

December 8, 2014

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

Re: Cost of Gas Adjustment  
(COG) Rate 88  
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 (132<sup>nd</sup> Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered January 1, 2015.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.358 per dk since the last filing due to an increase in the overall commodity price of gas. Attachment B explains the reasons for the increase in the market price of gas. There has also been a change in pipeline rates as shown on Attachment C, increasing the cost of gas by \$0.001 per dk. In addition, Montana-Dakota has increased its firm transportation capacity, resulting in a system wide change in demand allocation and a decrease of approximately \$0.010 per dk in North Dakota.

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 January 2015.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.349 per dk for residential and firm general customers, an increase of \$0.362 per dk for small and large interruptible customers and an increase of \$0.361 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 January 2015. The average cost of

gas for firm customers, adjusted for losses, is \$5.663.

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 7.881% was authorized by the Commission in Case No. PU-13-803.

Montana-Dakota purchases propane supplies from various wholesale suppliers. There is no change in the cost of propane from that established in the December 2014 PGA filing.

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

These proposed adjustments, calculated in accordance with Rate 88, will amount to an increase of approximately \$1,017,800 for natural gas customers during the month of January 2015. All of Montana-Dakota's retail natural customers in North Dakota may be affected by this proposal. There were 104,323 natural gas customers and 344 propane customers in North Dakota as of November 30, 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 also submits a check to the North Dakota Public Service Commission for \$650 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.

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  
132<sup>nd</sup> Revised Sheet No. 3  
Canceling 131<sup>st</sup> Revised Sheet No. 3

### RATE SUMMARY SHEET

Page 1 of 2

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	\$0.4935 per day	\$0.326	\$5.854	\$6.180
Air Force Rate 64	7				
Minot Air Force Base		\$2,000.00 per month			
PAR Site		\$175.00 per month			
Firm Service			\$0.329	\$5.854	\$6.183
Interruptible Service - PAR			\$0.260	\$4.863	\$5.123
Interruptible Service - MAFB			\$0.260	\$4.828	\$5.088
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$5.854	\$6.584
Small Interruptible Gas Rate 71	14	\$175.00 per month	(Maximum) \$0.929	\$4.863	(Maximum) \$5.792
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$5.961	\$6.691
Transportation Service	24				
Small Interruptible Rate 81		\$175.00 per month			
Maximum			\$0.485		
Minimum			\$0.102		
Fuel Charge				\$0.020	
Large Interruptible Rate 82		\$1,000.00 per month			
Maximum			\$0.297		
Minimum			\$0.061		
Fuel Charge				\$0.020	
Large Interruptible Gas Rate 85	27	\$1,000.00 per month	(Maximum) \$0.718	\$4.863	(Maximum) \$5.581
Residential Propane Rate 90	32	\$0.4935 per day	\$0.326	\$14.460	\$14.786
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$14.460	\$15.190

Date Filed: December 8, 2014

Effective Date: January 1, 2015

Issued By: Tamie A. Aberle  
Director - Regulatory Affairs

Case No.: PU-14-008

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

**January 2015**

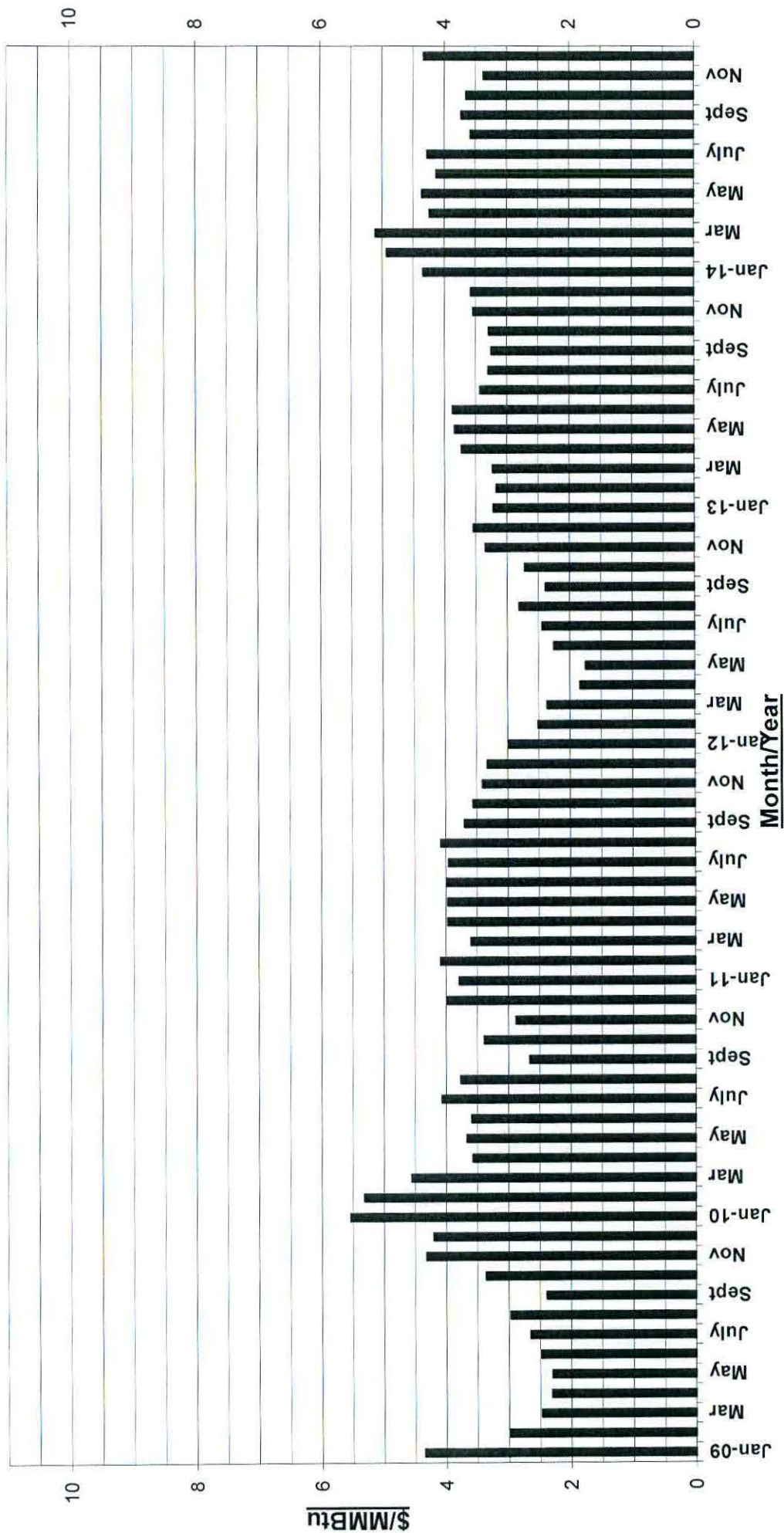
The established monthly price for the Rocky Mountain CIG Index has increased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid by willing sellers and buyers of quantities of gas in that region. That price is reflective of natural gas prices in the Rocky Mountain region and indicative of the supplies Montana-Dakota purchases for its requirements.

The first four weeks of November saw working natural gas storage inventory withdrawals represent the second largest net withdrawal for that period in more than 10 years, according to EIA's Weekly Natural Gas Storage Report (WNGSR.) While domestic production continues to be strong, the large storage withdrawals were likely the major cause of the increase in the index price of natural gas from the previous month. The EIA reported the national storage level as of November 28, 2014, was 9.8 percent below the five-year average and 6.2 percent below last year's storage balance.

