

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

May 8, 2015

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

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

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

Attachment A is the Rate Summary Sheet (138th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered June 1, 2015.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.091 per dk since the last filing due to a decrease in the overall commodity price of gas. Under the terms of Rate 88, Montana-Dakota is not required to file an adjustment if the amount of the adjustment is less than 10 cents. While the adjustment for residential, firm general, small and large interruptible and Air Force customers is less than 10 cents, the application of the summer season to the General Service Seasonal Rate 72 effective June 1 requires the filing of the COG change. There is no change in the cost of propane from that established in the May 2015 PGA filing. Attachment B explains the reasons for the decrease in the market price of gas.

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

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.091 per dk for residential and firm general customers, a decrease of \$0.082 per dk for small and large interruptible customers and a decrease of \$0.081 per dk for Air Force customers and a decrease of \$1.327 per dk for seasonal customers from the

currently effective rates.

Exhibit B shows the calculation of the current gas cost adjustment that will be applicable to Montana-Dakota's customers for the month of June 2015. The average cost of gas for firm customers, adjusted for losses, is \$3.886.

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

Montana-Dakota purchases propane supplies from various wholesale suppliers. There is no change in the cost of propane from that established in the May 2015 PGA filing.

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

These proposed adjustments, calculated in accordance with Rate 88, will amount to a decrease of approximately \$28,700 for natural gas customers during the month of June 2015. All of Montana-Dakota's retail natural gas customers in North Dakota may be affected by this proposal. There were 105,680 natural gas customers and 344 propane customers in North Dakota as of April 30, 2015.

Please refer all inquiries regarding this filing to:

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

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

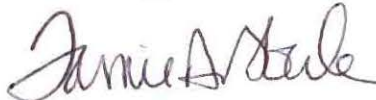
Mr. Daniel S. Kuntz
Associate General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

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

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

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

Sincerely,

A handwritten signature in cursive script that reads "Tamie A. Aberle".

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

138th Revised Sheet No. 3

Canceling 137th 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	\$4.077	\$4.403
Air Force Rate 64 ¹	7	\$2,000.00 per month \$175.00 per month			
Minot Air Force Base					
PAR Site					
Firm Service			\$0.329	\$4.077	\$4.406
Interruptible Service - PAR			\$0.260	\$3.155	\$3.415
Interruptible Service - MAFB			\$0.260	\$3.128	\$3.388
Firm General Service Rate 70 ¹	13	\$0.67 per day \$1.90 per day			
Meters rated < 500 cubic feet			\$0.730	\$4.077	\$4.807
Meters rated > 500 cubic feet					
Small Interruptible Gas Rate 71 ²	14	\$175.00 per month	(Maximum) \$0.929	\$3.155	(Maximum) \$4.084
Optional Seasonal Gas ¹					
Service Rate 72	15	\$0.67 per day \$1.90 per day			
Meters rated < 500 cubic feet			\$0.730	\$2.944	\$3.674
Meters rated > 500 cubic feet					
Transportation Service ¹	24	\$175.00 per month			
Small Interruptible Rate 81					
Maximum			\$0.485		
Minimum			\$0.102		
Fuel Charge				\$0.012	
Large Interruptible Rate 82		\$1,000.00 per month			
Maximum			\$0.297		
Minimum			\$0.061		
Fuel Charge				\$0.012	
Large Interruptible Gas Rate 85 ³	27	\$1,000.00 per month	(Maximum) \$0.718	\$3.155	(Maximum) \$3.873
Residential Propane Rate 90 ¹	32	\$0.4935 per day	\$0.326	\$5.704	\$6.030
Firm General Propane Rate 92 ¹	34	\$0.67 per day \$1.90 per day			
Meters rated < 500 cubic feet			\$0.730	\$5.704	\$6.434
Meters rated > 500 cubic feet					

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: May 8, 2015

Effective Date: June 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**

June 2015

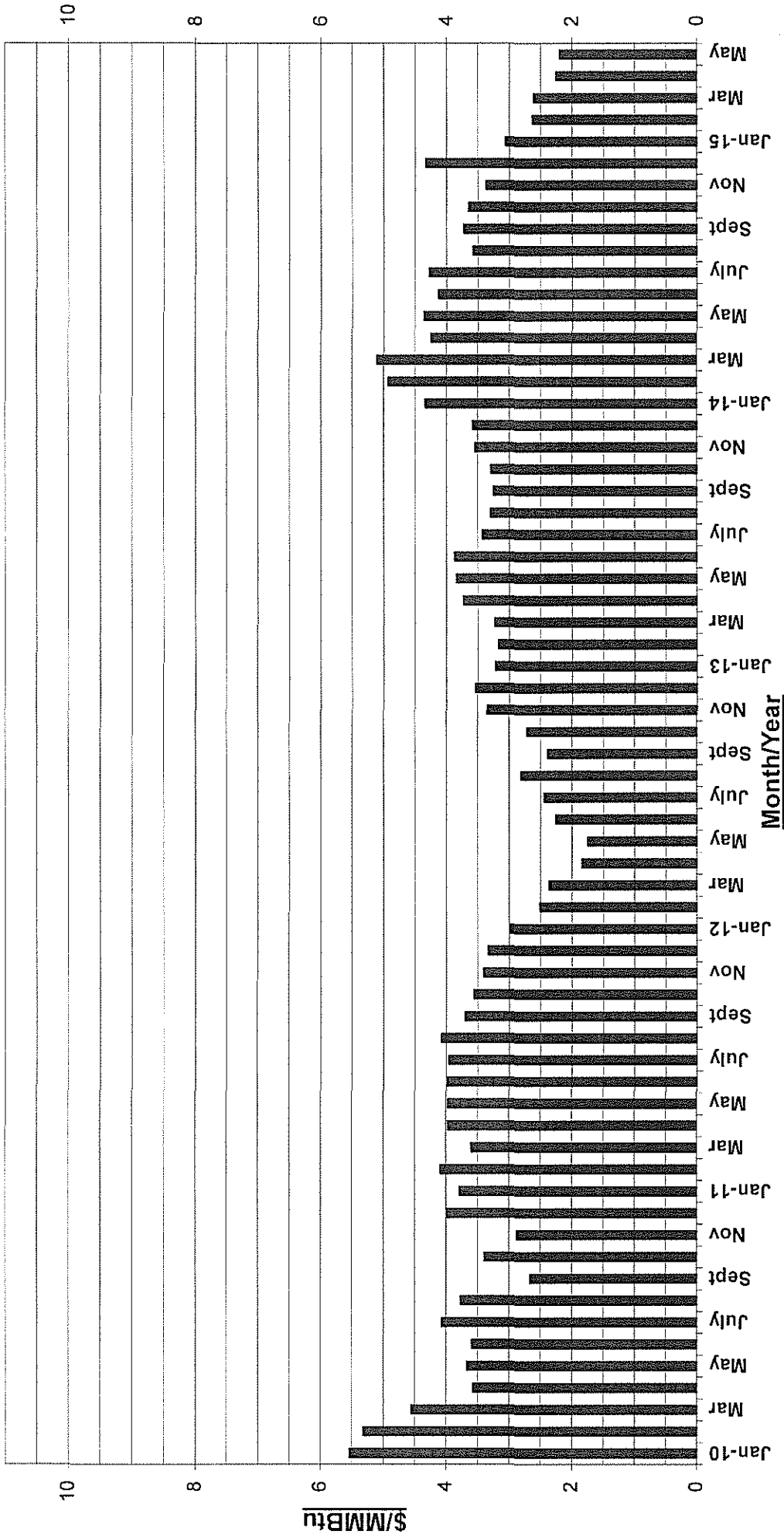
The established monthly price for the Rocky Mountain CIG Index has decreased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid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

Mild temperatures and relatively low demand in most regions from both the heating and cooling sectors resulted in ongoing low prices for natural gas. Domestic production levels continue to run near record levels. The EIA reported the national storage level as of May 1, 2015, was 3.6 percent below the five-year average and 71.1 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 April Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 22. The May Outlook will be published May 12, 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-\$2.55



Short-Term Energy and Summer Fuels Outlook (STEO)

