

July 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 (115th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered August 1, 2013.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.512 per dk since the last filing due to a decrease in the overall commodity price of gas. Attachment B explains the reasons for the decrease in the market price of gas. There has also been a change in pipeline rates as shown on Attachment C.

The COG tariff sheet, Exhibit A page 1, summarizes the gas cost adjustment, calculated pursuant to the terms of Rate 88, the surcharge adjustment and the market based pricing differential provision that will apply during the month of August 2013.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.512 per dk for residential customers and firm general customers, a decrease of \$0.494 per dk for small and large interruptible customers and a decrease of \$0.492 per dk for Air Force interruptible customers from the currently effective rates.

Exhibit B shows the calculation of the current gas cost adjustment that will be applicable to Montana-Dakota's customers for the month of August 2013. The average cost of gas for firm customers, adjusted for losses, is \$4.755.

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 June COG filing.

These proposed adjustments, calculated in accordance with Rate 88, will amount to a decrease of approximately \$160,100 for natural gas customers during the month of August 2013. All of Montana-Dakota's retail natural gas in North Dakota may be affected by this proposal. There were 98,771 natural gas 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:

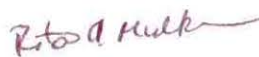
Mr. Daniel S. Kuntz
Associate General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

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,



Rita A. Mulkern
Director of Regulatory Affairs

Attachment

Attachment A

**Rate Summary Sheet
(Proposed)**



Montana-Dakota Utilities Co.

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

State of North Dakota Gas Rate Schedule

NDPSC Volume 7
115th Revised Sheet No. 3
Canceling 114th 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 | \$4.632 | \$5.444 |
| Air Force Rate 64 | 7 | | | | |
| Minot Air Force Base | | \$1,000.00 per month | | | |
| PAR Site | | \$135.00 per month | | | |
| Firm Service | | | \$0.138 | \$4.632 | \$4.770 |
| Interruptible Service - PAR | | | \$0.120 | \$3.669 | \$3.789 |
| Interruptible Service - MAFB | | | \$0.120 | \$3.390 | \$3.510 |
| 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 | \$4.632 | \$5.229 |
| Small Interruptible Gas Rate 71 | 14 | \$100.00 per month | (Maximum) \$0.871 | \$3.669 | (Maximum) \$4.540 |
| 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 | \$3.730 | \$4.327 |
| Transportation Service | 24 | | | | |
| Small Interruptible Rate 81 | | \$150.00 per month | | | |
| Maximum | | | \$0.427 | | |
| Minimum | | | \$0.102 | | |
| Fuel Charge | | | | \$0.017 | |
| Large Interruptible Rate 82 | | \$725.00 per month | | | |
| Maximum | | | \$0.298 | | |
| Minimum | | | \$0.061 | | |
| Fuel Charge | | | | \$0.017 | |
| Large Interruptible Gas Rate 85 | 27 | \$675.00 per month | (Maximum) \$0.719 | \$3.669 | (Maximum) \$4.388 |
| Residential Propane Rate 90 | 32 | \$0.30 per day | \$0.812 | \$9.093 | \$9.905 |
| 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 | \$9.093 | \$9.690 |

Date Filed: July 8, 2013

Effective Date:

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

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

August 2013

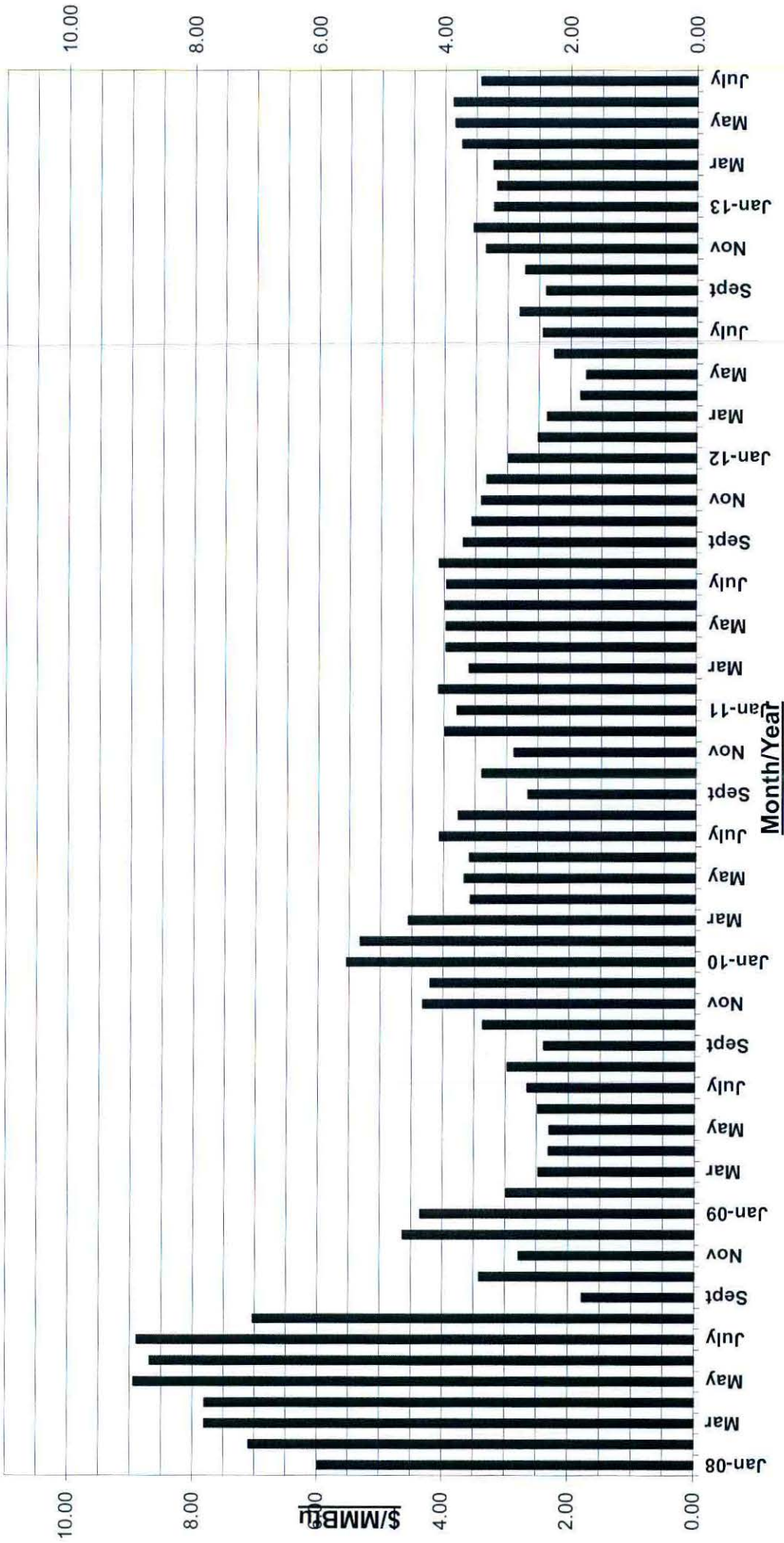
The established monthly price for the Rocky Mountain CIG Index has decreased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including “Inside FERC Gas Market” report and “Gas Daily” by McGraw-Hill Companies, of prices paid 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 decrease in natural gas prices is likely a result of the national storage level increasing more than anticipated, indicating an increase in natural gas supply despite warmer weather in the Northeast and record heat in the Southwest. The Energy Information Administration (EIA) reported storage levels nationwide as of June 28, 2013 to be 1.1 percent below the five-year average and 15.9 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 June Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 17. The July Outlook will be published July 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 - \$3.50



