

January 10, 2013

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

Re: Cost of Gas Adjustment  
(COG) Rate 88  
Case No. PU-12-008

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.

Attachment A is the Rate Summary Sheet (112<sup>th</sup> Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered February 1, 2013.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.170 per dk since the last filing due to an increase in the overall commodity price of gas. A decrease in the market price of gas was offset by the higher cost of gas withdrawn from storage. Attachment B explains the reasons for the decrease in the market price of gas. There has also been a change in pipeline rates, as shown on Attachment C, increasing the cost of gas \$0.001 per dk.

The COG tariff sheet, Exhibit A page 1, summarizes the gas cost adjustment, calculated pursuant to the terms of Rate 88, and the surcharge adjustment and market based pricing differential provision that will apply during the month of February 2013.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.171 per dk for residential customers and firm general customers, an increase of \$0.170 per dk for optional seasonal customers, an increase of \$0.183 per dk for small and large interruptible customers and an increase of \$0.182 per dk for Air Force interruptible 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 February 2013. The average cost of gas for firm customers, adjusted for losses, is \$4.774.

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 8.791% was authorized by the Commission in Case No. PU-04-97.

Montana-Dakota purchases propane supplies from various wholesale suppliers. The cost of propane has increased since the last COG filing due to an increase in the market price of propane. Attachment B page 2 explains the reasons for the increase in the market price of propane.

Exhibit A, page 2 summarizes the cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of February 2013. The net effect of this filing is an increase of \$0.549 per dk for all customers from the currently effective rates.

Exhibit D shows the calculation of the current cost of gas – propane that will be applicable to Montana-Dakota's customers for the month of February 2013. The average cost of propane for all customers, adjusted for losses, is \$10.429 per dk.

These proposed adjustments, calculated in accordance with Rate 88 and 99, will amount to an increase of approximately \$403,900 for natural gas customers and an increase of approximately \$3,500 for propane customers during the month of February 2013. All of Montana-Dakota's retail natural gas and propane customers in North Dakota may be affected by this proposal. There were 98,458 natural gas customers and 341 propane customers in North Dakota as of December 31, 2012.

Please refer all inquiries regarding this filing to:

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

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

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

Montana-Dakota also submits herewith its check for \$550 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment will cover the filing fee associated with the monthly COG filings for February through December 2013.

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,

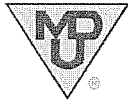


Rita A. Mulkern  
Director of Regulatory Affairs

Attachment

**Attachment A**

**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  
 112<sup>th</sup> Revised Sheet No. 3  
 Canceling 111<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	4	\$0.30 per day	\$0.812	\$4.651	\$5.463
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$4.651	\$4.789
Interruptible Service - PAR			\$0.120	\$3.637	\$3.757
Interruptible Service - MAFB			\$0.120	\$3.358	\$3.478
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$4.651	\$5.248
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$3.637	(Maximum) \$4.508
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$4.751	\$5.348
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.017	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.017	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$3.637	(Maximum) \$4.356
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$11.065	\$11.877
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$11.065	\$11.662

Date Filed: January 10, 2013

Effective Date:

Issued By: Tamie A. Aberle  
 Director - Regulatory Affairs

Case No.:

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

**February 2013**

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.

The decrease in natural gas prices is likely a result of record high levels of gas in storage for this time of the year as well as continued strong domestic natural gas production. The Energy Information Administration (EIA) reported storage levels nationwide as of December 28, 2012 to be 12.4 percent above the five-year average and 0.7 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.doe.gov>.

The January Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 19.

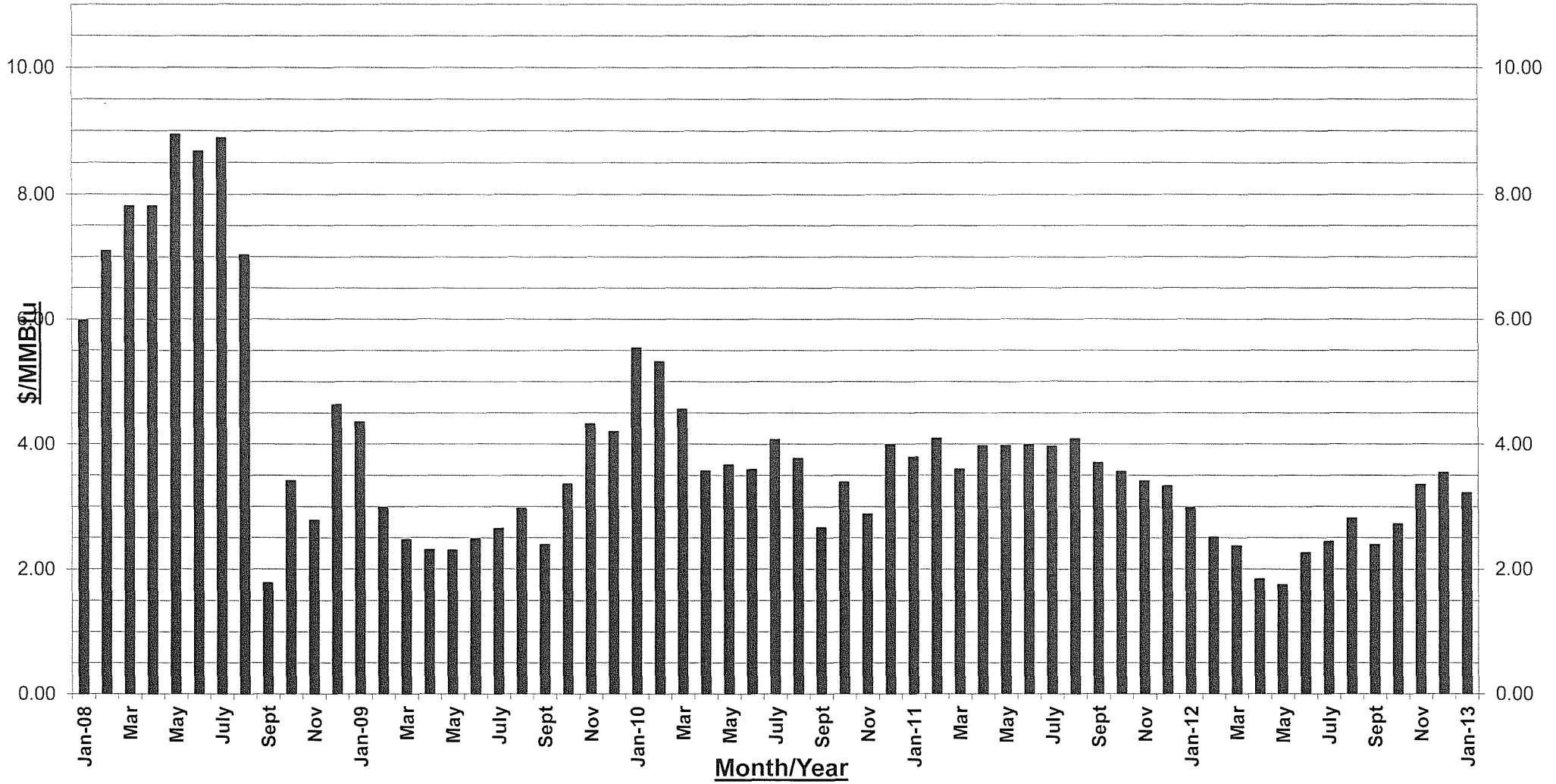
**Montana-Dakota Utilities Co.  
Market Conditions for Regional Propane  
February 2013**

Montana-Dakota uses two regional bulk wholesale propane suppliers for obtaining the lowest prices for Hettinger customers. Each time Montana-Dakota purchases propane, it requests a price quote from each supplier for a specific delivery date and quantity in truckloads, delivering 8,000 to 12,000 gallons. Montana-Dakota selects the lowest price, all other things being equal.

The February prices for propane have increased from the previous level. A change in the price of propane is generally driven by a combination of crude oil prices, weather, demand and inventory levels. As seasonal usage increases, this has resulted in a increase in the price of propane.