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

The October Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 18. The November Outlook will be published November 12, 2014.

### CIG Rocky Mountains Index Monthly Gas Prices 2009-2014



From Inside F.E.R.C.'s Gas Market Report  
Annual Averages: - 2012-\$2.58; 2013-\$3.45; 2014-\$4.17

*Independent Statistics & Analysis*U.S. Energy Information  
Administration

November 2014

## Short-Term Energy Outlook (STEO)

### Highlights

- North Sea Brent crude oil spot prices fell from \$95/barrel (bbl) on October 1 to \$84/bbl at the end of the month. The causes included weakening outlooks for global economic and oil demand growth, the return to the market of previously disrupted Libyan crude oil production, and continued growth in U.S. tight oil production. Brent crude oil spot prices averaged \$87/bbl in October, the first month Brent prices have averaged below \$90/bbl since November 2010. EIA projects that Brent crude oil prices will average \$83/bbl in 2015, \$18/bbl lower than forecast in last month's STEO. There is significant uncertainty over the crude oil price forecast because of the range of potential supply responses from the Organization of the Petroleum Exporting Countries (OPEC), particularly Saudi Arabia, and U.S. tight oil producers to the new lower oil price environment.
- Driven largely by falling crude oil prices, U.S. weekly regular gasoline retail prices averaged \$2.99/gallon (gal) on November 3, the lowest level since December 20, 2010. U.S. regular gasoline retail prices are projected to continue to decline for the remainder of the year to an average of \$2.80/gal in December, \$0.33/gal lower than in last month's STEO. EIA expects U.S. regular gasoline retail prices, which averaged \$3.51/gal in 2013, to average \$3.39/gal in 2014 and \$2.94/gal in 2015.
- Total U.S. crude oil production averaged an estimated 8.9 million barrels per day (bbl/d) in October, and monthly average production is forecast to surpass 9.0 million bbl/d in December 2014. Projected total crude oil production averages 9.4 million bbl/d in 2015, a reduction of 0.1 million bbl/d from last month's STEO. If realized, the 2015 forecast would be the highest annual average crude oil production since 1972. Natural gas plant liquids production is expected to increase from an average of 2.6 million bbl/d in 2013 to 3.2 million bbl/d in 2015.
- Natural gas working inventories on October 31 totaled 3.57 trillion cubic feet (Tcf), 0.24 Tcf (6%) below the level at the same time a year ago and 0.26 Tcf (7%) below the previous five-year average (2009-13). Despite the lower stocks at the start of this winter's heating season, EIA expects the Henry Hub natural gas spot price to average \$3.97/million British thermal units (MMBtu) this winter compared with \$4.53/MMBtu last winter. This price forecast reflects both lower expected heating demand and significantly higher natural gas production this winter.

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## Global Petroleum and Other Liquids

EIA made significant changes to its forecast global oil balance for this month's STEO. EIA expects that global oil markets will be looser than projected in last month's STEO, as global oil supply outpaces consumption by a larger amount, resulting in a global stock build of 0.4 million bbl/d in the fourth quarter of 2014 and a build of 0.4 million bbl/d in 2015. EIA's global supply forecast was revised upward by 0.2 million bbl/d to average 92.9 million bbl/d in 2015, mostly reflecting a smaller decline in Saudi Arabia's production compared with last month's forecast. The global demand forecast was revised downward by 0.2 million bbl/d to average 92.5 million bbl/d in 2015, based on weaker global economic growth prospects for next year.

Saudi Arabia's role in the oil market going forward is highly uncertain. Saudi Arabia has stated that it would rather maintain its export market share than cut production to keep prices higher. In the past, Saudi Arabia often played the role of the swing producer, cutting its production to accommodate supply growth elsewhere or increasing its output level to make up for a supply shortfall. EIA assumes that Saudi Arabia will continue to play some role as a swing producer, but perhaps to a lesser extent, as the country is sensitive to significant losses in market share. Saudi Arabia's production is still projected to decline in 2015 compared with this year, but by a smaller amount than previously expected. EIA projects that Saudi Arabia will cut production below its current level of 9.5 million bbl/d to avoid further downward pressure on oil prices amid high non-OPEC supply growth, but will maintain output above 9.0 million bbl/d through 2015.

EIA's projected global oil balance may be looser or tighter than expected depending on changes to Saudi Arabia's production level, Libya's supply outages, and global demand. Libya's crude oil production reached 1.0 million bbl/d in October 2014, its highest production level since early July 2013. However, Libya's production has since fallen because of new production outages. Intermittent supply outages in Libya will most likely persist as the country faces political instability and a deteriorated security environment in parts of the country.

**Global Petroleum and Other Liquids Consumption.** EIA estimates that global consumption grew by 1.3 million bbl/d in 2013, averaging 90.5 million bbl/d for the year. EIA expects global consumption to grow by 0.9 million bbl/d in 2014 and 1.1 million bbl/d in 2015. Projected global oil-consumption-weighted real gross domestic product (GDP), which increased by an estimated 2.7% in 2013, grows by 2.7% and 3.2% in 2014 and 2015, respectively. Global consumption was revised downward by 0.2 million bbl/d in 2015, based on a 0.1% reduction to forecast global oil-consumption-weighted real GDP growth. Short-term elasticities of demand with respect to income are more powerful (negatively) than the positive effects on demand from lower prices.

Consumption outside of the Organization for Economic Cooperation and Development (OECD) is projected to grow by 1.2 million bbl/d in 2014 and 1.0 million bbl/d in 2015, accounting for nearly all forecast global consumption growth during that period. China is the leading

contributor to projected global consumption growth, with consumption increasing by an annual average of 0.36 million bbl/d in 2014 and 2015.

EIA expects a 0.3-million-bbl/d decline in OECD consumption in 2014. Japan and Europe are expected to account for much of the projected OECD consumption decline. EIA expects Japan's consumption, which fell by 0.16 million bbl/d in 2013, to continue to decline by 0.14 million bbl/d in 2014 and 0.12 million bbl/d in 2015. Japan's oil consumption is expected to fall with less oil used in the electricity sector as the country returns some nuclear power plants to service in 2015 and increases the use of natural gas and coal to generate electricity. EIA projects that OECD Europe's consumption, which fell by 0.15 million bbl/d in 2013, will decline by 0.14 million bbl/d in 2014 and by a further 0.07 million bbl/d in 2015. U.S. consumption, which increased by 0.47 million bbl/d in 2013, is expected to decline by 0.06 million bbl/d in 2014 and then increase by 0.16 million bbl/d in 2015.

**Non-OPEC Petroleum and Other Liquids Supply.** EIA estimates that non-OPEC production grew by 1.4 million bbl/d in 2013, averaging 54.2 million bbl/d for the year. EIA expects non-OPEC production to grow by 1.9 million bbl/d in 2014 and 0.9 million bbl/d in 2015. The United States is the leading contributor to forecast non-OPEC supply growth, increasing by 1.5 million bbl/d in 2014 and 1.1 million bbl/d in 2015. EIA revised downward its U.S. total supply growth forecast by 0.1 million bbl/d in 2015 because of the recent decline in crude oil prices and the expectation that West Texas Intermediate crude oil spot prices will remain near \$80/bbl through 2015. EIA estimates that Eurasia's production will rise by an annual average of 0.06 million bbl/d in 2014 and decline by 0.09 million bbl/d in 2015, reflecting declines in Russia and Azerbaijan. In Russia, inadequate investment to offset natural decline rates at mature oil fields causes forecast production to decline by 0.05 million bbl/d in 2015.

