



**MONTANA-DAKOTA**

UTILITIES CO.

A Division of MDU Resources Group, Inc.

400 North Fourth Street  
Bismarck, ND 58501  
(701) 222-7900

January 9, 2014

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

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

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 (121<sup>st</sup> Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered February 1, 2014.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.626 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 \$0.002 per dk. In addition, Montana-Dakota has increased its firm transportation capacity to meet increasing capacity requirements, resulting in a system wide change in demand allocation and an increase of approximately \$0.045 per dk.

The COG tariff sheet, Exhibit A page 1, summarizes the gas cost adjustment, calculated pursuant to the terms of Rate 88, and the surcharge adjustment and the market based pricing differential provision that will apply during the month of February 2014.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.673 per dk for residential and firm general customers, an increase of \$0.623 per dk for small and large interruptible customers and an increase of \$0.620 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

gas for firm customers, adjusted for losses, is \$5.503.

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

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

Exhibit A, page 2 summarizes the cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of February 2014. The net effect of this filing is an increase of \$3.292 per dk for all customers from the currently effective rates.

Exhibit D shows the calculation of the current cost of gas – propane that will be applicable to Montana-Dakota's customers for the month of February 2014. The average cost of propane for all customers, adjusted for losses, is \$19.211 per dk.

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

These proposed adjustments, calculated in accordance with Rate 88 and Rate 99, will amount to an increase of approximately \$1,633,000 for natural gas customers and an increase of approximately \$25,000 for propane customers during the month of February 2014. All of Montana-Dakota's retail natural gas and propane customers in North Dakota may be affected by this proposal. There were 101,420 natural gas and 343 propane customers in North Dakota as of December 31, 2013.

Please refer all inquiries regarding this filing to:

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

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

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

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

Montana-Dakota respectfully requests that this filing be accepted as being in full compliance with the filing requirements of this Commission.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed stamped envelope.

Sincerely,



Rita A. Mulkern  
Director of Regulatory Affairs

Attachment

**Attachment A**

**Rate Summary Sheet  
(Proposed)**



# Montana-Dakota Utilities Co.

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

## State of North Dakota Gas Rate Schedule

NDPSC Volume 7  
 121<sup>st</sup> Revised Sheet No. 3  
 Canceling 120<sup>th</sup> Revised Sheet No. 3

### RATE SUMMARY SHEET

Page 1 of 2

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60 <sup>1</sup>	4	\$0.30 per day	\$0.812	\$5.515	\$6.327
Air Force Rate 64 <sup>1</sup>	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$5.515	\$5.653
Interruptible Service - PAR			\$0.120	\$4.586	\$4.706
Interruptible Service - MAFB			\$0.120	\$4.631	\$4.751
Firm General Service Rate 70 <sup>1</sup>	13				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$5.515	\$6.112
Small Interruptible Gas Rate 71 <sup>2</sup>	14	\$100.00 per month	(Maximum) \$0.871	\$4.586	(Maximum) \$5.457
Optional Seasonal Gas <sup>1</sup>					
Service Rate 72	15				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$5.607	\$6.204
Transportation Service <sup>1</sup>	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.020	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.020	
Large Interruptible Gas Rate 85 <sup>3</sup>	27	\$675.00 per month	(Maximum) \$0.719	\$4.586	(Maximum) \$5.305
Residential Propane Rate 90 <sup>1</sup>	32	\$0.30 per day	\$0.812	\$18.422	\$19.234
Firm General Propane Rate 92 <sup>1</sup>	34				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$18.422	\$19.019

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

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

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

Date Filed: January 9, 2014

Effective Date:

Issued By: Tamie A. Aberle  
 Director - Regulatory Affairs

Case No.:

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

**February 2014**

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 major contributing factor to the increase in natural gas prices is likely a result of the much colder weather that blanketed much of the United States during the month of December. This resulted in well freeze offs and higher than normal storage withdrawals. The EIA reported storage levels nationwide indicate the five year average as of December 27, 2013, was 8.9 percent below the five-year average and 15.9 percent below last year's storage balance.

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

The January Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 18.

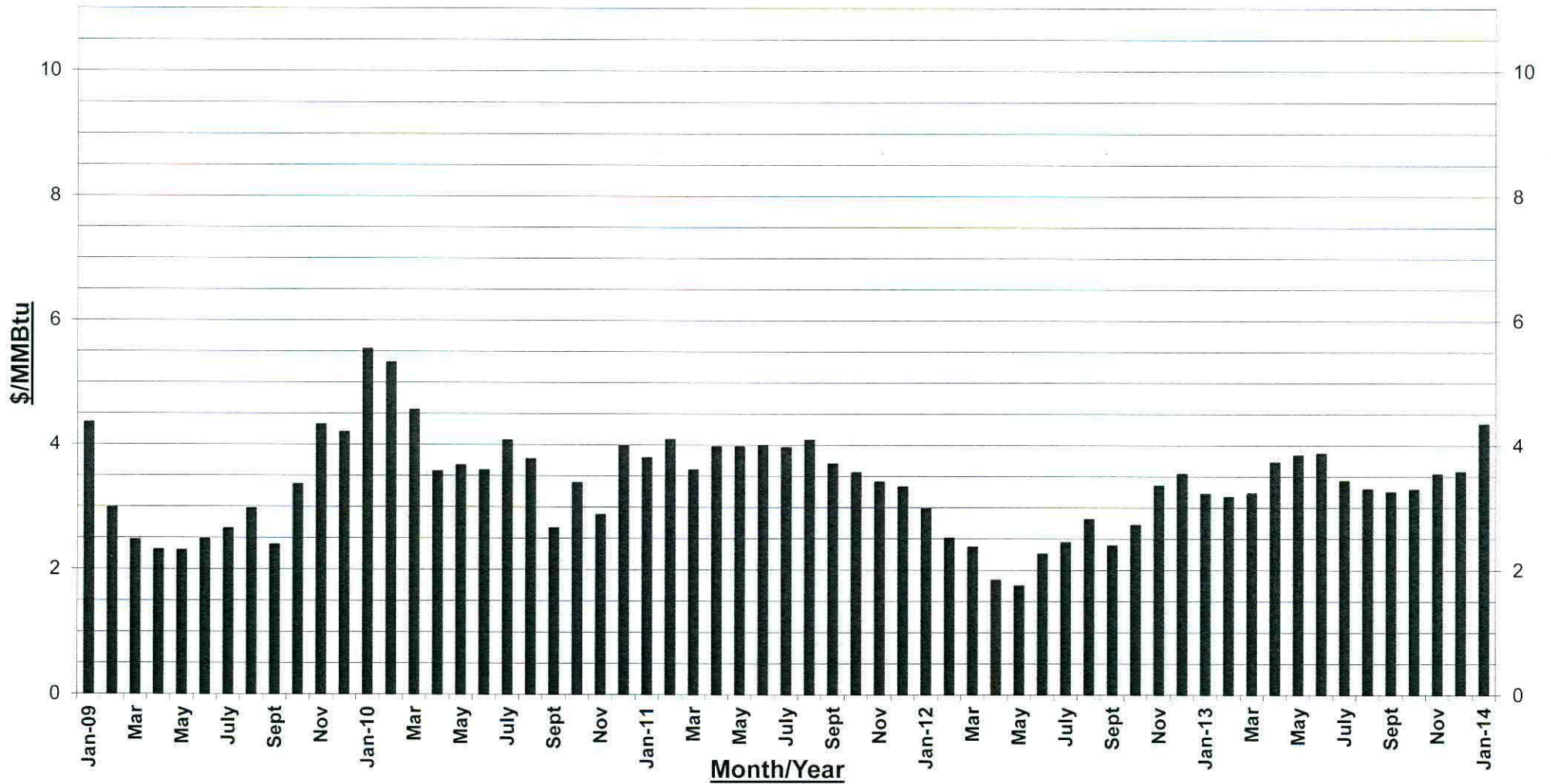
**Montana-Dakota Utilities Co.  
Market Conditions for Regional Propane  
February 2014**

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

The February prices for propane have increased from the previous level. A change in the price of propane is generally driven by a combination of crude oil prices, weather, demand and inventory levels. As seasonal usage increases, this has resulted in an increase in the price of propane.

