

September 8, 2015

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

Re: Cost of Gas Adjustment
(COG) Rate 88 and Rate 99
Case No. PU-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 (141st Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered October 1, 2015.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.121 per dk since the July 1, 2015 rates 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 \$0.023 per dk. The market based pricing differential credit decreased by \$0.006 per dk and the grain drying margin sharing provision increased by of \$0.008.

The COG tariff sheet, Exhibit A page 1, summarizes the gas cost adjustment, the surcharge adjustment, the market based pricing differential provision and the grain drying margin sharing provision, calculated pursuant to the terms of Rate 88 that will apply during the month of October 2015.

Exhibit B shows the calculation of the current gas cost adjustment that will be applicable to Montana-Dakota's customers for the month of October 2015. The average cost of gas for firm customers, adjusted for losses, is \$4.062.

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.

Exhibit D shows the calculation of the surcharge adjustment that will apply during the

period October 1, 2015 through September 30, 2016. The total surcharge is (\$0.310) per dk residential and general service customers, (\$0.018) per dk for small and large interruptible customers and (\$0.089) per dk for the Air Force, or a decrease of \$0.519 per dk for residential and general service customers, a decrease of \$0.398 per dk for small and large interruptible customers and a decrease of \$0.454 per dk for the Air Force from the adjustment effective October 1, 2014.

Exhibit E shows the calculation of the interruptible market based pricing differential pursuant to the terms of Rate 88 and the terms of the settlement agreement filed on August 26, 2015 in Case No. PU-15-90. Fifty percent of the non-gas commodity revenues received from small and large interruptible sales in excess of the authorized level are credited to residential and firm general service customers through the COG. A credit of \$0.011 per dk will be applicable to all residential and general service customers due to the market based pricing differential for the period October 1, 2015 through September 30, 2016.

Exhibit F shows the grain drying margin sharing provision pursuant to the terms of Rate 88. Ninety percent of the margin revenues collected from grain drying customers served under interruptible service rates will be credited to residential and firm general service customers through the COG. A credit of \$0.009 per dk will be applicable to all residential and general service customers due to the grain drying margin sharing provision for the period October 1, 2015 through September 30, 2016.

Exhibit G shows the calculation of the current cost of gas – propane that will be applicable to Montana-Dakota's customers for the month of October 2015. The average cost of propane for all customers, adjusted for losses, is \$2.415.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.665 per dk for residential customers and firm general customers, a decrease of \$0.507 per dk for small and large interruptible customers and a decrease of \$0.562 per dk for Air Force interruptible customers from the currently effective rates.

Montana-Dakota purchases propane supplies from various wholesale suppliers. The cost of propane did not change since the last September COG filing but the market based pricing differential credit decreased by \$0.006 per dk.

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 October 2015.

These proposed adjustments, calculated in accordance with Rate 88 and Rate 99, will amount to a decrease of approximately \$859,500 for natural gas customers during the month of October 2015. All of Montana-Dakota's retail natural gas customers in North Dakota may be affected by this proposal. There were 105,700 natural gas customers and

343 propane customers in North Dakota as of August 31, 2015.

Please refer all inquiries regarding this filing to:

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

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

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

Montana-Dakota submitted a check 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

141st Revised Sheet No. 3

Canceling 140th 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 ¹	4	\$0.4935 per day	\$0.326	\$3.732	\$4.058
Air Force Rate 64 ¹	7				
Minot Air Force Base		\$2,000.00 per month			
PAR Site		\$175.00 per month			
Firm Service			\$0.329	\$3.732	\$4.061
Interruptible Service - PAR			\$0.260	\$2.952	\$3.212
Interruptible Service - MAFB			\$0.260	\$2.868	\$3.128
Firm General Service Rate 70 ¹	13				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$3.732	\$4.462
Small Interruptible Gas Rate 71 ²	14	\$175.00 per month	(Maximum) \$0.929	\$2.952	(Maximum) \$3.881
Optional Seasonal Gas ¹					
Service Rate 72	15				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$3.833	\$4.563
Transportation Service ¹	24				
Small Interruptible Rate 81		\$175.00 per month			
Maximum			\$0.485		
Minimum			\$0.102		
Fuel Charge				\$0.013	
Large Interruptible Rate 82		\$1,000.00 per month			
Maximum			\$0.297		
Minimum			\$0.061		
Fuel Charge				\$0.013	
Large Interruptible Gas Rate 85 ³	27	\$1,000.00 per month	(Maximum) \$0.718	\$2.952	(Maximum) \$3.670
Residential Propane Rate 90 ¹	32	\$0.4935 per day	\$0.326	\$2.636	\$2.962
Firm General Propane Rate 92 ¹	34				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$2.636	\$3.366

1/ Interim increase of 13.523% applicable to amounts billed under Basic Service Charge and Distribution Delivery Charge.

2/ Interim increase of 8.669% applicable to amounts billed under Basic Service Charge and Distribution Delivery Charge.

3/ Interim increase of 8.309% applicable to amounts billed under Basic Service Charge and Distribution Delivery Charge.

Date Filed: September 8, 2015

Effective Date: October 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**

October 2015

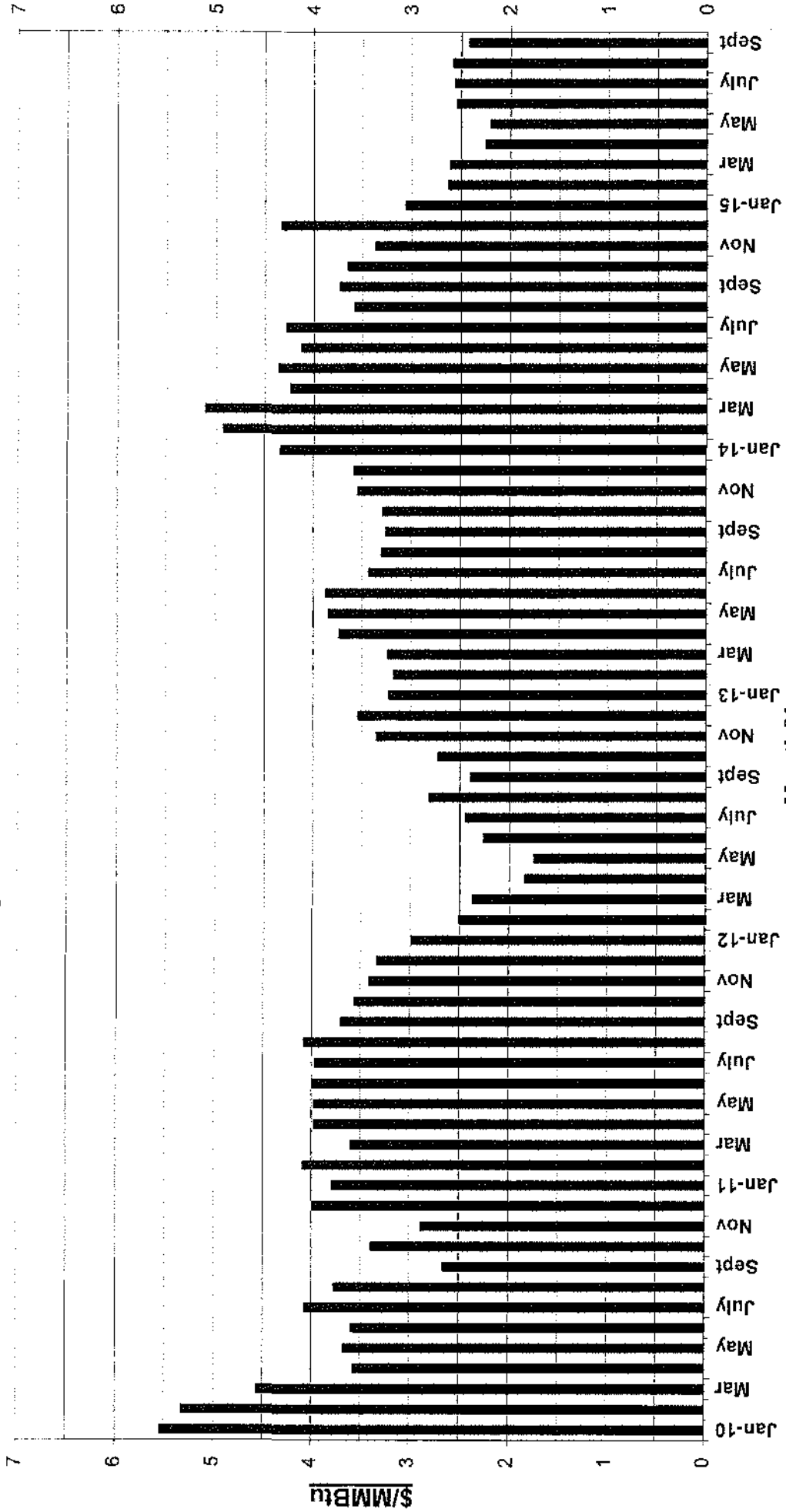
The established monthly price for the Rocky Mountain CIG Index has decreased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid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

Continued strong production of natural gas in the lower 48 states, driven mainly by increases in the Marcellus and Utica, offset the increase in usage for power generation and kept the price of natural gas in the same range as last month. Production of natural gas continues to be at or near historical highs. The EIA reported the national storage level as of August 28, 2015, was 4.0 percent above the five-year average and 18.3 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 August Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 21. The September Outlook will be published September 9, 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-\$2.54

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

August 2015

Short-Term Energy Outlook (STEO)

Highlights

- North Sea Brent crude oil prices averaged \$57/barrel (b) in July, a \$5/b decrease from June. Brent crude oil spot prices fell further in early August, settling at \$48/b on August 7. The recent price declines reflect concerns about lower economic growth in emerging markets, expectations of higher oil exports from Iran, and continuing actual and expected growth in global inventories.
- EIA forecasts that Brent crude oil prices will average \$54/b in 2015 and \$59/b in 2016, \$6/b and \$8/b lower than in last month's STEO, respectively. Forecast West Texas Intermediate (WTI) crude oil prices in both 2015 and 2016 average \$5/b less than the Brent price. The current values of futures and options contracts for November 2015 delivery (*Market Prices and Uncertainty Report*) suggest the market expects WTI prices to range from \$34/b to \$64/b (at the 95% confidence interval) in November 2015.
- On July 14, the P5+1 (the five permanent members of the United Nations Security Council and Germany) and Iran announced an agreement that could result in relief from United States and European Union nuclear-related sanctions (which include some oil-related sanctions). If the agreement is implemented and sanctions relief occurs, it will put additional Iranian oil supplies on a global market that has already seen oil inventories rise significantly over the past year. This forecast assumes sanctions relief occurs in 2016, contributing to an annual average increase in Iranian crude oil production of 0.3 million b/d from 2015 to 2016, with most of the increase coming in the second half of 2016.
- U.S. regular gasoline monthly average retail prices averaged \$2.79/gallon (gal) in July, a decrease of 1 cent/gal from June and 82 cents/gal lower than in July 2014. EIA expects monthly average gasoline prices to decline from their July level to an average of \$2.11/gal during the fourth quarter of 2015. EIA forecasts U.S. regular gasoline retail prices to average \$2.41/gal for all of 2015.
- EIA estimates total U.S. crude oil production declined by 100,000 barrels per day (b/d) in July compared with June. Production is expected to continue decreasing through mid-2016 before growth resumes late in 2016. Projected U.S. crude oil production averages 9.4 million b/d in 2015 and 9.0 million b/d in 2016, 0.1 million b/d and 0.4 million b/d lower, respectively, than in July's STEO.

- Natural gas working inventories were 2,912 billion cubic feet (Bcf) on July 31, which was 23% higher than a year earlier and 2% higher than the previous five-year average (2010-14). EIA projects inventories will close the injection season at the end of October at 3,867 Bcf, which would be the second-highest end-of-October level on record.
- U.S. population-weighted cooling degree days through the end of July were 14% more than in the same period last year. The hotter temperatures contribute to an EIA estimate that the typical residential electricity customer will use 3,134 kilowatthours in the months of June, July, and August this year, which is 4% more than during the same period in 2014.

Global Petroleum and Other Liquids

Global liquids production continues to outpace consumption, leading to strong inventory builds throughout the forecast period. Global oil inventory builds in the second quarter of 2015 averaged 2.7 million b/d, rising by 0.8 million b/d compared with the first quarter of the year. The pace of inventory builds is expected to slow in the second half of the year, to roughly 1.8 million b/d. In 2016, inventory builds are expected to slow to an average of 0.9 million b/d.

