

January 8, 2015

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

Re: Cost of Gas Adjustment
(COG) Rate 88
Case No. PU-15-

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 (133rd Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered February 1, 2015.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.618 per dk since the last filing due to a decrease in the overall commodity price of gas. Attachment B explains the reasons for the decrease in the market price of gas. There has also been a change in pipeline rates as shown on Attachment C, increasing the cost of gas by \$0.003 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 \$0.011 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 February 2015.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.626 per dk for residential and firm general customers, a decrease of \$0.613 per dk for small and large interruptible customers and a decrease of \$0.610 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 February 2015. The average cost of

gas for firm customers, adjusted for losses, is \$5.037.

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 a decrease of approximately \$1,534,700 for natural gas customers during the month of February 2015. All of Montana-Dakota's retail natural customers in North Dakota may be affected by this proposal. There were 104,857 natural gas customers and 344 propane customers in North Dakota as of December 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 submitted a check on December 8, 2014 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
133rd Revised Sheet No. 3
Canceling 132nd 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	\$5.228	\$5.554
Air Force Rate 64	7				
Minot Air Force Base		\$2,000.00 per month			
PAR Site		\$175.00 per month			
Firm Service			\$0.329	\$5.228	\$5.557
Interruptible Service - PAR			\$0.260	\$4.250	\$4.510
Interruptible Service - MAFB			\$0.260	\$4.218	\$4.478
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	\$5.228	\$5.958
Small Interruptible Gas Rate 71	14	\$175.00 per month	(Maximum) \$0.929	\$4.250	(Maximum) \$5.179
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	\$5.334	\$6.064
Transportation Service	24				
Small Interruptible Rate 81		\$175.00 per month			
Maximum			\$0.485		
Minimum			\$0.102		
Fuel Charge				\$0.017	
Large Interruptible Rate 82		\$1,000.00 per month			
Maximum			\$0.297		
Minimum			\$0.061		
Fuel Charge				\$0.017	
Large Interruptible Gas Rate 85	27	\$1,000.00 per month	(Maximum) \$0.718	\$4.250	(Maximum) \$4.968
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: January 8, 2015

Effective Date: February 1, 2015

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.: PU-15-

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

February 2015

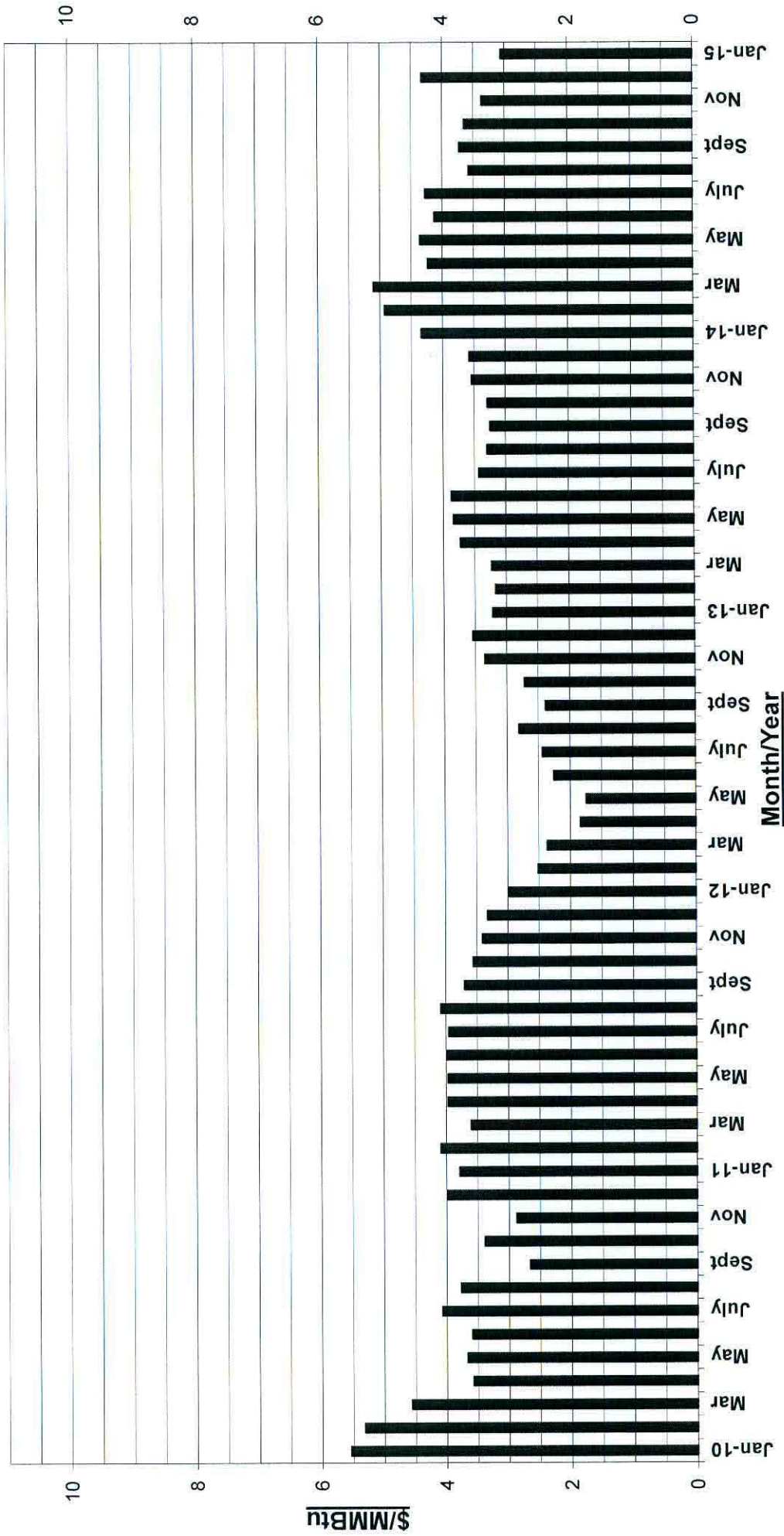
The established monthly price for the Rocky Mountain CIG Index has decreased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid 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.