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

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



From Inside F.E.R.C.'s Gas Market Report  
Annual Averages: - 2012-\$2.58; 2013-\$3.45; 2014YTD-\$4.34



Independent Statistics & Analysis

U.S. Energy Information  
Administration

January 2014

## Short-Term Energy Outlook (STEO)

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### Highlights

- This edition of the *Short-Term Energy Outlook* is the first to include forecasts for 2015.
- After falling to the lowest monthly average of 2013 in November, U.S. regular gasoline retail prices increased slightly to reach an average of \$3.28 per gallon (gal) during December. The annual average regular gasoline retail price, which was \$3.51/gal in 2013, is expected to fall to \$3.46/gal in 2014 and \$3.39/gal in 2015.
- The North Sea Brent crude oil spot price in December averaged near \$110 per barrel (bbl) for the sixth consecutive month. EIA expects the Brent crude oil price to decline gradually to average \$105/bbl and \$102/bbl in 2014 and 2015, respectively. Projected West Texas Intermediate (WTI) crude oil prices average \$93/bbl during 2014 and \$90/bbl during 2015.
- EIA expects liquid fuels production from countries outside of the Organization of the Petroleum Exporting Countries (OPEC) to grow year-over-year by a record high of 1.9 million barrels per day (bbl/d) in 2014. The United States and Canada together are projected to account for almost 70% of total non-OPEC supply growth this year.
- EIA estimates U.S. total crude oil production averaged 7.5 million bbl/d in 2013, an increase of 1.0 million bbl/d from the previous year. Projected domestic crude oil production continues to increase to 8.5 million bbl/d in 2014 and 9.3 million bbl/d in 2015. The 2015 forecast would mark the highest annual average level of production since 1972.
- Natural gas working inventories on December 27 totaled 2.97 trillion cubic feet (Tcf), 0.56 Tcf below the level at the same time a year ago and 0.29 Tcf below the previous five-year average (2008-12). EIA expects that the Henry Hub natural gas spot price, which averaged \$3.73 per million British thermal units (MMBtu) in 2013, will average \$3.89/MMBtu in 2014 and \$4.11/MMBtu in 2015.
- Coal production, which fell by almost 9% between 2011 and 2013, is expected to increase by 36 million short tons (MMst) (3.6%) in 2014 as higher natural gas prices favor the dispatch of coal-fired power plants and the drawdown of coal inventory ends. In 2015, however, forecast coal-fired production falls by 2.5% with declining coal use in the electric power sector as retirements of coal-fired power plants rise due to the implementation of the U.S. Environmental Protection Agency's [Mercury and Air Toxics Standards](#).

## Global Crude Oil and Liquid Fuels

EIA expects production from countries outside of the Organization of the Petroleum Exporting Countries (OPEC) to grow year-over-year by a record high of 1.9 million bbl/d in 2014. OPEC crude oil production is forecast to decline by 0.5 million bbl/d in 2014, mostly as a result of some OPEC producers cutting back production to accommodate non-OPEC supply growth. The projected decline in production by some OPEC producers increases in surplus crude oil production capacity, which grows from an average of 2.2 million bbl/d in 2013 to 2.7 million bbl/d in 2014. The call on OPEC crude oil and global stocks (world consumption less non-OPEC production and OPEC non-crude oil production) falls from an average 30.4 million bbl/d in 2013 to 29.6 million bbl/d in 2014.

In 2015, EIA forecasts that non-OPEC supply growth will moderate to 1.5 million bbl/d, slightly above projected global consumption growth of about 1.4 million bbl/d. The call on OPEC crude oil and global stocks is virtually unchanged from the previous year as projected OPEC non-crude liquids increase by 0.1 million bbl/d in 2015, accounting for the difference. However, some OPEC producers are expected to reduce production to accommodate higher production from Libya, Iraq, and Angola, leading to an increase in forecast surplus crude oil production capacity to an average of 3.7 million bbl/d in 2015.

EIA estimates that global unplanned supply disruptions averaged 2.6 million bbl/d in 2013, 0.7 million bbl/d higher than the previous year. OPEC producers contributed most of the total outage volume (1.8 million bbl/d). Global supply disruptions reached a high of 3.1 million bbl/d at the end of 2013 and remain close to that level at the start of 2014. Supply disruptions present considerable uncertainty over the forecast period because the issues underpinning the disruptions in most countries remain unresolved.

**Global Liquid Fuels Consumption.** EIA estimates that global consumption grew by 1.2 million bbl/d in 2013, exceeding 91 million bbl/d by the second half of the year. EIA expects global consumption to grow by a similar pace of 1.2 million bbl/d in 2014 and 1.4 million bbl/d in 2015, exceeding 93 million bbl/d by the second half of 2015.

Countries outside of the Organization for Economic Cooperation and Development (OECD) account for nearly all consumption growth over the forecast period, with year-over-year growth of 1.3 million bbl/d in 2014 and 1.4 million bbl/d in 2015. China is the single leading contributor to projected global consumption growth, increasing by 400,000 bbl/d in 2014 and 430,000 bbl/d in 2015. China's economic and oil consumption growth has moderated compared with levels before 2012, when GDP growth exceeded 9% and annual oil consumption growth averaged 790,000 bbl/d during 2009-11.

On the other hand, EIA expects OECD consumption to decline by roughly 0.1 million bbl/d in 2014 and remain flat in 2015. The projected decline in OECD consumption is led by Japan and

Europe. EIA expects Japan's oil consumption to decrease annually by 120,000 bbl/d in 2014 and 170,000 bbl/d in 2015, as the country continues to increase natural gas consumption in the electricity sector and returns some nuclear power plants to service. EIA projects that Europe's consumption continues to decline by 100,000 bbl/d in 2014 and 50,000 bbl/d in 2015, a slower decline compared with previous years.

**Non-OPEC Supply.** EIA estimates that non-OPEC production grew by 1.4 million bbl/d in 2013, exceeding 55 million bbl/d by the end of the year. EIA expects non-OPEC production to grow annually by 1.9 million bbl/d in 2014 and 1.5 million bbl/d in 2015, reaching 58 million bbl/d in the second half of 2015. North America contributes the most growth to non-OPEC supply over the forecast period.

EIA forecasts production from the United States and Canada to grow by an annual average of 0.98 million bbl/d and 0.25 million bbl/d, respectively, over the next two years. Brazil's production is expected to grow by an annual average of 0.15 million bbl/d over the next two years, attributed to new deepwater fields. Kazakhstan's production is also expected to grow by an annual average of 0.13 million bbl/d over the next two years, although most of the growth comes in 2015 as output grows at the Kashagan oil field.

Unplanned supply disruptions among non-OPEC producers averaged 0.8 million bbl/d in 2013, a slight decline from 0.9 million bbl/d in 2012 but still considerably above the 2011 level of 0.5 million bbl/d. Non-OPEC supply disruptions declined to an average of 0.6 million bbl/d during the last two months of 2013. South Sudan, Syria, and Yemen accounted for more than 70% of the total disrupted volumes among non-OPEC producers in 2013.

EIA expects Syria and Yemen to continue to account for a large portion of non-OPEC supply disruptions over the next two years as the issues underpinning the disruptions remain unresolved. The disruption volume in South Sudan fell during 2013, from an average of 330,000 bbl/d in the first quarter to below 100,000 bbl/d in the fourth quarter of 2013. However, in late December of 2013, armed conflict escalated in South Sudan, causing the shut in of some oil fields and increasing the disruption volume by around 50,000 bbl/d.

**OPEC Supply.** EIA estimates that OPEC crude oil production averaged 30 million bbl/d in 2013, a decline of 0.9 million bbl/d from the previous year, mostly as a result of increased outages in Libya, Nigeria, and Iraq. EIA expects OPEC crude oil production to continue to decline by 0.5 million bbl/d in 2014, as some OPEC countries, led by Saudi Arabia, reduce production to accommodate the non-OPEC supply growth in 2014. Although overall OPEC production in 2015 is forecast to remain close to its 2014 level, some key member countries continue to reduce their output to accommodate assumed recovery from production outages in Libya and growing production from other OPEC member countries, notably Iraq and Angola.

