



UTILITIES CO.

A Division of MDU Resources Group, Inc.

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

June 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 (139<sup>th</sup> Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered July 1, 2015.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.320 per dk since the last filing due to an increase in the overall commodity price of gas. 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 July 2015.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.320 per dk for residential and firm general customers, an increase of \$0.304 per dk for small and large interruptible customers and an increase of \$0.302 per dk for Air Force customers from the currently effective rates.

Exhibit B shows the calculation of the current gas cost adjustment that will be applicable to Montana-Dakota's customers for the month of July 2015. The average cost of gas for firm customers, adjusted for losses, is \$4.206.

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 an increase of approximately \$103,900 for natural gas customers during the month of July 2015. All of Montana-Dakota's retail natural gas customers in North Dakota may be affected by this proposal. There were 105,464 natural gas customers and 344 propane customers in North Dakota as of May 31, 2015.

Please refer all inquiries regarding this filing to:

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

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


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

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

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

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

Sincerely,



Tamie A. Aberle  
Director of Regulatory Affairs

Attachment

**Rate Summary Sheet  
(Proposed)**



# Montana-Dakota Utilities Co.

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

## State of North Dakota Gas Rate Schedule

NDPSC Volume 7

139<sup>th</sup> Revised Sheet No. 3

Canceling 138<sup>th</sup> Revised Sheet No. 3

### RATE SUMMARY SHEET

Page 1 of 2

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60 <sup>1</sup>	4	\$0.4935 per day	\$0.326	\$4.397	\$4.723
Air Force Rate 64 <sup>1</sup>	7				
Minot Air Force Base		\$2,000.00 per month			
PAR Site		\$175.00 per month			
Firm Service			\$0.329	\$4.397	\$4.726
Interruptible Service - PAR			\$0.260	\$3.459	\$3.719
Interruptible Service - MAFB			\$0.260	\$3.430	\$3.690
Firm General Service Rate 70 <sup>1</sup>	13				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$4.397	\$5.127
Small Interruptible Gas Rate 71 <sup>2</sup>	14	\$175.00 per month	(Maximum) \$0.929	\$3.459	(Maximum) \$4.388
Optional Seasonal Gas <sup>1</sup>					
Service Rate 72	15				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$3.251	\$3.981
Transportation Service <sup>1</sup>	24				
Small Interruptible Rate 81		\$175.00 per month			
Maximum			\$0.485		
Minimum			\$0.102		
Fuel Charge				\$0.014	
Large Interruptible Rate 82		\$1,000.00 per month			
Maximum			\$0.297		
Minimum			\$0.061		
Fuel Charge				\$0.014	
Large Interruptible Gas Rate 85 <sup>3</sup>	27	\$1,000.00 per month	(Maximum) \$0.718	\$3.459	(Maximum) \$4.177
Residential Propane Rate 90 <sup>1</sup>	32	\$0.4935 per day	\$0.326	\$5.704	\$6.030
Firm General Propane Rate 92 <sup>1</sup>	34				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$5.704	\$6.434

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: June 8, 2015

Effective Date: July 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**

**July 2015**

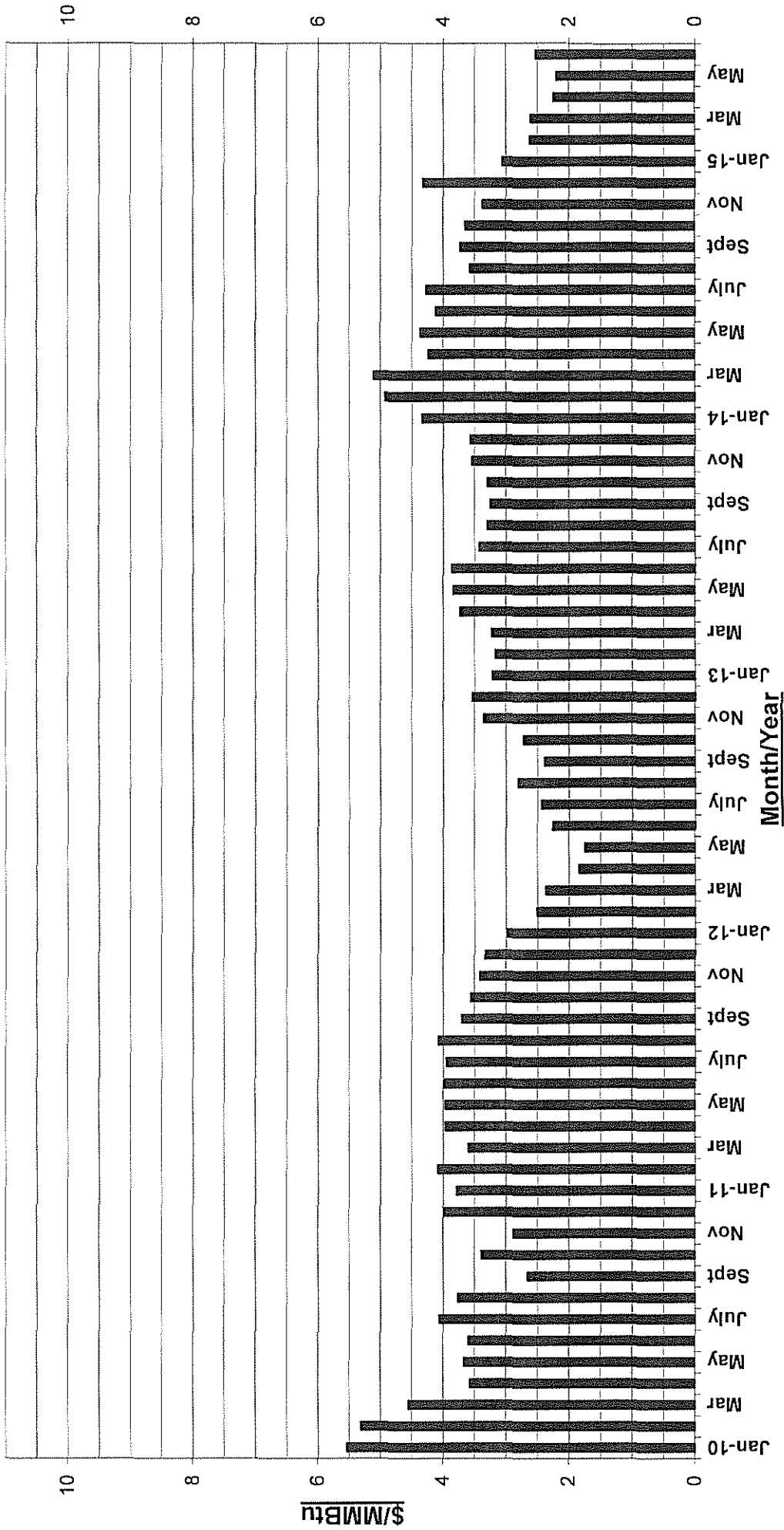
The established monthly price for the Rocky Mountain CIG Index has increased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid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