December temperatures returning to normal for much of the country, domestic production levels reaching record highs during the past month and the national storage level continuing to rebound from the large deficits after the last heating season, were the contributing factors to the decrease in first of the month index price of natural gas. The EIA reported the national storage level as of December 26, 2014, was 2.5 percent below the five-year average and 7.8 percent above 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 December Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 19. The January Outlook will be published January 13, 2015.

CIG Rocky Mountains Index Monthly Gas Prices 2009-2015YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2013-\$3.45; 2014-\$4.17; 2015YTD-\$3.06



Independent Statistics & Analysis

U.S. Energy Information
Administration

December 2014

Short-Term Energy Outlook (STEO)

Highlights

- North Sea Brent crude oil spot prices fell by more than 15% in November, declining from \$85/barrel (bbl) on November 3 to \$72/bbl on November 28. Monthly average Brent crude oil prices have declined 29% from their 2014 high of \$112/bbl in June to an average of \$79/bbl in November, the lowest monthly average since September 2010. The November price decline reflects continued growth in U.S. tight oil production along with weakening outlooks for the global economy and oil demand growth. The Organization of the Petroleum Exporting Countries' (OPEC) decision in late November to maintain its current crude oil production target, despite lower oil prices, put additional downward pressure on price expectations.
- The current values of futures and options contracts suggest high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for March 2015 delivery, traded during the five-day period ending December 4, averaged \$67/bbl. Implied volatility averaged 32%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in March 2015 at \$51/bbl and \$89/bbl, respectively. Last year at this time, WTI for March 2014 delivery averaged \$96/bbl and implied volatility averaged 19%. The corresponding lower and upper limits of the 95% confidence interval were \$82/bbl and \$112/bbl.
- Total U.S. crude oil production averaged an estimated 9.0 million barrels per day (bbl/d) in November. Projected total crude oil production averages 9.3 million bbl/d in 2015, a reduction of 0.1 million bbl/d from last month's STEO.
- Driven largely by falling crude oil prices, U.S. weekly regular gasoline retail prices averaged \$2.78/gallon (gal) on December 1, the lowest since October 4, 2010. U.S. regular gasoline retail prices are projected to continue declining for the remainder of the year, averaging \$2.61/gal in December. EIA expects U.S. regular gasoline retail prices, which averaged \$3.51/gal in 2013, to average \$3.37/gal in 2014 and \$2.60/gal in 2015. Forecast retail gasoline prices for 2015 are \$0.35/gal lower than in last month's STEO.
- U.S. population-weighted heating degree days (HDD) were an estimated 18% higher than the previous 10-year average for November. Despite a cold start to the winter, lower fuel prices and the National Oceanic and Atmospheric Administration's (NOAA) projection of near-normal temperatures for the remainder of the winter are expected to help lessen

consumer expenditures on home heating compared with last winter. Lower crude oil prices are expected to help reduce household heating oil expenditures by 27% (\$632) compared with last winter, with U.S. heating oil prices averaging 20% lower at \$3.09/gal. Propane prices are expected to be 13% lower in the Northeast and 26% lower in the Midwest, resulting in households spending 20% and 34% less on propane in those regions, respectively.

- Natural gas working inventories on November 28 totaled 3.41 trillion cubic feet (Tcf), 0.23 Tcf (6%) below the level at the same time a year ago and 0.37 Tcf (10%) 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 \$3.98/million British thermal units (MMBtu) this winter compared with \$4.53/MMBtu last winter, reflecting both lower expected heating demand and higher natural gas production this winter.

Global Petroleum and Other Liquids

At the conclusion of its meeting in late November, OPEC announced that it would maintain its current crude oil production target of 30 million bbl/d. EIA expects that global liquid fuels supply will continue to outpace consumption, resulting in an average stock build of 0.4 million bbl/d in 2015. Stock builds are expected to be concentrated in the first half of the year, averaging 0.7 million bbl/d during this period. EIA forecasts global liquid fuels supply to average 92.8 million bbl/d in 2015, 0.2 million bbl/d lower than in last month's STEO. The 2015 global demand forecast was also revised downward by 0.2 million bbl/d to an average of 92.3 million bbl/d, based on weaker global economic growth prospects for next year.

Consistent with OPEC's announcement, Saudi Arabia has indicated its intention to maintain its export market share rather than cut production to keep prices higher. In the past, Saudi Arabia often played the role of the swing producer, temporarily cutting its production to accommodate supply growth elsewhere or weaker global demand, or increasing its output level to make up for a supply shortfall. 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 9.6 million bbl/d amid high non-OPEC supply growth, but maintain output above 9.0 million bbl/d through 2015.

