

August 8, 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-13-008

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 (116th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered September 1, 2013.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.135 per dk since the last filing due to a decrease in the overall commodity price of gas. Attachment B explains the reasons for the decrease in the market price of gas. There has also been a change in pipeline rates as shown on Attachment C.

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

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.135 per dk for residential customers and firm general customers, a decrease of \$0.131 per dk for small and large interruptible customers and a decrease of \$0.130 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 September 2013. The average cost of gas for firm customers, adjusted for losses, is \$4.620.

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. There is no change in the cost of propane established in the June COG filing.

These proposed adjustments, calculated in accordance with Rate 88, will amount to a decrease of approximately \$70,600 for natural gas customers during the month of September 2013. All of Montana-Dakota's retail natural gas in North Dakota may be affected by this proposal. There were 98,952 natural gas customers in North Dakota as of July 31, 2013.

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:

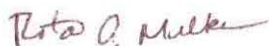
Mr. Daniel S. Kuntz
Associate General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

Montana-Dakota submitted a check for the amount of \$550 in accordance with North Dakota Century Code Section 49-05-05 on January 10, 2013. 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,



Rita A. Mulkern
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
 116th Revised Sheet No. 3
 Canceling 115th 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	\$4.497	\$5.309
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$4.497	\$4.635
Interruptible Service - PAR			\$0.120	\$3.538	\$3.658
Interruptible Service - MAFB			\$0.120	\$3.260	\$3.380
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	\$4.497	\$5.094
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$3.538	(Maximum) \$4.409
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	\$3.599	\$4.196
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.016	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.016	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$3.538	(Maximum) \$4.257
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$9.093	\$9.905
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	\$9.093	\$9.690

Date Filed: August 8, 2013

Effective Date:

Issued By: Tamie A. Aberle
 Director - Regulatory Affairs

Case No.:

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

September 2013

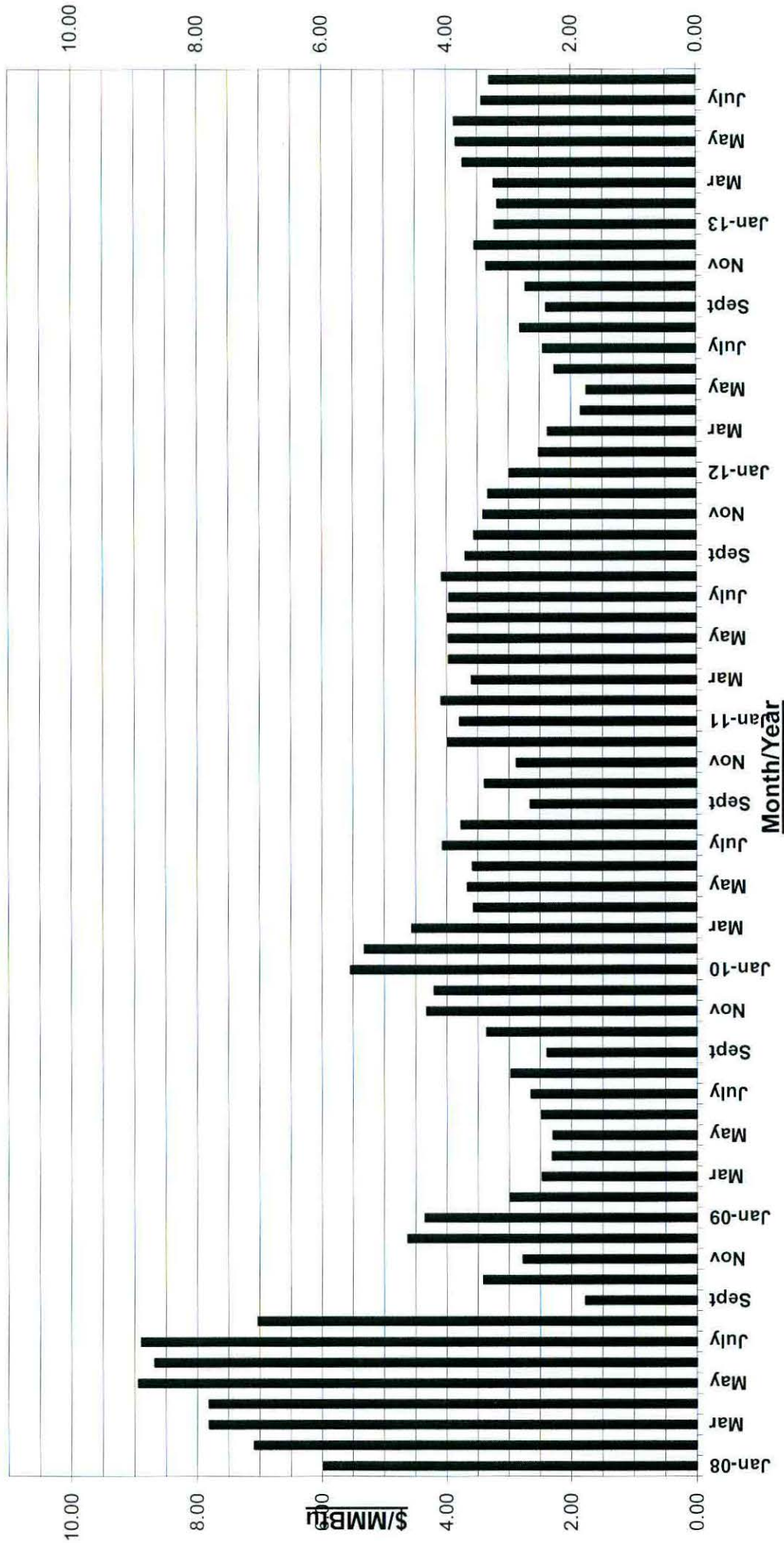
The established monthly price for the Rocky Mountain CIG Index has decreased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid 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 a fairly balanced supply and demand market in North America and the national storage level continuing to be near the five year average. Also, the country saw relatively stable pricing during July despite substantial swings in the price of day gas on the East coast. The Energy Information Administration (EIA) reported storage levels nationwide as of July 26, 2013 to be 1.2 percent below the five-year average and 11.5 percent below 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 August Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 18.

