



A Division of MDU Resources Group, Inc.

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

July 8, 2014

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

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

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

Attachment A is the Rate Summary Sheet (127th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered August 1, 2014.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.120 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.

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 August 2014.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.117 per dk for residential and firm general customers, an increase of \$0.122 per dk for small and large interruptible customers and an increase of \$0.121 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 August 2014. The average cost of gas for firm customers, adjusted for losses, is \$6.052.

Exhibit C shows the calculation of the return on storage inventory balances and prepaid

demand and commodity balances using the calculation procedure set forth in Rate 88. The overall rate of return of 7.881% was authorized by the Commission in Case No. PU-13-803.

Montana-Dakota purchases propane supplies from various wholesale suppliers. There is no change in the cost of propane 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, will amount to an increase of approximately \$42,500 for natural gas customers during the month of August 2014. All of Montana-Dakota's retail natural customers in North Dakota may be affected by this proposal. There were 101,831 natural gas customers in North Dakota as of May 31, 2014.

Please refer all inquiries regarding this filing to:

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

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

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

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

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

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

Sincerely,



Tamie A. Aberle
Director of Regulatory Affairs

Attachment

**Rate Summary Sheet
(Proposed)**



Montana-Dakota Utilities Co.

A Division of MDU Resources Group, Inc.

400 N 4th Street
Bismarck, ND 58501

State of North Dakota Gas Rate Schedule

NDPSC Volume 7
127th Revised Sheet No. 3
Canceling 126th 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	\$6.064	\$6.390
Air Force Rate 64	7	\$2,000.00 per month			
Minot Air Force Base		\$175.00 per month			
PAR Site					
Firm Service			\$0.329	\$6.064	\$6.393
Interruptible Service - PAR			\$0.260	\$4.991	\$5.251
Interruptible Service - MAFB			\$0.260	\$5.034	\$5.294
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	\$6.064	\$6.794
Small Interruptible Gas Rate 71	14	\$175.00 per month	(Maximum) \$0.929	\$4.991	(Maximum) \$5.920
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	\$4.881	\$5.611
Transportation Service	24				
Small Interruptible Rate 81		\$175.00 per month			
Maximum			\$0.485		
Minimum			\$0.102		
Fuel Charge				\$0.022	
Large Interruptible Rate 82		\$1,000.00 per month			
Maximum			\$0.297		
Minimum			\$0.061		
Fuel Charge				\$0.022	
Large Interruptible Gas Rate 85	27	\$1,000.00 per month	(Maximum) \$0.718	\$4.991	(Maximum) \$5.709
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: July 8, 2014

Effective Date: August 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**

August 2014

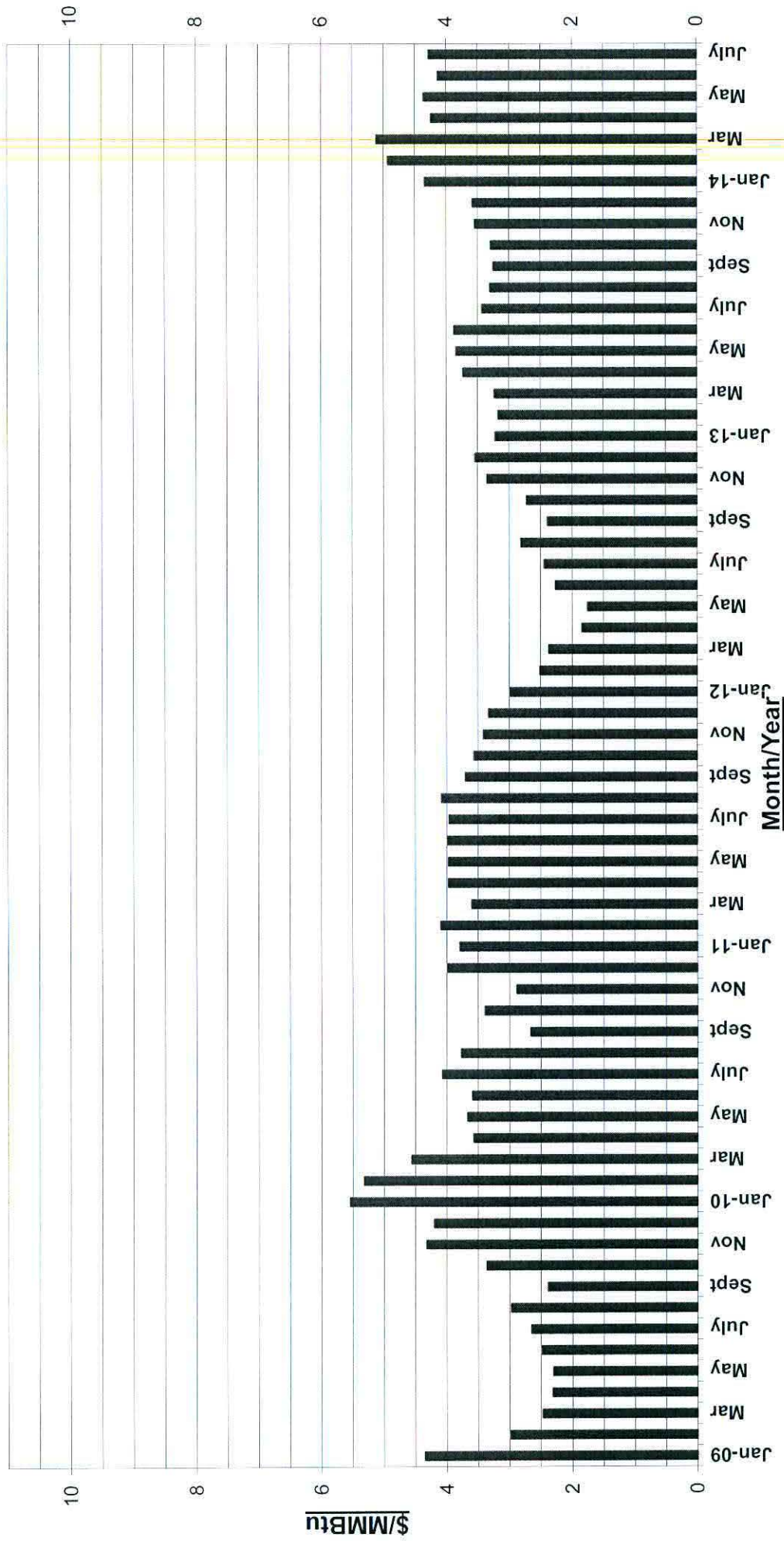
The established monthly price for the Rocky Mountain CIG Index has increased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including “Inside FERC Gas Market” report and “Gas Daily” by McGraw-Hill Companies, of prices paid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