Independent Statistics & Analysis

U.S. Energy Information
Administration

June 2013

Short-Term Energy Outlook (STEO)

Highlights

- After increasing to \$119 per barrel in early February 2013, the Brent crude oil spot price fell to a low of \$97 per barrel in mid-April and then recovered to an average of \$103 per barrel in May. EIA expects that the Brent crude oil spot price will average \$102 per barrel over the second half of 2013, and \$100 per barrel in 2014.
- EIA expects the price of regular gasoline will average \$3.53 per gallon over the summer driving season (April through September). The annual average regular gasoline retail price is projected to decline from \$3.63 per gallon in 2012 to \$3.49 per gallon in 2013 and to \$3.37 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 the projected levels.
- In April 2013, estimated total liquid fuels consumption in non-OECD (Organization for Economic Cooperation and Development) countries reached 44.5 million barrels per day (bbl/d), which was higher than consumption in OECD countries (44.3 million bbl/d) for the first time in history. EIA expects that consumption in OECD countries will average 45.5 million bbl/d in 2013 compared with 44.6 million bbl/d for non-OECD countries. EIA forecasts annual average non-OECD total liquids consumption to surpass OECD levels in 2014.
- EIA forecasts the summer 2013 average U.S. residential electric bill will total \$395 over the three-month period of June, July, and August, which is \$10 (2.5 percent) lower than the average customer's bill during summer 2012 (see [Summer 2013 Outlook for Residential Electric Bills](#)). Forecast milder temperatures than last summer contribute to a projected decline in average electricity usage per customer, which is partially offset by a projected 2-percent increase in average electricity prices.
- Based on the outlook from the National Oceanic and Atmospheric Administration (NOAA) for above-normal tropical weather activity this year, EIA estimates median outcomes for total shut-in production in the federal Gulf of Mexico (GOM) during the current hurricane season (June through November) of about 19 million barrels of crude oil and 46 billion cubic feet (Bcf) of natural gas (see [2013 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico](#)). Actual shut-ins are likely to differ significantly from this estimate depending on the number, track, and strength of hurricanes as the season progresses.

Global Crude Oil and Liquid Fuels

In April 2013, estimated total liquid fuels consumption in non-OECD countries reached 44.5 million barrels per day (bbl/d), which was higher than consumption in OECD countries (44.3 million bbl/d) for the first time in history. The expected stronger seasonal increase in consumption among the developed economies in 2013 pushes OECD consumption back on top through early 2014. On an average annual basis, non-OECD use of liquid fuels is forecast to exceed OECD levels in 2014.

Global Liquid Fuels Consumption. World liquid fuels consumption grew by 0.8 million bbl/d in 2012 to reach 89.2 million bbl/d. EIA expects world consumption to grow by 0.9 million bbl/d in 2013 and by 1.2 million bbl/d in 2014.

Non-OECD Asia, particularly China, is the leading contributor to projected global consumption growth. EIA expects refinery crude oil inputs in China to increase in 2013 as new refining capacity continues to come on line. EIA estimates that liquid fuels consumption in China increased by 380,000 bbl/d in 2012. Recent indicators of weaker industrial data at the beginning of 2013 signaled slower economic growth than in prior years and a downside risk to robust oil demand growth. Projected consumption increases by 420,000 bbl/d in 2013 and by 430,000 bbl/d in 2014, compared with average annual growth of about 520,000 bbl/d from 2004 through 2012.

OECD liquid fuels consumption fell by 0.6 million bbl/d in 2012. EIA projects OECD consumption to decline by an additional 0.5 million bbl/d in 2013 and 0.2 million bbl/d in 2014, largely because of declining consumption in Europe and Japan.

Non-OPEC Supply. EIA projects liquid fuels production by countries that are not members of the Organization of the Petroleum Exporting Countries (OPEC) will increase by 1.2 million bbl/d in 2013 and by 1.6 million bbl/d in 2014. North America accounts for much 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. EIA expects non-OPEC supply to also grow in Central and South America by an average of 160,000 bbl/d each year over the next two years, as Brazil and Colombia bring new production on line.

Total unplanned non-OPEC production outages averaged 1.0 million bbl/d in May 2013, up from 0.9 million bbl/d in last month's STEO. Sudan, South Sudan, Syria, and Yemen account for more than three-quarters of the disruptions. EIA expects supply disruptions to persist in Syria and Yemen over the forecast period. EIA has lowered its forecast of supply from Kazakhstan because of continued delays in the Kashagan field.

OPEC Supply. Projected OPEC total supply, which increased by 1.2 million bbl/d in 2012, falls by 0.4 million bbl/d in 2013 and by another 0.1 million bbl/d in 2014. Most of the decline in 2013 comes from Saudi Arabia in response to non-OPEC supply growth, although Saudi production

increases for the next few months because of seasonal demand. Iraq and Angola account for most of the increase in 2014. At the last OPEC meeting on May 31, 2013, the organization decided to retain its production target of 30 million bbl/d through the rest of 2013.

EIA estimates that OPEC surplus capacity, which is concentrated in Saudi Arabia, averaged about 2.7 million bbl/d in the first quarter of 2013. This was higher than the 2.1-million-bbl/d average during the same period last year but lower than the first-quarter average of 3.8 million bbl/d from 2009 through 2011. EIA projects OPEC surplus capacity will increase to an average of 4.6 million bbl/d in the fourth quarter of 2014. These estimates do not include additional capacity that may be available in Iran but is currently off line because of the effects of U.S. and EU sanctions on Iran's oil sector.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories at the end of 2012 totaled 2.65 billion barrels, equivalent to 57.7 days of supply. Projected OECD oil inventories stay relatively steady in 2013, ending the year at 2.64 billion barrels (57.3 days of supply). Projected inventories increase to 2.68 billion barrels (58.3 days of supply) at the end of 2014.

