

April 9, 2014

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

Re: Cost of Gas Adjustment
(COG) Rate 88 and Rate 99
Case No. PU-14-008

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 and 99.

Attachment A is the Rate Summary Sheet (124th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered May 1, 2014.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.924 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. In addition, Montana-Dakota has also seen a change in the pipeline rates, as shown on Attachment C, increasing the cost of gas \$0.589 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 the market based pricing differential provision that will apply during the month of May 2014.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.335 per dk for residential and firm general customers, a decrease of \$0.750 per dk for small and large interruptible customers and a decrease of \$0.747 per dk for Air Force 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 2014. The average cost of gas for firm customers, adjusted for losses, is \$6.414.

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

Montana-Dakota purchases propane supplies from various wholesale suppliers. The cost of propane has decreased since the last COG filing due to a decrease in the market price of propane. Attachment B page 2 explains the reasons for the decrease in the market price of propane.

Exhibit A, page 2 summarizes the cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of May 2014. The net effect of this filing is a decrease of \$3.519 per dk for all customers from the currently effective rates.

Exhibit D shows the calculation of the current cost of gas – propane that will be applicable to Montana-Dakota's customers for the month of May 2014. The average cost of propane for all customers, adjusted for losses, is \$11.527 per dk.

Montana-Dakota requests a deviation from Section 4 of the Cost of Gas - Propane tariff, which specifies that the unrecovered purchased cost of gas account will be calculated by dividing the applicable balance by the estimated dk sales for the twelve months following the effective date of the adjustment. Montana-Dakota is proposing to amortize the unrecovered cost balance over a 36 month time period. Given the volatility of propane pricing and resulting effect on the purchased cost of gas account, Montana-Dakota is proposing to amortize the balance over three years to mitigate the increase to customers.

Exhibit E shows the computation of the (over)/under recovered gas cost account balances.

Exhibit F shows the calculation of the surcharge adjustment which will apply during the period May 1, 2014 through April 30, 2015. The surcharge is \$1.193 per dk, an increase of \$1.970 per dk for all customers.

These proposed adjustments, calculated in accordance with Rate 88 and Rate 99, will amount to a decrease of approximately \$452,200 for natural gas customers and a decrease of approximately \$10,600 for propane customers during the month of May 2014. All of Montana-Dakota's retail natural gas and propane customers in North Dakota may be affected by this proposal. There were 102,031 natural gas and 343 propane customers in North Dakota as of March 31, 2014.

Please refer all inquiries regarding this filing to:

Ms. Tamie A. Aberle
Director - 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 mailed a check on February 5, 2014 to the North Dakota Public Service Commission for \$500 pursuant to the requirements of North Dakota Century Code Section 49-05-05. This payment will cover the filing fee associated with the monthly COG filings for March 2014 through January 2015.

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,



Tamie A. Aberle
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
 124th Revised Sheet No. 3
 Canceling 123rd 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 ¹ | 4 | \$0.30 per day | \$0.812 | \$6.426 | \$7.238 |
| Air Force Rate 64 ¹ | 7 | | | | |
| Minot Air Force Base | | \$1,000.00 per month | | | |
| PAR Site | | \$135.00 per month | | | |
| Firm Service | | | \$0.138 | \$6.426 | \$6.564 |
| Interruptible Service - PAR | | | \$0.120 | \$5.140 | \$5.260 |
| Interruptible Service - MAFB | | | \$0.120 | \$5.182 | \$5.302 |
| Firm General Service Rate 70 ¹ | 13 | | | | |
| Meters rated < 500 cubic feet | | \$0.52 per day | | | |
| Meters rated > 500 cubic feet | | \$1.75 per day | \$0.597 | \$6.426 | \$7.023 |
| Small Interruptible Gas Rate 71 ² | 14 | \$100.00 per month | (Maximum) \$0.871 | \$5.140 | (Maximum) \$6.011 |
| Optional Seasonal Gas ¹ Service Rate 72 | 15 | | | | |
| Meters rated < 500 cubic feet | | \$0.52 per day | | | |
| Meters rated > 500 cubic feet | | \$1.75 per day | \$0.597 | \$6.566 | \$7.163 |
| Transportation Service ¹ | 24 | | | | |
| Small Interruptible Rate 81 | | \$150.00 per month | | | |
| Maximum | | | \$0.427 | | |
| Minimum | | | \$0.102 | | |
| Fuel Charge | | | | \$0.023 | |
| Large Interruptible Rate 82 | | \$725.00 per month | | | |
| Maximum | | | \$0.298 | | |
| Minimum | | | \$0.061 | | |
| Fuel Charge | | | | \$0.023 | |
| Large Interruptible Gas Rate 85 ³ | 27 | \$675.00 per month | (Maximum) \$0.719 | \$5.140 | (Maximum) \$5.859 |
| Residential Propane Rate 90 ¹ | 32 | \$0.30 per day | \$0.812 | \$12.708 | \$13.520 |
| Firm General Propane Rate 92 ¹ | 34 | | | | |
| Meters rated < 500 cubic feet | | \$0.52 per day | | | |
| Meters rated > 500 cubic feet | | \$1.75 per day | \$0.597 | \$12.708 | \$13.305 |

1/ Interim increase of 15.678% applicable to amounts billed under Basic Service Charge and Distribution Delivery Charge.

2/ Interim increase of 8.671% applicable to amounts billed under Basic Service Charge and Distribution Delivery Charge.

3/ Interim increase of 9.382% applicable to amounts billed under Basic Service Charge and Distribution Delivery Charge.

Date Filed: April 9, 2014

Effective Date:

Issued By: Tamie A. Aberle
 Director - Regulatory Affairs

Case No.:

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

May 2014

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 cold weather across much of the U.S. continued during most of the month of March. April prices are lower as warmer weather is being forecasted and the market is in the midst of changing from the withdrawal season to the injection season for storage. The EIA reported storage levels nationwide indicate the five year average as of March 28, 2014, was 50.8 percent below the five-year average and 50.1 percent below last year's storage balance. Storage inventories are now lower than they have been in 14 years.

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

The February Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 19. The May Outlook will be published May 6, 2014.

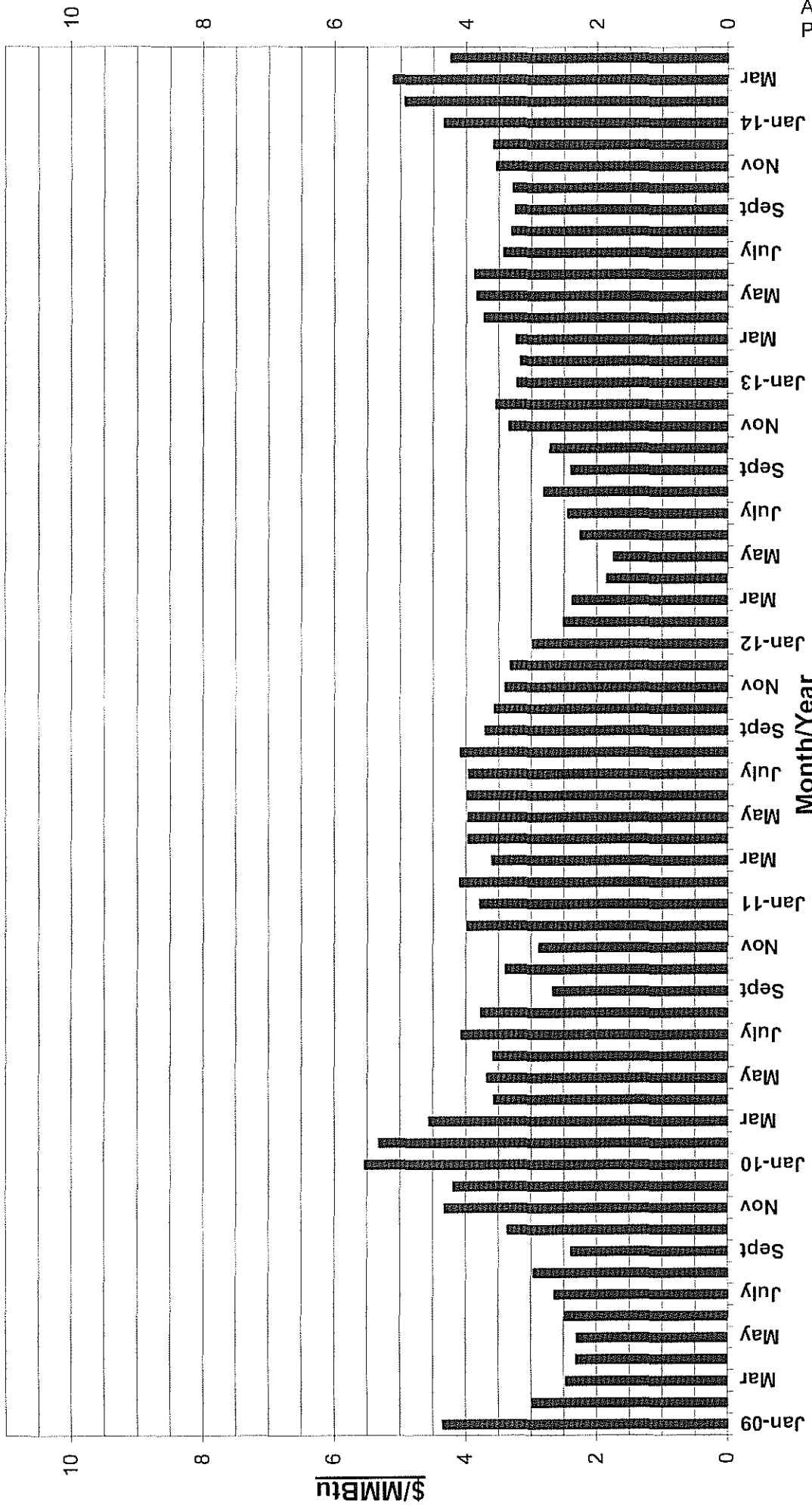
**Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
May 2014**

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

The May prices for propane have decreased from the previous level. A change in the price of propane is generally driven by a combination of crude oil prices, weather, and demand and inventory levels. As seasonal usage decreases have resulted in a decrease in the price of propane.