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 1.0 million bbl/d in 2014 and 0.9 million bbl/d in 2015. Projected global oil-consumption-weighted real gross domestic product (GDP), which increased by an estimated 2.7% in 2013, is projected to grow by 2.7% and 2.9% in 2014 and 2015, respectively. Compared with last month's forecast, global consumption was revised downward by 0.2 million bbl/d in 2015, based on a 0.3% reduction to forecast global oil-consumption-weighted real GDP growth. In the short term, the income elasticity of global demand is greater than the price elasticity of

global demand. Thus, the negative impact of lower forecast economic growth on demand outweighs the positive impact of lower oil 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 0.9 million bbl/d in 2015. 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 0.2-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 decline by an additional 0.16 million bbl/d in 2014 and 0.14 million bbl/d in 2015. Japan is expected to use less fuel oil 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 forecasts that OECD Europe's consumption, which fell by 0.15 million bbl/d in 2013, declines by an additional 0.12 million bbl/d in 2014 and 0.14 million bbl/d in 2015. U.S. consumption, which increased by 0.47 million bbl/d in 2013, is expected to remain flat in 2014 and then increase by 0.14 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 54.1 million bbl/d for the year. EIA expects non-OPEC production to grow by 1.9 million bbl/d in 2014 and 0.8 million bbl/d in 2015, with the United States as the leading contributor. Non-OPEC supply is forecast to increase by 1.6 million bbl/d in 2014 and 1.0 million bbl/d in 2015. EIA estimates that Eurasia's production will rise by an annual average of 0.05 million bbl/d in 2014 and decline by 0.09 million bbl/d in 2015, reflecting declines in Russia and Azerbaijan.

Unplanned supply disruptions among non-OPEC producers averaged slightly lower than 0.6 million bbl/d in November, 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 0.1 million bbl/d in 2014 and by 0.2 million bbl/d in 2015. Previously projected OPEC crude oil production declines were reduced based on a reassessment of Saudi Arabia's willingness to cut production.

The Iraqi government in Baghdad reached a deal on oil exports and revenue with the Kurdistan Regional Government (KRG) in early December 2014, which could facilitate increased production and exports from northern fields controlled by the KRG and by Baghdad. Notwithstanding this agreement, the threat of the Islamic State of Iraq and the Levant (ISIL) on northern production and exports still looms. As a result, Iraq is a major wildcard to the 2015 world oil production

forecast. EIA projects that Iraq's production will grow by 0.2 million bbl/d next year. Actual production growth has the potential to exceed this forecast if Baghdad and KRG follow through on the deal, and if ISIL does not substantially affect production.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.7 million bbl/d in November 2014, an increase of nearly 0.6 million bbl/d because of new production outages in Libya and continued outages in the Neutral Zone shared by Kuwait and Saudi Arabia. Intermittent supply outages in 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 2.5 million bbl/d in 2015. The 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 2.64 billion barrels at the end of 2014 and 2.71 billion barrels at the end of 2015.

Crude Oil Prices. North Sea Brent crude oil spot prices averaged \$79/bbl in November, down \$8/bbl from the October average and the first month Brent crude oil prices have averaged below \$80/bbl since September 2010. The combination of robust world crude oil supply growth and weak global demand has contributed to rising global inventories and falling crude oil prices (EIA, *This Week in Petroleum*, November 13, 2014). On November 27, following OPEC's decision to leave its crude oil production target unchanged, Brent crude oil spot prices fell by more than 10%, and have since fallen to \$68/bbl as of December 4, the lowest daily price since May 25, 2010.

EIA expects global oil inventories to continue to build over the next year, keeping downward pressure on oil prices. The forecast Brent crude oil price averages \$68/bbl in 2015, \$15/bbl lower than projected in last month's STEO. Based on current market balances, EIA expects downward price pressures to be concentrated in the first half of 2015 when global inventory builds are expected to be particularly strong. EIA projects that Brent prices will reach a 2015 monthly average low of \$63/bbl for each month from March through May, and then increase through the remainder of the year to average \$73/bbl during the fourth quarter.

The monthly average WTI crude oil spot price fell from an average of \$84/bbl in October to \$76/bbl in November. Like Brent crude oil prices, WTI prices have decreased considerably, falling by more than 28% since reaching their 2014 peak at an average of \$106/bbl in June. EIA now expects WTI crude oil prices to average \$75/bbl in the fourth quarter of 2014 and \$63/bbl in 2015, \$5/bbl and \$15/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 \$5/bbl in 2015.

However, the current values of futures and options contracts suggest high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for March 2015 delivery, traded during the five-day period ending December 4, averaged \$67/bbl. Implied volatility averaged 32%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in March 2015 at \$51/bbl and \$89/bbl, respectively. Last year at this time, WTI for March 2014 delivery averaged \$96/bbl and implied volatility averaged 19%. The corresponding lower and upper limits of the 95% confidence interval were \$82/bbl and \$112/bbl.

The recent declines in oil price and associated increases in oil price volatility have created a particularly uncertain forecasting environment, and several factors could cause oil prices to deviate significantly from current projections. Among these is the responsiveness of supply to the lower price environment. Despite OPEC's recent decision to leave its crude oil production target at 30 million bbl/d, if crude oil prices continue to fall, Saudi Arabia and others could choose to cut production, tightening market balances. The level of crude oil production outages could also vary from forecast levels for a wide range of producers, including OPEC members Libya, Iraq, Iran, Nigeria, and Venezuela. Additionally, the price and lag time required to cause a reduction in forecast non-OPEC supply growth, particularly U.S. tight oil, is not known. The degree to which non-OPEC supply growth is affected by lower oil prices will also affect market balances and prices.

Several OPEC and non-OPEC oil producers rely heavily on oil revenues to finance their fiscal budgets. Some producers have already started adjusting their upcoming budgets to reflect the crude oil price decline. If crude oil prices continue to fall or are sustained at a lower level, then oil-dependent producers will have to make tough policy decisions. This could potentially lead to austerity programs and fuel subsidy cuts that could spark social unrest, leaving some countries vulnerable to supply disruptions if protestors target oil infrastructure. Potential new supply disruptions are a real possibility in a lower-than-expected price climate and present an uncertainty in the world oil supply forecast.

