

April 8, 2013

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

Re: Cost of Gas Adjustment  
(COG) Rate 88  
Case No. PU-13-008

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 two (2) copies of a Cost of Gas (COG) change pursuant to the terms of Rates 88.

Attachment A is the Rate Summary Sheet (113<sup>th</sup> Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered May 1, 2013.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.356 per dk since the last filing due to an increase in the overall commodity price of gas. Attachment B explains the reasons for the increase in the market price of gas. In addition, firm transportation capacity was changed in certain areas of the system, resulting in a system wide change in demand allocation and a decrease of approximately \$0.028 per dk. There has also been a change in pipeline rates, as shown on Attachment C, decreasing the cost of gas \$0.021 per dk.

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 May 2013.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.307 per dk for residential customers and firm general customers, an increase of \$0.346 per dk for small and large interruptible customers and an increase of \$0.345 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 May 2013. The average cost of gas for firm customers, adjusted for losses, is \$5.081.

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. There is no change in the cost of propane since the February 2013 COG filing.

Exhibit E shows the calculation of the surcharge adjustment which will apply during the period May 1, 2013 through April 30, 2014. The surcharge is a negative \$0.777 per dk, a decrease of \$1.423 per dk for all customers.

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 May 2013. The net effect of this filing is a decrease of \$1.423 per dk for all customers from the currently effective rates.

These proposed adjustments, calculated in accordance with Rate 88 and 99, will amount to an increase of approximately \$192,100 for natural gas customers and a decrease of approximately \$3,100 for propane customers during the month of May 2013. All of Montana-Dakota's retail natural gas and propane customers in North Dakota may be affected by this proposal. There were 98,771 natural gas customers and 341 propane customers in North Dakota as of January 31, 2013.

Please refer all inquiries regarding this filing to:

Ms. Rita A. Mulkern  
Director of Regulatory Affairs  
Montana-Dakota Utilities Co.  
400 North Fourth Street  
Bismarck, ND 58501

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

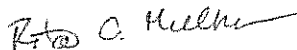
Mr. Daniel S. Kuntz  
Associate General Counsel  
MDU Resources Group, Inc.  
P. O. Box 5650  
Bismarck, ND 58506-5650

Montana-Dakota submitted a check for the amount of \$550 in accordance with North Dakota Century Code Section 49-05-05 on January 10, 2013. This payment will cover the filing fee associated with the monthly COG filings.

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,

A handwritten signature in black ink, appearing to read "Rita A. Mulkern". The signature is written in a cursive style with a loop at the end.

Rita A. Mulkern  
Director of Regulatory Affairs

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  
 113<sup>th</sup> Revised Sheet No. 3  
 Canceling 112<sup>th</sup> Revised Sheet No. 3

### RATE SUMMARY SHEET

Page 1 of 2

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	\$0.30 per day	\$0.812	\$4.958	\$5.770
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$4.958	\$5.096
Interruptible Service - PAR			\$0.120	\$3.983	\$4.103
Interruptible Service - MAFB			\$0.120	\$3.703	\$3.823
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	\$4.958	\$5.555
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$3.983	(Maximum) \$4.854
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	\$0.597	\$5.044	\$5.641
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	\$3.983	(Maximum) \$4.702
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$9.642	\$10.454
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	\$9.642	\$10.239

Date Filed: April 8, 2013

Effective Date:

Issued By: Tamie A. Aberle  
 Director - Regulatory Affairs

Case No.:

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

**May 2013**

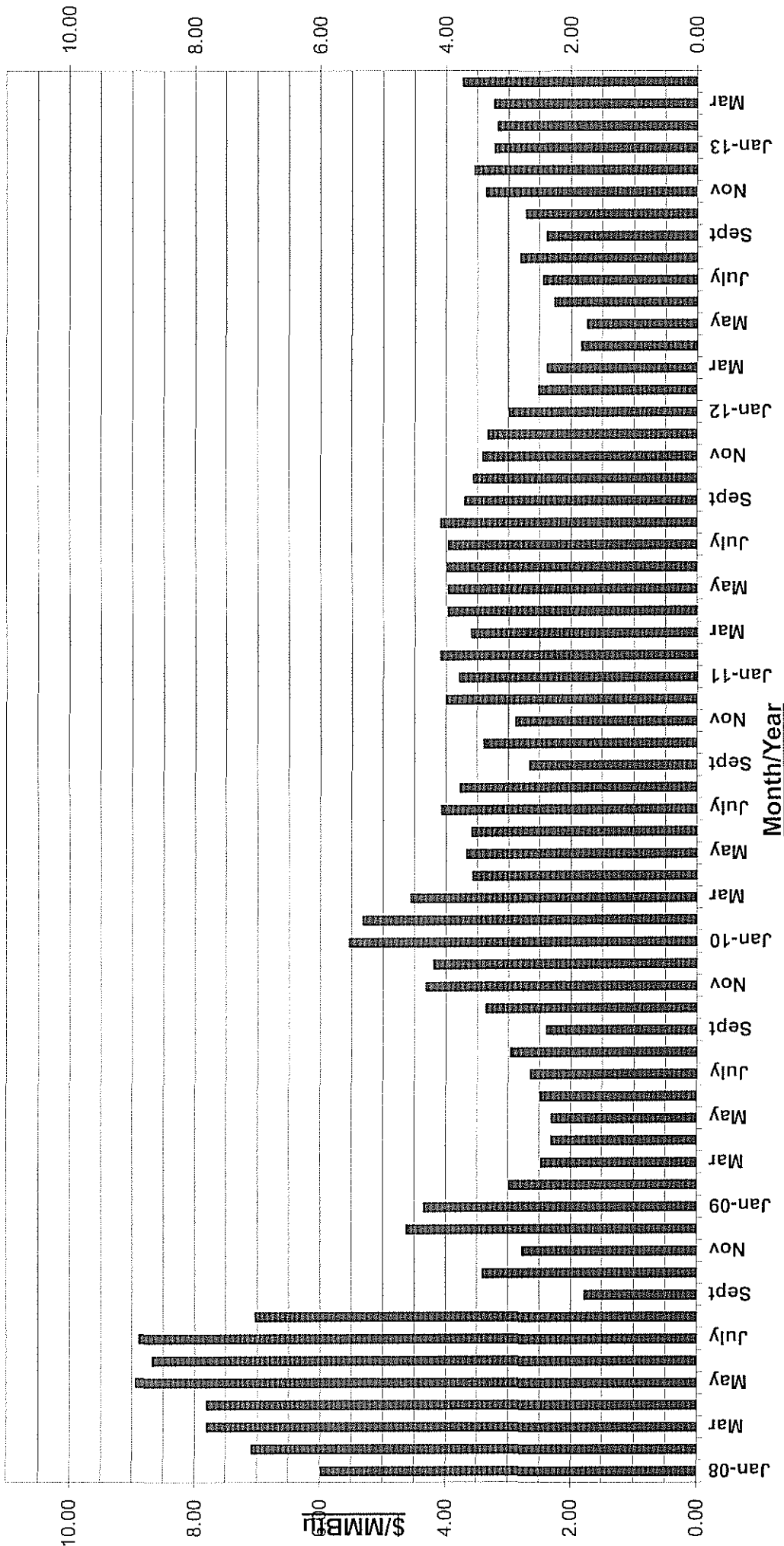
The established monthly price for the Rocky Mountain CIG Index has increased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid 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 increase in natural gas prices is likely a result of below normal seasonal temperatures, therefore causing the market price to be higher due to higher heating demand. The Energy Information Administration (EIA) reported storage levels nationwide as of March 22, 2013 to be 3.5 percent above the five-year average and 26 percent below last year's storage balance.

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

The March Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 16. The April Outlook will be published April 9, 2013.

# CIG Rocky Mountains Index Monthly Gas Prices 2008-2013YTD



From Inside F.E.R.C.'s Gas Market Report  
Annual Averages: - 2011-\$3.79; 2012-\$2.58; 2013YTD - \$3.34



*Independent Statistics & Analysis*

U.S. Energy Information  
Administration

March 2013

## Short-Term Energy Outlook (STEO)

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### Highlights

- The weekly U.S. average regular gasoline retail price fell in early March for the first time since mid-December. The March 11 average was \$3.71 per gallon, down \$0.07 per gallon from February 25. EIA expects that lower crude oil prices will result in monthly average regular gasoline prices staying near the February average of \$3.67 per gallon over the next few months, with the annual average regular gasoline retail price declining from \$3.63 per gallon in 2012 to \$3.55 per gallon in 2013 and \$3.38 per gallon in 2014. Energy price forecasts are highly uncertain and the current values of futures and options contracts suggest that prices could differ significantly from this forecast.
- EIA expects that the Brent crude oil spot price, which averaged \$112 per barrel in 2012 and rose to \$119 per barrel in early February 2013, will average \$108 per barrel in 2013 and \$101 per barrel in 2014. The projected discount of West Texas Intermediate (WTI) crude oil to Brent, which increased to a monthly average of more than \$20 per barrel in February 2013, will average \$16 per barrel in 2013 and \$9 per barrel in 2014, as planned new pipeline capacity lowers the cost of moving mid-continent crude oil to the Gulf Coast refining centers.
- U.S. crude oil production exceeded an average level of 7 million barrels per day (bbl/d) in November and December 2012, the highest volume since December 1992. EIA estimates that U.S. total crude oil production averaged 6.5 million barrels per day (bbl/d) in 2012, an increase of 0.8 million bbl/d from the previous year. Projected domestic crude oil production is expected to average 7.3 million bbl/d in 2013 and 7.9 million bbl/d in 2014.
- Total U.S. liquid fuels consumption fell from 20.8 million bbl/d in 2005 to 18.6 million bbl/d in 2012. EIA expects total consumption to rise slightly over the next two years to an average of 18.7 million bbl/d in 2014, driven by increases in distillate fuel and liquefied petroleum gas consumption, with little change in gasoline and jet fuel consumption.
- Natural gas working inventories ended February 2013 at an estimated 2.08 trillion cubic feet (Tcf), about 0.36 Tcf below the level at the same time a year ago but still 0.27 Tcf greater than the 5-year average (2008-12). EIA expects the Henry Hub natural gas spot price, which averaged \$2.75 per million British thermal units (MMBtu) in 2012, will average \$3.41 per MMBtu in 2013 and \$3.63 per MMBtu in 2014. Current options and futures prices imply that the lower and upper bounds for the 95-percent confidence interval for June 2013 contracts at \$2.79 per MMBtu and \$4.67 per MMBtu, respectively.

