

March 6, 2015

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

Re: Cost of Gas Adjustment
(COG) Rate 88
Case No. PU-15-008

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 (135th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered April 1, 2015.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.095 per dk since the last filing due to a decrease in the overall commodity price of gas. Attachment B explains the reasons for the decrease in the market price of gas. There has also been a change in pipeline rates as shown on Attachment C, decreasing the cost of gas by \$0.081 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 April 2015.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.176 per dk for residential and firm general customers, a decrease of \$0.174 per dk for small and large interruptible customers and a decrease of \$0.173 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 April 2015. The average cost of gas for firm customers, adjusted for losses, is \$4.476.

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. The cost of propane has decreased since the last COG filing due to a decrease in the market price of propane from that established in the March 2015 PGA filing.

Exhibit A, page 2 summarizes the cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of April 2015. The net effect of this filing is a decrease of \$3.842 per dk for all customers from the currently effective rates.

Exhibit D shows the calculation of the current cost of gas – propane that will be applicable to Montana-Dakota's customers for the month of April 2015. The average cost of propane for all customers, adjusted for losses, is \$6.368 per dk.

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

These proposed adjustments, calculated in accordance with Rate 88, will amount to a decrease of approximately \$219,400 for natural gas customers during the month of April 2015. All of Montana-Dakota's retail natural gas customers in North Dakota may be affected by this proposal. There were 105,262 natural gas customers and 344 propane customers in North Dakota as of February 28, 2015.

Please refer all inquiries regarding this filing to:

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

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

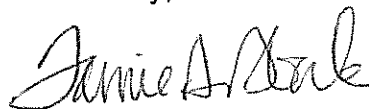
Mr. Daniel S. Kuntz
Associate General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

Montana-Dakota submitted a check on December 8, 2014 to the North Dakota Public Service Commission for \$650 pursuant to the requirements of North Dakota Century Code Section 49-05-05. This payment will cover the filing fee associated with the monthly COG filings.

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

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

Sincerely,



Tamie A. Aberle
Director of Regulatory Affairs

Attachment

**Rate Summary Sheet
(Proposed)**



Montana-Dakota Utilities Co.

A Division of MDU Resources Group, Inc.

400 N 4th Street
Bismarck, ND 58501

State of North Dakota Gas Rate Schedule

NDPSC Volume 7
135th Revised Sheet No. 3
Canceling 134th 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	\$4.667	\$4.993
Air Force Rate 64	7	\$2,000.00 per month			
Minot Air Force Base		\$175.00 per month			
PAR Site					
Firm Service			\$0.329	\$4.667	\$4.996
Interruptible Service - PAR			\$0.260	\$3.725	\$3.985
Interruptible Service - MAFB			\$0.260	\$3.695	\$3.955
Firm General Service Rate 70	13	\$0.67 per day			
Meters rated < 500 cubic feet		\$1.90 per day	\$0.730	\$4.667	\$5.397
Meters rated > 500 cubic feet					
Small Interruptible Gas Rate 71	14	\$175.00 per month	(Maximum) \$0.929	\$3.725	(Maximum) \$4.654
Optional Seasonal Gas Service Rate 72	15	\$0.67 per day			
Meters rated < 500 cubic feet		\$1.90 per day	\$0.730	\$4.770	\$5.500
Meters rated > 500 cubic feet					
Transportation Service	24	\$175.00 per month			
Small Interruptible Rate 81					
Maximum			\$0.485		
Minimum			\$0.102		
Fuel Charge				\$0.015	
Large Interruptible Rate 82		\$1,000.00 per month			
Maximum			\$0.297		
Minimum			\$0.061		
Fuel Charge				\$0.015	
Large Interruptible Gas Rate 85	27	\$1,000.00 per month	(Maximum) \$0.718	\$3.725	(Maximum) \$4.443
Residential Propane Rate 90	32	\$0.4935 per day	\$0.326	\$7.544	\$7.870
Firm General Propane Rate 92	34	\$0.67 per day			
Meters rated < 500 cubic feet		\$1.90 per day	\$0.730	\$7.544	\$8.274
Meters rated > 500 cubic feet					

Date Filed: March 6, 2015

Effective Date: April 1, 2015

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.: PU-15-008

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

April 2015

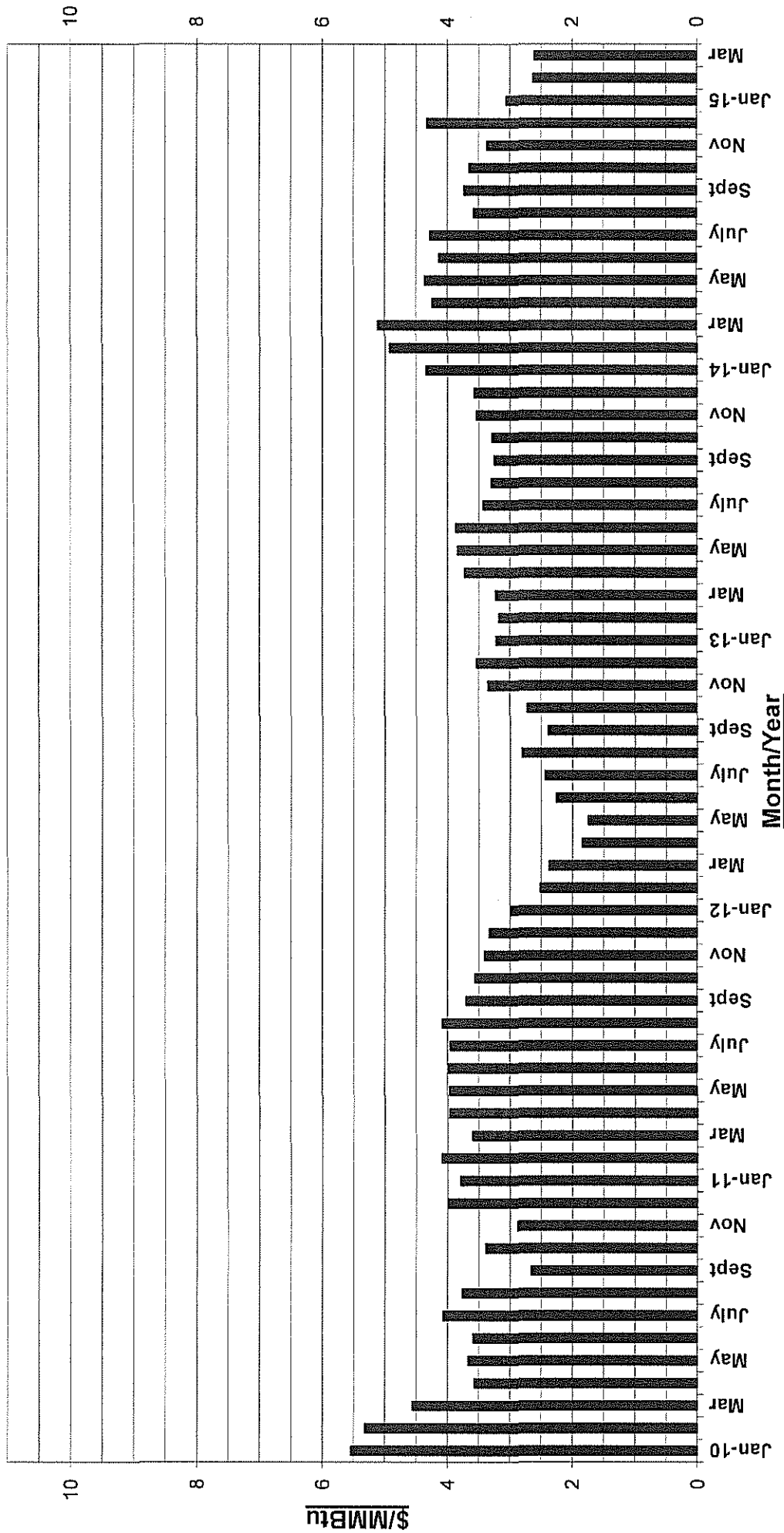
The established monthly price for the Rocky Mountain CIG Index has decreased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid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

Despite colder than normal weather over much of the eastern U.S., the western portion of the U.S. was much warmer than normal resulting in decreased demand for the month of February and a slight decrease in the price of gas for the Rocky Mountain region and the associated CIG index price. The EIA reported the national storage level as of February 20, 2015, was 1.5 percent below the five-year average and 42.3 percent above last year's storage balance.

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

The February Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 19. The March Outlook will be published March 10, 2015.