Highlights

- On April 2, Iran and the five permanent members of the United Nations Security Council plus Germany (P5+1) reached a framework agreement that could result in the lifting of oil-related sanctions against Iran. Lifting sanctions could substantially change the STEO forecast for oil supply, demand, and prices by allowing a significantly increased volume of Iranian barrels to enter the market. If and when sanctions are lifted, the baseline forecast for world crude oil prices in 2016 could be reduced \$5-\$15/barrel (bbl) from the level presented in this STEO.
- Iran is believed to hold at least 30 million barrels in storage, and EIA believes Iran has the technical capability to ramp up crude oil production by at least 700,000 bbl/day (bbl/d) by the end of 2016. The pace and magnitude at which those volumes would reach the market would depend on the terms of a final agreement. For additional analysis of the possible oil market effects of a lifting of sanctions against Iran, please see the analysis box beginning on page 5.
- North Sea Brent crude oil prices averaged \$56/bbl in March, a decrease of \$2/bbl from the February average. EIA forecasts that Brent crude oil prices will average \$59/bbl in 2015 and \$75/bbl in 2016, both unchanged from last month's STEO. West Texas Intermediate (WTI) prices in 2015 and 2016 are expected to average \$7/bbl and \$5/bbl below Brent, respectively. The current values of futures and options contracts continue to suggest very high uncertainty in the oil price outlook (*Market Prices and Uncertainty Report*). Although WTI futures contracts for the broadly held December 2015 delivery traded during the five-day period ending April 2 averaged \$52/bbl, the market's expectations (at the 95% confidence interval) for monthly average WTI prices in that month ranges from \$32/bbl to \$97/bbl.
- During the 2015 April-through-September summer driving season, regular gasoline retail prices are forecast to average \$2.45/gallon (gal) compared with \$3.59/gal last summer (see EIA Summer Fuels Outlook slideshow). Based on EIA's gasoline price forecast, the average U.S. household is expected to spend about \$700 less on gasoline in 2015 compared with 2014, as annual motor fuel expenditures are on track to fall to their lowest level in 11 years.

- Total U.S. crude oil production averaged an estimated 9.3 million bbl/d in March but will decline in June through September before growth resumes. Given EIA's price forecast, projected total crude oil production will average 9.2 million bbl/d in 2015 and 9.3 million bbl/d in 2016.
- Natural gas working inventories were 1,461 billion cubic feet (Bcf) on March 27, which was 75% higher than a year earlier, but 12% lower than the previous five-year (2010-14) average. The winter withdrawal season typically ends in March, and April is typically the beginning of the injection season, which runs through October. EIA projects natural gas inventories will end October 2015 at 3,781 Bcf, a net injection of 2,310 Bcf. This would be the fourth-highest injection season on record, but it would be 420 Bcf lower than last year's net April–October injection.
- Power generators are using more natural gas than last year, primarily because of lower natural gas prices compared with coal prices. The use of natural-gas-fired generation is projected to average 30.4% of total generation in 2015 compared with 27.4% during 2014. U.S. coal production is expected to fall by 7.1% in 2015, as natural gas displaces coal for power generation.

Global Petroleum and Other Liquids

As in last month's STEO, global production continues to exceed demand, resulting in inventory builds. Global oil inventory builds are projected to average 1.7 million bbl/d through the first half of 2015. Inventory builds moderate during the second half of the year, as demand rises and non-Organization of the Petroleum Exporting Countries (OPEC) supply growth slows, particularly in the United States, because of lower oil prices. The expected inventory builds in 2015 are on top of an estimated average 1.0 million bbl/d increase in 2014.

If the new framework agreement between the P5+1 and Iran results in a comprehensive deal and a lifting of sanctions, it could significantly change the STEO forecast for oil supply, demand, and prices, which still assumes that Iran's production will stay close to the current level through 2016. An analysis box on page 5 discusses the implications of increased flows of oil from Iran.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 0.9 million bbl/d in 2014, averaging 92.0 million bbl/d for the year. EIA expects global consumption will grow by 1.0 million bbl/d in 2015 and by 1.1 million bbl/d in 2016. Projected global oil-consumption-weighted real gross domestic product (GDP), which increased by an estimated 2.7% in 2014, is projected to grow by 2.6% in 2015 and by 3.1% in 2016.

Consumption outside of the Organization for Economic Cooperation and Development (OECD), which grew by 1.2 million bbl/d in 2014, is projected to grow by 0.8 million bbl/d in 2015 and by 1.1 million bbl/d in 2016. Lower forecast non-OECD consumption growth in 2015 is mostly attributable to a 0.2 million bbl/d decline in Russia's consumption as a result of its economic

downturn. Russia's oil consumption is expected to decline by a similar amount in 2016. China's economic growth slowed in the second half of 2014 and in the beginning of 2015, as key manufacturing indexes decreased. Nonetheless, China remains the main source of non-OECD oil consumption growth, with a projected annual average increase of 0.3 million bbl/d in both 2015 and 2016, down from growth of 0.4 million bbl/d in 2014.

OECD consumption, which fell by 0.4 million bbl/d in 2014, is expected to grow by 0.2 million bbl/d in 2015 and then stay relatively flat in 2016. Japan and Europe accounted for almost the entire 2014 decline in OECD oil consumption. Consumption in these areas is expected to continue declining over the next two years, albeit at a slower rate than in 2014. The United States is the leading contributor to projected OECD consumption growth, with U.S. consumption increasing by 0.3 million bbl/d in 2015 and by 0.1 million bbl/d in 2016.

Non-OPEC Petroleum and Other Liquids Supply. EIA estimates that non-OPEC production grew by 2.2 million bbl/d in 2014. EIA expects non-OPEC production to grow by 0.7 million bbl/d in 2015 and by 0.4 million bbl/d in 2016, in part because of lower projected oil prices. The slower growth in total non-OPEC supply is largely attributable to slower production growth in the United States and Canada and declining production in Europe and Eurasia. After remaining relatively flat in 2015, production in Eurasia is projected to decline by more than 0.1 million bbl/d in 2016. The projected decline reflects reduced investment in Russia's oil sector stemming from low oil prices and international sanctions.

Unplanned supply disruptions among non-OPEC producers averaged 0.6 million bbl/d in March 2015, similar to the previous month. South Sudan, Syria, and Yemen accounted for nearly 90% of total non-OPEC supply disruptions in March. EIA estimates that unplanned non-OPEC supply disruptions averaged 0.6 million bbl/d in 2014. Yemen has maintained a crude oil output of more than 100,000 bbl/d despite the ongoing conflict in that country. However, sustained port closures could halt oil and liquefied natural gas (LNG) exports and force production shut-ins in the near future.

OPEC Petroleum and Other Liquids Supply. EIA estimates that OPEC crude oil production averaged 30.1 million bbl/d in 2014, unchanged from the previous year. Crude oil production declines in Libya, Angola, Algeria, and Kuwait offset production growth in Iraq and Iran. In EIA's forecast, OPEC crude oil production rises by 0.1 million bbl/d in 2015 and falls by 0.5 million bbl/d in 2016. Iraq is the largest contributor to OPEC production growth over the forecast period, but its growth is expected to be offset by production declines from other OPEC producers.

OPEC noncrude liquids production, which averaged 6.3 million bbl/d in 2014, is expected to increase by 0.2 million bbl/d in 2015 and by 0.1 million bbl/d in 2016, led by production increases in Qatar, Iran, and Kuwait.

In March 2015, unplanned crude oil supply disruptions among OPEC producers averaged 2.3 million bbl/d, a decrease of 0.2 million bbl/d compared with the previous month. This decrease

was mainly attributable to fewer outages in Iraq and Libya. Unplanned OPEC crude supply disruptions averaged 2.4 million bbl/d in 2014, 0.5 million bbl/d higher than in the previous year. The high level of OPEC disruptions contributed to higher crude oil prices during the first half of 2014. Unplanned supply disruptions could still affect crude oil prices, but the threshold that the market can bear has risen in light of robust global production and increases in inventory levels.