## Global Crude Oil and Liquid Fuels

Oil market balances have not changed dramatically since last month's STEO, although somewhat lower expectations for production in Libya and Iraq, along with an increase in unplanned outages in countries outside the Organization of the Petroleum Exporting Countries (OPEC), implies slightly tighter conditions in 2013 than previously projected. Positive economic indicators, including upward revisions in estimates of Chinese GDP growth and continuing employment growth in the United States, could lend support to higher prices, but over the past week they have been counterbalanced by renewed uncertainty regarding economic growth in Europe.

EIA estimates that global liquid fuels consumption outpaced production in January and February 2013, resulting in a 1.1-million-bbl/d average draw in global oil stocks (see [The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran](#)). Projected world liquid fuels consumption grows by an annual average of 1.0 million bbl/d in 2013 and 1.4 million bbl/d in 2014. Countries outside the Organization for Economic Cooperation and Development (OECD) drive expected consumption growth. Projected world supply increases by 0.8 million bbl/d in 2013 and 1.9 million bbl/d in 2014, with most of the growth coming from North America and other non-OPEC countries.

**Global Crude Oil and Liquid Fuels Consumption.** World liquid fuels consumption grew by 0.8 million bbl/d in 2012 to reach 89.1 million bbl/d. EIA expects this growth rate will be higher in 2013 and 2014 because of a moderate recovery in global economic growth. World consumption reaches 90.1 million bbl/d in 2013 and 91.5 million bbl/d in 2014.

Non-OECD Asia is the leading regional contributor to expected global consumption growth. EIA expects refinery crude oil inputs in China to be bolstered in 2013 as oil product inventories are restocked and new refining capacity comes on line. EIA estimates that liquid fuels consumption in China increased by 380,000 bbl/d in 2012, and will increase by 450,000 bbl/d in 2013 and by 510,000 bbl/d in 2014. This compares with annual average growth of 540,000 bbl/d from 2004 through 2010.

OECD liquid fuels consumption fell by 0.5 million bbl/d in 2012. EIA projects OECD consumption to further decline by 0.3 million bbl/d in 2013 because of declining consumption in Europe. OECD consumption flattens in 2014 as European consumption begins to recover in response to higher economic growth.

**Non-OPEC Supply.** EIA projects non-OPEC liquids production will increase by 1.2 million bbl/d in 2013 and by another 1.4 million bbl/d in 2014. North America accounts for almost three-quarters of the projected growth in non-OPEC supply over the next two years because of continued production growth from U.S. tight oil formations and Canadian oil sands.

Unplanned production outages in non-OPEC countries increased to about 0.9 million bbl/d in February 2013. The increase in outages was the result of oil leaks, which forced a North Sea crude oil pipeline to shut down, and production problems at the Buzzard field in the U.K. sector of the North Sea. Syria and South Sudan continue to account for more than 60 percent of the total disruptions to non-OPEC production. EIA assumes production in Syria remains at current levels over the forecast period. EIA assumes that production restarts in South Sudan in the first half of 2014; however, if security problems persist, production may not resume during the forecast period.

**OPEC Supply.** OPEC member countries, particularly Saudi Arabia, cut production heavily in fourth-quarter 2012, which contributed to an increase in crude oil prices at the start of 2013. EIA estimates suggest that Saudi Arabia cut production from an average of 9.9 million bbl/d during third-quarter 2012 to 9.0 million bbl/d in February 2013.

Projected OPEC crude oil supply decreases by 0.4 million bbl/d in 2013 from the year before and then rises by 0.5 million bbl/d in 2014. Most of the decline in 2013 comes from Saudi Arabia, in response to non-OPEC supply growth.

The death of President Hugo Chávez crystallizes political risks in Venezuela, which the market had already internalized to some extent as news about his condition emerged. Though the outcome of the succession process could have implications for the oil sector, EIA is maintaining its Venezuelan production forecast on the assumption that current policies related to the oil sector will be continued. For more information, see ["Political risks focus attention on supply of Venezuelan oil to the United States"](#).

EIA has lowered its expectations for oil production in Libya to reflect the persistence of technical problems and political pressures, which have already curtailed output. Libya's precarious security environment creates downside production risks from the potential for additional disruptions due to attacks, strikes, or poorly maintained infrastructure. In Iraq, payment disputes between Baghdad and the Kurdistan Regional Government will lead to lost output in the north that at least partly offsets increased crude oil exports from the Iraq's southern fields.

EIA estimates that OPEC surplus capacity, which is concentrated in Saudi Arabia, continued at about 2.8 million bbl/d in February 2013, an increase of 0.8 million bbl/d compared with the year-ago level but still 0.2 million bbl/d lower than the previous three-year average. Projected OPEC surplus capacity averages 2.9 million bbl/d in 2013 and 3.4 million bbl/d in 2014. These estimates do not include additional capacity that may be available in Iran but is currently offline because of the effects of U.S. and EU sanctions on Iran's ability to sell its oil.

**OECD Petroleum Inventories.** EIA estimates that OECD commercial oil inventories at the end of 2012 totaled 2.69 billion barrels, equivalent to 58.4 days of supply. Projected OECD oil

inventories fall slightly and end 2013 at 2.63 billion barrels (56.7 days of supply). Inventories increase to 2.66 billion barrels (57.7 days of supply) by the end of 2014.

## U.S. Crude Oil and Liquid Fuels

The U.S. weekly average regular gasoline retail price increased from \$3.25 per gallon on December 17, 2012, which was the low for all of 2012, to \$3.78 per gallon on February 25, 2013, which was the highest nominal retail price ever during the month of February (see *This Week in Petroleum*, February 21, 2013). EIA expects that lower crude oil prices will result in monthly average regular gasoline prices staying near the February average of \$3.67 per gallon over the next few months, with the average annual retail prices projected at \$3.55 per gallon in 2013 and \$3.38 per gallon in 2014. The current values of futures and options contracts suggest that prices could differ significantly from this forecast. For example, there is a 16 percent probability that the New York Harbor reformulated gasoline blendstock for oxygenate blending (RBOB) futures price will exceed \$3.35 per gallon (consistent with a U.S. average regular gasoline retail price above \$4.00 per gallon) in June 2013.

**U.S. Liquid Fuels Consumption.** Total liquid fuels consumption fell from an annual average of 20.8 million bbl/d in 2005 to 18.6 million bbl/d in 2012. Total liquid fuels consumption grows modestly in this forecast, increasing by 30,000 bbl/d (0.1 percent) in 2013 and by 80,000 bbl/d (0.4 percent) in 2014. Distillate fuel oil consumption, which fell by 160,000 bbl/d in 2012, increases at an average annual rate of 10,000 bbl/d in 2013 and 60,000 bbl/d in 2014. Distillate fuel consumption growth is driven by increases in industrial output and winter weather in the Northeast, which is forecast to be colder in comparison with the mild winter months during 2012. Motor gasoline and jet fuel consumption remain flat in 2013 and 2014, as increasing travel is offset by fuel economy improvements.

**U.S. Liquid Fuels Supply and Imports.** EIA expects U.S. crude oil production to continue to grow rapidly over the next two years, increasing from an average 6.5 million bbl/d in 2012 to average 7.3 million bbl/d in 2013 and 7.9 million bbl/d in 2014. Drilling in tight oil plays in the onshore Williston, Western Gulf, and Permian basins is expected to account for the bulk of forecast production growth over the next two years. Projected Alaskan crude oil production declines from an average of 530,000 bbl/d in 2012 to 500,000 bbl/d in 2013 and 470,000 bbl/d in 2014. U.S. federal Gulf of Mexico (GOM) crude oil production averaged an estimated 1.3 million bbl/d in 2012, about 50,000 bbl/d lower than during 2011. EIA expects GOM production to increase to an average of 1.4 million bbl/d in 2013 and 1.5 million bbl/d in 2014.