Unplanned crude oil supply disruptions among OPEC producers averaged 1.8 million bbl/d in 2013, nearly double the amount from the previous year. OPEC disruptions increased in the

second half of 2013, reaching 2.5 million bbl/d by the end of the year due to increased outages in Libya. At the beginning of January 2014, EIA estimates that OPEC outages are still at elevated levels, contributing to considerable uncertainty over the forecast period.

EIA estimates that OPEC surplus crude oil production capacity averaged 2.2 million bbl/d in 2013, 0.1 million bbl/d above the previous year but still 0.9 million bbl/d below the previous three-year average (2010-12). EIA expects surplus crude oil production capacity to increase over the forecast period, averaging 2.7 million bbl/d in 2014 and 3.7 million bbl/d in 2015. These estimates do not include additional capacity that may be available in Iran but is currently offline because of the effects of U.S. and European Union sanctions on Iran's oil sector.

**OECD Petroleum Inventories.** EIA estimates that OECD commercial oil inventories at the end of 2013 totaled 2.6 billion barrels, equivalent to about 56 days of supply. EIA projects OECD oil inventories also to be 2.6 billion barrels at the end of 2014 and 2015.

**Crude Oil Prices.** Brent crude oil spot prices averaged between \$108/bbl and \$112/bbl for the sixth consecutive month in December 2013 at \$111/bbl. EIA expects the Brent crude oil price to weaken as non-OPEC supply growth exceeds growth in world consumption. The Brent crude oil price is projected to average \$105/bbl and \$102/bbl in 2014 and 2015, respectively.

The forecast WTI crude oil spot price, which fell from an average of \$106/bbl during September to \$94/bbl in November, increased to \$98/bbl in December as a result of strong U.S. refinery runs. EIA expects that WTI crude oil prices will average \$93/bbl in 2014 and \$90/bbl during 2015. The discount of WTI crude oil to Brent crude oil, which averaged \$18/bbl in 2012 and then fell to below \$4/bbl in July 2013, averaged \$12/bbl during the fourth quarter of 2013.

EIA expects the discount of the WTI crude oil price to Brent to average \$12/bbl in 2014, \$3/bbl higher than projected in last month's STEO. This increase in the projected WTI discount reflects increasing uncertainty of the existing refinery infrastructure's ability to absorb growing production of light sweet crude oil in North America at current prices. Because of pipeline capacity expansions and pipeline reversals, there is now ample capacity to ship crude oil via pipeline from the previous bottleneck in the U.S. Midcontinent to the U.S. Gulf Coast. As a result, the Light Louisiana Sweet (LLS) crude oil benchmark on the Gulf Coast, which was priced at a premium to Brent for much of the last two years, [has recently begun tracking WTI prices and selling at a discount to Brent](#). Thus, EIA expects the recent convergence of Gulf Coast crude oil prices with WTI to persist over the forecast period, with Gulf Coast crude oil prices moving in step with the WTI price plus a pipeline transport cost. At this price level, Gulf Coast crudes such as LLS and medium-grade Mars will, trade at historically wide discounts to similar international benchmarks such as Brent and Dubai, respectively. EIA expects North American price discounts to continue into 2015 at levels similar to 2014, as new infrastructure comes online to meet additional production growth.

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 April 2014 delivery, traded during the five-day period ending January 2, 2014, averaged \$98/bbl. Implied volatility averaged 16%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in April 2014 at \$86/bbl and \$113/bbl, respectively. Last year at this time, WTI for April 2013 delivery averaged \$93/bbl and implied volatility averaged 26%. The corresponding lower and upper limits of the 95% confidence interval were \$74/bbl and \$117/bbl.

## U.S. Crude Oil and Liquid Fuels

After reaching \$3.68/gal on July 22, 2013, the average U.S. regular gasoline retail price fell almost 50 cents/gal to \$3.19/gal by November 11, 2013. Continuing strong demand for gasoline in November and December and higher crude oil prices contributed to U.S. weekly average regular gasoline prices increasing to \$3.33/gal as of December 30, 2013. Despite recent price increases, EIA expects that high levels of refinery runs, lower crude oil prices, and strong export demand for diesel fuel will contribute to downward pressure on regular gasoline retail prices, which EIA expects to average \$3.29/gal during January 2014.

**U.S. Liquid Fuels Consumption.** Total U.S. liquid fuels consumption rose by an estimated 380,000 bbl/d (2.1%) in 2013. Consumption of liquefied petroleum gases registered the largest gain, increasing by 150,000 bbl/d (6.7%). Motor gasoline consumption grew by 110,000 bbl/d (1.2%), the largest increase since 2004. Stronger-than-expected growth in highway travel during the second half of 2013 contributed to that increase. Distillate fuel consumption increased 90,000 bbl/d (2.5%), reflecting colder weather and domestic economic growth.

Projected total liquid fuels consumption is flat in 2014. Motor gasoline consumption falls by 10,000 bbl/d (0.1%) as the recent strong growth in highway travel slows and continued improvements in new-vehicle fuel economy boost overall fuel efficiency growth. Distillate fuel oil consumption rises 40,000 bbl/d (1.2%) in 2014. Growing distillate demands from transportation and industrial use are offset by milder winter weather and declining heating oil use. Ethane consumption increases by an average of 60,000 bbl/d (5.8%) in 2014 as ethylene plant capacity expansions contribute to an increase in ethane cracking capacity. In 2015, total liquid fuels consumption increases by 90,000 bbl/d (0.5%) driven primarily by increasing demand for liquefied petroleum gas and distillate fuel oil.

**U.S. Liquid Fuels Supply.** EIA expects strong crude oil production growth, primarily concentrated in the Bakken, Eagle Ford, and Permian regions, continuing through 2015. Forecast production increases from an estimated 7.5 million bbl/d in 2013 to 8.5 million bbl/d in 2014 and 9.3 million bbl/d in 2015. The highest historical annual average U.S. production level was 9.6 million bbl/d in 1970.

Production from the Bakken formation in North Dakota and Montana averaged 0.88 million bbl/d in 2013, and surpassed 1 million bbl/d in December 2013. Production in the Eagle Ford formation in South Texas surpassed 1 million bbl/d in May 2013, reaching an estimated 1.23 million bbl/d in December 2013.

The Permian Basin in West Texas and New Mexico includes a variety of thick, overlapping formations such as the Spraberry, Bone Springs, and Wolfcamp. Crude oil producers are investing heavily in research and implementation of hydraulic fracturing in both vertical and horizontal wells. The stacked formations of the Permian allow vertical wells to reach several productive zones, while several horizontal wells drilled from the same surface location can target different formations or several pay zones within the same formation. EIA forecasts production in the Permian Basin, which averaged 1.32 million bbl/d in 2013, to grow more than any other region in the United States through 2015.

U.S. Federal Gulf of Mexico (GOM) oil production averaged 1.27 million bbl/d in 2013, unchanged from 2012. EIA forecasts 1.38 million bbl/d GOM production in 2014 and 1.59 million bbl/d in 2015. Production growth in 2014 comes from eight projects expected to come online: Jack, St. Malo, Entrada, Big Foot, Tubular Bells, Atlantis Phase 2, Hadrian South, and Lucius. Further production growth in 2015 comes from an additional 10 projects: Axe, Cardamom Deep, Dalmation, Deimos South, Kodiak, Pony, Samurai, West Boreas, Winter, and Mars B.

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 peaked at more than 60% in 2005 and fell to an average of 33% in 2013. EIA expects the net import share to decline to 24% in 2015, which would be the lowest level since 1970.