Nigeria's newly elected president, Muhammadu Buhari, will be inaugurated on May 29. Buhari may face significant challenges from groups associated with oil theft in the oil-rich Niger Delta and those receiving payments through the amnesty program. Buhari's campaign focused on curtailing corruption, and if those groups feel threatened by potential changes to the status quo, they might retaliate by disrupting oil production. For now, Nigeria's oil production forecast remains unchanged.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to increase to an annual average of 2.1 million bbl/d in 2015 and 2.6 million bbl/d in 2016, after averaging about 2.0 million bbl/d in 2014. Surplus capacity is typically an indication of market conditions, and surplus capacity below 2.5 million bbl/d is an indicator of a relatively tight market. However, the current and forecast levels of global inventory builds make the projected low surplus capacity level in 2015 less significant.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.72 billion barrels at the end of 2014, the highest end-of-year level on record and equivalent to roughly 59 days of consumption. Projected OECD oil inventories rise to 2.88 billion barrels at the end of 2015 and fall slightly to 2.87 billion barrels at the end of 2016.

Crude Oil Prices. North Sea Brent crude oil spot prices decreased by \$2/bbl in March to a monthly average of \$56/bbl. This decrease followed a \$10/bbl increase in February, the first increase in eight months. Several factors put upward pressure on Brent prices in February, including news of falling U.S. crude oil rig counts and announced reductions in capital expenditures by major oil companies. This upward price pressure abated in March, as the combination of robust world crude oil supply growth and weak global demand contributed to an increase in the rate of global inventory builds. Total global oil inventories are estimated to have increased by 2.1 million bbl/d in March, compared with a 0.9 million bbl/d increase in February. Strong global oil inventory builds are expected to continue in the coming months. Inventory builds are projected to moderate later in the year and provide support to crude oil prices.

The monthly average WTI crude oil spot price decreased to an average of \$48/bbl in March, down \$3/bbl from February. WTI prices fell in March in large part because of commercial crude oil inventories in Cushing, Oklahoma, which increased to a record 58.9 million barrels as of March 27. The record inventory levels have put downward pressure on the price of crude oil for prompt delivery compared with the price of crude oil for delivery in later months.

EIA projects the Brent crude oil price will average \$59/bbl in 2015, unchanged from last month's STEO, with prices rising from an average of \$56/bbl in the second quarter to an average of \$67/bbl in the fourth quarter. The Brent crude oil price is projected to average \$75/bbl in 2016. However, this price projection remains subject to the uncertainties surrounding the possible lifting of sanctions against Iran and other market events (see analysis box below). WTI prices in 2015 and 2016 are expected to average \$7/bbl and \$5/bbl, respectively, below Brent. The Brent-WTI spread for 2015 reflects continued large builds in U.S. crude oil inventories, including at the Cushing, Oklahoma, storage hub.

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 July 2015 delivery traded during the five-day period ending April 2 averaged \$52/bbl while implied volatility averaged 46%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in June 2015 at \$35/bbl and \$78/bbl, respectively. The 95% confidence interval for market expectations widens over time, with lower and upper limits of \$32/bbl and \$97/bbl for prices in December 2015. Last year at this time, WTI for July 2014 delivery averaged \$99/bbl, and implied volatility averaged 17%. The corresponding lower and upper limits of the 95% confidence interval were \$85/bbl and \$115/bbl.

Given the high level of uncertainty in oil markets, several factors could cause oil prices to deviate significantly from current projections. Among these factors is the potential lifting of sanctions against Iran if a comprehensive agreement is reached (see box below). The level of unplanned production outages could also vary from forecast levels for a wide range of producers, including OPEC members Libya, Iraq, Nigeria, and Venezuela. The degree to which non-OPEC supply growth is affected by lower oil prices will also affect market balances and prices.

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

Assessing oil market impacts of a potential comprehensive agreement with Iran

On April 2, Iran and the P5+1 reached a framework agreement to guide the next three months of negotiations, which will target a comprehensive agreement by June 30. Under the framework, U.S. and European Union nuclear-related sanctions (which includes oil-related sanctions) will be suspended after the International Atomic Energy Agency verifies that Iran has

complied with key nuclear-related steps. If a comprehensive agreement that results in the lifting of Iranian oil-related sanctions is reached, then this could significantly change the STEO forecast for oil supply, demand, and prices. However, the timing and order that sanctions could be suspended is uncertain. In addition, the pace and volume at which more Iranian oil can re-enter the market is uncertain and depends on how quickly Iran can move oil out of storage and ramp up production.

In this STEO, EIA's forecast of oil supply, demand, and price is mostly unchanged from last month. Given the preliminary nature of the recent developments, EIA has not changed its short-term projection for Iranian production, which assumes that production will stay close to the current level. However, if a comprehensive deal is reached, the re-entry of more Iranian barrels could result in a \$5-\$15/bbl lower baseline STEO price projection in 2016 compared with the current STEO.

Iran is believed to hold at least 30 million barrels in storage. It is possible that Iran will attempt to move oil out of storage more quickly sometime during the second half of 2015 in preparation to increase production if discussions on sanctions show progress. As a result, the global market may see incremental increases in Iran's crude oil exports before seeing a substantial increase to Iran's production, but the pace at which oil in storage could be withdrawn is uncertain.

EIA believes that Iran has the technical capability to ramp up crude oil production by at least 700,000 bbl/d by at least the end of 2016, of which 600,000 bbl/d represents capacity that was previously shut in and 100,000 bbl/d is new capacity. EIA's current STEO projects that growth in global inventories declines from 1 million bbl/d in 2015 to 100,000 bbl/d in 2016. If Iran ramps up production by 700,000 bbl/d by at least the end of 2016, then this could result in an annual average growth of about 500,000 bbl/d in global inventories in 2016, which would stress storage capacity limits and put downward pressure on prices. The potentially large inventory build in 2016 implies that production growth outside of Iran could be lower or that global consumption growth could be higher than projected in the current STEO.

Although the timing and volume of Iran's exports remain uncertain, the market perception surrounding increased future supplies will apply downward price pressure to near-term crude oil prices. Overall, North Sea Brent crude oil prices could be lower by about \$1-\$3/bbl in 2015, decreasing the 2015 annual Brent price from the current projection in the high \$50/bbl range. If and when significantly increased volumes of Iranian barrels start entering the market, the price effect could be greater. The uncertainty of the impact lies in the secondary effects on production outside of Iran, including in the United States, as well as any increases in global consumption as a response to lower oil prices, among other factors.

U.S. Petroleum and Other Liquids

U.S. average regular gasoline retail prices averaged \$2.46/gal in March, rising from \$2.04/gal on January 26, the lowest price in EIA's weekly survey of Monday prices since April 6, 2009. In

March, monthly average regional gasoline retail prices ranged from a low of \$2.21/gal in Petroleum Administration for Defense District (PADD) 3, the Gulf Coast region, to a high of \$3.10/gal in PADD 5 along the West Coast.

Although crude oil prices are projected to be relatively flat in the coming months, the spring switchover from winter-grade to summer-grade gasoline is expected to contribute to a slight increase in U.S. regular gasoline retail prices from an average of \$2.46/gal in March to a 2015 peak of \$2.50/gal in April. EIA expects U.S. retail gasoline prices to average \$2.40/gal for the full year of 2015.

For the first time, EIA is providing monthly data on rail movements of crude oil, which have significantly increased over the past five years. Total movements of crude oil by rail within the United States and between the United States and Canada were more than 1 million bbl/d in 2014, up from 55,000 bbl/d in 2010. In January 2015, shipments from PADD 2, which is the location of the Bakken tight oil formation, to PADD 1 on the East Coast accounted for about 40% of total crude oil shipped via rail in the United States including movements to and from Canada.

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 70,000 bbl/d (0.4%) in 2014. In 2015, total liquid fuels consumption is forecast to grow by 330,000 bbl/d (1.7%). EIA projects that in 2016, liquid fuels consumption growth will slow to 90,000 bbl/d (0.5%).