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

CIG Rocky Mountains Index Monthly Gas Prices 2009-2014YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2012-\$2.58; 2013-\$3.45; 2014YTD-\$4.66



Independent Statistics & Analysis

U.S. Energy Information
Administration

April 2014

Short-Term Energy and Summer Fuels Outlook (STEO)

Highlights

- During the April-through-September summer driving season this year, regular gasoline retail prices are forecast to average \$3.57/gallon (gal). The projected monthly national average regular retail gasoline price falls from \$3.66/gal in May to \$3.46/gal in September. EIA expects regular gasoline retail prices to average \$3.45/gal in 2014 and \$3.37/gal in 2015, compared with \$3.51/gal in 2013. The July 2014 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged \$2.85/gal for the five trading days ending April 3, 2014. Based on the market value of futures and options contracts for this key petroleum component of gasoline, there is a 3% probability that its price at expiration will exceed \$3.35/gal, consistent with a monthly average regular-grade gasoline retail price exceeding \$4.00/gal in July 2014 (see [EIA Summer Fuels Outlook slideshow](#)).
- The North Sea Brent crude oil spot price in March averaged near \$110 per barrel (bbl) for the ninth consecutive month, while West Texas Intermediate (WTI) crude oil prices remained flat near \$101/bbl. New pipeline capacity from the Midwest into the Gulf Coast helped reduce inventories at the Cushing, Oklahoma, storage hub to 27 million barrels by the end of March 2014, the lowest level since November 2009. The discount of WTI crude oil to Brent crude oil, which averaged more than \$13/bbl from November through January, fell to \$7/bbl in March. EIA expects the WTI discount to average \$9/bbl in 2014 and \$11/bbl in 2015.
- Natural gas working inventories on March 28, 2014, were 0.82 trillion cubic feet (Tcf), 0.88 Tcf (52%) below the level at the same time a year ago and 0.99 Tcf (55%) below the five-year average (2009-13). Henry Hub natural gas spot prices were volatile over the past few months, increasing from \$3.95 per million British thermal units (MMBtu) on January 10 to a high of \$8.15/MMBtu on February 10, before falling back to \$4.61/MMBtu on February 27, and then bouncing back up to \$7.98/MMBtu on March 4. EIA expects that the Henry Hub natural gas spot price, which averaged \$3.73/MMBtu in 2013, will average \$4.44/MMBtu in 2014 and \$4.11/MMBtu in 2015.

Global Petroleum and Other Liquids

EIA projects world petroleum and other liquids supply to increase by 1.4 million barrels per day (bbl/d) in 2014 and 1.3 million bbl/d in 2015, with most of the growth coming from countries outside of the Organization of the Petroleum Exporting Countries (OPEC). The United States and Canada will account for much of this growth. Projected world liquid fuels consumption grows by an annual average of 1.2 million bbl/d in 2014 and 1.4 million bbl/d in 2015. Countries outside the Organization for Economic Cooperation and Development (OECD), notably China, drive expected consumption growth.

EIA expects the combination of increased non-OPEC total liquids supply and OPEC noncrude supply to exceed world liquids demand growth over the next two years. The call on OPEC crude oil and global stocks falls from an average of 30.0 million bbl/d in 2013 to 29.5 million bbl/d in 2015 (Call on OPEC is world consumption less non-OPEC production and OPEC noncrude oil production). Forecast non-OPEC supply growth also contributes to an increase in global surplus crude oil production capacity from an average of 2.1 million bbl/d in 2013 to 3.6 million bbl/d in 2015.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 1.2 million bbl/d in 2013, averaging 90.4 million bbl/d for the year. EIA expects global consumption to grow 1.2 million bbl/d in 2014 and 1.4 million bbl/d in 2015. Projected global oil-consumption-weighted real GDP, which increased by an estimated 2.3% in 2013, grows by 2.9% and 3.4% in 2014 and 2015, respectively.

Non-OECD countries account for all of the expected consumption growth in 2014 and nearly all of the growth in 2015. China is the leading contributor to projected global consumption growth, with consumption increasing by 400,000 bbl/d in 2014 and 430,000 bbl/d in 2015. However, China's economic and oil consumption growth rates have moderated compared with rates before 2012, when annual GDP growth exceeded 9% and oil consumption growth averaged almost 800,000 bbl/d from 2009 through 2011.

EIA expects lower OECD consumption in 2014, led by projected consumption declines in both Japan and Europe. EIA expects Japan's oil consumption to fall by an annual average of 150,000 bbl/d in 2014 and 2015, as the country continues to increase natural gas and coal consumption in the electricity sector and returns some nuclear power plants to service in the second half of 2014 and in 2015. EIA projects that OECD Europe's consumption, which fell by 100,000 bbl/d in 2013, will decline by 60,000 bbl/d in 2014 and then remain relatively flat in 2015. U.S. liquids consumption, which increased by 400,000 bbl/d in 2013, is expected to remain relatively flat in 2014 and then increase by 90,000 bbl/d in 2015.

Non-OPEC Supply. EIA estimates that non-OPEC liquids production grew by 1.3 million bbl/d in 2013, averaging 54.0 million bbl/d for the year. EIA expects non-OPEC liquids production to grow by 1.6 million bbl/d in 2014 and 1.3 million bbl/d in 2015. EIA forecasts production from

the United States and Canada to grow by a combined annual average of 1.4 million bbl/d in 2014 and 1.2 million bbl/d in 2015. EIA estimates that the Former Soviet Union's production will rise by an annual average of 0.16 million bbl/d over the forecast period, led by Russia in 2014 and Kazakhstan in 2015.

Unplanned supply disruptions among non-OPEC producers averaged 0.6 million bbl/d in March 2014, about 40,000 bbl/d lower than in February as a result of fewer outages in the North Sea and Indonesia. South Sudan, Syria, and Yemen accounted for almost 90% of total non-OPEC supply disruptions. EIA does not assume a disruption to oil supply or demand as a result of ongoing events in Ukraine.

OPEC Supply. EIA estimates that OPEC crude oil production averaged 30.0 million bbl/d in 2013, a decline of 0.9 million bbl/d from the previous year, primarily reflecting increased outages in Libya, Nigeria, and Iraq, along with strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.2 million bbl/d in both 2014 and 2015, as a result of supply disruptions in OPEC and cutbacks in crude oil production to accommodate increased supplies in non-OPEC countries.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.6 million bbl/d in March 2014, 0.3 million bbl/d higher than the previous month. Libya continues to experience swings in its production, contributing to changes in the OPEC disruption estimate. Unplanned disruptions in Iraq escalated in March, averaging nearly 0.4 million bbl/d, as a result of attacks on the Kirkuk-Ceyhan pipeline.

EIA expects that OPEC surplus capacity, which is concentrated in Saudi Arabia, will average 2.3 million bbl/d in 2014 and 3.6 million bbl/d in 2015. This build in surplus capacity reflects production cutbacks by some OPEC members adjusting for the higher supply from non-OPEC producers. 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 European Union sanctions on Iran's oil sector.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.58 billion barrels by the end of 2013, equivalent to roughly 55 days of consumption. Projected OECD oil inventories rise to 2.61 billion barrels at the end of 2014 and 2.64 billion barrels at the end of 2015.

Crude Oil Prices. Brent crude oil spot prices in March averaged \$107/bbl. This was the ninth consecutive month Brent crude oil spot prices averaged between \$107/bbl and \$112/bbl. The Brent crude oil price is projected to average \$105/bbl and \$101/bbl in 2014 and 2015, respectively.

The WTI crude oil spot price, which fell to an average of \$95/bbl in January 2014, increased to an average of \$101/bbl in February and March as a result of strong Midwestern refinery runs

and the startup of the Marketlink pipeline moving crude from Cushing to the Gulf Coast. EIA expects that WTI crude oil prices will average \$96/bbl in 2014, \$1/bbl higher than in last month's STEO, and \$90/bbl during 2015. The discount of WTI crude oil to Brent crude oil, which averaged more than \$13/bbl from November 2013 through January 2014, fell to an average of nearly \$7/bbl in March 2014. EIA expects the discount of WTI crude oil to Brent crude oil to grow in the coming months to an average \$9/bbl in 2014 and \$11/bbl in 2015, reflecting the economics of transporting and processing the growing production of light sweet crude oil in U.S. and Canadian refineries.

Energy price forecasts are highly uncertain, and the current values of futures and options contracts suggest that prices could differ significantly from the forecast levels (*Market Prices and Uncertainty Report*). WTI futures contracts for July 2014 delivery, traded during the five-day period ending April 3, 2014, averaged \$99/bbl. Implied volatility averaged 17%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in June 2014 at \$85/bbl and \$115/bbl, respectively. Last year at this time, WTI for July 2013 delivery averaged \$96/bbl and implied volatility averaged 18%. The corresponding lower and upper limits of the 95% confidence interval were \$82/bbl and \$113/bbl.

U.S. Petroleum and Other Liquids

U.S. Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 400,000 bbl/d (2.1%) in 2013. Consumption of hydrocarbon gas liquids (HGL) registered the largest gain, increasing by 150,000 bbl/d (6.4%). Motor gasoline consumption grew by 90,000 bbl/d (1.1%), the largest increase since 2006. Stronger-than-expected growth in highway travel during the second half of 2013 contributed to that increase. Distillate fuel consumption increased by 90,000 bbl/d (2.5%), reflecting colder weather and domestic economic growth.

Projected total liquid fuels consumption remains flat in 2014. Motor gasoline consumption remains largely unchanged as the recent strong growth in highway travel slows and continued improvements in new-vehicle fuel economy boost overall fuel efficiency growth. Distillate fuel oil consumption rises 20,000 bbl/d (0.4%). In 2015, total liquid fuels consumption increases by 90,000 bbl/d (0.5%), driven primarily by increasing transportation demand for distillate fuel oil and industrial demand for HGL.

U.S. Liquid Fuels Supply. Weather conditions in the Lower 48 states during December 2013 and January 2014 caused operational issues in key producing regions. While a temporary slowdown in well completion activity resulted in flat crude oil production during those months, much of the production slowdown is expected to be made up by accelerated completion activity over the next few months.

Aside from seasonal issues, EIA expects strong crude oil production growth, primarily concentrated in the Bakken, Eagle Ford, and Permian regions, continuing through 2015.

Forecast production increases from an estimated 7.4 million bbl/d in 2013 to 8.4 million bbl/d in 2014 and 9.1 million bbl/d in 2015. The highest historical annual average U.S. production level was 9.6 million bbl/d in 1970.

Crude oil production from the Bakken formation in North Dakota and Montana averaged 0.9 million bbl/d in 2013. Production in the Eagle Ford formation in South Texas averaged 1.1 million bbl/d in 2013, reaching an estimated 1.2 million bbl/d in December 2013.

Summer Transportation Fuels Outlook

U.S. Gasoline and Diesel Fuel Prices. EIA expects that regular-grade gasoline retail prices, which averaged \$3.58/gal last summer, will average \$3.57/gal during the current summer (April through September) driving season. The projected monthly average regular retail gasoline price falls from \$3.66/gal in May to \$3.46/gal in September. Diesel fuel prices, which averaged \$3.89/gal last summer, are projected to average \$3.87/gal 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/gal or more. Any unforeseen refinery outages or other disruptions to supply also have the potential to increase regional product prices beyond forecast levels in the short term.

Because taxes and retail distribution costs are generally stable, movements in gasoline and diesel prices are driven primarily by changes in both crude oil prices and wholesale margins. The retail price projections reflect falling prices for crude oil, best represented by the Brent crude oil price, which averages about \$105/bbl (\$2.49/gal) this summer compared with the \$107/bbl (\$2.54/gal) average of last summer. Any difference between actual crude oil prices and EIA's forecast would be reflected in the price of motor fuels. Absent other factors specific to the gasoline and diesel fuel markets, each dollar per barrel of sustained change in crude oil prices compared with the forecast translates into approximately a 2.4-cent-per-gallon change in product prices.

EIA expects wholesale gasoline margins (the difference between the wholesale price of gasoline and the Brent crude oil price) will average 38 cents/gal this summer, about 3 cents higher than last summer and 4 cents higher than the previous five-summer average. Forecast wholesale diesel fuel margins are 46 cents/gal, 1 cent below last summer's level and 9 cents higher than the previous five-summer average.