EIA expects that U.S. crude oil production will exceed U.S. crude oil imports as early as the end of 2013, the first time this will have occurred since February 1995. Since reaching 12.5 million bbl/d in 2005, total U.S. liquid fuel net imports, including crude oil, have been falling. Total net imports fell to 7.4 million bbl/d in 2012, and EIA expects imports to continue declining to an average of 6.0 million bbl/d by 2014. Similarly, the share of total U.S. consumption met by liquid

fuel net imports peaked at more than 60 percent in 2005 and fell to an average of 40 percent in 2012. EIA expects the net import share to fall to 32 percent in 2014, which would be the lowest level since 1985, because of continued substantial increases in domestic production.

**Crude Oil Prices.** EIA projects the Brent crude oil spot price will fall from an average of \$112 per barrel in 2012 to annual averages of \$108 per barrel and \$101 per barrel in 2013 and 2014, respectively, reflecting the increasing supply of liquid fuels from non-OPEC countries. After averaging \$94 per barrel in 2012, the projected WTI price averages \$92 per barrel in both 2013 and 2014. By 2014, several pipeline projects from the mid-continent to the Gulf Coast refining centers are expected to come on line, reducing the cost of transporting crude oil to refiners, which is reflected in a drop in the price discount of WTI to Brent.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for June 2013 delivery during the five-day period ending March 7, 2013, averaged \$91.59 per barrel. Implied volatility averaged 22 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in June 2013 at \$76 per barrel and \$111 per barrel, respectively. Last year at this time, WTI for June 2012 delivery averaged \$109 per barrel and implied volatility averaged 31 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$83 per barrel and \$144 per barrel.

**U.S. Petroleum Product Prices.** U.S. regular gasoline retail prices averaged \$3.63 per gallon in 2012. EIA expects falling crude prices will lead to regular gasoline retail prices averaging \$3.55 per gallon in 2013 and \$3.38 per gallon in 2014. After averaging \$3.97 per gallon in 2012, EIA expects that on-highway diesel fuel retail prices will average \$3.90 per gallon in 2013 and \$3.80 per gallon in 2014.

As previously discussed, the market's expectation of uncertainty in monthly average gasoline prices is reflected in the pricing and implied volatility of futures and options contracts, which suggest a 16 percent probability that the average national retail pump prices for regular gasoline could exceed \$4.00 per gallon in June 2013.

## Natural Gas

In the past few years, U.S. pipeline exports of natural gas to Mexico have increased substantially, from around 0.9 billion cubic feet per day (Bcf/d) in 2010 to 1.7 Bcf/d in 2012. Mexico has expanded its natural-gas-fired power generation in recent years, and plans to continue to do so. Competitively-priced natural gas from the United States makes pipeline imports by Mexico an attractive option.

According to EIA's monthly natural gas gross production report, gross withdrawals fell in December 2012 from the month before in all major producing areas except Alaska. Total gross withdrawals fell about 0.7 percent from the November 2012 level to 82.6 Bcf/d in December

2012, equivalent to about 69.3 Bcf/d of marketed production. As natural gas production in the United States shifts inland, well freeze-offs have become a greater supply disruption risk during the winter. The 3.5-percent decline between November and December in New Mexico production was the largest of any state or region, as operators reported shut-ins resulting from freeze-offs. Well freeze-offs continued to affect production in western U.S. states in January 2013.

**U.S. Natural Gas Consumption.** EIA expects that natural gas consumption will average 70.0 Bcf/d in both 2013 and 2014. Forecasts for closer-to-average winter temperatures in 2013 and 2014 (compared with the record-warm temperatures in 2012) lead to increases in natural gas used for residential and commercial space heating. The projected increase in natural gas prices contributes to a decline in natural gas used for electric power generation from 25.0 Bcf/d in 2012 to 23.1 Bcf/d in 2013 and 22.7 Bcf/d in 2014.

**U.S. Natural Gas Production and Imports.** Projected natural gas marketed production increases from 69.1 Bcf/d in 2012 to 69.6 Bcf/d in 2013, and remains flat in 2014. Onshore production increases slightly over the forecast period, while GOM production declines.

Natural gas pipeline gross imports, which have declined over the last five years, are projected to remain near their 2012 level over the forecast period. Liquefied natural gas (LNG) imports are expected to remain at minimal levels of less than 0.5 Bcf/d in both 2013 and 2014.

**U.S. Natural Gas Inventories.** As of March 1, 2013, working gas stocks totaled 2,083 Bcf, which is 361 Bcf less than at the same time in 2012, but 269 Bcf greater than the five-year (2008-12) average, according to EIA's Weekly Natural Gas Storage Report. EIA expects an end-of-March level of just under 2,000 Bcf, which is less than the unusually high 2,477 Bcf at the end of March 2012, but still well above the five-year average of 1,726 Bcf.

**U.S. Natural Gas Prices.** Natural gas spot prices averaged \$3.33 per MMBtu at the Henry Hub in February 2013, relatively unchanged from the previous two months. EIA expects the Henry Hub price will increase from an average of \$2.75 per million Btu in 2012 to \$3.41 per MMBtu in 2013 and \$3.63 per MMBtu in 2014.

Natural gas futures prices for June 2013 delivery (for the five-day period ending March 7, 2013) averaged \$3.61 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for June 2013 contracts at \$2.79 per MMBtu and \$4.67 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for June 2012 averaged \$2.771 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were \$1.903 per MMBtu and \$4.06 per MMBtu.

## Coal

The U.S. coal market may have received a small boost from recent coal supply disruptions in Colombia, which include a strike at its largest exporter. Force majeure, a contract clause that allows a company to suspend contractual obligations in the face of unexpected events, was declared on several coal shipments destined for markets in Europe and the United States. According to preliminary data from [Form EIA-923](#), U.S. electric power producers imported 5.2 million short tons (MMst) of Colombian coal in 2012. This amount was over 95 percent of coal imported by the electric power sector and more than 57 percent of all U.S. coal imports for the year. A preliminary accord between striking union workers and the Colombian mine was reported on March 4, 2013.

**U.S. Coal Consumption.** Total coal consumption fell by 114 million short tons (MMst) (11.3 percent) in 2012, led by an 11.6-percent decline in coal use for electricity generation. EIA projects total coal consumption will increase from 889 MMst in 2012 to 941 MMst in 2013 and 955 MMst in 2014. EIA expects consumption in the electric power sector to increase over the forecast period as a result of higher electricity demand and higher natural gas prices, but remain below 900 MMst.

**U.S. Coal Supply.** Coal production is expected to increase by 1.0 percent in 2013 as primary and secondary inventory draws, combined with an increase in coal imports, meet most of the growth in consumption. Coal production is forecast to grow by 1.3 percent in 2014.

**U.S. Coal Trade.** Coal exports totaled 126 MMst in 2012, surpassing the previous peak of 113 MMst exported in 1981 by nearly 12 percent. EIA expects exports to average near 110 MMst in both 2013 and 2014. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), falling international coal prices, and increasing production in other coal-exporting countries are the primary reasons for the expected decline in U.S. coal exports.

**U.S. Coal Prices.** Delivered coal prices to the electric power industry increased steadily over an 11-year period through 2011, when the delivered coal price averaged \$2.39 per MMBtu (a 5-percent increase from 2010). EIA estimates that the delivered coal price averaged \$2.40 per MMBtu in 2012, and forecasts average delivered prices of \$2.42 per MMBtu in 2013 and \$2.45 per MMBtu in 2014.

## Electricity

Preliminary data from the EIA [Electric Power Monthly](#) indicate that 7.9 gigawatts (GW) of coal-fired generation capacity was retired in the electric industry during 2012, which represents 2.5 percent of installed coal capacity at the beginning of the year (and about 0.8 percent of total generating unit capacity). Two-thirds of the coal capacity retired in 2012 was located in the Midwest and Southeast regions of the United States. In comparison, the U.S. electric industry

retired 2.6 GW of coal capacity in 2011 and retired an average of 1.0 GW each year between 2006 and 2010. The coal-fired capacity retired during 2012 was offset somewhat by the addition of five new coal-fired generating units with a combined capacity of 3.6 GW.

**U.S. Electricity Consumption.** EIA projects U.S. residential sales of electricity during the upcoming summer months (June, July, and August) will average 6 percent below sales during the summer of 2012. EIA assumes that U.S. cooling degree days during June, July, and August 2013 will total about 10 percent lower than last summer and about 4 percent lower than the prior 10-year average. Overall, U.S. residential electricity sales decline by 0.6 percent during 2013 but are projected to grow by 1.0 percent in 2014. U.S. retail electricity sales to the commercial sector increase by 0.5 percent in 2013 and by 1.1 percent in 2014. Industrial electricity sales increase by 1.6 percent and 1.0 percent in 2013 and 2014, respectively.

**U.S. Electricity Generation.** EIA expects total U.S. generation of electricity across all sectors will grow by 0.5 percent in 2013 and by 1.0 percent in 2014. EIA expects generators to increase their utilization of existing coal capacity, leading to a 6.2-percent increase in U.S. coal generation during 2013. This increase, which results because of the increasing cost of natural gas relative to coal, raises the share of total generation fueled by coal from 37.4 percent 2012 to 39.5 percent in 2013, still below coal's 42.3-percent fuel share in 2011. Conversely, the rising cost of natural gas pushes the share of generation fueled by natural gas down from 30.4 percent in 2012 to 28.3 percent this year, compared with a share of 24.7 percent in 2011.