Motor gasoline consumption, which rose by 80,000 bbl/d in 2014, increases by a projected 150,000 bbl/d (1.6%) in 2015 and then falls by 70,000 bbl/d (0.8%) in 2016, as higher prices next year remove some of the stimulus to current consumption growth. Compared with last month's STEO, EIA revised the gasoline consumption forecasts upward by 70,000 bbl/d in 2015 and by 50,000 bbl/d in 2016 because of the larger-than-expected growth in gasoline consumption over the past six months, strong employment growth, and upward revisions in the Federal Highway Administration highway travel statistics of 0.8% in 2013 and 0.7% in 2014. Over the past six months (October 2014–March 2015), gasoline consumption increased by an average of 2.7% from the same period last year, compared with 0.2% year-over-year growth during the six months before that period. According to the U.S. Bureau of Labor Statistics monthly employment survey, seasonally adjusted employment increased by 1.6 million between October 2014 and March 2015.

Hydrocarbon gas liquids (HGL) consumption, which fell by 100,000 bbl/d (4.0%) in 2014, is projected to increase by 110,000 bbl/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 bbl/d in 2014 to 1.0 million bbl/d in 2016. HGL consumption is rising because of strong supply growth, with HGL production at natural gas processing plants forecast to increase by 550,000 bbl/d (19%) between 2014 and 2016.

Liquid Fuels Supply. U.S. crude oil production is projected to increase from an average of 8.7 million bbl/d in 2014 to 9.2 million bbl/d in 2015 and to 9.3 million bbl/d in 2016, which is 0.1 million bbl/d and 0.2 million bbl/d lower than forecast in last month's STEO, respectively. The reduction in the crude oil production forecast reflects rig counts falling faster than EIA had initially expected, as oil-directed rigs have declined to the lowest level in more than four years as of late March.

With WTI crude oil prices expected to average \$48/bbl in the second quarter of 2015, EIA expects 2015 onshore production to decline beginning in that period because of unattractive economic returns in some areas of both emerging and mature oil production regions. Reductions in 2015 capital expenditures, cash flows, and low-cost credit availability have encouraged companies to defer investment or redirect investment away from marginal exploration and research drilling to focus on core areas of major tight oil plays. Projected 2015 oil prices remain high enough to support continued development drilling activity in the core areas of the Bakken, Eagle Ford, Niobrara, and Permian basins. Companies with lower drilling and debt-service costs that operate on acreage in the sweet spots of these regions are expected to continue to drill highly productive wells in 2015.

EIA expects U.S. crude oil production to reach 9.4 million bbl/d in the second quarter of 2015, then decline by 210,000 bbl/d in the third quarter. With projected WTI crude oil prices rising to an average of \$57/bbl in the second half of 2015, drilling activity is expected to increase again as companies take advantage of lower costs for acreage leasing, drilling, and well-completion services, resulting in growing production despite the relatively low WTI price. Furthermore, a reduction of the backlog of wells drilled but not completed will bolster production by offsetting recent drops in drilling activity. However, the forecast remains particularly sensitive to actual prices available at the wellhead, drilling economics that vary across regions and operators, and whether additional production from the backlog of well completions materializes. Projected production in the federal offshore region rises during the forecast period, while production in Alaska falls. Production in these areas is less sensitive to short-term price movements than is onshore production in the Lower 48 states.

HGL production at natural gas processing plants, which reached a record high of 3.1 million bbl/d in October, is projected to average 3.2 million bbl/d in 2015 and 3.5 million bbl/d in 2016. EIA expects higher rates of ethane recoveries as a result of planned increases in petrochemical plant feedstock demand, while export terminal expansions will allow higher quantities of domestically produced propane and butanes to reach the international market.

The growth in domestic crude oil and other liquids production has contributed to a significant decline in imports. The share of total U.S. liquid fuels consumption met by net imports fell from 60% in 2005 to an estimated 26% in 2014. EIA expects the net import share to decline to 21% in 2016, which would be the lowest level since 1969.

Summer Transportation Fuels Outlook

U.S. Gasoline and Diesel Fuel Prices. EIA expects that regular-grade gasoline retail prices will average \$2.45/gal during the 2015 summer driving season (April through September), down from an average of \$3.59/gal last summer. The projected monthly average regular retail gasoline price falls from \$2.50/gal in April to \$2.43/gal in September. Diesel fuel retail prices are projected to average \$2.77/gal this summer, down from an average of \$3.89 last summer. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas exceeding the national average price by \$0.40/gal or more. Any unforeseen refinery outages or other disruptions to supply also have the potential to increase regional product prices beyond forecast levels in the short term.

Because taxes and retail distribution costs are generally stable, movements in gasoline and diesel prices are driven primarily by changes in both crude oil prices and wholesale margins. The retail price projections reflect slowly rising prices for crude oil, best represented by the Brent crude oil price, which will average about \$58/bbl (\$1.39/gal) this summer compared with an average of \$106/bbl (\$2.52/gal) last summer. Any difference between actual crude oil prices and EIA's forecast would be reflected in the retail price of motor fuels. Absent other factors specific to the gasoline and diesel fuel markets, each dollar per barrel of sustained change in crude oil prices compared with the forecast translates into approximately a 2.4-cent-per-gallon change in product prices.

EIA expects wholesale gasoline margins (the difference between the wholesale price of gasoline and the Brent crude oil price) will average 36 cents/gal this summer, less than 1 cent/gal higher than last summer and 2 cents/gal higher than the previous five-summer average. Forecast wholesale diesel fuel margins are 45 cents/gal, about 3 cents/gal above last summer's level and 4 cents/gal higher than the previous five-summer average.

As in the case of 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 RBOB futures contracts for July 2015 delivery traded over the five-day period ending April 2 averaged \$1.77/gal. The probability that the RBOB futures price will exceed \$2.35/gal (consistent with a U.S. average regular gasoline retail price above \$3.00/gal) in July 2015 is about 5%.

Motor Gasoline. During the 2015 summer driving season (April through September), projected motor gasoline consumption averages 9.2 million bbl/d, an increase of 0.14 million bbl/d (1.6%) over last summer. Year-over-year increases in summer highway travel, projected to be 2.5%, are offset by a 0.9% increase in fleetwide fuel efficiency. Finished motor gasoline is supplied by four sources: domestic refinery output, fuel ethanol blending, net imports of gasoline and gasoline blending components, and primary inventories. EIA expects that domestic refinery production, including gasoline blendstock output, will increase by almost 100,000 bbl/d from last summer.

Fuel ethanol blending into gasoline is projected to decrease by 10,000 bbl/d from last summer's level to 880,000 bbl/d, which is 9.6% of total gasoline consumption. Projected total gasoline net imports (including blending components) average 210,000 bbl/d, up 23% from last summer.

At the onset of the summer driving season (April 1), total gasoline stocks were 227 million barrels, up 7 million barrels from a year ago and 7 million barrels above the five-year average for beginning-of-season stocks. Stock withdrawals have not been a significant motor gasoline supply source for the summer season in recent years, having averaged only 40,000 bbl/d during the previous five summer seasons. This summer, the total gasoline stock draw is projected to average 55,000 bbl/d, compared with a 46,000 bbl/d draw last summer. Total gasoline inventories are projected to end the summer season at 217 million barrels, 5 million barrels above last year's level and 4 million barrels above the previous five-year average.

Diesel Fuel. Projected consumption of distillate fuel, which includes diesel fuel and heating oil, averages 4.0 million bbl/d this summer, up 120,000 bbl/d (3.0%) from last summer. This growth is driven by increasing manufacturing output and foreign trade. Additionally, some of the growth in distillate fuel consumption comes from Annex VI to the International Convention for the Prevention of Pollution from Ships (MARPOL Annex VI), which is an international agreement that generally requires the use of fuels below 1,000 parts per million sulfur by marine vessels in most U.S. waters, unless alternative devices, procedures, or compliance methods are used to achieve equivalent emissions reductions. The increase in marine distillate use because of MARPOL regulations will displace the use of some residual fuel oil.

Distillate fuel is supplied by four sources: domestic refinery output, biodiesel blending, primary inventories, and net imports. EIA expects refinery output of distillate fuel will average 5 million bbl/d this summer, up 30,000 bbl/d from last summer. The production of biodiesel is forecast to average 85,000 bbl/d this summer, almost unchanged from last summer. Projected distillate fuel net exports average 0.99 million bbl/d this summer, down from 1.05 million bbl/d last summer.