The Department of Energy's (DOE) Energy Information Administration (EIA) provides various publications on Energy issues. The information is available on their website:  
<http://www.eia.doe.gov>

# CIG Rocky Mountains Index Monthly Gas Prices 2008-2013YTD



From Inside F.E.R.C.'s Gas Market Report  
Annual Averages: - 2011-\$3.79; 2012-\$2.58; 2013YTD - \$3.22



Independent Statistics & Analysis

U.S. Energy Information  
Administration

January 2013

## Short-Term Energy Outlook (STEO)

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- This edition of the *Short-Term Energy Outlook* is the first to include forecasts for 2014.
- EIA expects that the Brent crude oil spot price, which averaged \$112 per barrel in 2012, will fall to an average of \$105 per barrel in 2013 and \$99 per barrel in 2014. The projected discount of West Texas Intermediate (WTI) crude oil to Brent, which averaged \$18 per barrel in 2012, falls to an average of \$16 per barrel in 2013 and \$8 per barrel in 2014, as planned new pipeline capacity lowers the cost of moving Mid-continent crude oil to the Gulf Coast refining centers.
- EIA expects that falling crude prices will help national average regular gasoline retail prices fall from an average \$3.63 per gallon in 2012 to annual averages of \$3.44 per gallon and \$3.34 per gallon in 2013 and 2014, respectively. Diesel fuel retail prices averaged \$3.97 per gallon during 2012 and are forecasted to fall to an average of \$3.87 per gallon in 2013 and \$3.78 per gallon in 2014.
- EIA estimates U.S. total crude oil production averaged 6.4 million barrels per day (bbl/d) in 2012, an increase of 0.8 million bbl/d from the previous year. Projected domestic crude oil production continues to increase to 7.3 million bbl/d in 2013 and 7.9 million bbl/d in 2014, which would mark the highest annual average level of production since 1988.
- Total U.S. liquid fuels consumption fell from an average 20.8 million bbl/d in 2005 to 18.6 million bbl/d in 2012. EIA expects total consumption to rise slowly over the next two years to an average 18.8 million bbl/d in 2014, driven by increases in distillate and liquefied petroleum gas consumption, with flat gasoline and jet fuel consumption.
- Natural gas working inventories, which a record-high level in early November, ended 2012 at an estimated 3.5 trillion cubic feet (Tcf), slightly above the level at the same time the previous year. EIA expects the Henry Hub natural gas spot price, which averaged \$4.00 per million British thermal units (MMBtu) in 2011 and \$2.75 per million MMBtu in 2012, will average \$3.74 per MMBtu in 2013 and \$3.90 per MMBtu in 2014.
- EIA expects the coal share of total electricity generation to rise from 37.6 percent in 2012 to 39.0 percent in 2013 and 39.6 percent in 2014, as natural gas prices rise relative to coal prices. Lower-than-projected natural gas prices along with the industry's response to future environmental regulations could cause the coal share of total generation to fall below this forecast.

## Global Crude Oil and Liquid Fuels

**Global Crude Oil and Liquid Fuels Overview.** EIA expects oil markets to loosen in 2013 and 2014 as increasing global supply more than offsets higher global consumption. Projected world supply increases by 1.0 million bbl/d in 2013 and 1.7 million bbl/d in 2014, with most of the growth coming from outside the Organization of the Petroleum Exporting Countries (OPEC). North America will account for much of this growth. Projected world liquid fuels consumption grows by an annual average of 0.9 million barrels per day (bbl/d) in 2013 and 1.3 million bbl/d in 2014. Countries outside the Organization for Economic Cooperation and Development (OECD) drive expected consumption growth.

**Global Crude Oil and Liquid Fuels Consumption.** World liquid fuels consumption grew by an estimated 0.9 million bbl/d in 2012 to reach 89.2 million bbl/d. EIA expects that this growth will remain about the same over the next year before picking up again in 2014 due to a moderate recovery in global economic growth; consumption reaches 90.1 million bbl/d in 2013 and 91.5 million bbl/d in 2014. Non-OECD Asia is the leading regional contributor to expected global consumption growth.

OECD liquid fuels consumption declined by 0.4 million bbl/d in 2012. EIA projects OECD consumption to further decline by 0.3 million bbl/d in 2013, as modest consumption growth in North America is more than offset by decreasing consumption in Europe. The OECD consumption decline narrows to 0.1 million bbl/d in 2014 as European consumption begins to flatten in response to higher economic growth. EIA projections do not assume any significant deterioration of the economic situation in the United States or the European Union (EU) next year.

**Non-OPEC Supply.** Although supply growth in the United States and Russia during 2012 outpaced our forecast at the beginning of the year, overall non-OPEC liquid fuels production fell below the year-ago expectations. EIA forecasts non-OPEC production to increase by 1.4 million bbl/d in 2013 and 1.3 million bbl/d in 2014, but assumptions about the mitigation of some of the current political impediments to production and the rapid evolution of the North American oil industry introduce considerable risks to the forecast. North America accounts for about two-thirds of the projected growth in non-OPEC supply over the next two years because of continued production growth from U.S. tight oil formations and Canadian oil sands.

Unplanned production outages in non-OPEC countries declined to 0.8 million bbl/d in December 2012, the lowest level since January 2012, but still above the historical baseline that prevailed during the fourth quarter of 2011. Syria and the Sudans are currently the most significant sources of disruption to non-OPEC production. EIA does not assume a resolution in Syria will occur during the forecast period. Sudan and South Sudan must still overcome political and technical obstacles before significant flows from the latter can be restarted. EIA projects that

Sudan and South Sudan combined will produce 0.2 million bbl/d in 2013 and 0.4 million bbl/d in 2014.

**OPEC Supply.** EIA expects that OPEC members will continue to produce at least 30 million bbl/d of crude oil over the next two years to accommodate the projected increase in world oil consumption and to counterbalance supply disruptions. However, OPEC crude supply decreases by 0.6 million bbl/d in 2013 and stays flat through 2014. Most of the decrease in 2013 comes from Saudi Arabia, which responds to non-OPEC growth and increasing production from some OPEC members, such as Iraq, Nigeria, and Angola.

Libyan oil production increased considerably over the last year to a level approaching pre-crisis capacity. Yet various small disruptions to Libyan production, refining, and exports over the last few months reinforce EIA's previous assessments of the continuing risks to the Libyan oil industry. We expect output to fluctuate around current levels until a permanent government is successfully installed.

Iraq has increased production by 0.4 million bbl/d since last year, in part due to new export infrastructure in the southern part of the country. However, heightened tensions between the central government, Kurdish Regional Government, and some Sunni and Shia factions could undermine the continued growth of its oil production over the near term.

Despite new output from deepwater fields, Nigeria's production declined slightly in 2012 from the previous year as increased oil theft and flooding cut crude oil production in the fourth quarter to 2.0 million bbl/d. Barring any major unforeseen supply disruptions, EIA projects Nigerian production to increase in 2013 and 2014 as output from deepwater fields ramps up and new fields are brought online. For more on upcoming oil projects in Nigeria, see EIA's [country analysis brief](#).

Technical and maintenance problems have plagued some of Angola's deepwater fields for years, particularly the Greater Plutonio Project, and will continue to limit Angola's crude oil production over the forecast period. The country's oil minister recently expressed skepticism over Angola's ability to reach its target of 2 million bbl/d in 2013. EIA's projection reflects that same skepticism, since several technical field problems remain unresolved. Nonetheless, EIA still anticipates Angolan crude oil output to gradually increase over the next two years as new deepwater production more than offsets chronic maintenance-related declines.

EIA estimates that liquid fuels production and consumption in Iran averaged 3.2 million bbl/d and 1.7 million bbl/d, respectively, during November and December 2012. Iranian crude oil production had been falling since at least the last quarter of 2011, due to the country's inability to carry out investment projects that are necessary to offset the natural decline in production from existing wells, while the latest round of U.S. and EU sanctions contributed to steeper declines in Iranian exports and production during the second and third quarters of 2012. However, this tentative interpretation of a very fluid situation could change as EIA revises data,

industry sources issue independent estimates of Iranian production, and more details about Iranian storage levels, refinery utilization, and domestic consumption emerge.

EIA estimates that OPEC surplus capacity, which is overwhelmingly concentrated in Saudi Arabia, remained relatively tight by historical standards at around 2.3 million bbl/d in December 2012. Projected OPEC surplus capacity increases to 3.1 million bbl/d in 2013. This estimate does not include additional capacity that may be available in Iran but which is currently offline due to the impacts of U.S. and EU sanctions on Iran's ability to sell its oil.

**OECD Petroleum Inventories.** EIA estimates that OECD commercial oil inventories ended 2012 at 2.67 billion barrels, equivalent to 58 days of supply. Projected OECD oil inventories remain relatively flat throughout the next year and end 2013 at 2.66 billion barrels (58 days of supply). Inventories grow to 2.69 billion barrels (59 days of supply) by the end of 2014.

**Crude Oil Prices.** EIA projects the Brent crude oil spot price will fall from an average of \$112 per barrel in 2012 to annual averages of \$105 per barrel and \$99 per barrel in 2013 and 2014, respectively, reflecting the increasing supply of liquid fuels by non-OPEC countries. After averaging \$94 in 2012, the WTI price will average \$90 per barrel in 2013 before increasing to an average of \$91 per barrel in 2014. By 2014, several pipeline projects from the Mid-continent to the Gulf Coast refining centers are expected to come on line, reducing the cost of transporting crude oil to refiners, which is reflected in a declining discount of WTI to Brent over the forecast period.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for April 2013 delivery during the five-day period ending January 3, 2013, averaged \$92.84 per barrel. Implied volatility averaged 26 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in April 2013 at \$74 per barrel and \$117 per barrel, respectively. Last year at this time, WTI for April 2012 delivery averaged \$102 per barrel and implied volatility averaged 35 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$75 per barrel and \$138 per barrel.