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 - \$3.47



Independent Statistics & Analysis

U.S. Energy Information
Administration

August 2013

Short-Term Energy Outlook (STEO)

Highlights

- Crude oil prices increased during the first three weeks of July 2013 as world oil markets tightened in the face of seasonal increases in world consumption, unexpected supply disruptions, and heightened uncertainty over the security of supply with the renewed unrest in Egypt. The U.S. Energy Information Administration (EIA) expects that the Brent crude oil spot price, which averaged \$108 per barrel over the first half of 2013, will average \$104 per barrel over the second half of 2013, and \$100 per barrel in 2014.
- The discount of West Texas Intermediate (WTI) crude oil to Brent crude oil, which averaged \$18 per barrel in 2012 and increased to a monthly average of \$21 per barrel in February 2013, closed below \$1.50 per barrel on July 19, 2013, and averaged \$3 per barrel for the month. The strong demand for light, sweet crude oil in the Midwest and new pipeline capacity to deliver production from the West Texas Permian Basin directly to the Gulf Coast contributed to the price of WTI rising relative to Brent crude oil. EIA expects the WTI discount to widen to \$6 per barrel by the end of 2013 as crude oil production in Alberta, Canada, recovers following the heavy June flooding and as midcontinent production continues to grow.
- Rising crude oil prices and seasonal demand increases contributed to U.S. regular gasoline retail prices increasing from an average of \$3.50 per gallon on July 1, 2013, to \$3.63 per gallon on August 5. EIA expects the regular gasoline retail price to average \$3.59 per gallon in the third quarter of 2013, and the annual average price to decline from an average of \$3.63 per gallon in 2012 to \$3.52 per gallon in 2013 and to \$3.37 per gallon in 2014.
- U.S. crude oil production increased to an average of 7.5 million barrels per day (bbl/d) in July 2013, the highest monthly level of production since 1991. EIA forecasts U.S. total crude oil production will average 7.4 million bbl/d in 2013 and 8.2 million bbl/d in 2014, both about 0.1 million bbl/d higher than forecast in last month's STEO.
- Natural gas working inventories ended July 2013 at an estimated 2.88 trillion cubic feet (Tcf), about 0.37 Tcf below the level at the same time a year ago and 0.04 Tcf below the five-year average (2008-12). EIA expects the Henry Hub natural gas spot price, which averaged \$2.75 per million British thermal units (MMBtu) in 2012, will average \$3.71 per MMBtu in 2013 and \$3.95 per MMBtu in 2014.

Global Crude Oil and Liquid Fuels

The recent increase in crude oil and liquid fuels production disruptions, which reached nearly 2.7 million bbl/d in July 2013, contributed to the recent increase in crude oil prices. During July, non-OPEC supply disruptions totaled about 800,000 bbl/d of liquid fuels, with the remaining 1.9 million bbl/d of the volume disruption occurring among OPEC producers. This level of crude oil production outages among OPEC producers is the highest since at least January 2009, and includes disruptions in Iran, Iraq, Libya, and Nigeria.

EIA estimates that global liquid fuels production outpaced consumption in the second quarter of 2013, resulting in an average global liquid fuel stock build of 260,000 bbl/d compared with an average second quarter stock draw of about 210,000 bbl/d over the previous four years. Projected global liquid fuels consumption outpaces liquid fuels production in the third quarter of 2013 with estimated global inventory withdrawal averaging 380,000 bbl/d, compared with the average withdrawal of 690,000 bbl/d during the same period over the previous four years.

Global Crude Oil and Liquid Fuels Consumption. Total world consumption increased by 390,000 bbl/d from the first quarter to the second quarter of 2013, reaching 89.5 million bbl/d. EIA projects consumption to grow by an additional 940,000 bbl/d in the third quarter of 2013, driven by seasonal consumption patterns. EIA expects annual average total world consumption to increase by 1.1 million bbl/d in 2013 and by 1.2 million bbl/d in 2014.

Non-OECD Asia, particularly China, is the leading contributor to projected global consumption growth. EIA estimates that liquid fuels consumption in China increased by 420,000 bbl/d in 2012. Projected consumption in China increases by 420,000 bbl/d in 2013 and by 440,000 bbl/d in 2014, compared with average annual growth of about 510,000 bbl/d from 2003 through 2012. Recent data indicating a weaker industrial sector and a tightening money supply in the first half of 2013 signaled slower economic growth than in prior years and, if it continues, China's oil demand growth could be lower than projected in the current STEO.

OECD liquid fuels consumption fell by 550,000 bbl/d in 2012. EIA projects that OECD consumption will decline by an additional 320,000 bbl/d in 2013 and 180,000 bbl/d in 2014, largely because of declining consumption in Europe and Japan.

Non-OPEC Supply. EIA projects non-OPEC liquid fuels production will increase by 1.3 million bbl/d in 2013 and by 1.7 million bbl/d in 2014. EIA expects non-OPEC liquid fuels production to increase by 540,000 bbl/d between the second and third quarters of 2013, and by an additional 750,000 bbl/d from the third to fourth quarters. North America accounts for most 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 non-OPEC supply disruptions, which includes all liquid fuels, averaged 800,000 bbl/d in July, virtually unchanged from June. Flooding in Alberta, Canada, during June 2013 forced disruptions on a number of pipelines and production areas, and resulted in an average of 190,000 bbl/d of disrupted production volume. Although the affected pipeline resumed production in early July, production had not returned to pre-flood levels as of the end of July, as the pipeline was operating at reduced pressure throughout the month. On average, approximately 177,000 bbl/d remained disrupted in July, but production is expected to return to normal level in August.

Sudan and South Sudan, Syria, and Yemen continue to account for most of the total unplanned non-OPEC supply disruptions, however Canada's disrupted volume was the second-largest disruption in July, and second only to Syria's 250,000 bbl/d shut-in volume. South Sudan scaled back production in the second half of July, which served to offset the gains made when Canadian production returned to near-normal levels. EIA expects supply disruptions to persist in Syria and Yemen over the projection period, leading to average production of about 100,000 bbl/d in Syria and 130,000 bbl/d in Yemen over the next two years. Intensified fighting in Syria's oil-producing regions over the past several weeks makes a return to pre-conflict operating status even more unlikely in the short term. In Yemen, multiple attacks on energy infrastructure during July led to temporary production declines at the beginning and end of the month.

OPEC Supply. EIA projects total OPEC crude oil and liquids production to decline by 620,000 bbl/d in 2013 from the year before. Most of the decline in 2013 comes from Saudi Arabia in response to non-OPEC supply growth.

Persistent attacks on the Kirkuk-Ceyhan pipeline between Iraq and Turkey contributed to total disruptions in Iraq of about 290,000 bbl/d, an increase of 60,000 bbl/d from the previous month. In Libya, ongoing labor-related protests at several oil facilities have severely curtailed production for a second consecutive month. EIA estimates that Libya's crude oil production averaged 1 million bbl/d in July. Further deterioration of the security environments in Iraq and Libya could reduce OPEC production in the short term. Overall OPEC crude oil unplanned disruptions in July totaled about 1.9 million bbl/d.

EIA's estimates of current unplanned crude oil production outages among OPEC producers only represent volumes that could return on stream within one year. The estimated volumes disrupted are neither measured against nameplate production capacity nor the production volumes in the respective countries prior to the disruption. The estimated volumes rely on a determination of an effective production capacity relative to the production level, with an assessment of the difference that can return to production within one year. EIA's assessment of OPEC outages is limited to crude oil and currently includes only four countries: Iran, Iraq, Libya, and Nigeria.

