

May 9, 2014

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

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

In accordance with North Dakota Century Code Section 49-05-05, Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., respectfully submits an original and two (2) copies of a Cost of Gas (COG) change pursuant to the terms of Rates 88 and 99.

Attachment A is the Rate Summary Sheet (125<sup>th</sup> Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered June 1, 2014.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.162 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. In addition, Montana-Dakota has seen a change in the pipeline rates, as shown on Attachment C, decreasing the cost of gas \$0.379 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 June 2014.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.212 per dk for residential and firm general customers, an increase of \$0.054 per dk for small and large interruptible customers and an increase of \$0.054 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 June 2014. The average cost of gas for firm customers, adjusted for losses, is \$6.202.

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

Montana-Dakota purchases propane supplies from various wholesale suppliers. There is no change in the cost of propane established in the May COG filing.

Exhibit D 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 a decrease of approximately \$226,500 for natural gas customers during the month of June 2014. All of Montana-Dakota's retail natural customers in North Dakota may be affected by this proposal. There were 102,057 natural gas customers in North Dakota as of April 30, 2014.

Please refer all inquiries regarding this filing to:

Ms. Tamie A. Aberle  
Director - Regulatory Affairs  
Montana-Dakota Utilities Co.  
400 North Fourth Street  
Bismarck, ND 58501

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


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

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

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

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

Sincerely,



Tamie A. Aberle  
Director of Regulatory Affairs

Attachment

**Rate Summary Sheet  
(Proposed)**



# Montana-Dakota Utilities Co.

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

## State of North Dakota Gas Rate Schedule

NDPSC Volume 7  
 125<sup>th</sup> Revised Sheet No. 3  
 Canceling 124<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	4	\$0.4935 per day	\$0.326	\$6.214	\$6.540
Air Force Rate 64	7				
Minot Air Force Base		\$2,000.00 per month			
PAR Site		\$175.00 per month			
Firm Service			\$0.329	\$6.214	\$6.543
Interruptible Service - PAR			\$0.260	\$5.194	\$5.454
Interruptible Service - MAFB			\$0.260	\$5.236	\$5.496
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	\$6.214	\$6.944
Small Interruptible Gas Rate 71	14	\$175.00 per month	(Maximum) \$0.929	\$5.194	(Maximum) \$6.123
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	\$5.071	\$5.801
Transportation Service	24				
Small Interruptible Rate 81		\$175.00 per month			
Maximum			\$0.485		
Minimum			\$0.102		
Fuel Charge				\$0.023	
Large Interruptible Rate 82		\$1,000.00 per month			
Maximum			\$0.297		
Minimum			\$0.061		
Fuel Charge				\$0.023	
Large Interruptible Gas Rate 85	27	\$1,000.00 per month	(Maximum) \$0.718	\$5.194	(Maximum) \$5.912
Residential Propane Rate 90	32	\$0.4935 per day	\$0.326	\$12.708	\$13.034
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	\$12.708	\$13.438

Date Filed: May 9, 2014

Effective Date: June 1, 2014

Issued By: Tamie A. Aberle  
 Director - Regulatory Affairs

Case No.: PU-14-008

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

**June 2014**

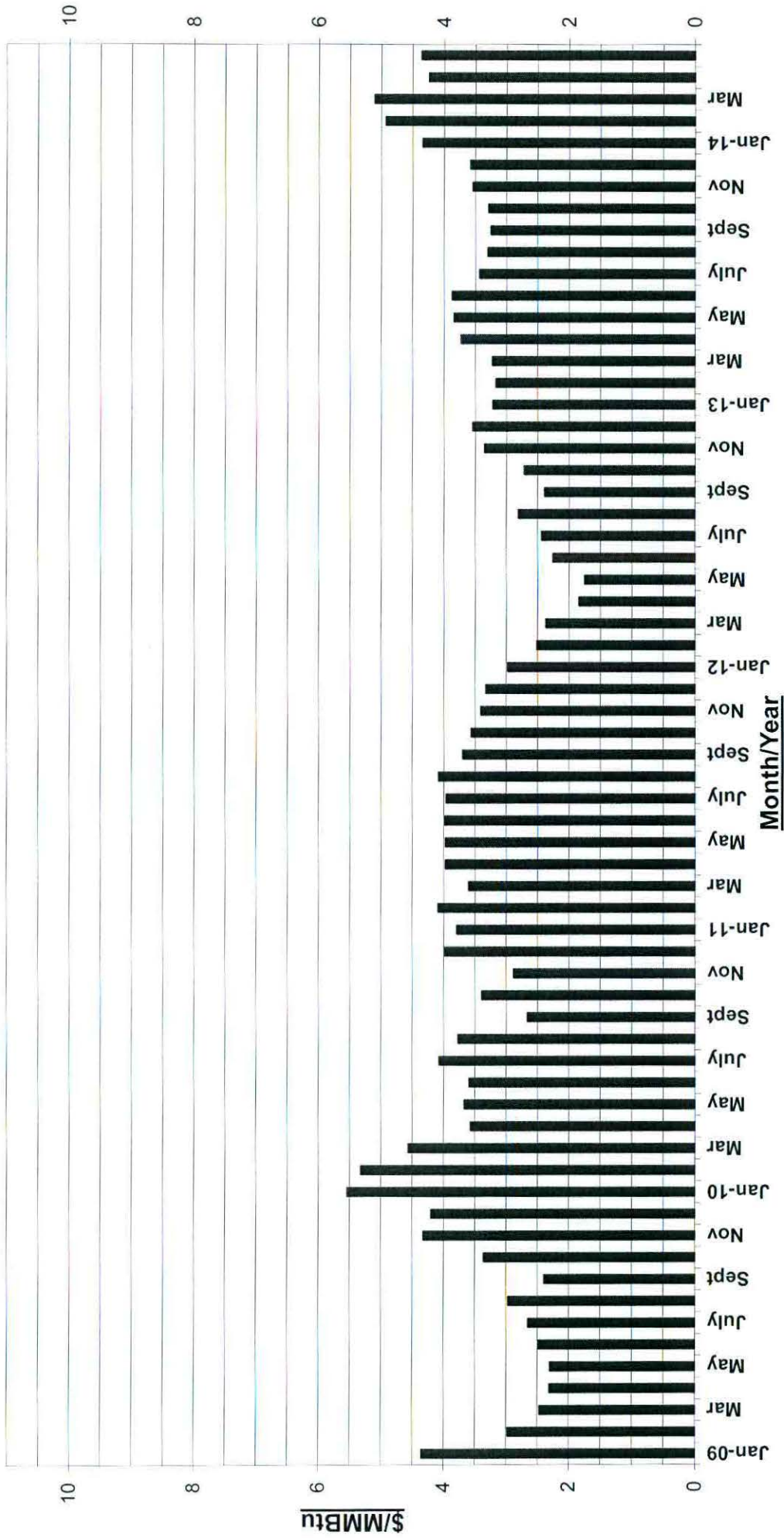
The established monthly price for the Rocky Mountain CIG Index has increased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including “Inside FERC Gas Market” report and “Gas Daily” by McGraw-Hill Companies, of prices paid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

National storage levels being at their lowest in the past 10 years was likely the driving factor in the month over month increase in the price of natural gas despite the continuing strong production levels in the lower 48 states. The storage level at the end of April was slightly under the 1 tcf level. The EIA reported the national storage level as of April 25, 2014, was 50.1 percent below the five-year average and 44.6 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 May Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 17. The June Outlook will be published June 10, 2014.