## U.S. Crude Oil and Liquid Fuels

**U.S. Liquid Fuels Consumption.** Having fallen 230,000 bbl/d (1.2 percent) in 2011, total liquid fuels consumption declined by an additional 300,000 bbl/d (1.6 percent) in 2012. All of the major petroleum categories contributed to the slide in consumption in 2012 despite the continued economic recovery and little change in year-over-year inflation-adjusted retail fuel prices. Projected total liquid fuels consumption increases by 70,000 bbl/d (0.4 percent) in 2013 and by 60,000 bbl/d in 2014. Most of the consumption growth comes from distillate fuel oil and liquefied petroleum gas, which rise because of continued growth in industrial use as well as the assumption of near-normal weather this winter compared with much warmer-than-normal weather last winter.

Forecast motor gasoline consumption in 2013 and 2014 remains almost unchanged from 2012 because continued slow growth in the driving-age population and highway travel is offset by improvements in the average fuel economy of new vehicles and retirement of older, less-fuel-efficient vehicles.

Distillate fuel consumption averaged 3.8 million bbl/d in 2012, 130,000 bbl/d (3.2 percent) lower than in 2011. Growth in on-highway diesel consumption in 2012 was offset by lower heating oil consumption for space heating (a 5.8-percent drop in heating degree days in the Northeast in 2012) and a decline in rail freight traffic (2.2-percent decline in estimated ton-miles over the first 51 weeks of 2012, as reported by the [American Association of Railroads](#) ) led by lower coal and grain shipments. EIA expects distillate consumption to increase by 20,000 bbl/d in 2013 and 30,000 bbl/d in 2014 as trucking continues to grow, winter temperatures return to near normal, and coal and grain production begin to recover in the second half of 2013 and increase in 2014.

Consumption of liquefied petroleum gas (and natural gas liquids) increased during 2012 despite the last winter's warm weather because growing supply of natural gas liquids over the last several years contributed to lower prices and increased demand, particularly by the petrochemical industry. Planned expansions at several ethylene plants in 2013 lead to increases in expected liquefied petroleum gas consumption of 40,000 bbl/d in 2013 and 30,000 bbl/d in 2014.

**U.S. Liquid Fuels Supply and Imports.** EIA expects crude oil production to continue to grow rapidly over the next two years, increasing from an average 6.4 million bbl/d in 2012 to average 7.3 million bbl/d in 2013, an increase of about 0.3 million bbl/d from last month's STEO, and 7.9 million bbl/d in 2014. Central to this projected growth will be ongoing development activity in key onshore basins. Drilling in tight oil plays in the Williston, Western Gulf, and Permian Basins is expected to account for the bulk of forecast production growth over the next two years.

The Williston Basin's Bakken formation in North Dakota and Montana, and the Western Gulf Basin's Eagle Ford formation in Texas currently contribute about two-thirds of U.S. tight oil production. Williston basin production rises from an estimated December 2012 level of 0.84 million bbl/d to 1.19 million bbl/d in December 2014. Western Gulf Basin production rises from an estimated December 2012 level of 1.07 million bbl/d to 1.75 million bbl/d in December 2014. Within the Western Gulf Basin roughly 0.4 million bbl/d of the oil production is outside of the Eagle Ford formation. The Western Gulf Basin accounts for more than half of the onshore domestic liquid production growth over the next two years.

The Permian Basin in West Texas, which includes plays such as Spraberry, Bonespring, and Wolfcamp, is another key growth area. (The term play refers to an oil or natural gas formation with active prospecting and development.) EIA estimates that crude oil production from the Permian Basin reached 1.23 million bbl/d in December 2012. Permian Basin production is projected to increase to 1.4 million bbl/d in December 2014. Although average initial liquids

production volumes from Permian wells have risen, in contrast to other basins, the production forecast for this basin has been scaled back due to lower rig efficiency across all wells being drilled in the region.

Alaska crude oil production reached a seasonal low this year of 400,000 bbl/d in August 2012 when summer maintenance typically decreases volumes, but recovered to 560,000 bbl/d in November. EIA expects Alaskan crude oil production will decline from an average of 530,000 bbl/d in 2012 to 510,000 bbl/d in 2013 and 480,000 bbl/d in 2014.

U.S. Federal Gulf of Mexico (GOM) average daily oil production was 1.17 million bbl/d in September 2012 because of outages early in the month related to Hurricane Isaac. Oil production recovered from the storm by the end of September and is estimated to have increased to 1.34 million bbl/d in November 2012. Average daily production for 2012 is expected to be 1.26 million bbl/d, approximately 60,000 bbl/d lower than during 2011.

EIA expects GOM production to increase to an average 1.37 million bbl/d in 2013. Much of that increase is due to the new projects that started producing in 2012, but do not reach peak production until late 2012 or early 2013, and six new field start-ups with a combined peak production of about 45,000 bbl/d, plus the Na Kika Phase 3 redevelopment project located 144 miles southeast of New Orleans.

Projected GOM production continues to increase in 2014, averaging 1.44 million bbl/d, as several relatively high-volume deepwater projects are expected onstream, including the Jack-St. Malo joint field development, Big Foot, Tubular Bells, and Lucius. Also expected onstream during 2014 is the Atlantis Phase 2 redevelopment project. The timing of and volumetric contribution from these projects is based on currently reported timetables.

Since peaking in 2005 at 12.5 million bbl/d, U.S. liquid fuel net imports, including crude oil, have been falling. Net imports declined to 7.5 million bbl/d in 2012, and EIA expects imports to continue declining to an average of 6.0 million bbl/d by 2014. Similarly, the share of total U.S. consumption met by liquid fuel net imports peaked at over 60 percent in 2005 and fell to an average of 40 percent in 2012, and EIA expects the net import share to average 32 percent in 2014 because of continued substantial increases in domestic crude oil production.

**U.S. Petroleum Product Prices.** Despite similar crude oil prices during 2011 and 2012, U.S. monthly average regular gasoline retail prices increased from an average of \$3.53 per gallon in 2011 to average \$3.63 per gallon in 2012, driven partly by isolated refinery outages and lower inventory levels on the East and West coasts. U.S. regular gasoline retail prices fell from an average of \$3.85 per gallon in September 2012 to an average of \$3.31 per gallon in December, which was the lowest average since December 2011. EIA expects regular-grade gasoline retail prices will average \$3.44 per gallon and \$3.34 per gallon in 2013 and 2014, respectively.

On-highway diesel fuel retail prices averaged \$4.12 per gallon in September 2012, and continued tight market conditions and strong demand for exports kept on-highway diesel fuel prices at an average of \$3.96 per gallon in December. On November 23, 2012, U.S. week-ending stocks of distillate fuel oil fell to their lowest level since May 30, 2008, despite the higher expected demand during the current winter heating season. Distillate inventories have since recovered, especially in the Northeast, though still remaining well below their five-year average. After averaging \$3.97 per gallon in 2012, EIA expects that on-highway diesel fuel retail prices will average \$3.87 per gallon in 2013 and \$3.78 per gallon in 2014. Wholesale diesel margins (the difference between the wholesale price of diesel and the U.S. average refiner acquisition cost of crude oil) averaged \$0.60 per gallon in the first half of 2012, and then climbed to an average of \$0.92 per gallon in November, the highest monthly average since October 2005. EIA projects wholesale diesel margins will average \$0.75 per gallon in 2013 and \$0.63 per gallon in 2014, compared with the previous five-year (2007-11) average of \$0.54 per gallon.

## Natural Gas

**U.S. Natural Gas Consumption.** EIA expects that natural gas consumption will average 69.7 billion cubic feet per day (Bcf/d) in 2013 and 69.4 Bcf/d in 2014. While total consumption is relatively unchanged from 2012, the makeup of consumption changes. Because of a warm winter last year, 2012 residential and commercial consumption was very low, and the hot summer (as well as relatively low natural gas prices) led to record-high use of natural gas for power generation. Forecasts for closer-to-normal temperatures in 2013 and 2014 will lead to increases in natural gas used for residential and commercial space heating. These increases are offset by declines in natural gas for power generation, as summer temperatures are expected to be closer to normal, meaning cooler than they were in 2012.

Despite projected declines in electric power consumption from 2012 levels, consumption of natural gas for electric power generation remains high by historical standards and reflects a structural shift toward using more natural gas for power generation. While the shift toward more natural gas for power generation has been most evident in the [Southeast](#), other major consuming areas have also increased natural gas consumption. [Increased pipeline flows in New England](#) during the summer months, for example, represent an increasing reliance on natural gas for power generation.

**U.S. Natural Gas Production and Imports.** This month's STEO expects continued growth in natural gas production, driven largely by onshore production in shale areas. In particular, production in the Marcellus Shale areas of Pennsylvania and West Virginia is expected to continue rising, as recently drilled wells become operational. Despite relatively low natural gas prices, [Pennsylvania drilling](#) continues at a strong pace as producers target combination oil-and-gas wells. Production has been rising despite large decreases in the natural gas rig count over the past year. According to Baker Hughes, the natural gas rig count was 431 as of December 28, 2012, compared with 811 at the start of 2012. The oil rig count has also declined in recent months (oil rigs often produce associated natural gas), although declines have been much

smaller than declines in the natural gas rig count. The declines in rig counts, coupled with continued production growth, suggest increases in rig efficiency, which will maintain production levels going forward.