Additional gas usage to handle cooling demand because of warmer summer time temperatures and U.S. storage levels well below the five year average were likely the main contributing factors to the increase of the August index. The EIA reported the national storage level as of June 27, 2014, was 29.1 percent below the five-year average and 25.7 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 June Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 18. The July Outlook will be published August 12, 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-\$4.48



Independent Statistics & Analysis

U.S. Energy Information
Administration

June 2014

Short-Term Energy Outlook (STEO)

Highlights

- North Sea Brent crude oil spot prices increased from a monthly average of \$108/barrel (bbl) in April to \$110/bbl in May. This was the 11th consecutive month in which the average Brent crude oil spot price fell within a relatively narrow range of \$107/bbl to \$112/bbl. The discount of West Texas Intermediate (WTI) crude oil to Brent crude oil, which averaged more than \$13/bbl from November through January, fell below \$4/bbl in early April before increasing to an average of \$7/bbl in May. EIA projects Brent crude oil prices to average \$108/bbl in 2014 and \$102/bbl in 2015 and the WTI discount to Brent to average \$9/bbl and \$11/bbl in 2014 and 2015, respectively.
- During the April-through-September summer driving season this year, regular gasoline retail prices are forecast to average \$3.62/gallon (gal), 4 cents higher than last year. The projected monthly national average regular gasoline retail price falls from the high this year of \$3.67/gal in May to \$3.54/gal in September. EIA expects regular gasoline retail prices to average \$3.50/gal in 2014 and \$3.38/gal in 2015, compared with \$3.51/gal in 2013.
- EIA estimates that U.S. total crude oil production averaged almost 8.4 million barrels/day (bbl/d) in May, 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 average 8.4 million bbl/d in 2014 and 9.3 million bbl/d in 2015. The 2015 forecast represents the highest annual average level of oil production since 1972.
- Natural gas working inventories on May 30 totaled 1.50 trillion cubic feet (Tcf), 0.74 Tcf (33%) below the level at the same time a year ago and 0.90 Tcf (37%) below the previous five-year average (2009-13). EIA expects that the Henry Hub natural gas spot price, which averaged \$3.73/MMBtu in 2013, will average \$4.74/MMBtu in 2014 and \$4.49/MMBtu in 2015.
- Based on the outlook from the National Oceanic and Atmospheric Administration (NOAA) for near- to below-normal tropical weather activity this year, EIA's mean estimates of shut-in production in the federal Gulf of Mexico (GOM) during the current hurricane season (June through November) total 12 million bbl of crude oil and 30 billion cubic feet (Bcf) of natural gas (see [2014 Outlook for Gulf of Mexico Hurricane-Related Production Outages](#)). Actual shut-ins are likely to differ significantly from this estimate depending on the number, track, and strength of hurricanes as the season progresses.

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 non-crude 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 Non-crude oil supply) is forecast to fall from an average of 30.1 million bbl/d in 2013 to 29.6 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 petroleum and other liquids consumption grew by 1.3 million bbl/d in 2013, averaging 90.5 million bbl/d for the year. EIA expects global consumption to grow by 1.3 million bbl/d in both 2014 and 2015. Projected global oil-consumption-weighted real GDP, which increased by an estimated 2.6% in 2013, grows by 3.0% and 3.5% 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. 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. Forecast consumption growth in Russia slows from 100,000 bbl/d last year to 30,000 bbl/d in 2014 and almost flat in 2015.

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 140,000 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 120,000 bbl/d in 2013, will decline by 60,000 bbl/d in 2014 and then remain flat in 2015. U.S. liquids consumption, which increased by 400,000 bbl/d in 2013, is expected to increase by only 50,000 bbl/d in both 2014 and 2015.

Non-OPEC Supply. EIA estimates that non-OPEC liquids production grew by 1.4 million bbl/d in 2013, averaging 54.1 million bbl/d for the year. EIA expects non-OPEC liquids production to grow by 1.5 million bbl/d in 2014 and 1.2 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 and 1.2 million bbl/d in 2014 and 2015, respectively. Forecast production increases by 0.17 million bbl/d in 2014 in countries of the Former Soviet Union, led by Russia. However, oil production growth in the region slows to 0.05 million bbl/d in 2015. The forecast 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.

Unplanned supply disruptions among non-OPEC producers averaged 0.72 million bbl/d in May 2014, up from the 0.66-million-bbl/d April average. South Sudan, Syria, and Yemen accounted for 75% of total non-OPEC supply disruptions, and Brazil, Colombia, and Mexico made up the remaining portion. EIA does not assume a disruption to oil supply as a result of ongoing events in Ukraine.

OPEC Supply. EIA estimates that OPEC crude oil production averaged 29.9 million bbl/d in 2013, a decline of 1.0 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 0.1 million bbl/d in 2014 and an additional 0.1 million bbl/d in 2015 to accommodate growing production in non-OPEC countries.

EIA revised downward its estimate for Iranian total liquid fuels production in 2013 by 0.2 million bbl/d to 3.2 million bbl/d, based on a review of annual production and exports data from multiple sources. The revision was made to Iran's production of crude oil and natural gas plant liquids. EIA estimates that Iran's total liquid fuels production averaged 3.4 million bbl/d in May.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.6 million bbl/d in May, down from the 2.7-million-bbl/d average in April. Libya continues to experience variation 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 2.2 million bbl/d in 2014 and 3.5 million bbl/d in 2015. This build in surplus capacity mainly reflects a reduction in production cutbacks by some OPEC members to accommodate higher supply from Iraq, Angola, and Libya as well as some non-OPEC countries. 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 2.55 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 \$110/bbl in May, an increase of \$2/bbl from April. This was the 11th consecutive month in which average Brent crude oil spot prices fell within a relatively narrow range of \$107/bbl to \$112/bbl. Reported record-high levels of Chinese crude oil imports in recent months and the ongoing tensions in Libya and Ukraine contributed to the upward price pressure for Brent crude oil. China's net crude oil imports reached a reported 6.8 million bbl/d in April, compared with an average of 5.6 million bbl/d during 2013. Higher volumes of crude oil imports and domestic production are outpacing China's refining input, indicating some crude oil is being stored in strategic or commercial

reserves. The forecast Brent crude oil price averages \$108/bbl in 2014, \$2/bbl higher than in last month's STEO, and \$102/bbl in 2015.