U.S. Petroleum and Other Liquids

U.S. weekly regular gasoline retail prices averaged \$2.78/gal on December 1, which marked a decrease of \$0.21/gal since the beginning of November and the lowest weekly price average since October 4, 2010. U.S. average regular gasoline retail prices have fallen for nine consecutive weeks and are down by 25% since their summer peak in late June. [Falling Brent crude oil prices have been largely responsible](#) for falling retail gasoline prices. EIA expects that the current low crude oil prices will contribute to further declines in gasoline prices, with the December price expected to average \$2.61/gal.

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 remain unchanged, with declines in the consumption of HGL, residual fuel oil, and other oils offsetting increases in distillate fuel and jet fuel. Total consumption is forecast to grow by 140,000 bbl/d in 2015, with HGL and distillate consumption accounting for most 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 during the forecast period, as modest increases projected for 2014 are offset by small declines in 2015. This projection shows that continued improvements in new-vehicle fuel economy offset highway travel growth.

Distillate fuel consumption increases by 120,000 bbl/d (3.1%) in 2014, reflecting colder-than-average first-quarter weather and economic growth. Distillate consumption rises by an additional 90,000 bbl/d (2.2%) 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.

Residual fuel oil consumption, which falls to an estimated 240,000 bbl/d in 2014, is projected to decline further to 210,000 bbl/d in 2015, which would be the lowest level on record.

Liquid Fuels Supply. Forecast U.S. crude oil production increases from an average of 7.4 million bbl/d in 2013 to 8.6 million bbl/d in 2014 and 9.3 million bbl/d in 2015. Recent onshore Lower 48 states oil production has been higher than expected, causing an upward revision of 155,000 bbl/d from the previous forecast in the fourth quarter of 2014. However, given the reduction in the 2015 crude oil price forecast, with WTI crude oil prices expected to average \$58/bbl in the second quarter of 2015, EIA expects 2015 drilling activity to decline due to unattractive economic returns in some areas of both emerging and mature oil production regions. Many companies will redirect investment away from marginal exploration and research drilling and into core areas of major tight oil plays. Oil prices remain high enough to support development drilling activity in the Bakken, Eagle Ford, Niobrara, and Permian Basin, which contribute the majority of U.S. oil production growth. The Gulf of Mexico oil production forecast has been revised downward this month by 95,000 bbl/d in 2015, as some projects which started producing in 2014 are ramping up production slower than initially expected, while other projects' start dates have been pushed back into late 2014 and early 2015.

HGL production at natural gas liquids plants, which reached a record high of 3.1 million bbl/d in September, is projected to increase to 3.3 million bbl/d by the end of 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. U.S. average regular gasoline retail prices fell from a monthly average of \$3.69/gal in June to \$2.91/gal in November, the first month in which prices have averaged below \$3.00/gal since December 2010. EIA expects that U.S. regular gasoline retail prices will fall to an average of \$2.61/gal in December 2014. The U.S. regular gasoline retail price, which averaged \$3.51/gal in 2013, is projected to average \$3.37/gal in 2014 and \$2.60/gal in 2015. Forecast retail gasoline prices for 2015 are \$0.35/gal lower than in last month's STEO. Diesel fuel prices, which averaged \$3.92/gal in 2013, are projected to fall to an average of \$3.82/gal in 2014 and \$3.07/gal in 2015. Forecast diesel fuel prices for 2015 are \$0.31/gal lower than in last month's STEO.

The February 2015 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged \$1.85/gal for the five trading days ending December 4, 2014. An RBOB futures contract price of \$1.85/gal is consistent with a monthly average regular-grade gasoline retail price less than \$2.50/gal in March 2015. There is a 4% 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 compared to last winter. The average household that uses heating oil as its primary space heating fuel is expected to pay an average of \$3.09/gal this winter, \$0.79/gal lower than last winter. The average household is now expected to spend \$1,722 for heating oil this winter, \$57 lower than in last month's STEO.

Natural Gas

After a record injection season, the 162-Bcf storage withdrawal for the week ending November 21 tied the record set last year for the largest November withdrawal. The large withdrawal reflected unseasonably cold weather east of the Rocky Mountains. As a result, this month's STEO revises downward end-of-March 2015 inventories to 1,431 Bcf, based on NOAA expectations that temperatures for the rest of the winter will be close to normal. EIA expects

the Henry Hub natural gas spot price to average \$3.98/MMBtu this winter, close to last month's forecast.

Natural Gas Consumption. EIA expects total natural gas consumption to average 73.9 Bcf/d in 2014, an increase of 3.2% from 2013 and 1% higher than in last month's STEO. This upward revision largely reflects colder-than-forecast temperatures in November. In 2015, total natural gas consumption is expected to decline as lower residential and commercial consumption offset increases in the electric power and industrial sectors. Natural gas consumption in the power sector is expected to average 22.1 Bcf/d in 2014, a 0.8% decline compared to last year, reflecting higher natural gas prices this year. 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 5.5% in 2014 and 3.1% in 2015. EIA projects that the strong increases already seen in the Lower 48 states for most of this year will continue through 2015, more than offsetting the long-term trend of declining production in the Gulf of Mexico. As of September, the most recent month for which EIA data are available, dry natural gas production was 4.6 Bcf/d greater than it was in September 2013. Production usually declines in September due to seasonal maintenance; however, production this year increased slightly from August to September.

Growing domestic natural gas production is expected to reduce demand for imports from Canada and spur exports to Mexico. EIA expects exports to Mexico, particularly from the Eagle Ford Shale in South Texas, 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 LNG exporters than the relatively low prices in the United States. EIA projects that the United States will become a net LNG exporter when Cheniere's LNG liquefaction plant begins service.