This month's STEO expects that total marketed production will increase from 69.2 Bcf/d in 2012 to 69.8 Bcf/d in 2013, and drop slightly to 69.5 Bcf/d in 2014. EIA expects growth in Lower 48 onshore production will continue through 2014, and will be offset by Gulf of Mexico declines next year.

Domestic supply continues to displace pipeline imports from Canada and liquefied natural gas (LNG) imports. EIA expects pipeline gross imports will stay mostly flat in 2013. Projected pipeline imports drop by 0.4 Bcf/d (4.5 percent) in 2014. Gross exports to Mexico have grown substantially since 2010, but EIA expects exports will stay flat in 2013 and increase by 0.2 Bcf/d (5.5 percent) the following year. LNG imports are expected to remain at minimal levels of less than 0.5 Bcf/d in both 2013 and 2014. Exports mainly arrive at the Elba Island terminal in Georgia and the Everett terminal in New England, either to fulfill long-term contract obligations or to take advantage of temporarily high local prices due to cold snaps and disruptions. Higher prices for LNG elsewhere in the world have made the United States a market of last resort for LNG suppliers.

**U.S. Natural Gas Inventories.** Inventories of working natural gas in storage remain at high levels, after setting an all-time weekly record in November 2012. As of December 28, working gas stocks totaled 3,517 Bcf, which is 23 Bcf greater than the same time in 2011 and 389 Bcf greater than the previous five-year (2007-11) average, according to EIA's [\*Weekly Natural Gas Storage Report\*](#). So far this winter, withdrawals have been limited, mainly because of warmer-than-normal temperatures in December. Five-year average weekly withdrawals in December are generally well above 100 billion cubic feet, but that occurred only during the last week of the month. For the week ending December 7, 2012, working gas inventories posted a net *injection* of 2 Bcf. Only two other net injections have been reported in the month of December: one in 2005 and the other time in 1998.

**U.S. Natural Gas Prices.** Natural gas spot prices averaged \$3.34 per MMBtu at the Henry Hub in December 2012, down \$0.20 per MMBtu from the November 2012 average and \$0.17 per MMBtu more than the December 2011 average. The warm December partially led to the month-over-month decline in prices. Through 2014, EIA expects prices will gradually rise but still remain relatively low. EIA expects the Henry Hub price will average \$3.74 per MMBtu in 2013 (compared to \$2.75 per MMBtu in 2012) and \$3.90 per MMBtu in 2014.

Natural gas futures prices for April 2013 delivery (for the five-day period ending January 3, 2013) averaged \$3.38 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for April 2013 contracts at \$2.42 per MMBtu and \$4.73 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for April 2012 averaged \$3.11 per MMBtu and the corresponding

lower and upper limits of the 95-percent confidence interval were \$2.15 per MMBtu and \$4.49 per MMBtu.

## Coal

**U.S. Coal Consumption.** EIA estimates coal consumption in the electric power sector totaled 829 million short tons (MMst) in 2012, the lowest amount since 1992. Lower natural gas prices paid by electric generators led to a significant increase in the share of natural gas-fired generation. Higher natural gas prices, coupled with slightly higher electricity demand, will lead to an increase in coal-fired generation over the forecast period.

**U.S. Coal Supply.** EIA estimates coal production declined by 6.3 percent in 2012 along with a drop in domestic consumption. Coal production is expected to decline by a further 3.6 percent in 2013 as primary and secondary inventory draws combined with a small increase in coal imports meet a small consumption increase in 2013. Although EIA forecasts that coal consumption will remain flat and that inventories will stabilize in 2014, production is forecast to grow by 3 percent as coal exports rise.

**U.S. Coal Trade.** EIA estimates coal exports totaled a record 124 MMst in 2012. Continuing economic weakness in Europe and lower international coal prices are expected to contribute to lower coal exports in 2013. U.S. metallurgical coal exports could be reduced if China removes an export tariff on Chinese coke, which steel producers import in lieu of metallurgical coal.

**U.S. Coal Prices.** Delivered coal prices to the electric power industry increased steadily over the 10-year period ending in 2011, when the delivered coal price averaged \$2.39 per MMBtu (a 6-percent increase from 2010). EIA expects that changing market conditions, including weaker domestic demand for coal and higher coal inventories, will slow increases in coal prices and contribute to the shut-in of higher-cost production. EIA forecasts that the delivered coal price will average \$2.40 per MMBtu in 2012, \$2.44 per MMBtu in 2013, and \$2.50 in 2014.

## Electricity

**U.S. Electricity Consumption.** Most regions of the United States experienced temperatures that were much warmer than normal during 2012, in both the winter and the summer. Based on the assumption that temperatures return closer to normal, EIA expects residential electricity sales during the winter months of 2013 will be higher than last year while summer electricity sales will be lower, leading to a projected annual decline of 0.3 percent during 2013. Weather during 2014 is assumed to be similar to that in 2013. The primary driver of residential electricity sales in 2014 is growth in the number of customers, which will be tempered somewhat by increased efficiency in residential electricity consumption. EIA projects retail sales to the residential sector will grow by 0.1 percent during 2014.

Growth in industrial electricity consumption picks up in the second half of 2013 when industrial electricity sales show year-over-year growth of 0.7 percent. During 2014, industrial electricity sales grow by 1.8 percent.

**U.S. Electricity Generation.** EIA expects total generation of electricity to remain largely unchanged in 2013 and to grow by 94 gigawatthours per day (GWh/d) (0.8 percent) in 2014. An expected 32-percent increase in the price of natural gas delivered to power generators drives a 264-GWh/d reduction in the use of natural gas in 2013, resulting in a fuel share of 27.9 percent of total generation compared with a share of 30.3 percent in 2012. The decline in natural gas generation this year is offset by a 166-GWh/d increase in coal generation (raising the coal share of generation from 37.6 percent in 2012 to 39.0 percent in 2013), a 75-GWh/d increase in generation from renewables, and a 32-GWh/d increase in nuclear generation.

EIA forecasts natural gas will account for 27.5 percent of total generation in 2014 and coal will account for 39.6 percent, both relatively unchanged from the projected 2013 fuel shares. However, there is a high degree of uncertainty in the generation fuel mix forecast. Lower-than-projected natural gas prices along with the industry's response to future environmental regulations could cause the natural gas share of total generation to exceed this forecast.

**U.S. Electricity Retail Prices.** Rising costs of infrastructure upgrades continue to drive increases in residential electricity rates, although lower fuel prices in recent years have kept growth in retail rates relatively modest. After an increase of 1.3 percent during 2012, EIA expects retail residential electricity prices will grow by 1.9 percent in 2013 and by 2.6 percent in 2014.

## Renewables and Carbon Dioxide Emissions

**U.S. Renewables.** Total renewable energy consumption is estimated to have declined by 2.5 percent in 2012 as the decline in hydropower from 2011 to 2012 more than offset the projected growth in the consumption of other renewable energy forms. This decrease was the result of hydropower production falling by 0.4 quadrillion Btu (13.7 percent) as the Pacific Northwest fell from the unusually high levels seen in 2011. Renewable energy consumption increases 3.6 percent in 2013 as hydropower is projected to grow by 1.7 percent and nonhydropower renewables grow by an average of 4.4 percent. In 2014 the growth in total renewables is projected to continue at a rate of 1.7 percent as a 2.4-percent decline in hydropower is more than offset by a 3.7-percent increase in nonhydropower renewables.

The federal production tax credit (PTC) for wind-powered generation and other renewable energy sources has been extended beyond 2012 as part of the compromise related to the fiscal cliff. This month's STEO does not include the potential effect of the PTC extension on the wind and other renewable energy generation capacity forecasts.

Wind-powered generation grew by 17 percent in 2012. Based on current reporting to EIA, more than 5 gigawatts of [wind capacity](#) was scheduled to come on line in December 2012, in addition

to the approximately 6 gigawatts that entered service from January through November of 2012. This is projected to lead to an additional 13-percent increase in wind generation in 2013 as compared to 2012, as this new capacity would be operating for the entire year. Very little new capacity was projected to come on line in 2013 prior to the PTC extension and, as a result, growth in generation in 2014 is projected to be flat. Projections for capacity additions may differ in future STEOs as the impact of the PTC extension is addressed.

Solar energy continues robust growth, although the total amount remains small compared to total U.S. generation. Consumption is projected to grow by 32 percent in 2012, 31 percent in 2013 and 28 percent in 2014.

Because of drought conditions depressing corn harvests throughout the Midwest, fuel ethanol production fell from an average of 900,000 bbl/d during the first half of 2012 to an average of 820,000 bbl/d in the second half of the year. EIA expects ethanol production will remain near current levels through mid-2013 before recovering to pre-drought production levels, averaging 870,000 bbl/d (13.3 billion gallons) for the year. Ethanol production is expected to rebound in 2014 as previously idled capacity comes back on line to meet the increasing Renewable Fuel Standard (RFS) mandate. Ethanol production averages 915,000 bbl/d (14.0 billion gallons) in 2014, meeting the RFS mandate along with banked Renewable Identification Number (RIN) credits generated in previous years. The ethanol share of the gasoline pool increases from an average 9.6 volume percent in 2012 to just under 11 volume percent by the end of 2014, which implies a need to expand from the current 10 gas stations with [E-15 blending pumps](#) and 2,500 [E-85 stations](#).