Unplanned supply disruptions among non-OPEC producers averaged slightly lower than 0.6 million bbl/d in October, virtually unchanged from the previous month. South Sudan, Syria, and Yemen accounted for more than 90% of total non-OPEC supply disruptions.

**OPEC Petroleum and Other Liquids Supply.** EIA estimates that OPEC crude oil production averaged 29.9 million bbl/d in 2013, a decline of almost 1.0 million bbl/d from the previous year, primarily reflecting increased outages in Libya, Nigeria, Iran, and Iraq, along with strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.10 million bbl/d in 2014 and by 0.15 million bbl/d in 2015. In last month's STEO, OPEC crude oil production was projected to decline by more than 0.4 million bbl/d in 2015, but the projected decline was reduced based on a reassessment of Saudi Arabia's willingness to cut production.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.0 million bbl/d in October 2014, slightly lower than the previous month, as fewer outages in Libya offset new outages in the Neutral Zone shared by Kuwait and Saudi Arabia. Libya's production increased to 1.0 million bbl/d in October, its highest production level since early July 2013, but Libya's production has since fallen because of new production outages. Intermittent supply outages in

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Libya will most likely persist as the country faces political instability and a deteriorated security environment. As a result, EIA does not expect Libya's oil production to recover to its pre-blockade level of 1.4 million bbl/d over the forecast period.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to average 2.1 million bbl/d in 2014 and 2.7 million bbl/d in 2015. These estimates do not include additional capacity that may be available in Iran but is offline because of the effects of U.S. and European Union sanctions on Iran's ability to sell its oil.

**OECD Petroleum Inventories.** EIA estimates that OECD commercial oil inventories totaled 2.55 billion barrels at the end of 2013, equivalent to roughly 55 days of consumption. Projected OECD oil inventories rise to 2.65 billion barrels at the end of 2014.

**Crude Oil Prices.** North Sea Brent crude oil spot prices averaged \$87/bbl in October, a decrease of \$10/bbl from September and the first month Brent crude oil prices have averaged below \$90/bbl since November 2010. The combination of robust world crude oil supply and weak global demand contributed to [rising global inventories and lower crude oil prices](#). The forecast Brent crude oil price averages \$83/bbl in 2015, \$18/bbl lower than projected in last month's STEO.

The monthly average WTI crude oil spot price fell from an average of \$93/bbl in September to \$84/bbl in October. High refinery runs contributed to the discount of WTI crude oil to Brent crude oil narrowing from an average of \$8/bbl during the first half of this year to an average of \$3/bbl in July. More recently, lower-than-expected demand in Europe and Asia combined with continued [growth in global liquids supply depressed global crude oil benchmarks like Brent](#), contributed to the WTI discount to Brent again falling to \$3/bbl in October. EIA now expects WTI crude oil prices to average \$80/bbl in the fourth quarter of 2014 and \$78/bbl in 2015, \$11/bbl and \$17/bbl lower than projected in last month's STEO, respectively. The discount of WTI to Brent crude oil is forecast to widen slightly from current levels, averaging \$6/bbl in 2015.

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 February 2015 delivery, traded during the five-day period ending November 6, averaged \$79/bbl. Implied volatility averaged 28%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in February 2015 at \$63/bbl and \$99/bbl, respectively. Last year at this time, WTI for February 2014 delivery averaged \$95/bbl and implied volatility averaged 20%. The corresponding lower and upper limits of the 95% confidence interval were \$80/bbl and \$112/bbl.

## U.S. Petroleum and Other Liquids

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U.S. weekly regular gasoline retail prices averaged \$2.99/gal on November 3, which marked a decrease of 36 cents since the end of September and the first time gasoline prices have averaged below \$3.00/gal since December 20, 2010. In addition to typical seasonal downturns in gasoline demand and the switchover to winter-grade gasoline, [falling crude oil prices have been largely responsible](#) for the drop in retail gasoline prices. EIA expects that low crude oil prices and weak demand will help gasoline prices decrease further in the coming months, falling to an average of \$2.80/gal in December.

**Liquid Fuels Consumption.** Total U.S. liquid fuels consumption rose by 470,000 bbl/d (2.5%) in 2013, the largest increase since 2004. Consumption of hydrocarbon gas liquids (HGL) registered the largest gain, increasing by 190,000 bbl/d (8.5%). In 2014, total liquid fuels consumption is expected to fall by 60,000 bbl/d (0.3%), with declines in the consumption of HGL, residual fuel oil, and other oils offsetting increases in distillate fuel, jet fuel, and unfinished oils consumption. Total consumption grows by 160,000 bbl/d in 2015, with distillate consumption accounting for 100,000 bbl/d of the growth.

Motor gasoline consumption grew by 160,000 bbl/d (1.9%) in 2013, the largest increase since 2004. EIA expects gasoline consumption to remain mostly unchanged in 2014 and then decline by 20,000 bbl/d in 2015, as improving fuel economy in new vehicles continues to offset highway travel growth. Distillate fuel consumption increases by 110,000 bbl/d (3.0%) in 2014, reflecting colder-than-average first-quarter weather and economic growth. Consumption of that fuel rises by a further 100,000 bbl/d (2.5%) in 2015. Some of the growth in distillate fuel consumption in 2015 comes from [Annex VI to the International Convention for the Prevention of Pollution from Ships](#) (MARPOL Annex VI), which is an international agreement that generally requires the use of fuels below 1,000 parts per million sulfur by marine vessels in most U.S. waters, unless alternative devices, procedures, or compliance methods are used to achieve equivalent emissions reductions. However, EIA also expects low-sulfur distillate fuels will continue to be blended into residual fuel to meet the new sulfur limit and reported as residual fuel production and consumption.

**Liquid Fuels Supply.** Forecast U.S. crude oil production increases from an average of 7.5 million bbl/d in 2013 to 8.6 million bbl/d in 2014 and 9.4 million bbl/d in 2015. Because of the recent decline in crude oil prices, EIA has revised U.S. crude oil production in 2015 downward by an average of 80,000 bbl/d compared with last month's forecast. As the WTI crude oil price is forecast to average \$78/bbl in 2015, EIA expects to see some reduction in drilling activity because of marginal economic returns in some areas. This will primarily occur in noncore areas of emerging and mature tight oil basins, where low-producing wells become less attractive at lower prices and companies scale back expensive exploration and research drilling. The production forecast is not affected significantly because the wells that will not be drilled at these prices produce relatively little compared to wells in the core areas of a formation. Oil prices remain high enough to support most drilling activity in the Bakken, Eagle Ford, Niobrara, and Permian Basin, which contribute the majority of U.S. oil production growth.

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HGL production at natural gas liquids plants is projected to increase from 2.6 million bbl/d in 2013 to 3.2 million bbl/d in 2015. Ethane and propane are expected to contribute most to the projected growth, with the majority of production directed towards domestic petrochemical use or exports. EIA expects higher rates of ethane recoveries as a result of planned increases in petrochemical facility feedstock demand, while export terminal expansions will allow higher quantities of domestically produced propane and butanes to reach the international market.