### 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-\$4.60

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

May 2014

## Short-Term Energy Outlook (STEO)

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### Highlights

- During the April-through-September summer driving season this year, regular gasoline retail prices are forecast to average \$3.61/gallon (gal), 3 cents higher than last year and 4 cents higher than projected in last month's STEO. The projected monthly national average regular gasoline retail price falls from \$3.72/gal in May to \$3.51/gal in September. EIA expects regular gasoline retail prices to average \$3.48/gal in 2014 and \$3.39/gal in 2015, compared with \$3.51/gal in 2013.
- Brent crude oil spot prices averaged \$108/barrel (bbl) in April. This was the 10<sup>th</sup> consecutive month in which the average Brent crude oil spot prices fell within a relatively narrow range of \$107/bbl to \$112/bbl. New pipeline capacity from the Midwest into the Gulf Coast helped reduce inventories at the Cushing, Oklahoma storage hub to 25 million barrels by the end of April, the lowest level since October 2009. The discount of WTI crude oil to Brent crude oil, which averaged more than \$13/bbl from November through January, fell below \$4/bbl in early April. Total U.S. commercial crude oil stocks at the end of April reached a record high of nearly 400 million barrels, which is expected to put downward pressure on crude oil prices. EIA projects Brent crude oil prices to average \$106/bbl in 2014 and \$102/bbl in 2015 and the WTI discount to Brent to average \$10/bbl and \$11/bbl in 2014 and 2015, respectively.
- EIA estimates U.S. total crude oil production averaged 8.3 million barrels/day (bbl/d) in April 2014, which would be the highest monthly average production since March 1988. U.S. total crude oil production, which averaged 7.4 million bbl/d in 2013, is expected to increase to 8.5 million bbl/d in 2014 and 9.2 million bbl/d in 2015. The 2015 forecast represents the highest annual average level of production since 1972.
- Natural gas working inventories on April 25 totaled 0.98 trillion cubic feet (Tcf), 0.79 Tcf (45%) below the level at the same time a year ago and 0.98 Tcf (50%) below the previous five-year average (2009-13). Very cold weather and low inventories contributed to volatile Henry Hub natural gas spot prices over the past few months, increasing from \$3.95 per million British thermal units (MMBtu) on January 10 to a high of \$8.15/MMBtu on February 10, before falling back to \$4.61/MMBtu on February 27, and then bouncing back up to \$7.98/MMBtu on March 4. EIA expects that the Henry Hub natural gas spot price, which averaged \$3.73/MMBtu in 2013, will average \$4.74/MMBtu in 2014, \$0.30 higher than in last month's STEO, and \$4.33/MMBtu in 2015.

## Global Petroleum and Other Liquids

EIA expects the combination of total liquids supply growth from countries outside of the Organization of the Petroleum Exporting Countries (OPEC) and noncrude oil supply growth in OPEC member countries to exceed world liquids demand growth over the next two years. The call on OPEC crude oil and global stocks (world consumption less non-OPEC supply and OPEC noncrude oil supply) is forecast to fall from an average of 30.0 million bbl/d in 2013 to 29.5 million bbl/d in 2015. Expected non-OPEC supply growth also contributes to an increase in global surplus crude oil production capacity held by OPEC countries from an average of 2.1 million bbl/d in 2013 to 3.5 million bbl/d in 2015.

**Global Petroleum and Other Liquids Consumption.** EIA estimates that global consumption grew by 1.2 million bbl/d in 2013, averaging 90.4 million bbl/d for the year. EIA expects global consumption to grow 1.2 million bbl/d in both 2014 and 2015. Projected global oil-consumption-weighted real GDP, which increased by an estimated 2.3% in 2013, grows by 2.8% and 3.3% in 2014 and 2015, respectively.

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

EIA expects lower OECD consumption in 2014, led by projected consumption declines in both Japan and Europe. EIA expects Japan's oil consumption to fall by an annual average of 130,000 bbl/d in 2014 and 160,000 bbl/d in 2015, as the country continues to increase natural gas and coal consumption in the electricity sector and returns some nuclear power plants to service in the second half of 2014 and in 2015. EIA projects that OECD Europe's consumption, which fell by 100,000 bbl/d in 2013, will decline by 70,000 bbl/d in 2014 and then remain flat in 2015. U.S. liquid fuel consumption, which increased by 400,000 bbl/d in 2013, is expected to increase by only 40,000 bbl/d in 2014 and then increase by 60,000 bbl/d in 2015.

**Non-OPEC Supply.** EIA estimates that non-OPEC liquid fuel production grew by 1.3 million bbl/d in 2013, averaging 54.0 million bbl/d for the year. EIA expects non-OPEC liquid fuel production to grow by 1.5 million bbl/d in 2014 and 1.1 million bbl/d in 2015. EIA forecasts production from the United States and Canada to grow by a combined annual average of 1.4 million bbl/d in 2014 and 1.1 million bbl/d in 2015. EIA estimates that production will rise by an annual average of 0.21 million bbl/d in 2014 in countries of the Former Soviet Union, led by Russia. However, production in the region only rises by 30,000 bbl/d in 2015. The forecast of completion of phase 1 of Kazakhstan's Kashagan field has been pushed back to the second half of 2015 because of continued problems delaying the start of commercial production at the field.

Unplanned supply disruptions among non-OPEC producers averaged 0.6 million bbl/d in April 2014, roughly unchanged from March. South Sudan, Syria, and Yemen accounted for almost 90% of total non-OPEC supply disruptions. EIA does not assume a disruption to oil supply or demand as a result of ongoing events in Ukraine.

**OPEC Supply.** EIA estimates that OPEC crude oil production averaged 30.0 million bbl/d in 2013, a decline of 0.9 million bbl/d from the previous year, primarily reflecting production declines in Iran, increased unplanned outages in Libya, Nigeria, and Iraq, and strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.4 million bbl/d in 2014 and an additional 0.1 million bbl/d in 2015, as a result of supply disruptions in OPEC and cutbacks in crude oil production to accommodate increased supplies in non-OPEC countries.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.6 million bbl/d in April, slightly lower than the previous month. Libya continues to experience swings in its production, contributing to changes in the OPEC disruption estimate.

EIA expects that OPEC surplus capacity, which is concentrated in Saudi Arabia, will average 2.3 million bbl/d in 2014 and 3.5 million bbl/d in 2015. This build in surplus capacity reflects production cutbacks by some OPEC members adjusting for the higher supply from non-OPEC producers. These estimates do not include additional capacity that may be available in Iran but is currently offline because of the effects of U.S. and European Union sanctions on Iran's oil sector.

**OECD Petroleum Inventories.** EIA estimates that OECD commercial oil inventories totaled 2.58 billion barrels at the end of 2013, equivalent to roughly 55 days of consumption. Projected OECD oil inventories remain near 2.60 billion barrels at the end of both 2014 and 2015.