The \$1-per-gallon biodiesel excise tax credit was recently retroactively reinstated beginning January 1, 2012, through the end of 2013 as part of the year-end fiscal package. This STEO does not include the possible impact of the biodiesel tax credit on the biodiesel forecast. Biodiesel production averaged about 65,000 bbl/d (1.00 billion gallons) in 2012. Forecast biodiesel production averages 74,000 bbl/d in 2013 and 2014, with biodiesel blending meeting the RFS requirement of 1.28 billion gallons set for 2013.

**U.S. Energy-Related Carbon Dioxide Emissions.** Fossil fuel emissions are estimated to have declined by 3.4 percent in 2012. This decline is projected to be followed by an increases of 0.9 percent in 2013 and 0.5 percent in 2014.

## U.S. Economic Assumptions

This new section of the STEO discusses the macroeconomic assumptions built into EIA's short-term energy forecasts. The economic projections in the STEO are derived from the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs. The GI model used in this STEO assumes that there are tax increases on higher-income earners beginning in 2013 and modest cuts to government spending, which are implemented in 2014.

**Current Trends.** Recent indicators continue to point to a modest economic recovery, and key sectors such as housing are improving. The [NAHB Housing Index](#) has risen for 8 consecutive months to levels last seen in 2006. The unemployment rate in December was 7.8 percent, unchanged from November, while [nonfarm payroll employment](#) grew by 155,000. The [ISM Manufacturing Index](#) rose in December to 50.7 (a value above 50 indicates expansion). One important indicator of financial market uncertainty, the [Federal Reserve Bank of Chicago's National Financial Conditions Index \(NFCI\)](#), is currently below its average level of zero and relatively unchanged from November.

**U.S. Output.** The STEO forecast for U.S. gross domestic product (GDP) growth in 2013 is 1.8 percent, rising to 2.6 percent in 2014. Growth starts out slowly in 2013 and then gradually increases throughout the year, reaching 2.2 percent in the fourth quarter of 2013. The same pattern is repeated in 2014, with real GDP growth reaching 2.9 percent in the fourth quarter. Residential investment and exports are important drivers of this growth in both years.

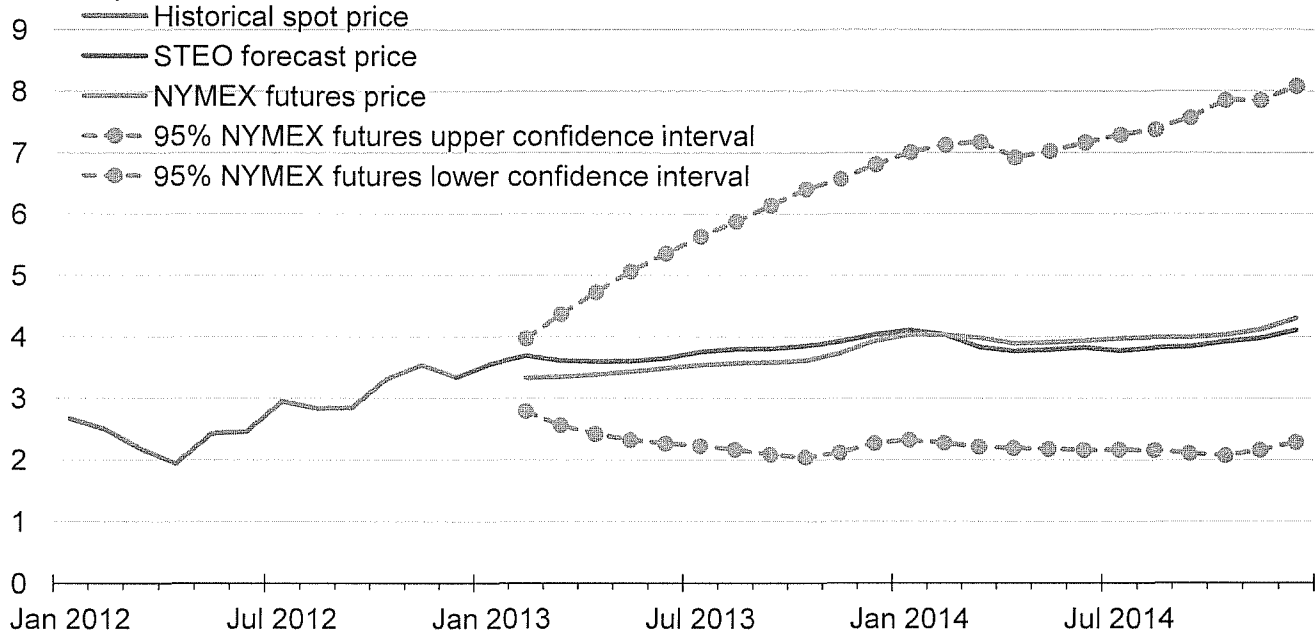
Total industrial production grows at a faster rate than real GDP in 2013 and 2014, at 1.9 percent and 2.9 percent, respectively. Industrial production growth in the manufacturing sector is slower than total production in 2013 at 1.8 percent, but accelerates to 3.4 percent in 2014. Both of these indexes mirror the rises in demand due to higher growth in real GDP.

**U.S. Income and Expenditures.** Consumption expenditures begin to pick up in 2014, rising by 2.4 percent compared with 2.0-percent growth forecast in 2013. This is partly due to higher real disposable income, which rises during this time period as well. Private fixed investment jumps to 9.2-percent growth in 2014 from 5.8 percent the year before, highlighting its importance for overall economic expansion, and export growth accelerates as well. Government expenditures fall more than 1 percent in both years.

**U.S. Employment, Housing, and Prices.** The unemployment rate in the forecast gradually falls from an average of 7.8 percent in 2013 to 7.5 percent in 2014. This will be accompanied by non-farm employment growth averaging just above 1.5 percent in both years. Housing starts stand out in this forecast, as they are projected to increase nearly 25 percent in 2013 and over 32 percent in 2014. Both consumer and producer prices continue to increase at a moderate pace. The consumer price index (CPI) for urban consumers averages annual growth of 1.8 percent in 2013 and 1.9 percent in 2014. The producer price index (PPI) for all commodities is forecast to increase by 1.4 percent year-on-year in 2013, slowing to 0.8-percent growth in 2014.

## Henry Hub Natural Gas Price

dollars per million btu



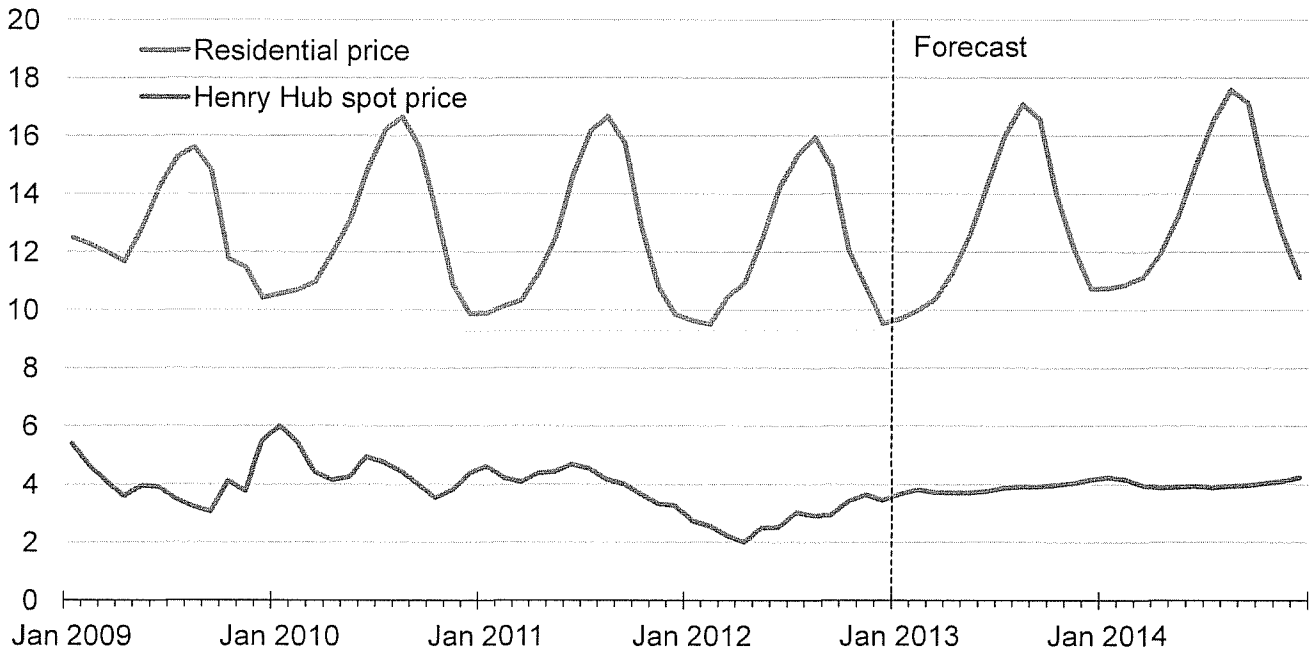
Note: Confidence interval derived from options market information for the 5 trading days ending January 3, 2013. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, January 2013