EIA estimates that OPEC surplus capacity, mainly held in Saudi Arabia, averaged 2.3 million bbl/d in the second quarter of 2013. This was higher than the 2.1 million bbl/d average during the

same period last year, but lower than the average 3.6 million bbl/d from 2009 through 2011. EIA projects OPEC surplus capacity will increase to an average of 3.6 million bbl/d in the fourth quarter of 2013 and to 4.6 million bbl/d in the fourth quarter of 2014. These estimates do not include additional capacity that may be available in Iran but is currently off line because of the effects of U.S. and EU sanctions on Iran's oil sector.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories at the end of 2012 totaled 2.65 billion barrels, equivalent to 57.7 days of supply. Projected OECD oil inventories stay relatively flat in 2013, ending the year at 2.64 billion barrels. Projected inventories increase to 2.69 billion barrels (58.3 days of supply) at the end of 2014.

Crude Oil Prices. After declining to a 2013 year-to-date low of \$97 per barrel on April 17, Brent crude oil spot prices increased to an average of \$108 per barrel in July. EIA projects the Brent crude oil spot price will fall from an average of \$112 per barrel in 2012 to annual averages of \$106 per barrel and \$100 per barrel in 2013 and 2014, respectively, reflecting the increasing supply of liquid fuels from non-OPEC countries.

The price discount of spot WTI crude oil to Brent, which averaged \$18 per barrel in 2012 and increased to a monthly average of \$21 per barrel in February, narrowed to an average of \$3 per barrel in July. The strong demand for light, sweet crude oil in the Midwest and new pipeline capacity delivering production from the West Texas Permian Basin directly to the Gulf Coast contributed to a [draw on crude oil stocks in the Midwest](#) and the strengthening of the price of WTI relative to Brent crude oil. EIA expects the WTI discount to begin widening again, to \$6 per barrel by the end of 2013, as crude oil production in Alberta, Canada, recovers following heavy June flooding, and midcontinent crude oil production growth outpaces increases in capacity to transport crude oil from the region to refining centers on the Gulf and East Coasts. After averaging \$94 per barrel in 2012 and increasing to \$105 per barrel in July 2013, the forecast WTI crude oil spot price averages \$97 per barrel in 2013 and \$93 per barrel in 2014. By 2014, [several pipeline projects](#) from the midcontinent 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 narrowing in the WTI price discount to Brent next year.

Energy price forecasts are highly uncertain, and the current values of futures and options contracts suggest that prices could differ significantly from the forecast levels ([Market Prices and Uncertainty Report](#)). WTI futures contracts for November 2013 delivery traded during the five-day period ending August 1, 2013, averaged \$103 per barrel. Implied volatility averaged 21 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in September 2013 at \$85 per barrel and \$125 per barrel, respectively. Last year at this time, WTI for November 2012 delivery averaged \$89 per barrel and implied volatility averaged 32 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$67 per barrel and \$119 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. regular gasoline retail prices increased from an average of \$3.50 per gallon to \$3.68 per gallon over the first three weeks of July. Prices have declined over the past two weeks, reaching \$3.63 per gallon on August 5. Isolated refinery outages and regional disruptions have contributed to greater volatility in [regional gasoline prices across the United States](#) this year. Some of the greatest volatility was again seen [across the Midwest](#). EIA expects gasoline prices to slowly fall from their mid-July levels as crude oil prices begin to fall and the summer driving season comes to a close.

U.S. Liquid Fuels Consumption. In 2012, total liquid fuels consumption declined by 395,000 bbl/d (2.1 percent). Total liquid fuels consumption for the first half of 2013 rose an estimated 120,000 bbl/d (0.6 percent) compared with the same period last year, led by increases in liquefied petroleum gas and distillate consumption. Projected total liquids consumption during the second half of 2013 increases by 150,000 bbl/d from the same period last year, with distillate fuel accounting for most of the growth.

Preliminary estimates of [gasoline consumption during July 2013](#) showed relatively strong growth over the same month last year. However, EIA continues to expect flat to declining gasoline consumption as improving fuel economy of new vehicles continues to outpace growth in highway travel.

U.S. Liquid Fuels Supply. EIA expects U.S. crude oil production to rise from an average of 6.5 million bbl/d in 2012 to 7.4 million bbl/d in 2013 and 8.2 million bbl/d in 2014. The continued focus on drilling in tight oil plays in the onshore Williston, Western Gulf, and Permian Basins is expected to account for the bulk of forecast production growth over the next two years. Offshore production from the Gulf of Mexico is forecast to average 1.3 million bbl/d in 2013 and 1.4 million bbl/d in 2014.

Since reaching 12.5 million bbl/d in 2005, total U.S. liquid fuel net imports, including crude oil and petroleum products, have been falling. Total net imports fell to 7.4 million bbl/d in 2012, and EIA expects net imports to continue declining to an average of 5.6 million bbl/d by 2014. Similarly, the share of total U.S. consumption met by liquid fuel net imports peaked at more than 60 percent in 2005 and fell to an average of 40 percent in 2012. EIA expects the net import share to continue to fall to 30 percent in 2014, which would be the lowest level since 1985.

U.S. Petroleum Product Prices. EIA expects that regular-grade gasoline retail prices, which averaged \$3.59 per gallon during the first half of 2013, will average \$3.59 per gallon and \$3.33 per gallon during the third and fourth quarters of 2013, respectively. Led by falling crude oil prices, the projected U.S. average regular gasoline retail price falls from \$3.63 per gallon in 2012 to an average \$3.52 per gallon in 2013 and \$3.37 per gallon in 2014. Diesel fuel prices, which averaged \$3.97 per gallon in 2012, are projected to average \$3.92 per gallon in 2013 and \$3.76 per gallon in 2014.

The current values of futures and options contracts suggest that gasoline prices could differ significantly from this forecast. For example, there is a 4-percent probability that the New York Harbor reformulated gasoline blendstock for oxygenate blending (RBOB) futures price will exceed \$3.35 per gallon (consistent with a U.S. average regular gasoline retail price above \$4.00 per gallon) in November 2013.

Natural Gas

A heat wave in the Northeast in mid-July contributed to spikes in the price of wholesale natural gas and electric power, as well as near-record consumption of natural gas for power generation in the Northeast. Although [recent pipeline capacity additions](#) have helped ease movement of natural gas supplies in the area, constraints continue to limit gas flow to the region, particularly in times of high demand. The day-ahead price of natural gas at the Algonquin Citygate, which serves Boston consumers, rose to \$8.09 per million British thermal units (MMBtu) at the end of trading on July 16. This was its highest level since March 2013, and more than \$4 per MMBtu greater than the benchmark Henry Hub price (\$3.69 per MMBtu) in Louisiana. Additionally, on New York's independent system operator's trading platform, real-time hourly wholesale power prices spiked to [more than \\$800 per megawatt hour](#) on July 17.