**U.S. Electricity Retail Prices.** Rising costs of infrastructure upgrades continue to drive increases in residential electricity rates, although lower fuel prices in recent years have kept growth in retail rates relatively modest. After an increase of 1.4 percent during 2012, EIA expects U.S. retail residential electricity prices will grow by 1.9 percent in 2013 and by 1.8 percent in 2014.

## Renewables and Carbon Dioxide Emissions

**U.S. Electricity Generation Renewables.** EIA estimates that total renewable energy consumption declined by 2.2 percent in 2012, as the decrease in hydropower more than offset the growth in the consumption of other renewable energy forms. This drop was the result of hydropower production falling by 13 percent as water supply in the Pacific Northwest fell from the unusually high levels seen in 2011. EIA projects renewable energy consumption to increase by 2.6 percent in 2013. While hydropower declines by 3.2 percent, nonhydropower renewables grow by an average of 5.5 percent. In 2014, the growth in total renewables is projected to continue at a rate of 4.5 percent, as a 2.6-percent increase in hydropower is combined with a 5.4-percent increase in nonhydropower renewables.

EIA currently estimates that wind capacity will increase by 6 percent in 2013 and by 14 percent in 2014. However, electricity generation from wind is projected to increase by 16 percent in 2013, as capacity that came [on line at the end of 2012](#) is available for the entire year in 2013. Wind-powered generation is projected to grow by 9 percent in 2014.

EIA expects a continuation of robust growth in the generation of solar energy, although the total amount remains a small share of total U.S. generation.

**U.S. Liquid Biofuels.** Fuel ethanol production averaged 865,000 bbl/d (13.3 billion gallons) in 2012, its lowest average since 2009. EIA expects ethanol production to remain near current levels of about 800,000 bbl/d through mid-2013 before recovering to pre-drought production levels, averaging 857,000 bbl/d for the year. Ethanol production is expected to rise in 2014, averaging 922,000 bbl/d. Despite the forecast increase in ethanol production, EIA expects the drawdown of banked renewable identification numbers, as the average ethanol share of the gasoline pool increases only modestly between 2012 and 2014. Biodiesel production, which averaged 63,000 bbl/d (1.0 billion gallons) in 2012 is forecast to increase to 82,000 bbl/d (1.3 billion gallons) in both 2013 and 2014. This forecast assumes that the 2014 renewable fuel volume obligations for biodiesel and advanced biofuel are identical to those in 2013.

**U.S. Energy-Related Carbon Dioxide Emissions.** EIA estimates that carbon dioxide emissions from fossil fuels declined by 3.9 percent in 2012, and projects increases of 1.9 percent in 2013 and 0.7 percent in 2014. The increase in emissions over the forecast primarily reflects the projected increase in coal use for electricity generation, especially in 2013.

### U.S. Economic Assumptions

EIA uses the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO. The GI model used in this STEO incorporates recent tax changes in the American Taxpayer Relief Act of 2012. The GI model simulation also assumes that the spending cuts mandated in the Budget Control Act of 2011 (sequestration) will be replaced by a combination of income tax increases and spending cuts that are implemented in 2014 and there will be an agreement reached to increase the amount of debt that can be issued by the U.S. Treasury (the debt ceiling) in the near term.

**U.S. Current Trends.** Recent economic indicators suggest that growth may be picking up, particularly in the manufacturing sector. The Institute for Supply Management (ISM) manufacturing index rose in February to its highest level since June 2011, at 54.2. The U.S. Bureau of Economic Analysis also reported that the annualized growth rate of fourth-quarter GDP for 2012 was revised upward to a positive 0.1 percent, higher than the originally estimated decline of 0.1 percent. The U.S. Census Bureau reported that new home sales in January 2013 were at their highest level since July 2008, increasing by 15.6 percent from the previous month. However, real disposable income fell by 4 percent in January from the preceding month according to the U.S. Bureau of Economic Analysis, although much of this is attributable to special factors related to higher payouts of dividends and bonuses in December and the ending of the payroll-tax holiday in January.

**U.S. Production.** The STEO assumes 1.8 percent U.S. real GDP growth in 2013, rising to 2.7 percent in 2014. Relatively slower growth in the beginning of 2013 follows the expiration of the payroll tax cut, which is also reflected in annual growth in real disposable income of only 0.5 percent. After mid-2013, real GDP year-over-year growth gradually increases through the final quarter of 2014, and the same is true for real disposable income. Residential and nonresidential investment are important components of growth in both 2013 and 2014.

Total industrial production grows at a faster rate than real GDP in 2013 and 2014, at 2.2 percent and 3.0 percent, respectively. Industrial production growth in the manufacturing sector is the same as total industrial production in 2013 at 2.2 percent, but accelerates to 3.6 percent in 2014.

**U.S. Income and Expenditures.** Real consumption expenditures grow at the same rate as real GDP in 2013, at 1.8 percent, but slow below the rate of real GDP growth in 2014 at 2.3 percent. Private fixed investment jumps to 9.1-percent growth in 2014 from 5.5 percent in 2013, highlighting its importance for overall economic expansion. Export growth more than doubles from 2.4 to 5.3 percent, while government expenditures fall more than 1 percent in both years.

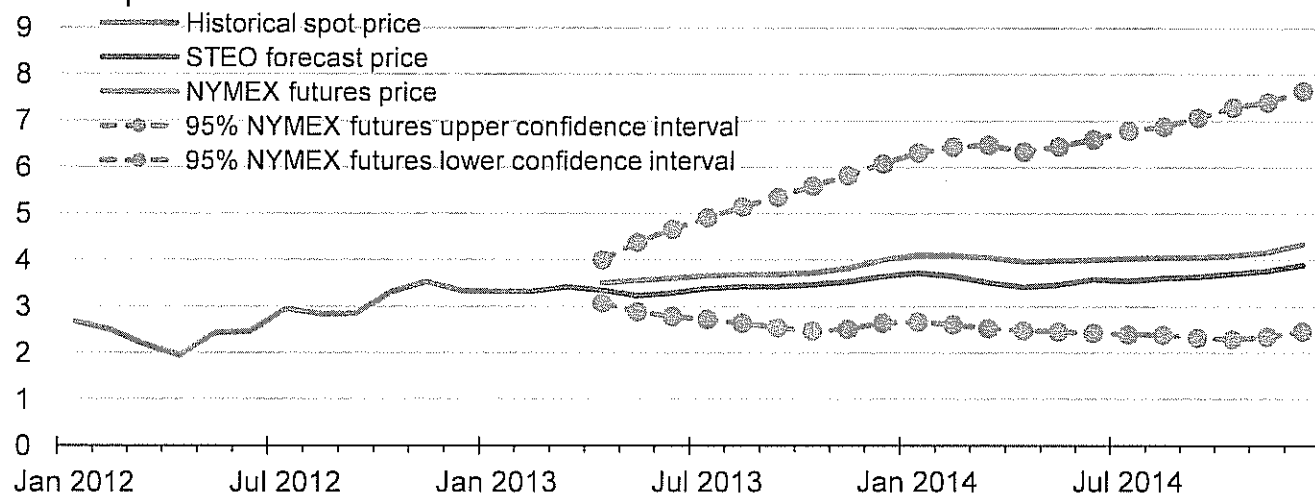
**U.S. Employment, Housing, and Prices.** The unemployment rate in the forecast gradually falls from 7.7 percent in February 2013 to 7.1 percent in December 2014. This is accompanied by nonfarm employment growth averaging 1.5 percent in 2013 and 1.6 percent in 2014. Consistent with an improving housing sector, housing starts show relatively fast growth, expanding by 22.0 percent and 31.6 percent in 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the U.S. Department of Energy or other federal agencies.



## Henry Hub Natural Gas Price

dollars per million btu

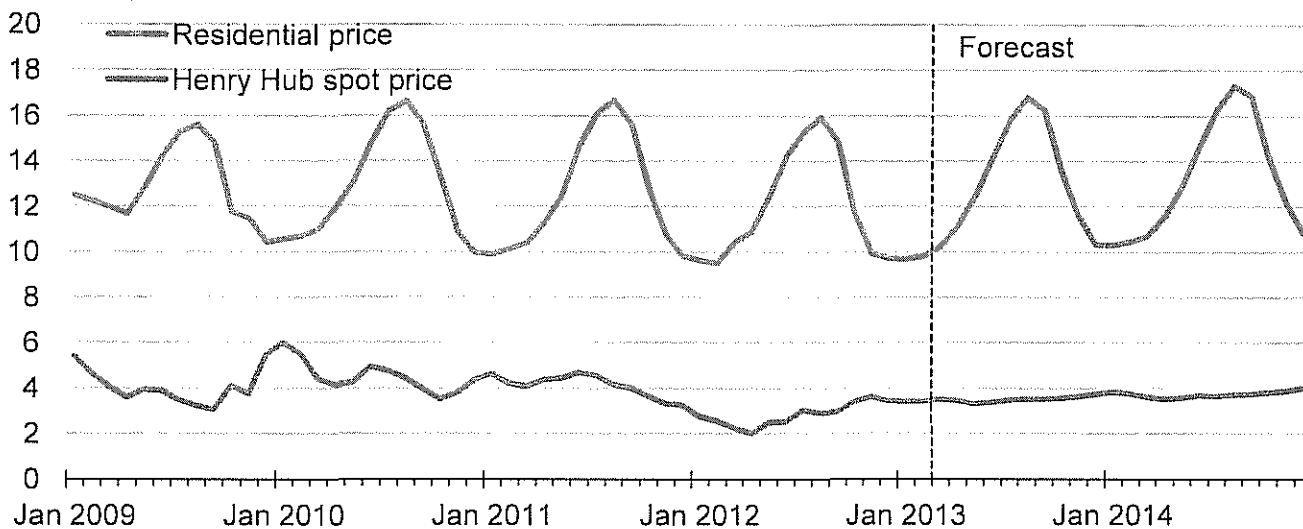


Note: Confidence interval derived from options market information for the 5 trading days ending March 7, 2013. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, March 2013