The January 2014 startup of TransCanada's Marketlink pipeline, moving crude oil 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 \$95/bbl in January to \$102/bbl in both April and May. Crude oil inventory levels at the Cushing, Oklahoma, storage hub, the delivery point for WTI, have fallen by almost half since the start of the year, from 41 million barrels on January 3 to less than 22 million barrels at the end of May, the lowest level since November 2008. The discount of WTI crude oil to Brent crude oil, which averaged more than \$13/bbl from November 2013 through January 2014, has since fallen to \$7/bbl in May. EIA expects high seasonal demand for refined products and strong refinery runs to help keep the discount of WTI crude oil to Brent crude oil around \$7/bbl over the next few months, before widening later in the year to reach \$12/bbl in December. EIA expects the discount to average of \$9/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 September 2014 delivery, traded during the five-day period ending June 5, averaged \$101/bbl. Implied volatility averaged 14%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in September 2014 at \$89/bbl and \$114/bbl, respectively. Last year at this time, WTI for September 2013 delivery averaged \$94/bbl and implied volatility averaged 23%. The corresponding lower and upper limits of the 95% confidence interval were \$77/bbl and \$114/bbl.

U.S. Petroleum and Other Liquids

Regular gasoline monthly average prices have increased for six consecutive months to an average of \$3.67/gal in May. EIA expects U.S. average regular gasoline retail prices to fall from current levels to average \$3.54/gal in September. Gasoline prices have recently increased in the Midwest (PADD 2), where the average regular retail price climbed \$0.10/gal over the last two weeks to reach \$3.71/gal on June 2. Total gasoline stocks fell below the bottom of their five-year range in May and a recent outage at one of the country's largest refineries further tightened gasoline supplies in PADD 2. A tornado on May 28 damaged a cooling water system at Marathon's Garyville, Louisiana refinery, causing the No. 1 crude unit and other units to be taken off-line. The Garyville refinery is the third-largest refinery in the country at 522,000 bbl/d of capacity, and a supplier of product to the Midwest. Marathon anticipates the crude unit will be operational by mid-June.

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 50,000 bbl/d in both 2014 and 2015.

Consumption of hydrocarbon gas liquids (HGL) registered the largest gain in 2013, increasing by 150,000 bbl/d (6.4%). HGL consumption increases by 80,000 bbl/d between 2013 and 2015, 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 30,000 bbl/d in 2014 and declines by 10,000 bbl/d 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 economic growth. Consumption of that fuel rises by 130,000 bbl/d and 40,000 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 8.4 million bbl/d in 2014 and 9.3 million bbl/d in 2015. The highest previous annual average U.S. production level was 9.6 million bbl/d in 1970. Recent U.S. crude oil production growth has consisted primarily of lighter, sweet crude (a description of crude quality, as measured by API gravity and sulfur content) from tight resource formations. Roughly 96% of the 1.8-million-bbl/d growth in production between 2011 and 2013 consisted of sweet grades with API gravity of 40 or above. [EIA analysis of current and forecast crude oil production](#) indicates that U.S. supply of lighter API gravity crude will continue to outpace that of medium and heavier crudes. More than 60% of EIA's forecast of production growth for 2014 and 2015 consists of light, sweet grades with API gravity of 40 or above.

NOAA predicts a [relatively quiet hurricane season](#) this year with near- to below-normal tropical weather activity in the Atlantic basin. Based on NOAA's projections, EIA's mean estimate is for 12 million barrels of crude oil production in the federally administered Gulf of Mexico to be shut in at some point because of disruptions during the 2014 hurricane season. There is a wide range of uncertainty around this forecast (see the [2014 Outlook for Gulf of Mexico Hurricane-Related Production Outages](#)). EIA's simulation results indicate a 69% probability of offshore crude oil production experiencing outages during the 2014 hurricane season that are equal to or larger than the 3.1 million barrels of production shut in last season.

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.

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 \$3.50/gal in 2014 and \$3.38 in 2015. EIA expects that the monthly average regular gasoline retail price has peaked at \$3.67/gal in May and will fall to \$3.54/gal in September. Diesel fuel prices, which averaged \$3.92/gal in 2013, are projected to average \$3.90/gal in 2014 and \$3.78/gal in 2015.

Natural Gas

Total marketed production of natural gas hit a record high of 72.7 Bcf/d in March, an increase of 1.5% from the previous month. The increase was partially due to better weather conditions, as cold temperatures this winter hampered production, and also the result of new wells coming on line in Texas and the Appalachian and Uinta basins.

This month's STEO raises the 2014 and 2015 outlook for onshore Lower 48 marketed production by 0.7 Bcf/d and 0.4 Bcf/d, respectively. Projected total marketed production, which averaged 70.2 Bcf/d in 2013, averages 73.0 Bcf/d in 2014 and 74.0 Bcf/d in 2015. EIA expects that [new infrastructure projects will support production growth](#) in the Marcellus formation, which is largely driving increases in overall production. [Several new projects](#) to support Marcellus production have either recently come on line or will begin operations this year. For example, in April, ANR Pipeline's Lebanon Lateral began sending Marcellus natural gas west to ANR's mainline; additionally, in November 2014 Texas Eastern Transmission expects to bring on line 0.9 Bcf/d of capacity to move gas out of Appalachia.

Natural Gas Consumption. EIA expects total natural gas consumption will average 72.5 Bcf/d in 2014, an increase of 1.7% from 2013, led by the industrial sector. In 2015, total natural gas consumption falls by 0.2 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 0.5% 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 23.0 Bcf/d in 2015 with lower natural gas prices and the retirement of some coal plants.

Natural Gas Production and Trade. EIA expects natural gas marketed production to grow by an average rate of 4.0% in 2014 and 1.3% 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 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.

NOAA predicts a [relatively quiet hurricane season](#) this year with near- to below-normal tropical weather activity in the Atlantic basin. Based on NOAA's projections, EIA's mean estimate is for 30 Bcf of natural gas production in the federally administered Gulf of Mexico to be shut in at some point as a result of disruptions during the 2013 hurricane season (see the [2014 Outlook for](#)

Gulf of Mexico Hurricane-Related Production Outages): EIA's simulation results indicate a 69% probability of offshore natural gas production experiencing outages during the 2014 hurricane season that are equal to or larger than the 6.7 Bcf of production shut in last season. Despite the potential for significant outages if a strong hurricane were to pass through the GOM producing region, the overall effect on U.S. supply would not be as severe as in past years because the share of total U.S. natural gas production originating in the GOM has declined sharply. In 1997, 26% of the nation's natural gas was produced in the federal Gulf of Mexico; by 2013, that share had fallen to 5%.

Growing domestic production is expected to continue to put downward pressure on natural gas imports from Canada. EIA projects net imports of 3.6 Bcf/d in 2014 and 3.1 Bcf/d in 2015, which would be the lowest level since 1987. Liquefied natural gas (LNG) imports have fallen 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. It is scheduled to come on line in stages beginning in late 2015.

