,115
August	9,624,355	369,766	1,995,745
September	11,768,944	681,273	2,794,372
October	13,235,532	728,737	3,038,212
13 month average	<u>\$5,881,264</u>	<u>\$301,383</u>	<u>\$708,634</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$517,022	\$26,495	\$62,296
Return Requirement	<u>\$711,633</u>	<u>\$36,468</u>	<u>\$85,745</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.  
COST OF GAS - PROPANE  
NORTH DAKOTA  
EFFECTIVE NOVEMBER 2010

Cost of Purchased Propane	\$47,212
Gallons Purchased	39,343
Projected dk Sales	3,600
Propane Cost per Dk	\$13.114
Average Cost of Propane as Adjusted for Losses @ 99.55%	13.173
Less: Propane Cost Level in Rates 1/	<u>10.978</u>
Current Propane Cost Adjustment	<u><u>\$2.195</u></u>

1/ Propane Cost Level in Current Rates - Case No. PU-10-8

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

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2010</b>									<b><u>(\$695,379)</u></b>
August	(\$305,149)	\$0	(\$94)	(\$305,243)	253,885	(\$0.515)	(\$130,750)	(\$174,493)	(869,872)
<b>Balance @ August 31, 2010</b>									<b><u>(\$869,872)</u></b>

1/ Interest calculated at the current investment rate.

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

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2010</b>									<b><u><u>(\$18,649)</u></u></b>
August	\$9,163	\$0	(\$3)	\$9,160	29,023	(\$0.152)	(\$4,411)	\$13,571	(5,078)
<b>Balance @ August 31, 2010</b>									<b><u><u>(\$5,078)</u></u></b>

1/ Interest calculated at the current investment rate.

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

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2010</b>									<b><u><u>\$14,139</u></u></b>
August	(\$14,595)	\$0	\$2	(\$14,593)	3,296	\$0.024	\$79	(\$14,672)	(533)
<b>Balance @ August 31, 2010</b>									<b><u><u>(\$533)</u></u></b>

1/ Interest calculated at the current investment rate.