**Crude Oil Prices.** North Sea Brent crude oil spot prices averaged \$108/bbl in April. This was the 10<sup>th</sup> consecutive month in which average Brent crude oil spot prices fell within a relatively narrow range of \$107/bbl to \$112/bbl. The forecast Brent crude oil price averages \$106/bbl and \$102/bbl in 2014 and 2015, respectively, both \$1/bbl higher than in last month's STEO.

The January 2014 startup of TransCanada's Marketlink pipeline, moving crude from Cushing to the Gulf Coast, and strong refinery runs contributed to an increase in the WTI crude oil spot price from an average of \$94/bbl in January to \$102/bbl in April. The discount of WTI crude oil to Brent crude oil, which averaged more than \$13/bbl from November 2013 through January 2014, fell to an average of less than \$6/bbl in April. EIA expects the discount of WTI crude oil to Brent crude oil to grow in the coming months to an average \$10/bbl in 2014 and \$11/bbl in 2015, reflecting [the economics of transporting and processing](#) the growing production of high API gravity (very light) sweet crude oil in the United States.

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 August 2014 delivery, traded during the five-day period ending May 1, 2014, averaged \$99/bbl. Implied volatility averaged 17%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in August 2014 at \$85/bbl and \$115/bbl, respectively. Last year at this time, WTI for August 2013 delivery averaged \$93/bbl and implied volatility averaged 22%. The corresponding lower and upper limits of the 95% confidence interval were \$77/bbl and \$113/bbl.

## U.S. Petroleum and Other Liquids

U.S. regular gasoline retail prices increased for the 12<sup>th</sup> consecutive week in late April 2014, rising from a weekly average of \$3.29/gal on February 3 to reach \$3.71/gal as of April 28. This price is about \$0.19/gal higher than at the same time last year, and has been driven by higher crude oil prices, strong demand for gasoline (both domestically and for export) and lower inventory levels. However, EIA expects crude oil prices to decline this summer, in contrast to last year when oil prices rose over the same time period. Consequently, the regular gasoline retail price is expected to average only 3 cents higher this summer compared with last summer.

**Liquid Fuels Consumption.** Total U.S. liquid fuels consumption rose by an estimated 400,000 bbl/d (2.1%) in 2013. Total consumption growth slows, to 40,000 bbl/d in 2014 and 70,000 bbl/d in 2015. Consumption of hydrocarbon gas liquids (HGL) registered the largest gain in 2013, increasing by 150,000 bbl/d (6.4%). HGL consumption growth of 30,000 bbl/d in 2014 and 50,000 bbl/d in 2015 is led by increasing ethane use as a feedstock in ethylene production units.

Motor gasoline consumption grew by 90,000 bbl/d (1.1%) in 2013, the largest increase since 2006. Motor gasoline consumption grows by 20,000 bbl/d in 2014 and remains flat in 2015 as improving new vehicle fuel economy increasingly offsets highway travel growth. Distillate fuel consumption increased by 90,000 bbl/d (2.5%) last year, reflecting colder weather and domestic economic growth. Distillate fuel oil consumption rises by 70,000 bbl/d and 60,000 bbl/d in 2014 and 2015, respectively. The increases in HGL, gasoline, and distillate consumption are partially offset by declines in consumption of residual fuel oil and unfinished oils.

**Liquid Fuels Supply.** Forecast total U.S. crude oil production increases from an estimated 7.4 million bbl/d in 2013 to 8.5 million bbl/d in 2014 and 9.2 million bbl/d in 2015. The highest previous annual average U.S. production level was 9.6 million bbl/d in 1970. EIA has increased its Gulf of Mexico crude oil production forecast as new wells in the Mars field began producing ahead of schedule in February 2014. The Olympus platform and Mars B infrastructure, owned by Shell and BP, is the first major expansion of the Mars field. Mars B production is expected to reach 100,000 bbl/d in 2015. Although the peak production levels have not changed, earlier reports indicated that the Mars B system would begin producing in late 2014 or early 2015. U.S. federal Gulf of Mexico (GOM) production, which has fallen for four consecutive years, is projected to increase by 150,000 bbl/d in 2014 and by an additional 240,000 bbl/d in 2015.

HGL production at natural gas liquids plants is projected to rise from 2.6 million bbl/d in 2013 to 2.9 million bbl/d in 2015. About half of this growth is expected to come from ethane production to meet growing demand associated with expanding domestic ethylene production and export capacity. Ethane exports recently began flowing to Canada on the Mariner West and Vantage pipelines. In the second half of 2015, the Mariner East pipeline and new infrastructure at Marcus Hook, near Philadelphia, are expected to facilitate the movement of ethane from the Marcellus and Utica shales to Europe.

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 23% in 2015, which would be the lowest level since 1970.

**Petroleum Product Prices.** Led by falling 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 \$3.48/gal in 2014 and \$3.39 in 2015. Diesel fuel prices, which averaged \$3.92/gal in 2013, are projected to average \$3.87/gal in 2014 and \$3.78/gal in 2015.

EIA expects that the monthly average regular gasoline retail price, which was \$3.66/gal in April, will peak at \$3.72/gal in May and then fall to \$3.51/gal in September. The August 2014 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged \$2.90/gal for the five trading days ending May 1. Based on the market value of futures and options contracts for this key petroleum component of gasoline, there is a 4% probability that its price at expiration will exceed \$3.35/gal, consistent with a monthly average regular-grade gasoline retail price exceeding \$4.00/gal in August 2014. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas exceeding the national average price by 30 cents/gal or more.

## Natural Gas

On April 23, one of the five units at the [Williams Company's Opal, Wyoming, natural gas processing plant exploded and caught on fire](#). The plant, which had been processing about 1.0 Bcf/d according to Williams, partially returned to service by Thursday, May 1. While the plant was down, natural gas pipeline flows into California and the Southwest (Arizona, Nevada, and New Mexico) from the Permian Basin in West Texas and New Mexico, and rerouted production from the Rockies, offset lost output from Opal. This limited natural gas price increases in the region that could result from temporary supply shortages.

**Natural Gas Consumption.** EIA expects total natural gas consumption will average 72.3 billion cubic feet per day (Bcf/d) in 2014, an increase of 1.3% from 2013, led by the industrial sector. In 2015, total natural gas consumption falls by 0.1 Bcf/d as a return to near-normal winter weather contributes to lower residential and commercial consumption. Higher natural gas prices this

year contribute to a 0.4% decline in natural gas consumption in the power sector to 22.2 Bcf/d in 2014. EIA expects natural gas consumption in the power sector to increase to 23.1 Bcf/d in 2015 with the retirement of some coal plants.

**Natural Gas Production and Trade.** EIA expects natural gas marketed production will grow by an average rate of 3.0% in 2014 and 1.8% in 2015. Rapid natural gas production growth in the Marcellus formation is contributing to falling natural gas forward prices in the Northeast, which often fall even with or below Henry Hub prices outside of peak winter demand months. Consequently, some drilling activity may move away from the Marcellus back to Gulf Coast plays such as the Haynesville and Barnett, where prices are closer to the Henry Hub spot price.