Natural Gas Inventories. Natural gas working inventories totaled 1,499 Bcf on May 30, which is 737 Bcf lower than the same time last year and 896 Bcf lower than the previous five-year (2009-2013) average. The injection season began April somewhat slowly, but has picked up in May, with injections over the last four weeks totaling 444 Bcf. EIA expects working gas stocks will reach 3,424 Bcf at the end of October, 392 Bcf lower than at the same time last year.

Natural Gas Prices. Natural gas spot prices averaged \$4.58/MMBtu at the Henry Hub in May, down \$0.08/MMBtu from April. EIA expects spot prices will remain near current levels until the start of the next winter heating season. Projected Henry Hub natural gas prices average \$4.74/MMBtu in 2014 and \$4.49/MMBtu in 2015.

Natural gas futures prices for September 2014 delivery (for the five-day period ending June 5) averaged \$4.58/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for September 2014 contracts at \$3.54/MMBtu and \$5.92/MMBtu, respectively. At this time last year, the natural gas futures contract for September 2013 averaged \$3.97/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$3.03/MMBtu and \$5.21/MMBtu.

Coal

Power sector stockpiles fell by 30 million short tons (MMst) (20%) between the end of December and the end of March. The average supply of coal held at electric power generators in December 2013 dropped below 60 days of burn (a function of both inventory levels and anticipated consumption) and EIA projects that stockpiles will remain below this level in 2014.

The 108 MMst of power sector coal inventories forecast for August 2014 would be the lowest monthly level since February 2006 and nearly 46 MMst lower than last August's stockpiles. Recent milder weather and [increased coal shipments](#) may help to increase inventory levels, but a warmer-than-forecast summer will increase the chance of even lower power sector stockpiles.

Coal Supply. EIA estimates of U.S. coal production (242 MMst) for the first quarter of 2014 were down 3 MMst (1.1%) from last year. EIA expects U.S. coal production will grow 3.4% to 1,017 MMst in 2014, driven by higher consumption. In 2015, forecast U.S. coal production falls by 0.8% to 1,009 MMst.

Coal Consumption. EIA estimates that 232 MMst of coal was consumed by the electric power sector during the first three months of 2014. This is a 20-MMst (9.3%) increase over the same period in 2013. EIA projects total coal consumption growth of 3.9% to 961 MMst in 2014 as electricity demand grows and natural gas prices remain more than 25% above their 2013 level. Total coal consumption is projected to decline by 3.1% 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 4.1%.

Coal Exports. Coal exports for the first quarter of 2014 are estimated at 28 MMst, 12.9% (4 MMst) below last year. Coal exports are projected to total 99 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 to 93 MMst, primarily because of slowing world coal demand growth, and increasing coal output in other coal-exporting countries.

Coal Prices. First quarter average coal prices to the electric power industry fell slightly (0.8%) compared with last year. Annual average prices have fallen over the past two years, from \$2.39/MMBtu in 2011 to \$2.35/MMBtu in 2013. EIA forecasts average delivered coal prices to increase over the forecast period, with prices of \$2.36/MMBtu in 2014 and \$2.38/MMBtu in 2015.

Electricity

Summer Residential Electricity Outlook. EIA forecasts that the average U.S. residential electricity customer will spend 4.9% more during summer (June, July, and August) than during the same time last year. This increase in the average residential bill reflects a projected 1.2% increase in average electricity usage and a 3.7% increase in the average retail price of electricity.

There is wide variation in the average usage projections, with the average customer in New England consuming 3.7% less electricity than last summer while customers in the East South Central area consume 3.9% more electricity. Electricity prices in all areas of the United States,

except for the West North Central, are expected to be higher than last summer. New England retail electricity prices rise by 9.6%, but the average bill only increases 5.6% because of reduced electricity usage. Customers in the East South Central states experience the highest overall increase in average electricity bills this summer (8.7%).

Electricity Consumption. Total consumption of electricity during the first quarter of 2014 was 5.0% higher than the same period last year. Much of this increase was driven by colder temperatures in the eastern half of the United States, which caused a 9.9% year-over-year increase in electricity sales to the residential sector and a 4.4% increase in commercial sector sales. A 0.8% decline in industrial sales slightly offset growth in the other sectors. During the second half of 2014, EIA projects overall electricity consumption will rise by 0.9% from the same period last year. This second-half growth is driven by a 5.1% year-over-year increase in cooling degree days and a 2.3% increase in GDP.

Electricity Generation. EIA projects total U.S. electricity generation in 2014 will grow by 1.9% from last year to an average of 11,335 gigawatthours per day (GWh/d). Recently rising costs for natural gas have driven power generators to use relatively more coal for supplying electricity. The use of coal for power generation rises 248 GWh/d (5.7%) this year while natural gas-fired generation falls 51 GWh/d (1.7%) and nuclear generation falls 53 GWh/d (2.5%) from last year's levels. The use of renewable energy sources grows by an average of 59 GWh/d (4.1%).

Electricity Retail Prices. Some areas of the United States, especially the Northeast, have experienced rapid increases in retail electricity prices in recent months. EIA expects the U.S. residential price of electricity to average 12.5 cents per kilowatthour during 2014, an increase of 3.4% from 2013. Growth in the electricity prices charged to the commercial and industrial sectors are higher than the residential sector this year: 4.8% and 4.6%, respectively. Projected residential prices increase an additional 2.4% 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 2.9% in 2014. Conventional hydropower is projected to increase by 0.5%, while nonhydropower renewables rise by 4.2%. In 2015, total renewables consumption for electric power and heat generation increases an additional 3.4%, as a result of a 2.2% increase in hydropower and a 4.0% increase in nonhydropower renewables.

EIA estimates that wind power capacity will increase by 7.3% in 2014 and 14.0% 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 expects that utility-scale solar capacity will increase by 57% 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. Ethanol production increased from an average of 907,000 bbl/d in March to 926,000 bbl/d in May, the highest level of the year. Ethanol production is forecast to average 920,000 bbl/d during 2014 and 935,000 bbl/d in 2015. Biodiesel production has recovered from the recent low of 56,000 bbl/d in January to 75,000 bbl/d in March. Biodiesel production averaged 89,000 bbl/d in 2013 and is forecast to average 81,000 bbl/d in 2014 and 84,000 bbl/d in 2015.

Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels increased by 2.2% in 2013 from the previous year. Emissions are forecast to rise again by 2.2% in 2014, followed by a 1.1% decline in 2015. The increase in emissions in 2013 and 2014 reflects growth in coal consumption for electric power generation. Coal emissions are projected to decline by 3.2% in 2015 with increasing coal plant retirements.