## U.S. Natural Gas Prices

dollars per thousand cubic feet



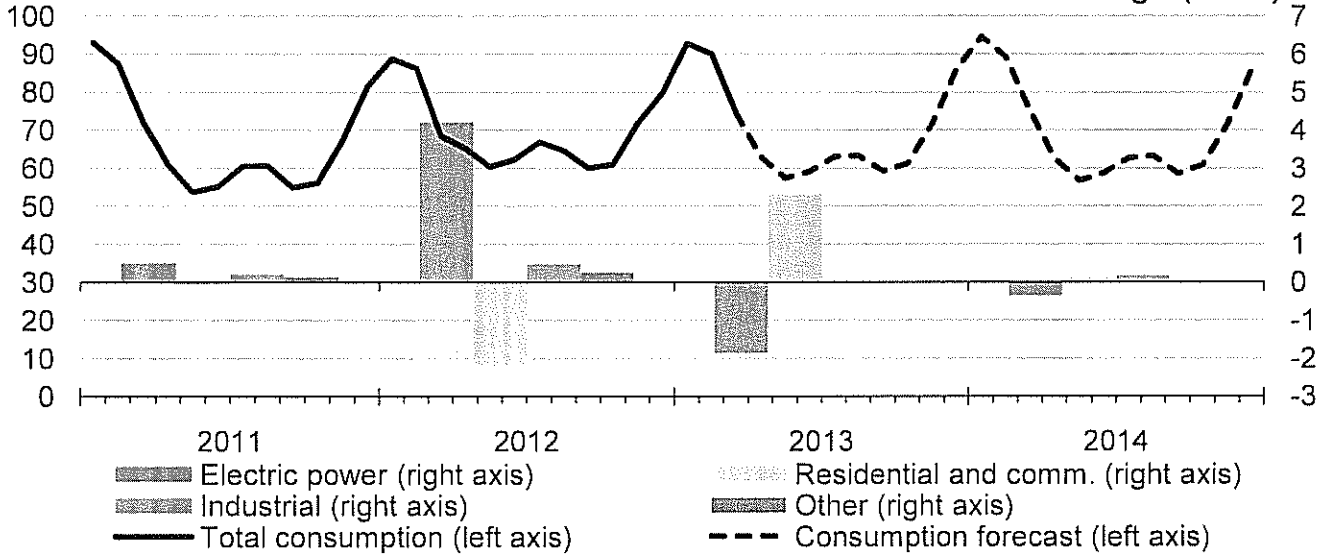
Source: Short-Term Energy Outlook, March 2013

# U.S. Natural Gas Consumption



billion cubic feet per day (bcf/d)

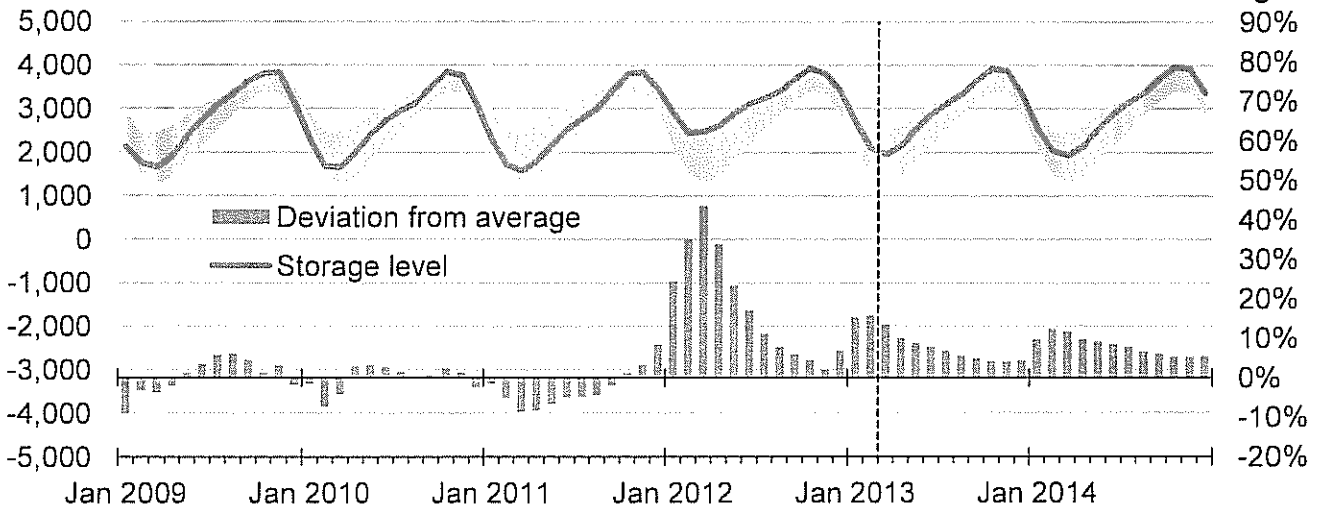
annual change (bcf/d)



Source: Short-Term Energy Outlook, March 2013

## U.S. Working Natural Gas in Storage

billion cubic feet



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2008 - Dec. 2012.

Source: Short-Term Energy Outlook, March 2013

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

**Northern Border Pipeline Company Docket No. RP13-403-000**

On December 19, 2012, Northern Border filed tariff records with the FERC in compliance with an order issued December 5, 2012 pursuant to the Settlement in Docket No. RP12-1093-000. On January 17, 2013, the FERC issued a Letter Order accepting the tariff effective January 1, 2013.

Approximate impact on Montana-Dakota's cost of gas: (0.2) cents per dk

**Williston Basin Interstate Pipeline Company Docket No. RP13-621-000**

On March 1, 2013, Williston Basin filed its semi-annual fuel and electric power reimbursement adjustment with the FERC in Docket No. RP13-621-000, reflecting revisions to the fuel and electric power components of Williston Basin's transportation and storage rates to be effective April 1, 2013. On March 18, 2013, the FERC issued a Letter Order accepting the tariff effective April 1, 2013.

Approximate impact on Montana-Dakota's cost of gas: (2.2) cents per dk

**NorthWestern Energy Docket No. D2012.9.94**

On September 28, 2012, NorthWestern Energy filed an application to increase natural gas rates in Montana with the Montana Public Service Commission. On March 20, 2013, the Montana Public Service Commission issued an interim order authorizing NorthWestern to implement an interim increase effective April 1, 2013.

Approximate impact on Montana-Dakota's cost of gas: 0.3 cents per dk

MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS TARIFF SHEET  
NORTH DAKOTA GAS  
EFFECTIVE MAY 2013

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<b><u>Gas Cost Adjustment:</u></b>				
Gas Cost Level (Exhibit B)	\$5.081	\$5.167	\$4.098	\$4.080
Prior Gas Cost	4.774	4.874	3.752	3.735
Current Gas Cost Adjustment	\$0.307	\$0.293	\$0.346	\$0.345
<b><u>Surcharge Adjustment:</u></b>				
Current Adjustment	(\$0.113)	(\$0.113)	(\$0.115)	(\$0.377)
Prior Adjustment	(0.113)	(0.113)	(0.115)	(0.377)
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<b><u>Market Based Pricing Differential</u></b>				
Current Adjustment	(\$0.010)	(\$0.010)	\$0.000	\$0.000
Prior Adjustment	(0.010)	(0.010)	0.000	0.000
Change in Margin Sharing Provision	\$0.000	\$0.000	\$0.000	\$0.000
<b>Net Increase (Decrease) in Gas Costs</b>	<b>\$0.307</b>	<b>\$0.293</b>	<b>\$0.346</b>	<b>\$0.345</b>
Gas Cost Level	\$5.081	\$5.167	\$4.098	\$4.080
Plus: Surcharge	(0.113)	(0.113)	(0.115)	(0.377)
<b>Total Gas Cost Level in Tariff Rates</b>	<b>\$4.968</b>	<b>\$5.054</b>	<b>\$3.983</b>	<b>\$3.703</b>

MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS - PROPANE TARIFF SHEET  
NORTH DAKOTA PROPANE  
EFFECTIVE MAY 2013

<b><u>Cost of Gas - Propane</u></b>	
Current Propane Cost 1/	\$10.429
Prior Propane Cost	<u>10.429</u>
Current Propane Cost Adjustment	<u>\$0.000</u>
<b><u>Surcharge Adjustment</u></b>	
Current Adjustment (Exhibit E)	(\$0.777)
Prior Adjustment	<u>0.646</u>
Change in Surcharge Adjustment	(\$1.423)
<b><u>Market Based Pricing Differential</u></b>	
Current Adjustment	(\$0.010)
Prior Adjustment	<u>(0.010)</u>
Change in Margin Sharing Provision	\$0.000
<b>Net Increase (Decrease) in Gas Costs</b>	<b><u>(\$1.423)</u></b>
Propane Cost Level	\$10.429
Plus: Surcharge	<u>(0.777)</u>
Total Propane Cost Level in Rates	<u><u>\$9.652</u></u>

1/ No change from Propane Cost of Gas effective February 1, 2013.