Distillate inventories are projected to start the summer at 126 million barrels, up from the 115 million barrels recorded at the start of last summer and below the five-year average of 133 million barrels. Distillate inventories typically build during the summer season in preparation for the heating season. This summer, the build is forecast to average 55,000 bbl/d, down from the 87,000 bbl/d build recorded last summer, but similar to the five-year average summer build of 48,000 bbl/d. End-of-summer stocks are 137 million barrels, up slightly from the 131 million barrels recorded at the end of last summer, but below the five-year end-of-summer average of 142 million barrels.

Natural Gas

Working gas in storage ended this year's heating season at an estimated 1,471 Bcf on March 31. A total of 2,116 Bcf of natural gas was withdrawn from storage inventories during this year's heating season, compared to an overall withdrawal of 2,960 Bcf during last year's heating

season. Although this year's winter was colder than normal, it was slightly warmer than last year's historically cold winter. Looking ahead to October, EIA projects inventories will end the injection season at 3,781 Bcf, which is slightly below the five-year average. This level would imply overall injections of 2,310 Bcf over the injection season. Strong projected electric power consumption of natural gas this summer are expected to keep injections below last year's refill, but the expected 2,310 Bcf refill is still significant compared with past years.

Natural Gas Consumption. EIA projects that U.S. total natural gas consumption will average 76.3 billion cubic feet per day (Bcf/d) in 2015 and 75.8 Bcf/d in 2016, compared with an estimated 73.5 Bcf/d in 2014. Consumption growth is largely driven by demand in the industrial and electric power sectors, while residential and commercial consumption are projected to decline in 2015 and 2016. EIA projects natural gas consumption in the power sector to grow by 11.5% in 2015 and then fall by 2.2% in 2016. Low natural gas prices support increased natural gas-fired electric power consumption in 2015. Industrial sector consumption increases by 4.9% and 2.5% in 2015 and 2016, respectively, as new industrial projects come online, particularly in the fertilizer and chemicals sectors, and as industrial consumers take advantage of low natural gas prices.

Natural Gas Production and Trade. EIA expects that marketed natural gas production will increase by 3.8 Bcf /d (5.0%) and 1.5 Bcf/d (1.9%) in 2015 and 2016, respectively, reflecting continuing production growth in the Lower 48 states, which more than offsets the long-term declining production in the Gulf of Mexico. Although natural gas prices have fallen dramatically in recent months, EIA expects that increases in drilling efficiency and growth in oil production (albeit at a slower rate) will continue to support growing natural gas production in the forecast. With most growth expected to come from the Marcellus Shale, a backlog of drilled but uncompleted wells will continue to support production growth, as new pipelines come online in the Northeast.

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

LNG imports have fallen over the past five years because higher prices in Europe and Asia are more attractive to LNG exporters than the relatively low prices in the United States. Forecast LNG gross imports average 0.2 Bcf/d in 2015 and 2016. EIA projects that LNG gross exports will increase from an average of 0.04 Bcf/d in 2014 to over 0.79 Bcf/d in 2016.

Natural Gas Inventories. On March 27, natural gas working inventories totaled 1,461 Bcf, 628 Bcf (75%) above the level at the same time in 2014 and 190 Bcf (12%) below the previous five-year (2010-14) average for the week. A 12 Bcf injection for the week ending March 20 was the first net injection of 2015, although inventories posted a net withdrawal the week ending March

27. EIA projects that end-of-October 2015 inventories will total 3,781 Bcf, 17 Bcf less than the five-year average.

Natural Gas Prices. The Henry Hub natural gas spot price averaged \$2.83/MMBtu in March, a decline of 4 cents/MMBtu from February. EIA expects monthly average spot prices to remain less than \$3/MMBtu through May, and less than \$4/MMBtu through the remainder of the forecast. The projected Henry Hub natural gas price averages \$3.07/MMBtu in 2015 and \$3.45/MMBtu in 2016.

Natural gas futures contracts for July 2015 delivery traded during the five-day period ending April 2 averaged \$2.76/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for July 2015 contracts at \$1.90/MMBtu and \$4.00/MMBtu, respectively. At this time last year, the natural gas futures contract for July 2014 delivery averaged \$4.46/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$3.40/MMBtu and \$5.87/MMBtu.

Coal

Electric power sector coal inventories increased by 3% in January 2015 from the previous month, leaving them 16% higher than in January 2014. Coal inventories have now increased for five consecutive months. The month-to-month increase was unusual, as inventories generally decrease during the winter months as coal-fired generation increases to meet winter heating demand. Warmer-than-normal January temperatures in areas where coal-fired generation is important, coupled with lower natural gas prices, contributed to the inventory growth.

Coal Consumption. EIA projects coal consumption in the electric power sector will decrease by 6% in 2015, despite an increase in overall electricity generation. Milder weather in the first quarter of 2015 compared with the same quarter in 2014 and lower natural gas prices are primary factors driving the decline. The retirements of coal power plants in response to the implementation of the Mercury and Air Toxics Standards also affect demand in the power sector and contribute to the decline. The full effect of the coal plant retirements will be felt in 2016, but projected rising electricity demand and higher natural gas prices increase the use of the remaining coal-fired fleet, mitigating the of the retirements as projected coal consumption in the electric power sector increases by 2%.

Coal Trade. Slower growth in world coal demand, lower international coal prices, and higher coal output in other coal-exporting countries have led to a two-year decline in coal exports. EIA projects coal exports will fall to an annual average of 83 million short tons (MMst) in 2015, then remain relatively flat in 2016. Global market conditions for coal are not expected to change significantly through 2016. U.S. coal imports, which increased by more than 2 MMst in 2014 to 11 MMst, are expected to remain near that level over the next two years.

Coal Supply. EIA estimates that U.S. coal production for 2014 totaled 997 MMst, 13 MMst (1.3%) higher than in 2013. EIA expects annual production to decline in 2015 to 926 MMst, as both domestic demand and exports continue to decline, before growing to 941 MMst in 2016.

Coal Prices. The annual average coal price to the electric power sector fell from \$2.39/MMBtu in 2011 to an estimated \$2.36/MMBtu in 2014. EIA expects the delivered coal price to average \$2.31/MMBtu in 2015 and \$2.33/MMBtu in 2016.

Electricity

Residential electricity prices increased during 2014, with growth ranging from 1.3% in the Pacific Coast states to 9.8% in New England. Retail electricity rates have risen for various reasons. Many electric utilities purchase their power from regional wholesale electricity markets, which experienced higher prices last year. Other reasons commonly cited for higher retail electricity prices are the increased investment in transmission and distribution infrastructure, rising requirements to generate electricity from renewable energy sources, and utility investment in demand-side efficiency.

Electricity Consumption. Retail sales of electricity to the residential sector during the first quarter of 2015 are estimated to be 2.3% lower than sales during the same period in 2014, as average U.S. temperatures this winter were milder than last winter despite colder-than-normal February temperatures in most of the eastern United States. EIA expects U.S. retail residential sales of electricity for the remaining nine months of 2015 will average 1.8% more than the same period last year. Residential sales are forecast to fall by 0.5% in 2016. Projected U.S. sales of electricity to the commercial sector increase by 1.7% this year and by 1.4% in 2016. Projected industrial electricity sales rise by 1.3% in 2015 and by 1.1% in 2016.

Electricity Generation. The use of natural gas for power generation has exceeded expectations in recent months, and as a result, EIA has raised its projections for natural-gas-fired generation from last month's STEO. During the first quarter of 2015, EIA estimates that natural gas accounted for 28.5% of total generation, which is substantially higher than the 23.6% fuel share during the first quarter of 2014. This increased use of natural gas is driven by lower fuel costs. The Henry Hub natural gas price averaged \$2.90/MMBtu in the first quarter of this year compared with \$5.20/MMBtu during the same period of 2014. EIA expects the natural gas fuel share to average 30.4% for all of 2015, up from 27.4% during 2014. In contrast, the share of total generation fueled by coal falls from 38.7% in 2014 to 35.8% this year.

Electricity Retail Prices. Residential electricity rates in New England have continued to increase, with the January 2015 price averaging about 10% more than the price in November 2014. For the United States as a whole, EIA expects continued growth in average residential electricity prices over the forecast period, albeit at a slower pace than last year. The U.S. retail residential price is projected to increase by 1.4% in 2015 and by 1.8% in 2016.