Global Petroleum and Other Liquids Consumption. EIA estimates global consumption of petroleum and other liquids grew by 1.1 million b/d in 2014, averaging 92.4 million b/d for the year. EIA expects global consumption of petroleum and other liquids to grow by 1.3 million b/d in 2015, unchanged from the previous month's STEO. Growth in 2016 global consumption was revised upward by 0.1 million b/d compared with last month to an average of 1.5 million b/d. Projected real gross domestic product (GDP) weighted for oil consumption, which increased by 2.8% in 2014, is projected to grow by 2.5% in 2015 and by 3.1% in 2016.

Consumption of petroleum and other liquids in countries outside of the Organization for Economic Cooperation and Development (OECD) grew by 1.4 million b/d in 2014 and is projected to grow by 0.8 million b/d in 2015 and by 1.2 million b/d in 2016. Iran is expected to experience an uptick in economic activity and petroleum consumption, assuming implementation of the Joint Comprehensive Plan of Action (JCPOA) between Iran and the P5+1, which was announced on July 14.

Despite the slowdown in economic growth in the second half of 2014 and thus far in 2015, China continues to be the main driver of non-OECD consumption growth. China's consumption growth is expected to average 0.3 million b/d in 2015 and 2016, below the 0.4 million b/d growth in 2014.

After falling by 0.4 million b/d in 2014, OECD petroleum and other liquids consumption is expected to rise by 0.5 million b/d in 2015 and by 0.3 million b/d in 2016, reaching an average of 46.5 million b/d, the highest annual average level of OECD consumption since 2010. The increase in 2015 stems from both economic and weather factors, with the United States contributing most of the annual consumption growth. U.S. consumption is expected to grow by an average of 0.4 million b/d in 2015 and 0.2 million b/d in 2016. Several other OECD countries

saw economic conditions improve as they emerged from recessions, particularly countries in Europe and to a lesser extent in Asia. In addition, colder-than-normal weather early in 2015 across Europe contributes to a projected 0.1 million b/d increase in consumption in OECD Europe in 2015.

Non-OPEC Petroleum and Other Liquids Supply. EIA estimates that petroleum and other liquids production in countries outside of the Organization of the Petroleum Exporting Countries (OPEC) grew by 2.3 million b/d in 2014, which mainly reflects production growth in the United States. EIA expects non-OPEC production to grow by 1.4 million b/d in 2015, but remain roughly flat in 2016. A number of producers will see output decrease amid lower prices, which have reduced investment. Furthermore, the ongoing corruption probe at state-owned Petrobras is expected to hurt Brazil's ability to expand production, limiting growth in 2016 to less than 0.1 million b/d, down from forecast growth of 0.2 million b/d in 2015. Brazil's relatively recent successes in bringing online a number of floating production, storage, and offloading (FPSO) facilities that had been delayed are driving the 2015 growth, with additional FPSOs slated to be delivered in 2016 at the Lula field.

Production growth in Canada is expected to average 0.3 million b/d in 2015 and increase to 0.4 million b/d in 2016, driven by continued expansion in oil sands projects. Although some previously announced oil sands projects have been put on hold, the vast majority continue as planned, including Imperial Oil and Cenovus oil sand projects scheduled to come online by the end of 2016.

Unplanned supply disruptions among non-OPEC producers averaged about 0.7 million b/d in July, about 0.1 million b/d lower compared with the previous month. In Canada, outages decreased and oil sands production returned to normal following the wildfires in western Canada. Additionally, output at Mexico's Abkatun Pol Chuc system continued to recover following an explosion at the offshore facility.

OPEC Petroleum and Other Liquids Supply. EIA estimates that OPEC crude oil production averaged 30.1 million b/d in 2014, unchanged from the previous year. Crude oil production declines in Libya, Angola, Algeria, and Kuwait offset production growth in Iraq and Iran. EIA forecasts OPEC crude oil production to increase by 0.8 million b/d in 2015 and remain relatively flat in 2016. Iraq is expected to be the largest contributor to OPEC production growth in 2015. In 2016, additional OPEC crude oil supply is expected to come from Iran, which is forecast to boost production if international sanctions targeting its oil sector are suspended.

On July 14, the P5+1 and Iran announced an agreement that could result in relief from United States and European Union nuclear-related sanctions (which include some oil-related sanctions). Sanctions relief is contingent on verification by the International Atomic Energy Agency that Iran has complied with key nuclear-related steps. The sanctions relief would put additional Iranian oil supplies on a global market that has already seen oil inventories rise significantly over the past year.

The JCPOA is currently undergoing a congressional review. As of the time of writing, Congress had not voted on the agreement, but for the purposes of this STEO, EIA assumes sanctions relief could occur in mid-2016. If sanctions relief occurs, EIA forecasts Iranian crude oil supplies will increase by about 0.3 million b/d on average in 2016, with most of the growth occurring in the second half of the year. While much uncertainty remains as to the timing of sanctions relief, EIA's updated Iran projection assumes that adoption takes place by the end of October 2015, with implementation occurring in the second quarter of 2016, clearing the way to easing of the sanctions.

Iran produced 3.6 million b/d of crude oil in late 2011, before the recent round of sanctions was enacted. The sanctions forced Iran to shut in a substantial portion of its production, with production currently averaging about 2.8 million b/d. Iran's ability to bring online previously shut-in volumes and increase exports depends on several factors, including the current condition of oil fields and infrastructure that were shut in and the pace of sanctions relief.

Saudi Arabia and other OPEC member countries are not expected to cut production to accommodate additional Iranian volumes, although some producers will see production declines in the near term. For example, Saudi Arabia's production is expected to respond to lower direct crude burn for electric power generation as seasonal power demand abates. However, there is considerable uncertainty regarding Iraq's ability to sustain its higher production and export levels, particularly in light of infrastructure constraints in the southern terminals.

OPEC noncrude liquids production, which averaged 6.3 million b/d in 2014, is expected to increase by 0.2 million b/d in 2015 and by 0.3 million b/d in 2016, led by production increases in Iran, Qatar, and Kuwait.

In July, unplanned crude oil supply disruptions among OPEC producers averaged 2.6 million b/d, remaining roughly unchanged compared with the previous month. Kuwait and Saudi Arabia continue to have a total of 0.5 million b/d disrupted at the Wafra and Khafji fields in the Neutral Zone that straddles the two countries.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to decrease to an average of 1.6 million b/d in 2015 and increase to 2.1 million b/d in 2016, after averaging 2.0 million b/d in 2014. Surplus capacity is typically an indicator of market conditions, and surplus capacity below 2.5 million b/d indicates a relatively tight oil market, but the current and forecast levels of global inventory builds make the projected low surplus capacity level in 2015 less significant. EIA does not expect any Iranian spare capacity to be available throughout the forecast period despite increases in effective capacity, as Iran is expected to produce crude oil at the maximum available level through the end of 2016 if and when sanctions are lifted.

OECD Petroleum Inventories. EIA estimates that OECD commercial crude oil and other liquids inventories totaled 2.69 billion barrels at the end of 2014, equivalent to roughly 59 days of consumption. Forecast OECD inventories rise to 2.99 billion barrels at the end of 2015 and then to 3.08 billion barrels at the end of 2016.

Crude Oil Prices. Brent crude oil spot prices decreased by \$5/b in July to a monthly average of \$57/b. Prices fell further at the end of July and into early August, with Brent spot prices settling at \$48/b on August 7. Continuing increases in global liquids inventories put significant downward pressure on prices. Inventories rose by an estimated 2.3 million b/d through the first seven months of 2015, compared with an average build of 0.6 million b/d over the same period last year. Inventory builds are projected to moderate somewhat in the coming months, but are expected to remain high compared with previous years. Concerns over the pace of economic growth in emerging markets and the possibility of increasing volumes of Iranian crude oil on the market also contributed to the recent oil price decline.

The monthly average WTI crude oil spot price fell to an average of \$51/b in July, down \$9/b from June. Crude oil inventories at Cushing, Oklahoma, despite having decreased by 5.0 million barrels from their record high of 62.2 million barrels on April 17, remain about 40 million barrels higher than at the same time last year. U.S. crude oil inventories remain elevated compared with historical levels, despite strong U.S. refinery runs, which in recent weeks reached record highs over 17 million b/d.

EIA projects the Brent crude oil price will average \$54/b in 2015 and \$59/b in 2016, \$6/b and \$8/b lower than in July's STEO, respectively. WTI prices in both 2015 and 2016 are expected to average \$5/b less than the Brent crude oil price. EIA's updated projection remains subject to significant uncertainties as the oil market moves toward balance. During this period of price discovery, oil prices could experience periods of heightened volatility. The oil market faces a host of uncertainties heading into 2016 including the pace and volume at which Iranian oil reenters the market, the strength of oil consumption growth, and the responsiveness of non-OPEC production to low oil prices. In the more immediate future, there is potential downward price pressure heading into the fourth quarter if refinery runs drop by more than expected during the fall maintenance season.

The current values of futures and options contracts continue to suggest high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for November 2015 delivery, traded during the five-day period ending August 6, averaged \$47/b, while implied volatility averaged 37%. These levels established the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in November 2015 at \$34/b and \$64/b, respectively. The 95% confidence interval for market expectations widens over time, with lower and upper limits of \$27/b and \$103/b for prices in December 2016. Last year at this time, WTI for November 2014 delivery averaged \$96/b, and implied volatility averaged 16%. The corresponding lower and upper limits of the 95% confidence interval were \$84/b and \$111/b.

U.S. Petroleum and Other Liquids

On July 13, U.S. average diesel fuel retail prices fell below average regular gasoline prices for the first time since the week of August 10, 2009, and have remained lower for four consecutive weeks. Ongoing refinery outages in California, as well as strong demand for gasoline in both the

United States and abroad, have kept gasoline prices elevated over the past two months despite falling crude oil prices. Data from the U.S. Federal Highway Administration show Americans drove a record 1.26 trillion miles during the first five months of 2015, compared with the previous record of 1.23 trillion miles driven in the first five months of 2007. As a result, refinery wholesale gasoline margins (the difference between the wholesale price of gasoline and the price of Brent crude oil) have been strong in recent months, leading to record-high refinery runs. U.S. average wholesale gasoline margins averaged 73 cents/gal in July, 42 cents/gal higher than in July of last year and 40 cents/gal higher than the five-year average (2010-14) for July.

Refinery outages on the West Coast have contributed to gasoline prices in that region rising by more than the U.S. average over the past few months, as well as significant price volatility. After declining by 22 cents/gal from May 18 to an average of \$3.30/gal on July 6, regular gasoline prices in Petroleum Administration for Defense District (PADD) 5 increased again to a new 2015 peak of \$3.60/gal on July 20. PADD 5 retail prices have fallen to \$3.36/gal as of August 10.

In July, monthly average regional gasoline retail prices ranged from a low of \$2.49/gal in PADD 3, the Gulf Coast region, to a high of \$3.51/gal in PADD 5. EIA expects gasoline prices to fall from their current levels, with the U.S. regular gasoline price averaging \$2.11/gal in the fourth quarter of 2015.

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 70,000 b/d (0.4%) in 2014. Total liquid fuels consumption is forecast to grow by 400,000 b/d (2.1%) in 2015 and by 190,000 b/d (1.0%) in 2016. The 2016 consumption forecast is about 70,000 b/d higher than forecast in last month's STEO.

Motor gasoline consumption, which rose by 80,000 b/d in 2014, increases by a projected 210,000 b/d (2.3%) in 2015 as the effects of employment growth and lower gasoline prices outweigh increases in vehicle fleet efficiency. Gasoline consumption is forecast to remain relatively flat in 2016, as a long-term trend toward more-fuel-efficient vehicles offsets the effects of continued economic growth.

Consumption of distillate fuel, which includes diesel fuel and heating oil, is forecast to rise by 40,000 b/d (1.1%) in 2015 and by an additional 100,000 b/d (2.4%) in 2016. This growth is driven by increasing manufacturing output, foreign trade, and marine fuel use.

Hydrocarbon gas liquids (HGL) consumption, which fell by 100,000 b/d (4.0%) in 2014, is projected to increase by 90,000 b/d in both 2015 and 2016, as new petrochemical plant capacity increases the use of HGL as a feedstock. In addition, new HGL export terminal capacity contributes to an increase in HGL net exports from an average of 560,000 b/d in 2014 to 1.1 million b/d in 2016.