Natural Gas Inventories. Natural gas working inventories totaled 3,410 Bcf as of November 28, which was 227 Bcf lower than at the same time last year and 372 Bcf lower than the previous five-year (2009-13) average. Following last year's extremely cold winter, inventories fell to about 1,000 Bcf below the five-year average in mid-April. After a strong injection season, inventories were 237 Bcf below the five-year average on November 7. EIA projects that end-of-March 2015 inventories will total 1,431 Bcf, which is 225 Bcf below the five-year (2010-14) average.

Natural Gas Prices. The Henry Hub natural gas spot price averaged \$4.12/MMBtu in November, an increase of 34 cents from October. EIA expects spot prices to remain above \$4/MMBtu through January. Projected Henry Hub natural gas prices average \$4.44/MMBtu in 2014 and \$3.83/MMBtu in 2015.

Natural gas futures prices for March 2015 delivery (for the five-day period ending December 4) averaged \$3.84/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for March 2015 contracts at \$2.40/MMBtu and \$6.13/MMBtu, respectively. At this time last year, the natural gas futures contract for March 2014 averaged \$3.98/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$3.01/MMBtu and \$5.26/MMBtu.

Coal

Total [electric power sector coal stocks increased](#) by 3.1 million short tons (MMst) in September compared with the previous month. This increase in stocks follows the typical seasonal pattern where coal plants build stocks during the autumn months in preparation for increased coal consumption in the winter. Despite the increase, end-of-September stocks are 28 MMst (18%) lower than last year and 23% lower than the previous four-year average for the month. The large year-over-year decrease in stocks reflects increased coal-fired electricity generation during the winter of 2013-14 across a large portion of the country and subsequent decreased coal deliveries because of lingering rail transportation issues.

Coal Supply. EIA estimates that coal production for the first 11 months of this year was 909 MMst, almost unchanged from the same period last year. EIA expects that annual production will grow by 1.2% in 2014 and remain flat in 2015.

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 electric power coal consumption of 868 MMst in 2014, an increase of 1.2% from last year. Power sector coal consumption is projected to fall by 0.4% in 2015, as retirements of coal power plants rise in response to the implementation of the [Mercury and Air Toxics Standards](#), and electricity 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 global market conditions, EIA projects coal exports to fall to 83 MMst in 2015, which would be the lowest since 2010.

EIA expects coal imports, which account for about 1% of U.S. coal consumption, to total 12.2 MMst in 2014 and fall to 10.8 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

The electricity industry has closed a number of coal-fired power plants over the past two years. During 2013, an estimated 5,700 megawatts (MW) of coal capacity was retired in the United States. From January through September of 2014, the industry shut down an additional 2,265 MW of coal capacity, with another 895 MW of retirements planned through the end of the year. These retirements account for 2.9% of existing coal-fired capacity at the end of 2012. Coal-fired power plant retirements pick up significantly next year, when more than 12,800 MW of capacity is expected to be shut down.

Electricity Consumption. Temperatures throughout the United States were significantly below normal last month, with the exception of the Pacific Coast. U.S. HDD in November were 18% higher than the previous 10-year average. However, HDD for the remainder of the winter are expected to be about 1% lower than the 10-year average and 10% lower than the same period last winter. EIA forecasts that U.S. residential electricity sales during the 2014-15 winter (October-March) will average about 1.8% less than the previous winter. EIA forecasts that sales of electricity to the commercial sector this winter will grow by 0.8%, while industrial electricity sales will grow by 1.2% from last winter.

Electricity Generation. EIA estimates that U.S. electricity generation in 2014 will average 11.2 terawatt-hours per day, which would be 1.1% higher than average generation last year. Rising natural gas prices this year have encouraged the industry to use existing coal capacity at higher utilization rates than last year, leading to an expected increase in coal's share of total generation from 39.1% in 2013 to 39.4% in 2014, while the share supplied by natural gas falls from 27.4% to 27.1%. In 2015, EIA expects that natural gas's fuel share will rise to 27.6% and coal's fuel share will decline to 38.9% in response to lower natural gas prices and retirements of coal-fired power plants.

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

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 4.4%, 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 4.3% as a result of similar increases in both hydropower and nonhydropower renewables. Electricity generation from wind is projected to contribute 4.7% of total electricity generation in 2015.

EIA expects continued growth in utility-scale solar power generation, which is projected to average more than 60 gigawatthours per day in 2015. Despite the growth, this remains just 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, with about two-thirds of this new capacity being built in California.

Liquid Biofuels. Ethanol production reached a weekly record of 982,000 bbl/d during the week ending November 21, exceeding the previous record of 972,000 bbl/d set during the week ending June 13, 2014. Ethanol production in November also reached a monthly average record of 963,000 bbl/d, exceeding the previous record of 959,000 bbl/d set in December 2011. EIA expects ethanol production to average 931,000 bbl/d in 2014 and 948,000 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 1.3% in 2014, primarily because of cold weather early in the year, and then to remain flat in 2015.

U.S. Economic Assumptions

Recent Economic Indicators. The Bureau of Economic Analysis (BEA) reported that [real gross domestic product \(GDP\)](#) grew at an annualized rate of 3.9% from the second to third quarters. This was an upward revision from their earlier estimate of 3.5% growth because private inventory investment decreased less than previously estimated, and both personal consumption expenditures and nonresidential fixed investment increased more. Results from other economic data have been relatively positive as well. The Census Bureau reported that [new home sales](#) in October rose 0.7% over September 2014 levels, and 1.8% over October 2013 levels. Census also reported that [new orders for durable goods](#) rose 0.4% from August to September, but fell 0.9% excluding transportation. Real personal consumption expenditures rose 0.2% from September to October according to the BEA, and [real personal disposable income](#) rose 0.1% during this time.