Planned and unplanned maintenance and higher temperatures resulting in increased natural gas usage by electric generation likely contributed to the increase in the index price for June. Domestic production levels continue to run near record levels. The EIA reported the national storage level as of May 29, 2015, was 1.0 percent above the five-year average and 50.7 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 May Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 18. The June Outlook will be published June 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-\$2.55



Independent Statistics &amp; Analysis

U.S. Energy Information  
Administration

May 2015

## Short-Term Energy Outlook (STEO)

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### Highlights

- North Sea Brent crude oil prices averaged \$60/barrel (b) in April, a \$4/b increase from March and the highest monthly average of 2015. Despite increasing global inventories, several factors contributed to higher prices in April, including indications of higher global oil demand growth, expectations for declining U.S. tight oil production in the coming months, and the growing risk of unplanned supply outages in the Middle East and North Africa.
- EIA forecasts that Brent crude oil prices will average \$61/b in 2015 and \$70/b in 2016, \$1/b higher and \$5/b lower than in last month's STEO, respectively. Average WTI prices in 2015 and 2016 are expected to be \$6/b and \$5/b below Brent, respectively. The current values of futures and options contracts for December 2015 delivery suggest (*Market Prices and Uncertainty Report*) the market's expectations (at the 95% confidence interval) for WTI prices in that month range from \$41/b to \$97/b.
- While U.S. monthly average regular gasoline retail prices in April were almost unchanged from March at \$2.47/gallon (gal), U.S. weekly regular gasoline retail prices reached an average of \$2.69/gal on May 11, reflecting rising crude oil prices and several outages at West Coast refineries. EIA expects U.S. regular gasoline retail prices, which averaged \$3.36/gal in 2014, to average \$2.43/gal in 2015 and \$2.63/gal in 2016. The average household is expected to spend \$675 less for gasoline in 2015 compared with last year because of lower prices.
- Total U.S. crude oil production averaged an estimated 9.3 million barrels per day (b/d) in March, but it is expected to decline from June through September before growth resumes. Given EIA's price forecast, projected total crude oil production averages 9.2 million b/d in both 2015 and 2016, 40,000 b/d (0.5%) and 100,000 b/d (1.1%) lower than in last month's STEO, respectively.
- Natural gas working inventories were 1,786 billion cubic feet (Bcf) on May 1, which was 71% higher than a year earlier, but 4% 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 3,890 Bcf, a net injection of 2,420 Bcf. This would be the second-highest injection season on record.

- Low natural gas prices in recent months have significantly increased the use of natural gas rather than coal for electricity generation. EIA expects natural gas generation in April and May will almost reach the level of coal generation, resulting in the closest convergence in generation shares between the two fuels since April 2012.

## Global Petroleum and Other Liquids

As in last month's STEO, global liquids production continues to exceed demand, resulting in inventory builds. Global oil inventory builds are projected to average 1.8 million b/d through the first half of 2015. Inventory builds moderate to 0.9 million b/d 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. The expected inventory builds in 2015 are on top of an estimated average 1.1 million b/d increase in 2014.

**Global Petroleum and Other Liquids Consumption.** EIA estimates that global consumption of petroleum and other liquids grew by 0.9 million b/d in 2014, averaging 92.0 million b/d for the year. EIA expects global consumption will grow by 1.2 million b/d in 2015 and by 1.3 million b/d in 2016. Forecast global consumption growth was revised upward from last month's STEO by an average of 0.2 million b/d in both 2015 and 2016, as lower oil prices stimulate demand growth more than previously expected. Projected global oil-consumption-weighted real gross domestic product (GDP), which increased by an estimated 2.7% in 2014, is projected to grow by 2.5% in 2015 and by 3.0% in 2016.

Consumption outside of the Organization for Economic Cooperation and Development (OECD) countries, which grew by 1.2 million b/d in 2014, is projected to grow by 0.9 million b/d in 2015 and by 1.2 million b/d in 2016. Lower forecast non-OECD consumption growth in 2015 mostly reflects a 0.2 million b/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, although it is offset by growth elsewhere. China's economic growth slowed in the second half of 2014 and in the beginning of 2015. Nonetheless, China remains the main source of non-OECD oil consumption growth, with a projected annual average increase of 0.3 million b/d in both 2015 and 2016, down from growth of 0.4 million b/d in 2014.

OECD petroleum and other liquids consumption, which fell by 0.4 million b/d in 2014, is expected to grow by 0.3 million b/d in 2015 and by 0.1 million b/d in 2016. Japan and Europe accounted for nearly all of the 2014 decline in OECD oil consumption. Japan's consumption is expected to continue declining over the next two years, albeit at a slower rate than in 2014, while Europe's consumption is expected to stay relatively flat. The United States is the leading contributor to projected OECD consumption growth, with U.S. consumption increasing by 0.3 million b/d in 2015 and by 0.1 million b/d in 2016.

**Non-OPEC Petroleum and Other Liquids Supply.** EIA estimates that non-OPEC production grew by 2.2 million b/d in 2014. EIA expects non-OPEC production to grow by 0.8 million b/d in 2015 and by 0.4 million b/d in 2016. The slower growth in total non-OPEC supply is largely attributable to slower production growth in the United States and Canada in response to lower

projected oil prices, as well as 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 b/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 about 0.7 million b/d in April 2015, almost 0.1 million b/d higher than the previous month because of more outages in Yemen and a new outage in Gabon. Yemen's production, which averaged 130,000 b/d in 2014, was halved when operations at an oil port and refinery were halted following the recent escalation in violence. In Gabon, a labor strike at oil fields resulted in a small supply disruption in April. South Sudan, Syria, and Yemen accounted for 90% of total non-OPEC supply disruptions in April. EIA estimates unplanned non-OPEC supply disruptions averaged 0.6 million b/d in 2014.