The growth in domestic production has contributed to a significant decline in petroleum imports. The share of total U.S. liquid fuels consumption met by net imports fell from 60% in 2005 to an average of 33% in 2013. EIA expects the net import share to decline to 21% in 2015, which would be the lowest level since 1969.

**Petroleum Product Prices.** Monthly U.S. average regular gasoline retail prices fell from \$3.69/gal in June to \$3.17/gal in October. EIA expects that U.S. regular gasoline retail prices will continue to fall to an average of \$2.80/gal in December 2014. The U.S. annual average regular gasoline retail price, which averaged \$3.51/gal in 2013, is projected to average \$3.39/gal in 2014 and \$2.94/gal in 2015, \$0.06/gal and \$0.44/gal lower than in last month's STEO, respectively. Diesel fuel prices, which averaged \$3.92/gal in 2013, are projected to fall to an average of \$3.82/gal in 2014 and \$3.38/gal in 2015, \$0.04 and \$0.41 lower than in last month's STEO, respectively.

The February 2015 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged \$2.12/gal for the five trading days ending November 6, 2014. Based on the market value of futures and options contracts for this key petroleum component of gasoline, there is a 15% probability that the RBOB futures contract price at expiration will fall below \$1.85/gal, consistent with a monthly average regular-grade gasoline retail price less than \$2.50/gal in February 2015. There is also a 19% probability that the RBOB futures contract price at expiration may exceed \$2.35/gal, consistent with a retail price of \$3.00/gal or higher. 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 falling above or below the national average price by \$0.30/gal or more.

Lower projected crude oil prices also contribute to a reduction in the forecast residential heating oil price and average household heating oil expenditures this winter. The average household that uses heating oil as its primary space heating fuel is expected to pay an average of \$3.27/gal this winter, \$0.36/gal lower than projected in last month's STEO. The average household is now expected to spend \$1,779 for heating oil this winter, \$213 lower than in last month's STEO.

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## Natural Gas

Following a strong injection season, working gas in storage ended the summer refill season at an estimated 3,571 Bcf. Sustained cold weather early this year left Lower 48 working gas stocks at 857 Bcf at the end of March, the lowest level since 2003. Beginning in mid-April, weekly storage injections have exceeded the five-year average for 29 consecutive weeks because of strong domestic production growth and a mild summer (implying less demand from electric generators to meet air conditioning demand). In addition, natural gas prices declined over the summer, as strong injections and production eased concerns about supply for this winter. Based on a forecast for a close-to-normal winter, EIA projects that inventories will end the winter season on March 31 at 1,562 Bcf.

**Natural Gas Consumption.** EIA expects total natural gas consumption to average 73.2 Bcf/d in 2014, an increase of 2.2% from 2013, with the industrial sector leading the growth. In 2015, total projected natural gas consumption is expected to be flat as continued industrial sector growth and higher electric power sector consumption offset lower residential and commercial consumption. Higher natural gas prices this year contribute to a 1.7% decline in natural gas consumption in the power sector to 22.0 Bcf/d in 2014. EIA expects natural gas consumption in the power sector to increase to 22.7 Bcf/d in 2015.

**Natural Gas Production and Trade.** EIA expects natural gas marketed production to grow by an annual rate of 4.8% in 2014 and 2.3% in 2015. EIA projects that the strong increases already seen in the Lower 48 states for most of this year will continue, more than offsetting the long-term declining trend in the Gulf of Mexico. As of August, the most recent month for which EIA data are available, dry natural gas production was 3.4 Bcf/d greater than it was in August 2013. Production usually declines in September; however, preliminary data indicate that growth has continued, with new production offsetting maintenance declines.

Growing domestic production is expected to continue to put downward pressure on natural gas imports from Canada and spur exports to Mexico. Exports to Mexico, particularly from the Eagle Ford Shale in South Texas, are expected to increase because of growing demand from Mexico's electric power sector and flat Mexican production.

Liquefied natural gas (LNG) imports have fallen over the past four years because higher prices in Europe and Asia are more attractive to sellers than the relatively low prices in the United States. LNG exports are still a very small part of the total market, however, and overall the United States will remain a net importer of natural gas because of pipeline imports from Canada.

**Natural Gas Inventories.** Natural gas working inventories totaled 3,571 Bcf as of October 31, which was 238 Bcf lower than at the same time last year and 261 Bcf lower than the previous five-year (2009-13) average. The injection season began somewhat slowly in April, but has continued at a strong pace, with injections above the five-year average throughout most of the injection season. The deficit to the five-year average and to last year's level has narrowed over

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the injection season with substantial weekly stock builds. Heading into next summer, EIA projects that end-of-March 2015 inventories will total 1,562 Bcf, 94 Bcf below the five-year (2010-14) average.

**Natural Gas Prices.** The Henry Hub natural gas spot price averaged \$3.78/MMBtu in October, a decline of 14 cents from September. EIA expects spot prices to remain relatively low but to rise slightly with winter heating demand. Projected Henry Hub natural gas prices average \$4.44/MMBtu in 2014 and \$3.83/MMBtu in 2015.

Natural gas futures prices for February 2015 delivery (for the five-day period ending November 6) averaged \$4.19/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for February 2015 contracts at \$2.76/MMBtu and \$6.38/MMBtu, respectively. At this time last year, the natural gas futures contract for February 2014 averaged \$3.57/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$2.70/MMBtu and \$4.73/MMBtu.

## Coal

According to data compiled by the Association of American Railroads (AAR), [year-to-date rail traffic](#) was up 4.5% as of November 1. AAR data show that, despite the large increase in overall rail traffic, [coal shipments](#) were only up 0.3%. Shipments of petroleum and grain are up year-to-date by 13.4% and 15.0%, respectively.

On October 8, the U.S. Surface Transportation Board (STB) announced that it is requiring all major freight (Class I) railroads that operate in the United States to publicly file [weekly data reports](#) regarding service performance. The measure was in response to ongoing rail service problems, particularly in the Midwest. These data, for which no ending date for their submission has been determined, are in addition to the STB annual requests for service assessments from all Class I railroads.

Several utilities in Minnesota and other Midwest states have cut back or curtailed operation of coal-fired generating units to conserve coal inventories. As a result, the governor of Minnesota and members of the state's congressional delegation [requested](#) that the Federal Energy Regulatory Commission (FERC) act to "convene a meeting to hear from utility and railroad representatives to discuss railroad coal-delivery matters and their impact on electric markets and reliability." The letter asked FERC "to protect utility consumers in Minnesota and the other impacted states from the adverse consequences of BNSF's service failures." BNSF, in a [response](#) to a petition filed earlier, stated to the STB that it would deliver approximately 24 million tons of coal in October, its highest total since August 2013.

**Coal Supply.** EIA estimates that coal production for the first 10 months of this year, 823 million short tons (MMst), was slightly lower (by 2 MMst, or 0.3%) than production over the same

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period last year. EIA expects that annual production will grow by 0.8% to 992 MMst in 2014. In 2015, forecast U.S. coal production increases by 0.7% to 999 MMst.

Electric power sector coal inventories fell to 121 MMst at the end of August, 4 MMst lower than the previous month. This stock drawdown was 1 MMst less than the same time last year. Coal inventories are more than 33 MMst lower when compared with last year.