U.S. Natural Gas Consumption. EIA expects that natural gas consumption, which averaged 69.7 Bcf/d in 2012, will average 69.9 Bcf/d and 69.3 Bcf/d in 2013 and 2014, respectively. Colder winter temperatures in 2013 and 2014 (compared with the record-warm temperatures in 2012) are expected to increase the amount of natural gas used for residential and commercial space heating. However, the projected year-over-year increases in natural gas prices contribute to declines in natural gas used for electric power generation from 25.0 Bcf/d in 2012 to 22.2 Bcf/d in 2013 and 21.6 Bcf/d in 2014.

U.S. Natural Gas Production and Trade. Natural gas marketed production is projected to increase from 69.2 Bcf/d in 2012 to 69.9 Bcf/d in 2013 and to 70.5 Bcf/d in 2014. Onshore production increases over the forecast period, while federal Gulf of Mexico production from existing fields declines as the economics of onshore drilling remain more favorable. Natural gas pipeline gross imports, which have fallen over the past five years, are projected to fall by 0.2 Bcf/d in 2013 and then remain near 2013 levels in 2014. LNG imports are expected to remain at minimal levels of around 0.4 Bcf/d in both 2013 and 2014.

U.S. Natural Gas Inventories. As of July 26, 2013, working gas stocks totaled 2,845 Bcf, which is 368 Bcf less than at the same time last year, but only 34 Bcf below the five-year (2008-12) average for that week. EIA projects working gas stocks at the end of this summer's stock-build season (end of October) will reach 3,800 Bcf, about 130 Bcf below the level at the same time last year.

Working gas storage capacity grew by about 2 percent in 2012, according to EIA's [most recent report](#) on maximum capacity in the Lower 48 states. EIA has two measures of the volume of working natural gas that can be stored in underground facilities for future use—demonstrated maximum and design capacity—and both increased by about 2 percent from November 2011 to November 2012. The producing region accounted for the largest increases in capacity.

U.S. Natural Gas Prices. Natural gas spot prices averaged \$3.62 per MMBtu at the Henry Hub in July 2013, down 21 cents from the previous month's price. EIA expects the Henry Hub price will increase from an average of \$2.75 per MMBtu in 2012 to \$3.71 per MMBtu in 2013 and \$3.95 per MMBtu in 2014. Despite declines in prices over the past few months, prices still remain substantially above their year-ago levels. (Henry Hub prices last July averaged \$2.95 per MMBtu, and the average spot prices at most other major trading hubs over the first 6 months of 2013 [increased by 40 percent to 60 percent](#) from the same period last year.)

Natural gas futures prices for November 2013 delivery (for the five-day period ending August 1, 2013) averaged \$3.58 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for November 2013 contracts at \$2.68 per MMBtu and \$4.79 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for November 2012 averaged \$3.26 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were \$2.13 per MMBtu and \$4.98 per MMBtu.

Coal

While [coal market fundamentals](#) changed in first-half 2013 compared with the same period of 2012, spot prices remained largely unchanged. Demand for coal was higher and production was lower in first-half 2013, but because electric companies chose to burn off large inventories instead of buying more coal and because international coal prices were weaker, the spot market price remained largely unchanged. EIA expects declines in exports and stocks to moderate during the second half of 2013 as the first year-over-year increases in quarterly coal consumption since 2010 continue.

U.S. Coal Consumption. EIA estimates that total coal consumption for the first half of 2013 was 448 million short tons (MMst), or 38 MMst (9.4 percent) higher than the amount of coal consumed in the first six months of 2012. The increase was primarily a result of consumption growth in the electric power sector because of higher electricity demand and higher natural gas prices. EIA expects that this trend will continue in the second half of 2013 with total coal consumption for the year of 952 MMst (a 6.9-percent increase over 2012). Consumption grows at a more modest pace of 1.4 percent to 966 MMst in 2014.

U.S. Coal Supply. Coal production in the first half of 2013 was 21 million tons, or 4 percent, lower than in the same period of 2012. The largest declines were in the Appalachian (13.6 MMst) and Western (8.1 MMst) regions. Interior region production was similar to last year. EIA

projects higher production in all regions during the second half of 2013 compared with the same period last year, with total coal production of 1,016 MMst in 2013, unchanged from last year. Coal production is forecast to grow by 3.3 percent in 2014 to 1,050 MMst as inventories stabilize and consumption increases.

Inventory draws are expected to meet most of the growth in consumption in 2013. Estimates of total coal inventories ended the first half of 2013 at 28 MMst lower than the same time last year. EIA forecasts an additional 9 MMst of inventory withdrawals over the second half of 2013.

U.S. Coal Exports. EIA estimates that first half 2013 exports totaled 61.2 MMst, which was 5.0 MMst lower than the same period last year despite [record monthly exports of 13.6 MMst in March](#). Exports for the next six months are expected to continue declining, with second-half exports totaling 53 MMst, down 7 MMst from last year. Exports are projected to total 108 MMst in 2014. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, increasing supply in other coal-exporting countries, and falling international coal prices are the primary reasons for the expected decline in U.S. coal exports.

U.S. Coal Prices. Delivered coal prices (to the electric power industry) were down an estimated 2.5 percent (\$0.06 per MMBtu) for the first six months of 2013 compared with the same period last year. EIA expects nominal annual average coal prices to the electric power industry to fall for the first time since 2000, from \$2.40 per MMBtu in 2012 to \$2.37 MMBtu in 2013. EIA forecasts average delivered coal prices of \$2.40 per MMBtu in 2014.

Electricity

The northeastern United States experienced a strong heat wave during mid-July. In response, many customers ran their air conditioners more than usual. EIA estimates the average residential customer in New England will use about 1.0 percent more electricity during the summer of 2013 (June-August) compared with last summer, while customers in the Middle Atlantic states are expected to use about 0.5 percent less electricity. In addition to increased electricity demand, the heat wave also caused [temporary spikes in wholesale power prices](#). State retail rate regulations shield many residential customers from price swings in the wholesale power market, but EIA expects summer electricity prices in the Northeast to average about 2.7 percent higher than summer 2012, primarily as a result of higher fuel costs paid by generators.

U.S. Electricity Consumption. Despite last month's heat wave in the Northeast, summer temperatures in other areas of the United States are cooler than last year, especially in the Midwest Census region where cooling degree days between June and August total 23 percent less than last summer. For the entire year, forecast U.S. retail sales of electricity to the residential sector during 2013 average 1.3 percent more than 2012, as lower summer consumption is offset by higher consumption during the non-summer months. Forecast retail

sales of electricity to the commercial sector grow by 0.5 percent in 2013, while industrial sector retail electricity sales fall by 0.5 percent.

U.S. Electricity Generation. EIA expects total U.S. electricity generation will grow by 0.5 percent in 2013 and by 0.4 percent in 2014. Electric generators have been running their existing coal capacity at higher rates so far this year in response to the increasing cost of natural gas relative to coal. During the first half of 2013, EIA estimates generation fueled by coal averaged 4,250 gigawatthours per day (GWh/d), corresponding to a 39.2 percent share of total generation. In contrast, coal's share of total generation during the first half of 2012 was 35.4 percent (3,810 GWh/d). Coal's recent gains in fuel share are expected to slow during the second half of 2013 when coal's projected share of total generation averages 41.4 percent compared with 39.3 percent in second half of 2012. Natural gas accounted for 30.4 percent of total generation during 2012, but EIA expects this share to fall to an average of 27.4 percent during 2013.