**OPEC Petroleum and Other Liquids Supply.** EIA estimates 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. In EIA's forecast, OPEC crude oil production rises by 0.4 million b/d in 2015 and falls by 0.2 million b/d in 2016. Forecast OPEC crude oil production was revised upward from last month's STEO by 0.3 million b/d in 2015 and by 0.2 million b/d in 2016. Iraq is expected to be the largest contributor to OPEC production growth over the next two years.

On April 2, Iran and the five permanent members of the United Nations Security Council plus Germany (P5+1) reached a framework agreement to guide negotiations targeting a comprehensive agreement by June 30. A comprehensive agreement could result in the lifting of oil-related sanctions against Iran and a subsequent increase in Iran's crude oil production and exports, although the potential timing and details of any suspension of sanctions are uncertain. EIA has not changed its short-term projection for Iranian crude oil production, which assumes that production will stay close to the current level.

Iran produced 3.6 million b/d of crude oil in late 2011, before the recent round of sanctions was enacted, forcing Iran to shut in a substantial portion of its production. Iran's ability to bring back 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, the pace of sanctions relief, and the ability of Iran to find buyers in the present market. If a comprehensive agreement is reached, EIA estimates that the re-entry of more Iranian barrels could result in a \$5/b-\$15/b lower baseline STEO price forecast for 2016 (see the analysis box on page 5 of the April 2015 STEO for further discussion).

OPEC noncrude liquids production, which averaged 6.3 million b/d in 2014, is expected to increase by 0.3 million b/d in 2015 and by 0.1 million b/d in 2016, led by production increases in Qatar, Iran, and Kuwait.

In April, unplanned crude oil supply disruptions among OPEC producers averaged 2.3 million b/d, almost 0.1 million b/d lower compared with the previous month. Unplanned OPEC crude

supply disruptions averaged 2.4 million b/d in 2014, 0.5 million b/d higher than in the previous year.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to decrease to an average of 1.8 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 indication of market conditions, and surplus capacity below 2.5 million b/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. Nonetheless, low surplus capacity heightens uncertainty about the market's ability to counteract unforeseen supply outages, particularly in the current geopolitical climate with ongoing conflicts in or next to major oil producing countries in the Middle East and North Africa. These factors may be applying upward pressure on crude oil prices that could continue through the forecast.

**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 2.91 billion barrels at the end of 2015 and then rise slightly to 2.93 billion barrels at the end of 2016.

**Crude Oil Prices.** North Sea Brent crude oil spot prices increased by \$4/b in April to a monthly average of \$60/b, which was the highest monthly average for Brent so far this year. Several factors put upward pressure on crude oil prices in April. These factors included indications that global oil demand growth is accelerating, evidence that U.S. tight oil production could decline in the coming months, and the growing risk of unplanned supply outages in the Middle East and North Africa. As of May 1, the number of rigs drilling for crude oil had fallen for 21 consecutive weeks and was more than 50% below its peak in October 2014. Brent crude oil prices increased despite growing global oil inventories, which built by more than 2 million b/d for the second consecutive month in April, compared with an average build of 0.8 million b/d in March and April of last year. Inventory builds are projected to moderate in the coming months.

The monthly average WTI crude oil spot price increased to an average of \$54/b in April, up \$7/b from March. While crude oil inventories at Cushing, Oklahoma increased in April, they fell by 0.5 million barrels during the week ending April 24, the first decline in 21 weeks, and were unchanged for the week ending May 1. Moderating Cushing inventory builds, along with expected declines in U.S. tight oil production and increasing U.S. refinery runs, have put upward pressure on the price of WTI crude oil.

EIA projects the Brent crude oil price will average \$61/b in 2015, \$1/b higher than in last month's STEO, with prices rising from an average of \$54/b in the first quarter to an average of \$63/b for the remainder of the year. The Brent crude oil price is projected to average \$70/b in 2016, \$5/b lower than in last month's STEO, reflecting an increase in forecast OPEC crude oil production in 2016. However, this price projection remains subject to the uncertainties surrounding the possible lifting of sanctions against Iran and other market events. WTI prices in 2015 and 2016 are expected to average \$6/b and \$5/b, respectively, below Brent.

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 August 2015 delivery traded during the five-day period ending May 7 averaged \$61/b while implied volatility averaged 33%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in August 2015 at \$46/b and \$81/b, respectively. The 95% confidence interval for market expectations widens over time, with lower and upper limits of \$41/b and \$97/b for prices in December 2015. Last year at this time, WTI for August 2014 delivery averaged \$99/b, and implied volatility averaged 17%. The corresponding lower and upper limits of the 95% confidence interval were \$85/b and \$115/b.

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. 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. The decline in oil prices since mid-2014 has led some governments to curb spending, potentially leading 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 always a major uncertainty in the world oil supply forecast.

## U.S. Petroleum and Other Liquids

U.S. weekly regular gasoline retail prices reached a 2015 high of \$2.69/gal on May 11, an increase of 28¢/gal from early April. Rising crude oil prices and a series of refinery outages in California have pushed gasoline prices higher in the past month. As a result of these outages, gasoline prices on the West Coast have increased by more than the U.S. average, with prices in Petroleum Administration for Defense District (PADD) 5 averaging \$3.44/gal on May 11, an increase of 49¢/gal from the first week in April. In April, monthly average regional gasoline retail prices ranged from a low of \$2.23/gal in PADD 3, the Gulf Coast region, to a high of \$3.01/gal in PADD 5, along the West Coast.

With crude oil prices projected to be relatively flat in the coming months, the U.S. monthly average gasoline price is projected to reach \$2.68/gal in May, then decline as refineries in California resolve outages and refineries in the rest of the country increase production of gasoline following the spring maintenance season. EIA projects regular gasoline retail prices to average \$2.51/gal during the third quarter and \$2.43/gal for the full year of 2015.