As in the case of 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 July 2014 delivery traded over the five-day period ending April 3 averaged \$2.85/gal. The probability that the RBOB futures price will exceed \$3.35/gal (consistent with a U.S. average regular gasoline retail price above \$4.00/gal) in July 2014 is about 3%.

Motor Gasoline. During this summer driving season (April through September), projected motor gasoline consumption remains unchanged from last summer's average of 9.0 million bbl/d. Year-over-year increases in highway travel, projected to be 0.7%, are offset by an increase in fleet-wide fuel efficiency. Finished motor gasoline is supplied by four sources: domestic refinery output, fuel ethanol blending, net imports of gasoline and gasoline blending components, and primary inventories. EIA expects that domestic refinery production, including gasoline blendstock output, will increase by 60,000 bbl/d from last summer. Fuel ethanol blending into gasoline is projected to decrease by 3,000 bbl/d from last summer's level to 870,000 bbl/d, which is 9.7% of total gasoline consumption. Projected total gasoline net imports (including blending components) average 240,000 bbl/d, down 7% from last summer.

At the onset of the summer driving season (April 1), total gasoline stocks were down 10 million barrels from a year ago and down 5 million barrels from the five-year average for beginning-of-season stocks. Stock withdrawals have not been a significant motor gasoline supply source for the summer season in recent years, having averaged only 35,000 bbl/d during the previous five summer seasons. This summer, total gasoline stocks are projected to remain almost unchanged, compared with a 31,000-bbl/d draw last summer. Moreover, the absence of a seasonal pattern differs from that of last summer, which saw a sizable draw on inventories during the third quarter. As a result, total gasoline inventories this summer are projected to end the season at 215 million barrels, 4 million barrels below last year's level but 1 million barrels above the five-year average.

Diesel Fuel. Projected consumption of distillate fuel, which includes diesel fuel and heating oil, averages 3.8 million bbl/d this summer, up 37,000 bbl/d (1.0%) from last summer. That growth is driven by increasing manufacturing output and foreign trade.

Distillate fuel is supplied by four sources: domestic refinery output, biodiesel blending, primary inventories, and net imports. EIA expects refinery output of distillate fuel will average 4.9 million bbl/d this summer, up 150,000 bbl/d from last summer. Biodiesel has been a small part of the distillate pool, averaging 93,000 bbl/d last summer and forecast to average about 78,000 bbl/d this summer. Projected distillate fuel net exports average 1.15 million bbl/d this summer, up from 1.06 million bbl/d last summer.

Distillate inventories are projected to start the summer at 112.6 million barrels, down from the 118.6 million barrels recorded at the start of last summer and the five-year average of 138.7 million barrels. Distillate inventories typically build during the summer season in preparation for the heating season. This summer, the build is forecast to average 89,000 bbl/d, up substantially from the 54,000 bbl/d build recorded last summer, but similar to the five-year average summer build of 60,000 bbl/d. End-of-summer stocks are 128.9 million barrels, up slightly from the 128.6 million barrels recorded at the end of last summer, but well below the five-year end-of-summer average of 149.8 million barrels.

Natural Gas

Following late-winter cold weather, working natural gas in storage ended March at an estimated 826 Bcf, the lowest level in 11 years. EIA now expects a large rebuild over the injection season, with inventories ending October at 3,422 Bcf. This represents a record stock build of nearly 2,600 Bcf. Expectations for lower demand from the electric power sector compared with the past several years, as well as increasing production, should help enable a record-high stock build. This month's STEO revises upward the outlook for natural gas marketed production in both 2014 and 2015. While production dipped in the winter months due to freeze-offs in various locations, recent outside data sources indicate production has bounced back and is exceeding record highs set in November.

U.S. Natural Gas Consumption. EIA expects total natural gas consumption will average 72.1 Bcf per day (Bcf/d) in 2014, an increase of 0.7 Bcf/d from 2013. Increased residential, commercial, and industrial use offsets declines from the electric power sector, which are related to higher natural gas prices. In 2015, total natural gas consumption falls by 0.4 Bcf/d as a decline in residential and commercial consumption more than offsets consumption growth in the industrial and electric power sectors. EIA expects natural gas consumption in the power sector to increase to 22.8 Bcf/d in 2015 with the retirement of some coal plants.

U.S. Natural Gas Production and Trade. EIA expects natural gas marketed production will grow by an average rate of 3.0% in 2014 and 1.5% in 2015. Rapid natural gas production growth in the Marcellus formation is contributing to falling natural gas forward prices in the Northeast, which often fall even with or below Henry Hub prices outside of peak winter demand months. Consequently, some drilling activity may move away from the Marcellus back to Gulf Coast plays such as the Haynesville and Barnett, where prices are closer to the Henry Hub spot price.

Liquefied natural gas (LNG) imports have declined over the past several years because higher prices in Europe and Asia are more attractive to sellers than the relatively low prices in the United States. Several companies are planning to build liquefaction capacity to export LNG from the United States. Cheniere Energy's Sabine Pass facility is planned to be the first to liquefy natural gas produced in the Lower 48 states for export. The facility has a total liquefaction capacity of 3 Bcf/d and is scheduled to come online in stages beginning in late 2015.

Growing domestic production over the past several years has displaced some pipeline imports from Canada, while exports to Mexico have increased. EIA projects net imports of 3.7 Bcf/d in 2014 and 3.0 Bcf/d in 2015, which would be the lowest level since 1987. Over the longer term, the EIA Annual Energy Outlook 2014 projects the United States will be a net exporter of natural gas beginning in 2018.

U.S. Natural Gas Inventories. Natural gas working inventories fell by 74 Bcf to 822 Bcf during the week ending March 28, 2014. Colder-than-normal temperatures and a few late-season

winter storms during the month resulted in increased heating demand, prompting larger-than-normal withdrawals. Stocks are now 878 Bcf less than last year at this time and 992 Bcf less than the five-year (2009-13) average for this time of year. Total stocks, as well as stocks in all three regions, are currently less than their five-year (2009-13) minimums.

U.S. Natural Gas Prices. Natural gas spot prices averaged \$4.90/MMBtu at the Henry Hub in March, down \$1.10/MMBtu from February, as weather in March was less extreme than the previous month, but still colder than normal. EIA projects that spot prices will continue to decline in the spring. Projected Henry Hub natural gas prices average \$4.44/MMBtu in 2014 and \$4.11/MMBtu in 2015.

Natural gas futures prices for July 2014 delivery (for the five-day period ending April 3, 2014) averaged \$4.46/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for July 2014 contracts at \$3.40/MMBtu and \$5.87/MMBtu, respectively. At this time last year, the natural gas futures contract for July 2013 averaged \$4.07/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$3.16/MMBtu and \$5.23/MMBtu.

Coal

Severe winter weather, increases in oil and grain rail traffic, and track work have combined to constrain coal shipments via rail from Powder River Basin (PRB) coal producers to power generators. Weather disruptions began early in the winter season, with October snowfall disrupting shipments from the PRB. Severe weather continued through the quarter and shipments from the Southern PRB and Colorado/Utah significantly declined.

Increases in other rail traffic have helped to create bottlenecks on western rail systems. According to data from the [Association of American Railroads](#), increased crude oil shipments, primarily from the Bakken shale play, and increased grain shipments have taxed rail infrastructure in the region. [Soaring volume](#) on Burlington Northern Santa Fe (BNSF) Corporation's main line in North Dakota, coupled with weather issues, prompted [Basin Electric Power Cooperative](#) to move coal in North Dakota by truck for 30 days.

The severe winter weather exacerbated the situation by increasing power demand and depleting coal inventories. Spot purchases of coal, which could aid in replenishing stockpiles, are competing for rail service, as the railroads are struggling to catch up with contracted shipments that have been delayed. Some utilities have reportedly taken coal units offline in order to conserve stockpiles. Coal sourced from other basins, primarily the Illinois and Central Appalachian, may be called upon to help replenish stockpiles.

U.S. Coal Supply. EIA projects coal production will grow 4.1% to 1,024 million short tons (MMst) in 2014. The increase this year is primarily a result of higher consumption. Coal production is projected to fall by less than 1% in 2015 to 1,022 MMst, but Appalachian coal production is

projected to decline by 2.7%. Interior production is expected to remain steady, while Western production grows by 0.9%.

U.S. Coal Consumption. EIA estimates total coal consumption for 2013 totaled 925 MMst, a 4.0% increase over 2012. The increase was primarily a result of increased consumption in the electric power sector due to higher natural gas prices. Consumption continues to grow at a rate of 4.2% to 964 MMst in 2014 as electricity demand grows and natural gas prices remain well above their 2012 level. Total coal consumption is projected to decline by 2.4% in 2015, as retirements of coal power plants rise in response to the implementation of the Mercury and Air Toxics Standards, and generation from renewable resources (wind, hydro, biomass, geothermal, and solar) grows by more than 3%.

U.S. Coal Exports. Exports are projected to total 101 MMst in 2014, making it the fourth consecutive year with more than 100 MMst of coal exports. This would be the second time that exports have exceeded 100 MMst for four consecutive years, with the first being from 1989 through 1992. Projected exports fall back to 96 MMst in 2015. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, increasing coal output 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. Annual average coal prices to the electric power industry fell for the second consecutive year, from \$2.38/MMBtu in 2012 to \$2.35/MMBtu in 2013. EIA forecasts average delivered coal prices of \$2.35/MMBtu in 2014 and \$2.36/MMBtu in 2015.

Electricity

Periods of extreme cold in the Midwest and Northeast this past winter caused spikes in wholesale electricity prices at certain times of peak demand. In early January, the low temperatures and constraints on natural gas delivery led to average day-ahead prices close to \$250/megawatthour in the New England and New York wholesale power markets. These high prices encouraged generation from power plants that have the capability to burn petroleum, leading to the highest level of generation from petroleum liquids in the Northeast since January 2006. However, these spikes in petroleum-fired generation were only temporary, and the fuel accounts for a very small share of total generation.

U.S. Electricity Consumption. The cold winter weather was a primary driver of the estimated 4.3% year-over-year increase in total U.S. retail sales of electricity during the first quarter of 2014. Year-over-year growth was especially strong in the residential sector, which grew by an estimated 7.3%. For the upcoming summer months, EIA projects residential sales during the second and third quarters will average 0.6% more than last summer. This growth is driven by a 5.8% increase in summer cooling degree days, offset slightly by efficiency improvements in air conditioning, lighting, and other electricity uses.

U.S. Electricity Generation. Preliminary EIA data indicate that 4.7 gigawatts (GW) of coal capacity was retired during 2013 (following 10.3 GW of coal capacity retirements during 2012). Despite these retirements, coal generators have increased their utilization of existing capacity in recent months so that the share of total generation fueled by coal during the first quarter of 2014 rose to 41.4% from 40.0% during the first quarter of 2013. This increase in utilization of coal-fired capacity was driven primarily by rising natural gas fuel costs, which in turn drove down the share of generation fueled by natural gas to 23.8% during the first quarter of 2014 from 25.6% during the same period last year. EIA projects total U.S. electricity generation will average 11.3 terawatt-hours per day in 2014, an increase of 1.8% from last year. Coal fuels 40.3% of total generation during 2014 while natural gas supplies 26.5%.