Crude Oil Prices. After declining to a 2013 year-to-date low of \$97 per barrel on April 17, Brent crude oil spot prices increased to an average of \$103 per barrel in May. EIA projects the Brent crude oil spot price will fall from an average of \$112 per barrel in 2012 to annual averages of \$105 per barrel and \$100 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 forecast WTI crude oil spot price averages \$93 per barrel in 2013 and \$92 per barrel in 2014. By 2014, [several pipeline projects](#) from the midcontinent 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 narrowing in the [price discount of WTI to Brent](#).

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures contracts for September 2013 delivery traded during the five-day period ending June 6, 2013 averaged \$93.75 per barrel. Implied volatility averaged 23 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in September 2013 at \$77 per barrel and \$114 per barrel, respectively. Last year at this time, WTI for September 2012 delivery averaged \$85 per barrel and implied volatility averaged 35 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$63 per barrel and \$115 per barrel.

U.S. Crude Oil and Liquid Fuels

Despite only slight increases in Brent crude oil prices in May, [refinery outages across the Midwest](#) helped bring the U.S. average regular gasoline retail price up from \$3.52 per gallon on April 29, 2013 to \$3.65 per gallon on June 3. The expected recovery in refinery production combined with lower crude oil prices contributes to lower projected regular gasoline retail

prices, averaging \$3.40 per gallon in the second half of 2013 and \$3.37 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 12-percent probability that the New York Harbor reformulated gasoline blendstock for oxygenate blending (RBOB) futures price will exceed \$3.10 per gallon (consistent with a U.S. average regular gasoline retail price above \$3.75 per gallon) in September 2013.

U.S. Liquid Fuels Consumption. In 2012, total liquid fuels consumption declined 390,000 bbl/d (2.1 percent). During the first quarter of 2013, total liquid fuels consumption rose by 180,000 bbl/d compared with the same period last year, led by increases in liquefied petroleum gas and distillate consumption. Much of that increase was due to weather, with heating degree days in the Northeast 21 percent higher than the mild first quarter seen last year. For the year as a whole, the forecast of total liquid fuels consumption increases by an average 90,000 bbl/d, followed by a slight decline in 2014. Motor gasoline consumption remains flat during the forecast interval as continued increases in vehicle fuel efficiency offset gains in motor vehicle travel.

U.S. Liquid Fuels Supply. EIA expects U.S. crude oil production to rise from an average of 6.5 million bbl/d in 2012 to 7.3 million bbl/d in 2013 and 8.1 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.

One current driver of production growth through 2014 is the continued exploration success seen in some of the major plays in the Permian Basin. Operators in the Bone Spring, Spraberry, and Wolfcamp plays are achieving greater success in finding sweet spots and hydraulically fracturing horizontal wells. EIA expects improvements in drilling and completing horizontal wells from multi-well drilling pads in the Permian Basin, which give operators greater access to large areas of resources in a number of stacked plays from a single surface location.

Gulf of Mexico oil production estimates have been revised downward by 160,000 bbl/d in May and 270,000 bbl/d in June from last month's STEO. Maintenance at the BP natural gas processing plant in Pascagoula, Mississippi, and on the NaKika offshore platform lowered production in May and early June. The Pascagoula plant is back in operation, and the NaKika system is scheduled to ramp up production by mid-June. Additional shut-in oil production will occur in June as Shell installs a new platform as part of the Mars B project, slated to begin producing during 2015.

The NOAA [Atlantic Hurricane Season Outlook](#) predicts that the Atlantic Basin likely will experience above-normal tropical weather activity during the current hurricane season. EIA estimates that the median outcome for shut-in crude oil production in the federally administered Gulf of Mexico because of disruptions during the 2013 hurricane season is 19 million barrels. There is a wide range of uncertainty around this forecast (see the [2013 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico](#)). EIA's simulation results

indicate a 58-percent probability of offshore crude oil production experiencing outages during the current hurricane season that are equal to or larger than the 14 million barrels of production shut in during the 2012 hurricane season.

Since reaching 12.5 million bbl/d in 2005, total U.S. liquid fuel net imports, including crude oil and petroleum products, 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 5.7 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 30 percent in 2014, which would be the lowest level since 1985.

U.S. Petroleum Product Prices. EIA expects that regular-grade gasoline retail prices, which averaged \$3.69 per gallon last summer, will average \$3.53 per gallon during the current summer (April through September) driving season. The projected monthly average regular retail gasoline price falls from \$3.61 per gallon in May to \$3.43 per gallon in September. Diesel fuel prices, which averaged \$3.95 per gallon last summer, are projected to average \$3.83 per gallon this summer. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas exceeding the national average price by 30 cents per gallon or more.

As is the case with crude oil, the market's expectation of uncertainty in monthly average gasoline prices is reflected in the pricing and implied volatility of futures and options contracts. New York Harbor RBOB futures contracts for September 2013 delivery traded over the five-day period ending June 6 averaged \$2.76 per gallon. The probability that the RBOB futures price will exceed \$3.10 per gallon (consistent with a U.S. average regular gasoline retail price above \$3.75 per gallon) in September 2013 is about 12 percent.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption, which averaged 69.7 Bcf/d in 2012, will average 70.0 Bcf/d and 69.6 Bcf/d in 2013 and 2014, respectively. Colder winter temperatures forecast for 2013 and 2014 (compared with the record-warm temperatures in 2012) are expected to increase the amount of natural gas used for residential and commercial space heating. However, the projected year-over-year increases in natural gas prices contribute to declines in natural gas used for electric power generation from 25.0 Bcf/d in 2012 to 22.5 Bcf/d in 2013 and 22.1 Bcf/d in 2014, although these forecast levels are still high by historical standards.

U.S. Natural Gas Production and Trade. Natural gas marketed production is projected to increase from 69.2 Bcf/d in 2012 to 70.0 Bcf/d in 2013, and to 70.4 Bcf/d in 2014. Onshore production increases over the forecast period, while federal Gulf of Mexico production declines. Natural gas pipeline gross imports, which have fallen over the past five years, are projected to

remain near their 2012 level over the forecast. LNG imports are expected to remain at minimal levels of around 0.4 Bcf/d in both 2013 and 2014.

Mexico's [domestic natural gas consumption](#) is rising faster than domestic production, leading to both [record pipeline gas imports](#) from the United States and growth in the country's imports of liquefied natural gas (LNG). Natural gas trade between Mexico and the United States has been growing; daily net exports from the United States to Mexico so far in 2013 (January 1-May 6) are estimated to average 1.6 billion cubic feet per day (Bcf/d), up almost 29 percent over the same period in 2012.

The NOAA [Atlantic Hurricane Season Outlook](#) predicts that the Atlantic Basin likely will experience above-normal tropical weather activity during the current hurricane season. EIA estimates that the median outcome for shut-in natural gas production in the federally administered Gulf of Mexico as a result of disruptions during the 2013 hurricane season is 46 Bcf (see the [2013 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico](#)). EIA's simulation results indicate a 58-percent probability of offshore natural gas production experiencing outages during the current hurricane season that are equal to or larger than the 32 Bcf of production shut in during the 2012 hurricane season.