**Liquid Fuels Consumption.** Total U.S. liquid fuels consumption rose by an estimated 70,000 b/d (0.4%) in 2014. In 2015, total liquid fuels consumption is forecast to grow by 340,000 b/d (1.8%). EIA projects that in 2016, liquid fuels consumption growth will slow to 70,000 b/d (0.4%).

Motor gasoline consumption, which rose by 80,000 b/d in 2014, increases by a projected 120,000 b/d (1.4%) in 2015 as lower prices and employment growth outweigh increases in vehicle fleet efficiency. Gasoline consumption is forecast to fall by 50,000 b/d (0.6%) in 2016, driven by higher prices and a long-term trend toward more-efficient vehicles.

Consumption of distillate fuel, which includes diesel fuel and heating oil, is forecast to rise by 80,000 b/d (2.0%) in 2015 and by 60,000 b/d (1.5%) in 2016. This growth is driven by increasing manufacturing output and foreign trade. Additionally, some of the growth in distillate fuel consumption comes from the implementation of Annex VI to the International Convention for the Prevention of Pollution from Ships (MARPOL Annex VI), which will increase marine distillate use in U.S. waters because of provisions that displace the use of some residual fuel oil.

Hydrocarbon gas liquids (HGL) consumption, which fell by 100,000 b/d (4.0%) in 2014, is projected to increase by 120,000 b/d in 2015 and by 60,000 b/d in 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 1.0 million b/d in 2016. HGL consumption rises as additional natural gas processing and pipeline capacity make HGL supplies more accessible, with HGL production forecast to increase by 520,000 b/d (17%) between 2014 and 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 9.2 million b/d in 2015 and remain flat in 2016. The 2015 and 2016 production forecasts are 40,000 b/d and 100,000 b/d lower than in last month's STEO, respectively. The reduction in the crude oil production forecast reflects a reduced WTI price forecast for 2016 in this STEO and a sustained drop in rig counts beyond what EIA had initially expected. Oil-directed rigs declined to the lowest level in almost five years as of early May.

EIA expects onshore production to decline beginning in the second quarter of 2015 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 exceed 9.3 million b/d in the second quarter of 2015, then decline by 280,000 b/d through the first quarter of 2016. With forecast WTI crude oil prices rising to an average of \$67/b in the second quarter of 2016, drilling activity is expected to increase again. Companies are expected to take advantage of lower costs for acreage leasing, drilling, and well-completion services, resulting in growing production beginning in the second quarter of 2016. 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 completion of backlogged wells 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 b/d in October, is projected to average 3.2 million b/d in 2015 and 3.5 million b/d in 2016. EIA expects higher ethane recovery rates following 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.

**Petroleum Product Prices.** Rising crude oil prices and several California refinery outages contributed to an increase in U.S. regular gasoline retail prices from a monthly average of \$2.47/gal in April to \$2.69/gal on May 11. The U.S. monthly average gasoline price is projected to reach \$2.68/gal in May, and then decline as refineries in California resolve outages and refineries in the rest of the country increase production of gasoline following the spring maintenance season. EIA projects regular gasoline retail prices to average \$2.51/gal during the third quarter of 2015.

The U.S. regular gasoline retail price, which averaged \$3.36/gal in 2014, is projected to average \$2.43/gal in 2015, 3¢/gal higher than in last month's STEO, and \$2.63/gal in 2016, which is 10¢/gal lower than in last month's STEO. The diesel fuel retail price, which averaged \$3.83/gal in 2014, is projected to fall to an average of \$2.88/gal in 2015 and then rise to \$3.12/gal in 2016.

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 August 2015 delivery traded over the five-day period ending May 7 averaged \$2.00/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 August 2015 is about 12%.

## Natural Gas

Natural gas prices fell throughout April, before rising slightly in early May. Production and inventories remain abundant, which is expected to keep prices at relatively low levels in 2015. Preliminary data indicate recent production has surpassed the December record. Storage injections were strong in April, and EIA expects working inventories in storage will end October at 3,890 Bcf, just above the five-year (2010-14) average. EIA's Henry Hub natural gas price forecast averages \$2.93/million British thermal units (MMBtu) in 2015 and \$3.32/MMBtu in 2016, 14¢/MMBtu and 13¢/MMBtu, respectively, lower than in last month's STEO.

**Natural Gas Consumption.** EIA's forecast of U.S. total natural gas consumption averages 76.9 Bcf per day (Bcf/d) in 2015 and 76.3 Bcf/d in 2016, compared with 73.5 Bcf/d in 2014. Consumption growth is largely driven by demand in the industrial and electric power sectors. EIA projects natural gas consumption in the power sector to grow by 12.9% in 2015 and then fall by 2.2% in 2016. Low natural gas prices support increased use of natural gas for electricity generation in 2015. Industrial sector consumption increases by 4.0% and by 2.7% in 2015 and 2016, respectively, as new industrial projects come online, particularly in the fertilizer and chemicals sectors, and as industrial consumers continue to take advantage of low natural gas prices. Consumption of natural gas in the residential and commercial sectors is projected to decline in 2015 and 2016.

**Natural Gas Production and Trade.** EIA expects that marketed natural gas production will increase by 4.5 Bcf/d (6.0%) and by 1.3 Bcf/d (1.7%) 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 EIA expects natural gas prices to remain low, 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. Most growth is expected to come from the Marcellus shale, as a backlog of drilled wells are completed and new pipelines come online to deliver Marcellus gas to markets in the Northeast. Preliminary data indicate significant production growth in April and the beginning of May.

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 0.79 Bcf/d in 2016.

**Natural Gas Inventories.** On May 1, natural gas working inventories totaled 1,786 Bcf, which was 742 Bcf (71%) above the level at the same time in 2014 and 67 Bcf (4%) below the previous five-year (2010-14) average for the week. So far during the refill season, injections have surpassed the five-year average injections by a wide margin. EIA projects end-of-October 2015 inventories will total 3,890 Bcf, 92 Bcf above the five-year average.

**Natural Gas Prices.** The Henry Hub natural gas spot price averaged \$2.61/MMBtu in April, a decline of 22 cents/MMBtu from March. EIA expects monthly average spot prices to remain lower than \$3/MMBtu through August, and lower than \$4/MMBtu through the remainder of the forecast. The projected Henry Hub natural gas price averages \$2.93/MMBtu in 2015 and \$3.32/MMBtu in 2016, 14¢/MMBtu and 13¢/MMBtu, respectively, lower than in last month's STEO.