**Coal Consumption.** Higher electricity demand and higher power sector natural gas prices are contributing to an increase in electric power sector coal consumption this year. EIA projects total coal consumption of 936 MMst in 2014 (870 MMst in the electric power sector), an increase of 1.2% from last year. Total coal consumption is projected to fall by 1.2% in 2015, as retirements of coal power plants rise in response to the implementation of the [Mercury and Air Toxics Standards](#), electricity sales growth slows to 0.7%, and natural gas prices fall relative to coal prices.

**Coal Trade.** Exports of coal are projected to decline to 96 MMst in 2014 from 118 MMst in 2013, primarily because of slowing world coal demand growth, lower international coal prices, and increasing coal output in other coal-exporting countries. With no improvement in conditions in global markets, EIA projects coal exports to fall below 90 MMst in 2015, the lowest since 2010.

EIA expects coal imports, which account for about 1% of U.S. coal consumption, to total 11.4 MMst in 2014 and fall slightly to 10.7 MMst in 2015.

**Coal Prices.** The annual average coal price to the electric power industry fell from a historically high \$2.39/MMBtu in 2011 to \$2.35/MMBtu in 2013. EIA expects the average delivered coal price to be \$2.36/MMBtu in 2014 and remain at that level in 2015.

## Electricity

Nuclear plant outages during October 2014 averaged 9% more than in October 2013, as some plants on 18-month schedules refueled their units and performed other maintenance. The Vermont Yankee nuclear facility will only be operating for another month or two before beginning the process of retiring. The closure of this plant [will have a measureable impact](#) on the mix of fuels used for supplying electricity to the region. In recent years, the electricity industry in New England has been moving toward natural gas as a primary fuel for power generation, along with [increased imports of hydroelectricity](#) from Canada.

**Electricity Consumption.** Total U.S. electricity retail sales, which increased by 0.2% in 2013, grow by 0.9% and 0.7% in 2014 and 2015, respectively. U.S. residential electricity sales during 2014 are estimated to reach an average that is 1.5% higher than 2013, driven primarily by high consumption during the winter months earlier in the year. EIA expects relatively flat residential sales during 2015 as weather returns closer to normal levels.

**Electricity Generation.** EIA estimates that U.S. electricity generation in 2014 will average 11.2 terawatt-hours per day (TWh/d), which would be 0.1 TWh/d higher than average generation last year. Relative fuel costs have favored coal-fired generation over natural gas this year, leading to an expected increase in coal's share of total generation from 39.1% in 2013 to 39.6% this year, while the share supplied by natural gas falls from 27.4% to 27.0%. In 2015, EIA expects that natural gas's fuel share will rise to 27.6% and coal's fuel share will decline to 38.8%. Within the Northeast region, the share of total generation supplied by nuclear power falls from 35.1% in 2014 to 33.2% in 2015.

**Electricity Retail Prices.** EIA expects the U.S. residential price to average 12.5 cents per kilowatt-hour in 2014, which is 3.0% higher than the average last year. Prices increase in all regions of the country except along the Pacific Coast. Average U.S. residential electricity prices grow at a slower rate of 1.7% in 2015.

## Renewables and Carbon Dioxide Emissions

California's drought, which began in 2011, has [significantly limited hydropower](#), requiring generation from other sources to make up for the shortfall. While the drought's effect on hydropower generation is most noticeable in California, the western United States as a whole has experienced a decline. Conventional hydropower, which is seasonal and typically peaks in the late spring and early summer, contributed 40% of electric power generation in the western United States in May 2011. That monthly maximum has steadily declined each year since. In May 2014, the maximum monthly contribution to western generation by the electric power sector from hydropower was 30%.

**Electricity and Heat Generation from Renewables.** EIA projects that total renewables used for electricity and heat generation will grow by 1.8% in 2014. Conventional hydropower generation is projected to fall by 4.2%, while nonhydropower renewables rise by 5.1%. [Nonhydropower renewables generation surpasses hydropower](#) on an annual basis for the first time in 2014. In 2015, total renewables consumption for electric power and heat generation increases by 4.5% as a result of a 4.2% increase in hydropower and a 4.6% increase in nonhydropower renewables.

EIA projects that wind power capacity will increase by 7.6% in 2014 and 17.8% in 2015. Electricity generation from wind is projected to contribute 4.7% of total electricity generation in 2015.

EIA expects continued robust growth in utility-scale solar power generation to an average of more than 60 gigawatt-hours per day in 2015, although this remains a small share (0.6%) of total U.S. generation. While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity slightly more than doubled in 2013. EIA expects that utility-scale solar capacity will nearly double again between the end of 2013 and the end of 2015; about two-thirds of this new capacity is being built in California. However, customer-sited photovoltaic capacity growth, which the STEO does not forecast, is

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expected to exceed utility-scale solar growth between 2013 and 2015, according to [EIA's Annual Energy Outlook 2014](#).

**Liquid Biofuels.** Ethanol production in June matched the monthly average production record of 959,000 bbl/d set in December 2011, and then fell back to an estimated average of 911,000 bbl/d in October. EIA expects ethanol production to average 927,000 bbl/d in 2014 and 934,000 bbl/d in 2015. Biodiesel production averaged 89,000 bbl/d in 2013 and is forecast to average 80,000 bbl/d in 2014 and 84,000 bbl/d in 2015.

**Energy-Related Carbon Dioxide Emissions.** EIA estimates that [carbon dioxide emissions from fossil fuels increased by 2.5% in 2013](#) from the previous year. [Emissions are forecast to rise by 1.0% in 2014](#), primarily because of cold weather early in the year, and then to decline by 0.1% in 2015. The increase in total emissions in 2013 and 2014 reflects increases in emissions from coal of 4.2% and 1.2%, respectively. The price of natural gas to electric power generators was \$0.91/MMBtu above its 2012 level in 2013 and is expected to rise by \$0.83/MMBtu in 2014, contributing to an increase in coal use. Coal emissions are projected to decline by 1.0% in 2015.

## U.S. Economic Assumptions

**Recent Economic Indicators.** The U.S. Bureau of Economic Analysis (BEA) reported that third-quarter [real gross domestic product \(GDP\)](#) grew at an annualized rate of 3.5% from the second quarter of 2014. Third-quarter GDP rose primarily because of increased government expenditures and exports. Results from other economic data show mixed impacts on consumption and investment. The Census Bureau reported that [new home sales](#) in September rose by 0.2% over August 2014 levels, and by 17.0% over September 2013 levels. Census also reported that [new orders for durable goods](#) fell by 1.3% from August to September, and fell by 0.2% excluding transportation. [Real personal consumption expenditures](#) fell by 0.2% from August to September, according to BEA, although real personal disposable income was unchanged during this time.

EIA used the October 2014 version of the IHS macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the current STEO.

**Production and Income.** Real GDP growth reaches 2.3% in 2014 and accelerates to 2.7% in 2015, above the 2.2% forecast last month for 2014, but below the 2.9% forecast last month for 2015. The combination of increased investment spending and higher exports is behind the stronger 2014 forecast. The projection for real GDP growth in 2015 has been lowered because of reduced expectations for growth in exports, resulting from a stronger dollar and less demand from slower-growing economies. Real disposable income grows by 2.6% in 2014, just above the 2.5% forecast last month, and total industrial production grows at 4.0% in 2014, just below the 4.1% forecast last month. In 2015, these economic indicators grow at 2.7% and 2.9%, respectively.