U.S. Electricity Retail Prices. Generation fuel costs and [wholesale electricity prices](#) have increased this year after a considerable decline in 2012. During the first half of 2013, EIA estimates the price of natural gas delivered to electric generators averaged \$4.46 per MMBtu, 44 percent higher than the same period last year. Changes in the costs of providing electricity are not immediately reflected on retail customer bills because state regulatory commissions must approve rate changes in many areas of the country. EIA expects the residential retail price of electricity in 2013 will average 12.1 cents per kilowatthour, about 1.9 percent higher than the price last year.

Renewables and Carbon Dioxide Emissions

U.S. Electricity and Heat Generation from Renewables. EIA projects renewable energy consumption for electricity and heat generation to increase by 3.4 percent in 2013. While hydropower declines by 4.2 percent, nonhydropower renewables used for electricity and heat generation grow by an average of 8.1 percent in 2013. In 2014, the growth in renewables consumption for electric power and heat generation is projected to continue at a rate of 4.2 percent, as a 3.1-percent increase in hydropower is combined with a 4.9-percent increase in nonhydropower renewables.

EIA estimates that wind capacity will increase by 5 percent this year to about 62 gigawatts, and reach over 72 gigawatts in 2014. However, electricity generation from wind is projected to increase by 19 percent in 2013, as capacity that came [on line at the end of 2012](#) is available for the entire year in 2013. Wind-powered generation is projected to grow by 7 percent in 2014.

EIA expects continued robust growth in the generation of solar energy, although the amount of [utility-scale generation](#) remains a small share of total U.S. generation, about 0.2 percent in 2013. Utility-scale capacity, which until recently experienced little growth compared with customer-sited distributed generation capacity, is projected to more than double between 2012 and 2014. Photovoltaics (PV) accounted for all [utility-scale solar growth](#) in 2012, but EIA expects that

several large solar thermal generation projects will enter service in 2013 and 2014. However, PV is still expected to account for most of the capacity additions in 2013 and 2014. Solar generation by the electric power sector increases 80 percent in 2013 and 55 percent in 2014.

U.S. Liquid Biofuels. Smaller corn harvests due to widespread drought resulted in U.S. fuel ethanol production falling from an average of approximately 900,000 bbl/d (13.9 billion gallons per year) in the first half of 2012 to an average of 820,000 bbl/d (12.6 billion gallons per year) from July 2012 through March 2013. Forecast ethanol production increases to an average 920,000 bbl/d in 2014, driven in part by increasing Renewable Fuel Standard (RFS) targets and strong demand for [Renewable Identification Numbers](#) (RINs). Biodiesel production, which averaged 63,000 bbl/d (1.0 billion gallons per year) in 2012, has been rising this year and [reached a record level](#) of 111 million gallons (85,000 bbl/d) in May 2013. Biodiesel production is forecast to average about 82,000 bbl/d in 2013 and 88,000 bbl/d in 2014. This forecast assumes that the 2014 renewable fuel standards are identical to those proposed for 2013.

The U.S. Environmental Protection Agency (EPA) proposed rule for the 2013 RFS program year maintains the statutory target of 16.55 billion ethanol-equivalent gallons of total renewable fuels. It would require refiners and importers of gasoline and diesel fuel to deliver RINs equivalent to the 2013 renewable volume obligation (RVO) of 9.63 percent of the gasoline or diesel fuel they sell domestically (not counting the biofuels blended into it). The market price of corn ethanol (D6 classification) RINs [increased dramatically during the first quarter of 2013](#), from \$0.05 per gallon at the start of the year to as high as \$1.05 per gallon on March 11. After weeks of hovering around \$0.80 per gallon, D6 RIN prices once again rose sharply in July, reaching new daily highs over \$1.40 per gallon, before returning to near the \$1.00 level at the end of month.

The increase in the ethanol RIN price provides an economic incentive for two changes in the market. First, a higher ethanol RIN price tends to lower the market price of E85 gasoline relative to E10 gasoline. Second, an ethanol RIN price equal to or near the biodiesel RIN price may motivate blending of biodiesel in excess of the biodiesel blending target that EPA announced in the 2013 RFS program.

At the retail level, EIA expects diesel fuel prices to be most affected by higher RIN prices as typical biodiesel blending yields only about one-third of the RINs required and diesel fuel refiners and blenders must make up for the shortfall by purchasing the now higher-priced RINs.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels [declined by 3.9 percent in 2012](#), and projects increases of 2.4 percent in 2013 and 0.3 percent in 2014. The increase in emissions over the forecast period primarily reflects the projected increase in coal use for electricity generation, especially in 2013 as it rebounds from the 2012 decline.

U.S. Economic Assumptions

EIA uses the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO. The GI simulation used in this STEO assumes that the spending cuts mandated in the Budget Control Act of 2011 (sequestration) are replaced by a combination of changes of tax and spending changes that are implemented in 2014. In addition, GI assumes there will be an agreement reached to increase the amount of debt that can be issued by the U.S. Treasury.

U.S. Current Trends. The [U.S. Census Bureau](#) reported that new orders for manufactured durable goods rose 4.2 percent in June, following a revised 5.2-percent increase in May. But the June increase falls to 0.1 percent when orders for defense and aircraft are excluded. The [U.S. Commerce Department](#) also reported that sales of new single-family homes increased by over 38 percent from June 2012 to June 2013, and 8.3 percent from May 2013 to June 2013. The [Federal Reserve Bank of Philadelphia's](#) survey of business conditions improved from June to July, but a more inclusive measure that includes inventories, orders, and shipments is barely in expansion territory at 51.1 (values above 50 indicate expansion). In addition, the [Federal Reserve Board](#) reported that total U.S. industrial production gained 0.3 percent from May to June 2013 and capacity utilization was up 0.1 percent over the same time period.

U.S. Production and Income. The STEO assumes 1.6-percent real U.S. GDP growth in 2013, rising to 2.6 percent in 2014. Year-on-year real GDP growth begins to accelerate in the second half of 2014, eventually rising to 3.1 percent in the fourth quarter of 2014. Forecast real disposable income increases 0.5 percent in 2013 and 3.4 percent in 2014. Total industrial production grows almost one percentage point faster than real GDP in 2013 at 2.5 percent, and its projected growth of 3.2 percent in 2014 is still well above the growth rate of real GDP.

U.S. Expenditures. Private fixed investment growth averages 6.0 and 7.9 percent over 2013 and 2014, respectively, down from the 6.1 and 8.6 percent projected last month. Real consumption expenditures grow faster than real GDP in 2013, at 1.9 percent, but slow below the rate of real GDP growth in 2014, at 2.3 percent. Export growth triples from 1.7 to 5.1 percent over the same two years. Government expenditures fall 3.0 percent in 2013, and rise by 0.2 percent in 2014.