U.S. Natural Gas Inventories. As of May 31, 2013, working gas stocks totaled 2,252 Bcf, which is 616 Bcf less than at the same time last year, but only 69 Bcf below the five-year (2008-12) average for the end of May. EIA projects working gas stocks at the end of this summer's stock-build season (end of October) will reach 3,813 Bcf, about 117 Bcf below the level at the same time last year.

U.S. Natural Gas Prices. Natural gas spot prices averaged \$4.04 per MMBtu at the Henry Hub in May 2013, down 13 cents from the \$4.17-per-MMBtu average seen the previous month. EIA expects the Henry Hub price will increase from an average of \$2.75 per MMBtu in 2012 to \$3.92 per MMBtu in 2013 and \$4.10 per MMBtu in 2014.

Natural gas futures prices for September 2013 delivery (for the five-day period ending June 6, 2013) averaged \$3.97 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for September 2013 contracts at \$3.03 per MMBtu and \$5.21 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for September 2012 averaged \$2.48 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were \$1.51 per MMBtu and \$4.07 per MMBtu.

Coal

Electric power sector coal stocks ended March 2013 at 173 million short tons (MMst), the lowest level since December 2011. It was the fourth consecutive month that stocks declined.

Inventories have fallen 6 percent (12 MMst) since the beginning of this year. Over the same period last year, electric power sector coal stocks increased by 13 percent (22 MMst).

U.S. Coal Consumption. EIA expects total coal consumption will increase by 7.1 percent from 890 MMst in 2012 to 954 MMst in 2013 as consumption in the electric power sector rises due to higher electricity demand and higher natural gas prices. Consumption grows at a more modest pace of 1.8 percent to 970 MMst in 2014.

U.S. Coal Supply. Coal production is expected to remain relatively stable, increasing by 0.5 percent, from 1,016 MMst in 2012 to 1,021 MMst in 2013. Inventory draws, combined with an increase in coal imports, meet most of the growth in consumption in 2013. Coal production is forecast to grow by 3.2 percent in 2014 to 1,054 MMst as inventories stabilize in the face of increasing consumption.

U.S. Coal Exports. EIA expects exports to decline from 126 MMst in 2012 to 110 MMst in 2013 despite a record 13.6 MMst exported in March. Exports are projected to be 107 MMst in 2014. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, increasing supply in other coal-exporting countries, and falling international coal prices 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 a 12-year period through 2012, when the delivered coal price averaged \$2.40 per MMBtu. EIA forecasts average delivered coal prices of \$2.36 per MMBtu in 2013 and \$2.40 per MMBtu in 2014.

Electricity

This month's STEO includes a special supplement ([Summer 2013 Outlook for Residential Electric Bills](#)) describing EIA's expectations about residential electricity usage and electric bills during the summer months. EIA forecasts the average U.S. residential electric bill over the period of June-August 2013 will total \$395, about 2.5 percent lower than the average bill last summer. A reduction in the average summer electricity usage per customer, because of forecast milder temperatures, is offset somewhat by projected higher average U.S. retail electricity prices in most areas of the country. Average customer electricity usage projections will also now appear in [STEO Table 7a](#) and in the [STEO custom table builder](#).

The North American Electric Reliability Corporation (NERC) has issued its [2013 Summer Reliability Assessment](#) for the electricity industry during the upcoming summer months. NERC's key findings indicate that [Texas and California](#) may face challenges balancing electricity demand with available capacity under extreme weather or adverse supply conditions. Also, increased wind and solar generation capacity in certain regions and persisting drought conditions west of the Mississippi could result in increased supply uncertainty during peak demand periods.

U.S. Electricity Consumption. For the summer months of June through August of 2013, EIA expects the average U.S. residential customer will use a total of 3,200 kilowatthours of electricity, which is 4.6 percent lower than last summer. However, because of the relatively cold first quarter of 2013, EIA projects residential customers will use an average of 10,883 kWh for the entire year of 2013, which is 0.4 percent more than 2012. This growth in annual electricity usage, combined with a projected 0.7-percent increase in the number of residential customers, translates to a forecast increase of 1.3 percent in total retail sales of electricity to the residential sector during 2013. Retail sales of electricity to the commercial sector grow by 0.9 percent in 2013, while retail sales to the industrial sector stay relatively flat this year.

U.S. Electricity Generation. EIA expects total U.S. electricity generation will grow by 0.9 percent annually in both 2013 and 2014. Water supply in the Pacific Northwest this spring is lower than last year, leading to a 4-percent decline in the level of conventional hydroelectric generation during the first quarter of 2013 compared with the same period last year. EIA has revised its forecast for hydropower generation for the upcoming summer months to better reflect the NOAA water supply outlook. Generators have been running their existing coal capacity at higher rates so far this year in response to the increasing cost of natural gas relative to coal. This trend is expected to continue, leading to an 8.5-percent annual increase in U.S. electricity generation from coal and an 8.2-percent decline in U.S. natural gas generation during 2013.

U.S. Electricity Retail Prices. The U.S. residential electricity price averaged 11.9 cents per kWh in 2012. EIA expects the average residential price will grow by 1.1 percent in 2013 and by 1.9 percent in 2014. The residential price during the summer months this year (June-August) is expected to average 12.3 cents/kWh, a 2.2-percent increase from the price last summer.

Renewables and Carbon Dioxide Emissions

U.S. Electricity and Heat Generation from Renewables. EIA projects renewable energy consumption for electricity and heat generation to increase by 3.0 percent in 2013. While hydropower declines by 4.4 percent, nonhydropower renewables used for electricity and heat grow by an average of 7.7 percent in 2013. In 2014, the growth in renewables consumption for power and heat generation is projected to continue at a rate of 5.3 percent, as a 3.9-percent increase in hydropower is combined with a 6.1-percent increase in nonhydropower renewables.

EIA currently estimates that wind capacity will increase by 6 percent this year to nearly 63,000 megawatts, and reach almost 73,000 megawatts in 2014. However, electricity generation from wind is projected to increase by 19 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 8 percent in 2014.

EIA expects continued robust growth in the generation of solar energy, both from central-station and distributed capacity, although the total amount remains a small share of total U.S. generation. Central-station capacity, which until recently experienced little growth compared

with distributed capacity, is projected to more than double between 2012 and 2014. Photovoltaics (PV) accounted for all central-station solar growth in 2012, but EIA expects that several large solar thermal generation projects will enter service in 2013 and 2014. However, PV is still expected to account for the majority of central station and distributed capacity additions in 2013 and 2014.