Liquid Fuels Supply. U.S. crude oil production is projected to increase from an average of 8.7 million b/d in 2014 to 9.4 million b/d in 2015 and then decrease to 9.0 million b/d in 2016. The forecast is about 0.1 million b/d lower and 0.4 million b/d lower for 2015 and 2016, respectively, than in July's STEO. The decrease in the crude oil production forecast reflects a lower oil price

outlook that will reduce expected oil-directed rig counts and drilling and well-completion activities throughout the forecast period.

EIA estimates that U.S. crude oil production averaged 9.5 million b/d in the first half of 2015. This level is 0.3 million b/d higher than the average production during the fourth quarter of 2014, despite an almost 60% decline in the total U.S. oil-directed rig count since October 2014. The most recent production estimates indicate U.S. crude oil output was 9.5 million b/d in May. EIA estimates that total U.S. production was unchanged in April and began declining in May, falling 180,000 b/d from the April level. Some of this decline reflects outages in the Gulf of Mexico that are expected to be temporary. The decrease in total production was preceded by declines in onshore production, which began in April.

EIA expects U.S. crude oil production declines to continue through the third quarter of 2016, when total crude oil production is forecast to average 8.8 million b/d. Forecast production begins rising in late 2016, returning to an average of 9.1 million b/d in the fourth quarter. A total of 13 projects are scheduled to come online in the Gulf of Mexico in 2015 and 2016, pushing up Gulf of Mexico production from an average of 1.4 million b/d in the fourth quarter of 2014 to more than 1.6 million b/d in the same period of 2016.

Expected crude oil production declines from May 2015 through the third quarter of 2016 are largely attributable to unattractive economic returns in some areas of both emerging and mature onshore oil production regions, as well as seasonal factors such as anticipated hurricane-related production disruptions in the Gulf of Mexico. Reductions in 2015 cash flows and capital expenditures have prompted companies to defer or redirect investment away from marginal exploration and research drilling to focus on core areas of major tight oil plays. Reduced investment has resulted in the lowest count of oil-directed rigs in nearly five years and well completions that are significantly behind 2014 levels.

Oil prices, particularly in the second quarter of 2015, remained high enough to support continued development drilling in the core areas of the Bakken, Eagle Ford, Niobrara, and Permian basins, with July showing the first month-to-month increase in the oil-directed rig count since October 2014. However, the recent fall in crude oil prices and lowered outlook for oil prices over the forecast period are expected to prolong and deepen onshore production declines. Lower crude oil prices are anticipated to slow the rate of recovery in onshore drilling activities and well completion totals, despite continued increases in rig and well productivity and falling drilling and completion costs. The forecast remains sensitive to actual wellhead prices and rapidly changing drilling economics that vary across regions and operators.

While projected oil production in the Gulf of Mexico rises during the forecast period, Alaska oil production falls. Production in these areas is less sensitive to short-term price movements than onshore production in the Lower 48 states and reflects anticipated growth from new projects and declines from legacy fields.

HGL production at natural gas processing plants reached a record level of 3.31 million b/d in April 2015, and it is projected to average 3.28 million b/d in 2015 and 3.53 million b/d in 2016.

EIA expects higher ethane recovery rates in 2016 following planned increases in petrochemical plant feedstock demand. Export terminal expansions will allow for higher quantities of domestically produced ethane, propane, and butanes to reach the international market.

U.S. petroleum product gross exports continue to grow, up almost 0.5 million b/d (13%) in the first five months of 2015 compared with the same period in 2014. More than half of the growth in liquid fuel exports came from HGL. The increase in refined product exports, combined with the growth in domestic liquid fuels consumption, contributed to U.S. refinery utilization rates averaging 89.9% over the first five months, up from 88.1% last year and the highest rate for this period since 2005. Gross inputs to U.S. refineries exceeded 17 million b/d in each of the last four weeks of July, a level that had not previously been reached or exceeded in any week since EIA began publishing the data in 1990.

Petroleum Product Prices. Rising crude oil prices, strong demand for U.S. gasoline, and several refinery outages in the Midwest and West Coast contributed to an increase in U.S. regular gasoline retail prices from a monthly average of \$2.47/gal in April to \$2.79/gal in July. EIA expects monthly average prices to decline in the coming months as refineries continue to produce high levels of gasoline, as demand begins to decrease following the peak in the summer driving season, and as the market transitions to lower-cost winter-grade gasoline. EIA projects regular gasoline retail prices to average \$2.60/gal during the third quarter of 2015 and \$2.11/gal in the fourth quarter.

The U.S. regular gasoline retail price, which averaged \$3.36/gal in 2014, is projected to average \$2.41/gal in 2015, 7 cents/gal lower than in July's STEO, and \$2.40/gal in 2016, which is 15 cents/gal lower than in July's STEO.

The diesel fuel retail price, which averaged \$3.83/gal in 2014, is projected to fall to an average of \$2.73/gal in 2015, 13 cents/gal lower than in July's STEO, and then rise to \$2.81/gal in 2016, 23 cents/gal lower than in last month's STEO.

As with crude oil, the market's expectation of uncertainty in monthly average gasoline prices is reflected in the pricing and implied volatility of futures and options contracts. New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contracts for November 2015 delivery, traded over the five-day period ending August 6, averaged \$1.45/gal. The probability that the RBOB futures price will exceed \$1.85/gal (consistent with a U.S. average regular gasoline retail price above \$2.50/gal) in November 2015 is about 7%.

Natural Gas

The natural gas storage injection season passed the halfway mark in mid-July, and inventories totaled 2,912 Bcf on July 31, which was 23% higher than a year earlier and 2% higher than the previous five-year average (2010-14). Inventories began the injection season about 173 Bcf lower than the five-year average, but have been greater than the five-year average since the end of May. EIA projects inventories will end October at 3,867 Bcf, which would be the second-highest October level on record. Year-over-year strength in production has boosted storage

injections this summer, despite warmer temperatures, which have increased natural gas use in the power sector to serve air conditioning demand.

Tallgrass Energy brought online the final phase of its east-to-west pipeline reversal on the Rockies Express Pipeline (REX) earlier this month. This expansion allows for 1.8 Bcf/d of Marcellus and Utica natural gas to flow westward from eastern Ohio to Missouri. REX began service in 2009 to move natural gas from the Rockies to Midwestern and Northeastern markets. Over the past several years, however, demand for Rockies natural gas in the east has declined because of exponential growth in Marcellus-area production.

Natural Gas Consumption. EIA's forecast of U.S. total natural gas consumption averages 76.5 Bcf/d in both 2015 and 2016, compared with 73.5 Bcf/d in 2014. EIA projects natural gas consumption in the power sector to increase by 13.9% in 2015 and then decrease by 3.4% in 2016. Relatively low natural gas prices support increased use of natural gas for electricity generation in 2015. Industrial sector consumption increases by 2.3% in 2015 and by 5.0% in 2016, as new industrial projects, particularly in the fertilizer and chemicals sectors, come online later this year and next year, and as industrial consumers continue to take advantage of low natural gas prices. Natural gas consumption in the residential and commercial sectors is projected to decline in both 2015 and 2016.

Natural Gas Production and Trade. EIA expects that marketed natural gas production will increase by 4.0 Bcf/d (5.4%) and by 1.8 Bcf/d (2.3%) in 2015 and 2016, respectively. Despite data showing month-over-month production declines in May and June, natural gas production remains higher than year-ago levels. EIA expects moderate growth through 2016, with increases in the Lower 48 states expected to more than offset long-term production declines in the Gulf of Mexico. Increases in drilling efficiency will continue to support growing natural gas production in the forecast despite relatively low natural gas prices. Most of the growth is expected to come from the Marcellus Shale, as the backlog of uncompleted wells is reduced and as new pipelines come online to deliver Marcellus natural gas to markets in the Northeast.

Increases in domestic natural gas production are expected to reduce demand for natural gas imports from Canada and are expected to support growth in exports to Mexico. EIA expects natural gas 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.

EIA projects LNG gross exports will increase to an average of 0.79 Bcf/d in 2016, with the startup of a major LNG liquefaction plant in the Lower 48 states.

Natural Gas Inventories. On July 31, natural gas working inventories totaled 2,912 Bcf, which was 535 Bcf (23%) above the level at the same time in 2014 and 64 Bcf (2%) above the five-year average for that week. To this point in the injection season, injections have surpassed the five-year average by a wide margin. EIA projects end-of-October 2015 inventories will total 3,867 Bcf, 69 Bcf (1.8%) above the five-year average for that time.

Natural Gas Prices. The Henry Hub natural gas spot price averaged \$2.84/million British thermal units (MMBtu) in July, an increase of 6 cents/MMBtu from the June price. The current STEO lowers the projection for prices slightly from last month's forecast; monthly average spot prices remain lower than \$3/MMBtu through October, and lower than \$4/MMBtu through the remainder of the forecast. The projected Henry Hub natural gas price averages \$2.89/MMBtu in 2015 and \$3.21/MMBtu in 2016.

Natural gas futures contracts for November 2015 delivery traded during the five-day period ending August 6 averaged \$2.91/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for November 2015 contracts at \$2.08/MMBtu and \$4.06/MMBtu, respectively. At this time last year, the natural gas futures contract for November 2014 delivery averaged \$3.96/MMBtu, and the corresponding lower and upper limits of the 95% confidence interval were \$3.03/MMBtu and \$5.16/MMBtu, respectively.

Coal

Recent changes in the global coal market contributed to lower U.S. coal production in the second quarter. Slower growth in world coal demand, lower international coal prices, and higher coal output in other coal-exporting countries have all led to a two-year decline in U.S. coal exports. Australia, the world's second-largest coal exporter, has seen exports continue to increase, but export earnings are expected to fall this year. Lower mining costs, cheaper transportation costs, and favorable exchange rates will continue to provide an advantage to Australian coal producers over their American counterparts in the forecast period. Other major coal-exporting countries (Indonesia, Colombia, Russia, and South Africa) currently have similar advantages compared with U.S. coal producers.

Activities in major coal consuming nations (China and India) have also affected the global coal market. India has seen an upswing in domestically produced coal, causing Indian coal import growth to be nearly flat. Chinese demand for coal and coal imports has fallen as well. Several factors have contributed to these developments, including slower electricity demand and industrial growth and the imposition of more stringent environmental regulations on the power and energy-intensive industries. Imported coal has also been affected by the levying of new taxes and stricter environmental quality testing, which has seen some imported shipments of coal being denied entry.

Coal Trade. EIA projects coal exports will fall by 14 million short tons (MMst), to 83 MMst, in 2015, and remain at that level in 2016. U.S. coal imports, which increased by more than 2 MMst in 2014 to 11 MMst, are expected to remain near that level in 2015 and 2016.

Coal Supply. Lower domestic coal consumption and exports, combined with a slight increase in coal imports, are projected to contribute to an 83 MMst (8%) decline in production for 2015. Coal production is expected to decrease in all coal-producing regions in 2015. However, production is expected to increase by 10 MMst (1%) in 2016, driven by modest production

growth in the Interior region and the Western region, as coal use increases in the electric power sector.

Electric power sector stockpiles increased to 175 MMst in May (the most recent month for which data are available), a 4% increase from the previous month. This monthly increase (April to May) in coal inventories follows the normal spring pattern in which coal stockpiles are usually built up for use in the summer months. Coal inventories were 38 MMst higher than in May 2014 when inventories were still recovering from the effects of colder-than-normal temperatures earlier in the year, and they are only 2 MMst lower than the previous five-year average for the month.

Coal Consumption. EIA expects a 7% decrease in coal consumption in the electric power sector in 2015. Lower natural gas prices and the growth of renewable-based generation are the key factors driving the decrease in coal consumption. Projected low natural gas prices make it more economical to run natural gas-fired generating units at higher utilization rates even in regions of the country that typically rely more heavily on coal-fired generation (Midwest and South). Nonhydropower renewable-based electricity generation is expected to grow by 4% in 2015, with the largest growth occurring in the South (8%). The retirements of coal-fired power plants in response to the implementation of the Mercury and Air Toxics Standards (MATS) also reduces coal-fired capacity in the power sector in 2015, but the full effect of the coal plant retirements on capacity will be felt in 2016.