CIG Rocky Mountains Index Monthly Gas Prices 2010-2015YTD



From Inside F.E.R. C.'s Gas Market Report
Annual Averages: - 2013-\$3.45; 2014-\$4.17; 2015YTD-\$2.77



Independent Statistics & Analysis

U.S. Energy Information
Administration

February 2015

Short-Term Energy Outlook (STEO)

Highlights

- January was the seventh consecutive month in which monthly average North Sea Brent crude oil prices decreased, reaching \$48/barrel (bbl), the lowest since March 2009. The price decline reflects continued growth in U.S. tight oil production and strong global supply, amid weaker global oil demand growth, which contributed to rising global oil inventories. In January, estimated Organization for Economic Cooperation and Development (OECD) total commercial oil inventories reached their highest level since August 2010.
- EIA forecasts that Brent crude oil prices will average \$58/bbl in 2015 and \$75/bbl in 2016, with 2015 and 2016 annual average West Texas Intermediate (WTI) prices expected to be \$3/bbl and \$4/bbl, respectively, below Brent. This price outlook is unchanged from last month's forecast. The current values of futures and options contracts continue to suggest very high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for May 2015 delivery, traded during the five-day period ending February 5, averaged \$52/bbl while implied volatility averaged 52%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in May 2015 at \$33/bbl and \$81/bbl, respectively. The 95% confidence interval for market expectations widens over time, with lower and upper limits of \$32/bbl and \$108/bbl for prices in December 2015.
- Total U.S. crude oil production averaged an estimated 9.2 million barrels per day (bbl/d) in January. Forecast total crude oil production averages 9.3 million bbl/d in 2015. Given EIA's price forecast, projected crude oil production averages 9.5 million bbl/d in 2016, close to the highest annual average level of production in U.S. history of 9.6 million bbl/d in 1970.
- Driven largely by falling crude oil prices, U.S. weekly regular gasoline retail prices averaged \$2.04/gallon (gal) on January 26, the lowest since April 6, 2009, before increasing to \$2.19/gal on February 9. EIA expects U.S. regular gasoline retail prices, which averaged \$3.36/gal in 2014, to average \$2.33/gal in 2015. The average household is now expected to spend about \$750 less for gasoline in 2015 compared with last year because of lower prices. The projected regular gasoline retail price increases to an average of \$2.73/gal in 2016.
- Natural gas working inventories on January 30 totaled 2,428 Bcf, 468 Bcf (24%) above the level at the same time in 2014 and 29 Bcf (1%) below the previous five-year (2010-14) average. EIA expects the Henry Hub natural gas spot price to average \$3.34/million British

thermal units (MMBtu) this winter (2014-15) compared with \$4.53/MMBtu last winter (2013-14), reflecting both lower-than-expected space heating demand and higher natural gas production this winter. EIA expects the Henry Hub natural gas spot price, which averaged \$4.39/MMBtu in 2014, to average \$3.05/MMBtu in 2015 and \$3.47/MMBtu in 2016, \$0.39/MMBtu lower for both years than in last month's STEO.

Global Petroleum and Other Liquids

Market fundamentals remain largely unchanged since last month's forecast, as global production continues to be higher than demand, contributing to inventory builds. Global oil inventory builds averaging 0.9 million bbl/d are projected through the first half of 2015, with the builds moderating during the second half of the year, as non-OPEC supply growth, particularly from the United States, weakens because of lower oil prices. The expected inventory builds in 2015 are on top of an estimated 0.8 million bbl/d increase in 2014.

EIA revised historical global supply and demand levels to reflect improved data estimates for various countries. These changes to history affected forecast levels of supply and demand, but did not affect forecast growth rates.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 0.9 million bbl/d in 2014, averaging 92.1 million bbl/d for the year. EIA expects global consumption to grow by 1.0 million bbl/d in both 2015 and 2016. Projected global oil-consumption-weighted real gross domestic product (GDP), which increased by an estimated 2.7% in 2014, is projected to grow by 2.8% in 2015 and by 3.2% in 2016.

Non-OECD consumption growth is the main driver of global consumption growth in the forecast, with projected growth of 0.8 million bbl/d in 2015 and of 1.1 million bbl/d in 2016, both lower than the estimated 1.2 million bbl/d of growth in 2014. China's consumption is projected to increase by an annual average of 0.3 million bbl/d in both 2015 and 2016, below the 0.4 million bbl/d of growth in 2014. China's economic growth slowed in the latter half of 2014, as key manufacturing indexes decreased. Nonetheless, China remains the main source of non-OECD consumption growth. Projected declines in Russia's oil consumption because of its economic downturn also contribute to lower non-OECD consumption growth over the forecast period compared with 2014. Russia's consumption is expected to decline by 0.2 million bbl/d in both 2015 and 2016.

OECD consumption, which fell by 0.3 million bbl/d in 2014, is expected to grow by 0.2 million bbl/d in 2015 and then decline by 0.1 million bbl/d in 2016. Japan and Europe accounted for almost the entire decline in 2014 and are expected to continue to decline over the next two years, albeit at a lesser rate than in 2014. The United States is the leading contributor to projected OECD consumption growth, with U.S. consumption increasing by 0.3 million bbl/d in 2015 and by 0.1 million bbl/d in 2016.

Non-OPEC Petroleum and Other Liquids Supply. After increasing by 2.1 million bbl/d in 2014, non-OPEC supply is expected to grow more slowly, by 0.8 million bbl/d annually in both 2015 and 2016, in part because of lower projected oil prices. The slower growth in non-OPEC supply over the forecast period is largely attributable to slower production growth in the United States, Canada, and South America. Additionally, oil production in Europe and Eurasia is projected to decline. The United States remains the leading contributor to non-OPEC supply in the forecast.

Unplanned supply disruptions among non-OPEC producers averaged slightly more than 0.6 million bbl/d in 2014, 0.2 million bbl/d less than in 2013. In January 2015, non-OPEC supply disruptions were 0.6 million bbl/d, similar to the previous month. South Sudan, Syria, and Yemen accounted for more than 85% of total non-OPEC supply disruptions.

OPEC Petroleum and Other Liquids Supply. EIA estimates that OPEC crude oil production averaged 30.1 million bbl/d in 2014, unchanged from the previous year. Crude oil production declines in Libya, Angola, Algeria, and Kuwait more than offset production growth in Iraq and Iran. EIA expects OPEC crude oil production to fall by 0.1 million bbl/d in 2015, and to fall by 0.4 million bbl/d in 2016. Iraq is the largest contributor to OPEC production growth over the forecast period, but its growth is expected to be offset by production declines from other Persian Gulf producers. However, the threat of the Islamic State of Iraq and the Levant (ISIL) on northern Iraqi production and exports still looms, and as a result, Iraq is a major wild card in the world oil production forecast.

EIA estimates that OPEC produced 6.4 million bbl/d of noncrude oil liquids in 2014, slightly less than its production in 2013. OPEC noncrude liquids production is expected to increase by less than 0.1 million bbl/d in both 2015 and 2016, led by Iran and Qatar.

In January 2015, unplanned crude oil supply disruptions among OPEC producers averaged 2.6 million bbl/d, an increase of less than 0.1 million bbl/d compared with the previous month. This increase was attributable to rising outages in Libya, which have been growing since late 2014. Unplanned OPEC crude supply disruptions averaged 2.4 million bbl/d in 2014, 0.6 million bbl/d higher than in the previous year. Libya and Iraq accounted for almost all of the growth in OPEC disruptions. The high level of OPEC disruptions contributed to higher crude oil prices during the first half of 2014. However, with continuous growth in non-OPEC production and strong production in Saudi Arabia outpacing world oil demand growth, the current volume of supply disruptions has become less significant. Unplanned supply disruptions could still affect crude oil prices, but the threshold that the market can bear has risen in light of robust global production.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to increase to an annual average of 2.3 million bbl/d in 2015 and 2.7 million bbl/d in 2016, after averaging about 2.0 million bbl/d in 2014. Surplus capacity is typically an indication of market conditions, and surplus capacity below 2.5 million bbl/d is an indicator of a relatively tight market. However, the current and forecast levels of global inventory builds make the projected low surplus capacity level in 2015 less significant.

OECD Commercial Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.74 billion barrels at the end of 2014, the highest end-of-year level on record and equivalent to roughly 58 days of consumption. Projected OECD oil inventories rise to 2.83 billion barrels at the end of 2015 and again total 2.83 billion barrels at the end of 2016.

Crude Oil Prices. North Sea Brent crude oil spot prices averaged \$48/bbl in January, the lowest monthly average Brent price since March 2009, down \$15/bbl from the December average. The combination of robust world crude oil supply growth and weak global demand has contributed to rising global inventories and falling crude oil prices (EIA, *This Week in Petroleum*, January 28, 2015).