EIA used the November 2014 version of 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. Real GDP growth reaches 2.2% in 2014 and rises to 2.4% in 2015, below the 2.3% and 2.7% forecast for 2014 and 2015 last month. Expected growth in 2014 is lower in this month's forecast because of less investment spending. Real GDP growth is lower in 2015 as a result of reduced exports—due to a stronger dollar and less demand from slower-growing economies. Real disposable income grows 2.7% in 2014, just above the 2.6% forecast

last month, and total industrial production grows at 4% in 2014. In 2015 real disposable income grows at 2.4% and industrial production grows at 2.3%.

Expenditures. Private real fixed investment growth averages 4.9% and 5.3% in 2014 and 2015, respectively, led by industrial and transportation equipment in 2014 and by a broad array of equipment categories in 2015. Real consumption expenditures grow at 2.2% in 2014, the same rate as real GDP, but rise above the real GDP growth rate in 2015 to 2.5%. Durable goods expenditures drive consumption spending in both years. Export growth is 3.2% and 2.9% over 2014 and 2015, respectively, while import growth is 3.4% and 2.6% over the same two years. Total government expenditures fall by 0.2% in 2014, but increase by 0.2% in 2015.

U.S. Employment, Housing, and Prices. Projected growth in nonfarm employment averages 1.8% in both 2014 and 2015. This is accompanied by a gradually declining unemployment rate that reaches 5.7% at the end of 2015. The employment growth in 2014 and 2015 is the same as projected last month, while the decline in the unemployment rate has slowed. Housing starts grow at an average of 7.4% and 16.6% in 2014 and 2015, respectively. Both consumer and producer price indexes increase at a moderate pace, and wages continue to show modest gains.

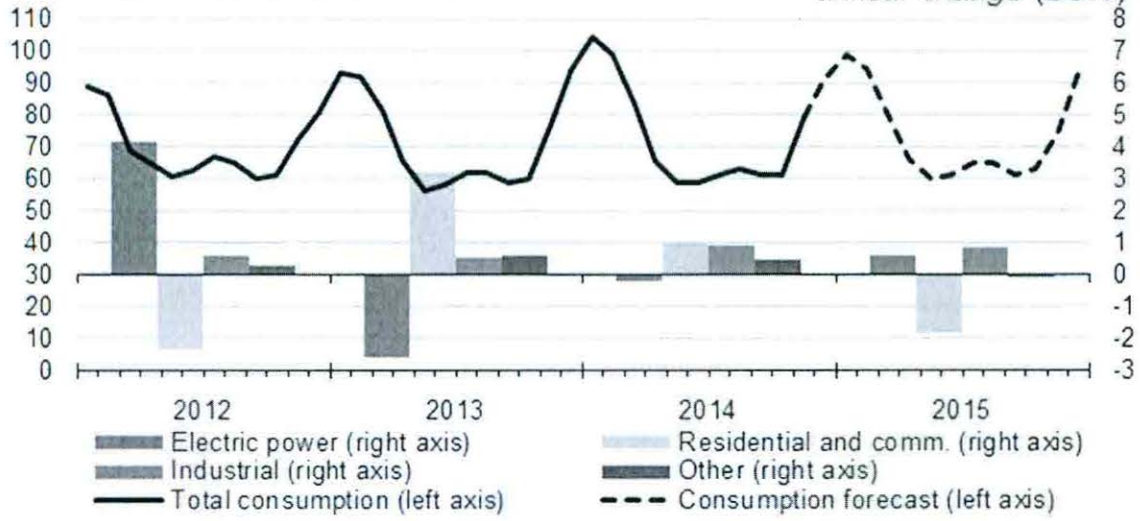
This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views 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)

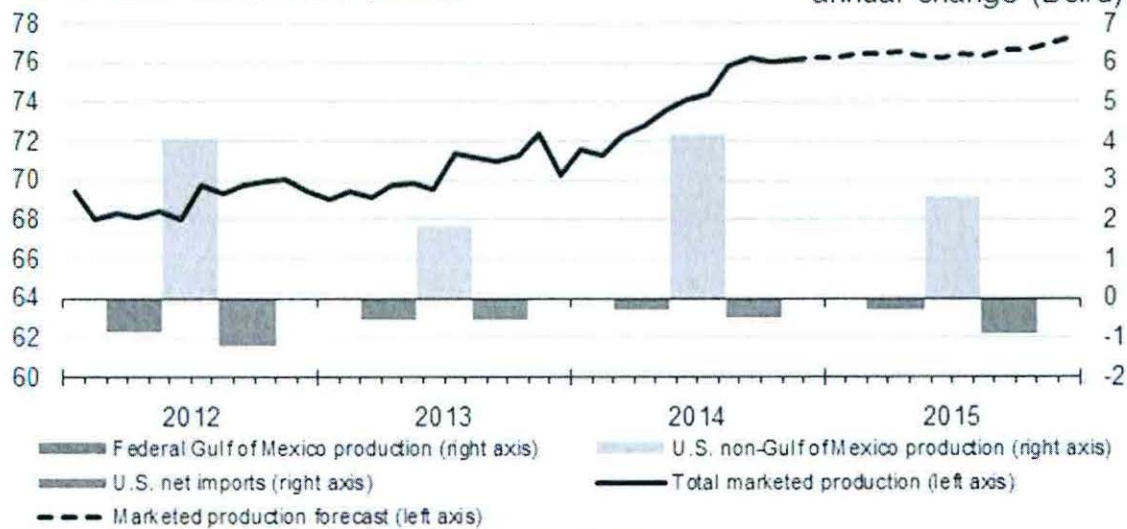


Source: Short-Term Energy Outlook, December 2014.