Projected rising electricity demand and higher natural gas prices next year are expected to contribute to higher utilization rates among the remaining coal-fired fleet. Even with continued implementation of MATS, which the U.S. Supreme Court recently sent back to the U.S. Court of Appeals for the D.C. Circuit for further review, coal consumption in the electric power sector is forecast to increase by 1.9% in 2016.

Coal Prices. The annual average coal price to the electric power sector decreased from \$2.39/MMBtu in 2011 to \$2.36/MMBtu in 2014. EIA expects the delivered coal price to average \$2.28/MMBtu in 2015 and 2016.

Electricity

Monthly data show 4,250 megawatts (MW) of new utility-scale generating capacity has come online in the United States this year through May, about the same amount that came online during the first five months of 2014. Generating units powered by renewable energy sources account for 55% of this year's new capacity, and new natural gas-fired capacity accounts for 44%. Texas is the state with the largest amount of new capacity this year (2,074 MW). Capacity additions in Texas are about evenly split between wind and natural gas.

Electricity Consumption. U.S. population-weighted cooling degree days so far in 2015 (through July) were 14% higher than the same period last year, which is a primary factor in the higher summer consumption of electricity. EIA estimates that the typical residential electricity

customer will use 3,134 kilowatthours of electricity during the months of June, July, and August this year, which is 4% more than in the same months in 2014.

EIA expects U.S. retail sales of electricity to the residential sector during 2015 to grow by 0.4% from 2014 levels. Residential sales of electricity are expected to fall by 1.0% in 2016, reflecting a forecast of milder summer and winter temperatures next year that reduces electricity use for cooling and heating-related demand.

Electricity Generation. U.S. generation of electricity fueled by natural gas exceeded coal-fired generation for the first time on record in April 2015, when the Henry Hub natural gas price hit a recent low of \$2.61/MMBtu. Since then, natural gas prices have risen to an average of \$2.84/MMBtu in July. EIA expects the price to continue increasing slowly through 2016, which contributes to projected coal-fired generation exceeding natural gas-fired generation through the short-term forecast horizon. EIA forecasts coal's share of U.S. total generation will average 35.6% in 2015, down from 38.7% in 2014. The natural gas fuel share averages 31.2% in 2015, up from 27.4% in 2014.

Electricity Retail Prices. The U.S. retail price of electricity to the residential sector is projected to average 12.7 cents per kilowatthour in 2015, which is 1.9% higher than the average price last year. This year-over-year increase in average electricity prices, combined with higher expected summer residential use, leads to a forecast 5.0% (\$20) increase in the typical residential customer's summer electricity expenditures compared with last summer.

Renewables and Carbon Dioxide Emissions

Electricity and Heat Generation from Renewables. EIA expects total renewables used in the electric power sector will decrease by 2.6% in 2015. Conventional hydropower generation is forecast to decrease by 9.9%, and nonhydropower renewable power generation is forecast to increase by 4.5%. The 2015 decrease in hydropower generation reflects the effects of the California drought, which are only partially offset by growth in hydropower use elsewhere. Generation from hydropower in the electric power sector is expected to increase by 12.3% in 2016. Total renewables consumption for electric power and heat generation decreases by 4.0% in 2015 and increases by 7.6% in 2016.

EIA expects continued growth in utility-scale solar power generation, which is projected to average 87 gigawatthours per day (GWh/d) in 2016. Because the growth is from a small base, utility-scale solar power averages only 0.8% of total U.S. electricity generation in 2016. Although solar growth has historically been concentrated in customer-sited distributed generation installations (rooftop panels), EIA expects utility-scale solar capacity will increase by almost 100% (10 GW) between the end of 2014 and the end of 2016, with 3.9 GW of this new capacity being built in California. Other leading states in utility-scale solar capacity include North Carolina and Nevada, which, combined with California, account for almost 70% of the projected utility-scale capacity additions for 2015 and 2016. Power plant developers have notified EIA of plans to construct 13 projects in Georgia (totaling 607 MW) with expected 2015 or 2016 in-service dates. Five of these new projects (166 MW) will be built on U.S. military bases. Georgia currently has

66 MW of utility-scale solar capacity. According to current law, projects coming online after the end of 2016 will see a federal investment tax credit of 10%, below the 30% investment tax credit available for projects that come online before the end of 2016. This impending decline in the tax credit provides a strong incentive for projects to enter service before the end of 2016.

Wind capacity, which grew by 8% in 2014, is forecast to increase by 12% in 2015 and by 14% in 2016. Because wind is starting from a much larger base than solar, even though the growth rate is lower, the absolute increase in wind capacity is twice that of solar: 18 GW of wind compared with 10 GW of utility-scale solar between 2014 and 2016.

Liquid Biofuels. On May 29, the U.S. Environmental Protection Agency (EPA) proposed a rule setting Renewable Fuel Standard (RFS) volumes for 2014 through 2016. Although these volumes could be modified before the final rule is issued, they are used in developing the current STEO. Ethanol production, which averaged 935,000 b/d in 2014, is forecast to remain near current levels in 2015 and 2016. Ethanol consumption, which averaged 878,000 b/d in 2014, is forecast to average about 900,000 b/d in both 2015 and 2016, resulting in an average 9.9% ethanol share of the total gasoline pool those years. EIA does not expect significant increases in E15 or E85 consumption over the forecast period. The proposed RFS targets are expected to encourage imports of Brazilian sugarcane ethanol, which were 3,000 b/d in 2014. Because of the expected increase in ethanol gross imports, net exports of ethanol are forecast to fall from 51,000 b/d in 2014 to 43,000 b/d in 2015, and to 37,000 b/d in 2016.

EIA expects the largest effect of the proposed RFS targets to be on biodiesel consumption, which contributes to meeting the biomass-based diesel, advanced biofuel, and total renewable fuel RFS targets. Biodiesel production averaged an estimated 81,000 b/d in 2014 and is forecast to average 91,000 b/d in 2015 and 98,000 b/d in 2016. Net imports of biomass-based diesel are also expected to increase from 16,000 b/d in 2014 to 24,000 b/d in 2015, and to 35,000 b/d in 2016. EIA expects that a combination of higher biomass-based diesel consumption, higher consumption of domestic and imported ethanol, and banked Renewable Identification Numbers (RINs) will help meet the newly proposed RFS volumes through 2016.

Energy-Related Carbon Dioxide Emissions. EIA estimates that emissions grew by 1.0% in 2014. Emissions are projected to fall by 0.2% in 2015 and then rise by 0.7% in 2016. These forecasts are sensitive to both weather and economic assumptions. Monthly carbon dioxide emissions from the electric power sector were at a 27-year low in April, which is typically the month with the lowest generation level in each year.

U.S. Economic Assumptions

Recent Economic Indicators. The Bureau of Economic Analysis (BEA) reported that real GDP increased at an annual rate of 2.3% in the second quarter of 2015. The growth of real GDP was broad-based and reflected positive contributions from consumption, exports, state and local government spending, and residential fixed investment. The estimate of growth in the first quarter of 2015 was also revised up to 0.6%; the previous estimate was -0.2%.

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

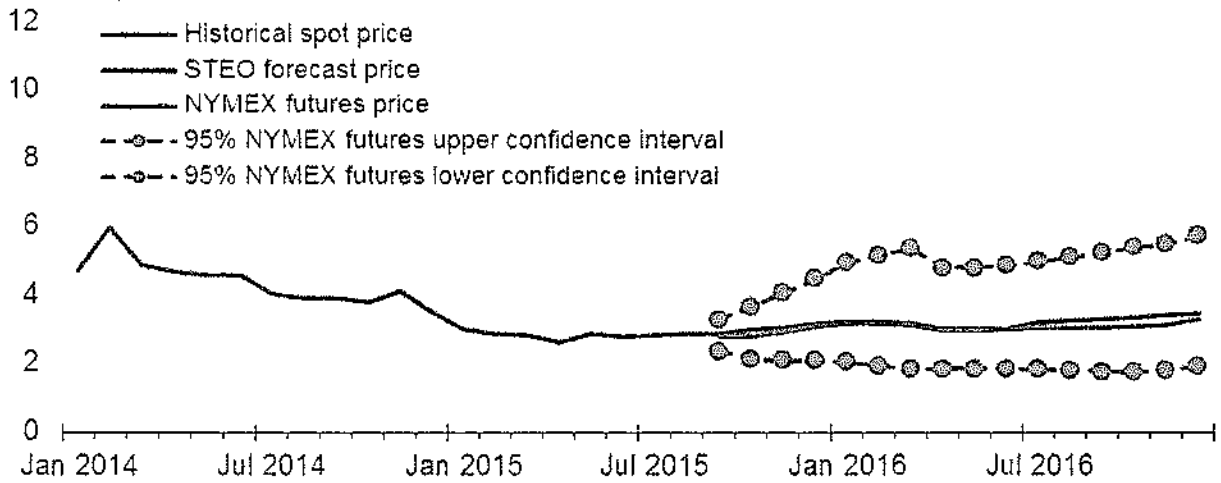
Production, Income, and Employment. Forecast real GDP growth reaches 2.2% in 2015 and rises to 3.0% in 2016. The 2015 growth is above the 2.0% forecast in last month's STEO, and the 2016 growth is also above the 2.8% July forecast. Real disposable income grows by 3.5% in 2015, the same as in the July forecast, and by 2.9% in 2016. Total industrial production grows at 1.8% in 2015 and 3.3% in 2016. Projected growth in nonfarm employment averages 2.1% in 2015 and 1.5% in 2016.

Expenditures. Forecast private real fixed investment growth averages 4.7% and 7.3% in 2015 and 2016, respectively, led by equipment in 2015 and 2016 and by equipment and structures in 2016. Real consumption expenditures grow faster than real GDP in 2015, at 3.0%, and the same as real GDP in 2016 at 3.0%. Durable goods expenditures drive consumption spending in both years. Export growth is 2.2% and 4.6% over the same two years, while import growth is 6.0% in 2015 and 2016. Total government expenditures rise by 0.9% in 2015 and by 0.8% 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



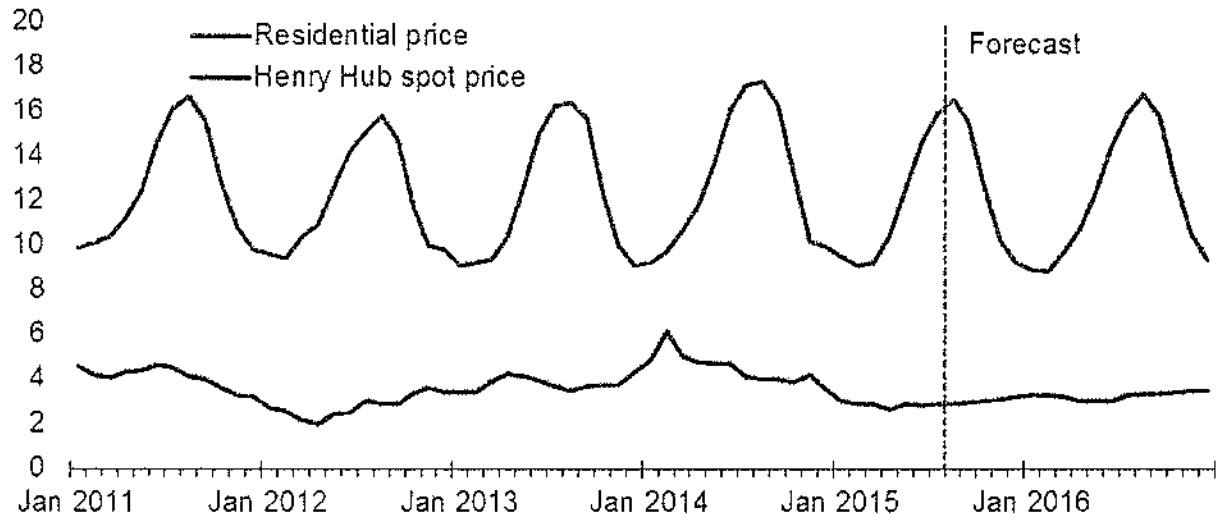
Note: Confidence interval derived from options market information for the 5 trading days ending Aug. 6, 2015. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, August 2015.