EIA expects global oil inventories to continue to build in 2015, limiting upward pressure on oil prices because of declining drilling activity. The forecast Brent crude oil price averages \$58/bbl in 2015, unchanged from last month's STEO. Based on current market balances, EIA expects prices to be relatively flat in the first half of 2015, when global inventory builds are projected to be significant. EIA projects that Brent prices will average \$67/bbl during the fourth quarter.

The monthly average WTI crude oil spot price fell from an average of \$59/bbl in December to \$47/bbl in January, its lowest level since February 2009. EIA expects the WTI crude oil price to average \$55/bbl in 2015 and \$71/bbl in 2016, both unchanged from last month's STEO. The discount of WTI to Brent crude oil averaged less than \$1/bbl in January, the narrowest monthly average price spread since August 2010. In the forecast, the discount of WTI to Brent is projected to average \$3/bbl in 2015 and \$4/bbl in 2016.

The current values of futures and options contracts suggest continuing high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for May 2015 delivery, traded during the five-day period ending February 5, averaged \$52/bbl. Implied volatility averaged 52%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in May 2015 at \$33/bbl and \$81/bbl, respectively. The 95% confidence interval for market expectations widens over time, with lower and upper limits of \$32/bbl and \$108/bbl for prices in December 2015. Last year at this time, WTI for May 2014 delivery averaged \$96/bbl, and implied volatility averaged 19%. The corresponding lower and upper limits of the 95% confidence interval were \$81/bbl and \$113/bbl.

The recent declines in oil prices and associated increase in oil price volatility continue to contribute to a particularly uncertain forecasting environment, and several factors could cause oil prices to deviate significantly from current projections. Among these factors is the responsiveness of supply to lower prices. Despite OPEC's November 2014 decision to leave its crude oil production target at 30 million bbl/d, key producers could decide to reduce output, tightening market balances. The level of unplanned production outages could also vary from forecast levels for a wide range of producers, including OPEC members Libya, Iraq, Iran, Nigeria,

and Venezuela. The degree to which non-OPEC supply growth is affected by lower oil prices will also affect market balances and prices.

Several OPEC and non-OPEC oil producers rely heavily on oil revenues to finance national budgets. Some producers have already started adjusting their upcoming budgets to reflect the crude oil price decline. If crude oil prices fall further or are sustained at current levels, then oil-dependent producers will face tough decisions. These decisions could potentially lead to austerity programs and fuel subsidy cuts that could spark social unrest, leaving some countries vulnerable to supply disruptions if protesters target oil infrastructure. Potential new supply disruptions are a real possibility and present a major uncertainty in the world oil supply forecast.

U.S. Petroleum and Other Liquids

Falling crude oil prices and high inventories of gasoline helped U.S. weekly regular gasoline retail prices fall to an average of \$2.04/gal on January 26, the lowest weekly price since April 6, 2009 (EIA, *This Week in Petroleum*, January 22, 2015). U.S. average weekly regular gasoline retail prices have since increased to \$2.19/gal as of February 9. In January, monthly average regional gasoline retail prices ranged from a low of \$1.90/gal in Petroleum Administration for Defense District (PADD) 3 to a high of \$2.45/gal in PADD 5. EIA expects retail gasoline prices to average \$2.13/gal during the first quarter of 2015 and \$2.33/gal for the full year.

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 60,000 bbl/d (0.3%) in 2014. Motor gasoline consumption increased by 80,000 bbl/d (0.8%) reflecting an increase in highway travel that was partially offset by fleetwide increases in fuel efficiency. Distillate consumption grew by 160,000 bbl/d (4.2%), as a result of colder-than-average weather in the first quarter as well as increases in industrial production. Jet fuel consumption increased by 30,000 bbl/d (2.2%). Hydrocarbon gas liquids (HGL) and residual fuel oil consumption fell by an estimated 100,000 bbl/d (4.1%) and 60,000 bbl/d (19.7%), respectively.

In 2015, total liquid fuels consumption is forecast to grow by 290,000 bbl/d (1.5%). Lower pump prices contribute to an 80,000-bbl/d increase (0.9%) in motor gasoline consumption. HGL consumption is expected to reverse 2014's decline, increasing by 140,000 bbl/d (5.7%). Consumption of distillate fuel is projected to increase by 80,000 bbl/d, driven largely by expanding industrial production. Additionally, some of the growth in distillate fuel consumption comes from Annex VI to the International Convention for the Prevention of Pollution from Ships (MARPOL Annex VI), which is an international agreement that generally requires the use of fuels below 1,000 parts per million sulfur by marine vessels in most U.S. waters, unless alternative devices, procedures, or compliance methods are used to achieve equivalent emissions reductions. The increase in marine distillate use because of MARPOL regulations will displace the use of residual fuel oil.

EIA projects that in 2016 liquid fuels consumption growth will slow to 100,000 bbl/d (0.5%). Motor gasoline consumption declines by 50,000 bbl/d (0.5%) as the annual average retail

gasoline price is projected to increase 17% from the 2015 level. Continuing industrial growth contributes to a 100,000 bbl/d (3.9%) increase in HGL consumption and a 60,000 bbl/d (1.5%) increase in distillate use. Jet fuel consumption declines by 10,000 bbl/d (0.4%) despite moderate increases in air travel, as the introduction of new aircraft improves fuel efficiency.

Liquid Fuels Supply. Forecast U.S. crude oil production increases from an average of 8.6 million bbl/d in 2014 to 9.3 million bbl/d in 2015 and 9.5 million bbl/d in 2016. With WTI crude oil prices expected to average \$50/bbl in the first half of 2015, EIA expects 2015 drilling activity to decline because of unattractive economic returns in some areas of both emerging and mature oil production regions. Many companies have begun redirecting investment away from marginal exploration and research drilling and focusing on core areas of major tight oil plays. Projected 2015 oil prices remain high enough to support some development drilling activity in the Bakken, Eagle Ford, Niobrara, and Permian Basin, albeit at lower levels than previously forecast. Companies that have lower drilling and debt costs and have acreage in the sweet spots of these regions will continue to drill highly productive wells in 2015.

Nevertheless, EIA expects 2015 production to reach 9.4 million bbl/d in the second quarter, then decline by 180,000 bbl/d in the third quarter. With projected WTI crude oil prices rising in the second half of 2015, drilling activity is expected to increase again as companies take advantage of lower costs for both leasing acreage and drilling services, resulting in growing production despite the relatively low WTI price. A notable risk to the production forecast is that some drilled wells will not be completed. EIA will continue monitoring the inventory of uncompleted wells to inform the production forecast. Additionally, this forecast remains particularly sensitive to actual prices available at the wellhead and drilling economics that vary across regions and operators. Projected production for the federal offshore region and Alaska, which rise and fall respectively, are less sensitive to short-term price movements than onshore production in the Lower 48 states.

HGL production at natural gas liquids plants, which reached a record high of 3.1 million bbl/d in October, is projected to increase to 3.3 million bbl/d by the end of 2015. Ethane and propane are expected to contribute most to the projected growth, with most of the production supplying domestic petrochemical demand or exports. EIA expects higher rates of ethane recoveries as a result of planned increases in petrochemical facility feedstock demand, while export terminal expansions will allow higher quantities of domestically produced propane and butanes to reach the international market.

The growth in domestic production has contributed to a significant decline in imports of crude oil and other liquids. The share of total U.S. liquid fuels consumption met by net imports fell from 60% in 2005 to an estimated 27% in 2014. EIA expects the net import share to decline to 20% in 2016, which would be the lowest level since 1968.

Petroleum Product Prices. U.S. average regular gasoline retail prices averaged \$2.12/gal in January, the lowest monthly average since April 2009. The U.S. regular gasoline retail price, which averaged \$3.36/gal in 2014, is projected to average \$2.33/gal in 2015 and \$2.73/gal in

2016, almost unchanged from last month's STEO. Diesel fuel retail prices, which averaged \$3.83/gal in 2014, are projected to fall to an average of \$2.83/gal in 2015 and then rise to \$3.24/gal in 2016.

The May 2015 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged \$1.77/gal for the five trading days ending February 5, 2015, and has a 15% probability of exceeding \$2.10/gal (consistent with a retail price of \$2.75/gal) at expiration. The current values of futures and options contracts suggest there is a 5% probability that the RBOB futures contract price at expiration may exceed \$2.35/gal, consistent with a retail price of \$3.00/gal or higher, and a 8% probability that the RBOB futures price may fall below \$1.35/gal, consistent with a retail price of \$2.00/gal or lower. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas falling above or below the national average price by \$0.30/gal or more.