Renewables and Carbon Dioxide Emissions

Electricity and Heat Generation from Renewables. EIA projects that total renewables used for electricity and heat generation will grow by 3.4% in 2015. Conventional hydropower generation increases by 6.3%, while nonhydropower renewables generation increases by 1.9%. In 2016, total renewables consumption for electric power and heat generation increases by 2.6% as a result of a 2.5% decline in hydropower and a 5.2% increase in nonhydropower renewables.

EIA expects continued growth in utility-scale solar power generation, which is projected to average 80 gigawatthours (GWh) per day in 2016. Despite this growth, utility-scale solar power averages only 0.7% of total U.S. electricity generation in 2016. Although solar growth has historically been concentrated in customer-sited distributed generation installations, EIA expects that utility-scale solar capacity will increase by 75% between the end of 2014 and the end of 2016, with about half of this new capacity being built in California. Other leading states include North Carolina, Nevada, Texas, and Utah, which combined with California, account for about 90% of the projected utility-scale capacity additions for 2015 and 2016. Utility-scale solar capacity additions during 2016 are about 1 GW (26%) higher than in last month's STEO, as EIA continues to receive new information about upcoming generation capacity builds. According to current law, projects coming online after the end of next year will see a significantly reduced federal investment tax credit of 10%, well below the 30% investment tax credit available for projects that come online before the end of 2016. This provides a strong incentive for projects to enter service before the end of 2016.

Wind capacity, which grew by 8.1% in 2014, is forecast to increase by 13.1% in 2015 and by another 10.9% in 2016. Because wind is starting from a much larger base than solar, even though the growth rate is lower, the absolute amount of the increase in capacity is more than twice that of solar: 17 GW of wind compared with 8 GW of utility-scale solar between 2014 and 2016.

Liquid Biofuels. After ethanol production in December 2014 topped 1.0 million bbl/d for the first time, it is estimated to have fallen to an average of 944,000 bbl/d in March 2015. Ethanol production averaged 935,000 bbl/d in 2014, and EIA expects it to average 944,000 bbl/d in 2015 and 937,000 bbl/d in 2016. Biodiesel production averaged an estimated 83,000 bbl/d in 2014 and is forecast to average 82,000 bbl/d in 2015 and 84,000 bbl/d in 2016.

Energy-Related Carbon Dioxide Emissions. EIA estimates that emissions grew 0.7% in 2014. Emissions are forecast to increase by 0.1% in 2015 and by 0.4% in 2016. These forecasts are sensitive to both weather and economic assumptions.

U.S. Economic Assumptions

Recent Economic Indicators. The Bureau of Economic Analysis (BEA) reported that real gross domestic product (GDP) grew at an annualized rate of 2.2% in the fourth quarter of 2014, the same as the previous estimate. With the latest estimate for the fourth quarter, private inventory investment increased less than previously estimated, while consumption increased more than previously estimated.

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

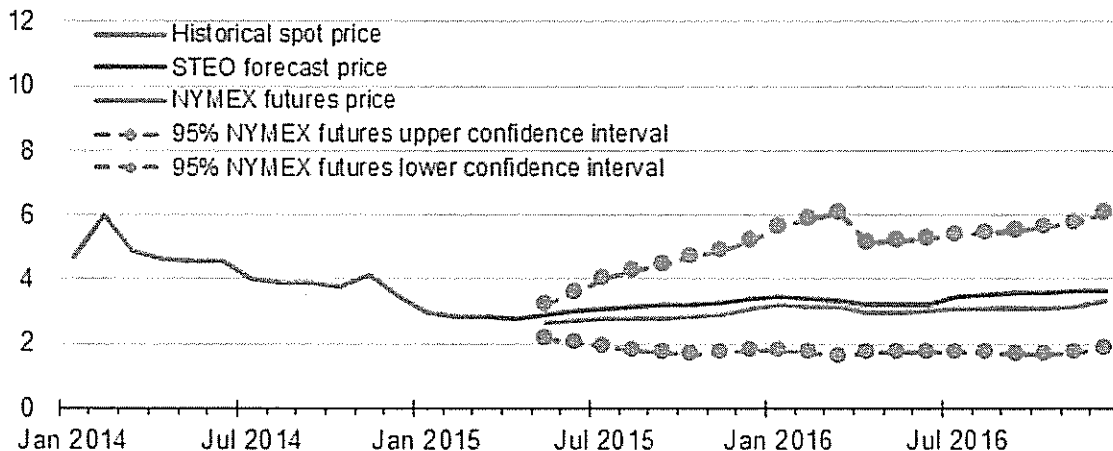
Production, Income, and Employment. Forecast real GDP growth reaches 2.7% in 2015 and declines to 2.3% in 2016. Growth is expected to be higher in 2015 because of greater business investment spending and increases in consumer purchases. However, a stronger dollar and lower demand from slower-growing economies are expected to reduce export growth and raise import growth. Real disposable income grows by 3.1% in 2015, below the 3.2% forecast last month, and by 2.2% in 2016. Total industrial production grows at 2.1% in 2015 and 2.8% in 2016. Projected growth in nonfarm employment averages 2.2% in 2015 and 1.5% in 2016.

Expenditures. Forecast private real fixed investment growth averages 5.2% and 6.7% in 2015 and 2016, respectively, led by equipment in 2015 and by residential investment in 2016. Real consumption expenditures grow faster than real GDP in 2015 and 2016, at 3.2% and 2.6%, respectively. Durable goods expenditures drive consumption spending in both years. Export growth is 2.2% and 3.2% over the same two years, while import growth is 4.4% in 2015 and 5.8% in 2016. Total government expenditures rise 0.9% in 2015 and 0.5% 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

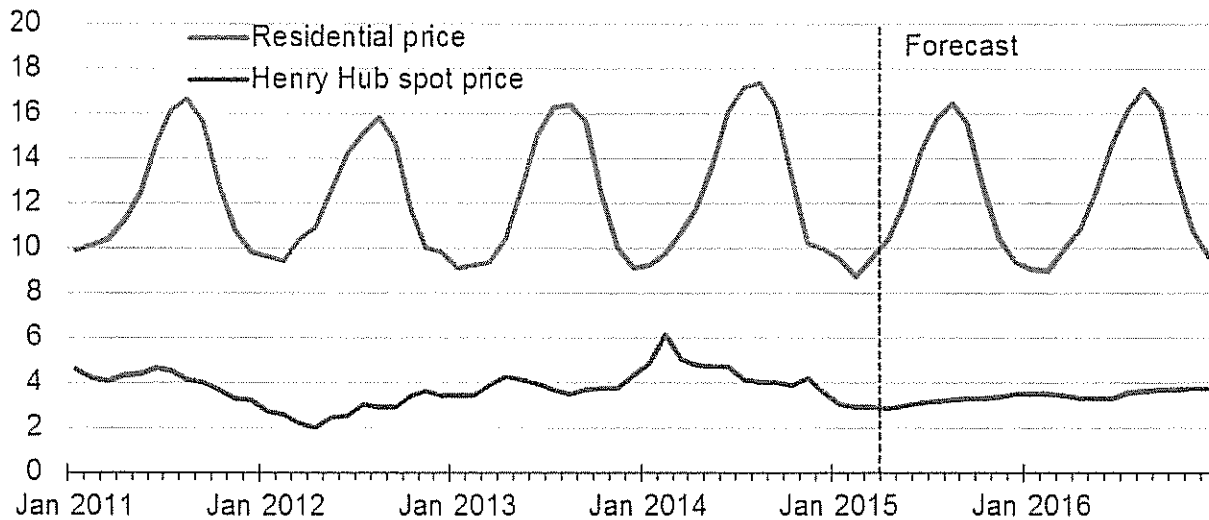


Note: Confidence interval derived from options market information for the 5 trading days ending Apr. 2, 2015. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, April 2015.