U.S. Natural Gas Prices

dollars per thousand cubic feet



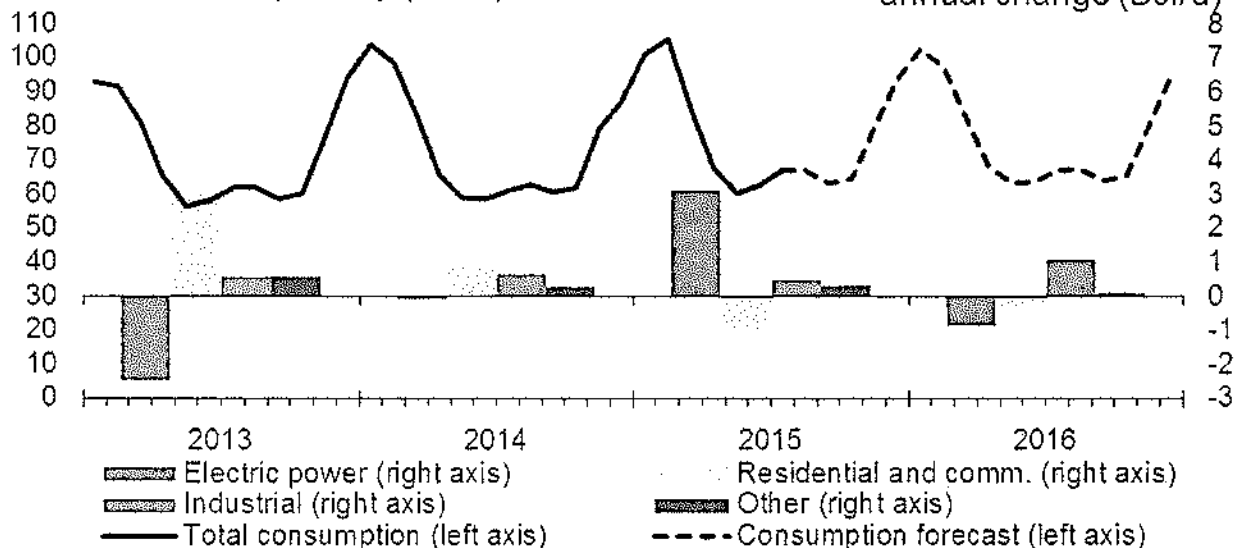
Source: Short-Term Energy Outlook, August 2015.

U.S. Natural Gas Consumption

billion cubic feet per day (Bcf/d)



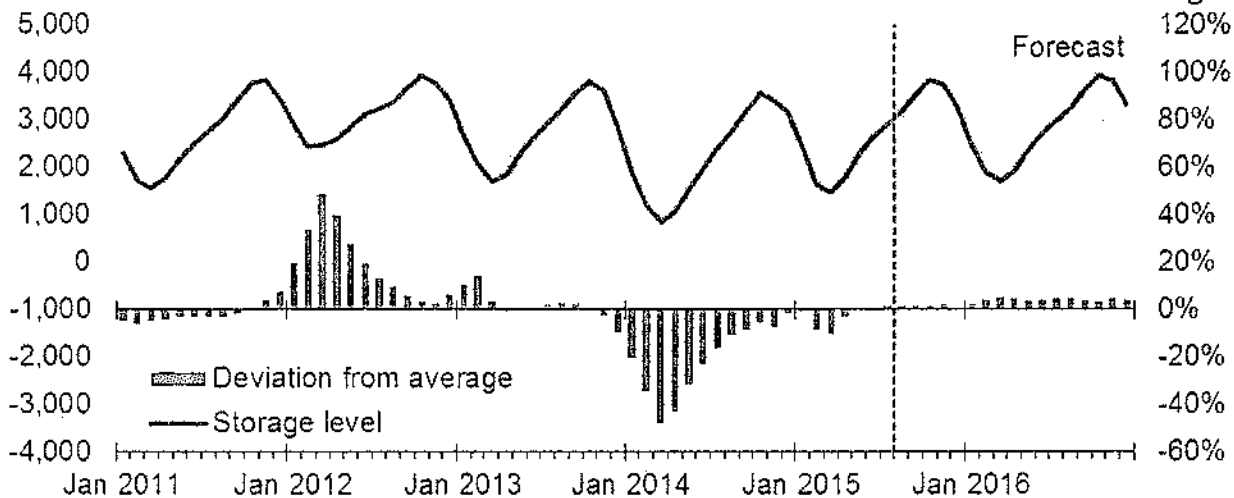
annual change (Bcf/d)



Source: Short-Term Energy Outlook, August 2015.

U.S. Working Natural Gas in Storage

billion cubic feet



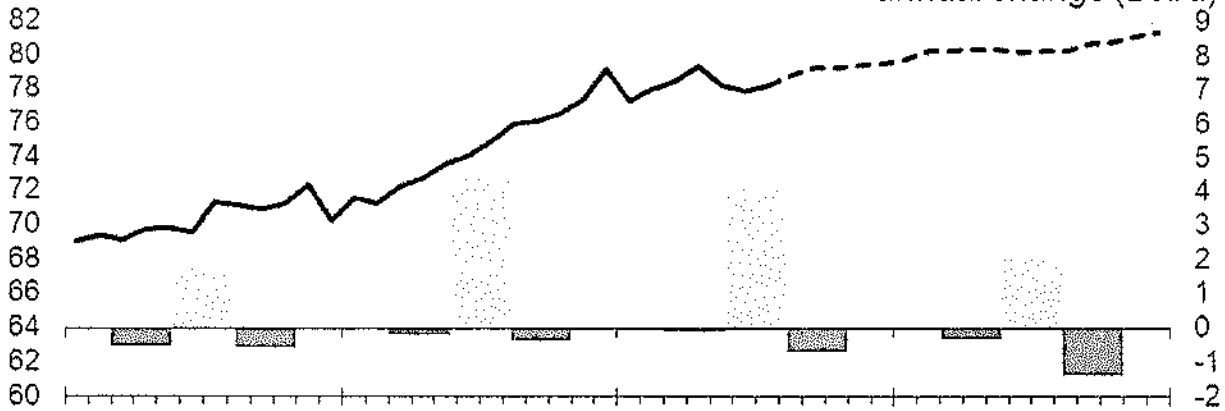
Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2010 - Dec. 2014.

Source: Short-Term Energy Outlook, August 2015.

U.S. Natural Gas Production and Imports

billion cubic feet per day (Bcf/d)

eia
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, August 2015.

**Montana-Dakota Utilities Co.
Pipeline Rate Changes Since Last Annual COG
North Dakota
October 2015 COG**

NOVA Gas Transmission Ltd.

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

Approximate impact on Montana-Dakota's cost of gas: 0.10 cents per dk

Foothills Pipe Lines Ltd.

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

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

NorthWestern Energy

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

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

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

Northwestern Energy

On June 5, 2015, NorthWestern Energy filed an application for approval to implement rates related to its Unreflected Gas Cost Account Balance and Projected Gas Cost, and Gas Transportation Adjustment Clause Balance. On June 24, 2015, Northwestern Energy filed revised rates to be effective July 1, 2015, on an interim basis.

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

Federal Energy Regulatory Commission Annual Charges Unit Charge

On June 25, 2015 the Federal Energy Regulatory Commission filed its annual charges unit charge (ACA) to be applied to its fiscal year 2016 for recovery of FY 2015 Current year and 2014 True-Up as \$0.0014 per Dekatherm. The new ACA surcharge will become effective October 1, 2015.

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

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

On August 31, 2015, WBI Energy Transmission, Inc. (WBI Energy) filed its semi-annual fuel and electric power reimbursement adjustments with the FERC in Docket No. RP15-1228-000, reflecting revisions to the fuel and electric power components of WBI Energy's storage and transportation rates effective October 1, 2015.

Approximate impact on Montana-Dakota's cost of gas: (2.3) cents per dk

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

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$4.062	\$4.163	\$2.970	\$2.957
Prior Gas Cost	4.206	3.060	3.079	3.065
Current Gas Cost Adjustment	(\$0.144)	\$1.103	(\$0.109)	(\$0.108)
<u>Surcharge Adjustment:</u>				
Current Adjustment	(\$0.310)	(\$0.310)	(\$0.018)	(\$0.089)
Prior Adjustment	0.209	0.209	0.380	0.365
Change in Surcharge Adjustment	(\$0.519)	(\$0.519)	(\$0.398)	(\$0.454)
Gas Cost Level	\$4.062	\$4.163	\$2.970	\$2.957
Plus: Surcharge	(0.310)	(0.310)	(0.018)	(0.089)
Total Gas Cost Level in Tariff Rates	<u>\$3.752</u>	<u>\$3.853</u>	<u>\$2.952</u>	<u>\$2.868</u>
<u>Market Based Pricing Differential</u>				
Current Adjustment	(\$0.011)	(\$0.011)	\$0.000	\$0.000
Prior Adjustment	(0.017)	(0.017)	0.000	0.000
Change in Market Based Pricing	\$0.006	\$0.006	\$0.000	\$0.000
<u>Grain Drying Margin Sharing</u>				
Current Adjustment	(\$0.009)	(\$0.009)	\$0.000	\$0.000
Prior Adjustment	(0.001)	(0.001)	0.000	0.000
Change in Grain Drying Margin Sharing	(\$0.008)	(\$0.008)	\$0.000	\$0.000
Total Cost of Gas Items	<u>\$3.732</u>	<u>\$3.833</u>	<u>\$2.952</u>	<u>\$2.868</u>
Net Increase (Decrease) in Gas Costs	<u>(\$0.665)</u>	<u>\$0.582</u>	<u>(\$0.507)</u>	<u>(\$0.562)</u>

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

Cost of Gas - Propane

Current Propane Cost (Exhibit G)	\$2.415
Prior Propane Cost	<u>2.415</u>
Current Propane Cost Adjustment	<u><u>\$0.000</u></u>

Surcharge Adjustment

Current Adjustment	\$0.232
Prior Adjustment	<u>0.232</u>
Change in Surcharge Adjustment	\$0.000

Market Based Pricing Differential

Current Adjustment	(\$0.011)
Prior Adjustment	<u>(0.017)</u>
Change in Margin Sharing Provision	\$0.006
Net Increase (Decrease) in Gas Costs	<u><u>\$0.006</u></u>

Propane Cost Level	\$2.415
Plus: Surcharge	<u>0.232</u>
Total Propane Cost Level in Rates	<u><u>\$2.647</u></u>

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

	Amount
Total Gas Costs 1/	\$64,321,437
Residential and General Service dk Requirements 2/	15,905,909
Average Cost of Gas per dk	\$4.044
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.062
Less: Gas Cost Level in Rates 3/	4.206
Current Gas Cost Adjustment	(\$0.144)

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5-16 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 June 30, 2015, adjusted for losses at .45%.

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

Cost of Purchased Gas	\$4.187
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.206

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

Total Gas Costs 1/	\$64,321,437
Less: Annual MDDQ Costs	<u>17,724,248</u>
Total Gas Costs excluding MDDQ	\$46,597,189
Firm Service Requirements 1/	15,905,909
Other Gas Costs per Dk (excluding MDDQ)	\$2.930
<u>Winter - October - May</u> Annual MDDQ Costs 1/	\$17,724,248
Winter Firm Service Requirements	14,595,625
MDDQ Costs per Winter Dk	\$1.214
Add: Other Gas Costs per Dk	<u>2.930</u>
Winter Seasonal Rate	\$4.144
Winter Seasonal Rate, adjusted for losses 2/	\$4.163
Less: Gas Cost Level in Rates 3/	<u>3.060</u>
Current Gas Cost Adjustment	<u><u>\$1.103</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 July 1, 2015:

	<u>Summer</u>
Cost of Purchased Gas	\$3.046
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.060

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

	Amount
Total Gas Costs 1/	\$20,683,578
Interruptible Service dk Requirements	6,993,666
Average Cost of Gas per dk	\$2.957
Average Cost of Gas as Adjusted for Losses @ 99.55%	2.970
Less: Gas Cost Level in Rates 2/	3.079
Current Gas Cost Adjustment	(\$0.109)

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5-16 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 July 1, 2015:

Cost of Purchased Gas	\$3.065
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.079

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

	<u>Amount</u>
Total Gas Costs 1/	<u>\$1,538,469</u>
Air Force Interruptible dk Requirements	520,209
Average Cost of Gas per dk	\$2.957
Less: Gas Cost Level in Rates 2/	<u>3.065</u>
Current Gas Cost Adjustment	<u><u>(\$0.108)</u></u>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5-16 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 July 1, 2015:
Cost of Purchased Gas \$3.065

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
October 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
VOLAMETRIC 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: RP15-540-000
 FERC Order Date: March 18, 2015

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 FTW-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 PS-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. 11A. 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.