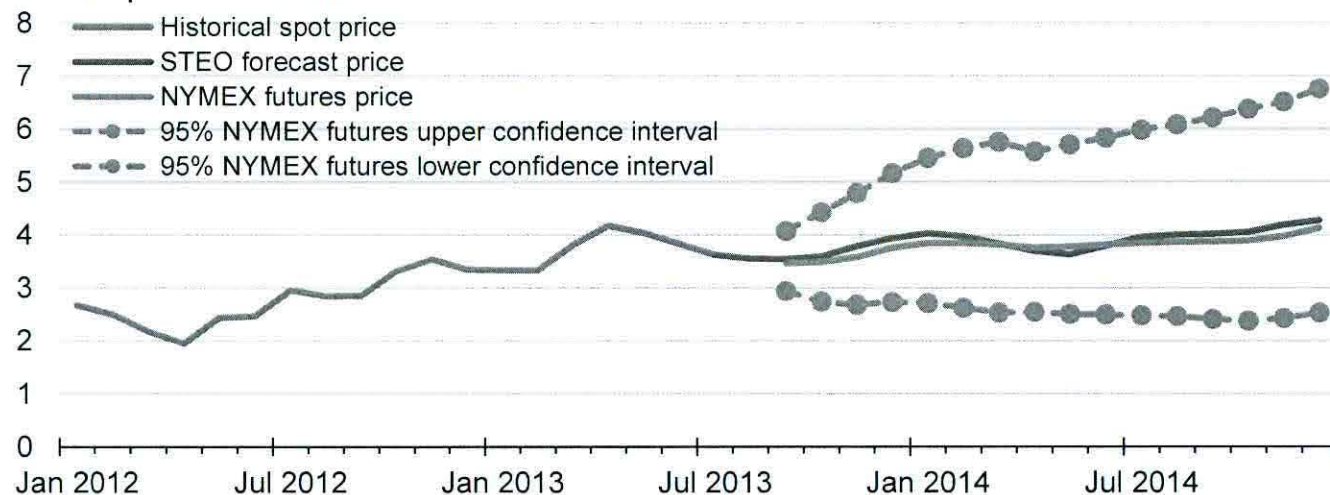
U.S. Employment, Housing, and Prices. The unemployment rate in the forecast averages 7.6 percent over 2013, and gradually falls to 7.1 percent at the end of 2014. This is accompanied by nonfarm employment growth averaging 1.6 percent in 2013 and 1.5 percent in 2014. Consistent with an improving housing sector, housing starts grow an average of 22.6 percent and 26.8 percent in 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.

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



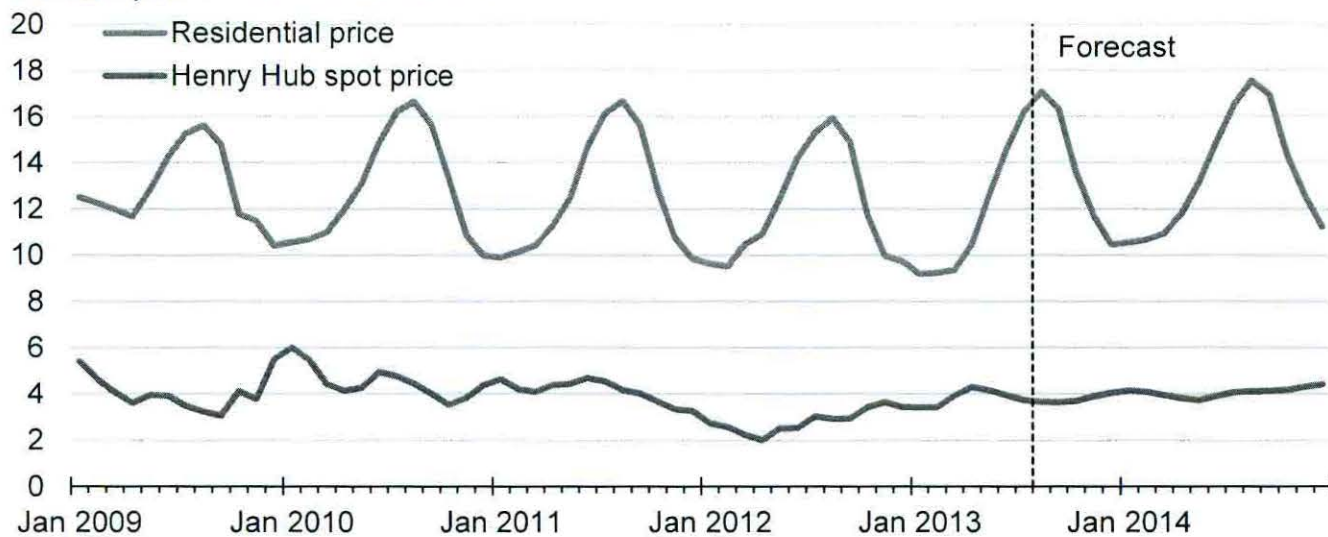
Note: Confidence interval derived from options market information for the 5 trading days ending August 1, 2013. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, August 2013



U.S. Natural Gas Prices

dollars per thousand cubic feet



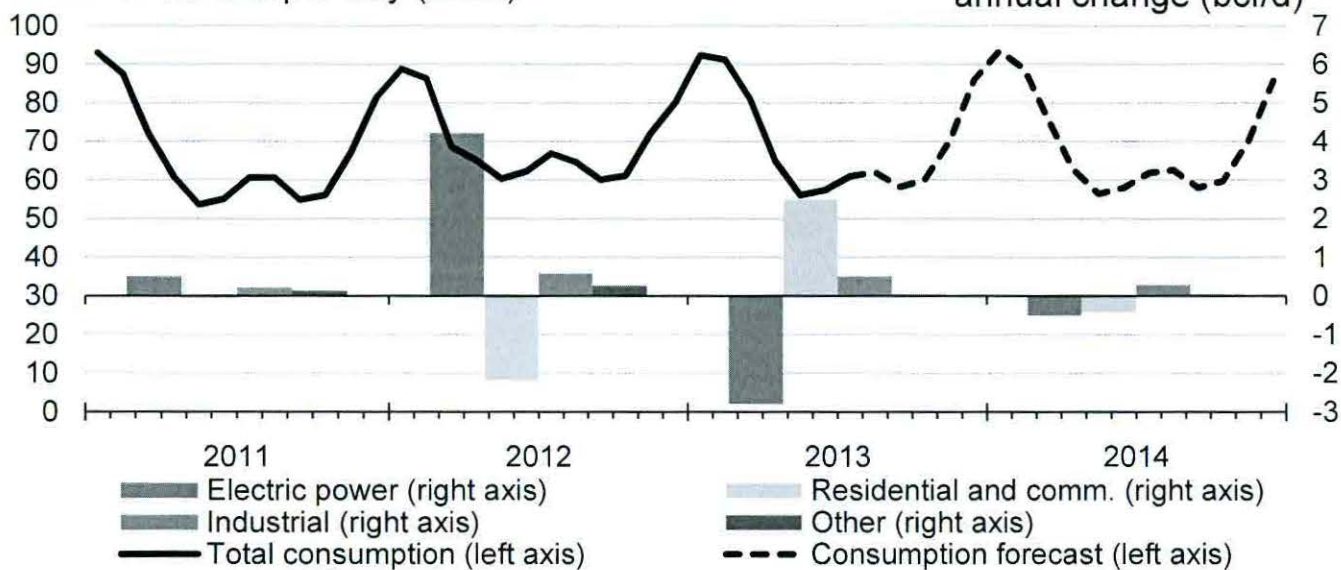
Source: Short-Term Energy Outlook, August 2013