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

Growing domestic production over the past several years has displaced some [pipeline imports from Canada](#), while [exports to Mexico](#) have increased. EIA projects net imports of 3.7 Bcf/d in 2014 and 3.1 Bcf/d in 2015, which would be the lowest level since 1987. Over the longer term, the [EIA Annual Energy Outlook 2014](#) projects the United States will be a net exporter of natural gas beginning in 2018.

**Natural Gas Inventories.** Natural gas working inventories increased by 159 Bcf over the last four weeks to reach 981 Bcf on April 25, which is 790 Bcf lower than the same time last year and 984 Bcf lower than the previous 5-year (2009-2013) average. The injection season has started somewhat slowly, but EIA expects injections will pick up over the summer to end October at just over 3,400 Bcf. EIA projects the rate of injections between April 25 and the end of October will average about 90 Bcf per week, which is 20 Bcf greater than the average weekly injection during the past five years.

**Natural Gas Prices.** Natural gas spot prices averaged \$4.66/MMBtu at the Henry Hub in April, down \$0.24/MMBtu from March, as spring weather finally arrived in much of the United States. EIA projects that spot prices will continue to decline but at a slower pace through the spring and summer. Projected Henry Hub natural gas prices average \$4.74/MMBtu in 2014 and \$4.33/MMBtu in 2015.

Natural gas futures prices for August 2014 delivery (for the five-day period ending May 1) averaged \$4.78/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for August 2014 contracts at \$3.63/MMBtu and \$6.31/MMBtu, respectively. At this time last year, the natural gas futures

contract for August 2013 averaged \$4.34/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$3.22/MMBtu and \$5.84/MMBtu.

## Coal

The severe winter weather, which increased power demand, combined with rail shipment constraints, contributed to a large drawdown in coal inventories. Power sector stockpiles have fallen by 34 million short tons (MMst) (21%) between the end of November and the end of March. Recent milder weather has helped to relieve some of the [rail congestion experienced this winter](#). According to [Association of American Railroads](#) data for the week ending April 26, total coal shipments increased 8.0% compared with the same week in 2013. It was the seventh consecutive week in which coal shipments increased, and year-to-date shipments of coal are up slightly (1.2%) from the same period last year.

**Coal Supply.** EIA projects U.S. coal production will grow 4.4% to 1,028 MMst in 2014, driven by higher consumption. In 2015, forecast U.S. coal production falls by 1.1% to 1,016 MMst.

**Coal Consumption.** EIA projects that U.S. consumption will grow at a rate of 5.0% to 971 MMst in 2014 as electricity demand grows and natural gas prices remain well above their 2013 level. Total coal consumption is projected to decline by 3.2% in 2015, as retirements of coal power plants rise in response to the implementation of the [Mercury and Air Toxics Standards](#), and generation from renewable resources (wind, hydro, biomass, geothermal, and solar) grows by more than 3.0%. EIA is currently not forecasting any additional changes in coal use based on the April 29 decision by the U.S. Supreme Court reversing a lower court opinion that vacated the [Cross-State Air Pollution Rule \(CSAPR\)](#). CSAPR will replace the [Clean Air Interstate Rule \(CAIR\)](#). The U.S. Environmental Protection Agency (EPA) is currently reviewing the Supreme Court opinion, and the EPA has stated that “At this time, CAIR remains in place and no immediate action from states or affected sources is expected.”

**Coal Exports.** Exports are projected to total nearly 100 MMst in 2014. Coal exports totaled more than 100 MMst per year between 2011 and 2013. Before that, coal exports had not reached 100 MMst since 1992. In 2015, projected exports fall back to 91 MMst, primarily because of continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, and increasing coal output in other coal-exporting countries.

**Coal Prices.** Annual average coal prices to the electric power industry fell for the second consecutive year, from \$2.38/MMBtu in 2012 to \$2.35/MMBtu in 2013. EIA forecasts average delivered coal prices of \$2.34/MMBtu in 2014 and \$2.35/MMBtu in 2015.

## Electricity

Retail electricity prices increased in many areas of the country during the first quarter of 2014, especially in the Northeast where high fuel costs drove up utilities' generation costs and the costs of purchasing electricity on wholesale power markets. EIA estimates first quarter retail electricity prices for the residential sector in New England were 11% higher than the same time last year, and residential prices in the Middle Atlantic region were 8% higher. Year-over-year increases in commercial sector electricity prices were highest in the Middle Atlantic (11%) and Pacific (8%) regions, while industrial prices increased the most in Middle Atlantic (19%) and South Atlantic (9%) regions.

**Electricity Consumption.** U.S. cooling degree days during the summer months (April-September) of 2014 are projected to total 5.7% more than last summer, when average summer temperatures in the United States were lower than normal. The increased need for space cooling contributes to the expected 1.5% summer-over-summer increase in U.S. electricity sales to the residential sector and the 2.2% increase in sales to the commercial sector.

**Electricity Generation.** EIA projects total U.S. electricity generation will average 11.4 terawatt-hours per day in 2014, an increase of 2.2% from last year. The use of coal for power generation rises 6.4% this year while natural gas-fired generation falls 2.0% and nuclear generation falls 2.7% from last year's levels. Both coal-fired and natural gas-fired generation decline in the West, as more hydropower and other renewable generation becomes available. There is little change in total generation during 2015, but the relative share of generation fueled by coal declines 1.5 percentage points to 39.2% next year, while the share fueled by natural gas rises to 27.4%.

**Electricity Retail Prices.** EIA has raised its forecasts for retail electricity prices from last month's STEO to reflect the higher-than-expected first quarter rate increases in the Northeast. The U.S. residential price of electricity is forecast to average 12.5 cents per kilowatt-hour during 2014, an increase of 2.9% from 2013. Projected residential prices increase an additional 2.1% during 2015.

## Renewables and Carbon Dioxide Emissions

**Electricity and Heat Generation from Renewables.** EIA projects total renewables consumption for electricity and heat generation will grow by about 3.3% in 2014. Hydropower is projected to increase by 2.9%, while nonhydropower renewables rise by 3.6%. In 2015, projected renewables consumption for electric power and heat generation increases by 3.2% from 2014, as a 0.3% decrease in hydropower is combined with a 5.1% increase in nonhydropower renewables.

EIA estimates that wind power capacity will increase by 9.0% in 2014 and 15.5% in 2015. Electricity generation from wind is projected to contribute 4.5% of total electricity generation in 2015.

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

**Liquid Biofuels.** [Railroad delays because of extreme winter temperatures in the Midwest contributed to sharp ethanol price increases across the United States](#) in February and March, especially in PADD 1 (East Coast). These rail constraints have since eased and ethanol prices fell as ethanol production increased from an average of 890,000 bbl/d in March to more than 910,000 bbl/d in April. Ethanol production is forecast to average 911,000 bbl/d during 2014 and 922,000 bbl/d in 2015.

Biodiesel production reached [104,000 bbl/d \(135 million gallons\) in December 2013](#), then fell to 54,000 bbl/d in January following the expiration of the biodiesel production tax credit at the end of 2013. Biodiesel production averaged 89,000 bbl/d in 2013 and is forecast to average 84,000 bbl/d in 2014 and 86,000 bbl/d in 2015.