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
RESIDENTIAL AND GENERAL SERVICE  
EFFECTIVE MAY 2013**

	Amount
Total Gas Costs 1/	\$73,511,461
Residential and General Service dk Requirements 2/	14,533,472
Average Cost of Gas per dk	\$5.058
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.081
Less: Gas Cost Level in Rates 3/	4.774
<b>Current Gas Cost Adjustment</b>	<b>\$0.307</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 February 28, 2013, adjusted for losses at .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-13-008 effective February 1, 2013:

Cost of Purchased Gas	\$4.753
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.774

MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
OPTIONAL SEASONAL - RATE 72  
EFFECTIVE MAY 2013

Total Gas Costs 1/	\$73,511,461
Less: Annual MDDQ Costs 1/	<u>13,113,139</u>
Total Gas Costs excluding MDDQ	\$60,398,322
Firm Service Requirements 1/	14,533,472
Other Gas Costs per Dk (excluding MDDQ)	\$4.156
<u>Winter - October - May</u> Annual MDDQ Costs 1/	\$13,113,139
Winter Firm Service Requirements	13,272,126
MDDQ Costs per Winter Dk	\$0.988
Add: Other Gas Costs per Dk	<u>4.156</u>
Winter Seasonal Rate	\$5.144
Winter Seasonal Rate, adjusted for losses 2/	\$5.167
Less: Gas Cost Level in Rates 3/	<u>4.874</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.293</u></u></b>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-13-008 effective February 1, 2013:

	<u>Winter</u>
Cost of Purchased Gas	\$4.852
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.874

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
INTERRUPTIBLE  
EFFECTIVE MAY 2013**

	Amount
Total Gas Costs 1/	\$14,292,794
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$4.080
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.098
Less: Gas Cost Level in Rates 2/	3.752
<b>Current Gas Cost Adjustment</b>	<b>\$0.346</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-13-008 effective February 1, 2013:

Cost of Purchased Gas	\$3.735
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.752

MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
AIR FORCE INTERRUPTIBLE  
EFFECTIVE MAY 2013

	<u>Amount</u>
Total Gas Costs 1/	\$3,590,804
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$4.080
Less: Gas Cost Level in Rates 2/	<u>3.735</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.345</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-13-008 effective February 1, 2013:  
Cost of Purchased Gas \$3.735

**Montana-Dakota Utilities Co.  
Schedule of Applicable Effective Pipeline Rates  
May 2013 PGA**

WBI Energy Transmission, Inc. - Exhibit B, pages 6 - 8 for Schedules FT-1, FTN-1, and FS-1.

Northern Border Pipeline Company - Exhibit B, page 9 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, pages 10-11 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	0.180	N.A.	N.A.	3.300
MINIMUM A/B/	RATE PER DKT	3.120	0.180	N.A.	N.A.	3.300
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.180	N.A.	N.A.	31.064
MINIMUM A/B/	RATE PER DKT	3.120	0.180	N.A.	N.A.	3.300
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 1.705%, CONSISTING OF 1.996% FOR THE CURRENT PERCENTAGE AND (0.291%) 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 0.600 CENTS, CONSISTING OF 0.670 CENTS FOR THE CURRENT RATE AND (0.070) 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
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: November 1, 2010

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 CHARGE						
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 CHARGE						
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 CHARGE						
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 CHARGE						
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 0.506%, CONSISTING OF 0.673% FOR THE CURRENT PERCENTAGE AND (0.167%) 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 0.033 CENTS, CONSISTING OF 0.000 CENTS FOR THE CURRENT RATE AND 0.033 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

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

PART 4.1  
4.1 - Statement of Rates  
T-1 and T-1B - Long Term Base Tariff Rates  
v.2.0.0 Superseding v.1.0.0

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	\$0.0286
Minimum	\$0.0000
Daily Reservation Rate - Ventura, IA to North Hayden, IN	
Maximum	\$0.0307
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 Rates, pursuant to Articles II and VII of the September 27, 2012, Stipulation at Docket Nos. RP06-72-000, et al., remain in effect until such rates are superseded by new 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 V.A of the September 27, 2012, Stipulation at Docket Nos. RP06-72-000, et al.

NOVA Gas Transmission Ltd.

Table of Rates, Tolls and Charges  
Page 1 of 2

Service	Rates, Tolls and Charges		
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month based on a three year term (Price Point "B") & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) \$ 197.27/10 <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 <sup>3</sup>	Refer to Attachment "2" for applicable FT-D Demand Rate per month based on a one year term (Price Point "Z") & Surcharge for each Group 1 or Group 2 Delivery Point. Average FT-D Demand Rate for Group 1 Delivery Points \$ 5.34/GJ FT-D Demand Rate for Group 2 Delivery Points <sup>1</sup> \$ 3.12/GJ FT-D Demand Rate for Group 3 Delivery Points <sup>2</sup> \$ 3.74/GJ		
4. Rate Schedule STFT	STFT Bid Price = Minimum of 100% of the applicable FT-D Demand Rate based on a one year term (Price Point "Z") for each Group 1 Delivery Point		
5. Rate Schedule FT-DW	FT-DW Bid Price = Minimum of 125% of the applicable FT-D Demand Rate based on a three year term (Price Point "Y") for each Group 1 Delivery Point		
6. Rate Schedule FT-P <sup>3</sup>	Refer to Attachment "3" for applicable FT-P Demand Rate per month		
7. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10<sup>3</sup>m<sup>3</sup>/day)</u>	
	1-5 years	11.07	
	6-10 years	9.25	
	15 years	8.30	
	20 years	7.36	
8. Rate Schedule LRS-2	LRS-2 Rate per month	\$ 50,000	
9. Rate Schedule LRS-3	LRS-3 Demand Rate per month	\$ 129.55/10 <sup>3</sup> m <sup>3</sup>	
10. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
11. Rate Schedule IT-D <sup>3</sup>	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point		
12. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
13. Rate Schedule PT	<u>Schedule No</u> 9009-01001-1	<u>PT Rate</u> \$ 660.00/d	<u>PT Gas Rate</u> 50.0 10 <sup>3</sup> m <sup>3</sup> /d
14. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2013568692	\$ 14.00	/ month
	2013568691	\$ 2.00	/ month
	2013568690	\$ 2.00	/ month
	2013568689	\$ 2,125.00	/ month
	2013568688	\$ 51.00	/ month
	2013568687	\$ 138.00	/ month
	2013568686	\$ 88.00	/ month
	2013568682	\$ 20.00	/ month
	2013568681	\$ 194.00	/ month
	2013568680	\$ 210.00	/ month
	2003004522	\$ 83,333.00	/ month
	2011476052 / 2011476054	\$ 0.1026	/ GJ subject to Minimum Annual Charge
	2011475772	\$ 9,250.00	/ month
	2011475056	\$ 0.095	/ GJ and
		\$ 1,000.00	/ month
	2011476092	\$ 0.095	/ GJ and
		\$ 1,000.00	/ month
	2011494569	\$ 0.095	/ GJ and
		\$ 1,000.00	/ month

NOVA Gas Transmission Ltd.

Group 1 Delivery Point Number	Group 1 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" (\$/GJ)	IT-D Rate per Day (\$/GJ)
2000	ALBERTA-B.C. BORDER	5.38	0.1945
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	3.12	0.1128
31110	ALLIANCE EDSON INTERCONNECT APN	3.12	0.1128
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	3.12	0.1128
3002	BOUNDARY LAKE BORDER	3.33	0.1204
1958	EMPRESS BORDER	5.29	0.1912
3886	GORDONDALE BORDER	3.33	0.1204
6404	MCNEILL BORDER	5.29	0.1912