U.S. Liquid Biofuels. Smaller corn harvests due to widespread drought resulted in U.S. fuel ethanol production falling from an average of approximately 900,000 bbl/d (13.8 billion gallons per year) in the first half of 2012 to an average of 820,000 bbl/d (12.6 billion gallons per year) from July 2012 through March 2013. [Ethanol production has partially recovered since April](#), averaging about 870,000 bbl/d in May 2013, driven in part by increasing Renewable Fuel Standard (RFS) targets and strong demand for [Renewable Identification Numbers](#) (RINs). EIA expects ethanol production to remain near current levels through the third quarter before recovering to pre-drought production levels, averaging 870,000 bbl/d for the year. Ethanol production is expected to average 930,000 bbl/d in 2014. Biodiesel production, which averaged 63,000 bbl/d (1.0 billion gallons per year) in 2012, is forecast to average about 81,000 bbl/d in 2013 and 82,000 bbl/d in 2014 (1.3 billion gallons per year). This forecast assumes that the 2014 renewable fuel volume obligations are identical to those in 2013, which is 1.6 billion gallons below the 2014 statutory target of 18.15 billion ethanol-equivalent gallons of total renewable fuels.

In 2013, the statutory RFS target of 16.55 billion ethanol-equivalent gallons of total renewable fuels would require refiners and importers of gasoline and diesel fuel to deliver RINs to the U.S. Environmental Protection Agency (EPA) equivalent to 9.63 percent of the gasoline or diesel fuel they sell domestically (not counting the biofuels blended into it), unless the EPA reduces this requirement in its final rulemaking for the 2013 RFS program year. The market price of ethanol RINs increased dramatically during the first quarter of 2013, from \$0.05 per gallon at the start of the year to as high as \$1.05 per gallon on March 11, and has averaged over \$0.80 per gallon during May 2013.

The increase in the ethanol RIN price provides an economic incentive for two changes in the market. First, although present RIN prices do not appear sufficient to make E85 an economical fuel choice, a higher ethanol RIN price tends to lower the market price of E85 gasoline relative to E10 gasoline. Second, an ethanol RIN price equal to or near the biodiesel RIN price may motivate blending of biodiesel that exceeds the biodiesel blending requirements that EPA announced in a proposed rulemaking for the 2013 RFS program that has yet to be finalized.

At the retail level, EIA expects diesel fuel prices to be most affected by higher RIN prices as typical biodiesel blending yields only about one-third of the RINs required and diesel fuel refiners and blenders must make up for the shortfall by purchasing the now higher-priced RINs.

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 2.6 percent in 2013

and 0.5 percent in 2014. The increase in emissions over the forecast period primarily reflects the projected increase in coal use for electricity generation, especially in 2013 as it rebounds from the 2012 decline.

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 assumes that the spending cuts mandated in the Budget Control Act of 2011 (sequestration) will soon be replaced by a combination of income tax increases and spending cuts that are implemented in 2014. The GI model also assumes 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. Current economic indicators portray a mixed picture on the strength of the expansion to date. The [Reuters/University of Michigan Consumer Sentiment Index](#) showed an increase in May, after declining in April. The [U.S. Bureau of Economic Analysis \(BEA\)](#) reported real disposable income increased by 0.1 percent in April. The [U.S. Census Bureau](#) also reported that new orders for manufactured durable goods rose 3.3 percent from March to April, following a 5.9-percent decline from February to March. According to the [U.S. Commerce Department](#), sales of new single-family homes increased by 2.3 percent from March to April 2013. This was a 29-percent rise from April 2012. However, the [BEA](#) revised downward real GDP growth in the first quarter of 2013 from 2.5 to 2.4 percent. The [ISM Purchasing Managers Index](#) fell to 49 percent in May, its lowest level since June 2009. Most projections continue to show stronger economic growth in the second half of 2013.

U.S. Production. This STEO assumes U.S. real GDP growth of 1.8 percent in 2013, rising to 2.6 percent in 2014. Year-on-year real GDP growth begins to accelerate in 2014, eventually rising to 3.0 percent in its final quarter. Forecast real disposable income increases 0.6 percent in 2013 and 3.3 percent in 2014. Total industrial production grows at a faster rate than real GDP in 2013 and 2014, at around 3.0 percent in each year. Industrial production growth in the manufacturing sector is 3.2 percent in 2013, but accelerates to 3.7 percent in 2014.

U.S. Income and Expenditures. Private fixed investment growth averages 6.5 and 8.3 percent over 2013 and 2014, respectively. This is driven partly by business equipment and software spending, as well as increasing expenditures on buildings. Real consumption expenditures grow faster than real GDP in 2013, at 2.1 percent, but slow below the rate of real GDP growth in 2014, at 2.2 percent. Export growth more than doubles from 2.0 to 5.2 percent over the same two years. Government expenditures fall by 2.8 percent in 2013, and rise by 0.3 percent in 2014.

U.S. Employment, Housing, and Prices. The unemployment rate in the forecast averages 7.6 percent over 2013, and gradually falls to 7.0 percent at the end of 2014. This is accompanied by nonfarm employment growth averaging 1.5 percent in both 2013 and 2014. Consistent with an

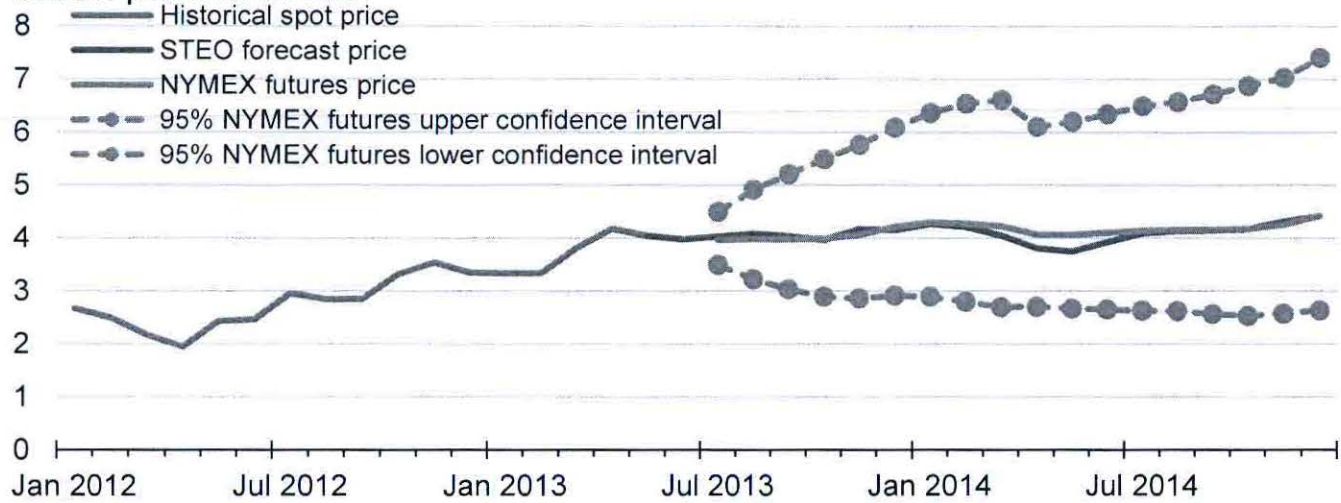
improving housing sector, housing starts grow an average of 23.8 percent and 25.8 percent over 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.