U.S. Economic Assumptions

Recent Economic Indicators. Recent economic indicators signal economic growth slowing in the first quarter of 2014 with signs of improvement later in the year. The Bureau of Economic Analysis (BEA) reported that [real gross domestic product \(GDP\)](#) fell at an annual rate of 1.0 % in the first quarter (that is, from the fourth quarter of 2013 to the first quarter of 2014). This was a revision from BEA's initial first quarter estimate that reported an annualized 0.1% increase in real GDP. The revision was associated with a significant decline in inventory investment. According to the [U.S. Bureau of Labor Statistics](#) (BLS), the U.S. economy added 217,000 jobs in May, and the unemployment rate was unchanged at 6.3%.

[New orders for durable goods](#) also show recent deceleration in growth, as April's new orders rose 0.8%, according to the U.S. Census Bureau, compared to the 3.6% increase reported in March. Orders fell 0.8% excluding defense, but rose 0.1% excluding transportation. BEA also reported that [real personal disposable income](#) rose 0.2% between March and April, while real personal consumption expenditures fell 0.3%. Census reported that [sales of new single-family homes](#) rose 6.4% from March to April, but is 4.2% below the April 2013 sales estimate. The Bureau of Labor Statistics (BLS) reported that the [consumer price index for all urban consumers](#) rose 2.0% from April 2013 to April 2014, the largest year-over-year increase since July 2013, primarily due to increases in the prices of food and gasoline.

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

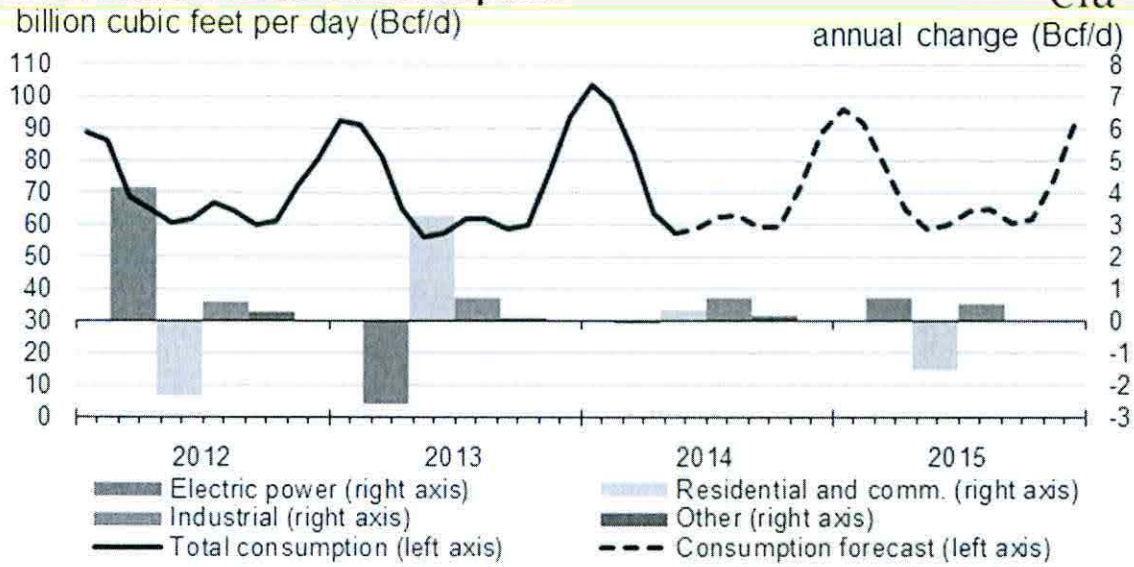
Production and Income. Forecast real GDP growth reaches 2.4% in 2014 and accelerates to 3.1% in 2015, above the 2.3% and 2.9% forecast last month. The increases reflect greater optimism about exports of capital goods and investment in capital equipment for the remainder of 2014 and into 2015. Forecast real disposable income increases 2.0% in 2014 and 3.6% in 2015. Total industrial production grows at 3.7% in 2014 and 3.5% in 2015. Growth in industrial production in the manufacturing sector is lower than total industrial production in 2014, at 3.6%, but jumps higher in 2015 to 4.0%.

Expenditures. Private real fixed investment growth averages 4.1% and 9.6% in 2014 and 2015, respectively, led by transportation equipment in 2014 and by a broad array of equipment categories in 2015. Real consumption expenditures grow faster than real GDP in 2014 at 2.7%, but fall slightly below the real GDP growth rate in 2015 at 3.0%. Durable goods expenditures drive consumption spending in both years. Export growth is 2.8% and 5.3% over the same two years, while import growth is 2.1% in 2014 and 6.5% in 2015. Total government expenditures fall 0.8% in 2014, but increase by 0.4% in 2015.

Employment, Housing, and Prices. Projected growth in nonfarm employment averages 1.8% in 2014 and 1.9% in 2015. This is accompanied by a gradually declining unemployment rate that reaches 6.3% by the end of 2014 and 5.8% at the end of 2015. The employment growth in 2014 and 2015 is faster than projected last month and the declines in the unemployment rate are about the same. Housing starts grow an average of 10.3% and 35.6% 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.

U.S. Natural Gas Consumption

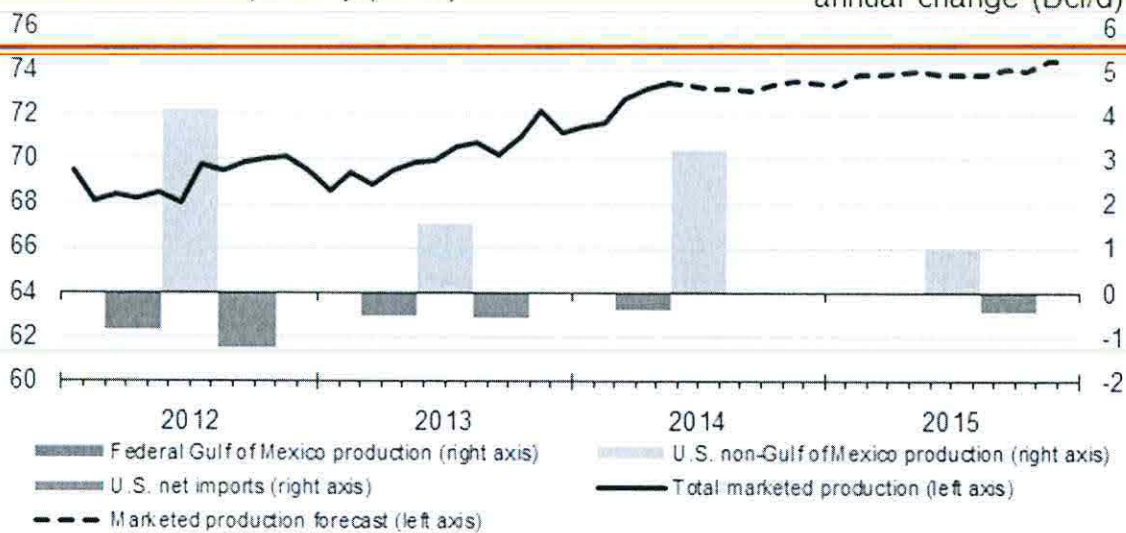


Source: Short-Term Energy Outlook, June 2014.