Group 2 Delivery Point Number	Group 2 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" (\$/GJ)	IT-D Rate per Day (\$/GJ)	Subject to ATCO Pipelines Franchise Fees <sup>1</sup>
31000	A.T. PLASTICS SALES APN	3.39	0.1226	Yes
31001	ADM AGRI INDUSTRIES SALES APN	3.39	0.1226	Yes
3880	AECO INTERCONNECTION	3.12	0.1128	
31003	AGRIUM CARSELAND SALES APS	3.12	0.1128	
31002	AGRIUM FT. SASK SALES APN	3.12	0.1128	Yes
31004	AGRIUM REDWATER SALES APN	3.12	0.1128	
31005	AINSWORTH SALES APGP	3.39	0.1226	
31006	AIR LIQUIDE SALES APN	3.39	0.1226	
3214	AKUINU RIVER WEST SALES	3.12	0.1128	
31007	ALBERTA ENVIROFUELS SALES APN	3.39	0.1226	Yes <sup>2</sup>
31008	ALBERTA HOSPITAL SALES APN	3.39	0.1226	Yes
3868	ALBERTA-MONTANA BORDER	3.33	0.1204	
3059	ALLISON CREEK SALES	3.12	0.1128	
31009	ALTASTEEL SALES APN	3.39	0.1226	Yes <sup>2</sup>
3562	AMOCO SALES (BP SALES TAP)	3.12	0.1128	
31012	APL JASPER SALES APN	3.39	0.1226	Yes
3488	ARDLEY SALES	3.12	0.1128	
3216	AURORA NO 2 SALES	3.12	0.1128	
3135	AURORA SALES	3.12	0.1128	
3423	BASHAW WEST SALES	3.12	0.1128	
31013	BAYMAG SALES APS	3.12	0.1128	
31014	BEAR CREEK COGEN SALES APGP	3.39	0.1226	
3068	BEAVER HILLS SALES	3.12	0.1128	
3933	BIG EDDY INTERCONNECTION	3.12	0.1128	
3067	BIGSTONE SALES	3.12	0.1128	
3468	BLEAK LAKE SALES	3.12	0.1128	
3225	BOTHA SALES	3.12	0.1128	
3164	BRAINARD LAKE SALES	3.12	0.1128	
3918	BUFFALO CREEK INTERCONNECTION	3.12	0.1128	
31015	BURDETT COGEN SALES APS	3.12	0.1128	
3204	CABIN SALES	3.12	0.1128	
3109	CALDWELL SALES	3.12	0.1128	
31016	CALGARY ENERGY CENTRE SALES APS	3.12	0.1128	Yes
3634	CANOE LAKE SALES	3.12	0.1128	
3165	CANOE LAKE SALES NO 2	3.12	0.1128	
3866	CARBON INTERCONNECTION	3.12	0.1128	
3484	CARIBOU LAKE SALES	3.12	0.1128	
3157	CARIBOU LAKE SOUTH SALES	3.12	0.1128	
3106	CARMON CREEK SALES	3.12	0.1128	
3101	CAROLINE SALES	3.12	0.1128	
31017	CARSELAND COGEN SALES APS	3.12	0.1128	
3495	CAVALIER SALES	3.12	0.1128	
31018	CHAIN LAKES COOP SALES APS	3.12	0.1128	
3907	CHANCELLOR INTERCONNECTION	3.12	0.1128	
3151	CHEECHAM WEST NO 2 SALES	3.12	0.1128	
3622	CHEECHAM WEST SALES	3.12	0.1128	
6014	CHEVRON AURORA SALES	3.12	0.1128	
31019	CHEVRON FT. SASK SALES APN	3.39	0.1226	Yes
3097	CHICKADEE CREEK SALES	3.12	0.1128	
3305	CHIGWELL NORTH SALES	3.12	0.1128	
3496	CHIPEWYAN RIVER SALES	3.12	0.1128	

NATURAL GAS TARIFF

**NorthWestern**  
Energy

Canceling 31<sup>st</sup> Revised Sheet No. 80.1  
30<sup>th</sup> 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	\$ 116.25	(I)
10,001 to 30,000	\$ 167.15	(I)
>30,000	\$ 370.95	(I)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for  
Maximum Daily Delivery Quantity (MDDQ) \$ 0.9506118 (I)

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum \$ 0.0072035 (I)

Minimum \$ 0.0017935

GTAC Amortization \$ (0.0010312)

Balancing Penalty Rate Higher of \$25.00/ Dekatherm 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)

Staff Approved: March 22, 2013  
Docket No.: D2012.9.94, Interim Order No. 7249d  
Tariff Letter No. 223-G

Effective for service rendered on or after  
April 1, 2013

PUBLIC SERVICE COMMISSION  
*Aleisha Salem* Secretary

**GAS RATE SCHEDULE**

**South Dakota Intrastate Pipeline Company**  
1415 N. Airport Rd  
Pierre, SD 57501

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

Date Filed: January 24, 2001

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

NG-00-001

**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  
Fourth Revised Sheet No. 12  
Cancels Third Revised 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	\$0.1040	\$0.0010	0.611%
	MLI	MLE	\$145.00	\$0.1040	\$0.0010	0.611%
	MLI	DSE	\$225.00	\$0.1978	\$0.0020	2.072%
Interruptible						
Transportation 4/	MLI	MLI	\$0.00	\$0.0844	\$0.0010	0.611%
	MLI	MLE	\$145.00	\$0.0844	\$0.0010	0.611%
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 therm.

3/ For fuel, lost and unaccounted for gas, the Company shall be entitled to retain the stated percentage of all therms received for transportation, unless otherwise agreed in writing. On or before March 1 of each year, the Company shall file with the Commission an application to revise the stated percentage to be effective June 1 of that year through May 31 of the following year. The Company shall calculate the stated percentage using not less than twelve (12) consecutive months of actual data.

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: March 1, 2012  
By: William N. Cantrell

Date Effective: June 1, 2012  
Title: President and CEO

**MONTANA-DAKOTA UTILITIES CO.  
RETURN ON CYCLE STORAGE BALANCES  
AND PREPAID DEMAND AND COMMODITY BALANCES  
NORTH DAKOTA GAS  
EFFECTIVE MAY 2013**

	General Service		
	Storage Balance 1/	Commodity Balance 2/	Prepaid Demand
October 2012	\$12,647,019	\$616,455	\$3,086,520
November	11,646,866	563,795	2,521,344
December	8,000,589	427,541	1,235,777
January 2013	4,079,005	272,801	(365,590)
February	1,206,550	171,608	(1,356,493)
March	(622,894)	96,229	(2,041,836)
April	(979,419)	83,600	(1,869,809)
May	564,288	140,728	(1,093,366)
June	2,640,929	217,491	(17,757)
July	4,972,250	303,671	1,115,480
August	7,587,849	400,533	2,231,716
September	10,395,469	504,462	3,106,296
October	11,631,616	550,131	3,357,912
13 month average	<u>\$5,674,624</u>	<u>\$334,542</u>	<u>\$762,323</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$498,856	\$29,410	\$67,016
Return Requirement	<u>\$680,274</u>	<u>\$40,105</u>	<u>\$91,388</u>

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

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

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

	<u>(Over) Under Recovery</u>	<u>Refunds &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, 2012</b>									<b><u>(\$1,670,167)</u></b>
August	(\$117,641)	\$0	(\$140)	(\$117,781)	264,054	(\$0.032)	(\$8,450)	(\$109,331)	(1,779,498)
September	66,156	0	(163)	65,993	256,762	(0.032)	(8,216)	74,209	(1,705,289)
October	122,687	0	(143)	122,544	571,227	(0.113)	(37,497) 2/	160,041	(1,545,248)
November	519,117	0	(116)	519,001	1,182,061	(0.113)	(133,573)	652,574	(892,674)
December	509,484	0	(52)	509,432	1,863,462	(0.113)	(210,571)	720,003	(172,671)
January 2012	(754)	0	(10)	(764)	2,547,247	(0.113)	(287,839)	287,075	114,404
February	(166,201)	0	7	(166,194)	2,403,906	(0.113)	(271,641)	105,447	219,851
<b>Balance @ February 28, 2013</b>									<b><u>\$219,851</u></b>

1/ Interest calculated at the 90 day Treasury Note rate.

2/ Reflects 333,969.6 Dk @ (\$0.032) and 237,257.7 Dk @ (\$0.113).

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
<b>Balance @ July 31, 2012</b>									<b><u>(\$144,649)</u></b>
August	(\$620)	\$0	(\$12)	(\$632)	34,895	\$0.064	\$2,233	(\$2,865)	(147,514)
September	20,949	0	(13)	20,936	50,462	0.064	3,230	17,706	(129,808)
October	(5,608)	0	(11)	(5,619)	61,663	(0.115)	2,121 2/	(7,740)	(137,548)
November	37,236	0	(10)	37,226	89,540	(0.115)	(10,297)	47,523	(90,025)
December	52,605	0	(5)	52,600	118,275	(0.115)	(13,602)	66,202	(23,823)
January 2012	24,783	0	(1)	24,782	99,565	(0.115)	(11,450)	36,232	12,409
February	23,033	0	1	23,034	114,013	(0.115)	(13,111)	36,145	48,554
<b>Balance @ February 28, 2013</b>									<b><u>\$48,554</u></b>

1/ Interest calculated at the 90 day Treasury Note rate.

2/ Reflects 51,466.6 Dk @ \$0.064 and 10,197.4 Dk @ (\$0.115).

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, 2012</b>									<b><u>(\$189,388)</u></b>
August	(\$10,033)	\$0	(\$16)	(\$10,049)	3,688	\$0.041	\$151	(\$10,200)	(199,588)
September	2,337	0	(19)	2,318	4,426	0.041	181	2,137	(197,451)
October	(2,128)	0	(16)	(2,144)	8,573	(0.377)	352 2/	(2,496)	(199,947)
November	4,067	0	(15)	4,052	35,430	(0.377)	(13,358)	17,410	(182,537)
December	25,326	0	(11)	25,315	57,310	(0.377)	(21,607)	46,922	(135,615)
January 2012	20,733	0	(7)	20,726	77,436	(0.377)	(29,193)	49,919	(85,696)
February	18,711	0	(4)	18,707	82,757	(0.377)	(31,199)	49,906	(35,790)
<b>Balance @ February 28, 2013</b>									<b><u>(\$35,790)</u></b>

1/ Interest calculated at the 90 day Treasury Note rate.