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**Expenditures.** Private real fixed investment growth averages 5.5% and 6.9% in 2014 and 2015, respectively. Growth is led by industrial and transportation equipment in 2014 and by a broad array of equipment categories in 2015. Real consumption expenditures grow at the same rate as real GDP in 2014 and 2015, at 2.3% and 2.7%. Durable goods expenditures drive consumption spending in both years. Export growth is 3.1% and 3.6% over the same two years, while import growth is 3.3% in 2014 and 4.0% in 2015. Total government expenditures fall by 0.4% in 2014, but increase by 0.5% in 2015.

**U.S. Employment, Housing, and Prices.** Projected growth in nonfarm employment averages 1.8% in 2014 and 2015. This is accompanied by a gradually declining unemployment rate that reaches 5.6% at the end of 2015. The employment growth in 2015 is the same as projected last month, and the declines in the unemployment rate are slightly greater. Housing starts grow at an average of 7.2% and 19.6% in 2014 and 2015, respectively. Both consumer and producer price indexes increase at a moderate pace, and wages continue to show modest gains.

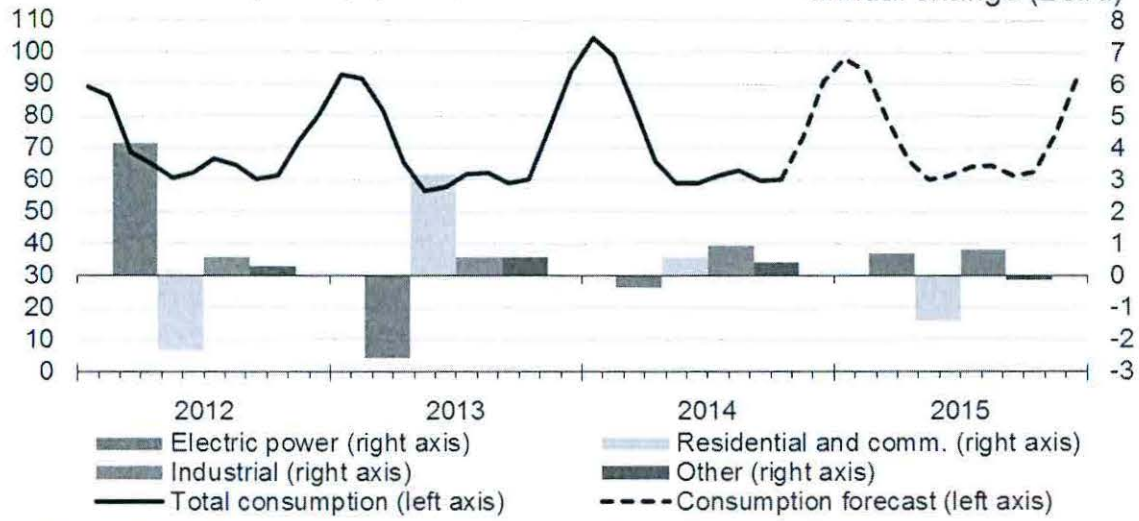
This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views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

# U.S. Natural Gas Consumption

billion cubic feet per day (Bcf/d)



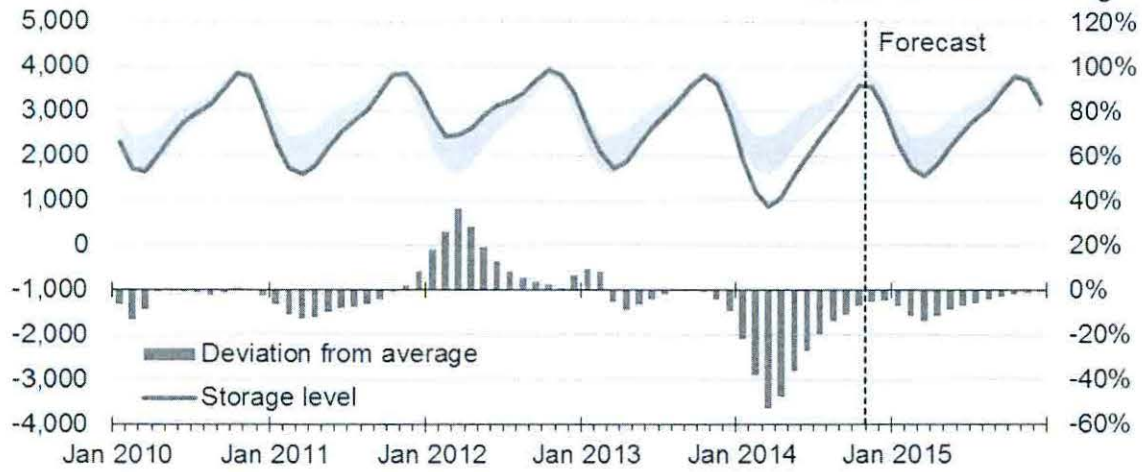
annual change (Bcf/d)



Source: Short-Term Energy Outlook, November 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, November 2014.

## Henry Hub Natural Gas Price

dollars per million Btu

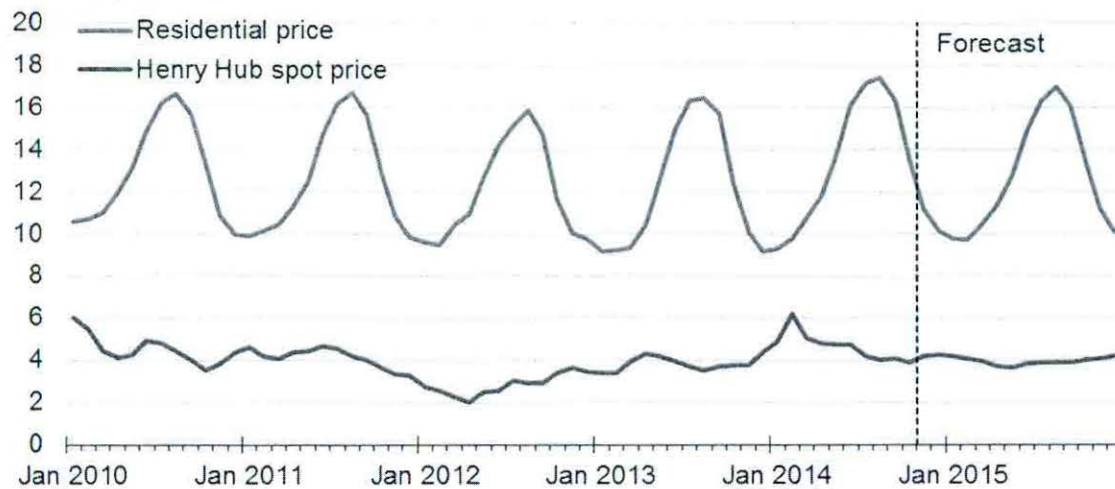


Note: Confidence interval derived from options market information for the 5 trading days ending Nov. 6, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, November 2014.

## U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, November 2014.

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

**NOVA Gas Transmission Ltd.**

On October 31, 2014, TransCanada filed new interim rates for the Alberta System with the National Energy Board (NEB) to be effective January 1, 2015.