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



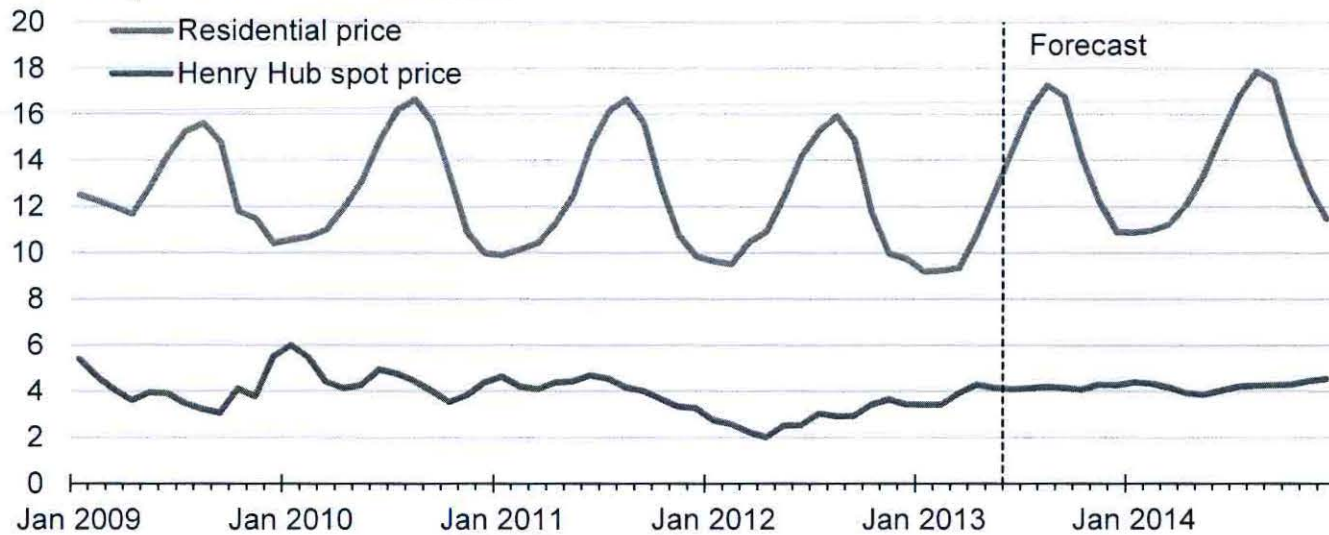
Note: Confidence interval derived from options market information for the 5 trading days ending June 6, 2013. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, June 2013