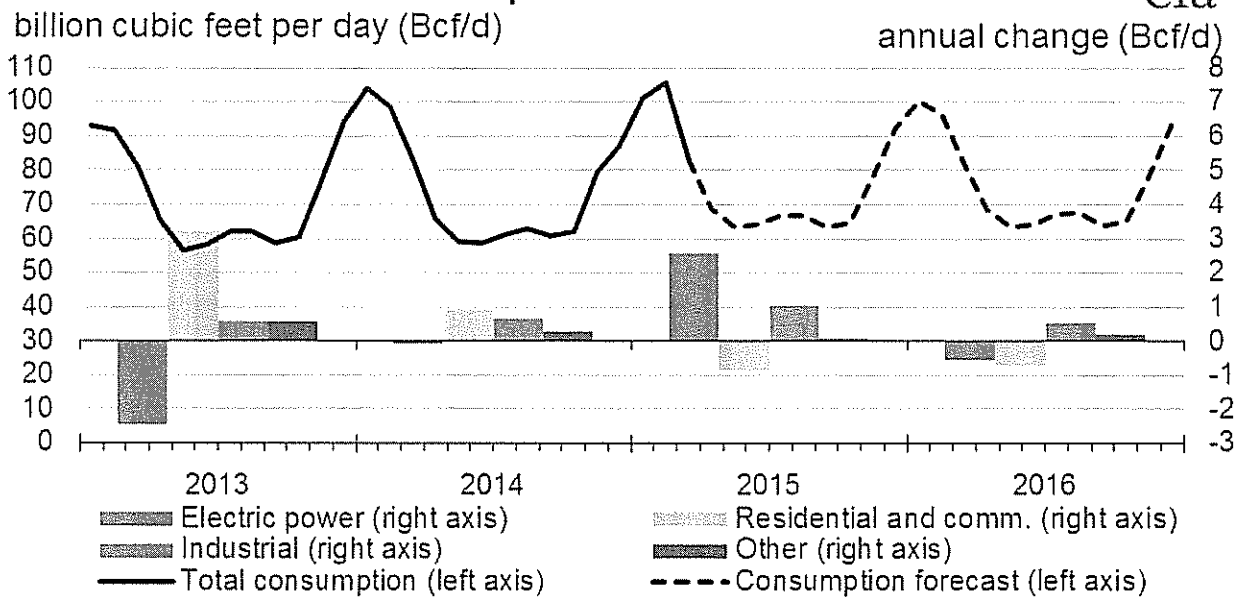
U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, April 2015.

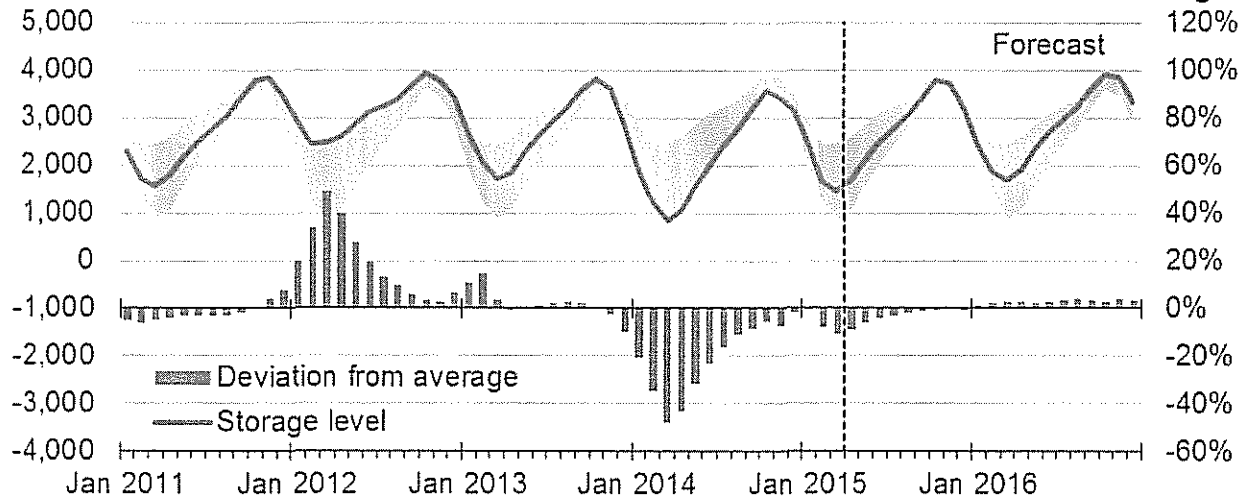
U.S. Natural Gas Consumption



Source: Short-Term Energy Outlook, April 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.

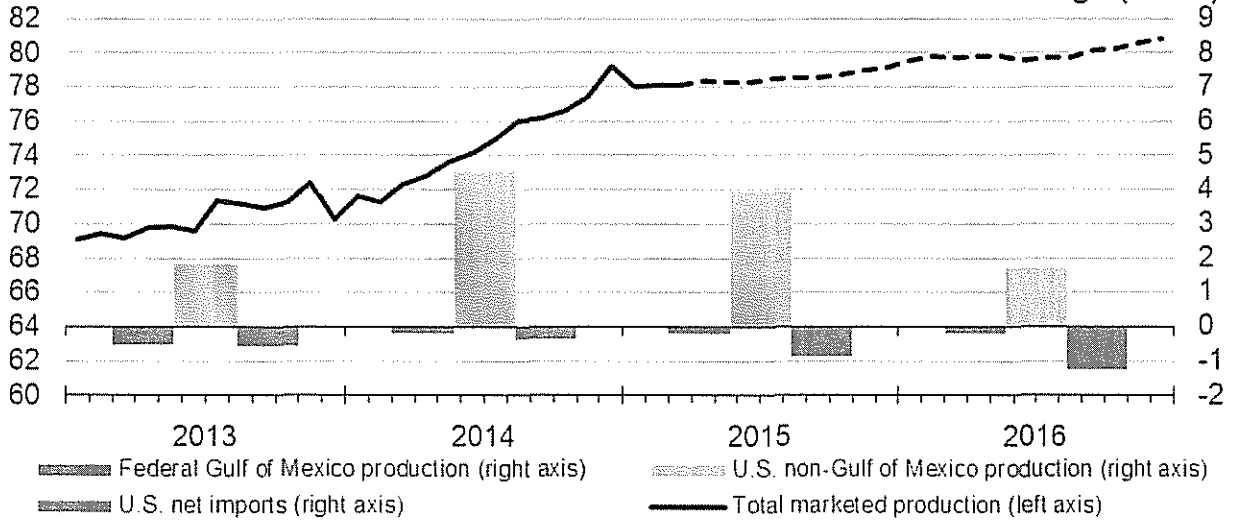
Source: Short-Term Energy Outlook, April 2015.

U.S. Natural Gas Production and Imports



billion cubic feet per day (Bcf/d)

annual change (Bcf/d)



Source: Short-Term Energy Outlook, April 2015.

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

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$3.886	\$2.753	\$2.775	\$2.763
Prior Gas Cost	3.977	4.080	2.857	2.844
Current Gas Cost Adjustment	(\$0.091)	(\$1.327)	(\$0.082)	(\$0.081)
<u>Surcharge Adjustment:</u>				
Current Adjustment	\$0.209	\$0.209	\$0.380	\$0.365
Prior Adjustment	0.209	0.209	0.380	0.365
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
Gas Cost Level	\$3.886	\$2.753	\$2.775	\$2.763
Plus: Surcharge	0.209	0.209	0.380	0.365
Total Gas Cost Level in Tariff Rates	\$4.095	\$2.962	\$3.155	\$3.128
<u>Market Based Pricing Differential</u>				
Current Adjustment	(\$0.017)	(\$0.017)	\$0.000	\$0.000
Prior Adjustment	(0.017)	(0.017)	0.000	0.000
Change in Market Based Pricing	\$0.000	\$0.000	\$0.000	\$0.000
<u>Grain Drying Margin Sharing</u>				
Current Adjustment	(\$0.001)	(\$0.001)	\$0.000	\$0.000
Prior Adjustment	(0.001)	(0.001)	0.000	0.000
Change in Grain Drying Margin Sharing	\$0.000	\$0.000	\$0.000	\$0.000
Total Cost of Gas Items	\$4.077	\$2.944	\$3.155	\$3.128
Net Increase (Decrease) in Gas Costs	(\$0.091)	(\$1.327)	(\$0.082)	(\$0.081)

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

	Amount
Total Gas Costs 1/	\$60,796,828
Residential and General Service dk Requirements 2/	15,712,756
Average Cost of Gas per dk	\$3.869
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.886
Less: Gas Cost Level in Rates 3/	3.977
Current Gas Cost Adjustment	(\$0.091)

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

2/ Normalized dk sales for the twelve months ended March 31, 2015, adjusted for losses at .45%.