Natural gas futures contracts for August 2015 delivery traded during the five-day period ending May 7 averaged \$2.85/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for August 2015 contracts at \$1.98/MMBtu and \$4.11/MMBtu, respectively. At this time last year, the natural gas futures contract for August 2014 delivery averaged \$4.78/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$3.63/MMBtu and \$6.31/MMBtu.

## Coal

**Coal Consumption.** EIA expects a 6% decrease in coal consumption in the electric power sector in 2015, despite a 1% increase in total electric power generation. Lower natural gas prices are the main driver of the decline. Projected low natural gas prices will make it more economical to run natural gas-fired generating units at higher utilization rates even in regions of the country (Midwest, South) that typically rely more heavily on coal-fired generation. The retirements of coal power plants in response to the implementation of the Mercury and Air Toxics Standards also reduces coal demand in the power sector in 2015. The full effect of the coal plant retirements on capacity 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 effects of the retirements as projected coal consumption in the electric power sector increases by 1% next year.

**Coal Supply.** EIA estimates that U.S. coal production for 2014 totaled 997 million short tons (MMst), 13 MMst (1.3%) higher than in 2013. Lower demand for coal (domestic consumption and exports) contributes to a projected 7% (66 MMst) decline in 2015 production. EIA projects a decline in all coal-producing regions with the largest decline occurring in Appalachia (34 MMst, or 13%). Declines in the Interior and Western regions are projected to be 2% and 5%, respectively. Coal production growth is projected to be flat in 2016.

**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 U.S. coal exports. EIA projects coal exports will fall by 10 MMst, to 87 MMst, in 2015, and then increase by 2 MMst 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 over the next two years.

**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 \$2.32/MMBtu in 2016.

## Electricity

Henry Hub natural gas prices below \$3/MMBtu have led to a shift away from the use of coal and toward natural gas for fueling power generation. During the first two months of 2015, coal fueled 37.4% of total U.S. electricity generation, down from 43.0% during the same period in 2014. In contrast, natural gas generation accounted for 27.6% of total generation, up from

23.7% during the first two months of 2014. The January-February natural gas fuel share of total electricity generation has been higher only once, in 2012, when it averaged 27.9%.

**Electricity Consumption.** The National Oceanic and Atmospheric Administration projects warmer temperatures this summer than last year's mild summer. U.S. cooling degree days during the summer months (April-September) of 2015 are projected to total about 6% more than the same period last year. Higher temperatures should lead to increased use of electricity for air conditioning. EIA forecasts U.S. retail sales of electricity to the residential sector will be 3,920 gigawatthours per day (GWh/d) during the summer of 2015, which is 2.9% higher than last summer. Higher residential consumption of electricity this summer is offset somewhat by a year-over-year decline in sales during the first quarter, leading to forecast 2015 annual growth in U.S. residential electricity sales of 0.5%. EIA expects U.S. retail sales of electricity to the commercial and industrial sectors to grow by 1.5% and 0.6%, respectively, during 2015.

**Electricity Generation.** Total U.S. generation of electricity is forecast to average about 11,340 GWh/d in 2015, which is 1.2% higher than total generation last year. The use of coal for power generation stays low by historical standards as the forecast natural gas price at Henry Hub remains below \$3/MMBtu through August. Lower use of existing coal capacity, combined with some coal retirements and regular seasonal maintenance, reduce projected U.S. coal generation in April and May so that its share of total generation is only 1.2 percentage points higher than the natural gas generation share. This is the closest convergence in generation shares between the two fuels since April 2012. EIA forecasts coal's share of U.S. total generation will be 35.8% in 2015, down from 38.7% in 2014. In contrast, the natural gas fuel share averages 30.7% this year, up from 27.4% in 2014.

**Electricity Retail Prices.** EIA expects continued growth in average U.S. residential electricity prices over the forecast period, but at a slower pace than last year. The forecast U.S. retail residential price increases by 1.6% in 2015 and by 1.8% in 2016. Industrial electricity prices, which are more responsive to changes in fuel costs, are expected to fall by 2.4% in 2015 and then rise by 1.2% in 2016.

## Renewables and Carbon Dioxide Emissions

**Electricity and Heat Generation from Renewables.** EIA expects renewables used in the electric power sector will grow by 3.0% in 2015 as conventional hydropower generation decreases by 0.9%, while nonhydropower renewable power generation increases 6.8%. The 2015 decrease in hydropower generation occurs because the effects of the California drought are only partially offset by resources elsewhere. Generation from hydropower is expected to return to longer-term average levels with an increase of 4.0% in 2016. Total renewables consumption for electric power and heat generation decreases by 0.4% in 2015 but increases by 4.5% in 2016.

EIA expects continued growth in utility-scale solar power generation, which is projected to average 83 GWh/d 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 utility-scale

solar capacity will increase by 84% 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. According to current law, projects coming online after the end of next year will see a 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 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 8.1% in 2014, is forecast to increase by 13.0% in 2015 and by another 11.3% 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 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 b/d for the first time, it is estimated to have fallen to an average of 927,000 b/d in April 2015. Ethanol production averaged 935,000 b/d in 2014, and EIA expects it to average 936,000 b/d in 2015 and 937,000 b/d in 2016. Biodiesel production averaged an estimated 81,000 b/d in 2014 and is forecast to average 81,000 b/d in 2015 and 84,000 b/d in 2016.

**Energy-Related Carbon Dioxide Emissions.** EIA estimates that emissions grew 1.0% in 2014 and are projected to remain flat over the forecast period. These forecasts are sensitive to both weather and economic assumptions.

## U.S. Economic Assumptions

**Recent Economic Indicators.** The Bureau of Economic Analysis reported that real gross domestic product (GDP) grew at an annual rate of 0.2% in the first quarter of 2015. Personal consumption expenditures and private inventory investment contributed positively to this initial estimate, and they were partly offset by negative contributions from exports and nonresidential fixed investment.

EIA used the April 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 2.6% in 2015 and slows to 2.4% in 2016. Growth is expected to rise in 2015 because of 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 3.3% in 2015, above the 3.1% forecast last month, and by 2.0% in 2016. Total industrial production grows at 1.6% in 2015 and 2.5% in 2016. Projected growth in nonfarm employment averages 2.0% in 2015 and 1.2% in 2016.