**U.S. Petroleum Product Prices.** EIA expects that regular gasoline retail prices, which averaged \$3.24/gal during November and \$3.28/gal in December, will average \$3.29/gal in January 2014. Led by falling Brent crude oil prices, the projected U.S. annual average regular gasoline retail price, which fell from \$3.63/gal in 2012 to an average of \$3.51/gal in 2013, will continue to fall to \$3.46/gal in 2014 and \$3.39 in 2015. Diesel fuel prices, which averaged \$3.92/gal in 2013, are projected to average \$3.81/gal in 2014 and \$3.72/gal in 2015.

## Natural Gas

Cold weather in December had significant effects on demand, supply, and prices across the country. Cold weather led to a net withdrawal of 285 billion cubic feet (Bcf) for the week ending Friday, December 13. This was the largest storage withdrawal since recordkeeping began in 1994. Another larger-than-normal storage withdrawal of 177 Bcf occurred the following week. [Widespread freeze-offs occurred](#) in December and disrupted production for several days in the Piceance Basin in Utah and Wyoming, the Uinta Basin in Utah, the San Joaquin Basin in

California, and the Williston Basin in North Dakota. Imports from Canada helped mitigate the loss of supply. During the month, prices rose across most of the country, and the Henry Hub price averaged about \$0.60/MMBtu higher than the previous month's average. Price effects were also seen in regional markets, particularly in New England. At the Algonquin Citygate, which serves Boston consumers, prices spiked to \$33.14/MMBtu on Friday, December 13.

**U.S. Natural Gas Consumption.** EIA expects that total natural gas consumption to average a record high 71.2 billion cubic feet per day (Bcf/d) in 2013, an increase of 1.5 Bcf/d (2.1%) from the previous year. Projected natural gas consumption falls by 1.6 Bcf/d (2.2%) in 2014 because of the forecast 4.6% decline in heating degree days and lower natural gas use by the electric power sector. In 2015, natural gas consumption increases by 1.4 Bcf/d with growth in use by the industrial and electric power sectors. The projected year-over-year increases in natural gas prices contribute to declines in natural gas used for electric power generation from 24.9 Bcf/d in 2012 to 22.3 Bcf/d in 2013 and 21.7 Bcf/d in 2014. However, as retirements of coal power plants rise in 2015 in response to the implementation of the [Mercury and Air Toxics Standards](#), EIA expects natural gas consumption in the power sector to increase to 22.6 Bcf/d.

**U.S. Natural Gas Production and Trade.** EIA expects natural gas marketed production will grow at an average rate of 2.1% in 2014 and 1.3% in 2015. Rapid Marcellus production growth is causing natural gas forward prices in the Northeast to fall even with or below Henry Hub prices outside of peak-demand winter months. Consequently, some drilling activity may move away from the Marcellus back to Gulf Coast plays such as the Haynesville and Barnett, where prices are closer to the Henry Hub spot price. EIA projects Gulf of Mexico production will continue a long-term decline and fall slightly in 2014 and moderately in 2015.

LNG imports have declined over the past several years because higher prices in Europe and Asia are more attractive to sellers than the relatively low prices in the United States. Several companies are planning to build [liquefaction capacity](#) to export LNG from the United States. The first of the new facilities to liquefy gas produced in the lower-48 states for export is expected to partially come online in the fourth quarter of 2015.

Growing domestic production over the past several years has replaced [pipeline imports from Canada](#), while [exports to Mexico](#) have increased. EIA expects these trends will continue through 2015. EIA projects net imports of 3.0 Bcf/d in 2014 and 2.5 Bcf/d in 2015, which would be the lowest level since 1986. Over the longer term, the [EIA Annual Energy Outlook 2014](#) projects the United States will be a net exporter of natural gas beginning in 2018.

**U.S. Natural Gas Inventories.** Natural gas working inventories fell by 97 Bcf to 2,974 Bcf during the week ending December 27, 2013. Colder-than-normal temperatures during the month resulted in increased heating demand, prompting larger-than-normal withdrawals, and the highest withdrawal on record. Stocks are now 562 Bcf less than last year at this time and 289 Bcf less than the five-year (2008-12) average for this time of year.

**U.S. Natural Gas Prices.** Natural gas spot prices averaged \$4.24/MMBtu at the Henry Hub in December, up 60 cents from November, likely the result of colder-than-normal weather during the month. Prices averaged \$3.73/MMBtu for 2013 overall. Projected Henry Hub natural gas prices average \$3.89/MMBtu in 2014 and \$4.11/MMBtu in 2015.

Natural gas futures prices for April 2014 delivery (for the five-day period ending December 5, 2013) 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 April 2014 contracts at \$3.21/MMBtu and \$5.46/MMBtu, respectively. At this time a year ago, the natural gas futures contract for April 2013 averaged \$3.38/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$2.42/MMBtu and \$4.73/MMBtu.

## Coal

**U.S. Coal Supply.** Coal production for 2013 was estimated to total 1,001 million short tons (MMst), 15 MMst (1.5%) lower than in 2012. EIA estimates inventory draws of nearly 43 MMst for the year, fulfilling most of the growth in consumption in 2013. Coal production is forecast to grow 3.6% to 1,037 MMst in 2014 as inventories stabilize and consumption increases. Coal production in 2015 is projected to fall 2.5% to 1,012 MMst.

**U.S. Coal Consumption.** EIA expects total coal consumption for 2013 to reach 924 MMst, a 3.9% increase over 2012. The increase was primarily a result of increased consumption in the electric power sector due to higher natural gas prices. Projected consumption grows more slowly (3.3%) to 955 MMst in 2014. Despite increases in electricity demand in 2015, coal consumption is projected to decline by 2.6%. The decline is primarily a result of the implementation of the U.S. Environmental Protection Agency's [Mercury and Air Toxics Standards](#) regulations.

**U.S. Coal Exports.** EIA estimates that exports for 2013 totaled 118 MMst, which was 5.9% (7 MMst) lower than 2012. Exports are projected to total 105 MMst in both 2014 and 2015. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, increasing coal output in other coal-exporting countries, and falling international coal prices are the primary reasons for the expected decline in U.S. coal exports.

**U.S. Coal Prices.** Nominal annual average coal prices to the electric power industry fell for the second consecutive year, from \$2.38/MMBtu in 2012 to \$2.35/MMBtu in 2013. EIA forecasts average delivered coal prices of \$2.38/MMBtu in 2014 and \$2.39/MMBtu in 2015.

## Electricity

[Electricity sales have stagnated](#) in recent years, and consumption has declined in some sectors. During 2013, EIA estimates the average U.S. residential customer used 10,870 kilowatthours (kWh) of electricity, which is 2.2% lower than the average level of consumption between 2008

and 2012. In contrast, residential electricity consumption per customer grew an average of 1.2% per year between 1990 and 2005. Year-to-year fluctuations in residential electricity use are driven primarily by weather patterns. However, the overall growth trend has been slowing in recent years. Improvements in appliance and lighting efficiency are one reason for this slowdown. [Efficiency standards for general use light bulbs](#) that began in 2012 and become fully implemented in 2014 have led to more widespread use of compact fluorescent and LED lighting, which use about 75% less energy than traditional incandescent bulbs.

**U.S. Electricity Consumption.** Improvements in energy efficiency are likely to continue affecting growth in electricity consumption. EIA expects the average sales of electricity per residential customer to fall by 1.1% in 2014 and by 0.4% in 2015. Energy efficiency also impacts sales of electricity to the commercial sector, which are expected to decline by 0.5% this year but grow by 0.3% in 2015. Improved economic conditions, especially in the chemicals and primary metals industries, drive a 2.2% increase in industrial electricity sales during 2014 and a 2.5% increase in 2015.

**U.S. Electricity Generation.** EIA estimates that total U.S. electricity generation averaged 11.1 terawatthours per day in 2013, and projects growth of 0.3% and 1.0% in 2014 and 2015, respectively. Natural-gas-fired generation accounts for a 26.8% share of total generation during 2014, down from 27.5% in 2013 as a result of rising natural gas prices. In contrast, the share of generation fueled by coal increases from 39.1% in 2013 to 40.2% in 2014. As the retirements of coal power plants pick up in 2015 in response to the implementation of the [Mercury and Air Toxics Standards](#), EIA expects the share of coal to fall to 38.6% of total generation while the natural gas share rises back to 27.6%.