Lower projected crude oil prices also contribute to lower expected residential heating oil prices. Average retail heating oil prices are expected to average \$2.96/gal this winter, \$0.92/gal lower than last winter. The average household that uses heating oil as its primary space heating fuel is now expected to spend \$1,645 for heating this winter, \$710 lower than last winter. Propane prices are expected to be 17% lower in the Northeast and 27% lower in the Midwest compared with last winter, resulting in households spending 23% and 35% less on propane in those regions, respectively.

Natural Gas

Recent data indicate marketed natural gas production reached a record 77.3 Bcf/d in November. Despite cold weather and reports of production freeze-offs this winter, supply has remained abundant and prices have fallen. The February 2015 natural gas futures contract expired at \$2.87/MMBtu, and prices for the March contract have fallen further, settling at \$2.60/MMBtu on February 5. Henry Hub spot prices are now projected to average \$3.05/MMBtu in 2015, \$1.34/MMBtu lower than in 2014 and \$0.39/MMBtu lower than in last month's forecast. Lower expected prices in 2015 contribute to increasing consumption of natural gas for power generation, which is projected to be 5.5% above the 2014 level.

Natural Gas Consumption. EIA projects that U.S. total natural gas consumption will average 74.3 Bcf/d in 2015 and 75.2 Bcf/d in 2016, compared with an estimated 73.3 Bcf/d in 2014. Growth is largely driven by demand in the industrial and electric power sectors, while residential and commercial consumption is projected to decline in 2015 and 2016. Natural gas consumption in the power sector is expected to average 23.5 Bcf/d in 2015, a 0.5 Bcf/d increase from last month's STEO. EIA expects power sector consumption to grow by 2.6%, to 24.1 Bcf/d, in 2016. Industrial sector consumption increases by 5.6% and 1.9% in 2015 and 2016, respectively, as new industrial projects come online, particularly in the fertilizer and chemicals sectors, and industrial consumers are able to take advantage of low natural gas prices.

Natural Gas Production and Trade. EIA expects that marketed natural gas production will increase by 2.9 Bcf/d (3.8%) and 1.7 Bcf/d (2.2%) in 2015 and 2016, respectively. This increase reflects continuing strong production in the Lower 48 states, which more than offsets the long-term declining production in the Gulf of Mexico. Although natural gas prices have fallen dramatically in recent months, EIA expects that increases in drilling efficiency and growth in oil production (albeit at a slower rate) will continue to support growing natural gas production in the forecast. Additionally, preliminary data indicate freeze-offs modestly reduced production in January, but production has quickly recovered and growth continues. With most growth expected to come from the Marcellus Shale, a backlog of drilled but uncompleted wells will continue to support production growth, as new pipelines come online in the Northeast.

Increases in domestic natural gas production are expected to contribute to lower demand for natural gas imports from Canada and increasing exports to Mexico. EIA expects exports to Mexico, particularly from the Eagle Ford Shale in South Texas, to increase because of growing demand from Mexico's electric power sector, coupled with flat Mexican natural gas production.

Liquefied natural gas (LNG) imports have fallen over the past five years because higher prices in Europe and Asia are more attractive to LNG exporters than the relatively low prices in the United States. Forecast LNG gross imports average 0.2 Bcf/d in both 2015 and 2016. EIA projects that LNG gross exports will increase from an average of 0.04 Bcf/d in 2014 to almost 0.8 Bcf/d in 2016.

Natural Gas Inventories. On January 30, natural gas working inventories totaled 2,428 Bcf, 468 Bcf (24%) above the level at the same time in 2014 and 29 Bcf (1%) below the previous five-year (2010-14) average. Following last year's extremely cold winter, inventories fell 1,000 Bcf below the five-year average in mid-April but since then have consistently narrowed the gap. EIA projects that end-of-March 2015 inventories will total 1,699 Bcf, 43 Bcf more than the five-year (2010-14) average.

Natural Gas Prices. The Henry Hub natural gas spot price averaged \$2.99/MMBtu in January, a decline of \$0.49/MMBtu from December, and the first monthly average price under \$3/MMBtu since September 2012. EIA expects monthly average spot prices to remain less than \$3/MMBtu through the winter, and less than \$4/MMBtu through the remainder of the forecast. The projected Henry Hub natural gas price averages \$3.05/MMBtu in 2015 and \$3.47/MMBtu in 2016.

Natural gas futures contracts for May 2015 delivery, traded during the five-day period ending February 5, averaged \$2.71/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for May 2015 contracts at \$1.79/MMBtu and \$4.11/MMBtu, respectively. At this time last year, the natural gas futures contract for May 2014 delivery averaged \$4.48/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$3.28/MMBtu and \$6.13/MMBtu.

Coal

Total electric power sector coal stocks increased by 6 million short tons (MMst) in November 2014 to 142 MMst at month-end. The increase in coal stocks followed the typical seasonal pattern where coal-fired electric power plants build stocks during the autumn months in preparation for increased coal consumption during the winter. Despite the increase, end-of-November 2014 stocks were 14 MMst (9%) below a year ago and 21% lower than the previous five-year (2009-13) average for November.

Coal Supply. EIA estimates that coal production for 2014 totaled 997 MMst, 13 MMst (1%) higher than in 2013. EIA expects that annual production will decline in both 2015 and 2016, totaling 966 MMst and 960 MMst, respectively.

Coal Consumption. Electric power sector coal consumption was largely unchanged in 2014 compared with the previous year. Power sector coal consumption is projected to decrease by 1.5% in 2015, despite an increase in electricity demand, as natural gas prices decline relative to coal prices and retirements of coal power plants rise in response to the implementation of the Mercury and Air Toxics Standards. The full effect of the coal plant retirements will be felt in 2016, as projected electric power sector coal consumption declines by an additional 0.6%.

Coal Trade. Coal exports in 2014 were estimated at 97 MMst, a 17% decline from 2013. The decline was primarily a result of slowing world coal demand growth, lower international coal prices, and increasing coal output in other coal-exporting countries. EIA expects no significant change in global market conditions, and coal exports will fall 15% to 82 MMst in both 2015 and 2016.

Coal Prices. The annual average coal price to the electric power industry fell from a record-high \$2.39/MMBtu in 2011 to an estimated \$2.35/MMBtu in 2014. EIA expects the delivered coal price to average \$2.33/MMBtu in 2015 and \$2.34/MMBtu in 2016.

Electricity

At the end of 2014, the nuclear generating unit at the Vermont Yankee power plant shut down for decommissioning after more than 40 years of operation. Five other nuclear units have been retired in the past two years. There are 99 remaining nuclear units in the United States, including 23 in the Northeast Census region, where Vermont Yankee operated.

Electricity Consumption. Despite the January snowstorms in the Midwest and Northeast, average U.S. heating degree days (HDD) for the month were 10% lower than in January 2014. Based on weather forecasts from the National Oceanic and Atmospheric Administration, EIA expects HDD during the first quarter of 2015 to be 13% lower than last year. Cooling degree days during the summer months (April—September) are expected to be 6% higher than last summer. Lower consumption of electricity for space heating coupled with efficiency

improvements are projected to offset increased air-conditioning use during the summer, leading to a projected 0.4% year-over-year decline in residential electricity sales during 2015. Residential electricity sales are projected to grow by 0.9% in 2016. Projected sales of electricity to the commercial sector increase by 1.3% in 2015 and by 0.5% in 2016. Projected industrial electricity sales rise by an average of 1.8% annually in both 2015 and 2016.

Electricity Generation. EIA forecasts that U.S. electricity generation will grow by an average of 1.0% 2015 and 0.9% 2016. The cost of natural gas used for power generation has fallen in recent months, with the Henry Hub spot price declining from an average of \$4.29/MMBtu last summer to an average of \$2.99/MMBtu in January. This decline in fuel costs, combined with upcoming coal plant retirements, is likely to increase the use of natural gas-fired generating capacity. EIA expects the share of total generation fueled by natural gas to average 28.4% during 2015, up from 27.2% last year. In contrast, the share of generation provided by coal falls from 38.9% to 37.8%. The retirement of the Vermont Yankee plant contributes to a decline in the Northeast region's nuclear power fuel share from 35.5% in 2014 to 33.3% this year.

Electricity Retail Prices. EIA expects continued growth in average residential electricity prices over the forecast period, albeit at a slower pace than in 2014. The U.S. retail residential price is projected to increase by 1.1% in 2015 and by 1.8% in 2016. Electricity prices in most areas of the country are projected to increase in 2015. Projected price increases in 2015 are highest in the Midwest states (2.6%).

Renewables and Carbon Dioxide Emissions

Electricity and Heat Generation from Renewables. EIA projects that total renewables used for electricity and heat generation will grow by 3.8% in 2015. Conventional hydropower generation increases by 5.7%, while nonhydropower renewables generation increases by 2.9%. In 2016, total renewables consumption for electric power and heat generation increases by 2.9% as a result of a 3.2% decline in hydropower and a 6.0% increase in nonhydropower renewables.