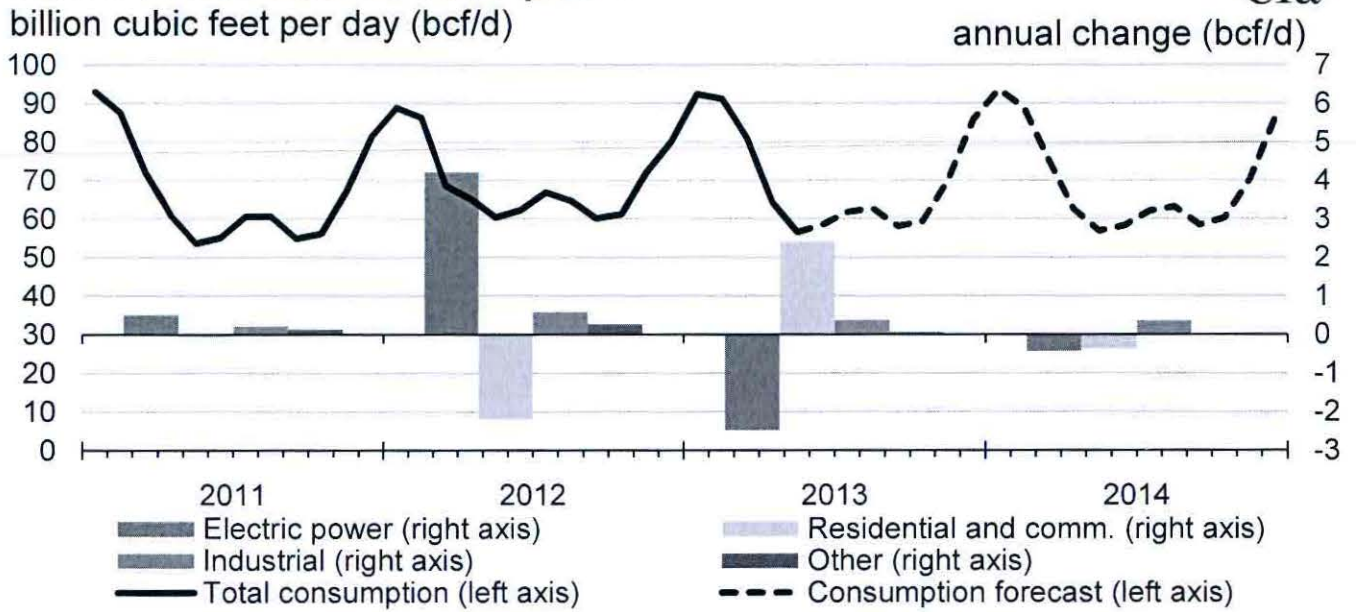
U.S. Natural Gas Prices

dollars per thousand cubic feet



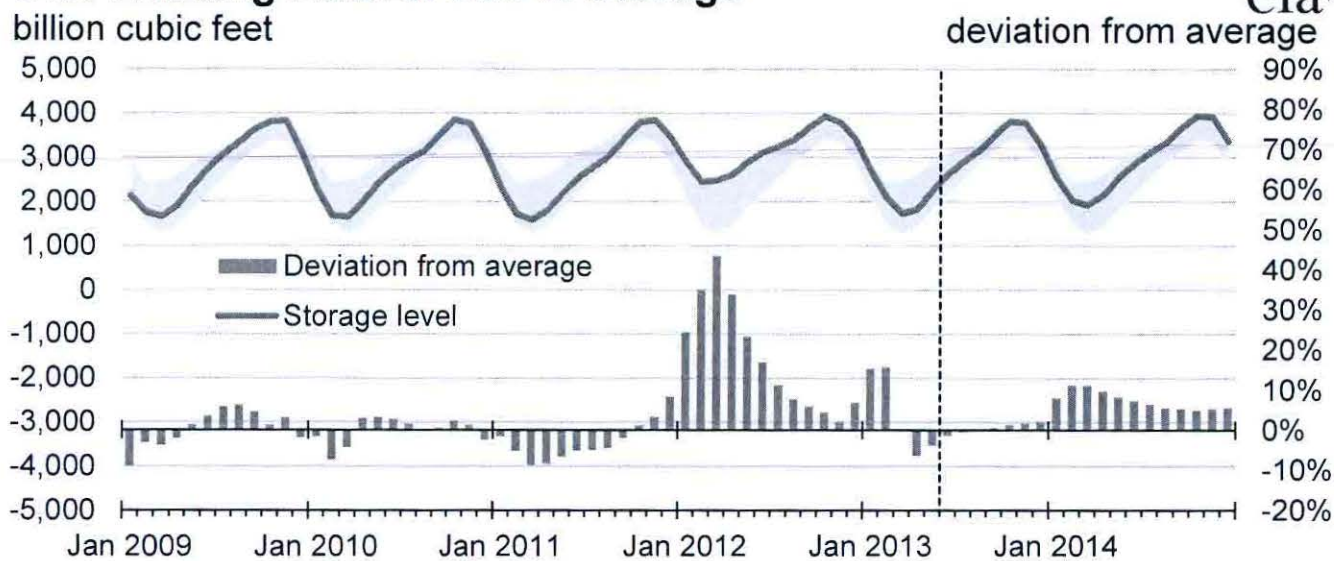
Source: Short-Term Energy Outlook, June 2013

U.S. Natural Gas Consumption



Source: Short-Term Energy Outlook, June 2013

U.S. Working Natural Gas in Storage



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

Source: Short-Term Energy Outlook, June 2013

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

NorthWestern Energy Docket No. D2012.9.94

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

On May 7, 2013, the Montana PSC issued a Final Order with rates effective June 1, 2013.

Approximate impact on Montana-Dakota's cost of gas: 0.0 cents per dk

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

| | Firm | | Small & Large Interruptible | Air Force Interruptible |
|---|-------------------------------------|-------------------------|-----------------------------------|----------------------------|
| | Residential & General Service | Optional Seasonal | | |
| <u>Gas Cost Adjustment:</u> | | | | |
| Gas Cost Level (Exhibit B) | \$4.755 | \$3.853 | \$3.784 | \$3.767 |
| Prior Gas Cost | 5.267 | 4.355 | 4.278 | 4.259 |
| Current Gas Cost Adjustment | (\$0.512) | (\$0.502) | (\$0.494) | (\$0.492) |
| <u>Surcharge Adjustment:</u> | | | | |
| 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 |
| <u>Market Based Pricing Differential</u> | | | | |
| 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 |
| Net Increase (Decrease) in Gas Costs | <u>(\$0.512)</u> | <u>(\$0.502)</u> | <u>(\$0.494)</u> | <u>(\$0.492)</u> |
| Gas Cost Level | \$4.755 | \$3.853 | \$3.784 | \$3.767 |
| Plus: Surcharge | (0.113) | (0.113) | (0.115) | (0.377) |
| Total Gas Cost Level in Tariff Rates | <u>\$4.642</u> | <u>\$3.740</u> | <u>\$3.669</u> | <u>\$3.390</u> |

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

| | Amount |
|---|------------------|
| Total Gas Costs 1/ | \$69,226,692 |
| Residential and General Service dk Requirements 2/ | 14,624,127 |
| Average Cost of Gas per dk | \$4.734 |
| Average Cost of Gas as Adjusted for Losses @ 99.55% | 4.755 |
| Less: Gas Cost Level in Rates 3/ | 5.267 |
| Current Gas Cost Adjustment | (\$0.512) |

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

2/ Normalized dk sales for the twelve months ended May 31, 2013, adjusted for losses at .45%.

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

| | |
|-------------------------------------|---------|
| Cost of Purchased Gas | \$5.243 |
| Adjustment for Distribution Losses | 0.9955 |
| Gas Cost Level in Base Tariff Rates | \$5.267 |

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

| | |
|--|--------------------------------|
| Total Gas Costs 1/ | \$69,226,692 |
| Less: Annual MDDQ Costs 1/ | <u>13,121,509</u> |
| Total Gas Costs excluding MDDQ | \$56,105,183 |
| Firm Service Requirements 1/ | 14,624,127 |
| Other Gas Costs per Dk (excluding MDDQ) | \$3.836 |
| <u>Summer - June - September</u> | |
| Summer Seasonal Rate, adjusted for losses 2/ | 3.853 |
| Less: Gas Cost Level in Rates 3/ | <u>4.355</u> |
| Current Gas Cost Adjustment | <u><u>(\$0.502)</u></u> |

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

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

| | <u>Summer</u> |
|-------------------------------------|---------------|
| Cost of Purchased Gas | \$4.335 |
| Adjustment for Distribution Losses | 0.9955 |
| Gas Cost Level in Base Tariff Rates | \$4.355 |

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

| | Amount |
|---|------------------|
| Total Gas Costs 1/ | \$13,194,187 |
| Interruptible Service dk Requirements | 3,502,739 |
| Average Cost of Gas per dk | \$3.767 |
| Average Cost of Gas as Adjusted for Losses @ 99.55% | 3.784 |
| Less: Gas Cost Level in Rates 2/ | 4.278 |
| Current Gas Cost Adjustment | (\$0.494) |

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 June 1, 2013:

| | |
|-------------------------------------|---------|
| Cost of Purchased Gas | \$4.259 |
| Adjustment for Distribution Losses | 0.9955 |
| Gas Cost Level in Base Tariff Rates | \$4.278 |

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

| | Amount |
|---|------------------|
| Total Gas Costs 1/ | \$3,314,800 |
| Air Force Interruptible dk Requirements | 880,000 |
| Average Cost of Gas per dk | \$3.767 |
| Less: Gas Cost Level in Rates 2/ | 4.259 |
| Current Gas Cost Adjustment | (\$0.492) |

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 June 1, 2013:
Cost of Purchased Gas \$4.259

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

Issued On: March 1, 2013
 Docket Number: RP13-621-000
 FERC Order Date: March 18, 2013

Effective On: April 1, 2013

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

8NOTICE 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.