U.S. Natural Gas Production and Imports

billion cubic feet per day (Bcf/d)

eia
annual change (Bcf/d)



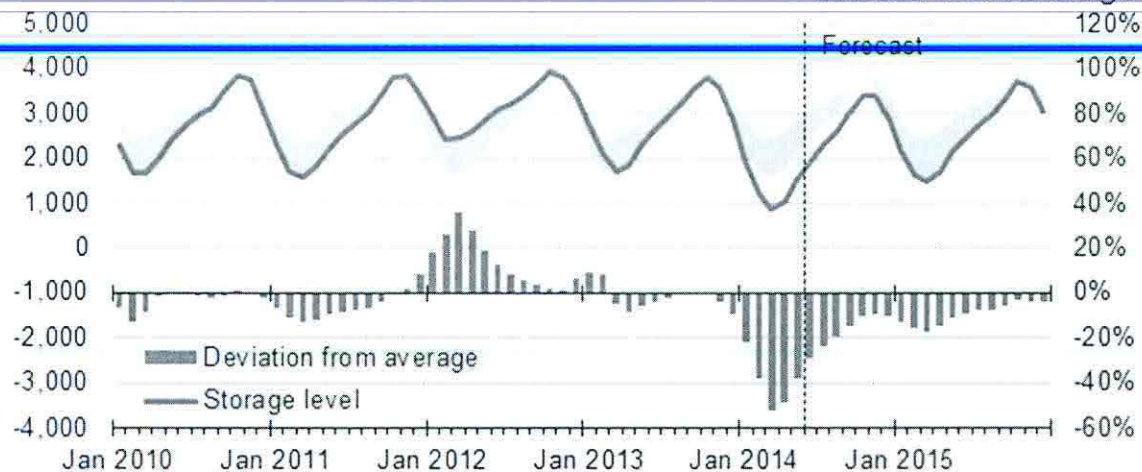
Source: Short-Term Energy Outlook, June 2014.

U.S. Working Natural Gas in Storage

billion cubic feet

eia

deviation from average



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

Source: Short-Term Energy Outlook, June 2014.

Henry Hub Natural Gas Price

dollars per million Btu

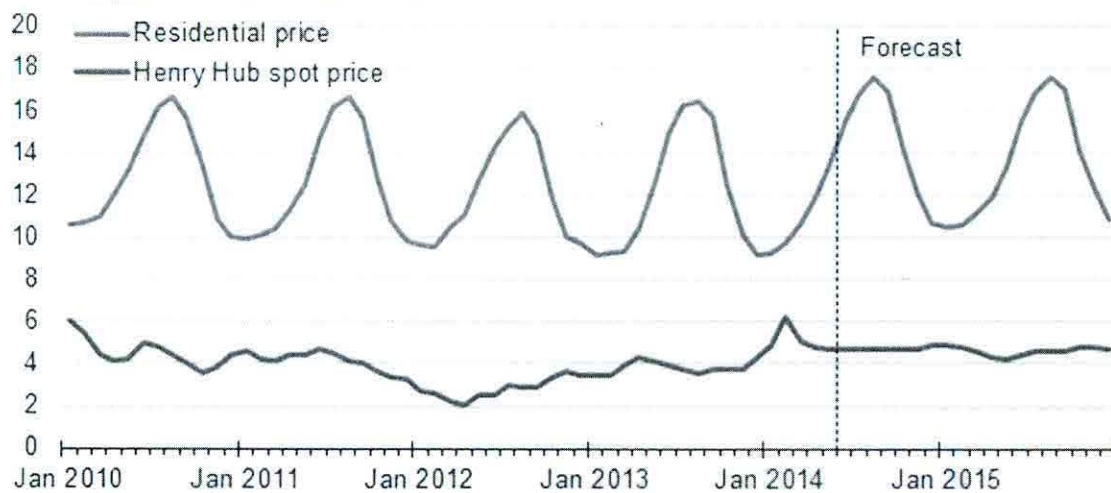


Note: Confidence interval derived from options market information for the 5 trading days ending Jun. 5, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, June 2014.

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, June 2014.

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

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$6.052	\$4.869	\$4.875	\$4.853
Prior Gas Cost	5.935	4.747	4.753	4.732
Current Gas Cost Adjustment	\$0.117	\$0.122	\$0.122	\$0.121
<u>Surcharge Adjustment:</u>				
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
<u>Market Based Pricing Differential</u>				
Current Adjustment	(\$0.012)	(\$0.012)	\$0.000	\$0.000
Prior Adjustment	(0.012)	(0.012)	0.000	0.000
Change in Margin Sharing Provision	\$0.000	\$0.000	\$0.000	\$0.000
Net Increase (Decrease) in Gas Costs	\$0.117	\$0.122	\$0.122	\$0.121
Gas Cost Level	\$6.052	\$4.869	\$4.875	\$4.853
Plus: Surcharge	0.024	0.024	0.116	0.181
Total Gas Cost Level in Tariff Rates	\$6.076	\$4.893	\$4.991	\$5.034

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

	Amount
Total Gas Costs 1/	\$89,219,629
Residential and General Service dk Requirements 2/	14,807,635
Average Cost of Gas per dk	\$6.025
Average Cost of Gas as Adjusted for Losses @ 99.55%	6.052
Less: Gas Cost Level in Rates 3/	5.935
Current Gas Cost Adjustment	\$0.117

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 April 30, 2014, adjusted for losses at .45%.