U.S. Natural Gas Production and Imports

billion cubic feet per day (Bcf/d)

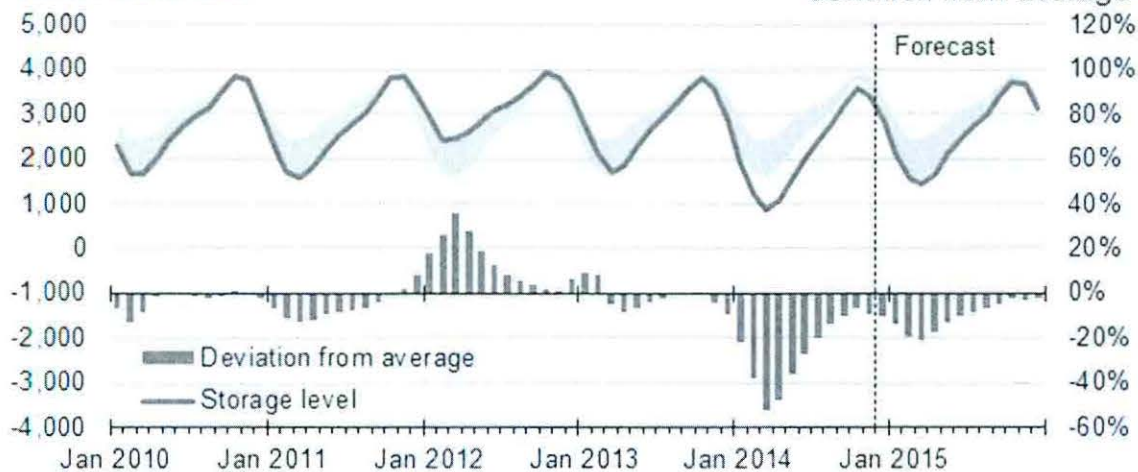
eia
annual change (Bcf/d)



Source: Short-Term Energy Outlook, December 2014.

U.S. Working Natural Gas in Storage

billion cubic feet

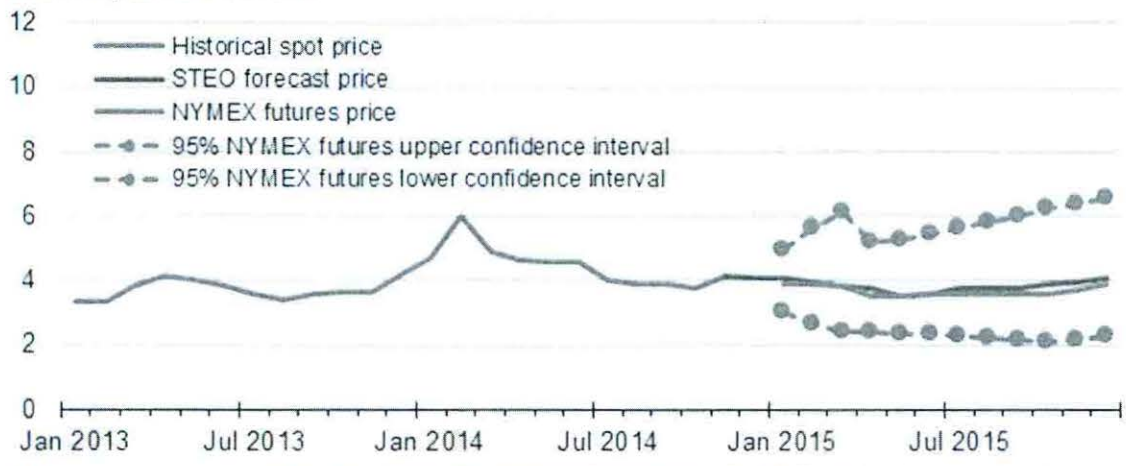


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2009 - Dec. 2013.

Source: Short-Term Energy Outlook, December 2014.

Henry Hub Natural Gas Price

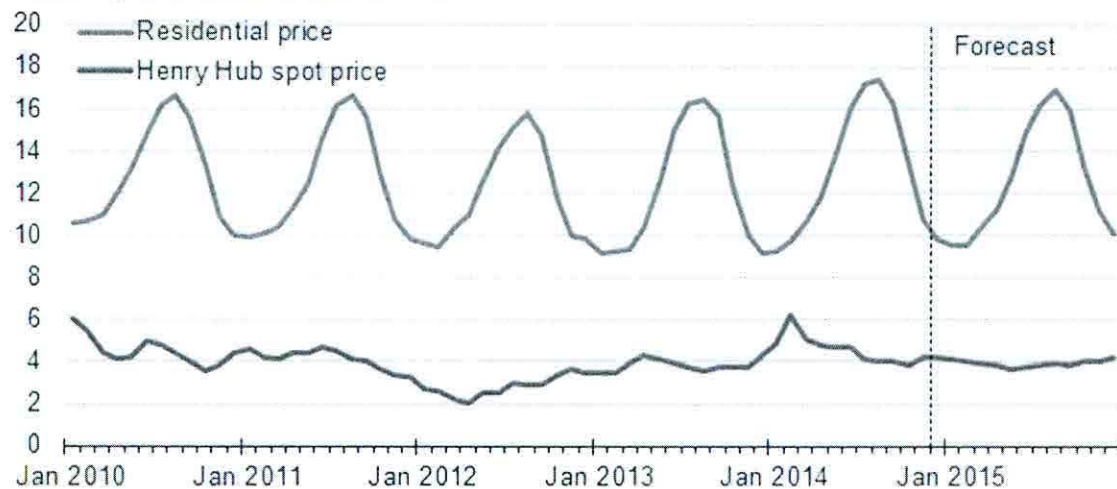
dollars per million Btu



Note: Confidence interval derived from options market information for the 5 trading days ending Dec. 4, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.
Source: Short-Term Energy Outlook, December 2014.

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, December 2014.