Issued On: March 1, 2013
 Docket Number: RP13-621-000
 FERC Order Date: March 18, 2013

Effective On: April 1, 2013

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 ³ m ³ | | |
| 2. Rate Schedule FT-RN | Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point | | |
| 3. Rate Schedule FT-D ³ | 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 ¹ \$ 3.12/GJ FT-D Demand Rate for Group 3 Delivery Points ² \$ 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 ³ | Refer to Attachment "3" for applicable FT-P Demand Rate per month | | |
| 7. Rate Schedule LRS | <u>Contract Term</u> | <u>Effective LRS Rate (\$/10³m³/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 ³ m ³ | |
| 10. Rate Schedule IT-R | Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point | | |
| 11. Rate Schedule IT-D ³ | 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> | <u>PT Rate</u> | <u>PT Gas Rate</u> |
| | 9009-01001-1 | \$ 660.00/d | 50.0 10 ³ m ³ /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 |
| | | \$ 717,000.00 | 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.

Attachment 2
Table of Rates, Tolls and Charges
Page 1 of 5

| 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 ¹ |
|-------------------------------------|---------------------------------|---|---------------------------------|---|
| 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 ² |
| 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 ² |
| 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



| | | | | |
|-----------|------------------------|---------|-----------|-------------|
| | <u>32nd</u> | Revised | Sheet No. | <u>80.1</u> |
| Canceling | <u>31st</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 | \$ 119.15 | (I) |
| 10,001 to 30,000 | \$ 171.30 | (I) |
| >30,000 | \$ 380.15 | (I) |

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

| | | |
|--|--------------|-----|
| Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ) | \$ 0.9742067 | (I) |
|--|--------------|-----|

Transmission Commodity Rate (Monthly Rate per Therm):

| | | |
|------------------------|---|-----|
| Maximum | \$ 0.0073823 | (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: May 28, 2013
Docket No.: D2012.9.94, Final Order No. 7249e
Tariff Letter No. 227-G

Effective for service rendered on or after
June 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

STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

NG-00-001

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
Sixth Revised Sheet No. 12
Cancels Fifth 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

| Division | Receipt Point | Delivery Point | Monthly Customer Charge | Maximum Demand Charge 6/ | Minimum Demand Charge 6/ | Maximum Transportation Charge 2/ | Minimum Transportation Charge 2/ | Fuel Reimbursement Quantity Percentage 3/ |
|---------------------------------|---------------|----------------|-------------------------|--------------------------|--------------------------|----------------------------------|----------------------------------|---|
| TC (Casper) Firm Transportation | MLI | MLI | \$0.00 | \$9.50 | \$0.00 | \$0.1040 | \$0.0010 | 0.526% |
| | MLI | MLE | \$145.00 | \$0.00 | \$0.00 | \$0.1040 | \$0.0010 | 0.526% |
| | MLI | DSE | \$225.00 | \$0.00 | \$0.00 | \$0.1978 | \$0.0020 | 2.684% |
| Interruptible Transportation 4/ | MLI | MLI | \$0.00 | \$0.00 | \$0.00 | \$0.0844 | \$0.0010 | 0.526% |
| | MLI | MLE | \$145.00 | \$0.00 | \$0.00 | \$0.0844 | \$0.0010 | 0.526% |
| 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.
- 6/ Per Dth of MDTQ per month.

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

- MDTQ Maximum Daily Transportation Quantity

Date Issued: March 1, 2013
By: William N. Cantrell

Date Effective: June 1, 2013
Title: President and CEO

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

| | General Service | | |
|--------------------|-----------------------|------------------------------------|-------------------|
| | Storage Balance 1/ | Prepaid 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 | (1,423,715) | 78,946 | (2,036,918) |
| April | (3,157,116) | 17,880 | (1,870,955) |
| May | (1,416,806) | 89,179 | (1,094,135) |
| June | 1,747,190 | 212,883 | (12,089) |
| July | 5,262,275 | 342,791 | 1,120,782 |
| August | 7,872,053 | 442,601 | 2,236,643 |
| September | 10,532,847 | 539,667 | 3,110,723 |
| October | 12,154,316 | 597,867 | 3,361,520 |
| 13 month average | <u>\$5,319,313</u> | <u>\$336,463</u> | <u>\$764,395</u> |
| Rate of Return | 8.791% | 8.791% | 8.791% |
| Return | \$467,621 | \$29,578 | \$67,198 |
| Return Requirement | <u>\$637,680</u> | <u>\$40,335</u> | <u>\$91,636</u> |

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

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

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

| | (Over) Under Recovery | Refunds & Other | Interest 1/ | Total Net Additions | Actual Dk Sales | Adjustment Per Dk | Total Adjustment Amount | Net Change- Additions less Adjustment | Cumulative Balance |
|--------------------------------|--------------------------|--------------------|-------------|------------------------|--------------------|----------------------|-------------------------------|---|-----------------------------|
| Balance @ July 31, 2012 | | | | | | | | | <u>(\$1,670,167)</u> |
| 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 |
| March | (455,645) | 0 | 11 | (455,634) | 2,116,255 | (0.113) | (239,137) | (216,497) | 3,354 |
| April | (569,359) | 0 | 0 | (569,359) | 2,017,766 | (0.113) | (228,008) | (341,351) | (337,997) |
| May | (82,661) | 0 | (11) | (82,672) | 1,254,451 | (0.113) | (141,753) | 59,081 | (278,916) |
| Balance @ May 31, 2013 | | | | | | | | | <u>(\$278,916)</u> |

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 |
|--------------------------------|--------------------------|--------------------|-------------|------------------------|--------------------|----------------------|-------------------------------|---|---------------------------|
| Balance @ July 31, 2012 | | | | | | | | | <u>(\$144,649)</u> |
| 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 |
| March | 1,156 | 0 | 2 | 1,158 | 93,198 | (0.115) | (10,718) | 11,876 | 60,430 |
| April | 7,751 | 0 | 2 | 7,753 | 84,523 | (0.115) | (9,721) | 17,474 | 77,904 |
| May | 25,382 | 0 | 3 | 25,385 | 68,968 | (0.115) | (7,931) | 33,316 | 111,220 |
| Balance @ May 31, 2013 | | | | | | | | | <u>\$111,220</u> |

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**

| | (Over) Under Recovery | Refunds & Other | Interest 1/ | Total Net Additions | Actual Dk Sales | Adjustment Per Dk | Total Adjustment Amount | Net Change- Additions less Adjustment | Cumulative Balance |
|--------------------------------|--------------------------|--------------------|-------------|------------------------|--------------------|----------------------|-------------------------------|---|---------------------------|
| Balance @ July 31, 2012 | | | | | | | | | <u>(\$189,388)</u> |
| 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) |
| March | 625 | 0 | (2) | 623 | 65,562 | (0.377) | (24,717) | 25,340 | (10,450) |
| April | 2,674 | 0 | 0 | 2,674 | 71,332 | (0.377) | (26,892) | 29,566 | 19,116 |
| May | 14,648 | 0 | 1 | 14,649 | 49,614 | (0.377) | (18,705) | 33,354 | 52,470 |
| Balance @ May 31, 2013 | | | | | | | | | <u>\$52,470</u> |

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

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