**Energy-Related Carbon Dioxide Emissions.** EIA estimates that carbon dioxide emissions from fossil fuels increased by 2.2% in 2013 from the previous year. Emissions are forecast to rise 2.3% in 2014, followed by a 1.0% decline in 2015. The increase in emissions in 2013 and 2014 reflects growth in coal consumption because of its higher use in electric power generation. Coal emissions are projected to decline by 3.3% in 2015 with increasing coal plant retirements.

## U.S. Economic Assumptions

New orders for durable goods rose 2.6% from February to March according to the [U.S. Census Bureau](#), up from the 2.1% reported last month. The gain was more broad-based than from January to February, as it was driven by transportation, defense, and core capital goods, beating expectations of 0.6%. The [Federal Reserve's industrial production index](#) also gained 0.7% percent in March, and the February estimate was revised upwards. The news on the housing market, however, was less upbeat. [Census](#) reported that sales of new single-family homes fell 14.5% from February to March, and were 13.3% below the March 2013 estimate.

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

**Production and Income.** The [Bureau of Economic Analysis](#) estimates that real gross domestic product increased at an annual rate of 0.1 percent in the first quarter (that is, from the fourth quarter of 2013 to the first quarter of 2014). Forecast real GDP grows by 2.3% in 2014 and 2.9% in 2015, lower than the 2.5% and 3.2% forecast last month. The lower 2014 GDP growth forecast reflects concerns about lower inventory growth, first quarter weather, and capital spending and exports. In 2015, the reduced growth rate results from lower expectations of growth in the housing market and residential construction, and the subsequent impact on housing-related expenditures. Forecast real disposable income increases 2.1% in 2014 and 3.4% in 2015. Total industrial production grows at 3.6% in 2014 and 3.2% in 2015.

**Expenditures.** Private real fixed investment growth averages 5.5% and 8.7% in 2014 and 2015, respectively, with equipment and structures both growing around 6% in 2014. Real consumption expenditures grow at nearly the same rate as real GDP in 2014 and 2015, at 2.4% and 2.9%. Durable goods expenditures drive consumption spending. Export growth is 4.2% and 4.1% over the same two years, while import growth is 2.9% in 2014 and 6.2% in 2015. Total government expenditures fall 0.6% in 2014, but increase by 0.4% in 2015.

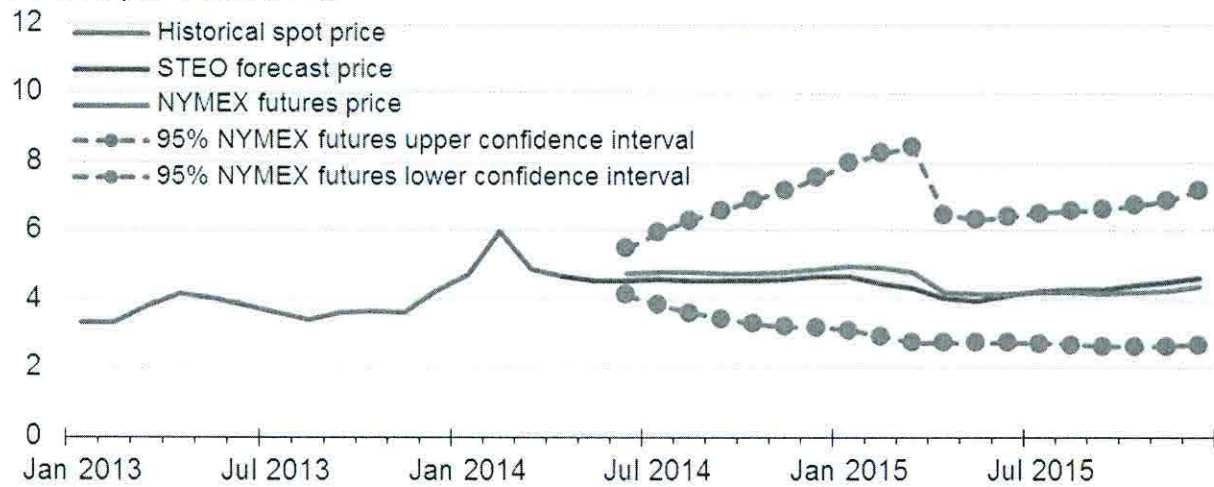
**Employment, Housing, and Prices.** Projected growth in nonfarm employment averages 1.6% in 2014 and 1.8% in 2015. This is accompanied by a gradually declining unemployment rate that reaches 6.4% by the end of 2014 and 5.9% at the end of 2015. The employment growth in 2014 and 2015 is slower than projected last month with more modest declines in unemployment. These reflect the lowering of the real GDP growth forecasts for 2014 and 2015. Housing starts grow an average of 12.0% and 32.5% in 2014 and 2015, respectively. Both consumer and producer price indexes continue to increase at a moderate pace, as wages continue to show modest gains.

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

## Henry Hub Natural Gas Price



dollars per million Btu

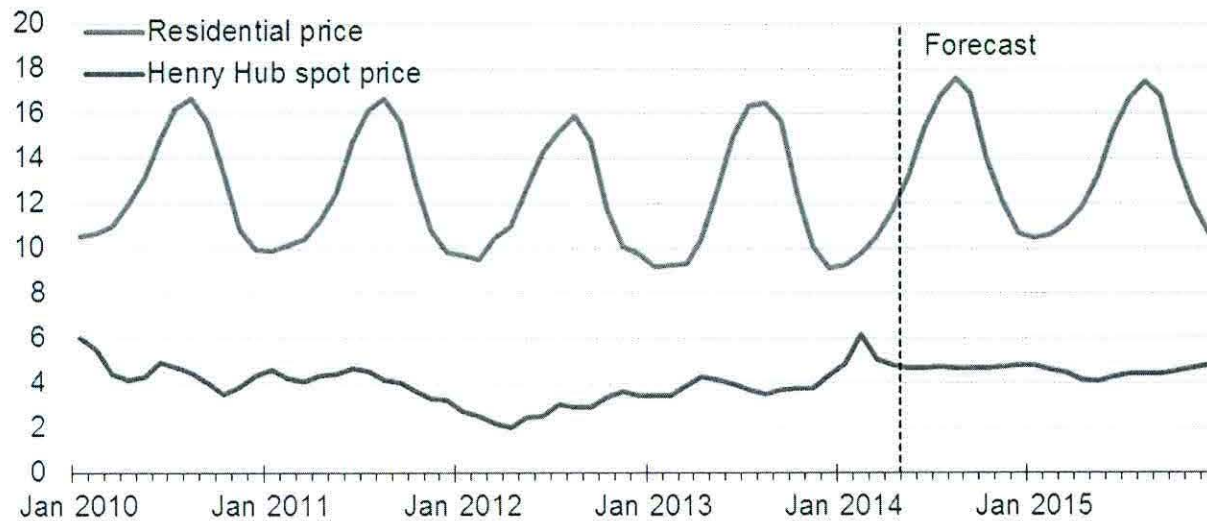


Note: Confidence interval derived from options market information for the 5 trading days ending May, 1, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, May 2014.