In 2013, the electricity generation shares were 6.6% and 6.2% from hydropower and nonhydropower renewables, respectively. In 2014, 6.3% of generation came from hydropower and 6.9% from nonhydropower renewables. This trend is expected to continue, with the electricity generation share from nonhydropower renewables rising to 7.9% by 2016, and the hydropower share remaining near 6.5%. Wind is the largest source of nonhydropower renewable generation, and it is projected to contribute 5.2% of total electricity generation in 2016.

EIA expects continued growth in utility-scale solar power generation, which is projected to average almost 80 gigawatthours (GWh) per day in 2016. Despite this growth, solar power averages only 0.7% of total U.S. electricity generation in 2016. Although solar growth has historically been concentrated in customer-sited distributed generation installations, EIA expects that utility-scale solar capacity will increase by more than 60% between the end of 2014

and the end of 2016, with about half of this new capacity being built in California. Wind capacity, which grew by 7.7% in 2014, is forecast to increase by 16.1% in 2015 and by another 6.5% in 2016. Because wind is starting from a much larger base than solar, even though the growth rate is lower, the absolute amount of the increase in capacity is more than twice that of solar: 15 GW of wind versus 6 GW of utility-scale solar between 2014 and 2016.

Liquid Biofuels. After reaching a record monthly average of 978,000 bbl/d in December 2014, ethanol production in January 2015 is estimated to be 969,000 bbl/d. Ethanol production averaged 933,000 bbl/d in 2014, and EIA expects it to average 938,000 bbl/d in 2015 and 936,000 bbl/d in 2016. Biodiesel production averaged an estimated 80,000 bbl/d in 2014 and is forecast to average 84,000 bbl/d in both 2015 and 2016.

Energy-Related Carbon Dioxide Emissions. EIA estimates that emissions grew 0.9% in 2014. Emissions are forecast to increase by 0.3% in 2015 and 0.5% in 2016. These forecasts are sensitive to both weather and economic assumptions.

U.S. Economic Assumptions

Recent Economic Indicators. The Commerce Department's Bureau of Economic Analysis (BEA) reported that real GDP grew at an annualized rate of 2.6% from the third quarter to the fourth quarter of 2014. The increase in real GDP in the fourth quarter reflected positive contributions from personal consumption expenditures and investment. Growth in the third quarter of 2014 was 5.0%.

EIA used the January 2015 version of the IHS macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

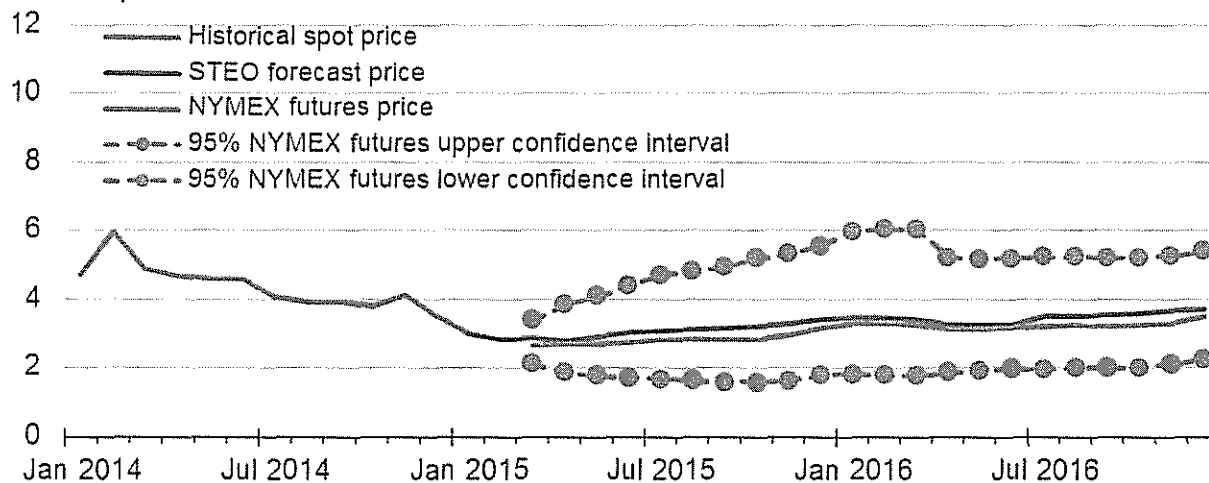
Production, Income, and Employment. After expanding by 2.4% in 2014, real GDP is projected to grow by 3.1% in 2015 and by 2.5% in 2016. Growth is expected to rise in 2015 because of higher business investment spending, increases in consumer purchases, and recent declines in gasoline prices. However, a stronger dollar and lower demand from slower-growing economies are expected to reduce export growth and raise import growth. Real disposable income is projected to grow by 3.3% in 2015 (compared with 2.8% forecast last month) and by 2.6% in 2016. Projected total industrial production grows by 3.4% in both 2015 and 2016. Projected growth in nonfarm employment averages 2.1% in 2015 and 1.7% in 2016.

Expenditures. Forecast private real fixed investment growth averages 6.0% and 6.6% in 2015 and 2016, respectively. Real consumption expenditures grow faster than real GDP in 2015 and 2016, at 3.5% and 2.9%, respectively. Durable goods expenditures drive consumption spending in both years. Export growth is 3.9% and 3.2% over the same two years, while import growth is 5.3% in both 2015 and 2016. Total government expenditures rise by 0.6% in 2015 and 0.4% in 2016.

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

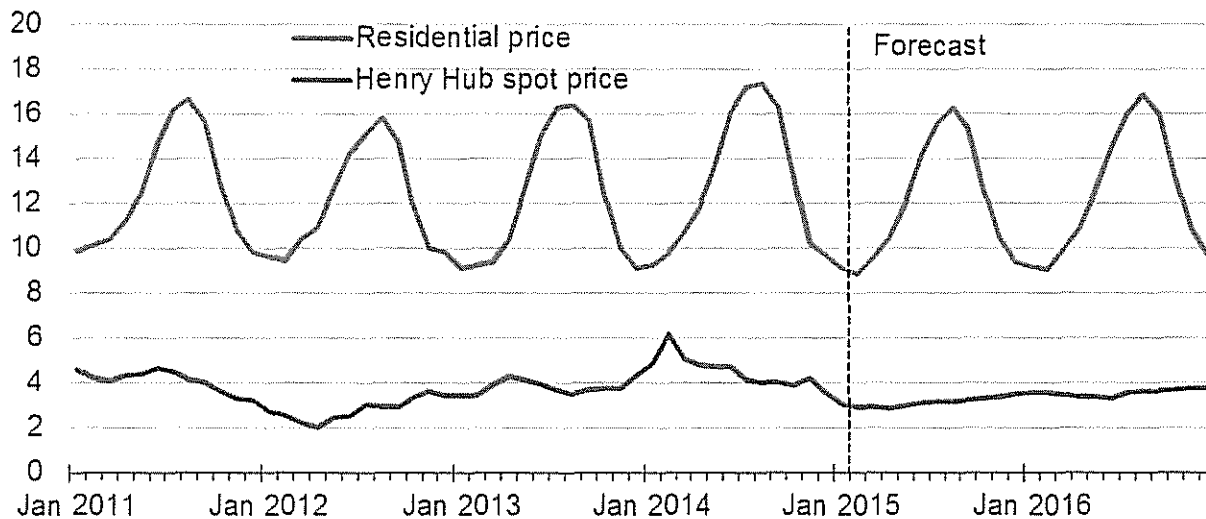


Note: Confidence interval derived from options market information for the 5 trading days ending Feb. 5, 2015. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, February 2015.