**U.S. Electricity Retail Prices.** The rising cost of generation fuels, particularly natural gas, contributes to a projected increase in the residential price of electricity. EIA expects the U.S. residential price of electricity to average 12.4 cents/kWh during 2014, an increase of 2.0% from 2013. Residential electricity prices increase 2.0% during 2015.

## Renewables and Carbon Dioxide Emissions

**U.S. Electricity and Heat Generation from Renewables.** EIA projects both hydropower and nonhydropower renewables used for electricity and heat generation will grow by about 3.0% in 2014. In 2015, the growth in renewables consumption for electric power and heat generation is projected to continue at a rate of 4.7%, as a 2.2% increase in hydropower is combined with a 6.1% increase in nonhydropower renewables.

EIA estimates that wind capacity will increase by 8.8% in 2014 to about 66 gigawatts (GW) by the end of the year and will increase 14.6% to total more than 75 GW at the end of 2015. Electricity generation from wind is projected to increase by 2.2% in 2014 and by 11.4% in 2015, contributing more than 5% of total electricity generation by the end of 2015.

EIA expects continued robust growth in the generation of solar electricity generation, although the amount of utility-scale generation remains a small share of total U.S. generation at about 0.4% by 2015.

While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity has taken off in the last few years, more than doubling in both 2012 and 2013. EIA currently projects that utility-scale solar capacity will increase by approximately 40% between year-end 2013 and year-end 2015, with photovoltaic (PV) capacity accounting for about 85% of that growth. However, customer-sited PV capacity growth, which the STEO does not forecast, is still projected to exceed utility-scale solar growth between 2013 and 2015 according to [EIA's Annual Energy Outlook 2014](#).

EIA projects that solar PV electric capacity will continue to grow in 2014 and 2015 in both the electric power and end-use sectors, and will dominate growth in solar thermal electric capacity, due in part to significant cost declines that the PV industry has experienced in recent years. However, in October 2013, Arizona's 250-megawatt Solana generation station became the first major solar thermal electric power plant to enter service since 2007 – and the only operational solar thermal plant with integrated thermal storage. EIA expects that additional projects currently under construction will continue to come on line in 2014.

**U.S. Liquid Biofuels.** Ethanol and biodiesel production have recovered from last year's drought. Ethanol production increased from an average of 825,000 bbl/d in December 2012 to an estimated 920,000 bbl/d during December 2013 and is forecast to average 913,000 bbl/d during 2014. Biodiesel production, which averaged 64,000 bbl/d (1.0 billion gallons per year) in 2012, [rose to a record-high level](#) of 101,000 bbl/d (132 million gallons) in October 2013. Biodiesel production averaged about 87,000 bbl/d in 2013 and is forecast to average 84,000 bbl/d in both 2014 and 2015.

**U.S. Energy-Related Carbon Dioxide Emissions.** EIA estimates that carbon dioxide emissions from fossil fuels increased by 2.1% in 2013 from the previous year. Emissions are forecast to rise 0.7% in 2014, followed by no change in 2015. The increase in emissions in 2013 primarily reflected growth in coal use for electricity generation in response to higher natural gas prices relative to coal. Coal emissions are projected to decline by 2.5% in 2015 as the power sector responds to the Mercury and Air Toxics Standards regulations by increasing coal plant retirements.

## U.S. Economic Assumptions

The [U.S. Bureau of Economic Analysis](#) reported that real GDP increased at an annual rate of 4.1% during the third quarter, revised upward from 2.8% and 3.6% in its previous two estimates. The [U.S. Department of Labor](#) reported that initial weekly unemployment insurance claims were 339,000 in the week ending December 28, a decrease of 2,000 from the previous week's figure, and the four-week moving average rose to 357,000. The [U.S. Census Bureau](#) reported that new

orders for manufactured durable goods rose 3.5% in November, following a 0.7% decrease in October. The [Federal Reserve Board](#) reported that U.S. industrial production rose in November by 1.1%, following an upwardly revised 0.1% gain in October.

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

**U.S. Production and Income.** Forecast U.S. real GDP grows by 2.4% in 2014 and 3.1% in 2015. Forecast real disposable income increases 3.2% per year in both 2014 and 2015. Total industrial production grows at 2.2% in 2014, and is projected to grow 3.5% in 2015.

**U.S. Expenditures.** Private real fixed investment growth averages 6.4% and 8.4% over 2014 and 2015, respectively. Real consumption expenditures grow faster than real GDP in 2014, at 2.6%, but are below the rate of real GDP growth in 2015, at 2.8%. Export growth is 4.9% and 5.1% over the same two years. Government expenditures fall 0.3% in 2014, but increase by 0.3% in 2015.

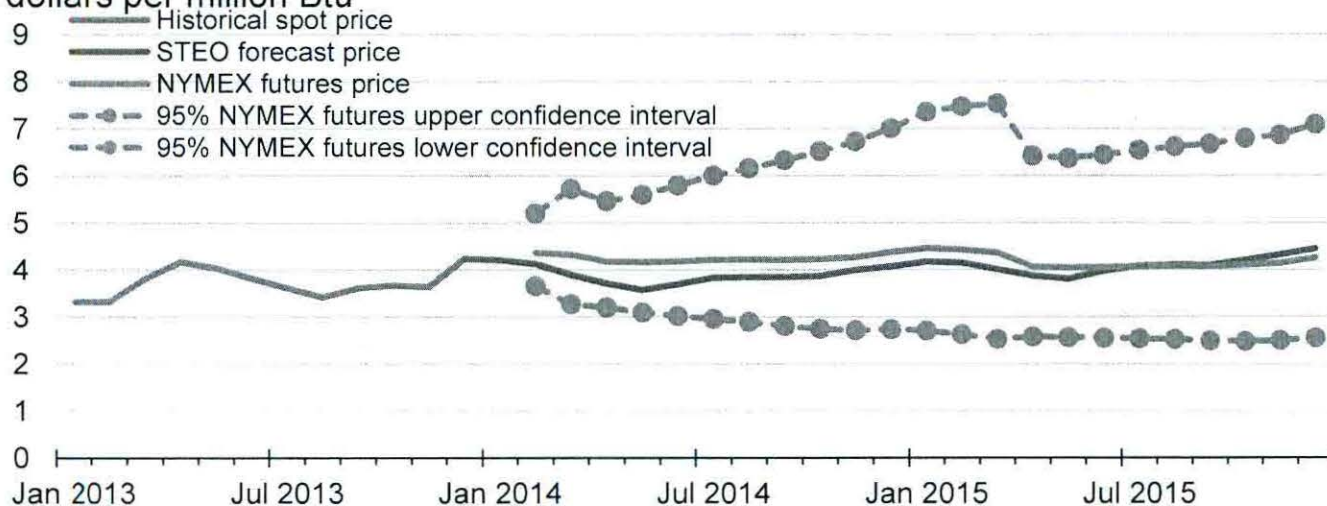
**U.S. Employment, Housing, and Prices.** The unemployment rate in the forecast averages 6.6% over 2014, and gradually falls to 5.9% at the end of 2015. This is accompanied by nonfarm employment growth averaging 1.7% in 2014 and 1.8% in 2015. Housing starts grow an average of 23.3% and 29.9% in 2014 and 2015, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.