## U.S. Natural Gas Prices

dollars per thousand cubic feet



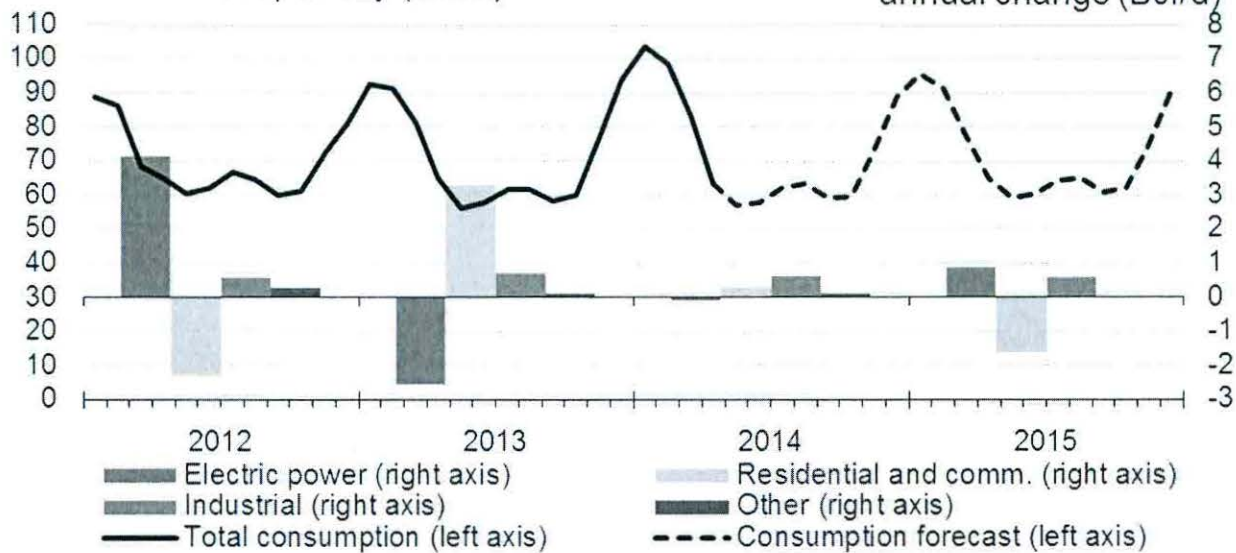
Source: Short-Term Energy Outlook, May 2014.

# U.S. Natural Gas Consumption

billion cubic feet per day (Bcf/d)

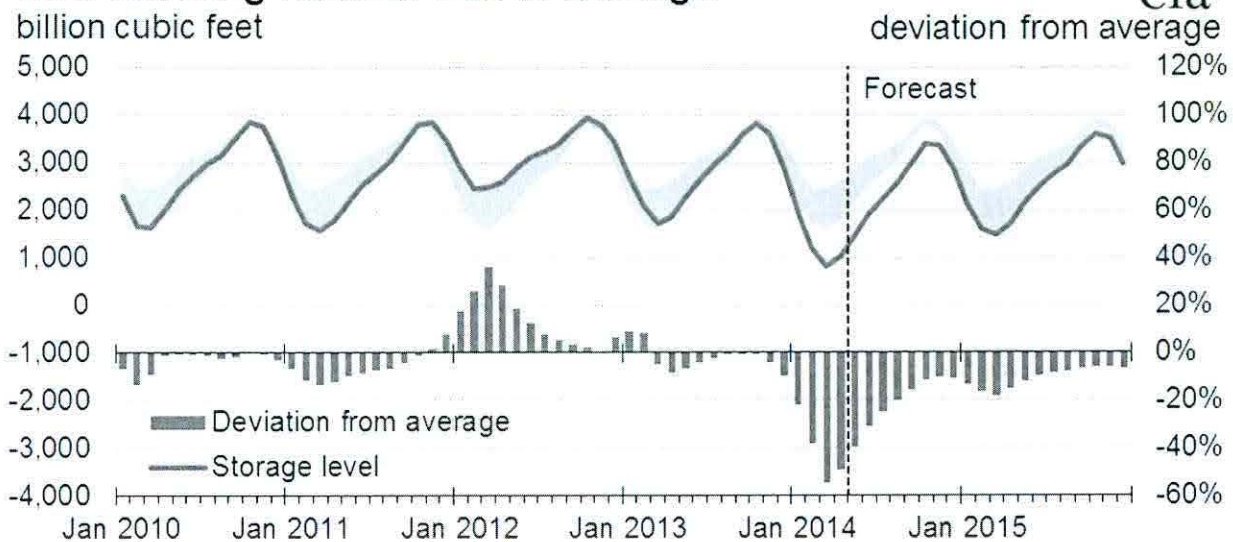


annual change (Bcf/d)



Source: Short-Term Energy Outlook, May 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.

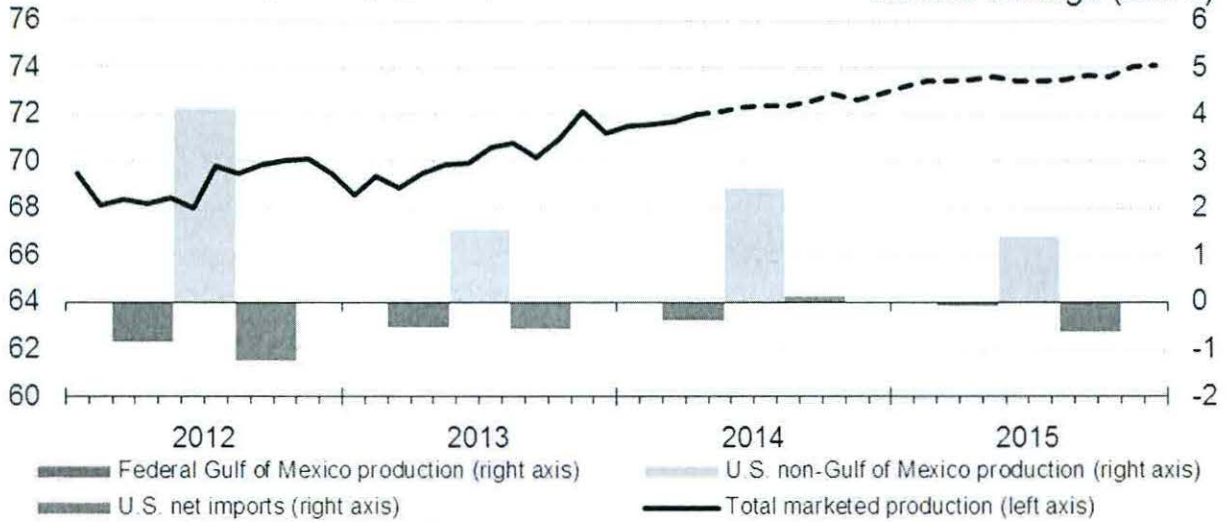
Source: Short-Term Energy Outlook, May 2014.

## U.S. Natural Gas Production and Imports

billion cubic feet per day (Bcf/d)



annual change (Bcf/d)



Source: Short-Term Energy Outlook, May 2014.