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

Cost of Purchased Gas	\$5.908
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.935

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

Total Gas Costs 1/	\$89,219,629
Less: Annual MDDQ Costs	<u>17,452,859</u>
Total Gas Costs excluding MDDQ	\$71,766,770
Firm Service Requirements 1/	14,807,635
Other Gas Costs per Dk (excluding MDDQ)	\$4.847
<u>Summer - June - September</u>	
Summer Seasonal Rate, adjusted for losses 2/	4.869
Less: Gas Cost Level in Rates 3/	<u>4.747</u>
Current Gas Cost Adjustment	<u><u>\$0.122</u></u>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

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

	<u>Summer</u>
Cost of Purchased Gas	\$4.726
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.747

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

	Amount
Total Gas Costs 1/	\$33,943,252
Interruptible Service dk Requirements	6,993,666
Average Cost of Gas per dk	\$4.853
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.875
Less: Gas Cost Level in Rates 2/	4.753
Current Gas Cost Adjustment	\$0.122

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 July 1, 2014:

Cost of Purchased Gas	\$4.732
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.753

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

	<u>Amount</u>
Total Gas Costs 1/	<u>\$2,524,768</u>
Air Force Interruptible dk Requirements	520,209
Average Cost of Gas per dk	\$4.853
Less: Gas Cost Level in Rates 2/	<u>4.732</u>
Current Gas Cost Adjustment	<u><u>\$0.121</u></u>

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 July 1, 2014:
Cost of Purchased Gas \$4.732

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
August 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: RP14-118-003
 FERC Order Date: May 14, 2014

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

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
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STATEMENT OF RATES
2/ 3/

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

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

Service	Rates, Tolls and Charges		
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month based on a three year term (Price Point "B") & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) \$ 216.98/10 ³ m ³		
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D ¹	Refer to Attachment "2" for applicable FT-D Demand Rate per month based on a one year term (Price Point "Z") & Surcharge for each Group 1 or Group 2 Delivery Point Average FT-D Demand Rate for Group 1 Delivery Points \$ 5.23/GJ FT-D Demand Rate for Group 2 Delivery Points \$ 4.19/GJ FT-D Demand Rate for Group 3 Delivery Points \$ 5.02/GJ		
4. Rate Schedule STFT	STFT Bid Price = Minimum of 100% of the applicable FT-D Demand Rate based on a one year term (Price Point "Z") for each Group 1 Delivery Point		
5. Rate Schedule FT-DW	FT-DW Bid Price = Minimum of 125% of the applicable FT-D Demand Rate based on a three year term (Price Point "Y") for each Group 1 Delivery Point		
6. Rate Schedule FT-P ¹	Refer to Attachment "3" for applicable FT-P Demand Rate per month		
7. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10³m³/day)</u>	
	1-5 years	11.29	
	6-10 years	9.44	
	15 years	8.46	
	20 years	7.51	
8. Rate Schedule LRS-3	LRS-3 Demand Rate per month	\$ 129.55/10 ³ m ³	
9. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
10. Rate Schedule IT-D ¹	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point		
11. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
12. Rate Schedule PT	<u>Schedule No.</u>	<u>PT Rate</u>	<u>PT Gas Rate</u>
	9009-01001-1	\$ 660.00/d	50.0 10 ³ m ³ /d
13. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2014612719	\$ 2.00	/ month
	2014612718	\$ 2.00	/ month
	2014612720	\$ 2,174.00	/ month
	2014612725	\$ 20.00	/ month
	2014612724	\$ 129.00	/ month
	2014612723	\$ 71.00	/ month
	2014612722	\$ 15.00	/ month
	2014612721	\$ 283.00	/ month
	2014612717	\$ 212.00	/ month
	2011475772	\$ 9,250.00	/ month
	2014613454	\$ 650.00	/ month
	2003004522	Applicable IT-R and IT-D Rate	
	2011476052 /	\$ 0.1376	/ GJ subject to
	2011476054	\$ 717,000.00	Minimum Annual Charge
	2011475056 / 2011476092 /	\$ 0.095	/ GJ and
	2011476049 / 2011476050	\$ 1,000.00	/ month
14. Rate Schedule CO ₂	<u>Tier</u>	<u>CO₂ Rate (\$/10³m³)</u>	
	1	528.30	
	2	418.06	
	3	272.20	

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

Group 1 Delivery Point Number	Group 1 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" (\$/GJ)	IT-D Rate per Day (\$/GJ)
2000	ALBERTA-B.C. BORDER	5.18	0.1874
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	4.19	0.1514
31110	ALLIANCE EDSON INTERCONNECT APN	4.19	0.1514
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	4.19	0.1514
3002	BOUNDARY LAKE BORDER	4.19	0.1514
1958	EMPRESS BORDER	5.35	0.1935
3886	GORDONDALE BORDER	4.19	0.1514
6404	MCNEILL BORDER	5.35	0.1935

Group 2 Delivery Point Number	Group 2 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" (\$/GJ)	IT-D Rate per Day (\$/GJ)	Subject to ATCO Pipelines Franchise Fees ¹
31000	A.T. PLASTICS SALES APN	4.19	0.1514	Yes
31001	ADM AGRI INDUSTRIES SALES APN	4.19	0.1514	Yes
3880	AECO INTERCONNECTION	4.19	0.1514	
31003	AGRIUM CARSELAND SALES APS	4.19	0.1514	
31002	AGRIUM FT. SASK SALES APN	4.19	0.1514	Yes
31004	AGRIUM REDWATER SALES APN	4.19	0.1514	
31005	AINSWORTH SALES APGP	4.19	0.1514	
31006	AIR LIQUIDE SALES APN	4.19	0.1514	
3214	AKUINU RIVER WEST SALES	4.19	0.1514	
31007	ALBERTA ENVIROFUELS SALES APN	4.19	0.1514	Yes ²
31008	ALBERTA HOSPITAL SALES APN	4.19	0.1514	Yes
3868	ALBERTA-MONTANA BORDER	4.19	0.1514	
3059	ALLISON CREEK SALES	4.19	0.1514	
31009	ALTASTEEL SALES APN	4.19	0.1514	Yes ²
3562	AMOCO SALES (BP SALES TAP)	4.19	0.1514	
31012	APL JASPER SALES APN	4.19	0.1514	Yes
3488	ARDLEY SALES	4.19	0.1514	
3237	ASPEN SALES	4.19	0.1514	
3216	AURORA NO 2 SALES	4.19	0.1514	
3135	AURORA SALES	4.19	0.1514	
3423	BASHAW WEST SALES	4.19	0.1514	
31013	BAYMAG SALES APS	4.19	0.1514	
31014	BEAR CREEK COGEN SALES APGP	4.19	0.1514	
3068	BEAVER HILLS SALES	4.19	0.1514	
3268	BENBOW SOUTH SALES	4.19	0.1514	
3933	BIG EDDY INTERCONNECTION	4.19	0.1514	
3067	BIGSTONE SALES	4.19	0.1514	
3468	BLEAK LAKE SALES	4.19	0.1514	
3225	BOTHA SALES	4.19	0.1514	
3259	BOULDER CREEK SALES	4.19	0.1514	
3164	BRAINARD LAKE SALES	4.19	0.1514	
3918	BUFFALO CREEK INTERCONNECTION	4.19	0.1514	
31015	BURDETT COGEN SALES APS	4.19	0.1514	
3265	BURNT TIMBER SALES	4.19	0.1514	
3204	CABIN SALES	4.19	0.1514	
3109	CALDWELL SALES	4.19	0.1514	
31016	CALGARY ENERGY CENTRE SALES APS	4.19	0.1514	Yes
3634	CANOE LAKE SALES	4.19	0.1514	
3165	CANOE LAKE SALES NO 2	4.19	0.1514	
3866	CARBON INTERCONNECTION	4.19	0.1514	
3484	CARIBOU LAKE SALES	4.19	0.1514	
3157	CARIBOU LAKE SOUTH SALES	4.19	0.1514	
3106	CARMON CREEK SALES	4.19	0.1514	
3101	CAROLINE SALES	4.19	0.1514	
31017	CARSELAND COGEN SALES APS	4.19	0.1514	
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 35th Revised
34th Revised