U.S. Electricity Retail Prices. EIA expects the U.S. residential price of electricity to average 12.4 cents per kilowatt-hour during 2014, an increase of 2.6% from 2013. Price increases are highest in the New England (7.1%) and Middle Atlantic (4.0%) regions.

Renewables and Carbon Dioxide Emissions

U.S. Electricity and Heat Generation from Renewables. EIA projects renewables used for electricity and heat generation will grow by about 3.7% in 2014. Hydropower is projected to increase by 3.6%, while nonhydropower renewables rise by 3.7%. In 2015, projected renewables consumption for electric power and heat generation increases by 3.0% from 2014, as a 1.0% decrease in hydropower is combined with a 5.2% increase in nonhydropower renewables.

EIA estimates that wind power capacity will increase by 8.9% in 2014 and 15.5% in 2015, reaching about 66 gigawatts (GW) at the end of 2014 and 76 GW at the end of 2015. Electricity generation from wind is projected to contribute 4.5% of total electricity generation in 2015.

EIA expects continued robust growth in solar electricity generation, although the amount of utility-scale generation remains a small share of total U.S. generation at about 0.5% in 2015. While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity doubled in 2013. EIA currently expects that utility-scale solar capacity will increase by approximately 56% between year-end 2013 and year-end 2015. Approximately 70% of this new capacity is being built in California. However, customer-sited photovoltaic capacity growth, which the STEO does not forecast, is expected to exceed utility-scale solar growth between 2013 and 2015, according to [EIA's Annual Energy Outlook 2014](#).

U.S. Liquid Biofuels. Logistical constraints, primarily railroad delays resulting from extreme winter temperatures in the Midwest, led ethanol production to decline from an average of about 900,000 bbl/d in January and February 2014 to 890,000 bbl/d in March 2014. [These logistical problems led to sharp ethanol price increases across the United States](#) in March, but especially in PADD 1 (East Coast). These constraints are expected to be short-lived as warmer

temperatures arrive and ethanol production rebounds to a forecast average of 908,000 bbl/d during 2014.

Biodiesel production, which averaged 64,000 bbl/d (1.0 billion gallons per year) in 2012, rose to 104,000 bbl/d (135 million gallons) in December 2013, 7 million gallons higher than in November. A biodiesel production tax credit expired at the end of 2013. Biodiesel production averaged 87,000 bbl/d in 2013 and is forecast to average 75,000 bbl/d in 2014 and 77,000 bbl/d in 2015.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels increased by 2.1% in 2013 from the previous year. Emissions are forecast to rise 1.9% in 2014, followed by a decline in 2015 of 0.8%. The increase in emissions in 2013 and 2014 reflects growth in coal consumption because of its higher use in electric power generation. Coal emissions are projected to decline by 2.5% in 2015 with increasing coal plant retirements.

U.S. Economic Assumptions

The U.S. Bureau of Economic Analysis (BEA) revised the fourth quarter 2013 gross domestic product estimate upwards, now showing growth at an annual rate of 2.6%, compared to the 2.4% growth of the previous estimate. Consumption expenditures (primarily due to increases in health care spending and utilities) and corporate profits came in higher than the previous fourth quarter 2013 estimate. BEA also reported that real personal consumption expenditures rose 0.2% from January to February, exceeding the 0.1% rise from December to January. Real disposable personal income rose 0.3% from January to February. New orders for durable goods rose 2.2% over the same time period, reversing declines in the two previous months according to the U.S. Census Bureau. The gain was driven primarily by transportation goods, with a more modest a 0.2% monthly gain for other orders. Finally, the U.S. Department of Housing and Urban Development reported that sales of new single-family houses in February were 3.3% below the January level, and 1.1% below the February 2013 estimate.

EIA uses the IHS/Global Insight macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

Production and Income. Forecast real GDP grows by 2.5% in 2014 and 3.2% in 2015. Even though forecast real GDP growth accelerates over the next two years, it is only in 2015 that GDP growth exceeds the economy's average annual growth of 3% from 1990 through 2007. Forecast real disposable income increases 2.2% in 2014 and 3.6% in 2015. Total industrial production grows at 2.7% in 2014 and is projected to grow 4.0% in 2015.

Expenditures. Private real fixed investment growth averages 6.1% and 9.7% over 2014 and 2015, respectively, with equipment spending accounting for most of investment's growth. Real consumption expenditures grow at the same rate as real GDP in 2014, at 2.5%, and are below the rate of real GDP growth in 2015, at 2.9%. Durable goods expenditures drive the

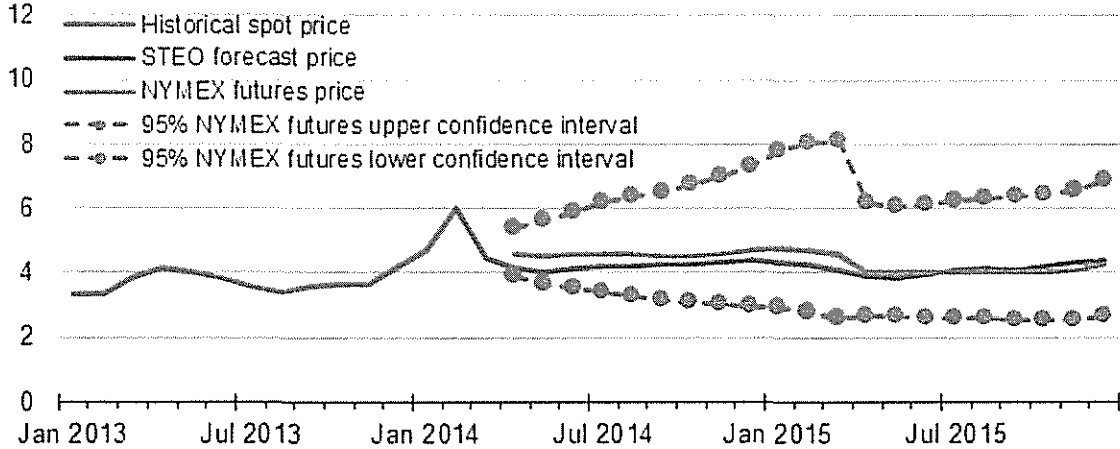
consumption spending. Export growth is 4.2% and 4.1% over the same two years, while import growth is 2.4% in 2014 and 6.5% in 2015. Total government expenditures fall 0.6% in 2014, but increase by 0.4% in 2015.

Employment, Housing, and Prices. Projected growth in nonfarm employment averages 1.6% in 2014 and 2.1% in 2015. This is accompanied by a gradually declining unemployment rate that reaches 6.2% by the end 2014 and 5.7% at the end of 2015, the same as projected last month. Housing starts grow an average of 17.2% and 33.9% in 2014 and 2015, respectively. Both consumer and producer price indexes continue to increase at a moderate pace, as wages continue to show modest gains.

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

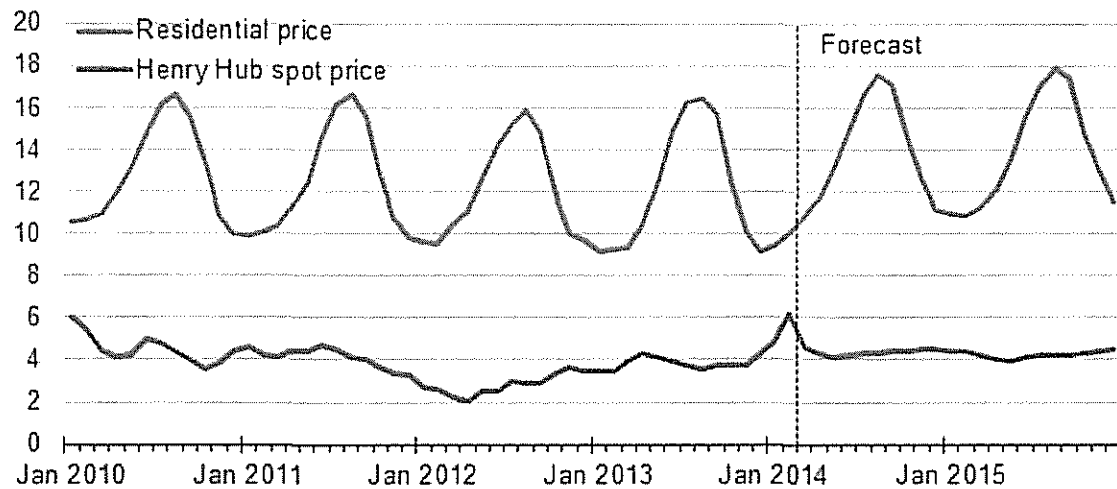


Note: Confidence interval derived from options market information for the 5 trading days ending Mar. 6, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, March 2014.

U.S. Natural Gas Prices

dollars per thousand cubic feet



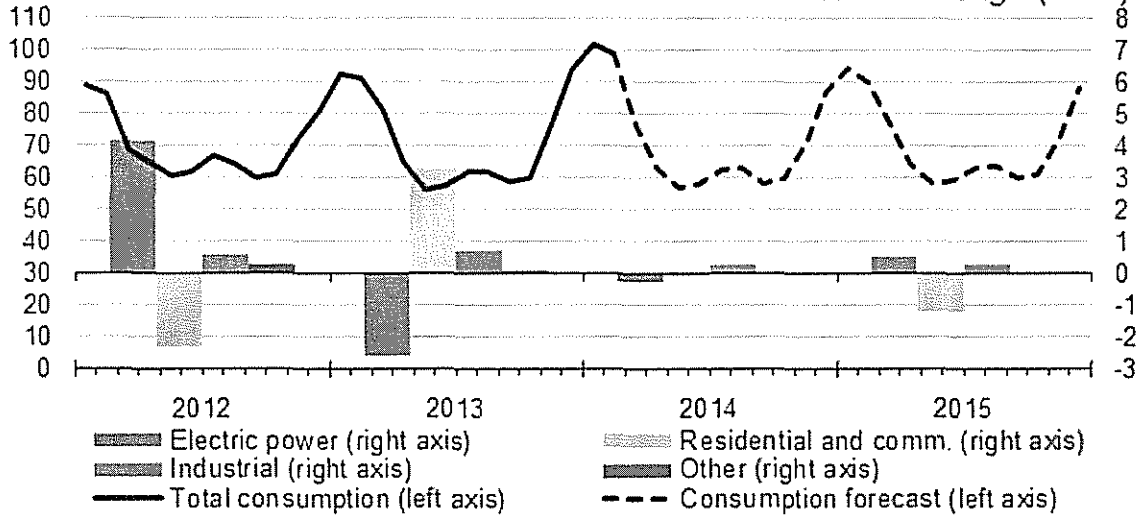
Source: Short-Term Energy Outlook, March 2014.