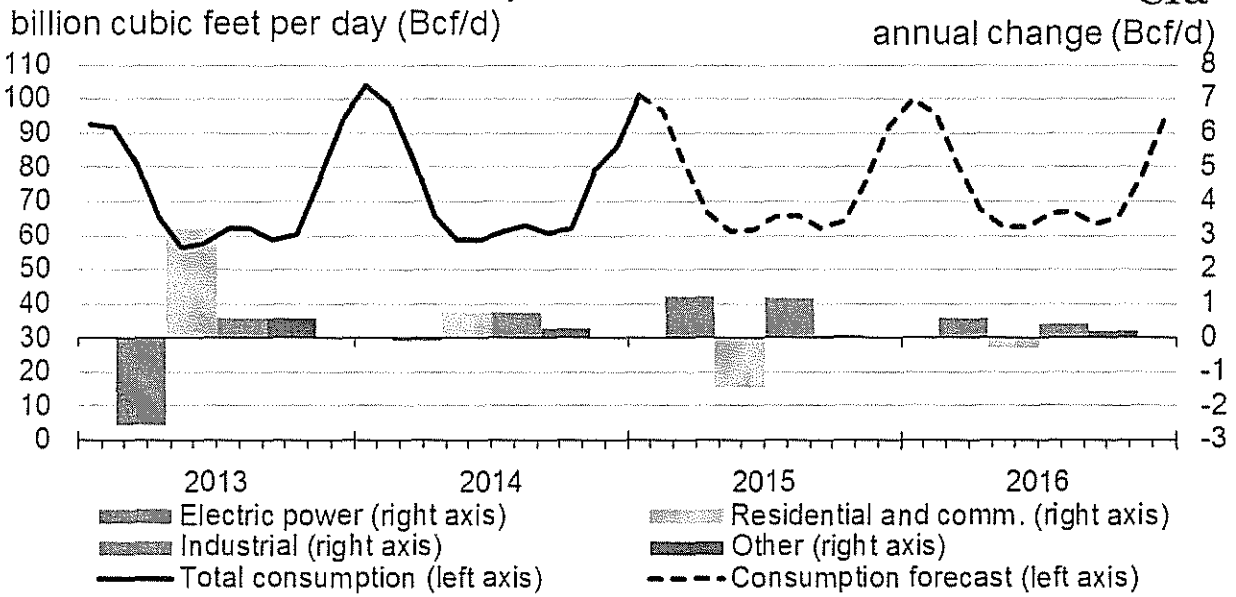
U.S. Natural Gas Prices

dollars per thousand cubic feet



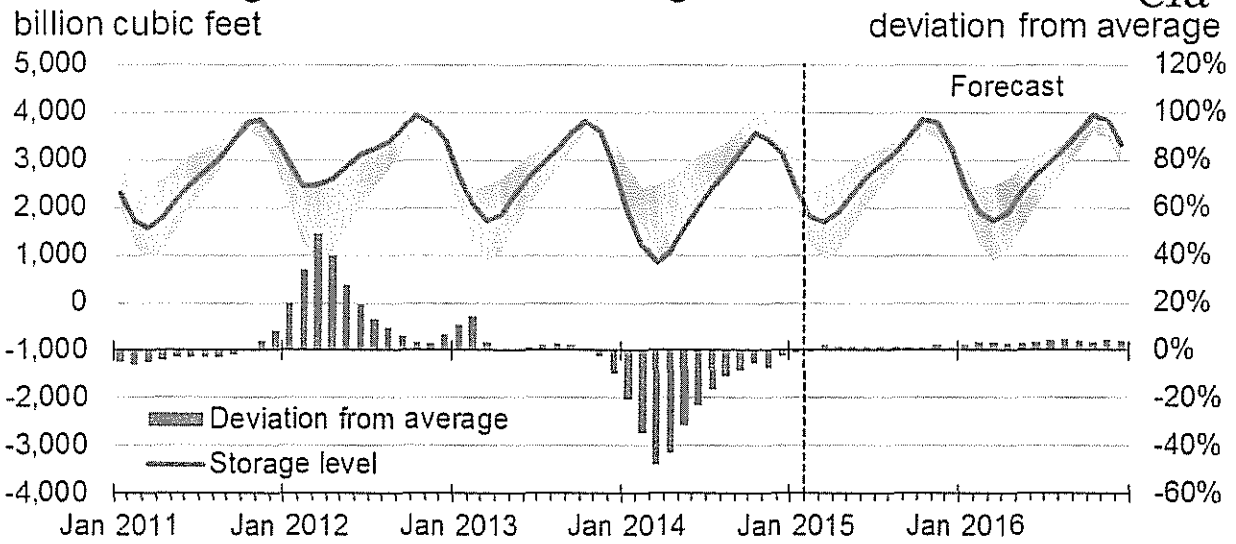
Source: Short-Term Energy Outlook, February 2015.

U.S. Natural Gas Consumption



Source: Short-Term Energy Outlook, February 2015.

U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2010 - Dec. 2014.

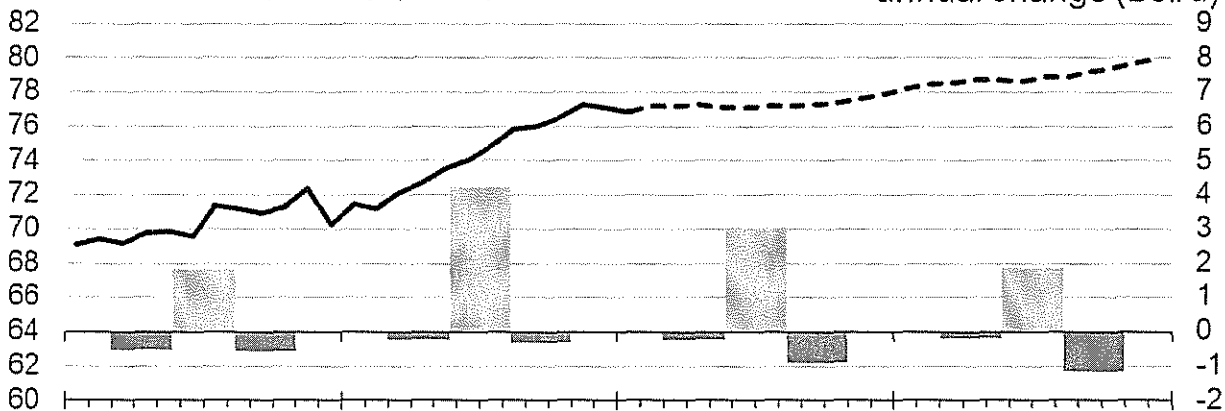
Source: Short-Term Energy Outlook, February 2015.

U.S. Natural Gas Production and Imports



billion cubic feet per day (Bcf/d)

annual change (Bcf/d)



- Federal Gulf of Mexico production (right axis)
- U.S. non-Gulf of Mexico production (right axis)
- U.S. net imports (right axis)
- Total marketed production (left axis)
- - - Marketed production forecast (left axis)

Source: Short-Term Energy Outlook, February 2015.

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

WBI Energy Transmission, Inc. Docket No. RP15-540-000

On February 27, 2015, WBI Energy Transmission, Inc. (WBI Energy) filed its semi-annual fuel and electric power reimbursement adjustments with the FERC in Docket No. RP15-540-000, reflecting revisions to the fuel and electric power components of WBI Energy's storage and transportation rates effective April 1, 2015.

Approximate impact on Montana-Dakota's cost of gas: (8.1) cents per dk

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

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$4.476	\$4.579	\$3.345	\$3.330
Prior Gas Cost	4.652	4.754	3.519	3.503
Current Gas Cost Adjustment	(\$0.176)	(\$0.175)	(\$0.174)	(\$0.173)
<u>Surcharge Adjustment:</u>				
Current Adjustment	\$0.209	\$0.209	\$0.380	\$0.365
Prior Adjustment	0.209	0.209	0.380	0.365
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
Gas Cost Level	\$4.476	\$4.579	\$3.345	\$3.330
Plus: Surcharge	0.209	0.209	0.380	0.365
Total Gas Cost Level in Tariff Rates	<u>\$4.685</u>	<u>\$4.788</u>	<u>\$3.725</u>	<u>\$3.695</u>
<u>Market Based Pricing Differential</u>				
Current Adjustment	(\$0.017)	(\$0.017)	\$0.000	\$0.000
Prior Adjustment	(0.017)	(0.017)	0.000	0.000
Change in Market Based Pricing	\$0.000	\$0.000	\$0.000	\$0.000
<u>Grain Drying Margin Sharing</u>				
Current Adjustment	(\$0.001)	(\$0.001)	\$0.000	\$0.000
Prior Adjustment	(0.001)	(0.001)	0.000	0.000
Change in Grain Drying Margin Sharing	\$0.000	\$0.000	\$0.000	\$0.000
Total Cost of Gas Items	<u>\$4.667</u>	<u>\$4.770</u>	<u>\$3.725</u>	<u>\$3.695</u>
Net Increase (Decrease) in Gas Costs	<u>(\$0.176)</u>	<u>(\$0.175)</u>	<u>(\$0.174)</u>	<u>(\$0.173)</u>

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

<u>Cost of Gas - Propane</u>	
Current Propane Cost (Exhibit D)	\$6.368
Prior Propane Cost	<u>10.210</u>
Current Propane Cost Adjustment	<u><u>(\$3.842)</u></u>
<u>Surcharge Adjustment</u>	
Current Adjustment	\$1.193
Prior Adjustment	<u>1.193</u>
Change in Surcharge Adjustment	\$0.000
<u>Market Based Pricing Differential</u>	
Current Adjustment	(\$0.017)
Prior Adjustment	<u>(0.017)</u>
Change in Margin Sharing Provision	\$0.000
Net Increase (Decrease) in Gas Costs	<u><u>(\$3.842)</u></u>
Propane Cost Level	\$6.368
Plus: Surcharge	<u>1.193</u>
Total Propane Cost Level in Rates	<u><u>\$7.561</u></u>