U.S. Natural Gas Consumption



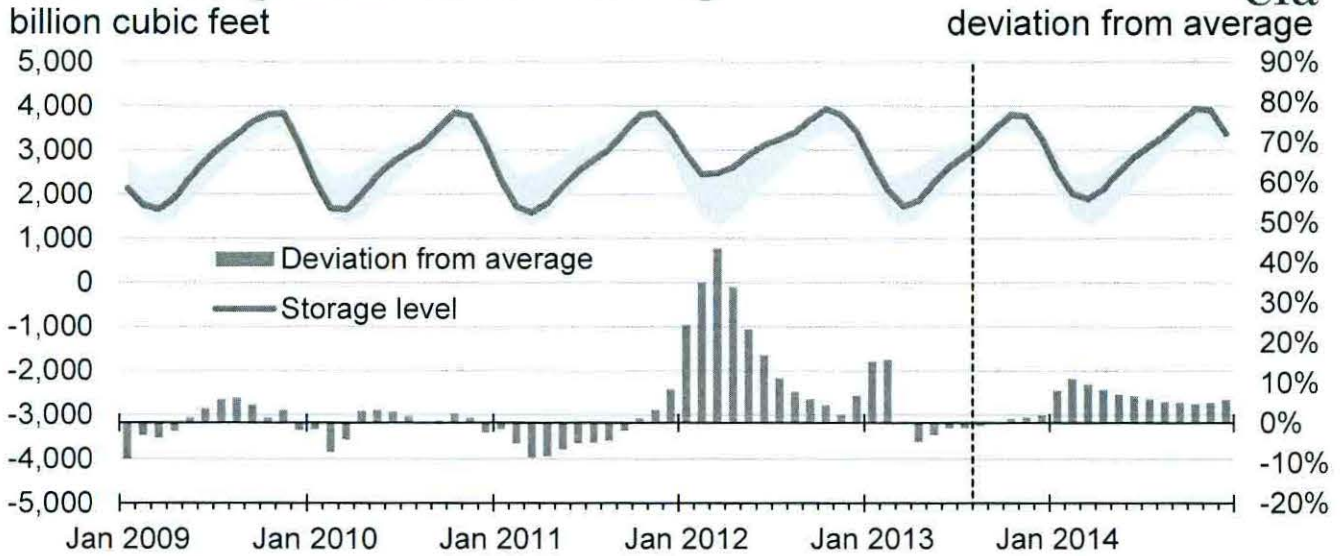
billion cubic feet per day (bcf/d)

annual change (bcf/d)



Source: Short-Term Energy Outlook, August 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, August 2013

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

NorthWestern Energy Docket No. D2013.5.34

On May 31, 2013, NorthWestern Energy filed its Annual Unreflected Gas Cost Account, Projected Gas Cost and Gas Transportation Adjustment Clause balances with the Montana Public Service Commission (Commission) in Docket No. 2013.5.34. On June 18, 2013, the Commission approved these changes to be effective July 1, 2013 on an interim basis.

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

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

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$4.620	\$3.722	\$3.653	\$3.637
Prior Gas Cost	4.755	3.853	3.784	3.767
Current Gas Cost Adjustment	(\$0.135)	(\$0.131)	(\$0.131)	(\$0.130)
<u>Surcharge Adjustment:</u>				
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
<u>Market Based Pricing Differential</u>				
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
Net Increase (Decrease) in Gas Costs	<u>(\$0.135)</u>	<u>(\$0.131)</u>	<u>(\$0.131)</u>	<u>(\$0.130)</u>
Gas Cost Level	\$4.620	\$3.722	\$3.653	\$3.637
Plus: Surcharge	(0.113)	(0.113)	(0.115)	(0.377)
Total Gas Cost Level in Tariff Rates	<u>\$4.507</u>	<u>\$3.609</u>	<u>\$3.538</u>	<u>\$3.260</u>

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

	Amount
Total Gas Costs 1/	\$67,501,228
Residential and General Service dk Requirements 2/	14,675,874
Average Cost of Gas per dk	\$4.599
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.620
Less: Gas Cost Level in Rates 3/	4.755
Current Gas Cost Adjustment	(\$0.135)

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 June 30, 2013, adjusted for losses at .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-13-008 effective August 1, 2013:

Cost of Purchased Gas	\$4.734
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.755

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

Total Gas Costs 1/	\$67,501,228
Less: Annual MDDQ Costs 1/	<u>13,121,509</u>
Total Gas Costs excluding MDDQ	\$54,379,719
Firm Service Requirements 1/	14,675,874
Other Gas Costs per Dk (excluding MDDQ)	\$3.705
<u>Summer - June - September</u>	
Summer Seasonal Rate, adjusted for losses 2/	3.722
Less: Gas Cost Level in Rates 3/	<u>3.853</u>
Current Gas Cost Adjustment	<u><u>(\$0.131)</u></u>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-13-008 effective August 1, 2013:

	<u>Summer</u>
Cost of Purchased Gas	\$3.836
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.853

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

	Amount
Total Gas Costs 1/	\$12,740,020
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$3.637
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.653
Less: Gas Cost Level in Rates 2/	3.784
Current Gas Cost Adjustment	(\$0.131)

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-13-008 effective August 1, 2013:

Cost of Purchased Gas	\$3.767
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.784

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
EFFECTIVE SEPTEMBER 2013

	<u>Amount</u>
Total Gas Costs 1/	\$3,200,698
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$3.637
Less: Gas Cost Level in Rates 2/	<u>3.767</u>
Current Gas Cost Adjustment	<u><u>(\$0.130)</u></u>

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

2/ Gas Cost Level in Current Tariff Rates Case No. PU-13-008 effective August 1, 2013:
Cost of Purchased Gas \$3.767

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
September 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 1.705%, CONSISTING OF 1.996% FOR THE CURRENT PERCENTAGE AND (0.291%) 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 0.600 CENTS, CONSISTING OF 0.670 CENTS FOR THE CURRENT RATE AND (0.070) 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.

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 0.506%, CONSISTING OF 0.673% FOR THE CURRENT PERCENTAGE AND (0.167%) 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 0.033 CENTS, CONSISTING OF 0.000 CENTS FOR THE CURRENT RATE AND 0.033 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.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.