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

## Henry Hub Natural Gas Price



dollars per million Btu

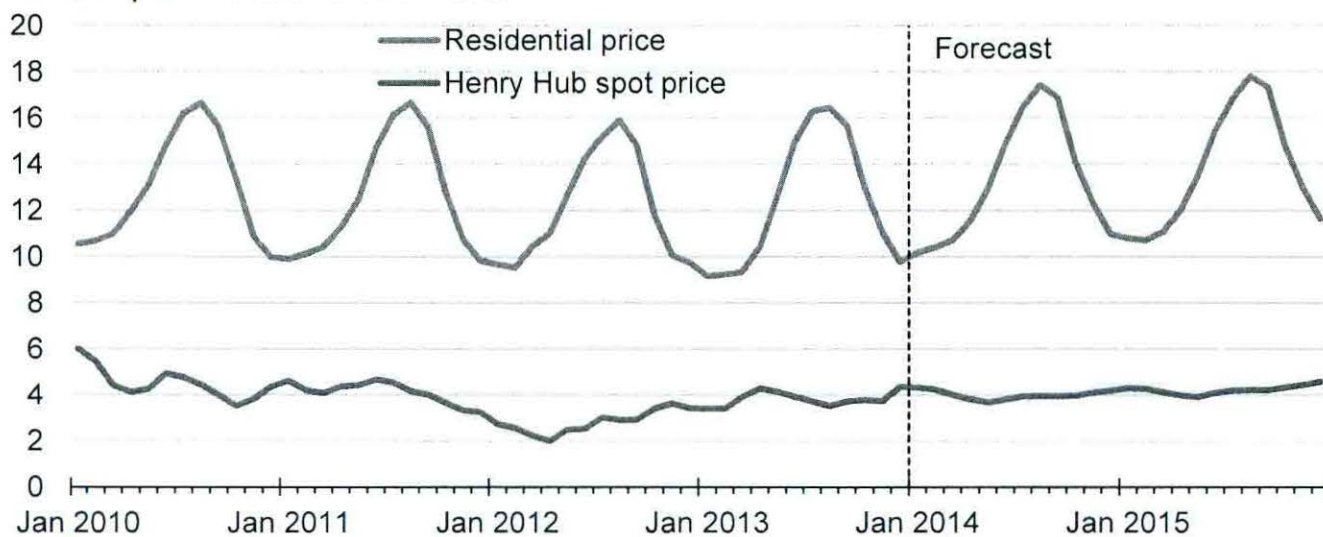


Note: Confidence interval derived from options market information for the 5 trading days ending Jan. 2, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, January 2014.

## U.S. Natural Gas Prices

dollars per thousand cubic feet



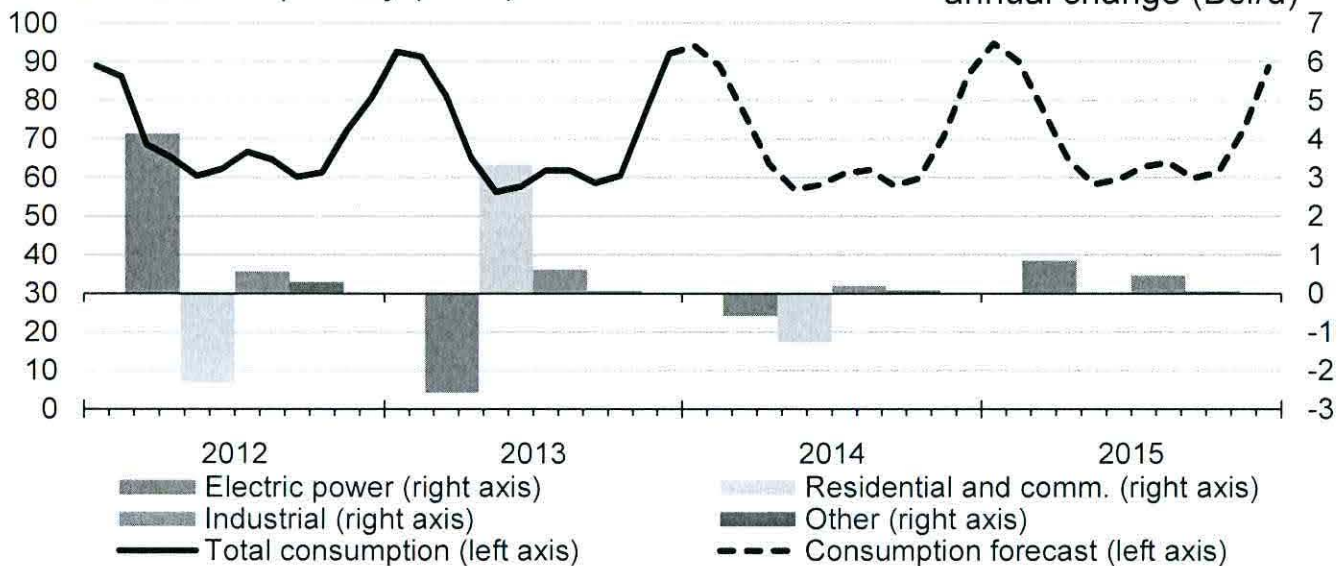
Source: Short-Term Energy Outlook, January 2014.

## U.S. Natural Gas Consumption

billion cubic feet per day (Bcf/d)

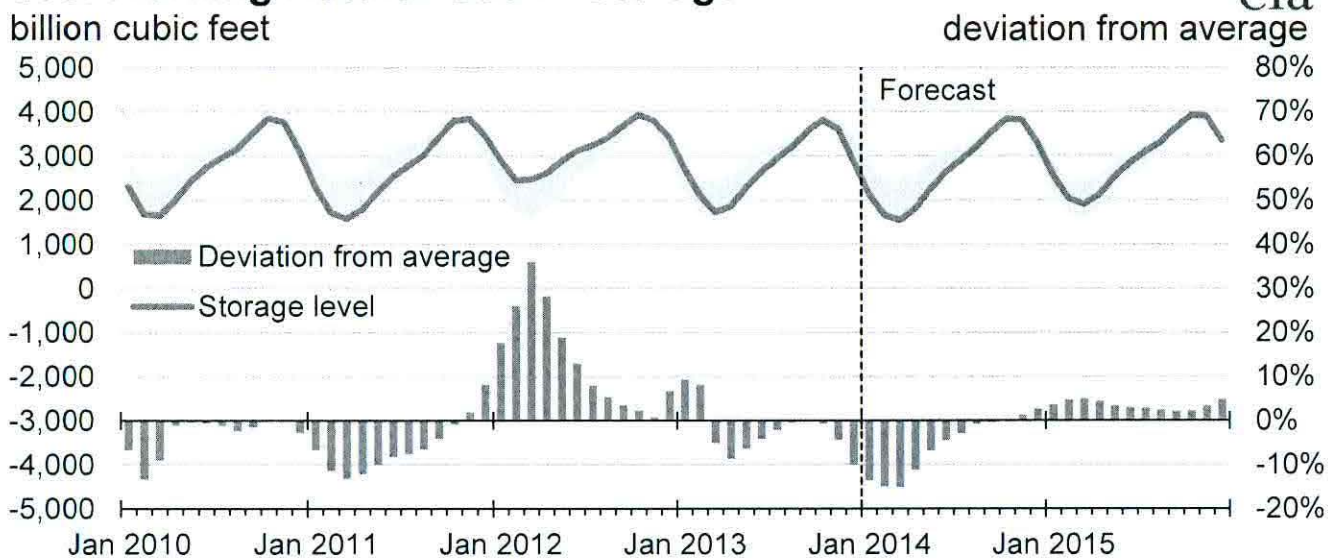


annual change (Bcf/d)



Source: Short-Term Energy Outlook, January 2014.

## U.S. Working Natural Gas in Storage



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

Source: Short-Term Energy Outlook, January 2014.

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

**Foothills Pipe Lines Ltd.**

On October 31, 2013, TransCanada filed new rates for the Foothills Pipe Lines Ltd. System with the National Energy Board (NEB) to be effective January 1, 2014.

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

**NOVA Gas Transmission Ltd.**

On October 31, 2013, TransCanada filed new interim rates for the Alberta System with the National Energy Board (NEB) to be effective January 1, 2014. On November 14, 2013, the NEB approved the proposed interim 2014 rates, pending an order.

Approximate impact on Montana-Dakota's cost of gas: (0.1) cents per dk

**NorthWestern Energy**

On December 11, 2013, NorthWestern Energy filed its 2014 Electric and Natural Gas Tax Tracker filing in Docket No. D2013.12.83 with the Montana Public Service Commission to be effective January 1, 2014. On December 17, 2013, NorthWestern Energy filed revised rates to be effective January 1, 2014, on an interim basis.