## U.S. Natural Gas Prices

dollars per thousand cubic feet



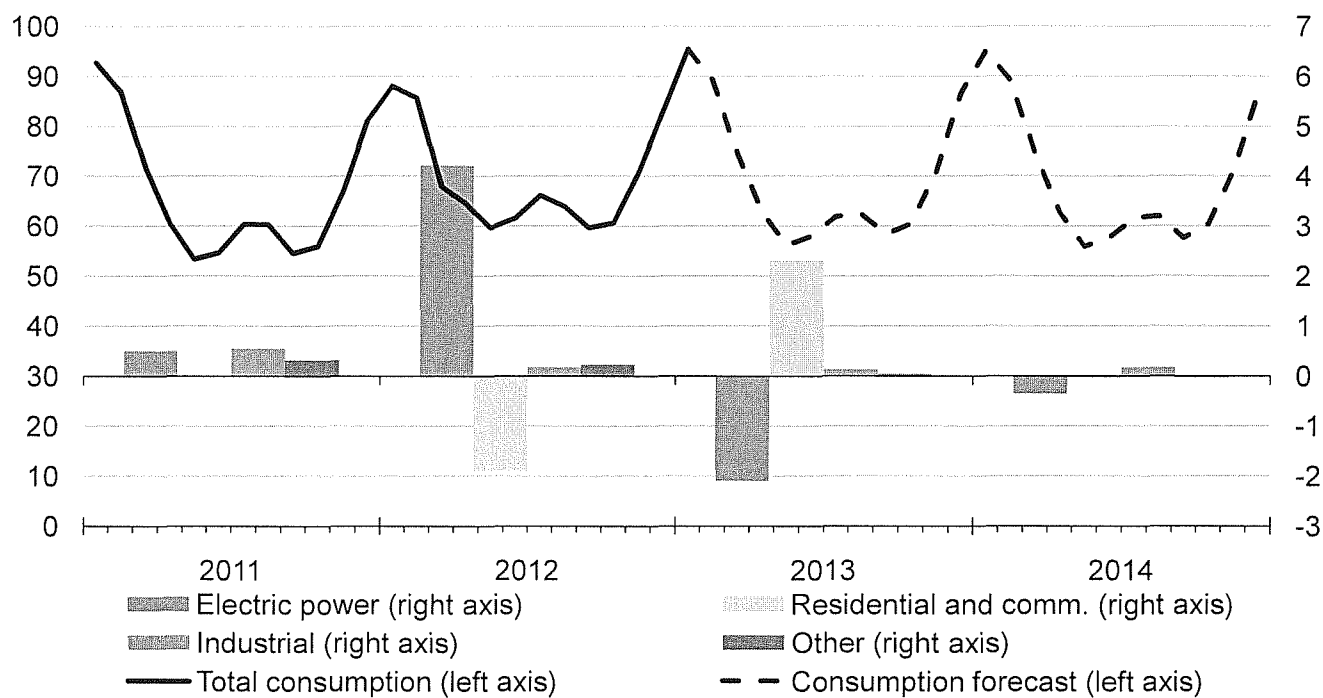
Source: Short-Term Energy Outlook, January 2013



## U.S. Natural Gas Consumption

billion cubic feet per day (bcf/d)

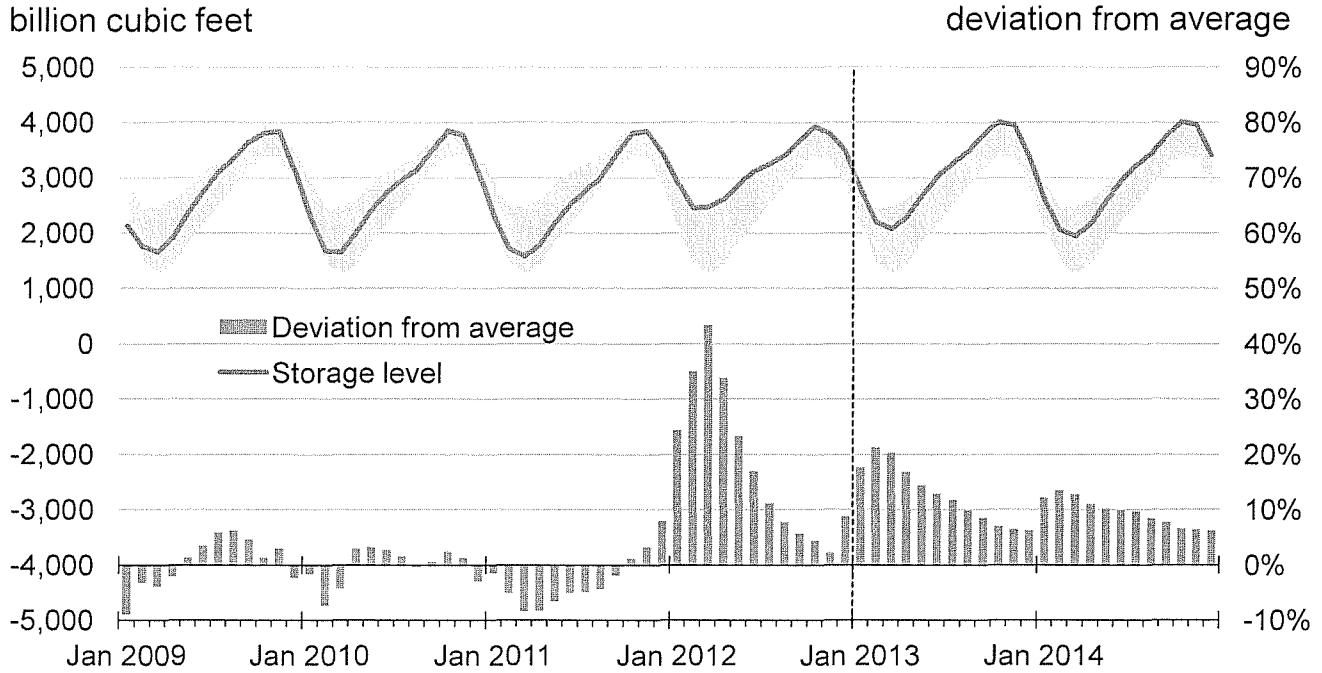
annual change (bcf/d)



Source: Short-Term Energy Outlook, January 2013



## U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2008 - Dec. 2012.

Source: Short-Term Energy Outlook, January 2013



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

**NorthWestern Energy**

On December 12, 2012, NorthWestern Energy filed its 2013 Electric and Natural Gas State and Local Tax and Fee Tracker filing in Docket No. D2012.12.124 to be effective January 1, 2013. On December 24, 2012, NorthWestern Energy filed revised rate schedules. On December 26, 2012, the Montana Public Service Commission issued a Letter Order for rates to be effective January 1, 2013.

Approximate impact on Montana-Dakota's cost of gas: 0.1 cents per dk

MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS TARIFF SHEET  
NORTH DAKOTA GAS  
EFFECTIVE FEBRUARY 2013

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<b><u>Gas Cost Adjustment:</u></b>				
Gas Cost Level (Exhibit B)	\$4.774	\$4.874	\$3.752	\$3.735
Prior Gas Cost	4.603	4.704	3.569	3.553
Current Gas Cost Adjustment	\$0.171	\$0.170	\$0.183	\$0.182
<b><u>Surcharge Adjustment:</u></b>				
Current Adjustment	(\$0.113)	(\$0.113)	(\$0.115)	(\$0.377)
Prior Adjustment	(0.113)	(0.113)	(0.115)	(0.377)
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<b><u>Market Based Pricing Differential</u></b>				
Current Adjustment	(\$0.010)	(\$0.010)	\$0.000	\$0.000
Prior Adjustment	(0.010)	(0.010)	0.000	0.000
Change in Margin Sharing Provision	\$0.000	\$0.000	\$0.000	\$0.000
<b>Net Increase (Decrease) in Gas Costs</b>	<b>\$0.171</b>	<b>\$0.170</b>	<b>\$0.183</b>	<b>\$0.182</b>
Gas Cost Level	\$4.774	\$4.874	\$3.752	\$3.735
Plus: Surcharge	(0.113)	(0.113)	(0.115)	(0.377)
<b>Total Gas Cost Level in Tariff Rates</b>	<b>\$4.661</b>	<b>\$4.761</b>	<b>\$3.637</b>	<b>\$3.358</b>

MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS - PROPANE TARIFF SHEET  
NORTH DAKOTA PROPANE  
EFFECTIVE FEBRUARY 2013

**Cost of Gas - Propane**

Current Propane Cost (Exhibit D)	\$10.429
Prior Propane Cost	<u>9.880</u>
Current Propane Cost Adjustment	<u><u>\$0.549</u></u>