NOVA Gas Transmission Ltd.

Table of Rates, Tolls and Charges
Page 1 of 2

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 ³ m ³		
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D ³	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 ¹ \$ 3.12/GJ FT-D Demand Rate for Group 3 Delivery Points ² \$ 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 ³	Refer to Attachment "3" for applicable FT-P Demand Rate per month		
7. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10³m³/day)</u>	
	1-5 years	11.07	
	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 ³ m ³	
10. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
11. Rate Schedule IT-D ³	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>	<u>PT Rate</u>	<u>PT Gas Rate</u>
	9009-01001-1	\$ 660.00/d	50.0 10 ³ m ³ /d
14. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2013568692	\$ 14.00	/ month
	2013568691	\$ 2.00	/ month
	2013568690	\$ 2.00	/ month
	2013568689	\$ 2,125.00	/ month
	2013568688	\$ 51.00	/ month
	2013568687	\$ 138.00	/ month
	2013568686	\$ 88.00	/ month
	2013568682	\$ 20.00	/ month
	2013568681	\$ 194.00	/ month
	2013568680	\$ 210.00	/ 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 ¹
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	AQUINU RIVER WEST SALES	3.12	0.1128	
31007	ALBERTA ENVIROFUELS SALES APN	3.39	0.1226	Yes ²
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 ²
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
3097	CHICKADEE CREEK SALES	3.12	0.1128	
3305	CHIGWELL NORTH SALES	3.12	0.1128	
3496	CHIPEWYAN RIVER SALES	3.12	0.1128	

NATURAL GAS TARIFF



	<u>33rd</u>	Revised	Sheet No.	<u>80.1</u>
Canceling	<u>32nd</u>	Revised	Sheet No.	<u>80.1</u>

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge
5,001 to 10,000	\$ 119.15
10,001 to 30,000	\$ 171.30
>30,000	\$ 380.15

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	\$ 0.9742067
--	--------------

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	\$ 0.0073823
Minimum	\$ 0.0017935
GTAC Amortization	\$ (0.0013032) (R)
Balancing Penalty Rate	Higher of \$25.00/ Dekatherm Or 150% of Market Price

PLUS:

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

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

MINIMUM BILL: Per respective contracts.

(continued)

Staff Approved: June 28, 2013
Docket No.: D2013.5.34, Interim Order No. 7282
Tariff Letter No. 228-G

Effective for service rendered on or after
July 1, 2013

PUBLIC SERVICE COMMISSION
Aleisha Salem Secretary

GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company
1415 N. Airport Rd
Pierre, SD 57501
Date Filed: January 24, 2001

SD P.U.C. Section No. 3
Original Sheet No. 1
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
Sixth Revised Sheet No. 12
Cancels Fifth 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 Demand Charge 6/</u>	<u>Minimum Demand Charge 6/</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	\$9.50	\$0.00	\$0.1040	\$0.0010	0.526%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.1040	\$0.0010	0.526%
	MLI	DSE	\$225.00	\$0.00	\$0.00	\$0.1978	\$0.0020	2.684%
Interruptible Transportation 4/	MLI	MLI	\$0.00	\$0.00	\$0.00	\$0.0844	\$0.0010	0.526%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.0844	\$0.0010	0.526%
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: March 1, 2013
By: William N. Cantrell

Date Effective: June 1, 2013
Title: President and CEO

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

	General Service		
	Storage Balance 1/	Prepaid	
		Commodity Balance 2/	Prepaid Demand
October 2012	\$12,647,019	\$616,455	\$3,086,520
November	11,646,866	563,795	2,521,344
December	8,000,589	427,541	1,235,777
January 2013	4,079,005	272,801	(365,590)
February	1,206,550	171,608	(1,356,493)
March	(1,423,715)	78,946	(2,036,918)
April	(3,157,116)	17,880	(1,870,955)
May	(1,416,806)	89,179	(1,094,135)
June	1,595,058	191,167	(20,504)
July	5,116,499	317,569	1,113,054
August	8,702,792	447,313	2,229,614
September	10,939,849	527,899	3,104,577
October	11,989,333	566,053	3,356,731
13 month average	<u>\$5,378,917</u>	<u>\$329,862</u>	<u>\$761,771</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$472,861	\$28,998	\$66,967
Return Requirement	<u>\$641,921</u>	<u>\$39,366</u>	<u>\$90,909</u>

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

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

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2012									<u>(\$1,670,167)</u>
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)
December	509,484	0	(52)	509,432	1,863,462	(0.113)	(210,571)	720,003	(172,671)
January 2013	(754)	0	(10)	(764)	2,547,247	(0.113)	(287,839)	287,075	114,404
February	(166,201)	0	7	(166,194)	2,403,906	(0.113)	(271,641)	105,447	219,851
March	(455,645)	0	11	(455,634)	2,116,255	(0.113)	(239,137)	(216,497)	3,354
April	(569,359)	0	0	(569,359)	2,017,766	(0.113)	(228,008)	(341,351)	(337,997)
May	(82,661)	0	(11)	(82,672)	1,254,451	(0.113)	(141,753)	59,081	(278,916)
June	322,505	0	(11)	322,494	474,018	(0.113)	(53,564)	376,058	97,142
Balance @ June 30, 2013									<u>\$97,142</u>

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 & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2012									<u>(\$144,649)</u>
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)
December	52,605	0	(5)	52,600	118,275	(0.115)	(13,602)	66,202	(23,823)
January 2013	24,783	0	(1)	24,782	99,565	(0.115)	(11,450)	36,232	12,409
February	23,033	0	1	23,034	114,013	(0.115)	(13,111)	36,145	48,554
March	1,156	0	2	1,158	93,198	(0.115)	(10,718)	11,876	60,430
April	7,751	0	2	7,753	84,523	(0.115)	(9,721)	17,474	77,904
May	25,382	0	3	25,385	68,968	(0.115)	(7,931)	33,316	111,220
June	26,648	0	5	26,653	45,241	(0.115)	(5,203)	31,855	143,075
Balance @ June 30, 2013									<u>\$143,075</u>

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**

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2012									<u>(\$189,388)</u>
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)	(13,358)	17,410	(182,537)
December	25,326	0	(11)	25,315	57,310	(0.377)	(21,607)	46,922	(135,615)
January 2013	20,733	0	(7)	20,726	77,436	(0.377)	(29,193)	49,919	(85,696)
February	18,711	0	(4)	18,707	82,757	(0.377)	(31,199)	49,906	(35,790)
March	625	0	(2)	623	65,562	(0.377)	(24,717)	25,340	(10,450)
April	2,674	0	0	2,674	71,332	(0.377)	(26,892)	29,566	19,116
May	14,648	0	1	14,649	49,614	(0.377)	(18,705)	33,354	52,470
June	12,310	0	2	12,312	18,245	(0.377)	(6,878)	19,190	71,660
Balance @ June 30, 2013									<u>\$71,660</u>

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

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