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	1.618%	(0.191)%	1.427%
L&U REIMBURSEMENT	(0.074)%	0.001%	(0.073)%

GATHERING - FIRM AND INTERRUPTIBLE

	<u>CURRENT PERCENTAGE</u>	<u>DEFERRAL PERCENTAGE</u>	<u>TOTAL PERCENTAGE</u>
FUEL USE REIMBURSEMENT	4.868%	(0.620)%	4.248%
L&U REIMBURSEMENT	(0.003)%	(0.001)%	(0.004)%

STORAGE - RATE SCHEDULES FS-1 AND IS-1

	<u>CURRENT PERCENTAGE</u>	<u>DEFERRAL PERCENTAGE</u>	<u>TOTAL PERCENTAGE</u>
FUEL USE REIMBURSEMENT	0.948%	(0.015)%	0.933%
L&U REIMBURSEMENT	(0.143)%	0.000%	(0.143)%

Issued On: August 31, 2015
 Docket Number:
 FERC Order Date:

Effective On: October 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	0.690	(0.105)	0.585

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: August 31, 2015
Docket Number:
FERC Order Date:

Effective On: October 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.

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>	
	2015659057	\$ 878.00 / month	
	2015659060	\$ 1347.00 / month	
	2015657921	\$ 12.00 / month	
	2015657920	\$ 122.00 / month	
	2015657919	\$ 67.00 / month	
	2015657918	\$ 18.00 / month	
	2015657917	\$ 303.00 / month	
	2011475772	\$ 9,250.00 / month	
	2015657915	\$ 1,259.00 / 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	
	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	

1. 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, are subject to the ATCO Pipelines Franchise Fees pursuant to paragraph 15.13 of the General Terms and Conditions.

2. Monthly Abandonment Surcharge applicable to Rate Schedules FT-R, FT-D, FT-P, FT-RN, FT-DW, STFT, and LRS-3.

3. Daily Abandonment Surcharge applicable to Rate Schedules IT-R, IT-D, LRS, the following Rate Schedules OS: 2011476052, 2011476054, 2011475056, 2011476092, 2011476050, 2003004522, and if applicable Over-Run Gas.

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 APGP	4.55	0.1646	
31006	AIR LIQUIDE SALES APN	4.55	0.1646	
3214	AQUINU 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	
3297	ALDER FLATS SOUTH NO 2 SALES	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	
3136	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	
3295	BOOTIS HILL SALES	4.55	0.1646	
3226	BOTHA SALES	4.55	0.1646	
3259	BOULDER CREEK SALES	4.55	0.1646	
3164	BRAINARD LAKE SALES	4.55	0.1646	
3289	BRAZEAU EAST SALES	4.55	0.1646	
3918	BUFFALO CREEK INTERCONNECTION	4.55	0.1646	
31015	BURDETT COGEN SALES APS	4.55	0.1646	
3266	BURNT TIMBER SALES	4.55	0.1646	
3204	CABIN SALES	4.55	0.1646	
3293	CADOGAN 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	

NATURAL GAS TARIFF



Canceling 38th Revised Sheet No. 80.1
37th 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
10,001 to 30,000	\$ 172.45
>30,000	\$ 382.65

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for
Maximum Daily Delivery Quantity (MDDQ) \$ 0.9805387

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	\$ 0.0074304
Minimum	\$ 0.0017935
GTAC Amortization	\$ (0.0008111) (I)
Balancing Penalty Rate	Higher of \$25.00/ Dekatherm Or 150% of Market Price

PLUS:

OTHER APPLICABLE CHARGES: All charges contained on other applicable rate schedules approved by the Public Service Commission of Montana.

GAS TRANSPORTATION ADJUSTMENT CLAUSE: Pursuant to MPSC Order the above GTAC Amortization shall be in effect until the balance is extinguished.

MINIMUM BILL: Per respective contracts.

(continued)

Staff Approved: June 26, 2015
Docket No.: D2014.7.59, Interim Order 7421
Tariff Letter No. 257-G

Effective for service rendered on or after
July 1, 2015

PUBLIC SERVICE COMMISSION
(Signature) Secretary

GAS RATE SCHEDULE

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

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

Date Filed: January 24, 2001

Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is \$2.398 per dekatherm.

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

NG-00-001

STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

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

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

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

Administrative Fee 5/ \$325.00

- 1/ Casper Division service area is defined on Sheet Nos. 3 and 4 of this Tariff.
- 2/ All charges are per therm.
- 3/ For fuel, lost and unaccounted for gas, the Company shall be entitled to retain the stated percentage of all therms received for transportation, unless otherwise agreed in writing. On or before March 1 of each year, the Company shall file with the Commission an application to revise the stated percentage to be effective June 1 of that year through May 31 of the following year. The Company shall calculate the stated percentage using not less than twelve (12) consecutive months of actual data.
- 4/ Interruptible Transportation Service is not available to DSE customers. The Customer Charge will be charged only for those months gas actually flows.
- 5/ In addition to the transportation charges stated above, Shippers are responsible for the monthly administrative fee as stated, applicable to each meter located at the customer location. For interruptible Transportation Shippers, the Administrative Fee will be charged only for those months gas actually flows. Firm Transportation Shippers will be charged each month, regardless of gas flow.
- 6/ Per Dth of MDTQ per month.

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

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

- MDTQ Maximum Daily Transportation Quantity

Date Issued: February 28, 2014
By: Michael Noone

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

**MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS
EFFECTIVE OCTOBER 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	(2,680,689)	264,708	(1,829,866)
March	(3,223,380)	231,380	(2,754,335)
April	(2,989,843)	242,859	(2,545,811)
May	(1,569,975)	300,398	(1,475,399)
June	1,154,717	402,889	(40,284)
July	4,132,663	512,604	1,386,541
August	6,962,262	605,599	2,798,094
September	9,122,811	695,950	3,988,347
October	9,172,305	697,914	4,108,265
13 month average	<u>\$3,720,538</u>	<u>\$555,851</u>	<u>\$959,772</u>
Rate of Return	7.881%	7.881%	7.881%
Return	\$293,216	\$43,807	\$75,640
Return Requirement	<u>\$409,297</u>	<u>\$61,150</u>	<u>\$105,585</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 ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
FIRM
TO BE EFFECTIVE OCTOBER 1, 2015 THROUGH SEPTEMBER 30, 2016**

(Over)/under recovered gas costs @ July 31, 2015 (\$4,772,872)

Less: Projected recovery from rates already established

	Volume	Rate	Amount
August	285,000	\$0.209	59,565
September	438,000	0.209	91,542
	723,000		151,107

Additional recovery required (\$4,923,979)

Projected sales volumes (dk)

October 2015	1,140,000		
November	1,921,000		
December	2,684,000		
January 2016	2,832,000		
February	2,438,000		
March	1,983,000		
April	1,156,000		
May	520,000		
June	261,000		
July	269,000		
August	263,000		
September	404,000		
Total			15,871,000

Total (over)/under recovered gas cost adjustment
to be effective October 1, 2015 through September 30, 2016 (\$0.310)

**MONTANA-DAKOTA UTILITIES CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE
TO BE EFFECTIVE OCTOBER 1, 2015 THROUGH SEPTEMBER 30, 2016**

(Over)/under recovered gas costs @ July 31, 2015 \$17,007

Less: Projected recovery from rates already established

	Volume	Rate	Amount
August	37,000	\$0.380	14,060
September	52,000	0.380	19,760
	89,000		33,820

Additional recovery required (\$16,813)

Projected sales volumes (dk)

October 2015	102,000		
November	137,000		
December	114,000		
January 2016	114,000		
February	119,000		
March	97,000		
April	59,000		
May	36,000		
June	27,000		
July	33,000		
August	31,000		
September	49,000		
Total			<u>918,000</u>

Total (over)/under recovered gas cost adjustment
to be effective October 1, 2015 through September 30, 2016 (\$0.018)

**MONTANA-DAKOTA UTILITIES CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
TO BE EFFECTIVE OCTOBER 1, 2015 THROUGH SEPTEMBER 30, 2016**

(Over)/under recovered gas costs @ July 31, 2015 (\$21,765)

Less: Projected recovery from rates already established

	Volume	Rate	Amount
August	13,000	\$0.365	4,745
September	19,000	0.365	6,935
	32,000		11,680

Additional recovery required (\$33,445)

Projected sales volumes (dk)

October 2015		30,000	
November		45,000	
December		62,000	
January 2016		61,000	
February		56,000	
March		44,000	
April		28,000	
May		16,000	
June		8,000	
July		8,000	
August		8,000	
September		8,000	
Total			374,000

Total (over)/under recovered gas cost adjustment
to be effective October 1, 2015 through September 30, 2016 (\$0.089)

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2014									<u>\$3,163,455</u>
August	\$226,615	\$0	\$49	\$226,664	277,347	\$0.024	\$6,656	\$220,008	3,383,463
September	(85,563)	0	35	(85,528)	328,455	0.024	7,883	(93,411)	3,290,052
October	9,216	0	34	9,250	599,658	0.209	56,897 2/	(47,647)	3,242,405
November	(234,355)	0	33	(234,322)	918,828	0.209	192,034	(426,356)	2,816,049
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
February	(1,669,539)	0	13	(1,669,526)	2,298,486	0.209	480,383	(2,149,909)	(870,891)
March	(1,193,182)	0	(22)	(1,193,204)	2,660,157	0.209	555,974	(1,749,178)	(2,620,069)
April	(9,665)	0	(44)	(9,709)	1,484,452	0.209	310,250	(319,959)	(2,940,028)
May	(323,360)	0	(49)	(323,409)	809,340	0.209	169,153	(492,562)	(3,432,590)
June	(609,920)	0	(57)	(609,977)	602,203	0.209	125,860	(735,837)	(4,168,427)
July	(533,563)	0	(104)	(533,667)	338,647	0.209	70,778	(604,445)	(4,772,872)
	<u>(\$4,865,983)</u>	<u>(\$1,696)</u>	<u>(\$43)</u>	<u>(\$4,867,722)</u>	<u>15,545,978</u>		<u>\$3,068,605</u>	<u>(\$7,936,327)</u>	<u>(\$4,772,872)</u>
Balance @ July 31, 2015									

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**

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2014									<u>\$553,358</u>
August	\$27,773	\$0	\$9	\$27,782	37,258	\$0.116	\$4,323	\$23,459	576,817
September	(4,907)	0	6	(4,901)	40,083	0.116	4,649	(9,550)	567,267
October	13,995	0	6	14,001	81,768	0.380	14,393 2/	(392)	566,875
November	(11,543)	0	6	(11,537)	101,794	0.380	38,681	(50,218)	516,657
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
February	(90,057)	0	5	(90,052)	132,058	0.380	50,183	(140,235)	312,460
March	(44,010)	0	8	(44,002)	150,446	0.380	57,169	(101,171)	211,289
April	(29,044)	0	4	(29,040)	104,456	0.380	39,694	(68,734)	142,555
May	(32,160)	0	2	(32,158)	53,528	0.380	20,341	(52,499)	90,056
June	(23,799)	0	2	(23,797)	44,754	0.380	17,006	(40,803)	49,253
July	(17,453)	0	1	(17,452)	38,932	0.380	14,794	(32,246)	17,007
	<u>(\$168,036)</u>	<u>\$0</u>	<u>\$64</u>	<u>(\$167,972)</u>	<u>1,067,042</u>		<u>\$368,379</u>	<u>(\$536,351)</u>	<u>\$17,007</u>
Balance @ July 31, 2015									

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>\$185,080</u>
August	\$16,626	\$0	\$3	\$16,629	4,035	\$0.181	\$731	\$15,898	200,978
September	(888)	0	2	(886)	3,604	0.181	652	(1,538)	199,440
October	2,549	0	2	2,551	9,112	0.365	1,649 2/	902	200,342
November	(4,099)	0	2	(4,097)	26,445	0.365	9,652	(13,749)	186,593
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
February	(46,276)	0	2	(46,274)	69,121	0.365	25,229	(71,503)	100,166
March	(19,355)	0	3	(19,352)	70,518	0.365	25,740	(45,092)	55,074
April	(2,005)	0	1	(2,004)	46,600	0.365	17,009	(19,013)	36,061
May	(15,430)	0	1	(15,429)	29,821	0.365	10,886	(26,315)	9,746
June	(10,947)	0	0	(10,947)	17,599	0.365	6,423	(17,370)	(7,624)
July	(12,315)	0	0	(12,315)	5,004	0.365	1,826	(14,141)	(21,765)
	<u>(\$61,068)</u>	<u>\$0</u>	<u>\$21</u>	<u>(\$61,047)</u>	<u>407,894</u>		<u>\$145,798</u>	<u>(\$206,845)</u>	<u>(\$21,765)</u>
Balance @ July 31, 2015									