U.S. Natural Gas Consumption

billion cubic feet per day (Bcf/d)



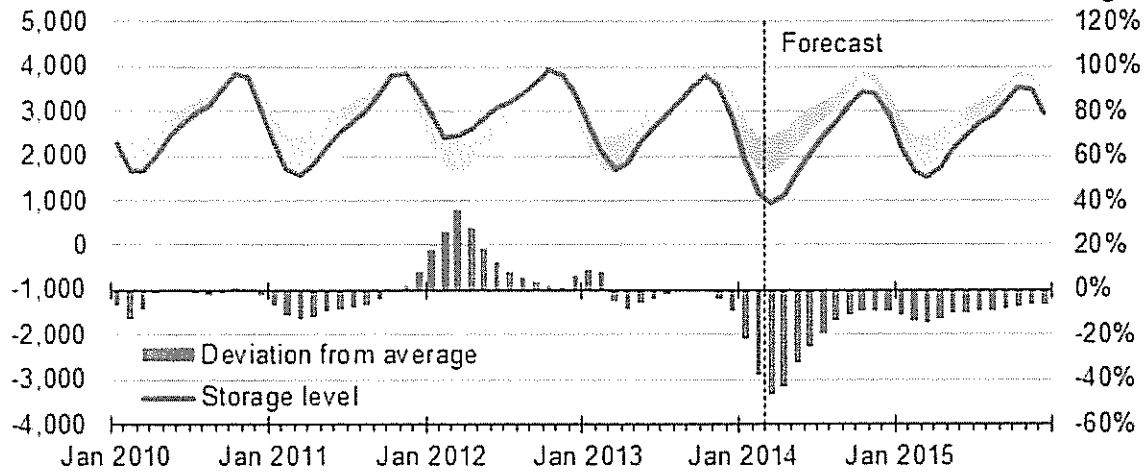
annual change (Bcf/d)



Source: Short-Term Energy Outlook, March 2014.

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. 2009 - Dec. 2013.

Source: Short-Term Energy Outlook, March 2014.

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

WBI Energy Transmission, Inc. Docket No. RP14-118-000

On October 31, 2013, WBI Energy Transmission, Inc. (WBI Energy) filed revised tariff records reflecting a general rate increase with the FERC in Docket No. RP14-118-000, reflecting revisions to its rates in FERC Gas Tariff, Third Revised Volume No. 1. The rates were proposed to be effective on December 1, 2013 on an interim basis or alternatively on May 1, 2014, following the suspension period.

Approximate impact on Montana-Dakota's cost of gas: \$0.59 per dk

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS TARIFF SHEET
NORTH DAKOTA GAS
EFFECTIVE MAY 2014

| | Firm | | | |
|---|-------------------------------------|----------------------|-----------------------------------|----------------------------|
| | Residential & General Service | Optional Seasonal | Small & Large Interruptible | Air Force Interruptible |
| Gas Cost Adjustment: | | | | |
| Gas Cost Level (Exhibit B) | \$6.414 | \$6.554 | \$5.024 | \$5.001 |
| Prior Gas Cost | 6.749 | 6.838 | 5.774 | 5.748 |
| Current Gas Cost Adjustment | (\$0.335) | (\$0.284) | (\$0.750) | (\$0.747) |
| Surcharge Adjustment: | | | | |
| Current Adjustment | \$0.024 | \$0.024 | \$0.116 | \$0.181 |
| Prior Adjustment | 0.024 | 0.024 | 0.116 | 0.181 |
| Change in Surcharge Adjustment | \$0.000 | \$0.000 | \$0.000 | \$0.000 |
| Market Based Pricing Differential | | | | |
| Current Adjustment | (\$0.012) | (\$0.012) | \$0.000 | \$0.000 |
| Prior Adjustment | (0.012) | (0.012) | 0.000 | 0.000 |
| Change in Margin Sharing Provision | \$0.000 | \$0.000 | \$0.000 | \$0.000 |
| Net Increase (Decrease) in Gas Costs | (\$0.335) | (\$0.284) | (\$0.750) | (\$0.747) |
| Gas Cost Level | \$6.414 | \$6.554 | \$5.024 | \$5.001 |
| Plus: Surcharge | 0.024 | 0.024 | 0.116 | 0.181 |
| Total Gas Cost Level in Tariff Rates | \$6.438 | \$6.578 | \$5.140 | \$5.182 |

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE TARIFF SHEET
NORTH DAKOTA PROPANE
EFFECTIVE MAY 2014

| | |
|---|--------------------------------|
| <u>Cost of Gas - Propane</u> | |
| Current Propane Cost (Exhibit A) | \$11.527 |
| Prior Propane Cost | <u>17.016</u> |
| Current Propane Cost Adjustment | <u><u>(\$5.489)</u></u> |
| <u>Surcharge Adjustment</u> | |
| Current Adjustment | \$1.193 |
| Prior Adjustment | <u>(0.777)</u> |
| Change in Surcharge Adjustment | \$1.970 |
| <u>Market Based Pricing Differential</u> | |
| Current Adjustment | (\$0.012) |
| Prior Adjustment | <u>(0.012)</u> |
| Change in Margin Sharing Provision | \$0.000 |
| Net Increase (Decrease) in Gas Costs | <u><u>(\$3.519)</u></u> |
| Propane Cost Level | \$11.527 |
| Plus: Surcharge | <u>1.193</u> |
| Total Propane Cost Level in Rates | <u><u>\$12.720</u></u> |

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
RESIDENTIAL AND GENERAL SERVICE
EFFECTIVE MAY 2014**

| | Amount |
|---|------------------|
| Total Gas Costs 1/ | \$97,885,639 |
| Residential and General Service dk Requirements 2/ | 15,329,905 |
| Average Cost of Gas per dk | \$6.385 |
| Average Cost of Gas as Adjusted for Losses @ 99.55% | 6.414 |
| Less: Gas Cost Level in Rates 3/ | 6.749 |
| Current Gas Cost Adjustment | (\$0.335) |

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, 2014, adjusted for losses at .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-14-008 effective April 1, 2014:

| | |
|-------------------------------------|---------|
| Cost of Purchased Gas | \$6.719 |
| Adjustment for Distribution Losses | 0.9955 |
| Gas Cost Level in Base Tariff Rates | \$6.749 |

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
OPTIONAL SEASONAL - RATE 72
EFFECTIVE MAY 2014**

| | |
|---|--------------------------------|
| Total Gas Costs 1/ | \$97,885,639 |
| Less: Annual MDDQ Costs 1/ | <u>22,552,956</u> |
| Total Gas Costs excluding MDDQ | \$75,332,683 |
| Firm Service Requirements 1/ | 15,329,905 |
| Other Gas Costs per Dk (excluding MDDQ) | \$4.914 |
| <u>Winter - October - May</u> Annual MDDQ Costs 1/ | \$22,552,956 |
| Winter Firm Service Requirements | 13,999,438 |
| MDDQ Costs per Winter Dk | \$1.611 |
| Add: Other Gas Costs per Dk | <u>4.914</u> |
| Winter Seasonal Rate | \$6.525 |
| Winter Seasonal Rate, adjusted for losses 2/ | \$6.554 |
| Less: Gas Cost Level in Rates 3/ | <u>6.838</u> |
| Current Gas Cost Adjustment | <u><u>(\$0.284)</u></u> |

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-14-008 effective April 1, 2014:

| | |
|-------------------------------------|---------------|
| | <u>Winter</u> |
| Cost of Purchased Gas | \$6.807 |
| Adjustment for Distribution Losses | 0.9955 |
| Gas Cost Level in Base Tariff Rates | \$6.838 |

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
INTERRUPTIBLE
EFFECTIVE MAY 2014**

| | Amount |
|---|------------------|
| Total Gas Costs 1/ | \$17,517,707 |
| Interruptible Service dk Requirements | 3,502,739 |
| Average Cost of Gas per dk | \$5.001 |
| Average Cost of Gas as Adjusted for Losses @ 99.55% | 5.024 |
| Less: Gas Cost Level in Rates 2/ | 5.774 |
| Current Gas Cost Adjustment | (\$0.750) |

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-14-008 effective April 1, 2014:

| | |
|-------------------------------------|---------|
| Cost of Purchased Gas | \$5.748 |
| Adjustment for Distribution Losses | 0.9955 |
| Gas Cost Level in Base Tariff Rates | \$5.774 |

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
May 2014 PGA**

WBI Energy Transmission, Inc. - Exhibit B, pages 6 - 10 for Schedules FT-1, FTN-1, and FS-1.

Northern Border Pipeline Company - Exhibit B, page 11 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 12-13 for Schedule FT-D.

NorthWestern Energy - Exhibit B, page 14 for Schedule T-FTG-1.

South Dakota Intrastate Pipeline - Exhibit B, page 15 for Rate 1.

SourceGas Distribution LLC - Exhibit B, Page 16 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 | 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. | 737.928 |
| MINIMUM | RATE PER EQV. DKT PER MO | 0.000 | N.A. | N.A. | 0.000 |
| COMMODITY CHARGE | | | | | |
| MAXIMUM A/B/C/ | RATE PER DKT | 3.120 | N.A. | N.A. | 3.120 |
| MINIMUM A/B/C/ | RATE PER DKT | 3.120 | N.A. | N.A. | 3.120 |
| SCHEDULED OVERRUN CHARGE | | | | | |
| MAXIMUM A/B/C/ | RATE PER DKT | 30.884 | N.A. | N.A. | 30.884 |
| MINIMUM A/B/C/ | RATE PER DKT | 3.120 | N.A. | N.A. | 3.120 |
| VOLUMETRIC CAPACITY RELEASE CHARGE | | | | | |
| MAXIMUM | RATE PER DKT | 24.261 | N.A. | N.A. | 24.261 |
| MINIMUM | RATE PER DKT | 0.000 | N.A. | N.A. | 0.000 |

-
- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 2.560%, CONSISTING OF 2.275% FOR THE CURRENT PERCENTAGE AND 0.285% 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 1.727 CENTS, CONSISTING OF 1.407 CENTS FOR THE CURRENT RATE AND 0.320 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.
 - C/ SHIPPER MUST REIMBURSE TRANSPORTER FOR THE ACA SURCHARGE. SUCH SURCHARGE SHALL BE THE ACA UNIT CHARGE SPECIFIED IN THE ANNUAL NOTICE ISSUED BY THE FERC ENTITLED "FY [YEAR] GAS ANNUAL CHARGES CORRECTION FOR ANNUAL CHARGES UNIT CHARGE."