**Surcharge Adjustment**

Current Adjustment	\$0.646
Prior Adjustment	<u>0.646</u>
Change in Surcharge Adjustment	\$0.000

**Market Based Pricing Differential**

Current Adjustment	(\$0.010)
Prior Adjustment	<u>(0.010)</u>
Change in Margin Sharing Provision	\$0.000

**Net Increase (Decrease) in Gas Costs** \$0.549

Propane Cost Level	\$10.429
Plus: Surcharge	<u>0.646</u>
Total Propane Cost Level in Rates	<u><u>\$11.075</u></u>

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
RESIDENTIAL AND GENERAL SERVICE  
EFFECTIVE FEBRUARY 2013**

	Amount
Total Gas Costs 1/	\$68,583,896
Residential and General Service dk Requirements 2/	14,430,720
Average Cost of Gas per dk	\$4.753
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.774
Less: Gas Cost Level in Rates 3/	4.603
<b>Current Gas Cost Adjustment</b>	<b>\$0.171</b>

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 November 30, 2012, adjusted for losses at .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective January 1, 2013:

Cost of Purchased Gas	\$4.582
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.603

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
OPTIONAL SEASONAL - RATE 72  
EFFECTIVE FEBRUARY 2013**

Total Gas Costs 1/	\$68,583,896
Less: Annual MDDQ Costs 1/	<u>13,436,528</u>
Total Gas Costs excluding MDDQ	\$55,147,368
Firm Service Requirements 1/	14,430,720
Other Gas Costs per Dk (excluding MDDQ)	\$3.822
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$13,436,528
Winter Firm Service Requirements	13,042,384
MDDQ Costs per Winter Dk	\$1.030
Add: Other Gas Costs per Dk	<u>3.822</u>
Winter Seasonal Rate	\$4.852
Winter Seasonal Rate, adjusted for losses 2/	\$4.874
Less: Gas Cost Level in Rates 3/	<u>4.704</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.170</u></u></b>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective January 1, 2013:

	<u>Winter</u>
Cost of Purchased Gas	\$4.683
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.704

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
INTERRUPTIBLE  
EFFECTIVE FEBRUARY 2013**

	Amount
Total Gas Costs 1/	\$13,082,005
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$3.735
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.752
Less: Gas Cost Level in Rates 2/	3.569
<b>Current Gas Cost Adjustment</b>	<b>\$0.183</b>

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-12-008 effective January 1, 2013:

Cost of Purchased Gas	\$3.553
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.569



**Montana-Dakota Utilities Co.  
Schedule of Applicable Effective Pipeline Rates  
February 2013 PGA**

WBI Energy Transmission, Inc. - Exhibit B, pages 6 - 8 for Schedules FT-1, FTN-1, and FS-1.

Northern Border Pipeline Company - Exhibit B, page 9 for Schedule T-1.

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

NOVA Gas Transmission - Exhibit B, pages 10-11 for Schedule FT-D.

NorthWestern Energy - Exhibit B, page 12 for Schedule T-FTG-1.

South Dakota Intrastate Pipeline - Exhibit B, page 13 for Rate 1.

SourceGas Distribution LLC - Exhibit B, Page 14 for Schedule TC.

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	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.	737.928	N.A.	N.A.	N.A.	737.928
MINIMUM	RATE PER EQV. DKT PER MO	0.000	N.A.	N.A.	N.A.	0.000
COMMODITY CHARGE						
MAXIMUM A/B/	RATE PER DKT	3.120	0.180	N.A.	N.A.	3.300
MINIMUM A/B/	RATE PER DKT	3.120	0.180	N.A.	N.A.	3.300
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.180	N.A.	N.A.	31.064
MINIMUM A/B/	RATE PER DKT	3.120	0.180	N.A.	N.A.	3.300
VOLUMETRIC CAPACITY RELEASE CHARGE						
MAXIMUM	RATE PER DKT	24.261	N.A.	N.A.	N.A.	24.261
MINIMUM	RATE PER DKT	0.000	N.A.	N.A.	N.A.	0.000

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 1.932%, CONSISTING OF 2.209% FOR THE CURRENT PERCENTAGE AND (0.277%) FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR TRANSPORTATION. THE APPLICABLE RATE IS 0.801 CENTS, CONSISTING OF 0.677 CENTS FOR THE CURRENT RATE AND 0.124 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.

Issued On: August 31, 2012  
 Docket Number: RP12-986-000  
 FERC Order Date: September 27, 2012

Effective On: October 1, 2012

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	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.	47.491	N.A.	N.A.	N.A.	47.491
MINIMUM	RATE PER EQV. DKT PER MO.	1.589	N.A.	N.A.	N.A.	1.589
VOLUMETRIC CAPACITY RELEASE CHARGE						
MAXIMUM	RATE PER DKT	1.561	N.A.	N.A.	N.A.	1.561
MINIMUM	RATE PER DKT	0.052	N.A.	N.A.	N.A.	0.052

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	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.	2.102	N.A.	N.A.	N.A.	2.102
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
CAPACITY DELIVERABILITY CHARGE						
MAXIMUM	RATE PER EQV. DKT PER MO.	190.602	N.A.	N.A.	N.A.	190.602
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
INJECTION CHARGE						
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
WITHDRAWAL CHARGE						
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
SCHEDULED OVERRUN CHARGE						
INJECTION						
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
WITHDRAWAL						
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 0.938%, CONSISTING OF 0.863% FOR THE CURRENT PERCENTAGE AND 0.075% FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR STORAGE. THE APPLICABLE RATE IS 0.528 CENTS, CONSISTING OF 0.323 CENTS FOR THE CURRENT RATE AND 0.205 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

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.1.0.0 Superseding v.0.0.0

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	\$0.0321
Minimum	\$0.0000
Daily Reservation Rate - Ventura, IA to North Hayden, IN	
Maximum	\$0.0345
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 Base Rates, pursuant to the Stipulation at Docket No. RP06-72-000, et al., remain in effect until such rates are superseded by new base 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 X of the Stipulation at Docket No. 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) \$ 197.27/10 <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>3</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 \$ 5.34/GJ FT-D Demand Rate for Group 2 Delivery Points <sup>1</sup> \$ 3.12/GJ FT-D Demand Rate for Group 3 Delivery Points <sup>2</sup> \$ 3.74/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>3</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	11.07	
	6-10 years	9.25	
	15 years	8.30	
	20 years	7.36	
8. Rate Schedule LRS-2	LRS-2 Rate per month	\$ 50,000	
9. Rate Schedule LRS-3	LRS-3 Demand Rate per month	\$ 129.55/10 <sup>3</sup> m <sup>3</sup>	
10. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
11. Rate Schedule IT-D <sup>3</sup>	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point		
12. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
13. Rate Schedule PT	<u>Schedule No</u> 9009-01001-1	<u>PT Rate</u> \$ 660.00/d	<u>PT Gas Rate</u> 50.0 10 <sup>3</sup> m <sup>3</sup> /d
14. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2012519486	\$ 22.00	/ month
	2012515644	\$ 8.00	/ month
	2012515643	\$ 14.00	/ month
	2012515647	\$ 2.00	/ month
	2012515648	\$ 1.00	/ month
	2012515639	\$ 2,082.00	/ month
	2012515642	\$ 2.00	/ month
	2012515641	\$ 55.00	/ month
	2012515650	\$ 126.00	/ month
	2012515645	\$ 70.00	/ month
	2012515646	\$ 19.00	/ month
	2012515651	\$ 226.00	/ month
	2012515640	\$ 203.00	/ month
	2003004522	\$ 83,333.00	/ month
	2011476052 / 2011476054	\$ 0.1026	/ GJ subject to
		\$ 717,000.00	Minimum Annual Charge
	2011475772	\$ 9,250.00	/ month
	2011475056	\$ 0.095	/ GJ and
		\$ 1,000.00	/ month
	2011476092	\$ 0.095	/ GJ and
		\$ 1,000.00	/ month
	2011494569	\$ 0.095	/ GJ and
		\$ 1,000.00	/ month

NOVA Gas Transmission Ltd.