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

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

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
FIRM

	Residential and Firm General				Seasonal	Total
	1/	2/	3/	Total		
<u>August 2014</u>						
Cost of Gas - Actual	\$5.62479	\$8.11072	\$5.62479		\$4.70908	
Cost of Gas - Recovered	6.05200	5.93500	5.93500		4.74700	
(Over) Under recovery per dk	(\$0.42721)	\$2.17572	(\$0.31021)		(\$0.03792)	
dk billed	86,758	129,523	58,068	274,349	2,998	277,347
(Over) Under recovery	(\$37,064)	\$281,806	(\$18,013)	\$226,729	(\$114)	\$226,615
<u>September 2014</u>						
Cost of Gas - Actual	\$5.47721	\$5.62479	\$5.47721		\$4.37108	
Cost of Gas - Recovered	5.38800	6.05200	6.05200		4.86900	
(Over) Under recovery per dk	\$0.08921	(\$0.42721)	(\$0.57479)		(\$0.49792)	
dk billed	108,891	208,737	9,262	326,890	1,565	328,455
(Over) Under recovery	\$9,714	(\$89,174)	(\$5,324)	(\$84,784)	(\$779)	(\$85,563)
<u>October 2014</u>						
Cost of Gas - Actual	\$5.50895	\$5.47721	\$5.50895		\$4.30549	
Cost of Gas - Recovered	5.62000	5.38800	5.38800		4.15900	
(Over) Under recovery per dk	(\$0.11105)	\$0.08921	\$0.12095		\$0.14649	
dk billed	229,758	315,715	53,730	599,203	455	599,658
(Over) Under recovery	(\$25,515)	\$28,165	\$6,499	\$9,149	\$67	\$9,216
<u>November 2014</u>						
Cost of Gas - Actual	\$4.98665	\$5.50895	\$4.98665		\$5.45921	
Cost of Gas - Recovered	5.51200	5.62000	5.62000		5.73600	
(Over) Under recovery per dk	(\$0.52535)	(\$0.11105)	(\$0.63335)		(\$0.27679)	
dk billed	303,159	602,510	12,729	918,398	430	918,828
(Over) Under recovery	(\$159,265)	(\$66,909)	(\$8,062)	(\$234,236)	(\$119)	(\$234,355)
<u>December 2014</u>						
Cost of Gas - Actual	\$5.82974	\$4.98665	\$5.82974		\$5.95876	
Cost of Gas - Recovered	5.31400	5.51200	5.51200		5.61700	
(Over) Under recovery per dk	\$0.51574	(\$0.52535)	\$0.31774		\$0.34176	
dk billed	728,251	1,941,193	(187,066)	2,482,378	777	2,483,155
(Over) Under recovery	\$375,588	(\$1,019,806)	(\$59,440)	(\$703,658)	\$266	(\$703,392)
<u>January 2015</u>						
Cost of Gas - Actual	\$4.87688	\$5.82974	\$4.87688		\$5.04469	
Cost of Gas - Recovered	5.66300	5.31400	5.31400		5.42000	
(Over) Under recovery per dk	(\$0.78612)	\$0.51574	(\$0.43712)		(\$0.37531)	
dk billed	907,062	1,865,161	(27,869)	2,744,354	896	2,745,250
(Over) Under recovery	(\$713,059)	\$961,938	\$12,182	\$261,061	(\$336)	\$260,725

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
FIRM

Exhibit D
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	Residential and Firm General				Seasonal	Total
	1/	2/	3/	Total		
<u>February 2015</u>						
Cost of Gas - Actual	\$4.42272	\$4.87688	\$4.42272		\$4.81501	
Cost of Gas - Recovered	5.03700	5.66300	5.66300		5.77000	
(Over) Under recovery per dk	(\$0.61428)	(\$0.78612)	(\$1.24028)		(\$0.95499)	
dk billed	586,378	1,792,171	(80,837)	2,297,712	774	2,298,486
(Over) Under recovery	(\$360,200)	(\$1,408,861)	\$100,261	(\$1,668,800)	(\$739)	(\$1,669,539)
<u>March 2015</u>						
Cost of Gas - Actual	\$4.71703	\$4.42272	\$4.71703		\$4.67228	
Cost of Gas - Recovered	4.65200	5.03700	5.03700		5.14300	
(Over) Under recovery per dk	\$0.06503	(\$0.61428)	(\$0.31997)		(\$0.47072)	
dk billed	788,621	2,193,253	(322,609)	2,659,265	892	2,660,157
(Over) Under recovery	\$51,284	(\$1,347,271)	\$103,225	(\$1,192,762)	(\$420)	(\$1,193,182)
<u>April 2015</u>						
Cost of Gas - Actual	\$4.04240	\$4.71703	\$4.04240		\$4.02443	
Cost of Gas - Recovered	4.47600	4.65200	4.65200		4.75400	
(Over) Under recovery per dk	(\$0.43360)	\$0.06503	(\$0.60960)		(\$0.72957)	
dk billed	427,331	1,215,652	(159,105)	1,483,878	574	1,484,452
(Over) Under recovery	(\$185,290)	\$79,054	\$96,990	(\$9,246)	(\$419)	(\$9,665)
<u>May 2015</u>						
Cost of Gas - Actual	\$2.94025	\$4.04240	\$2.94025		\$3.61576	
Cost of Gas - Recovered	3.97700	4.47600	4.47600		4.57900	
(Over) Under recovery per dk	(\$1.03675)	(\$0.43360)	(\$1.53575)		(\$0.96324)	
dk billed	211,405	738,429	(140,901)	808,933	407	809,340
(Over) Under recovery	(\$219,174)	(\$320,183)	\$216,389	(\$322,968)	(\$392)	(\$323,360)
<u>June 2015</u>						
Cost of Gas - Actual	\$2.39298	\$2.94025	\$2.39298		\$4.25873	
Cost of Gas - Recovered	3.88600	3.97700	3.97700		4.08000	
(Over) Under recovery per dk	(\$1.49302)	(\$1.03675)	(\$1.58402)		\$0.17873	
dk billed	147,431	598,577	(145,497)	600,511	1,692	602,203
(Over) Under recovery	(\$220,117)	(\$620,575)	\$230,470	(\$610,222)	\$302	(\$609,920)
<u>July 2015</u>						
Cost of Gas - Actual	\$2.31813	\$2.39298	\$2.31813		\$3.11126	
Cost of Gas - Recovered	4.20600	3.88600	3.88600		2.75300	
(Over) Under recovery per dk	(\$1.88787)	(\$1.49302)	(\$1.56787)		\$0.35826	
dk billed	108,449	334,315	(107,788)	334,976	3,671	338,647
(Over) Under recovery	(\$204,737)	(\$499,139)	\$168,998	(\$534,878)	\$1,315	(\$533,563)

- 1/ Consumed in current month.
2/ Consumed in prior month.
3/ True-up of prior month volumes.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>August 2014</u>				
Cost of Gas - Actual	\$4.75558	\$6.42507	\$4.75558	
Cost of Gas - Recovered	4.87500	4.75300	4.75300	
(Over) Under recovery per dk	(\$0.11942)	\$1.67207	\$0.00258	
dk billed	7,876	17,154	12,228	37,258
(Over) Under recovery	(\$940)	\$28,682	\$31	\$27,773
<u>September 2014</u>				
Cost of Gas - Actual	\$4.44082	\$4.75558	\$4.44082	
Cost of Gas - Recovered	4.16000	4.87500	4.87500	
(Over) Under recovery per dk	\$0.28082	(\$0.11942)	(\$0.43418)	
dk billed	9,243	18,705	12,135	40,083
(Over) Under recovery	\$2,596	(\$2,234)	(\$5,269)	(\$4,907)
<u>October 2014</u>				
Cost of Gas - Actual	\$4.33732	\$4.44082	\$4.33732	
Cost of Gas - Recovered	4.39900	4.16000	4.16000	
(Over) Under recovery per dk	(\$0.06168)	\$0.28082	\$0.17732	
dk billed	18,588	38,049	25,131	81,768
(Over) Under recovery	(\$1,146)	\$10,685	\$4,456	\$13,995
<u>November 2014</u>				
Cost of Gas - Actual	\$4.19403	\$4.33732	\$4.19403	
Cost of Gas - Recovered	4.32400	4.39900	4.39900	
(Over) Under recovery per dk	(\$0.12997)	(\$0.06168)	(\$0.20497)	
dk billed	13,545	57,968	30,281	101,794
(Over) Under recovery	(\$1,760)	(\$3,576)	(\$6,207)	(\$11,543)
<u>December 2014</u>				
Cost of Gas - Actual	\$4.72600	\$4.19403	\$4.72600	
Cost of Gas - Recovered	4.12100	4.32400	4.32400	
(Over) Under recovery per dk	\$0.60500	(\$0.12997)	\$0.40200	
dk billed	14,225	96,500	43,675	154,400
(Over) Under recovery	\$8,606	(\$12,542)	\$17,558	\$13,622
<u>January 2015</u>				
Cost of Gas - Actual	\$3.80704	\$4.72600	\$3.80704	
Cost of Gas - Recovered	4.48300	4.12100	4.12100	
(Over) Under recovery per dk	(\$0.67596)	\$0.60500	(\$0.31396)	
dk billed	13,817	81,177	32,571	127,565
(Over) Under recovery	(\$9,340)	\$49,113	(\$10,226)	\$29,547

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>February 2015</u>				
Cost of Gas - Actual	\$3.59320	\$3.80704	\$3.59320	
Cost of Gas - Recovered	3.87000	4.48300	4.48300	
(Over) Under recovery per dk	<u>(\$0.27680)</u>	<u>(\$0.67596)</u>	<u>(\$0.88980)</u>	
dk billed	10,318	98,784	22,956	132,058
(Over) Under recovery	<u>(\$2,856)</u>	<u>(\$66,774)</u>	<u>(\$20,427)</u>	(\$90,057)
<u>March 2015</u>				
Cost of Gas - Actual	\$3.45903	\$3.59320	\$3.45903	
Cost of Gas - Recovered	3.51900	3.87000	3.87000	
(Over) Under recovery per dk	<u>(\$0.05997)</u>	<u>(\$0.27680)</u>	<u>(\$0.41097)</u>	
dk billed	15,573	92,065	42,808	150,446
(Over) Under recovery	<u>(\$934)</u>	<u>(\$25,484)</u>	<u>(\$17,592)</u>	(\$44,010)
<u>April 2015</u>				
Cost of Gas - Actual	\$2.83884	\$3.45903	\$2.83884	
Cost of Gas - Recovered	3.34500	3.51900	3.51900	
(Over) Under recovery per dk	<u>(\$0.50616)</u>	<u>(\$0.05997)</u>	<u>(\$0.68016)</u>	
dk billed	13,133	64,039	27,284	104,456
(Over) Under recovery	<u>(\$6,647)</u>	<u>(\$3,840)</u>	<u>(\$18,557)</u>	(\$29,044)
<u>May 2015</u>				
Cost of Gas - Actual	\$2.27419	\$2.83884	\$2.27419	
Cost of Gas - Recovered	2.85700	3.34500	3.34500	
(Over) Under recovery per dk	<u>(\$0.58281)</u>	<u>(\$0.50616)</u>	<u>(\$1.07081)</u>	
dk billed	7,151	38,375	8,002	53,528
(Over) Under recovery	<u>(\$4,167)</u>	<u>(\$19,424)</u>	<u>(\$8,569)</u>	(\$32,160)
<u>June 2015</u>				
Cost of Gas - Actual	\$2.37341	\$2.27419	\$2.37341	
Cost of Gas - Recovered	2.77500	2.85700	2.85700	
(Over) Under recovery per dk	<u>(\$0.40159)</u>	<u>(\$0.58281)</u>	<u>(\$0.48359)</u>	
dk billed	7,599	28,007	9,148	44,754
(Over) Under recovery	<u>(\$3,052)</u>	<u>(\$16,323)</u>	<u>(\$4,424)</u>	(\$23,799)
<u>July 2015</u>				
Cost of Gas - Actual	\$2.44812	\$2.37341	\$2.44812	
Cost of Gas - Recovered	3.07900	2.77500	2.77500	
(Over) Under recovery per dk	<u>(\$0.63088)</u>	<u>(\$0.40159)</u>	<u>(\$0.32688)</u>	
dk billed	10,920	18,840	9,172	38,932
(Over) Under recovery	<u>(\$6,889)</u>	<u>(\$7,566)</u>	<u>(\$2,998)</u>	(\$17,453)