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

**WBI Energy Transmission, Inc. Docket No. RP14-118-003**

On May 8, 2014, WBI Energy Transmission, Inc. (WBI Energy) filed interim settlement rates to place into effect on May 1, 2014, in Docket No. RP14-118-003, reflecting revisions to its rates in FERC Gas Tariff, Third Revised Volume No. 1.

Approximate impact on Montana-Dakota's cost of gas: (\$0.38) per dk

MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS TARIFF SHEET  
NORTH DAKOTA GAS  
EFFECTIVE JUNE 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)	\$6.202	\$5.059	\$5.078	\$5.055
Prior Gas Cost	6.414	6.554	5.024	5.001
Current Gas Cost Adjustment	(\$0.212)	(\$1.495)	\$0.054	\$0.054
<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>(\$0.212)</b>	<b>(\$1.495)</b>	<b>\$0.054</b>	<b>\$0.054</b>
Gas Cost Level	\$6.202	\$5.059	\$5.078	\$5.055
Plus: Surcharge	0.024	0.024	0.116	0.181
Total Gas Cost Level in Tariff Rates	\$6.226	\$5.083	\$5.194	\$5.236

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

	Amount
Total Gas Costs 1/	\$94,649,845
Residential and General Service dk Requirements 2/	15,329,905
Average Cost of Gas per dk	\$6.174
Average Cost of Gas as Adjusted for Losses @ 99.55%	6.202
Less: Gas Cost Level in Rates 3/	6.414
<b>Current Gas Cost Adjustment</b>	<b>(\$0.212)</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 February 28, 2014, adjusted for losses at .45%.
- 3/ Gas Cost Level in Current Tariff Rates Case No. PU-14-008 effective May 1, 2014:
- |                                     |         |
|-------------------------------------|---------|
| Cost of Purchased Gas               | \$6.385 |
| Adjustment for Distribution Losses  | 0.9955  |
| Gas Cost Level in Base Tariff Rates | \$6.414 |

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

Total Gas Costs 1/	\$94,649,845
Less: Annual MDDQ Costs 1/	<u>17,452,859</u>
Total Gas Costs excluding MDDQ	\$77,196,986
Firm Service Requirements 1/	15,329,905
Other Gas Costs per Dk (excluding MDDQ)	\$5.036
<u>Summer - June - September</u>	
Summer Seasonal Rate, adjusted for losses 2/	5.059
Less: Gas Cost Level in Rates 3/	<u>6.554</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>(\$1.495)</u></u></b>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

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

	<u>Winter</u>
Cost of Purchased Gas	\$6.525
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$6.554

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

	Amount
Total Gas Costs 1/	\$17,706,957
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$5.055
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.078
Less: Gas Cost Level in Rates 2/	5.024
<b>Current Gas Cost Adjustment</b>	<b>\$0.054</b>

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

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

Cost of Purchased Gas	\$5.001
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.024

MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
AIR FORCE INTERRUPTIBLE  
EFFECTIVE JUNE 2014

	<u>Amount</u>
Total Gas Costs 1/	\$4,448,533
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$5.055
Less: Gas Cost Level in Rates 2/	<u>5.001</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.054</u></u></b>

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

2/ Gas Cost Level in Current Tariff Rates Case No. PU-14-008 effective May 1, 2014:  
Cost of Purchased Gas \$5.001

**Montana-Dakota Utilities Co.  
Schedule of Applicable Effective Pipeline Rates  
June 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.	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 2.560%, CONSISTING OF 2.275% FOR THE CURRENT PERCENTAGE AND 0.285% FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR TRANSPORTATION. THE APPLICABLE RATE IS 1.727 CENTS, CONSISTING OF 1.407 CENTS FOR THE CURRENT RATE AND 0.320 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.
- C/ SHIPPER MUST REIMBURSE TRANSPORTER FOR THE ACA SURCHARGE. SUCH SURCHARGE SHALL BE THE ACA UNIT CHARGE SPECIFIED IN THE ANNUAL NOTICE ISSUED BY THE FERC ENTITLED "FY [YEAR] GAS ANNUAL CHARGES CORRECTION FOR ANNUAL CHARGES UNIT CHARGE."

Issued On: May 8, 2014  
 Docket Number:  
 FERC Order Date:

Effective On: May 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

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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 0.642%, CONSISTING OF 0.684% FOR THE CURRENT PERCENTAGE AND (0.042%) FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR STORAGE. THE APPLICABLE RATE IS (0.140) CENTS, CONSISTING OF 0.000 CENTS FOR THE CURRENT RATE AND (0.140) CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

Issued On: May 8, 2014  
 Docket Number:  
 FERC Order Date:

Effective On: May 1, 2014

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

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

STATEMENT OF RATES  
2/ 3/

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

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

Service	Rates, Tolls and Charges		
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month based on a three year term (Price Point "B") & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) \$ 216.98/10 <sup>3</sup> m <sup>3</sup>		
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D <sup>1</sup>	Refer to Attachment "2" for applicable FT-D Demand Rate per month based on a one year term (Price Point "Z") & Surcharge for each Group 1 or Group 2 Delivery Point Average FT-D Demand Rate for Group 1 Delivery Points \$ 5.23/GJ FT-D Demand Rate for Group 2 Delivery Points \$ 4.19/GJ FT-D Demand Rate for Group 3 Delivery Points \$ 5.02/GJ		
4. Rate Schedule STFT	STFT Bid Price = Minimum of 100% of the applicable FT-D Demand Rate based on a one year term (Price Point "Z") for each Group 1 Delivery Point		
5. Rate Schedule FT-DW	FT-DW Bid Price = Minimum of 125% of the applicable FT-D Demand Rate based on a three year term (Price Point "Y") for each Group 1 Delivery Point		
6. Rate Schedule FT-P <sup>1</sup>	Refer to Attachment "3" for applicable FT-P Demand Rate per month		
7. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10<sup>3</sup>m<sup>3</sup>/day)</u>	
	1-5 years	11.29	
	6-10 years	9.44	
	15 years	8.46	
	20 years	7.51	
8. Rate Schedule LRS-3	LRS-3 Demand Rate per month	\$ 129.55/10 <sup>3</sup> m <sup>3</sup>	
9. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
10. Rate Schedule IT-D <sup>1</sup>	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point		
11. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
12. Rate Schedule PT	<u>Schedule No.</u>	<u>PT Rate</u>	<u>PT Gas Rate</u>
	9009-01001-1	\$ 660.00/d	50.0 10 <sup>3</sup> m <sup>3</sup> /d
13. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2014612719	\$ 2.00 / month	
	2014612718	\$ 2.00 / month	
	2014612720	\$ 2,174.00 / month	
	2014612725	\$ 20.00 / month	
	2014612724	\$ 129.00 / month	
	2014612723	\$ 71.00 / month	
	2014612722	\$ 15.00 / month	
	2014612721	\$ 283.00 / month	
	2014612717	\$ 212.00 / month	
	2011475772	\$ 9,250.00 / month	
	2014613454	\$ 650.00 / month	
	2003004522	Applicable IT-R and IT-D Rate	
	2011476052 /	\$ 0.1376	/ GJ subject to
	2011476054	\$ 717,000.00	Minimum Annual Charge
	2011475056 / 2011476092 /	\$ 0.095	/ GJ and
	2011476049 / 2011476050	\$ 1,000.00	/ month
14. Rate Schedule CO <sub>2</sub>	<u>Tier</u>	<u>CO<sub>2</sub> Rate (\$/10<sup>3</sup>m<sup>3</sup>)</u>	
	1	528.30	
	2	418.06	
	3	272.20	