NOTICE OF CURRENTLY EFFECTIVE RATES

(ALL RATES ARE STATED IN CENTS PER DEKATHERM OR EQUIVALENT DEKATHERM AS INDICATED)

| RATE SCHEDULE | UNIT | BASE TARIFF RATE | 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. | 2.102 |
| MINIMUM | RATE PER EQV. DKT PER MO. | 0.000 | N.A. | N.A. | 0.000 |
| CAPACITY DELIVERABILITY CHARGE | | | | | |
| MAXIMUM | RATE PER EQV. DKT PER MO. | 190.602 | N.A. | N.A. | 190.602 |
| MINIMUM | RATE PER EQV. DKT PER MO. | 0.000 | N.A. | N.A. | 0.000 |
| INJECTION CHARGE | | | | | |
| MAXIMUM A/B/ | RATE PER DKT | 0.888 | N.A. | N.A. | 0.888 |
| MINIMUM A/B/ | RATE PER DKT | 0.888 | N.A. | N.A. | 0.888 |
| WITHDRAWAL CHARGE | | | | | |
| MAXIMUM A/B/ | RATE PER DKT | 0.888 | N.A. | N.A. | 0.888 |
| MINIMUM A/B/ | RATE PER DKT | 0.888 | N.A. | N.A. | 0.888 |
| SCHEDULED OVERRUN CHARGE | | | | | |
| INJECTION | | | | | |
| MAXIMUM A/B/ | RATE PER DKT | 23.920 | N.A. | N.A. | 23.920 |
| MINIMUM A/B/ | RATE PER DKT | 0.888 | N.A. | N.A. | 0.888 |
| WITHDRAWAL | | | | | |
| MAXIMUM A/B/ | RATE PER DKT | 23.920 | N.A. | N.A. | 23.920 |
| MINIMUM A/B/ | RATE PER DKT | 0.888 | 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 0.642%, CONSISTING OF 0.684% FOR THE CURRENT PERCENTAGE AND (0.042%) 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 (0.140) CENTS, CONSISTING OF 0.000 CENTS FOR THE CURRENT RATE AND (0.140) 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.

NOTICE OF CURRENTLY EFFECTIVE RATES

(ALL RATES ARE STATED IN CENTS PER DEKATHERM OR EQUIVALENT DEKATHERM AS INDICATED)

| RATE SCHEDULE | UNIT | BASE TARIFF RATE | 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. | 1195.814 | N.A. | N.A. | 1195.814 |
| MINIMUM | RATE PER EQV. DKT PER MO | 0.000 | N.A. | N.A. | 0.000 |
| COMMODITY CHARGE | | | | | |
| MAXIMUM A/B/C/ | RATE PER DKT | 3.836 | N.A. | N.A. | 3.836 |
| MINIMUM A/B/C/ | RATE PER DKT | 3.836 | N.A. | N.A. | 3.836 |
| SCHEDULED OVERRUN CHARGE | | | | | |
| MAXIMUM A/B/C/ | RATE PER DKT | 41.537 | N.A. | N.A. | 41.537 |
| MINIMUM A/B/C/ | RATE PER DKT | 3.836 | N.A. | N.A. | 3.836 |
| VOLUMETRIC CAPACITY RELEASE CHARGE | | | | | |
| MAXIMUM | RATE PER DKT | 39.314 | N.A. | N.A. | 39.314 |
| MINIMUM | RATE PER DKT | 0.000 | N.A. | N.A. | 0.000 |

-
- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 2.766%, CONSISTING OF 3.057% 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 1.230 CENTS, CONSISTING OF 1.300 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.
 - C/ SHIPPER MUST REIMBURSE TRANSPORTER FOR THE ACA SURCHARGE. SUCH SURCHARGE SHALL BE THE ACA UNIT CHARGE SPECIFIED IN THE ANNUAL NOTICE ISSUED BY THE FERC ENTITLED "FY [YEAR] GAS ANNUAL CHARGES CORRECTION FOR ANNUAL CHARGES UNIT CHARGE."

NOTICE OF CURRENTLY EFFECTIVE RATES

(ALL RATES ARE STATED IN CENTS PER DEKATHERM OR EQUIVALENT DEKATHERM AS INDICATED)

| RATE SCHEDULE | UNIT | BASE TARIFF RATE | 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. | 28.954 | N.A. | N.A. | 28.954 |
| MINIMUM | RATE PER EQV. DKT PER MO. | 1.329 | N.A. | N.A. | 1.329 |
| VOLUMETRIC CAPACITY RELEASE CHARGE | | | | | |
| MAXIMUM | RATE PER DKT | 0.952 | N.A. | N.A. | 0.952 |
| MINIMUM | RATE PER DKT | 0.044 | N.A. | N.A. | 0.044 |

NOTICE OF CURRENTLY EFFECTIVE RATES

(ALL RATES ARE STATED IN CENTS PER DEKATHERM OR EQUIVALENT DEKATHERM AS INDICATED)

| RATE SCHEDULE | UNIT | BASE TARIFF RATE | 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. | 1.915 | N.A. | N.A. | 1.915 |
| MINIMUM | RATE PER EQV. DKT PER MO. | 0.000 | N.A. | N.A. | 0.000 |
| CAPACITY DELIVERABILITY CHARGE | | | | | |
| MAXIMUM | RATE PER EQV. DKT PER MO. | 234.832 | N.A. | N.A. | 234.832 |
| MINIMUM | RATE PER EQV. DKT PER MO. | 0.000 | N.A. | N.A. | 0.000 |
| INJECTION CHARGE | | | | | |
| MAXIMUM A/B/ | RATE PER DKT | 1.281 | N.A. | N.A. | 1.281 |
| MINIMUM A/B/ | RATE PER DKT | 1.281 | N.A. | N.A. | 1.281 |
| WITHDRAWAL CHARGE | | | | | |
| MAXIMUM A/B/ | RATE PER DKT | 1.281 | N.A. | N.A. | 1.281 |
| MINIMUM A/B/ | RATE PER DKT | 1.281 | N.A. | N.A. | 1.281 |
| SCHEDULED OVERRUN CHARGE | | | | | |
| INJECTION | | | | | |
| MAXIMUM A/B/ | RATE PER DKT | 24.324 | N.A. | N.A. | 24.324 |
| MINIMUM A/B/ | RATE PER DKT | 1.281 | N.A. | N.A. | 1.281 |
| WITHDRAWAL | | | | | |
| MAXIMUM A/B/ | RATE PER DKT | 24.324 | N.A. | N.A. | 24.324 |
| MINIMUM A/B/ | RATE PER DKT | 1.281 | N.A. | N.A. | 1.281 |

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 0.996%, CONSISTING OF 1.163% 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 0.131 CENTS, CONSISTING OF 0.098 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.

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.

| 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) \$ 216.98/10 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 ¹ | 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 \$ 5.23/GJ FT-D Demand Rate for Group 2 Delivery Points \$ 4.19/GJ FT-D Demand Rate for Group 3 Delivery Points \$ 5.02/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 ¹ | 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 | 11.29 | |
| | 6-10 years | 9.44 | |
| | 15 years | 8.46 | |
| | 20 years | 7.51 | |
| 8. Rate Schedule LRS-3 | LRS-3 Demand Rate per month \$ 129.55/10 ³ m ³ | | |
| 9. Rate Schedule IT-R | Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point | | |
| 10. Rate Schedule IT-D ¹ | Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point | | |
| 11. Rate Schedule FCS | The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service | | |
| 12. 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 |
| 13. Rate Schedule OS | <u>Schedule No.</u> | <u>Charge</u> | |
| | 2014612719 | \$ 2.00 | / month |
| | 2014612718 | \$ 2.00 | / month |
| | 2014612720 | \$ 2,174.00 | / month |
| | 2014612725 | \$ 20.00 | / month |
| | 2014612724 | \$ 129.00 | / month |
| | 2014612723 | \$ 71.00 | / month |
| | 2014612722 | \$ 15.00 | / month |
| | 2014612721 | \$ 283.00 | / month |
| | 2014612717 | \$ 212.00 | / month |
| | 2011475772 | \$ 9,250.00 | / month |
| | 2014613454 | \$ 650.00 | / month |
| | 2003004522 | Applicable IT-R and IT-D Rate | |
| | 2011476052 / | \$ 0.1376 | / GJ subject to |
| | 2011476054 | \$ 717,000.00 | Minimum Annual Charge |
| | 2011475056 / 2011476092 / | \$ 0.095 | / GJ and |
| | 2011476049 / 2011476050 | \$ 1,000.00 | / month |
| 14. Rate Schedule CO ₂ | <u>Tier</u> | <u>CO₂ Rate (\$/10³m³)</u> | |
| | 1 | 528.30 | |
| | 2 | 418.06 | |
| | 3 | 272.20 | |

1. Service under rate Schedule FT-D, FT-P and IT-D for delivery stations identified in Attachment 2, and stations identified on rate Schedule OS No. 2011476092 and No. 2011476049, are subject to the ATCO Pipelines Franchise Fees pursuant to paragraph 15.13 of the General Terms and Conditions.

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 | 5.18 | 0.1874 |
| 31111 | ALLIANCE CLAIRMONT INTERCONNECT APN | 4.19 | 0.1514 |
| 31110 | ALLIANCE EDSON INTERCONNECT APN | 4.19 | 0.1514 |
| 31112 | ALLIANCE SHELL CREEK INTERCONNECT APGC | 4.19 | 0.1514 |
| 3002 | BOUNDARY LAKE BORDER | 4.19 | 0.1514 |
| 1958 | EMPRESS BORDER | 5.35 | 0.1935 |
| 3886 | GORDONDALE BORDER | 4.19 | 0.1514 |
| 6404 | MCNEILL BORDER | 5.35 | 0.1935 |

| 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 | 4.19 | 0.1514 | Yes |
| 31001 | ADM AGRI INDUSTRIES SALES APN | 4.19 | 0.1514 | Yes |
| 3880 | AECO INTERCONNECTION | 4.19 | 0.1514 | |
| 31003 | AGRIUM CARSELAND SALES APS | 4.19 | 0.1514 | |
| 31002 | AGRIUM FT. SASK SALES APN | 4.19 | 0.1514 | Yes |
| 31004 | AGRIUM REDWATER SALES APN | 4.19 | 0.1514 | |
| 31005 | AINSWORTH SALES APGP | 4.19 | 0.1514 | |
| 31006 | AIR LIQUIDE SALES APN | 4.19 | 0.1514 | |
| 3214 | AKUINU RIVER WEST SALES | 4.19 | 0.1514 | |
| 31007 | ALBERTA ENVIROFUELS SALES APN | 4.19 | 0.1514 | Yes ² |
| 31008 | ALBERTA HOSPITAL SALES APN | 4.19 | 0.1514 | Yes |
| 3868 | ALBERTA-MONTANA BORDER | 4.19 | 0.1514 | |
| 3059 | ALLISON CREEK SALES | 4.19 | 0.1514 | |
| 31009 | ALTASTEEL SALES APN | 4.19 | 0.1514 | Yes ² |
| 3562 | AMOCO SALES (BP SALES TAP) | 4.19 | 0.1514 | |
| 31012 | APL JASPER SALES APN | 4.19 | 0.1514 | Yes |
| 3488 | ARDLEY SALES | 4.19 | 0.1514 | |
| 3237 | ASPEN SALES | 4.19 | 0.1514 | |
| 3216 | AURORA NO 2 SALES | 4.19 | 0.1514 | |
| 3135 | AURORA SALES | 4.19 | 0.1514 | |
| 3423 | BASHAW WEST SALES | 4.19 | 0.1514 | |
| 31013 | BAYMAG SALES APS | 4.19 | 0.1514 | |
| 31014 | BEAR CREEK COGEN SALES APGP | 4.19 | 0.1514 | |
| 3068 | BEAVER HILLS SALES | 4.19 | 0.1514 | |
| 3933 | BIG EDDY INTERCONNECTION | 4.19 | 0.1514 | |
| 3067 | BIGSTONE SALES | 4.19 | 0.1514 | |
| 3468 | BLEAK LAKE SALES | 4.19 | 0.1514 | |
| 3225 | BOTHA SALES | 4.19 | 0.1514 | |
| 3259 | BOULDER CREEK SALES | 4.19 | 0.1514 | |
| 3164 | BRAINARD LAKE SALES | 4.19 | 0.1514 | |
| 3918 | BUFFALO CREEK INTERCONNECTION | 4.19 | 0.1514 | |
| 31015 | BURDETT COGEN SALES APS | 4.19 | 0.1514 | |
| 3204 | CABIN SALES | 4.19 | 0.1514 | |
| 3109 | CALDWELL SALES | 4.19 | 0.1514 | |
| 31016 | CALGARY ENERGY CENTRE SALES APS | 4.19 | 0.1514 | Yes |
| 3634 | CANOE LAKE SALES | 4.19 | 0.1514 | |
| 3165 | CANOE LAKE SALES NO 2 | 4.19 | 0.1514 | |
| 3866 | CARBON INTERCONNECTION | 4.19 | 0.1514 | |
| 3484 | CARIBOU LAKE SALES | 4.19 | 0.1514 | |
| 3157 | CARIBOU LAKE SOUTH SALES | 4.19 | 0.1514 | |
| 3106 | CARMON CREEK SALES | 4.19 | 0.1514 | |
| 3101 | CAROLINE SALES | 4.19 | 0.1514 | |
| 31017 | CARSELAND COGEN SALES APS | 4.19 | 0.1514 | |
| 3495 | CAVALIER SALES | 4.19 | 0.1514 | |
| 31018 | CHAIN LAKES COOP SALES APS | 4.19 | 0.1514 | |
| 3907 | CHANCELLOR INTERCONNECTION | 4.19 | 0.1514 | |
| 3151 | CHEECHAM WEST NO 2 SALES | 4.19 | 0.1514 | |
| 3622 | CHEECHAM WEST SALES | 4.19 | 0.1514 | |
| 6014 | CHEVRON AURORA SALES | 4.19 | 0.1514 | |
| 31019 | CHEVRON FT. SASK SALES APN | 4.19 | 0.1514 | Yes |
| 3097 | CHICKADEE CREEK SALES | 4.19 | 0.1514 | |
| 3305 | CHIGWELL NORTH SALES | 4.19 | 0.1514 | |
| 3496 | CHIPEWYAN RIVER SALES | 4.19 | 0.1514 | |
| 3163 | CHRISTINA LAKE NORTH SALES | 4.19 | 0.1514 | |