- 1/ Consumed in current month.
2/ Consumed in prior month.
3/ True-up of prior month volumes.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
AIR FORCE

	<u>1/</u>	<u>2/</u>	<u>Total</u>
<u>August 2014</u>			
Cost of Gas - Actual	\$8.64612	\$4.60526	
Cost of Gas - Recovered	4.73200	4.73200	
(Over) Under recovery per dk	\$3.91412	(\$0.12674)	
dk billed	4,241	(206)	4,035
(Over) Under recovery	<u>\$16,600</u>	<u>\$26</u>	\$16,626
<u>September 2014</u>			
Cost of Gas - Actual	\$4.60526	\$4.41961	
Cost of Gas - Recovered	4.85300	4.85300	
(Over) Under recovery per dk	(\$0.24774)	(\$0.43339)	
dk billed	3,632	(28)	3,604
(Over) Under recovery	<u>(\$900)</u>	<u>\$12</u>	(\$888)
<u>October 2014</u>			
Cost of Gas - Actual	\$4.41961	\$4.22347	
Cost of Gas - Recovered	4.14100	4.14100	
(Over) Under recovery per dk	\$0.27861	\$0.08247	
dk billed	9,165	(53)	9,112
(Over) Under recovery	<u>\$2,553</u>	<u>(\$4)</u>	\$2,549
<u>November 2014</u>			
Cost of Gas - Actual	\$4.22347	\$4.17582	
Cost of Gas - Recovered	4.37900	4.37900	
(Over) Under recovery per dk	(\$0.15553)	(\$0.20318)	
dk billed	26,736	(291)	26,445
(Over) Under recovery	<u>(\$4,158)</u>	<u>\$59</u>	(\$4,099)
<u>December 2014</u>			
Cost of Gas - Actual	\$4.17582	\$4.70440	
Cost of Gas - Recovered	4.30500	4.30500	
(Over) Under recovery per dk	(\$0.12918)	\$0.39940	
dk billed	62,179	(620)	61,559
(Over) Under recovery	<u>(\$8,033)</u>	<u>(\$249)</u>	(\$8,282)
<u>January 2015</u>			
Cost of Gas - Actual	\$4.70440	\$3.78975	
Cost of Gas - Recovered	4.10200	4.10200	
(Over) Under recovery per dk	\$0.60240	(\$0.31225)	
dk billed	65,038	(562)	64,476
(Over) Under recovery	<u>\$39,179</u>	<u>\$175</u>	\$39,354

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
AIR FORCE

	<u>1/</u>	<u>2/</u>	<u>Total</u>
<u>February 2015</u>			
Cost of Gas - Actual	\$3.78975	\$3.57617	
Cost of Gas - Recovered	4.46300	4.46300	
(Over) Under recovery per dk	(\$0.67325)	(\$0.88683)	
dk billed	70,335	(1,214)	69,121
(Over) Under recovery	<u>(\$47,353)</u>	<u>\$1,077</u>	(\$46,276)
<u>March 2015</u>			
Cost of Gas - Actual	\$3.57617	\$3.44423	
Cost of Gas - Recovered	3.85300	3.85300	
(Over) Under recovery per dk	(\$0.27683)	(\$0.40877)	
dk billed	71,778	(1,260)	70,518
(Over) Under recovery	<u>(\$19,870)</u>	<u>\$515</u>	(\$19,355)
<u>April 2015</u>			
Cost of Gas - Actual	\$3.44423	\$2.81211	
Cost of Gas - Recovered	3.50300	3.50300	
(Over) Under recovery per dk	(\$0.05877)	(\$0.69089)	
dk billed	47,762	(1,162)	46,600
(Over) Under recovery	<u>(\$2,807)</u>	<u>\$802</u>	(\$2,005)
<u>May 2015</u>			
Cost of Gas - Actual	\$2.81211	\$2.18577	
Cost of Gas - Recovered	3.33000	3.33000	
(Over) Under recovery per dk	(\$0.51789)	(\$1.14423)	
dk billed	29,843	(22)	29,821
(Over) Under recovery	<u>(\$15,455)</u>	<u>\$25</u>	(\$15,430)
<u>June 2015</u>			
Cost of Gas - Actual	\$2.18577	\$0.24816	
Cost of Gas - Recovered	2.84400	2.84400	
(Over) Under recovery per dk	(\$0.65823)	(\$2.59584)	
dk billed	17,928	(329)	17,599
(Over) Under recovery	<u>(\$11,801)</u>	<u>\$854</u>	(\$10,947)
<u>July 2015</u>			
Cost of Gas - Actual	\$0.24816	(\$2.66949)	
Cost of Gas - Recovered	2.76300	2.76300	
(Over) Under recovery per dk	(\$2.51484)	(\$5.43249)	
dk billed	5,096	(92)	5,004
(Over) Under recovery	<u>(\$12,815)</u>	<u>\$500</u>	(\$12,315)

1/ Consumed in prior month.

2/ True-up of prior month volumes.

**MONTANA-DAKOTA UTILITIES CO.
NORTH DAKOTA GAS
INTERRUPTIBLE MARKET BASED PRICING DIFFERENTIAL
EFFECTIVE OCTOBER 1, 2015 THROUGH SEPTEMBER 30, 2016**

Balance of Accumulated Revenues 1/	\$168,047
Projected Residential & General Service Sales Volumes	<u>15,871,000</u>
Market Based Pricing Differential Provision	<u><u>\$0.011</u></u>

1/ Represents 50% of margin above the approved margin from all interruptible sales, calculated on Exhibit E, page 2.

**MONTANA-DAKOTA UTILITIES CO.
NORTH DAKOTA GAS
INTERRUPTIBLE MARKET BASED PRICING DIFFERENTIAL
EFFECTIVE OCTOBER 1, 2015 THROUGH SEPTEMBER 30, 2016**

Rates 71 & 85 Credit - Balance @ 7/31/14			\$257,781
Additional Credits 1/			182,613
Reduction to Credit Balance			<u>(260,056)</u>
Balance @ 7/31/15			<u><u>\$180,338</u></u>
Less: Projected recovery from current amortization			
	<u>dk</u>	<u>Rate</u>	<u>Amount</u>
August	285,000	{ \$0.017 }	(\$4,845)
September	438,000	(0.017)	<u>(7,446)</u>
			(\$12,291)
Balance @ 9/30/15			<u><u>\$168,047</u></u>
Firm Volumes October 2015 - September 2016			15,871,000
Market Based Pricing Differential Provision			<u><u>\$0.011</u></u>

1/ Interruptible gas sales margin sharing amount (50% of additional margin) through March 31, 2015 as shown on Exhibit E, page 3. Effective with implementation of interim rates in Case No. PU-15-90 the margin sharing provision was stopped based on the settlement agreement currently pending before the Commission.

**MONTANA-DAKOTA UTILITIES CO.
NORTH DAKOTA GAS
INTERRUPTIBLE MARKET BASED PRICING DIFFERENTIAL
MARKET BASED PRICING DIFFERENTIAL CALCULATION**

<u>Additional Credits</u>	Interruptible Gas Sales Additional Margin	Pricing Differential Amount @ 50%
August 2014	\$16,529	\$8,265
September	17,816	8,908
October	36,252	18,126
November	45,180	22,590
December	68,226	34,113
January 2015	55,760	27,880
February	58,498	29,249
March	66,964	33,482
April 1/	0	0
May	0	0
June	0	0
July	0	0
Total	<u>\$365,225</u>	<u>\$182,613</u>

<u>Reduction to Credit Bal.</u>	Firm DK Sales	Pricing Differential Provision	Total Amount
August 2014	278,288.1	(\$0.012)	(\$3,339)
September	329,756.4	(0.012)	(3,957)
October 2/	371,636.6	(0.012)	(4,460)
October 3/	229,758.1	(0.017)	(3,906)
November	921,974.5	(0.017)	(15,674)
December	2,489,758.8	(0.017)	(42,326)
January 2015	2,751,934.2	(0.017)	(46,783)
February	2,304,293.2	(0.017)	(39,173)
March	2,665,750.0	(0.017)	(45,318)
April	1,487,991.6	(0.017)	(25,296)
May	811,258.9	(0.017)	(13,791)
June	603,579.3	(0.017)	(10,261)
July	339,537.4	(0.017)	(5,772)
Total	<u>15,585,517.1</u>		<u>(\$260,056)</u>

1/ Reflects cessation of margin sharing provision in the Settlement Agreement in Case No. PU-15-90 filed on August 26, 2015.

2/ Billed @ September rate.

3/ Billed @ October rate.

**MONTANA-DAKOTA UTILITIES CO.
NORTH DAKOTA GAS
GRAIN DRYING MARGIN SHARING PROVISION
EFFECTIVE OCTOBER 1, 2015 THROUGH SEPTEMBER 30, 2016**

Rate 71 Grain Drying Credit - Balance @ 7/31/14		\$21,744
Additional Credits 1/		133,987
Reduction to Credit Balance		<u>14,566</u>
Balance @ 7/31/15		<u><u>\$141,165</u></u>
Less: Projected recovery from current amortization		
	<u>dk</u>	<u>Rate</u>
August	285,000	\$0.001
September	<u>438,000</u>	<u>0.001</u>
	723,000	<u>\$723</u>
Balance @ 9/30/15		<u><u>\$140,442</u></u>
Projected Residential & General Service Sales Volumes		15,871,000
Grain Drying Margin Sharing Provision		<u><u>\$0.009</u></u>

1/ Represents 90% of margin above the approved margin from all Grain Drying sales as shown on Exhibit F, page 2.

**MONTANA-DAKOTA UTILITIES CO.
NORTH DAKOTA GAS
GRAIN DRYING MARGIN SHARING PROVISION
EFFECTIVE OCTOBER 1, 2015 THROUGH SEPTEMBER 30, 2016**

<u>Additional Credits</u>	Grain Drying Sales	Distribution Charge	Distribution Delivery Revenue	Basic Service Charge
August 2014	2,566.6	\$0.485	\$1,245	\$4,725
September	3,859.0	0.485	1,872	4,725
October	20,751.5	0.485	10,064	4,725
November	35,514.6	0.485	17,225	5,734
December	34,035.5	0.485	16,507	6,440
January 2015	12,376.6	0.485	6,003	6,411
February	9,690.1	0.485	4,700	5,950
March	10,358.9	0.485	5,024	5,775
April 1/	13,622.1	0.929	12,655	5,775
May	2,245.5	0.929	2,086	5,775
June	1,202.2	0.929	1,117	5,775
July	3,005.3	0.929	2,792	5,775
Total	<u>149,227.9</u>		<u>\$81,290</u>	<u>\$67,585</u>

<u>Additional Credits</u>	Total Margin	Grain Drying Margin Sharing Provision @ 90%
August 2014	\$5,970	\$5,373
September	6,597	5,937
October	14,789	13,310
November	22,959	20,663
December	22,947	20,652
January 2015	12,414	11,173
February	10,650	9,585
March	10,799	9,719
April	18,430	16,587
May	7,861	7,075
June	6,892	6,203
July	8,567	7,710
Total	<u>\$148,875</u>	<u>\$133,987</u>

1/ Reflects cessation of margin sharing provision in the Settlement Agreement in Case No. PU-15-90 filed on August 26, 2015.

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

Cost of Purchased Propane	\$5,049
Gallons Purchased	22,950
Projected dk Sales	2,100
Propane Cost per Dk	\$2.404
Average Cost of Propane as Adjusted for Losses @ 99.55%	2.415
Less: Propane Cost Level in Rates 1/	<u>2.415</u>
Current Propane Cost Adjustment	<u><u>\$0.000</u></u>

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