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

Group 1 Delivery Point Number	Group 1 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" (\$/GJ)	IT-D Rate per Day (\$/GJ)
2000	ALBERTA-B.C. BORDER	5.18	0.1874
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	4.19	0.1514
31110	ALLIANCE EDSON INTERCONNECT APN	4.19	0.1514
31112	ALLIANCE SHELL CREEK INTERCONNECT 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	
3259	BOULDER CREEK SALES	4.19	0.1514	
3164	BRAINARD LAKE SALES	4.19	0.1514	
3918	BUFFALO CREEK INTERCONNECTION	4.19	0.1514	
31015	BURDETT COGEN SALES APS	4.19	0.1514	
3204	CABIN SALES	4.19	0.1514	
3109	CALDWELL SALES	4.19	0.1514	
31016	CALGARY ENERGY CENTRE SALES APS	4.19	0.1514	Yes
3634	CANOE LAKE SALES	4.19	0.1514	
3165	CANOE LAKE SALES NO 2	4.19	0.1514	
3866	CARBON INTERCONNECTION	4.19	0.1514	
3484	CARIBOU LAKE SALES	4.19	0.1514	
3157	CARIBOU LAKE SOUTH SALES	4.19	0.1514	
3106	CARMON CREEK SALES	4.19	0.1514	
3101	CAROLINE SALES	4.19	0.1514	
31017	CARSELAND COGEN SALES APS	4.19	0.1514	
3495	CAVALIER SALES	4.19	0.1514	
31018	CHAIN LAKES COOP SALES APS	4.19	0.1514	
3907	CHANCELLOR INTERCONNECTION	4.19	0.1514	
3151	CHEECHAM WEST NO 2 SALES	4.19	0.1514	
3622	CHEECHAM WEST SALES	4.19	0.1514	
6014	CHEVRON AURORA SALES	4.19	0.1514	
31019	CHEVRON FT. SASK SALES APN	4.19	0.1514	Yes
3097	CHICKADEE CREEK SALES	4.19	0.1514	
3305	CHIGWELL NORTH SALES	4.19	0.1514	
3496	CHIPEWYAN RIVER SALES	4.19	0.1514	
3163	CHRISTINA LAKE NORTH SALES	4.19	0.1514	

NATURAL GAS TARIFF

**NorthWestern**  
**Energy**

Canceling <sup>35<sup>th</sup></sup> Revised Sheet No. 80.1  
<sup>34<sup>th</sup></sup> Revised Sheet No. 80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT  
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge	
5,001 to 10,000	\$ 120.40	(1)
10,001 to 30,000	\$ 173.05	(1)
>30,000	\$ 384.05	(1)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

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

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum \$ 0.0074572 (1)

Minimum \$ 0.0017935

GTAC Amortization \$ (0.0013032)

Balancing Penalty Rate Higher of \$25.00/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)

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

Effective for service rendered on or after  
January 1, 2014

PUBLIC SERVICE COMMISSION  
*Aleisha Salem* Secretary

**GAS RATE SCHEDULE**

**South Dakota Intrastate Pipeline Company**  
1415 N. Airport Rd  
Pierre, SD 57501  
Date Filed: January 24, 2001

SD P.U.C. Section No. 3  
Original Sheet No. 1  
Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is \$2.398 per dekatherm.

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

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  
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

<u>Division</u>	<u>Receipt Point</u>	<u>Delivery Point</u>	<u>Monthly Customer Charge</u>	<u>Maximum Demand Charge 6/</u>	<u>Minimum Demand Charge 6/</u>	<u>Maximum Transportation Charge 2/</u>	<u>Minimum Transportation Charge 2/</u>	<u>Fuel Reimbursement Quantity Percentage 3/</u>
TC (Casper) Firm Transportation	MLI	MLI	\$0.00	\$9.50	\$0.00	\$0.1040	\$0.0010	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 JUNE 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	2,713,665	282,335	1,290,628
January 2014	1,718,601	140,548	(516,571)
February	(7,802,409)	0	(1,585,437)
March	(8,760,334)	17,312	(2,249,296)
April	(9,647,685)	59,613	(2,349,974)
May	(6,055,130)	223,048	(1,417,061)
June	(1,981,446)	405,172	(47,395)
July	2,048,401	585,337	1,378,162
August	6,627,987	791,123	2,808,100
September	11,166,949	995,182	3,989,784
October	12,899,301	1,073,064	4,216,421
13 month average	<u>\$1,914,171</u>	<u>\$428,095</u>	<u>\$894,904</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$168,275	\$37,634	\$78,671
Return Requirement	<u>\$228,437</u>	<u>\$51,089</u>	<u>\$106,798</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</u>	<u>Refunds &amp;</u>		<u>Total Net</u>	<u>Actual Dk</u>	<u>Adjustment</u>	<u>Total</u>	<u>Net Change-</u>	<u>Cumulative</u>
	<u>Recovery</u>	<u>Other</u>	<u>Interest 1/</u>	<u>Additions</u>	<u>Sales</u>	<u>Per Dk</u>	<u>Adjustment</u>	<u>Additions less</u>	<u>Balance</u>
							<u>Amount</u>	<u>Adjustment</u>	
<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
December	448,098	0	25	448,123	2,259,276	0.024	54,223	393,900	1,024,333
January 2014	218,746	0	22	218,768	3,260,430	0.024	78,250	140,518	1,164,851
February	(243,381)	(98,337) 5/	30	(341,688)	2,668,333	0.024	64,040	(405,728)	759,123
March	2,821,004	0	20	2,821,024	2,727,677	0.024	65,465	2,755,559	3,514,682
<b>Balance @ March 31, 2014</b>									<b><u>\$3,514,682</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.

5/ Adjustment to correct prior misallocation between states.

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

	<u>(Over) Under 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>\$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
December	67,199	0	7	67,206	203,609	0.116	23,618	43,588	227,623
January 2014	86,756	0	5	86,761	165,685	0.116	19,220	67,541	295,164
February	8,193	4,502 4/	8	12,703	157,100	0.116	18,224	(5,521)	289,643
March	239,148	0	8	239,156	149,744	0.116	17,371	221,785	511,428
<b>Balance @ March 31, 2014</b>									<b><u>\$511,428</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.

4/ Adjustment to correct prior misallocation between states.

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

	(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
<b>Balance @ July 31, 2013</b>									<b><u>\$86,961</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
December	4,326	0	4	4,330	52,750	0.181	9,547	(5,217)	81,715
January 2014	63,099	0	2	63,101	88,671	0.181	16,050	47,051	128,766
February	(50,998)	2,212 4/	3	(48,783)	86,357	0.181	15,631	(64,414)	64,352
March	133,077	0	2	133,079	73,450	0.181	13,295	119,784	184,136
<b>Balance @ March 31, 2014</b>									<b><u>\$184,136</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.

4/ Adjustment to correct prior misallocation between states.