2/ Reflects 8,573.0 Dk @ \$0.041.

**MONTANA-DAKOTA UTILITIES CO.**  
**COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ADJUSTMENT**  
**APPLICABLE TO NORTH DAKOTA**  
**PROPANE**  
**TO BE EFFECTIVE MAY 1, 2013 THROUGH APRIL 30, 2014**

(Over)/under recovered gas costs @ February 28, 2013 (\$29,815)

Less: Projected recovery from rates already established

	Volume	Rate	Amount
March	6,300	\$0.646	4,070
April	3,500	\$0.646	2,261
	9,800		6,331

Additional recovery required (\$36,146)

Projected sales volumes (dk)

May 2013	2,200	
June	1,600	
July	1,000	
August	1,100	
September	1,000	
October	2,700	
November	5,000	
December	7,000	
January 2014	7,500	
February	7,600	
March	6,300	
April	3,500	
Total		46,500

Total (over)/under recovered gas cost adjustment  
to be effective May 1, 2013 through April 30, 2014. (\$0.777)

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

	(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
<b>Balance @ February 29, 2012</b>									<b><u>\$34,370</u></b>
March 2012	(\$15,600)	\$0	\$2	(\$15,598)	5,287	\$0.511	\$2,702	(\$18,300)	16,070
April	(11,661)	0	1	(11,660)	3,052	0.511	1,559	(13,219)	2,851
May	(5,234)	0	0	(5,234)	1,950	0.646	1,160 2/	(6,394)	(3,543)
June	(2,930)	0	0	(2,930)	1,446	0.646	934	(3,864)	(7,407)
July	(1,439)	0	(1)	(1,440)	993	0.646	641	(2,081)	(9,488)
August	(2,922)	0	(1)	(2,923)	1,175	0.646	759	(3,682)	(13,170)
September	(3,681)	0	(1)	(3,682)	981	0.646	634	(4,316)	(17,486)
October	7,603	0	(1)	7,602	2,412	0.646	1,558	6,044	(11,442)
November	5,478	0	(1)	5,477	4,219	0.646	2,725	2,752	(8,690)
December	(11,624)	0	(1)	(11,625)	5,869	0.646	3,791	(15,416)	(24,106)
January 2013	(3,984)	0	(1)	(3,985)	7,868	0.646	5,083	(9,068)	(33,174)
February	7,511	0	(2)	7,509	6,424	0.646	4,150	3,359	(29,815)
	<u>(\$38,483)</u>	<u>\$0</u>	<u>(\$6)</u>	<u>(\$38,489)</u>	<u>41,676</u>		<u>\$25,696</u>	<u>(\$64,185)</u>	
<b>Balance @ February 28, 2013</b>									<b><u>(\$29,815)</u></b>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Reflects 740.4 Dk @ \$0.511 and 1,210.1 Dk @ \$0.646.

**MONTANA-DAKOTA UTILITIES CO.**  
**CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS**  
**APPLICABLE TO NORTH DAKOTA**  
**PROPANE**

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>March 2012</u>				
Cost of Gas - Actual	\$14.12622	\$14.83160	\$14.12622	
Cost of Gas - Recovered	17.01600	18.11400	18.11400	
(Over) Under recovery per dk	<u>(\$2.88978)</u>	<u>(\$3.28240)</u>	<u>(\$3.98778)</u>	
dk billed	3,024	3,070	(807)	5,287
(Over) Under recovery	<u>(\$8,738)</u>	<u>(\$10,078)</u>	<u>\$3,216</u>	<u>(\$15,600)</u>
<u>April 2012</u>				
Cost of Gas - Actual	\$8.24982	\$14.12622	\$8.24982	
Cost of Gas - Recovered	13.17400	17.01600	17.01600	
(Over) Under recovery per dk	<u>(\$4.92418)</u>	<u>(\$2.88978)</u>	<u>(\$8.76618)</u>	
dk billed	1,788	1,399	(135)	3,052
(Over) Under recovery	<u>(\$8,803)</u>	<u>(\$4,043)</u>	<u>\$1,185</u>	<u>(\$11,661)</u>
<u>May 2012</u>				
Cost of Gas - Actual	\$11.53014	\$8.24982	\$11.53014	
Cost of Gas - Recovered	12.07600	13.17400	13.17400	
(Over) Under recovery per dk	<u>(\$0.54586)</u>	<u>(\$4.92418)</u>	<u>(\$1.64386)</u>	
dk billed	1,210	1,023	(283)	1,950
(Over) Under recovery	<u>(\$660)</u>	<u>(\$5,039)</u>	<u>\$465</u>	<u>(\$5,234)</u>
<u>June 2012</u>				
Cost of Gas - Actual	\$8.17425	\$11.53014	\$8.17425	
Cost of Gas - Recovered	12.07600	12.07600	12.07600	
(Over) Under recovery per dk	<u>(\$3.90175)</u>	<u>(\$0.54586)</u>	<u>(\$3.90175)</u>	
dk billed	0	808	638	1,446
(Over) Under recovery	<u>\$0</u>	<u>(\$441)</u>	<u>(\$2,489)</u>	<u>(\$2,930)</u>
<u>July 2012</u>				
Cost of Gas - Actual	\$8.91616	\$8.17425	\$8.91616	
Cost of Gas - Recovered	8.67300	12.07600	12.07600	
(Over) Under recovery per dk	<u>\$0.24316</u>	<u>(\$3.90175)</u>	<u>(\$3.15984)</u>	
dk billed	632	607	(246)	993
(Over) Under recovery	<u>\$154</u>	<u>(\$2,370)</u>	<u>\$777</u>	<u>(\$1,439)</u>
<u>August 2012</u>				
Cost of Gas - Actual	\$1.67384	\$8.91616	\$1.67384	
Cost of Gas - Recovered	8.67300	8.67300	8.67300	
(Over) Under recovery per dk	<u>(\$6.99916)</u>	<u>\$0.24316</u>	<u>(\$6.99916)</u>	
dk billed	0	732	443	1,175
(Over) Under recovery	<u>\$0</u>	<u>\$178</u>	<u>(\$3,100)</u>	<u>(\$2,922)</u>

**MONTANA-DAKOTA UTILITIES CO.**  
**CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS**  
**APPLICABLE TO NORTH DAKOTA**  
**PROPANE**

	1/	2/	3/	Total
<u>September 2012</u>				
Cost of Gas - Actual	\$9.19359	\$1.67384	\$9.19359	
Cost of Gas - Recovered	7.13600	8.67300	8.67300	
(Over) Under recovery per dk	\$2.05759	(\$6.99916)	\$0.52059	
dk billed	663	693	(375)	981
(Over) Under recovery	<u>\$1,363</u>	<u>(\$4,849)</u>	<u>(\$195)</u>	<u>(\$3,681)</u>
<u>October 2012</u>				
Cost of Gas - Actual	\$13.20228	\$9.19359	\$13.20228	
Cost of Gas - Recovered	7.13600	7.13600	7.13600	
(Over) Under recovery per dk	\$6.06628	\$2.05759	\$6.06628	
dk billed	0	1,753	659	2,412
(Over) Under recovery	<u>\$0</u>	<u>\$3,608</u>	<u>\$3,995</u>	<u>\$7,603</u>
<u>November 2012</u>				
Cost of Gas - Actual	\$7.55567	\$13.20228	\$7.55567	
Cost of Gas - Recovered	9.33100	7.13600	7.13600	
(Over) Under recovery per dk	(\$1.77533)	\$6.06628	\$0.41967	
dk billed	2,560	1,652	7	4,219
(Over) Under recovery	<u>(\$4,545)</u>	<u>\$10,020</u>	<u>\$3</u>	<u>\$5,478</u>
<u>December 2012</u>				
Cost of Gas - Actual	\$8.38874	\$7.55567	\$8.38874	
Cost of Gas - Recovered	10.42900	9.33100	9.33100	
(Over) Under recovery per dk	(\$2.04026)	(\$1.77533)	(\$0.94226)	
dk billed	3,323	2,935	(389)	5,869
(Over) Under recovery	<u>(\$6,780)</u>	<u>(\$5,211)</u>	<u>\$367</u>	<u>(\$11,624)</u>
<u>January 2013</u>				
Cost of Gas - Actual	\$10.86129	\$8.38874	\$10.86129	
Cost of Gas - Recovered	9.88000	10.42900	10.42900	
(Over) Under recovery per dk	\$0.98129	(\$2.04026)	\$0.43229	
dk billed	4,467	3,979	(578)	7,868
(Over) Under recovery	<u>\$4,384</u>	<u>(\$8,118)</u>	<u>(\$250)</u>	<u>(\$3,984)</u>
<u>February 2013</u>				
Cost of Gas - Actual	\$11.44168	\$10.86129	\$11.44168	
Cost of Gas - Recovered	9.88000	9.88000	9.88000	
(Over) Under recovery per dk	\$1.56168	\$0.98129	\$1.56168	
dk billed	3,649	4,345	(1,570)	6,424
(Over) Under recovery	<u>\$5,699</u>	<u>\$4,264</u>	<u>(\$2,452)</u>	<u>\$7,511</u>

- 1/ Consumed in current month.  
2/ Consumed in prior month.  
3/ True-up of prior month volumes.