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

	Amount
Total Gas Costs 1/	\$69,183,804
Residential and General Service dk Requirements 2/	15,526,160
Average Cost of Gas per dk	\$4.456
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.476
Less: Gas Cost Level in Rates 3/	4.652
Current Gas Cost Adjustment	(\$0.176)

- 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 January 31, 2015, adjusted for losses at .45%.
- 3/ Gas Cost Level in Current Tariff Rates Case No. PU-15-008 effective March 1, 2015:
- | | |
|-------------------------------------|---------|
| Cost of Purchased Gas | \$4.631 |
| Adjustment for Distribution Losses | 0.9955 |
| Gas Cost Level in Base Tariff Rates | \$4.652 |

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

Total Gas Costs 1/	\$69,183,804
Less: Annual MDDQ Costs	<u>17,724,248</u>
Total Gas Costs excluding MDDQ	\$51,459,556
Firm Service Requirements 1/	15,526,160
Other Gas Costs per Dk (excluding MDDQ)	\$3.314
<u>Winter - October - May</u> Annual MDDQ Costs 1/	\$17,724,248
Winter Firm Service Requirements	14,247,158
MDDQ Costs per Winter Dk	\$1.244
Add: Other Gas Costs per Dk	<u>3.314</u>
Winter Seasonal Rate	\$4.558
Winter Seasonal Rate, adjusted for losses 2/	\$4.579
Less: Gas Cost Level in Rates 3/	<u>4.754</u>
Current Gas Cost Adjustment	<u><u>(\$0.175)</u></u>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-15-008 effective March 1, 2015:

	<u>Winter</u>
Cost of Purchased Gas	\$4.733
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.754

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

	Amount
Total Gas Costs 1/	\$23,288,471
Interruptible Service dk Requirements	6,993,666
Average Cost of Gas per dk	\$3.330
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.345
Less: Gas Cost Level in Rates 2/	3.519
Current Gas Cost Adjustment	(\$0.174)

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-15-008 effective March 1, 2015:

Cost of Purchased Gas	\$3.503
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.519

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

	Amount
Total Gas Costs 1/	\$1,732,228
Air Force Interruptible dk Requirements	520,209
Average Cost of Gas per dk	\$3.330
Less: Gas Cost Level in Rates 2/	3.503
Current Gas Cost Adjustment	(\$0.173)

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-15-008 effective March 1, 2015:
Cost of Purchased Gas \$3.503

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

WBI Energy Transmission, Inc. - Exhibit B, pages 6 - 10 for Schedules FT-1, FTN-1, and FS-1.

Northern Border Pipeline Company - Exhibit B, page 11 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 12-13 for Schedule FT-D.

NorthWestern Energy - Exhibit B, page 14 for Schedule T-FTG-1.

South Dakota Intrastate Pipeline - Exhibit B, page 15 for Rate 1.

SourceGas Distribution LLC - Exhibit B, Page 16 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 AND LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGES ARE REFLECTED ON SHEET NO. 21A. THESE PERCENTAGES 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 REFLECTED ON SHEET NO. 21B. 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: February 27, 2015
 Docket Number:
 FERC Order Date:

Effective On: April 1, 2015

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 AND LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGES ARE REFLECTED ON SHEET NO. 21A. THESE PERCENTAGES 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 REFLECTED ON SHEET NO. 21B. 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.

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Effective On: April 1, 2015

NOTICE OF CURRENTLY EFFECTIVE RATES

 FUEL USE AND LOST AND UNACCOUNTED FOR GAS ("L&U") REIMBURSEMENT PERCENTAGES

TRANSPORTATION - RATE SCHEDULES FT-1 AND IT-1

	<u>CURRENT PERCENTAGE</u>	<u>DEFERRAL PERCENTAGE</u>	<u>TOTAL PERCENTAGE</u>
FUEL USE REIMBURSEMENT	1.667%	(0.191)%	1.476%
L&U REIMBURSEMENT	0.474%	0.001%	0.475%

GATHERING - FIRM AND INTERRUPTIBLE

	<u>CURRENT PERCENTAGE</u>	<u>DEFERRAL PERCENTAGE</u>	<u>TOTAL PERCENTAGE</u>
FUEL USE REIMBURSEMENT	4.361%	(0.620)%	3.741%
L&U REIMBURSEMENT	0.036%	(0.001)%	0.035%

STORAGE - RATE SCHEDULES FS-1 AND IS-1

	<u>CURRENT PERCENTAGE</u>	<u>DEFERRAL PERCENTAGE</u>	<u>TOTAL PERCENTAGE</u>
FUEL USE REIMBURSEMENT	0.822%	(0.015)%	0.807%
L&U REIMBURSEMENT	0.406%	0.000%	0.406%

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 FERC Order Date:

Effective On: April 1, 2015

NOTICE OF CURRENTLY EFFECTIVE RATES

ELECTRIC POWER REIMBURSEMENT RATES (CENTS/DKT)

TRANSPORTATION - RATE SCHEDULES FT-1 AND IT-1

	<u>CURRENT RATE</u>	<u>DEFERRAL RATE</u>	<u>TOTAL RATE</u>
ELECTRIC POWER REIMBURSEMENT	0.773	(0.105)	0.668

GATHERING - FIRM AND INTERRUPTIBLE

	<u>CURRENT RATE</u>	<u>DEFERRAL RATE</u>	<u>TOTAL RATE</u>
ELECTRIC POWER REIMBURSEMENT	0.000	0.000	0.000

STORAGE - RATE SCHEDULES FS-1 AND IS-1

	<u>CURRENT RATE</u>	<u>DEFERRAL RATE</u>	<u>TOTAL RATE</u>
ELECTRIC POWER REIMBURSEMENT	0.000	0.056	0.056

Issued On: February 27, 2015
Docket Number:
FERC Order Date:

Effective On: April 1, 2015

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

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

STATEMENT OF RATES
2/ 3/

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

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

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

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

Service	Rates, Tolls and Charges		
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month based on a three year term (Price Point "B") & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) \$ 225.73 /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 \$ 5.32 /GJ FT-D Demand Rate for Group 2 Delivery Points \$ 4.55 /GJ FT-D Demand Rate for Group 3 Delivery Points \$ 5.46 /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	11.52	
	20 years	7.66	
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 /	\$ 0.1496 / 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 CO2	<u>Tier</u>	<u>CO₂ Rate (\$/10³m³)</u>	
	1	542.06	
	2	428.98	
	3	279.71	
15. Monthly Abandonment Surcharge ²	\$12.45/10 ³ m ³ /month	\$0.33/GJ/month	
16. Daily Abandonment Surcharge ³	\$ 0.41/10 ³ m ³ /day	\$0.0108/GJ/day	

- Service under rate Schedules FT-D, FT-P and IT-D for delivery stations identified in Attachment 2, and stations identified on rate Schedules 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.
- Monthly Abandonment Surcharge applicable to Rate Schedules FT-R, FT-D, FT-P, FT-RN, FT-DW, STFT, and LRS-3.
- Daily Abandonment Surcharge applicable to Rate Schedules IT-R, IT-D, LRS, the following Rate Schedules OS: 2011476052, 2011476054, 2011475056, 2011476092, 2011476049, 2011476050, 2003004522, and if applicable Over-Run Gas.