Approximate impact on Montana-Dakota's cost of gas: 0.10 cents per dk

MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS TARIFF SHEET  
NORTH DAKOTA GAS  
EFFECTIVE JANUARY 2015

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<b><u>Gas Cost Adjustment:</u></b>				
Gas Cost Level (Exhibit B)	\$5.663	\$5.770	\$4.483	\$4.463
Prior Gas Cost	5.314	5.420	4.121	4.102
Current Gas Cost Adjustment	\$0.349	\$0.350	\$0.362	\$0.361
<b><u>Surcharge Adjustment:</u></b>				
Current Adjustment	\$0.209	\$0.209	\$0.380	\$0.365
Prior Adjustment	0.209	0.209	0.380	0.365
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
Gas Cost Level	\$5.663	\$5.770	\$4.483	\$4.463
Plus: Surcharge	0.209	0.209	0.380	0.365
<b>Total Gas Cost Level in Tariff Rates</b>	<b>\$5.872</b>	<b>\$5.979</b>	<b>\$4.863</b>	<b>\$4.828</b>
<b><u>Market Based Pricing Differential</u></b>				
Current Adjustment	(\$0.017)	(\$0.017)	\$0.000	\$0.000
Prior Adjustment	(0.017)	(0.017)	0.000	0.000
Change in Market Based Pricing	\$0.000	\$0.000	\$0.000	\$0.000
<b><u>Grain Drying Margin Sharing</u></b>				
Current Adjustment	(\$0.001)	(\$0.001)	\$0.000	\$0.000
Prior Adjustment	(0.001)	(0.001)	0.000	0.000
Change in Grain Drying Margin Sharing	\$0.000	\$0.000	\$0.000	\$0.000
<b>Total Cost of Gas Items</b>	<b>\$5.854</b>	<b>\$5.961</b>	<b>\$4.863</b>	<b>\$4.828</b>
<b>Net Increase (Decrease) in Gas Costs</b>	<b>\$0.349</b>	<b>\$0.350</b>	<b>\$0.362</b>	<b>\$0.361</b>

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
RESIDENTIAL AND GENERAL SERVICE  
EFFECTIVE JANUARY 2015**

	Amount
Total Gas Costs 1/	\$84,999,095
Residential and General Service dk Requirements 2/	15,074,844
Average Cost of Gas per dk	\$5.638
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.663
Less: Gas Cost Level in Rates 3/	5.314
<b>Current Gas Cost Adjustment</b>	<b>\$0.349</b>

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

2/ Normalized dk sales for the twelve months ended September 30, 2014, adjusted for losses at .45%.

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

Cost of Purchased Gas	\$5.290
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.314

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
OPTIONAL SEASONAL - RATE 72  
EFFECTIVE JANUARY 2015**

Total Gas Costs 1/	\$84,999,095
Less: Annual MDDQ Costs	<u>17,725,335</u>
Total Gas Costs excluding MDDQ	\$67,273,760
Firm Service Requirements 1/	15,074,844
Other Gas Costs per Dk (excluding MDDQ)	\$4.463
<u>Winter - October - May</u> Annual MDDQ Costs 1/	\$17,725,335
Winter Firm Service Requirements	13,833,021
MDDQ Costs per Winter Dk	\$1.281
Add: Other Gas Costs per Dk	<u>4.463</u>
Winter Seasonal Rate	\$5.744
Winter Seasonal Rate, adjusted for losses 2/	\$5.770
Less: Gas Cost Level in Rates 3/	<u>5.420</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.350</u></u></b>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

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

	<u>Winter</u>
Cost of Purchased Gas	\$5.396
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.420

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
INTERRUPTIBLE  
EFFECTIVE JANUARY 2015**

	Amount
Total Gas Costs 1/	\$31,211,064
Interruptible Service dk Requirements	6,993,666
Average Cost of Gas per dk	\$4.463
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.483
Less: Gas Cost Level in Rates 2/	4.121
<b>Current Gas Cost Adjustment</b>	<b>\$0.362</b>

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

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

Cost of Purchased Gas	\$4.102
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.121

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
AIR FORCE INTERRUPTIBLE  
EFFECTIVE JANUARY 2015**

	Amount
Total Gas Costs 1/	\$2,321,537
Air Force Interruptible dk Requirements	520,209
Average Cost of Gas per dk	\$4.463
Less: Gas Cost Level in Rates 2/	4.102
<b>Current Gas Cost Adjustment</b>	<b>\$0.361</b>

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

2/ Gas Cost Level in Current Tariff Rates Case No. PU-14-008 effective December 1, 2014:  
Cost of Purchased Gas \$4.102

**Montana-Dakota Utilities Co.  
Schedule of Applicable Effective Pipeline Rates  
January 2015 PGA**

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

Northern Border Pipeline Company - Exhibit B, page 9 for Schedule T-1.

Foothills Pipe Lines, Ltd. - Billed on a cost of service basis so there are no tariff sheets.

NOVA Gas Transmission - Exhibit B, pages 10-11 for Schedule FT-D.

NorthWestern Energy - Exhibit B, page 12 for Schedule T-FTG-1.

South Dakota Intrastate Pipeline - Exhibit B, page 13 for Rate 1.

SourceGas Distribution LLC - Exhibit B, Page 14 for Schedule TC.

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	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.	921.000	N.A.	N.A.	921.000
MINIMUM	RATE PER EQV. DKT PER MO	0.000	N.A.	N.A.	0.000
COMMODITY CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
MINIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
SCHEDULED OVERRUN CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	32.112	N.A.	N.A.	32.112
MINIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	30.279	N.A.	N.A.	30.279
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 3.867%, CONSISTING OF 3.582% 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 1.138 CENTS, CONSISTING OF 0.818 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."

Issued On: August 29, 2014  
 Docket Number: RP14-1219-000  
 FERC Order Date: September 23, 2014

Effective On: October 1, 2014

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.	24.274	N.A.	N.A.	24.274
MINIMUM	RATE PER EQV. DKT PER MO.	1.263	N.A.	N.A.	1.263
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	0.798	N.A.	N.A.	0.798
MINIMUM	RATE PER DKT	0.042	N.A.	N.A.	0.042

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.	1.757	N.A.	N.A.	1.757
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.	201.507	N.A.	N.A.	201.507
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	0.000
INJECTION CHARGE					
MAXIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
MINIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
WITHDRAWAL CHARGE					
MAXIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
MINIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
SCHEDULED OVERRUN CHARGE					
INJECTION					
MAXIMUM A/B/	RATE PER DKT	18.683	N.A.	N.A.	18.683
MINIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
WITHDRAWAL					
MAXIMUM A/B/	RATE PER DKT	18.683	N.A.	N.A.	18.683
MINIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 2.132%, CONSISTING OF 2.174% 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 0.661 CENTS, CONSISTING OF 0.801 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.

Issued On: August 29, 2014  
 Docket Number: RP14-1219-000  
 FERC Order Date: September 23, 2014

Effective On: October 1, 2014

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

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

STATEMENT OF RATES  
2/ 3/

Rate Schedule -----	Long-Term Base Tariff Rate (per 100 Dth-Miles) 1/ -----
T-1 and T-1B	
Daily Reservation Rate - Port of Morgan, MT to Ventura, IA	
Maximum	\$0.0286
Minimum	\$0.0000
Daily Reservation Rate - Ventura, IA to North Hayden, IN	
Maximum	\$0.0307
Minimum	\$0.0000
Commodity Rate - Port of Morgan, MT to North Hayden, IN	
Maximum	\$0.0004
Minimum	\$0.0004

- 1/ Applicable to any Rate Schedule T-1 U.S. Shippers Service Agreement or any Rate Schedule T-1B Service Agreement with a primary term of at least twelve consecutive months.
- 2/ The Settlement Rates, pursuant to Articles II and VII of the September 27, 2012, Stipulation at Docket Nos. RP06-72-000, et al., remain in effect until such rates are superseded by new rates placed into effect consistent with the provisions of the Stipulation.
- 3/ Rates in this section are subject to the revenue retrieval provision pursuant to Article V.A of the September 27, 2012, Stipulation at Docket Nos. RP06-72-000, et al.