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

Cost of Purchased Gas	\$3.959
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.977

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

Total Gas Costs 1/	\$60,796,828
Less: Annual MDDQ Costs	<u>17,724,248</u>
Total Gas Costs excluding MDDQ	\$43,072,580
Firm Service Requirements 1/	15,712,756
Other Gas Costs per Dk (excluding MDDQ)	\$2.741
<u>Summer - June - September</u>	
Summer Seasonal Rate, adjusted for losses 2/	2.753
Less: Gas Cost Level in Rates 3/	<u>4.080</u>
Current Gas Cost Adjustment	<u><u>(\$1.327)</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 May 1, 2015:

	<u>Winter</u>
Cost of Purchased Gas	\$4.062
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.080

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

	Amount
Total Gas Costs 1/	\$19,322,726
Interruptible Service dk Requirements	6,993,666
Average Cost of Gas per dk	\$2.763
Average Cost of Gas as Adjusted for Losses @ 99.55%	2.775
Less: Gas Cost Level in Rates 2/	2.857
Current Gas Cost Adjustment	(\$0.082)

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

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

Cost of Purchased Gas	\$2.844
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$2.857

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

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

Northern Border Pipeline Company - Exhibit B, page 11 for Schedule T-1.

Foothills Pipe Lines, Ltd. - Billed on a cost of service basis so there are no tariff sheets.

NOVA Gas Transmission - Exhibit B, pages 12-13 for Schedule FT-D.

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

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

SourceGas Distribution LLC - Exhibit B, Page 16 for Schedule TC.

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FT-1					
RESERVATION CHARGE					
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)					
MAXIMUM	RATE PER EQV. DKT PER MO.	921.000	N.A.	N.A.	921.000
MINIMUM	RATE PER EQV. DKT PER MO	0.000	N.A.	N.A.	0.000
COMMODITY CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
MINIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
SCHEDULED OVERRUN CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	32.112	N.A.	N.A.	32.112
MINIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	30.279	N.A.	N.A.	30.279
MINIMUM	RATE PER DKT	0.000	N.A.	N.A.	0.000

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE AND LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGES ARE REFLECTED ON SHEET NO. 21A. THESE PERCENTAGES SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR TRANSPORTATION. THE APPLICABLE RATE IS REFLECTED ON SHEET NO. 21B. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.
- C/ SHIPPER MUST REIMBURSE TRANSPORTER FOR THE ACA SURCHARGE. SUCH SURCHARGE SHALL BE THE ACA UNIT CHARGE SPECIFIED IN THE ANNUAL NOTICE ISSUED BY THE FERC ENTITLED "FY [YEAR] GAS ANNUAL CHARGES CORRECTION FOR ANNUAL CHARGES UNIT CHARGE."

Issued On: February 27, 2015
 Docket Number: 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 FTN-1					

RESERVATION CHARGE					
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)					
MAXIMUM	RATE PER EQV. DKT PER MO.	24.274	N.A.	N.A.	24.274
MINIMUM	RATE PER EQV. DKT PER MO.	1.263	N.A.	N.A.	1.263
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	0.798	N.A.	N.A.	0.798
MINIMUM	RATE PER DKT	0.042	N.A.	N.A.	0.042

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FS-1					
CAPACITY RESERVATION CHARGE					
MAXIMUM	RATE PER EQV. DKT PER MO.	1.757	N.A.	N.A.	1.757
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	0.000
CAPACITY DELIVERABILITY CHARGE					
MAXIMUM	RATE PER EQV. DKT PER MO.	201.507	N.A.	N.A.	201.507
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	0.000
INJECTION CHARGE					
MAXIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
MINIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
WITHDRAWAL CHARGE					
MAXIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
MINIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
SCHEDULED OVERRUN CHARGE					
INJECTION					
MAXIMUM A/B/	RATE PER DKT	18.683	N.A.	N.A.	18.683
MINIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
WITHDRAWAL					
MAXIMUM A/B/	RATE PER DKT	18.683	N.A.	N.A.	18.683
MINIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE AND LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGES ARE REFLECTED ON SHEET NO. 21A. THESE PERCENTAGES SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR STORAGE. THE APPLICABLE RATE IS REFLECTED ON SHEET NO. 21B. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

NOTICE OF CURRENTLY EFFECTIVE RATES

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

TRANSPORTATION - RATE SCHEDULES FT-1 AND IT-1

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

GATHERING - FIRM AND INTERRUPTIBLE

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

STORAGE - RATE SCHEDULES FS-1 AND IS-1

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

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

ELECTRIC POWER REIMBURSEMENT RATES (CENTS/DKT)

TRANSPORTATION - RATE SCHEDULES FT-1 AND IT-1

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

GATHERING - FIRM AND INTERRUPTIBLE

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

STORAGE - RATE SCHEDULES FS-1 AND IS-1

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

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

NATURAL GAS TARIFF



Canceling	<u>37th</u>	Revised	Sheet No.	<u>80.1</u>
	<u>36th</u>	Revised	Sheet No.	<u>80.1</u>

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge	
5,001 to 10,000	\$ 119.95	(R)
10,001 to 30,000	\$ 172.45	(R)
>30,000	\$ 382.65	(R)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

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

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	\$ 0.0074304	(R)
Minimum	\$ 0.0017935	
GTAC Amortization	\$ (0.0009972)	
Balancing Penalty Rate	Higher of \$25.00/ Dekatherm Or 150% of Market Price	

PLUS:

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

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

MINIMUM BILL: Per respective contracts.

(continued)

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 JUNE 2015**

	General Service		
	Storage Balance 1/	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	(2,612,375)	247,477	(2,545,684)
May	(782,752)	319,317	(1,476,517)
June	1,757,120	425,648	(43,286)
July	4,286,929	531,558	1,374,590
August	6,659,536	647,798	2,788,124
September	8,855,878	761,941	3,980,188
October	9,234,713	781,624	4,101,093
13 month average	<u>\$3,829,315</u>	<u>\$575,632</u>	<u>\$956,599</u>
Rate of Return	7.881%	7.881%	7.881%
Return	\$301,788	\$45,366	\$75,390
Return Requirement	<u>\$421,263</u>	<u>\$63,326</u>	<u>\$105,236</u>

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

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

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 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)
Balance @ February 28, 2015									<u>(\$2,620,069)</u>

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

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

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

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

	<u>(Over) Under</u> <u>Recovery</u>	<u>Refunds &</u> <u>Other</u>	<u>Interest 1/</u>	<u>Total Net</u> <u>Additions</u>	<u>Actual Dk</u> <u>Sales</u>	<u>Adjustment</u> <u>Per Dk</u>	<u>Total</u> <u>Adjustment</u> <u>Amount</u>	<u>Net Change-</u> <u>Additions less</u> <u>Adjustment</u>	<u>Cumulative</u> <u>Balance</u>
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
Balance @ February 28, 2015									<u>\$211,289</u>

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

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

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2014									<u><u>\$185,080</u></u>
August	\$16,626	\$0	\$3	\$16,629	4,035	\$0.181	\$731	\$15,898	200,978
September	(888)	0	2	(886)	3,604	0.181	652	(1,538)	199,440
October	2,549	0	2	2,551	9,112	0.365	1,649 2/	902	200,342
November	(4,099)	0	2	(4,097)	26,445	0.365	9,652	(13,749)	186,593
December	(8,282)	0	3	(8,279)	61,559	0.365	22,468	(30,747)	155,846
January 2015	39,354	0	2	39,356	64,476	0.365	23,533	15,823	171,669
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
Balance @ February 28, 2015									<u><u>\$55,074</u></u>

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

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