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 2014

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<b><u>Gas Cost Adjustment:</u></b>				
Gas Cost Level (Exhibit B)	\$5.503	\$5.595	\$4.470	\$4.450
Prior Gas Cost	4.830	4.917	3.847	3.830
Current Gas Cost Adjustment	\$0.673	\$0.678	\$0.623	\$0.620
<b><u>Surcharge Adjustment:</u></b>				
Current Adjustment	\$0.024	\$0.024	\$0.116	\$0.181
Prior Adjustment	0.024	0.024	0.116	0.181
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<b><u>Market Based Pricing Differential</u></b>				
Current Adjustment	(\$0.012)	(\$0.012)	\$0.000	\$0.000
Prior Adjustment	(0.012)	(0.012)	0.000	0.000
Change in Margin Sharing Provision	\$0.000	\$0.000	\$0.000	\$0.000
<b>Net Increase (Decrease) in Gas Costs</b>	<b>\$0.673</b>	<b>\$0.678</b>	<b>\$0.623</b>	<b>\$0.620</b>
Gas Cost Level	\$5.503	\$5.595	\$4.470	\$4.450
Plus: Surcharge	0.024	0.024	0.116	0.181
<b>Total Gas Cost Level in Tariff Rates</b>	<b>\$5.527</b>	<b>\$5.619</b>	<b>\$4.586</b>	<b>\$4.631</b>

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

<b><u>Cost of Gas - Propane</u></b>	
Current Propane Cost (Exhibit A)	\$19.211
Prior Propane Cost	<u>15.919</u>
Current Propane Cost Adjustment	<u><u>\$3.292</u></u>
<b><u>Surcharge Adjustment</u></b>	
Current Adjustment	(\$0.777)
Prior Adjustment	<u>(0.777)</u>
Change in Surcharge Adjustment	\$0.000
<b><u>Market Based Pricing Differential</u></b>	
Current Adjustment	(\$0.012)
Prior Adjustment	<u>(0.012)</u>
Change in Margin Sharing Provision	\$0.000
<b>Net Increase (Decrease) in Gas Costs</b>	<b><u><u>\$3.292</u></u></b>
Propane Cost Level	\$19.211
Plus: Surcharge	<u>(0.777)</u>
Total Propane Cost Level in Rates	<b><u><u>\$18.434</u></u></b>

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

	Amount
Total Gas Costs 1/	\$80,554,642
Residential and General Service dk Requirements 2/	14,703,928
Average Cost of Gas per dk	\$5.478
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.503
Less: Gas Cost Level in Rates 3/	4.830
<b>Current Gas Cost Adjustment</b>	<b>\$0.673</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 November 30, 2013, adjusted for losses at .45%.

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

Cost of Purchased Gas	\$4.808
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.830

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

Total Gas Costs 1/	\$80,554,642
Less: Annual MDDQ Costs 1/	<u>14,055,342</u>
Total Gas Costs excluding MDDQ	\$66,499,300
Firm Service Requirements 1/	14,703,928
Other Gas Costs per Dk (excluding MDDQ)	\$4.523
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$14,055,342
Winter Firm Service Requirements	13,427,789
MDDQ Costs per Winter Dk	\$1.047
Add: Other Gas Costs per Dk	<u>4.523</u>
Winter Seasonal Rate	\$5.570
Winter Seasonal Rate, adjusted for losses 2/	\$5.595
Less: Gas Cost Level in Rates 3/	<u>4.917</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.678</u></u></b>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

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

	<u>Winter</u>
Cost of Purchased Gas	\$4.895
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.917

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

	Amount
Total Gas Costs 1/	\$15,587,025
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$4.450
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.470
Less: Gas Cost Level in Rates 2/	3.847
<b>Current Gas Cost Adjustment</b>	<b>\$0.623</b>

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

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

Cost of Purchased Gas	\$3.830
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.847



**Montana-Dakota Utilities Co.  
Schedule of Applicable Effective Pipeline Rates  
February 2014 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.	737.928	N.A.	N.A.	737.928
MINIMUM	RATE PER EQV. DKT PER MO	0.000	N.A.	N.A.	0.000
COMMODITY CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	3.120	N.A.	N.A.	3.120
MINIMUM A/B/C/	RATE PER DKT	3.120	N.A.	N.A.	3.120
SCHEDULED OVERRUN CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	30.884	N.A.	N.A.	30.884
MINIMUM A/B/C/	RATE PER DKT	3.120	N.A.	N.A.	3.120
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	24.261	N.A.	N.A.	24.261
MINIMUM	RATE PER DKT	0.000	N.A.	N.A.	0.000

- 
- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 2.766%, CONSISTING OF 3.057% FOR THE CURRENT PERCENTAGE AND (0.291%) FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.
  - B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR TRANSPORTATION. THE APPLICABLE RATE IS 1.230 CENTS, CONSISTING OF 1.300 CENTS FOR THE CURRENT RATE AND (0.070) CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.
  - C/ SHIPPER MUST REIMBURSE TRANSPORTER FOR THE ACA SURCHARGE. SUCH SURCHARGE SHALL BE THE ACA UNIT CHARGE SPECIFIED IN THE ANNUAL NOTICE ISSUED BY THE FERC ENTITLED "FY [YEAR] GAS ANNUAL CHARGES CORRECTION FOR ANNUAL CHARGES UNIT CHARGE."

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
-----					
RATE SCHEDULE FTN-1					
-----					
RESERVATION CHARGE					
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)					
MAXIMUM	RATE PER EQV. DKT PER MO.	47.491	N.A.	N.A.	47.491
MINIMUM	RATE PER EQV. DKT PER MO.	1.589	N.A.	N.A.	1.589
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	1.561	N.A.	N.A.	1.561
MINIMUM	RATE PER DKT	0.052	N.A.	N.A.	0.052

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
-----					
RATE SCHEDULE FS-1					
-----					
CAPACITY RESERVATION CHARGE					
MAXIMUM	RATE PER EQV. DKT PER MO.	2.102	N.A.	N.A.	2.102
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	0.000
CAPACITY DELIVERABILITY CHARGE					
MAXIMUM	RATE PER EQV. DKT PER MO.	190.602	N.A.	N.A.	190.602
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	0.000
INJECTION CHARGE					
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
WITHDRAWAL CHARGE					
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
SCHEDULED OVERRUN CHARGE					
INJECTION					
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
WITHDRAWAL					
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 0.996%, CONSISTING OF 1.163% FOR THE CURRENT PERCENTAGE AND (0.167%) FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR STORAGE. THE APPLICABLE RATE IS 0.131 CENTS, CONSISTING OF 0.098 CENTS FOR THE CURRENT RATE AND 0.033 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

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.

Issued: December 19, 2012  
Effective: January 1, 2013

Docket No. RP13-403-000  
Accepted: January 17, 2013

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>	
	2013568692	\$ 14.00	/ month
	2013568691	\$ 2.00	/ month
	2013568690	\$ 2.00	/ month
	2013568689	\$ 2,125.00	/ month
	2013568688	\$ 51.00	/ month
	2013568687	\$ 138.00	/ month
	2013568686	\$ 88.00	/ month
	2013568682	\$ 20.00	/ month
	2013568681	\$ 194.00	/ month
	2013568680	\$ 210.00	/ month
	2003004522	\$ 83,333.00	/ month
	2011475772	\$ 9,250.00	/ month
	2011476052 / 2011476054	\$ 0.1376 \$ 717,000.00	/ GJ subject to Minimum Annual Charge
	2011475056 / 2011476092 / 2011494569 / 2011476049 / 2011476050	\$ 0.095 \$ 1,000.00	/ GJ and / 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.