Sheet No. 80.1
Sheet No. 80.1

Schedule No. T-FPG-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

**STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE**

NG-00-001

South Dakota Intrastate Pipeline Company

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

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

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

<u>Division</u>	<u>Receipt Point</u>	<u>Delivery Point</u>	<u>Monthly Customer Charge</u>	<u>Maximum Demand Charge 6/</u>	<u>Minimum Demand Charge 6/</u>	<u>Maximum Transportation Charge 2/</u>	<u>Minimum Transportation Charge 2/</u>	<u>Fuel Reimbursement Quantity Percentage 3/</u>
TC (Casper) Firm Transportation	MLI	MLI	\$0.00	\$9.50	\$0.00	\$0.1040	\$0.0010	1.153%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.1040	\$0.0010	1.153%
	MLI	DSE	\$225.00	\$0.00	\$0.00	\$0.1978	\$0.0020	3.579%
Interruptible Transportation 4/	MLI	MLI	\$0.00	\$0.00	\$0.00	\$0.0844	\$0.0010	1.153%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.0844	\$0.0010	1.153%
Administrative Fee 5/			\$325.00					

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

2/ All charges are per therm.

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

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

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

6/ Per Dth of MDTQ per month.

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

MLI Mainline System Interconnect

MLE Mainline System End-user

DSE Distribution System End-user

MDTQ Maximum Daily Transportation Quantity

Date Issued: February 28, 2014
By: Michael Noone

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

**MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS
EFFECTIVE AUGUST 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	(8,193,736)	55,269	(2,031,162)
May	(5,576,042)	204,090	(1,264,517)
June	(2,671,668)	380,124	(45,837)
July	1,923,491	583,312	1,380,271
August	6,391,091	781,021	2,810,763
September	11,176,202	991,821	3,992,828
October	13,190,409	1,080,552	4,219,182
13 month average	<u>\$2,005,045</u>	<u>\$423,760</u>	<u>\$932,096</u>
Rate of Return	7.881%	7.881%	7.881%
Return	\$158,018	\$33,397	\$73,458
Return Requirement	<u>\$220,576</u>	<u>\$46,618</u>	<u>\$102,539</u>

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

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

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2013									<u><u>\$268,918</u></u>
August	(\$171,535)	\$0	\$6	(\$171,529)	283,161	(\$0.113)	(\$31,997)	(\$139,532)	129,386
September	(10,802)	387,468 2/	2	376,668	259,134	(0.113)	(29,282)	405,949	535,335
October	91,702	0	15	91,717	509,627	0.024	(28,445) 3/	120,162	655,497
November	(43,397)	46,049 4/	27	2,679	1,155,975	0.024	27,743	(25,064)	630,433
December	448,098	0	25	448,123	2,259,276	0.024	54,223	393,900	1,024,333
January 2014	218,746	0	22	218,768	3,260,430	0.024	78,250	140,518	1,164,851
February	(243,381)	(98,337) 5/	30	(341,688)	2,668,333	0.024	64,040	(405,728)	759,123
March	2,821,004	0	20	2,821,024	2,727,677	0.024	65,465	2,755,559	3,514,682
April	(316,839)	0	55	(316,784)	1,876,237	0.024	45,030	(361,814)	3,152,868
May	(777,340)	0	49	(777,291)	1,120,204	0.024	26,885	(804,176)	2,348,692
Balance @ May 31, 2014									<u><u>\$2,348,692</u></u>

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

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

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

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

5/ Adjustment to correct prior misallocation between states.

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2013									<u><u>\$162,872</u></u>
August	(\$8,729)	\$0	\$4	(\$8,725)	32,348	(\$0.115)	(\$3,719)	(\$5,006)	157,866
September	(2,593)	0	1	(2,592)	33,833	(0.115)	(3,891)	1,299	159,165
October	9,049	0	4	9,053	55,674	0.116	(4,732) 2/	13,785	172,950
November	19,660	6,105 3/	7	25,772	126,614	0.116	14,687	11,085	184,035
December	67,199	0	7	67,206	203,609	0.116	23,618	43,588	227,623
January 2014	86,756	0	5	86,761	165,685	0.116	19,220	67,541	295,164
February	8,193	4,502 4/	8	12,703	157,100	0.116	18,224	(5,521)	289,643
March	239,148	0	8	239,156	149,744	0.116	17,371	221,785	511,428
April	56,003	0	8	56,011	119,450	0.116	13,856	42,155	553,583
May	(48,683)	0	9	(48,674)	89,162	0.116	10,344	(59,018)	494,565
Balance @ May 31, 2014									<u><u>\$494,565</u></u>

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

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

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

4/ Adjustment to correct prior misallocation between states.

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2013									<u>\$86,961</u>
August	(\$1,327)	\$0	\$2	(\$1,325)	4,039	(\$0.377)	(\$1,522)	\$197	87,158
September	(5,633)	0	1	(5,632)	4,641	(0.377)	(1,750)	(3,882)	83,276
October	1,205	0	2	1,207	6,585	0.181	(2,484) 2/	3,691	86,967
November	3,672	1,691 3/	3	5,366	29,839	0.181	5,401	(35)	86,932
December	4,326	0	4	4,330	52,750	0.181	9,547	(5,217)	81,715
January 2014	63,099	0	2	63,101	88,671	0.181	16,050	47,051	128,766
February	(50,998)	2,212 4/	3	(48,783)	86,357	0.181	15,631	(64,414)	64,352
March	133,077	0	2	133,079	73,450	0.181	13,295	119,784	184,136
April	30,408	0	3	30,411	60,313	0.181	10,917	19,494	203,630
May	(30,439)	0	3	(30,436)	38,279	0.181	6,929	(37,365)	166,265
Balance @ May 31, 2014									<u>\$166,265</u>

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

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

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

4/ Adjustment to correct prior misallocation between states.