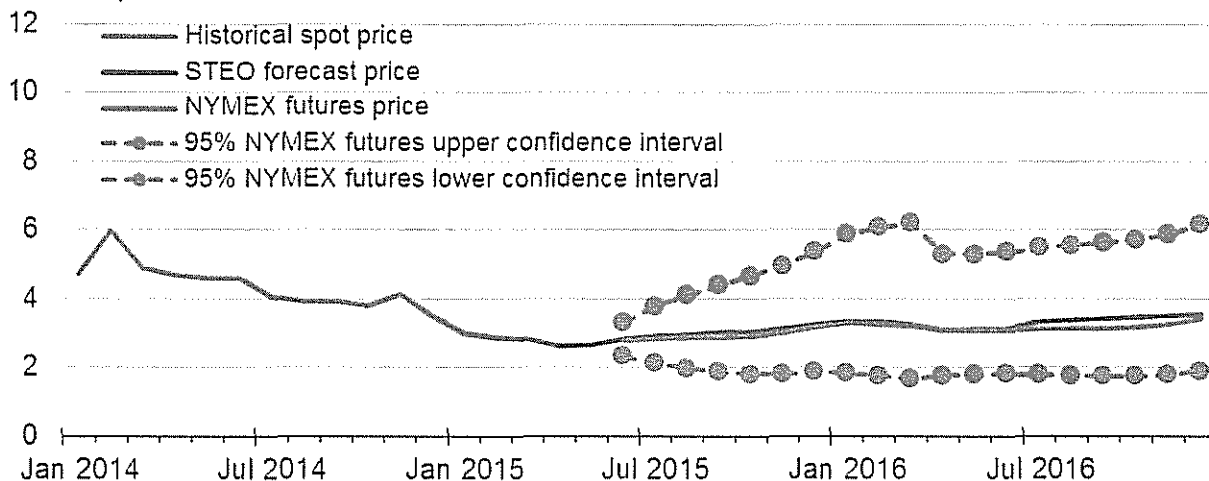
**Expenditures.** Forecast private real fixed investment growth averages 4.6% and 7.1% in 2015 and 2016, respectively, led by equipment in 2015 and 2016 and by equipment and structures in

2016. Real consumption expenditures grow faster than real GDP in 2015 and 2016, at 3.1% and 2.6%, respectively. Durable goods expenditures drive consumption spending in both years. Export growth is 2.1% and 4.2% over the same two years, while import growth is 3.7% in 2015 and 7.1% in 2016. Total government expenditures rise 0.9% in 2015 and 0.4% in 2016.

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

## Henry Hub Natural Gas Price

dollars per million Btu

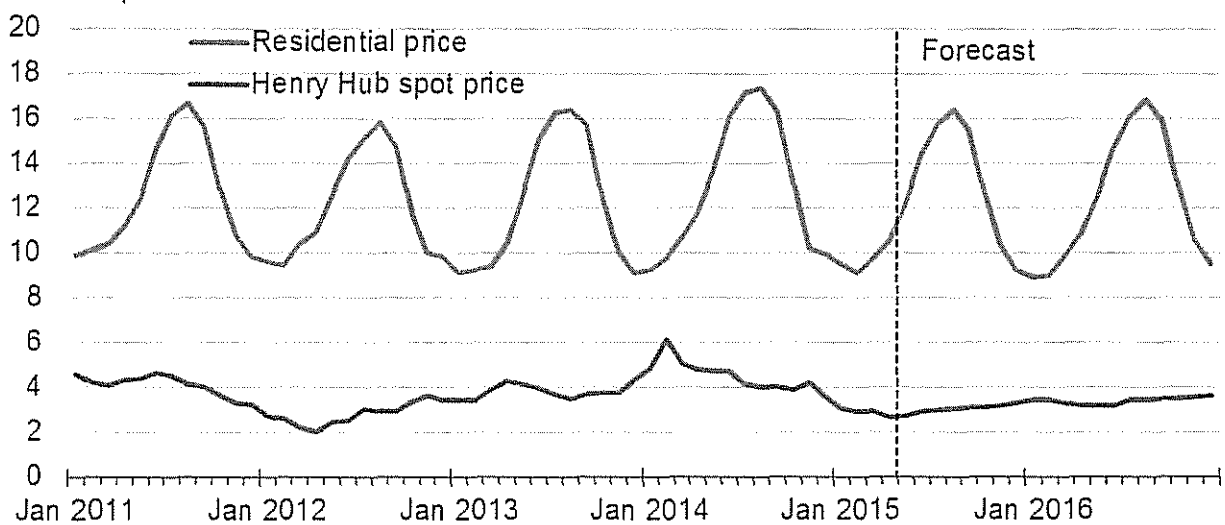


Note: Confidence interval derived from options market information for the 5 trading days ending May. 7, 2015. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, May 2015.

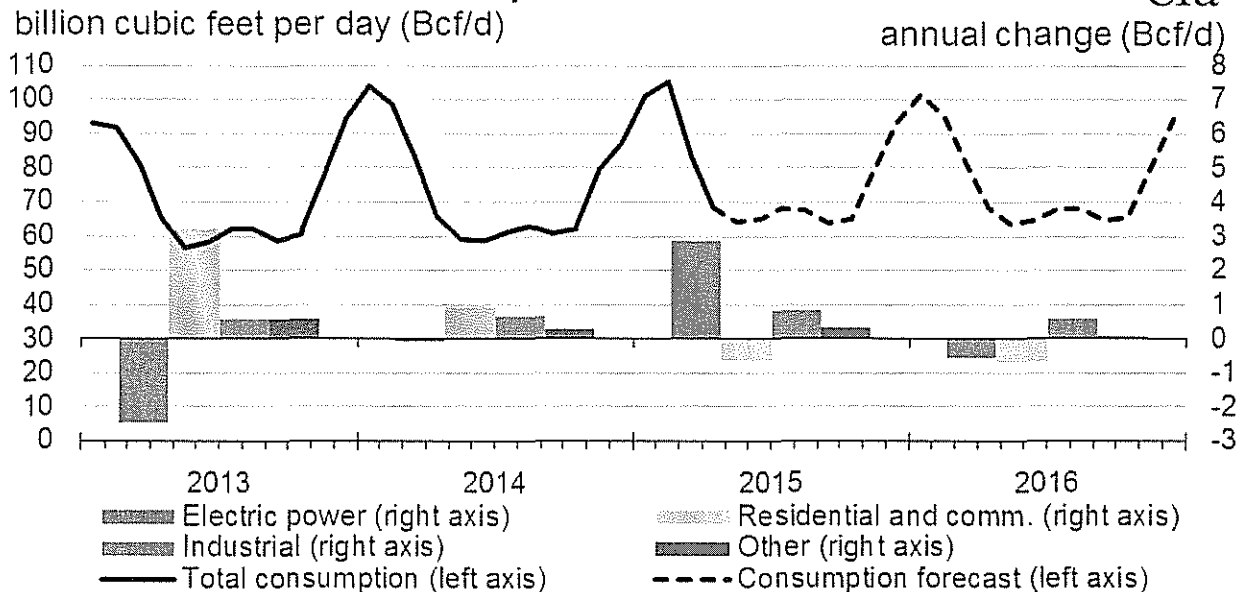
### U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, May 2015.