NATURAL GAS TARIFF

NorthWestern
Energy

Canceling $\frac{35^{th}}{34^{th}}$ Revised
Revised

Sheet No. 80.1
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 | |
|------------------------------------|---------------------|-----|
| 1,001 to 10,000 | \$ 120.40 | (1) |
| 10,001 to 30,000 | \$ 173.05 | (1) |
| >30,000 | \$ 224.05 | (1) |

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for
Maximum Daily Delivery Quantity (MDDQ) \$ 0.9840814 (1)

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum \$ 0.0074572 (1)
Minimum \$ 0.0017935
GTAC Amortization \$ (0.0013032)

Balancing Penalty Rate Higher of \$25.00/Decatherm 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)

Docket No. D2013.12.83
Tariff Letter No. 237-G
By Operation of Law

Effective for service rendered on or after
January 1, 2014

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

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 MAY 2014**

| | General Service | | |
|--------------------|-----------------------|-------------------------|-------------------|
| | Prepaid | | |
| | Storage Balance 1/ | Commodity Balance 2/ | Prepaid Demand |
| October 2013 | \$11,873,285 | \$524,021 | \$3,373,058 |
| November | 10,083,032 | 468,480 | 2,743,332 |
| December | 2,713,665 | 282,335 | 1,290,628 |
| January 2014 | 1,718,601 | 140,548 | (516,571) |
| February | (7,802,409) | 0 | (1,585,437) |
| March | (9,953,841) | (22,851) | (3,129,229) |
| April | (9,493,216) | (255) | (3,071,443) |
| May | (6,709,729) | 132,922 | (1,812,473) |
| June | (2,895,273) | 315,426 | (45,932) |
| July | 872,779 | 495,710 | 1,748,479 |
| August | 4,762,893 | 681,949 | 3,548,406 |
| September | 9,666,467 | 916,043 | 5,035,765 |
| October | 12,375,478 | 1,045,274 | 5,320,656 |
| 13 month average | <u>\$1,323,979</u> | <u>\$383,046</u> | <u>\$992,249</u> |
| Rate of Return | 8.791% | 8.791% | 8.791% |
| Return | \$116,391 | \$33,674 | \$87,229 |
| Return Requirement | <u>\$158,004</u> | <u>\$45,713</u> | <u>\$118,416</u> |

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

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

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE
NORTH DAKOTA
EFFECTIVE MAY 2014

| | |
|---|-------------------------|
| Cost of Purchased Propane | \$34,425 |
| Gallons Purchased | 32,786 |
| Projected dk Sales | 3,000 |
| Propane Cost per Dk | \$11.475 |
| Average Cost of Propane as Adjusted for Losses @ 99.55% | 11.527 |
| Less: Propane Cost Level in Rates 1/ | <u>17.016</u> |
| Current Propane Cost Adjustment | <u><u>(\$5,489)</u></u> |

1/ Propane Cost Level in Current Rates - Case No. PU-14-008, effective April 1, 2014.

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

| | <u>(Over) Under</u> | <u>Refunds &</u> | | <u>Total Net</u> | <u>Actual Dk</u> | <u>Adjustment</u> | <u>Total</u> | <u>Net Change-</u> | <u>Cumulative</u> |
|------------------------------------|---------------------|----------------------|--------------------|------------------|------------------|-------------------|-------------------|-----------------------|-------------------------|
| | <u>Recovery</u> | <u>Other</u> | <u>Interest 1/</u> | <u>Additions</u> | <u>Sales</u> | <u>Per Dk</u> | <u>Adjustment</u> | <u>Additions less</u> | <u>Balance</u> |
| | | | | | | | <u>Amount</u> | <u>Adjustment</u> | |
| Balance @ July 31, 2013 | | | | | | | | | <u>\$268,918</u> |
| August | (\$171,535) | \$0 | \$6 | (\$171,529) | 283,161 | (\$0.113) | (\$31,997) | (\$139,532) | 129,386 |
| September | (10,802) | 387,468 2/ | 2 | 376,668 | 259,134 | (0.113) | (29,282) | 405,949 | 535,335 |
| October | 91,702 | 0 | 15 | 91,717 | 509,627 | 0.024 | (28,445) 3/ | 120,162 | 655,497 |
| November | (43,397) | 46,049 4/ | 27 | 2,679 | 1,155,975 | 0.024 | 27,743 | (25,064) | 630,433 |
| December | 448,098 | 0 | 25 | 448,123 | 2,259,276 | 0.024 | 54,223 | 393,900 | 1,024,333 |
| January 2014 | 218,746 | 0 | 22 | 218,768 | 3,260,430 | 0.024 | 78,250 | 140,518 | 1,164,851 |
| February | (243,381) | (98,337) 5/ | 30 | (341,688) | 2,668,333 | 0.024 | 64,040 | (405,728) | 759,123 |
| Balance @ February 28, 2014 | | | | | | | | | <u>\$759,123</u> |

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

2/ Adjustment to correct gas costs for the period December 2010 - August 2013 due to a billing error.

3/ Reflects 296,905.6 Dk @ (\$0.113) and 212,721.2 Dk @ \$0.024.

4/ Adjustment to correct gas costs for the period February 2013 - October 2013 for revisions to volume calculations.

5/ Adjustment to correct prior misallocation between states.

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

| | <u>(Over) Under</u> <u>Recovery</u> | <u>Refunds &</u> <u>Other</u> | <u>Interest 1/</u> | <u>Total Net</u> <u>Additions</u> | <u>Actual Dk</u> <u>Sales</u> | <u>Adjustment</u> <u>Per Dk</u> | <u>Total</u> <u>Adjustment</u> <u>Amount</u> | <u>Net Change-</u> <u>Additions less</u> <u>Adjustment</u> | <u>Cumulative</u> <u>Balance</u> |
|------------------------------------|--|--------------------------------------|--------------------|--------------------------------------|----------------------------------|------------------------------------|--|--|-------------------------------------|
| Balance @ July 31, 2013 | | | | | | | | | <u>\$162,872</u> |
| August | (\$8,729) | \$0 | \$4 | (\$8,725) | 32,348 | (\$0.115) | (\$3,719) | (\$5,006) | 157,866 |
| September | (2,593) | 0 | 1 | (2,592) | 33,833 | (0.115) | (3,891) | 1,299 | 159,165 |
| October | 9,049 | 0 | 4 | 9,053 | 55,674 | 0.116 | (4,732) 2/ | 13,785 | 172,950 |
| November | 19,660 | 6,105 3/ | 7 | 25,772 | 126,614 | 0.116 | 14,687 | 11,085 | 184,035 |
| December | 67,199 | 0 | 7 | 67,206 | 203,609 | 0.116 | 23,618 | 43,588 | 227,623 |
| January 2014 | 86,756 | 0 | 5 | 86,761 | 165,685 | 0.116 | 19,220 | 67,541 | 295,164 |
| February | 8,193 | 4,502 4/ | 8 | 12,703 | 157,100 | 0.116 | 18,224 | (5,521) | 289,643 |
| Balance @ February 28, 2014 | | | | | | | | | <u>\$289,643</u> |

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

2/ Reflects 48,442.5 Dk @ (\$0.115) and 7,230.6 Dk @ \$0.116.

3/ Adjustment to correct gas costs for the period February 2013 - October 2013 for revisions to volume calculations.

4/ Adjustment to correct prior misallocation between states.

**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 & 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> |
|------------------------------------|----------------------------------|--------------------------------|--------------------|--------------------------------|----------------------------|------------------------------|--|--|-------------------------------|
| Balance @ July 31, 2013 | | | | | | | | | <u>\$86,961</u> |
| August | (\$1,327) | \$0 | \$2 | (\$1,325) | 4,039 | (\$0.377) | (\$1,522) | \$197 | 87,158 |
| September | (5,633) | 0 | 1 | (5,632) | 4,641 | (0.377) | (1,750) | (3,882) | 83,276 |
| October | 1,205 | 0 | 2 | 1,207 | 6,585 | 0.181 | (2,484) 2/ | 3,691 | 86,967 |
| November | 3,672 | 1,691 3/ | 3 | 5,366 | 29,839 | 0.181 | 5,401 | (35) | 86,932 |
| December | 4,326 | 0 | 4 | 4,330 | 52,750 | 0.181 | 9,547 | (5,217) | 81,715 |
| January 2014 | 63,099 | 0 | 2 | 63,101 | 88,671 | 0.181 | 16,050 | 47,051 | 128,766 |
| February | (50,998) | 2,212 4/ | 3 | (48,783) | 86,357 | 0.181 | 15,631 | (64,414) | 64,352 |
| Balance @ February 28, 2014 | | | | | | | | | <u>\$64,352</u> |

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

2/ Reflects 6,585.1 Dk @ (\$0.377).

3/ Adjustment to correct gas costs for the period February 2013 - October 2013 for revisions to volume calculations.