Effective Date: January 1, 2014

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 <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	
3933	BIG EDDY INTERCONNECTION	4.19	0.1514	
3067	BIGSTONE SALES	4.19	0.1514	
3468	BLEAK LAKE SALES	4.19	0.1514	
3225	BOTHA SALES	4.19	0.1514	
3164	BRAINARD LAKE SALES	4.19	0.1514	
3918	BUFFALO CREEK INTERCONNECTION	4.19	0.1514	
31015	BURDETT COGEN SALES APS	4.19	0.1514	
3204	CABIN SALES	4.19	0.1514	
3109	CALDWELL SALES	4.19	0.1514	
31016	CALGARY ENERGY CENTRE SALES APS	4.19	0.1514	Yes
3634	CANOE LAKE SALES	4.19	0.1514	
3165	CANOE LAKE SALES NO 2	4.19	0.1514	
3866	CARBON INTERCONNECTION	4.19	0.1514	
3484	CARIBOU LAKE SALES	4.19	0.1514	
3157	CARIBOU LAKE SOUTH SALES	4.19	0.1514	
3106	CARMON CREEK SALES	4.19	0.1514	
3101	CAROLINE SALES	4.19	0.1514	
31017	CARSELAND COGEN SALES APS	4.19	0.1514	
3495	CAVALIER SALES	4.19	0.1514	
31018	CHAIN LAKES COOP SALES APS	4.19	0.1514	
3907	CHANCELLOR INTERCONNECTION	4.19	0.1514	
3151	CHEECHAM WEST NO 2 SALES	4.19	0.1514	
3622	CHEECHAM WEST SALES	4.19	0.1514	
6014	CHEVRON AURORA SALES	4.19	0.1514	
31019	CHEVRON FT. SASK SALES APN	4.19	0.1514	Yes
3097	CHICKADEE CREEK SALES	4.19	0.1514	
3305	CHIGWELL NORTH SALES	4.19	0.1514	
3496	CHIPEWYAN RIVER SALES	4.19	0.1514	
3163	CHRISTINA LAKE NORTH SALES	4.19	0.1514	

NATURAL GAS TARIFF



Canceling  $\frac{35^{th}}{34^{th}}$  Revised Revised Sheet No. 80.1  
Sheet No. 80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT  
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

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

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	\$ 0.9840814	(I)
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Transmission Commodity Rate (Monthly Rate per Therm):

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

**GAS RATE SCHEDULE**

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

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

Date Filed: January 24, 2001

Effective Date: January 10, 2001

TRANSPORTATION SERVICE    Rate 1

Transportation rate is \$2.398 per dekatherm.

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

NG-00-001

**STATE OF SOUTH DAKOTA**  
**GAS RATE SCHEDULE**

**South Dakota Intrastate Pipeline Company**

SD P.U.C. Section No. 4

SourceGas Distribution LLC

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

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

Division	Receipt Point	Delivery Point	Monthly Customer Charge	Maximum Demand Charge 6/	Minimum Demand Charge 6/	Maximum Transportation Charge 2/	Minimum Transportation Charge 2/	Fuel Reimbursement Quantity Percentage 3/
TC (Casper) Firm Transportation	MLI	MLI	\$0.00	\$9.50	\$0.00	\$0.1040	\$0.0010	0.526%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.1040	\$0.0010	0.526%
	MLI	DSE	\$225.00	\$0.00	\$0.00	\$0.1978	\$0.0020	2.684%
Interruptible Transportation 4/	MLI	MLI	\$0.00	\$0.00	\$0.00	\$0.0844	\$0.0010	0.526%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.0844	\$0.0010	0.526%
Administrative Fee 5/			\$325.00					

1/ Casper Division service area is defined on Sheet Nos. 3 and 4 of this Tariff.

2/ All charges are per therm.

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

4/ Interruptible Transportation Service is not available to DSE customers. The Customer Charge will be charged only for those months gas actually flows.

5/ In addition to the transportation charges stated above, Shippers are responsible for the monthly administrative fee as stated, applicable to each meter located at the customer location. For Interruptible Transportation Shippers, the Administrative Fee will be charged only for those months gas actually flows. Firm Transportation Shippers will be charged each month, regardless of gas flow.

6/ Per Dth of MDTQ per month.

Abbreviations (as defined in the General Terms and Conditions of this Tariff):

MLI Mainline System Interconnect  
MLE Mainline System End-user  
DSE Distribution System End-user

MDTQ Maximum Daily Transportation Quantity

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

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

**MONTANA-DAKOTA UTILITIES CO.  
RETURN ON CYCLE STORAGE BALANCES  
AND PREPAID DEMAND AND COMMODITY BALANCES  
NORTH DAKOTA GAS  
EFFECTIVE FEBRUARY 2014**

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2013	\$11,873,285	\$524,021	\$3,373,058
November	10,083,032	468,480	2,743,332
December	3,405,996	301,762	1,299,466
January 2014	(870,018)	173,420	(416,084)
February	(5,008,969)	49,193	(1,618,301)
March	(5,668,252)	29,405	(2,402,201)
April	(5,540,094)	36,060	(2,208,793)
May	(2,966,387)	170,290	(1,282,405)
June	475,833	349,353	(46,291)
July	3,884,976	526,720	1,173,372
August	7,396,832	709,582	2,396,784
September	10,309,962	861,269	3,407,753
October	10,994,980	896,929	3,601,436
13 month average	<u>\$2,951,629</u>	<u>\$392,037</u>	<u>\$770,856</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$259,478	\$34,464	\$67,766
Return Requirement	<u>\$352,248</u>	<u>\$46,786</u>	<u>\$91,994</u>

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

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

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

Cost of Purchased Propane	\$145,352
Gallons Purchased	83,058
Projected dk Sales	7,600
Propane Cost per Dk	\$19.125
Average Cost of Propane as Adjusted for Losses @ 99.55%	19.211
Less: Propane Cost Level in Rates 1/	<u>15.919</u>
Current Propane Cost Adjustment	<u><u>\$3.292</u></u>

1/ Propane Cost Level in Current Rates - Case No. PU-13-008, effective January 1, 2014.

**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, 2013</b>									<b><u>\$268,918</u></b>
August	(\$171,535)	\$0	\$6	(\$171,529)	283,161	(\$0.113)	(\$31,997)	(\$139,532)	129,386
September	(10,802)	387,468 2/	2	376,668	259,134	(0.113)	(29,282)	405,949	535,335
October	91,702	0	15	91,717	509,627	0.024	(28,445) 3/	120,162	655,497
November	(43,397)	46,049 4/	27	2,679	1,155,975	0.024	27,743	(25,064)	630,433
<b>Balance @ November 30, 2013</b>									<b><u>\$630,433</u></b>

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

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

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

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

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

	<u>(Over) Under</u> <u>Recovery</u>	<u>Refunds &amp;</u> <u>Other</u>	<u>Interest 1/</u>	<u>Total Net</u> <u>Additions</u>	<u>Actual Dk</u> <u>Sales</u>	<u>Adjustment</u> <u>Per Dk</u>	<u>Total</u> <u>Adjustment</u> <u>Amount</u>	<u>Net Change-</u> <u>Additions less</u> <u>Adjustment</u>	<u>Cumulative</u> <u>Balance</u>
<b>Balance @ July 31, 2013</b>									<b><u>\$162,872</u></b>
August	(\$8,729)	\$0	\$4	(\$8,725)	32,348	(\$0.115)	(\$3,719)	(\$5,006)	157,866
September	(2,593)	0	1	(2,592)	33,833	(0.115)	(3,891)	1,299	159,165
October	9,049	0	4	9,053	55,674	0.116	(4,732) 2/	13,785	172,950
November	19,660	6,105 3/	7	25,772	126,614	0.116	14,687	11,085	184,035
<b>Balance @ November 30, 2013</b>									<b><u>\$184,035</u></b>

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

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

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

**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, 2013</b>									<b><u><u>\$86,961</u></u></b>
August	(\$1,327)	\$0	\$2	(\$1,325)	4,039	(\$0.377)	(\$1,522)	\$197	87,158
September	(5,633)	0	1	(5,632)	4,641	(0.377)	(1,750)	(3,882)	83,276
October	1,205	0	2	1,207	6,585	0.181	(2,484) 2/	3,691	86,967
November	3,672	1,691 3/	3	5,366	29,839	0.181	5,401	(35)	86,932
<b>Balance @ November 30, 2013</b>									<b><u><u>\$86,932</u></u></b>

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

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

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