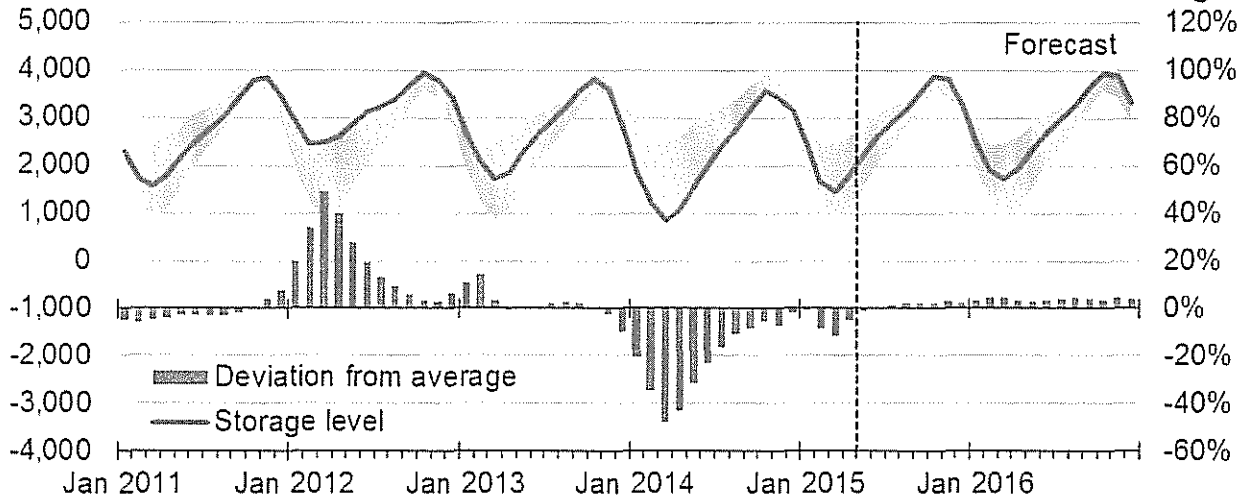
# U.S. Natural Gas Consumption



Source: Short-Term Energy Outlook, May 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.

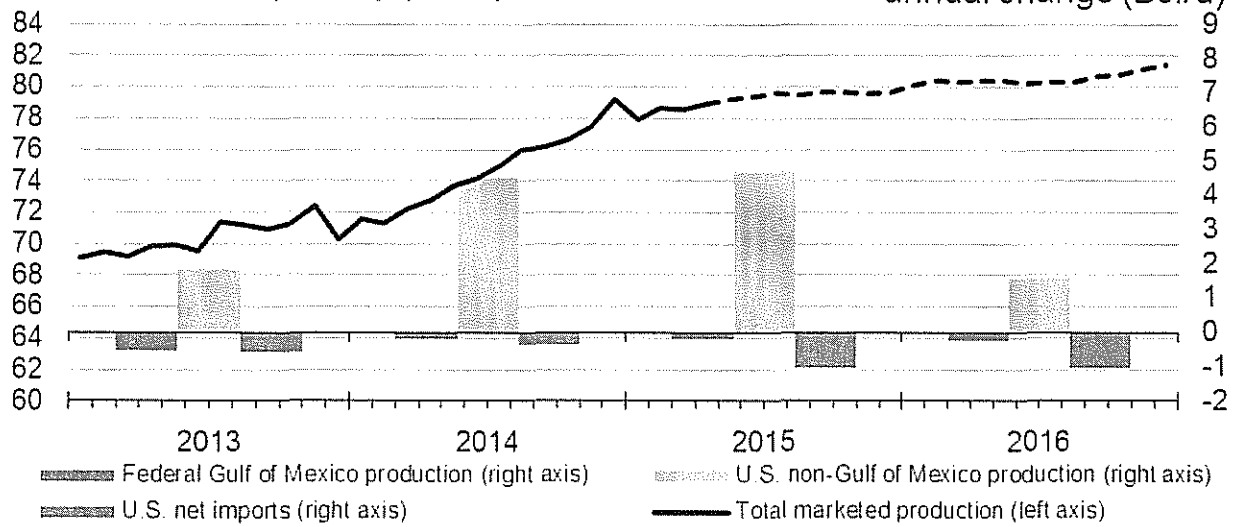
Source: Short-Term Energy Outlook, May 2015.

# U.S. Natural Gas Production and Imports



billion cubic feet per day (Bcf/d)

annual change (Bcf/d)



Source: Short-Term Energy Outlook, May 2015.