4/ Adjustment to correct prior misallocation between states.

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, 2014 \$161,026

Less: Projected recovery from rates already established

| | Volume | Rate | Amount |
|-------|--------|-----------|---------|
| March | 5,800 | (\$0.777) | (4,507) |
| April | 5,300 | (\$0.777) | (4,118) |
| | 11,100 | | (8,625) |

Additional recovery required \$169,651

Projected sales volumes (dk)

| | | |
|--------------|-------|---------|
| May 2014 | 3,000 | |
| June | 1,500 | |
| July | 1,100 | |
| August | 1,200 | |
| September | 1,000 | |
| October | 2,700 | |
| November | 4,300 | |
| December | 7,500 | |
| January 2015 | 7,700 | |
| February | 6,300 | |
| March | 5,800 | |
| April | 5,300 | |
| May | 3,000 | |
| June | 1,500 | |
| July | 1,100 | |
| August | 1,200 | |
| September | 1,000 | |
| October | 2,700 | |
| November | 4,300 | |
| December | 7,500 | |
| January 2016 | 7,700 | |
| February | 6,300 | |
| March | 5,800 | |
| April | 5,300 | |
| May | 3,000 | |
| June | 1,500 | |
| July | 1,100 | |
| August | 1,200 | |
| September | 1,000 | |
| October | 2,700 | |
| November | 4,300 | |
| December | 7,500 | |
| January 2017 | 7,700 | |
| February | 6,300 | |
| March | 5,800 | |
| April | 5,300 | |
| Total | | 142,200 |

Total (over)/under recovered gas cost adjustment
to be effective May 1, 2014 through April 30, 2017. \$1.193

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

| | <u>(Over) Under Recovery</u> | <u>Refunds & 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> |
|------------------------------------|----------------------------------|--------------------------------|--------------------|--------------------------------|----------------------------|------------------------------|--|--|-------------------------------|
| Balance @ February 29, 2013 | | | | | | | | | <u>(\$29,815)</u> |
| March 2013 | \$6,308 | \$0 | (\$1) | \$6,307 | 5,943 | \$0.646 | \$3,839 | \$2,468 | (27,347) |
| April | (2,944) | 0 | (1) | (2,945) | 5,395 | 0.646 | 3,485 | (6,430) | (33,777) |
| May | (3,685) | 0 | (1) | (3,686) | 3,064 | 0.646 | (468) 2/ | (3,218) | (36,995) |
| June | 5,221 | 0 | (1) | 5,220 | 1,561 | (0.777) | (1,213) | 6,433 | (30,562) |
| July | 2,307 | 0 | (1) | 2,306 | 1,128 | (0.777) | (877) | 3,183 | (27,379) |
| August | (1,157) | 0 | (1) | (1,158) | 1,185 | (0.777) | (921) | (237) | (27,616) |
| September | 3,217 | 0 | 0 | 3,217 | 966 | (0.777) | (751) | 3,968 | (23,648) |
| October | 3,453 | 0 | (1) | 3,452 | 2,700 | (0.777) | (2,098) | 5,550 | (18,098) |
| November | 11,514 | 0 | (1) | 11,513 | 4,366 | (0.777) | (3,392) | 14,905 | (3,193) |
| December | 34,616 | 0 | 0 | 34,616 | 7,668 | (0.777) | (5,958) | 40,574 | 37,381 |
| January 2014 | 63,133 | 0 | 1 | 63,134 | 8,850 | (0.777) | (6,876) | 70,010 | 107,391 |
| February | 47,697 | 0 | 3 | 47,700 | 7,639 | (0.777) | (5,935) | 53,635 | 161,026 |
| | <u>\$169,680</u> | <u>\$0</u> | <u>(\$4)</u> | <u>\$169,676</u> | <u>50,465</u> | | <u>(\$21,165)</u> | <u>\$190,841</u> | |
| Balance @ February 28, 2014 | | | | | | | | | <u>\$161,026</u> |

1/ Interest calculated at 90 day Treasury Note rate.

2/ Reflects 1,343.0 Dk @ \$0.646 and 1,720.6 Dk @ -\$0.777.

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

| | 1/ | 2/ | 3/ | Total |
|------------------------------|--------------------|--------------------|--------------------|------------------|
| <u>March 2013</u> | | | | |
| Cost of Gas - Actual | \$10.53538 | \$11.44168 | \$10.53538 | |
| Cost of Gas - Recovered | 9.88000 | 9.88000 | 9.88000 | |
| (Over) Under recovery per dk | <u>\$0.65538</u> | <u>\$1.56168</u> | <u>\$0.65538</u> | |
| dk billed | 0 | 2,663 | 3,280 | 5,943 |
| (Over) Under recovery | <u>\$0</u> | <u>\$4,159</u> | <u>\$2,149</u> | <u>\$6,308</u> |
| <u>April 2013</u> | | | | |
| Cost of Gas - Actual | \$8.02558 | \$10.53538 | \$8.02558 | |
| Cost of Gas - Recovered | 9.88000 | 9.88000 | 9.88000 | |
| (Over) Under recovery per dk | <u>(\$1.85442)</u> | <u>\$0.65538</u> | <u>(\$1.85442)</u> | |
| dk billed | 0 | 2,813 | 2,582 | 5,395 |
| (Over) Under recovery | <u>\$0</u> | <u>\$1,844</u> | <u>(\$4,788)</u> | <u>(\$2,944)</u> |
| <u>May 2013</u> | | | | |
| Cost of Gas - Actual | \$10.68074 | \$8.02558 | \$10.68074 | |
| Cost of Gas - Recovered | 10.42900 | 9.88000 | 9.88000 | |
| (Over) Under recovery per dk | <u>\$0.25174</u> | <u>(\$1.85442)</u> | <u>\$0.80074</u> | |
| dk billed | 1,721 | 1,956 | (613) | 3,064 |
| (Over) Under recovery | <u>\$433</u> | <u>(\$3,627)</u> | <u>(\$491)</u> | <u>(\$3,685)</u> |
| <u>June 2013</u> | | | | |
| Cost of Gas - Actual | \$18.32964 | \$10.68074 | \$18.32964 | |
| Cost of Gas - Recovered | 9.88000 | 10.42900 | 10.42900 | |
| (Over) Under recovery per dk | <u>\$8.44964</u> | <u>\$0.25174</u> | <u>\$7.90064</u> | |
| dk billed | 907 | 995 | (341) | 1,561 |
| (Over) Under recovery | <u>\$7,666</u> | <u>\$250</u> | <u>(\$2,695)</u> | <u>\$5,221</u> |
| <u>July 2013</u> | | | | |
| Cost of Gas - Actual | \$7.00613 | \$18.32964 | \$7.00613 | |
| Cost of Gas - Recovered | 9.88000 | 9.88000 | 9.88000 | |
| (Over) Under recovery per dk | <u>(\$2.87387)</u> | <u>\$8.44964</u> | <u>(\$2.87387)</u> | |
| dk billed | 0 | 490 | 638 | 1,128 |
| (Over) Under recovery | <u>\$0</u> | <u>\$4,140</u> | <u>(\$1,833)</u> | <u>\$2,307</u> |
| <u>August 2013</u> | | | | |
| Cost of Gas - Actual | \$9.19700 | \$7.00613 | \$9.19700 | |
| Cost of Gas - Recovered | 9.88000 | 9.88000 | 9.88000 | |
| (Over) Under recovery per dk | <u>(\$0.68300)</u> | <u>(\$2.87387)</u> | <u>(\$0.68300)</u> | |
| dk billed | 0 | 158 | 1,027 | 1,185 |
| (Over) Under recovery | <u>\$0</u> | <u>(\$455)</u> | <u>(\$702)</u> | <u>(\$1,157)</u> |

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>September 2013</u> | | | | |
| Cost of Gas - Actual | \$16.97630 | \$9.19700 | \$16.97630 | |
| Cost of Gas - Recovered | 9.88000 | 9.88000 | 9.88000 | |
| (Over) Under recovery per dk | <u>\$7.09630</u> | <u>(\$0.68300)</u> | <u>\$7.09630</u> | |
| dk billed | 0 | 468 | 498 | 966 |
| (Over) Under recovery | <u>\$0</u> | <u>(\$320)</u> | <u>\$3,537</u> | <u>\$3,217</u> |
| <u>October 2013</u> | | | | |
| Cost of Gas - Actual | \$11.27151 | \$16.97630 | \$11.27151 | |
| Cost of Gas - Recovered | 12.07500 | 9.88000 | 9.88000 | |
| (Over) Under recovery per dk | <u>(\$0.80349)</u> | <u>\$7.09630</u> | <u>\$1.39151</u> | |
| dk billed | 1,706 | 603 | 391 | 2,700 |
| (Over) Under recovery | <u>(\$1,371)</u> | <u>\$4,280</u> | <u>\$544</u> | <u>\$3,453</u> |
| <u>November 2013</u> | | | | |
| Cost of Gas - Actual | \$16.46780 | \$11.27151 | \$16.46780 | |
| Cost of Gas - Recovered | 12.07500 | 12.07500 | 12.07500 | |
| (Over) Under recovery per dk | <u>\$4.39280</u> | <u>(\$0.80349)</u> | <u>\$4.39280</u> | |
| dk billed | 0 | 1,475 | 2,891 | 4,366 |
| (Over) Under recovery | <u>\$0</u> | <u>(\$1,185)</u> | <u>\$12,699</u> | <u>\$11,514</u> |
| <u>December 2013</u> | | | | |
| Cost of Gas - Actual | \$18.20943 | \$16.46780 | \$18.20943 | |
| Cost of Gas - Recovered | 13.72300 | 12.07500 | 12.07500 | |
| (Over) Under recovery per dk | <u>\$4.48643</u> | <u>\$4.39280</u> | <u>\$6.13443</u> | |
| dk billed | 4,175 | 3,183 | 310 | 7,668 |
| (Over) Under recovery | <u>\$18,731</u> | <u>\$13,982</u> | <u>\$1,902</u> | <u>\$34,615</u> |
| <u>January 2014</u> | | | | |
| Cost of Gas - Actual | \$25.61495 | \$18.20943 | \$25.61495 | |
| Cost of Gas - Recovered | 15.91900 | 13.72300 | 13.72300 | |
| (Over) Under recovery per dk | <u>\$9.69595</u> | <u>\$4.48643</u> | <u>\$11.89195</u> | |
| dk billed | 5,008 | 4,201 | (359) | 8,850 |
| (Over) Under recovery | <u>\$48,556</u> | <u>\$18,850</u> | <u>(\$4,273)</u> | <u>\$63,133</u> |
| <u>February 2014</u> | | | | |
| Cost of Gas - Actual | \$23.06970 | \$25.61495 | \$23.06970 | |
| Cost of Gas - Recovered | 19.21100 | 15.91900 | 15.91900 | |
| (Over) Under recovery per dk | <u>\$3.85870</u> | <u>\$9.69595</u> | <u>\$7.15070</u> | |
| dk billed | 4,290 | 2,827 | 522 | 7,639 |
| (Over) Under recovery | <u>\$16,554</u> | <u>\$27,410</u> | <u>\$3,733</u> | <u>\$47,697</u> |

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