Attachment 2  
Table of Rates, Tolls and Charges  
Page 1 of 5

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	5.38	0.1945
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	3.12	0.1128
31110	ALLIANCE EDSON INTERCONNECT APN	3.12	0.1128
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	3.12	0.1128
3002	BOUNDARY LAKE BORDER	3.33	0.1204
1958	EMPRESS BORDER	5.29	0.1912
3886	GORDONDALE BORDER	3.33	0.1204
6404	MCNEILL BORDER	5.29	0.1912

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	3.39	0.1226	Yes
31001	ADM AGRI INDUSTRIES SALES APN	3.39	0.1226	Yes
3880	AECO INTERCONNECTION	3.12	0.1128	
31003	AGRIUM CARSELAND SALES APS	3.12	0.1128	
31002	AGRIUM FT. SASK SALES APN	3.12	0.1128	Yes
31004	AGRIUM REDWATER SALES APN	3.12	0.1128	
31005	AINSWORTH SALES APGP	3.39	0.1226	
31006	AIR LIQUIDE SALES APN	3.39	0.1226	
3214	AKUINU RIVER WEST SALES	3.12	0.1128	
31007	ALBERTA ENVIROFUELS SALES APN	3.39	0.1226	Yes <sup>2</sup>
31008	ALBERTA HOSPITAL SALES APN	3.39	0.1226	Yes
3868	ALBERTA-MONTANA BORDER	3.33	0.1204	
3059	ALLISON CREEK SALES	3.12	0.1128	
31009	ALTASTEEL SALES APN	3.39	0.1226	Yes <sup>2</sup>
3562	AMOCO SALES (BP SALES TAP)	3.12	0.1128	
31012	APL JASPER SALES APN	3.39	0.1226	Yes
3488	ARDLEY SALES	3.12	0.1128	
3216	AURORA NO 2 SALES	3.12	0.1128	
3135	AURORA SALES	3.12	0.1128	
3423	BASHAW WEST SALES	3.12	0.1128	
31013	BAYMAG SALES APS	3.12	0.1128	
31014	BEAR CREEK COGEN SALES APGP	3.39	0.1226	
3068	BEAVER HILLS SALES	3.12	0.1128	
3933	BIG EDDY INTERCONNECTION	3.12	0.1128	
3067	BIGSTONE SALES	3.12	0.1128	
3468	BLEAK LAKE SALES	3.12	0.1128	
3225	BOTHA SALES	3.12	0.1128	
3164	BRAINARD LAKE SALES	3.12	0.1128	
3918	BUFFALO CREEK INTERCONNECTION	3.12	0.1128	
31015	BURDETT COGEN SALES APS	3.12	0.1128	
3204	CABIN SALES	3.12	0.1128	
3109	CALDWELL SALES	3.12	0.1128	
31016	CALGARY ENERGY CENTRE SALES APS	3.12	0.1128	Yes
3634	CANOE LAKE SALES	3.12	0.1128	
3165	CANOE LAKE SALES NO 2	3.12	0.1128	
3866	CARBON INTERCONNECTION	3.12	0.1128	
3484	CARIBOU LAKE SALES	3.12	0.1128	
3157	CARIBOU LAKE SOUTH SALES	3.12	0.1128	
3106	CARMON CREEK SALES	3.12	0.1128	
3101	CAROLINE SALES	3.12	0.1128	
31017	CARSELAND COGEN SALES APS	3.12	0.1128	
3495	CAVALIER SALES	3.12	0.1128	
31018	CHAIN LAKES COOP SALES APS	3.12	0.1128	
3907	CHANCELLOR INTERCONNECTION	3.12	0.1128	
3151	CHEECHAM WEST NO 2 SALES	3.12	0.1128	
3622	CHEECHAM WEST SALES	3.12	0.1128	
6014	CHEVRON AURORA SALES	3.12	0.1128	
31019	CHEVRON FT. SASK SALES APN	3.39	0.1226	Yes

NATURAL GAS TARIFF



Canceling  $\frac{30^{\text{th}}}{29^{\text{th}}}$  Revised Revised Sheet No. 80.1  
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:

<u>Meters Rated @</u> <u>Cu. Ft. per hour</u>	<u>Per Meter</u> <u>Charge</u>	
5,001 to 10,000	\$ 104.90	(I)
10,001 to 30,000	\$ 150.85	(I)
>30,000	\$ 334.80	(I)

**PLUS:**

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	\$ 0.8578501	(I)
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Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	\$ 0.0065006	(I)
Minimum	\$ 0.0017935	
GTAC Amortization	\$ (0.0010312)	
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. D2012.12.124  
Tariff Letter No. 219-G  
By Operation of Law

Effective for service rendered on or after  
January 1, 2013

PUBLIC SERVICE COMMISSION

*Aleisha Salem* Secretary

**GAS RATE SCHEDULE**

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

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

Date Filed: January 24, 2001

Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is \$2.398 per dekatherm.

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

NG-00-001

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

**South Dakota Intrastate Pipeline Company**

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5  
Fourth Revised Sheet No. 12  
Cancels Third Revised Sheet No. 12

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

<u>Division</u>	<u>Receipt Point</u>	<u>Delivery Point</u>	<u>Monthly Customer Charge</u>	<u>Maximum Transportation Charge 2/</u>	<u>Minimum Transportation Charge 2/</u>	<u>Fuel Reimbursement Quantity Percentage 3/</u>
TC (Casper) Firm Transportation	MLI	MLI	\$0.00	\$0.1040	\$0.0010	0.611%
	MLI	MLE	\$145.00	\$0.1040	\$0.0010	0.611%
	MLI	DSE	\$225.00	\$0.1978	\$0.0020	2.072%
Interruptible Transportation 4/	MLI	MLI	\$0.00	\$0.0844	\$0.0010	0.611%
	MLI	MLE	\$145.00	\$0.0844	\$0.0010	0.611%
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.

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

Date Issued: March 1, 2012  
By: William N. Cantrell

Date Effective: June 1, 2012  
Title: President and CEO

**MONTANA-DAKOTA UTILITIES CO.  
RETURN ON CYCLE STORAGE BALANCES  
AND PREPAID DEMAND AND COMMODITY BALANCES  
NORTH DAKOTA GAS  
EFFECTIVE FEBRUARY 2013**

	General Service		
	Storage Balance 1/	Commodity Balance 2/	Prepaid Demand
October 2012	\$12,647,019	\$616,455	\$3,086,520
November	11,646,866	563,796	2,521,344
December	8,782,122	421,376	1,200,073
January 2013	4,316,575	269,692	(528,253)
February	1,174,738	162,970	(1,542,651)
March	(845,007)	94,363	(2,183,143)
April	(873,082)	93,409	(1,970,551)
May	335,593	147,457	(1,156,565)
June	2,191,198	230,433	(44,902)
July	4,460,164	331,893	1,116,000
August	8,012,745	490,992	2,259,557
September	10,767,527	614,264	3,156,564
October	11,907,425	665,258	3,417,991
13 month average	<u>\$5,732,606</u>	<u>\$361,720</u>	<u>\$717,845</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$503,953	\$31,799	\$63,106
Return Requirement	<u>\$687,224</u>	<u>\$43,363</u>	<u>\$86,056</u>

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

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

MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS - PROPANE  
NORTH DAKOTA  
EFFECTIVE FEBRUARY 2013

Cost of Purchased Propane	\$65,408
Gallons Purchased	68,851
Projected dk Sales	6,300
Propane Cost per Dk	\$10.382
Average Cost of Propane as Adjusted for Losses @ 99.55%	10.429
Less: Propane Cost Level in Rates 1/	<u>9.880</u>
Current Propane Cost Adjustment	<u><u>\$0.549</u></u>

1/ Propane Cost Level in Current Rates - Case No. PU-12-008, effective January 1, 2013.

**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 &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, 2012</b>									<b><u>(\$1,670,167)</u></b>
August	(\$117,641)	\$0	(\$140)	(\$117,781)	264,054	(\$0.032)	(\$8,450)	(\$109,331)	(1,779,498)
September	66,156	0	(163)	65,993	256,762	(0.032)	(8,216)	74,209	(1,705,289)
October	122,687	0	(143)	122,544	571,227	(0.113)	(37,497) 2/	160,041	(1,545,248)
November	519,117	0	(116)	519,001	1,182,061	(0.113)	(133,573)	652,574	(892,674)
<b>Balance @ November 30, 2012</b>									<b><u>(\$892,674)</u></b>

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

2/ Reflects 333,969.6 Dk @ (\$0.032) and 237,257.7 Dk @ (\$0.113).

**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, 2012</b>									<b><u>(\$144,649)</u></b>
August	(\$620)	\$0	(\$12)	(\$632)	34,895	\$0.064	\$2,233	(\$2,865)	(147,514)
September	20,949	0	(13)	20,936	50,462	0.064	3,230	17,706	(129,808)
October	(5,608)	0	(11)	(5,619)	61,663	(0.115)	2,121 2/	(7,740)	(137,548)
November	37,236	0	(10)	37,226	89,540	(0.115)	(10,297)	47,523	(90,025)
<b>Balance @ November 30, 2012</b>									<b><u>(\$90,025)</u></b>

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

2/ Reflects 51,466.6 Dk @ \$0.064 and 10,197.4 Dk @ (\$0.115).

**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, 2012</b>									<b><u>(\$189,388)</u></b>
August	(\$10,033)	\$0	(\$16)	(\$10,049)	3,688	\$0.041	\$151	(\$10,200)	(199,588)
September	2,337	0	(19)	2,318	4,426	0.041	181	2,137	(197,451)
October	(2,128)	0	(16)	(2,144)	8,573	(0.377)	352 2/	(2,496)	(199,947)
November	4,067	0	(15)	4,052	35,430	(0.377)	(13,357)	17,409	(182,538)
<b>Balance @ November 30, 2012</b>									<b><u>(\$182,538)</u></b>

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

2/ Reflects 8,573.0 Dk @ \$0.041.