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 <sup>3</sup> m <sup>3</sup>		
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D <sup>1</sup>	Refer to Attachment "2" for applicable FT-D Demand Rate per month based on a one year term (Price Point "Z") & Surcharge for each Group 1 or Group 2 Delivery Point Average FT-D Demand Rate for Group 1 Delivery Points \$ 5.23/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 <sup>1</sup>	Refer to Attachment "3" for applicable FT-P Demand Rate per month		
7. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10<sup>3</sup>m<sup>3</sup>/day)</u>	
	1-5 years	11.29	
	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 <sup>3</sup> m <sup>3</sup>	
9. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
10. Rate Schedule IT-D <sup>1</sup>	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 <sup>3</sup> m <sup>3</sup> /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 <sub>2</sub>	<u>Tier</u>	<u>CO<sub>2</sub> Rate (\$/10<sup>3</sup>m<sup>3</sup>)</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.

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 APG	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 <sup>1</sup>
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 <sup>2</sup>
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 <sup>2</sup>
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	
3268	BENBOW SOUTH SALES	4.19	0.1514	
3933	BIG EDDY INTERCONNECTION	4.19	0.1514	
3067	BIGSTONE SALES	4.19	0.1514	
3285	BILBO 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	
3265	BURNT TIMBER SALES	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	
3275	CARSON CREEK SALES	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 36<sup>th</sup> Revised Sheet No. 80.1  
35<sup>th</sup> Revised Sheet No. 80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT  
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge
5,001 to 10,000	\$ 120.40
10,001 to 30,000	\$ 173.05
>30,000	\$ 384.05

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

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

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	\$ 0.0074572
Minimum	\$ 0.0017935
GTAC Amortization	\$ (0.0009972) (I)
Balancing Penalty Rate	Higher of \$25.00/ Dekatherm Or 150% of Market Price

PLUS:

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

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

MINIMUM BILL: Per respective contracts.

(continued)

Staff Approved: June 17, 2014  
Docket No.: D2013.5.34, Interim Order No. 7282b  
Tariff Letter No. 243-G

Effective for bills rendered on or after  
July 1, 2014

PUBLIC SERVICE COMMISSION  
*Aleisha Salen* Secretary

**GAS RATE SCHEDULE**

**South Dakota Intrastate Pipeline Company**

1415 N. Airport Rd  
Pierre, SD 57501

Date Filed: January 24, 2001

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

Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is \$2.398 per dekatherm.

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

**STATE OF SOUTH DAKOTA  
GAS RATE SCHEDULE**

NG-00-001

**South Dakota Intrastate Pipeline Company**

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5  
Seventh Revised Sheet No. 12  
Cancels Sixth Revised Sheet No. 12

Statement of Firm and Interruptible Transportation Service Rates  
Applicable to Shippers Not Receiving  
Choice Gas Service  
Rate Schedule TC 1/  
Casper Division

<u>Division</u>	<u>Receipt Point</u>	<u>Delivery Point</u>	<u>Monthly Customer Charge</u>	<u>Maximum Demand Charge 6/</u>	<u>Minimum Demand Charge 6/</u>	<u>Maximum Transportation Charge 2/</u>	<u>Minimum Transportation Charge 2/</u>	<u>Fuel Reimbursement Quantity Percentage 3/</u>
TC (Casper) Firm								
Transportation	MLI	MLI	\$0.00	\$9.50	\$0.00	\$0.1040	\$0.0010	1.153%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.1040	\$0.0010	1.153%
	MLI	DSE	\$225.00	\$0.00	\$0.00	\$0.1978	\$0.0020	3.579%
Interruptible Transportation 4/								
	MLI	MLI	\$0.00	\$0.00	\$0.00	\$0.0844	\$0.0010	1.153%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.0844	\$0.0010	1.153%
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: February 28, 2014  
By: Michael Noone

Date Effective: June 1, 2014  
Title: President and CEO

**MONTANA-DAKOTA UTILITIES CO.  
RETURN ON CYCLE STORAGE BALANCES  
AND PREPAID DEMAND AND COMMODITY BALANCES  
NORTH DAKOTA GAS  
EFFECTIVE JANUARY 2015**

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2014	\$13,138,114	\$1,130,570	\$4,252,066
November	9,630,025	929,602	3,407,621
December	5,585,213	700,337	1,657,304
January 2015	2,052,424	515,036	(385,278)
February	(1,883,054)	308,615	(1,817,795)
March	(4,046,008)	195,165	(2,744,087)
April	(4,192,819)	187,465	(2,539,667)
May	(1,475,067)	400,017	(1,472,791)
June	2,028,198	673,941	(41,024)
July	5,536,395	948,239	1,376,333
August	9,122,958	1,228,686	2,789,348
September	10,937,709	1,370,611	3,980,929
October	11,606,508	1,422,732	4,101,518
13 month average	<u>\$4,464,661</u>	<u>\$770,078</u>	<u>\$966,498</u>
Rate of Return	7.881%	7.881%	7.881%
Return	\$351,860	\$60,690	\$76,170
Return Requirement	<u>\$491,157</u>	<u>\$84,716</u>	<u>\$106,325</u>

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

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

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

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2014</b>									<b><u>\$3,163,455</u></b>
August	\$226,615	\$0	\$49	\$226,664	277,347	\$0.024	\$6,656	\$220,008	3,383,463
September	(85,563)	0	35	(85,528)	328,455	0.024	7,883	(93,411)	3,290,052
October	9,216	0	34	9,250	599,658	0.209	56,897 2/	(47,647)	3,242,405
<b>Balance @ October 31, 2014</b>									<b><u>\$3,242,405</u></b>

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

2/ Reflects 369,900 dk @ \$0.024 and 229,758 dk @ \$0.209.

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

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2014</b>									<b><u>\$553,358</u></b>
August	\$27,773	\$0	\$9	\$27,782	37,258	\$0.116	\$4,323	\$23,459	576,817
September	(4,907)	0	6	(4,901)	40,083	0.116	4,649	(9,550)	567,267
October	13,995	0	6	14,001	81,768	0.380	14,393 2/	(392)	566,875
<b>Balance @ October 31, 2014</b>									<b><u>\$566,875</u></b>

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

2/ Reflects 63,180 dk @ \$0.116 and 18,588 dk @ \$0.380.

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

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2014</b>									<b><u>\$185,080</u></b>
August	\$16,626	\$0	\$3	\$16,629	4,035	\$0.181	\$731	\$15,898	200,978
September	(888)	0	2	(886)	3,604	0.181	652	(1,538)	199,440
October	2,549	0	2	2,551	9,112	0.365	1,649 2/	902	200,342
<b>Balance @ October 31, 2014</b>									<b><u>\$200,342</u></b>

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

2/ Reflects 9,112 dk @ \$0.181 and 0 dk @ \$0.365.