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

Foothills Pipe Lines Ltd.

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

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

NorthWestern Energy

On December 11, 2014, NorthWestern Energy filed its 2015 Electric and Natural Gas Tax Tracker filing in Docket No. D2014.12.96 with the Montana Public Service Commission to be effective January 1, 2015.

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

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

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$5.037	\$5.143	\$3.870	\$3.853
Prior Gas Cost	5.663	5.770	4.483	4.463
Current Gas Cost Adjustment	(\$0.626)	(\$0.627)	(\$0.613)	(\$0.610)
<u>Surcharge Adjustment:</u>				
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	\$5.037	\$5.143	\$3.870	\$3.853
Plus: Surcharge	0.209	0.209	0.380	0.365
Total Gas Cost Level in Tariff Rates	<u>\$5.246</u>	<u>\$5.352</u>	<u>\$4.250</u>	<u>\$4.218</u>
<u>Market Based Pricing Differential</u>				
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
<u>Grain Drying Margin Sharing</u>				
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
Total Cost of Gas Items	<u>\$5.228</u>	<u>\$5.334</u>	<u>\$4.250</u>	<u>\$4.218</u>
Net Increase (Decrease) in Gas Costs	<u>(\$0.626)</u>	<u>(\$0.627)</u>	<u>(\$0.613)</u>	<u>(\$0.610)</u>

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

	Amount
Total Gas Costs 1/	\$75,925,526
Residential and General Service dk Requirements 2/	15,141,368
Average Cost of Gas per dk	\$5.014
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.037
Less: Gas Cost Level in Rates 3/	5.663
Current Gas Cost Adjustment	(\$0.626)

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 October 31, 2014, adjusted for losses at .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-14-008 effective January 1, 2015:

Cost of Purchased Gas	\$5.638
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.663

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

Total Gas Costs 1/	\$75,925,526 ✓
Less: Annual MDDQ Costs	<u>17,724,248</u> ✓
Total Gas Costs excluding MDDQ	\$58,201,278 ✓
Firm Service Requirements 1/	15,141,368 ✓
Other Gas Costs per Dk (excluding MDDQ)	\$3.844 ✓
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$17,724,248 ✓
Winter Firm Service Requirements	13,894,064 ✓
MDDQ Costs per Winter Dk	\$1.276 ✓
Add: Other Gas Costs per Dk	<u>3.844</u> ✓
Winter Seasonal Rate	\$5.120 ✓
Winter Seasonal Rate, adjusted for losses 2/	\$5.143 ✓
Less: Gas Cost Level in Rates 3/	<u>5.770</u> ✓
Current Gas Cost Adjustment	<u><u>(\$0.627)</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 January 1, 2015:

	<u>Winter</u>
Cost of Purchased Gas	\$5.744 ✓
Adjustment for Distribution Losses	0.9955 ✓
Gas Cost Level in Base Tariff Rates	\$5.770 ✓

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

	Amount
Total Gas Costs 1/	\$26,945,600
Interruptible Service dk Requirements	6,993,666
Average Cost of Gas per dk	\$3.853
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.870
Less: Gas Cost Level in Rates 2/	4.483
Current Gas Cost Adjustment	(\$0.613)

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 January 1, 2015:

Cost of Purchased Gas	\$4.463
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.483

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

	Amount
Total Gas Costs 1/	\$2,004,260
Air Force Interruptible dk Requirements	520,209
Average Cost of Gas per dk	\$3.853
Less: Gas Cost Level in Rates 2/	4.463
Current Gas Cost Adjustment	(\$0.610)

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 January 1, 2015:
Cost of Purchased Gas \$4.463

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

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 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.

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	
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



	<u>36th</u>	Revised	Sheet No.	<u>80.1</u>
Canceling	<u>35th</u>	Revised	Sheet No.	<u>80.1</u>

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge
5,001 to 10,000	\$ 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 Salem Secretary

GAS RATE SCHEDULE

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

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

Date Filed: January 24, 2001

Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is \$2.398 per dekatherm.

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

NG-00-001

STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5
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

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	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 FEBRUARY 2015**

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2014	\$13,138,114	\$1,130,570	\$4,252,066
November	9,055,168	929,233	3,379,652
December	4,760,563	670,776	1,635,610
January 2015	1,309,193	485,127	(402,406)
February	(2,535,586)	278,317	(1,830,790)
March	(4,648,691)	164,653	(2,753,310)
April	(4,792,119)	156,938	(2,545,922)
May	(2,137,003)	364,281	(1,476,691)
June	1,285,525	634,673	(42,830)
July	4,712,869	905,426	1,375,945
August	8,227,442	1,182,250	2,790,375
September	10,011,714	1,322,698	3,983,155
October	10,660,619	1,373,749	4,103,903
13 month average	<u>\$3,772,908</u>	<u>\$738,361</u>	<u>\$959,135</u>
Rate of Return	7.881%	7.881%	7.881%
Return	\$297,343	\$58,190	\$75,589
Return Requirement	<u>\$415,058</u>	<u>\$81,227</u>	<u>\$105,514</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 & 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, 2014									<u>\$3,163,455</u>
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
November	(234,355)	0	33	(234,322)	918,828	0.209	192,034	(426,356)	2,816,049
Balance @ November 30, 2014									<u>\$2,816,049</u>

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 & 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, 2014									<u>\$553,358</u>
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
November	(11,543)	0	6	(11,537)	101,794	0.380	38,681	(50,218)	516,657
Balance @ November 30, 2014									<u>\$516,657</u>

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**

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2014									<u>\$185,080</u>
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
November	(4,099)	0	2	(4,097)	26,445	0.365	9,652	(13,749)	186,593
Balance @ November 30, 2014									<u>\$186,593</u>

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

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