Effective Date: January 1, 2015

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	5.01	0.1811
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	4.55	0.1646
31110	ALLIANCE EDSON INTERCONNECT APN	4.55	0.1646
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	4.55	0.1646
3002	BOUNDARY LAKE BORDER	4.55	0.1646
1958	EMPRESS BORDER	5.62	0.2034
3886	GORDONDALE BORDER	4.55	0.1646
6404	MCNEILL BORDER	5.62	0.2034

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	4.55	0.1646	Yes
31001	ADM AGRI INDUSTRIES SALES APN	4.55	0.1646	Yes
3880	AECO INTERCONNECTION	4.55	0.1646	
31003	AGRIUM CARSELAND SALES APS	4.55	0.1646	
31002	AGRIUM FT. SASK SALES APN	4.55	0.1646	Yes
31004	AGRIUM REDWATER SALES APN	4.55	0.1646	
31005	AINSWORTH SALES APGC	4.55	0.1646	
31006	AIR LIQUIDE SALES APN	4.55	0.1646	
3214	AKUJINU RIVER WEST SALES	4.55	0.1646	
31007	ALBERTA ENVIROFUELS SALES APN	4.55	0.1646	Yes ²
31008	ALBERTA HOSPITAL SALES APN	4.55	0.1646	Yes
3868	ALBERTA-MONTANA BORDER	4.55	0.1646	
3059	ALLISON CREEK SALES	4.55	0.1646	
31009	ALTASTEEL SALES APN	4.55	0.1646	Yes ²
3562	AMOCO SALES (BP SALES TAP)	4.55	0.1646	
31012	APL JASPER SALES APN	4.55	0.1646	Yes
3488	ARDLEY SALES	4.55	0.1646	
3237	ASPEN SALES	4.55	0.1646	
3216	AURORA NO 2 SALES	4.55	0.1646	
3135	AURORA SALES	4.55	0.1646	
3288	BANTRY SALES	4.55	0.1646	
3423	BASHAW WEST SALES	4.55	0.1646	
31013	BAYMAG SALES APS	4.55	0.1646	
31014	BEAR CREEK COGEN SALES APGP	4.55	0.1646	
3068	BEAVER HILLS SALES	4.55	0.1646	
3268	BENBOW SOUTH SALES	4.55	0.1646	
3933	BIG EDDY INTERCONNECTION	4.55	0.1646	
3067	BIGSTONE SALES	4.55	0.1646	
3285	BILBO SALES	4.55	0.1646	
3468	BLEAK LAKE SALES	4.55	0.1646	
3225	BOTHA SALES	4.55	0.1646	
3259	BOULDER CREEK SALES	4.55	0.1646	
3164	BRAINARD LAKE SALES	4.55	0.1646	
3918	BUFFALO CREEK INTERCONNECTION	4.55	0.1646	
31015	BURDETT COGEN SALES APS	4.55	0.1646	
3265	BURNT TIMBER SALES	4.55	0.1646	
3204	CABIN SALES	4.55	0.1646	
3109	CALDWELL SALES	4.55	0.1646	
31016	CALGARY ENERGY CENTRE SALES APS	4.55	0.1646	Yes
3634	CANOE LAKE SALES	4.55	0.1646	
3165	CANOE LAKE SALES NO 2	4.55	0.1646	
3866	CARBON INTERCONNECTION	4.55	0.1646	
3484	CARIBOU LAKE SALES	4.55	0.1646	
3157	CARIBOU LAKE SOUTH SALES	4.55	0.1646	
3106	CARMON CREEK SALES	4.55	0.1646	
3248	CARMON CREEK EAST SALES	4.55	0.1646	
3101	CAROLINE SALES	4.55	0.1646	
31017	CARSELAND COGEN SALES APS	4.55	0.1646	
3275	CARSON CREEK SALES	4.55	0.1646	
3495	CAVALIER SALES	4.55	0.1646	
31018	CHAIN LAKES COOP SALES APS	4.55	0.1646	
3907	CHANCELLOR INTERCONNECTION	4.55	0.1646	
3151	CHEECHAM WEST NO 2 SALES	4.55	0.1646	
3622	CHEECHAM WEST SALES	4.55	0.1646	
6014	CHEVRON AURORA SALES	4.55	0.1646	
31019	CHEVRON FT. SASK SALES APN	4.55	0.1646	Yes
3097	CHICKADEE CREEK SALES	4.55	0.1646	
3305	CHIGWELL NORTH SALES	4.55	0.1646	
3496	CHIPEWYAN RIVER SALES	4.55	0.1646	
3163	CHRISTINA LAKE NORTH SALES	4.55	0.1646	

NATURAL GAS TARIFF



	37 th	Revised	Sheet No.	80.1
Canceling	36 th	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	\$ 119.95	(R)
10,001 to 30,000	\$ 172.45	(R)
>30,000	\$ 382.65	(R)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	\$ 0.9805387	(R)
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Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	\$ 0.0074304	(R)
Minimum	\$ 0.0017935	
GTAC Amortization	\$ (0.0009972)	
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.: D2014.12.96
Tariff Letter No. 250-G
By Operation of Law

Effective for service rendered on or after
January 1, 2015

PUBLIC SERVICE COMMISSION
Aleisha Balcom Secretary

GAS RATE SCHEDULE

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

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

Date Filed: January 24, 2001

Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is \$2.398 per dekatherm.

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

NG-00-001

STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

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

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

Division	Receipt Point	Delivery Point	Monthly Customer Charge	Maximum Demand Charge 6/	Minimum Demand Charge 6/	Maximum Transportation Charge 2/	Minimum Transportation Charge 2/	Fuel Reimbursement Quantity Percentage 3/
TC (Casper) Firm Transportation	MLI	MLI	\$0.00	\$9.50	\$0.00	\$0.1040	\$0.0010	1.153%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.1040	\$0.0010	1.153%
	MLJ	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 APRIL 2015**

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2014	\$13,138,114	\$1,130,570	\$4,252,066
November	9,055,168	929,233	3,379,652
December	5,147,252	724,553	1,610,827
January 2015	945,586	487,405	(401,064)
February	(1,677,166)	285,022	(1,827,083)
March	(3,348,636)	179,397	(2,747,927)
April	(3,020,022)	195,614	(2,540,401)
May	(1,148,196)	287,747	(1,472,205)
June	1,423,242	414,314	(39,878)
July	4,573,559	569,914	1,377,231
August	7,794,831	728,723	2,789,999
September	10,529,658	863,508	3,981,333
October	11,347,686	903,776	4,101,687
13 month average	<u>\$4,212,390</u>	<u>\$592,290</u>	<u>\$958,787</u>
Rate of Return	7.881%	7.881%	7.881%
Return	\$331,978	\$46,678	\$75,562
Return Requirement	<u>\$463,404</u>	<u>\$65,157</u>	<u>\$105,476</u>

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

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

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE
NORTH DAKOTA
EFFECTIVE APRIL 2015

Cost of Purchased Propane	\$30,426
Gallons Purchased	52,458
Projected dk Sales	4,800
Propane Cost per Dk	\$6.339
Average Cost of Propane as Adjusted for Losses @ 99.55%	6.368
Less: Propane Cost Level in Rates 1/	<u>10.210</u>
Current Propane Cost Adjustment	<u><u>(\$3.842)</u></u>

1/ Propane Cost Level in Current Rates - Case No. PU-15-008, effective March 1, 2015.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2014									<u>\$3,163,455</u>
August	\$226,615	\$0	\$49	\$226,664	277,347	\$0.024	\$6,656	\$220,008	3,383,463
September	(85,563)	0	35	(85,528)	328,455	0.024	7,883	(93,411)	3,290,052
October	9,216	0	34	9,250	599,658	0.209	56,897 2/	(47,647)	3,242,405
November	(234,355)	0	33	(234,322)	918,828	0.209	192,034	(426,356)	2,816,049
December	(703,392)	(1,696) 3/	44	(705,044)	2,483,155	0.209	518,979	(1,224,023)	1,592,026
January 2015	260,725	0	25	260,750	2,745,250	0.209	573,758	(313,008)	1,279,018
Balance @ January 31, 2015									<u>\$1,279,018</u>

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

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

3/ Record immaterial under or over refunded portions of the 1998 and 2005 WBI Energy Transmission, Inc. refunds.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2014									<u>\$553,358</u>
August	\$27,773	\$0	\$9	\$27,782	37,258	\$0.116	\$4,323	\$23,459	576,817
September	(4,907)	0	6	(4,901)	40,083	0.116	4,649	(9,550)	567,267
October	13,995	0	6	14,001	81,768	0.380	14,393 2/	(392)	566,875
November	(11,543)	0	6	(11,537)	101,794	0.380	38,681	(50,218)	516,657
December	13,622	0	8	13,630	154,400	0.380	58,672	(45,042)	471,615
January 2015	29,547	0	7	29,554	127,565	0.380	48,474	(18,920)	452,695
Balance @ January 31, 2015									<u>\$452,695</u>

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

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

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2014									<u><u>\$185,080</u></u>
August	\$16,626	\$0	\$3	\$16,629	4,035	\$0.181	\$731	\$15,898	200,978
September	(888)	0	2	(886)	3,604	0.181	652	(1,538)	199,440
October	2,549	0	2	2,551	9,112	0.365	1,649 2/	902	200,342
November	(4,099)	0	2	(4,097)	26,445	0.365	9,652	(13,749)	186,593
December	(8,282)	0	3	(8,279)	61,559	0.365	22,468	(30,747)	155,846
January 2015	39,354	0	2	39,356	64,476	0.365	23,533	15,823	171,669
Balance @ January 31, 2015									<u><u>\$171,669</u></u>

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

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