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

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
<b><u>Gas Cost Adjustment:</u></b>				
Gas Cost Level (Exhibit B)	\$4.206	\$3.060	\$3.079	\$3.065
Prior Gas Cost	3.886	2.753	2.775	2.763
Current Gas Cost Adjustment	\$0.320	\$0.307	\$0.304	\$0.302
<b><u>Surcharge Adjustment:</u></b>				
Current Adjustment	\$0.209	\$0.209	\$0.380	\$0.365
Prior Adjustment	0.209	0.209	0.380	0.365
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
Gas Cost Level	\$4.206	\$3.060	\$3.079	\$3.065
Plus: Surcharge	0.209	0.209	0.380	0.365
<b>Total Gas Cost Level in Tariff Rates</b>	<b><u>\$4.415</u></b>	<b><u>\$3.269</u></b>	<b><u>\$3.459</u></b>	<b><u>\$3.430</u></b>
<b><u>Market Based Pricing Differential</u></b>				
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
<b><u>Grain Drying Margin Sharing</u></b>				
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
<b>Total Cost of Gas Items</b>	<b><u>\$4.397</u></b>	<b><u>\$3.251</u></b>	<b><u>\$3.459</u></b>	<b><u>\$3.430</u></b>
<b>Net Increase (Decrease) in Gas Costs</b>	<b><u>\$0.320</u></b>	<b><u>\$0.307</u></b>	<b><u>\$0.304</u></b>	<b><u>\$0.302</u></b>

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

	Amount
Total Gas Costs 1/	\$65,076,752
Residential and General Service dk Requirements 2/	15,544,215
Average Cost of Gas per dk	\$4.187
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.206
Less: Gas Cost Level in Rates 3/	3.886
<b>Current Gas Cost Adjustment</b>	<b>\$0.320</b>

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 April 30, 2015, adjusted for losses at .45%.

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

Cost of Purchased Gas	\$3.869
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.886

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

Total Gas Costs 1/	\$65,076,752
Less: Annual MDDQ Costs	<u>17,724,248</u>
Total Gas Costs excluding MDDQ	\$47,352,504
Firm Service Requirements 1/	15,544,215
Other Gas Costs per Dk (excluding MDDQ)	\$3.046
<u>Summer - June - September</u>	
Summer Seasonal Rate, adjusted for losses 2/	3.060
Less: Gas Cost Level in Rates 3/	<u>2.753</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.307</u></u></b>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

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

	<u>Summer</u>
Cost of Purchased Gas	\$2.741
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rate	\$2.753

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

	Amount
Total Gas Costs 1/	\$21,434,161
Interruptible Service dk Requirements	6,993,666
Average Cost of Gas per dk	\$3.065
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.079
Less: Gas Cost Level in Rates 2/	2.775
<b>Current Gas Cost Adjustment</b>	<b>\$0.304</b>

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 June 1, 2015:

Cost of Purchased Gas	\$2.763
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$2.775

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

	<u>Amount</u>
Total Gas Costs 1/	<u>\$1,594,297</u>
Air Force Interruptible dk Requirements	520,209
Average Cost of Gas per dk	\$3.065
Less: Gas Cost Level in Rates 2/	<u>2.763</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.302</u></u></b>

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 June 1, 2015:  
Cost of Purchased Gas \$2.763

**Montana-Dakota Utilities Co.  
Schedule of Applicable Effective Pipeline Rates  
July 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%

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Effective On: April 1, 2015

NOTICE OF CURRENTLY EFFECTIVE RATES  
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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 <sup>3</sup> m <sup>3</sup>		
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D <sup>1</sup>	Refer to Attachment "2" for applicable FT-D Demand Rate per month based on a one year term (Price Point "Z") & Surcharge for each Group 1 or Group 2 Delivery Point Average FT-D Demand Rate for Group 1 Delivery Points \$ 5.32/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 <sup>1</sup>	Refer to Attachment "3" for applicable FT-P Demand Rate per month		
7. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10<sup>3</sup>m<sup>3</sup>/day)</u>	
	1-5 years	11.52	
	20 years	7.66	
8. Rate Schedule LRS-3	LRS-3 Demand Rate per month	\$ 129.55/10 <sup>3</sup> m <sup>3</sup>	
9. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
10. Rate Schedule IT-D <sup>1</sup>	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point		
11. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
12. Rate Schedule PT	<u>Schedule No.</u>	<u>PT Rate</u>	<u>PT Gas Rate</u>
	9009-01001-1	\$ 660.00/d	50.0 10 <sup>3</sup> m <sup>3</sup> /d
13. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	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>CO<sub>2</sub> Rate (\$/10<sup>3</sup>m<sup>3</sup>)</u>	
	1	542.06	
	2	428.98	
	3	279.71	
15. Monthly Abandonment Surcharge <sup>2</sup>	\$12.45/10 <sup>3</sup> m <sup>3</sup> /month	\$0.33/GJ/month	
16. Daily Abandonment Surcharge <sup>3</sup>	\$ 0.41/10 <sup>3</sup> m <sup>3</sup> /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 <sup>1</sup>
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 <sup>2</sup>
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 <sup>2</sup>
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



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

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT  
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge	
5,001 to 10,000	\$ 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)

Docket No.: D2014.12.96  
Tariff Letter No. 250-G  
By Operation of Law

Effective for service rendered on or after  
January 1, 2015

PUBLIC SERVICE COMMISSION  
*Alicia Salom* 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

**STATE OF SOUTH DAKOTA**  
**GAS RATE SCHEDULE**

NG-00-001

**South Dakota Intrastate Pipeline Company**

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

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

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

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 JULY 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	(1,108,819)	306,530	(1,477,359)
June	1,775,878	427,979	(44,920)
July	4,364,590	535,747	1,372,372
August	6,623,760	646,421	2,785,326
September	8,808,079	759,513	3,976,968
October	9,224,891	781,080	4,098,217
13 month average	<u>\$3,775,430</u>	<u>\$574,460</u>	<u>\$955,544</u>
Rate of Return	7.881%	7.881%	7.881%
Return	\$297,542	\$45,273	\$75,306
Return Requirement	<u>\$415,336</u>	<u>\$63,196</u>	<u>\$105,119</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**

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
<b>Balance @ July 31, 2014</b>									<b><u>\$3,163,455</u></b>
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)
<b>Balance @ April 30, 2015</b>									<b><u>(\$2,940,028)</u></b>

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 &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2014</b>									<b><u><u>\$553,358</u></u></b>
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
<b>Balance @ April 30, 2015</b>									<b><u><u>\$142,555</u></u></b>

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 &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2014</b>									<b><u>\$185,080</u></b>
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
<b>Balance @ April 30, 2015</b>									<b><u>\$36,061</u></b>

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

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