MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

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

November 12, 2013

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

Re: Cost of Gas Adjustment
(COG) Rate 88 and Rate 99
Case No. PU-13-

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

Attachment A is the Rate Summary Sheet (119th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered December 1, 2013.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.160 per dk since the last filing due to an increase in the overall commodity price of gas. Attachment B explains the reasons for the increase in the market price of gas. There has also been a change in pipeline rates as shown on Attachment C. In addition, Montana-Dakota has increased its firm transportation capacity to meet increasing capacity requirements, resulting in a system wide change in demand allocation and an increase of approximately \$0.029 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 the market based pricing differential provision that will apply during the month of December 2013.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.189 per dk for residential and firm general customers, an increase of \$0.170 per dk for small, large and 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 December 2013. The average cost of gas for firm customers, adjusted for losses, is \$4.830.

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December 2013 cost of natural gas and propane
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.

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 December 2013. The net effect of this filing is an increase of $1.648 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 December 2013. The average cost of propane for all customers, adjusted for losses, is $13.723 per dk.

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

These proposed adjustments, calculated in accordance with Rate 88 and Rate 99, will amount to an increase of approximately $513,500 for natural gas customers and an increase of approximately $11,500 for propane customers during the month of December 2013. All of Montana-Dakota's retail natural gas and propane customers in North Dakota may be affected by this proposal. There were 99,413 natural gas and 341 propane customers in North Dakota as of September 30, 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

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

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60 [1]	4	$0.30 per day	$0.812	$4.842	$5.654
Air Force Rate 64 [1]	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$4.842	$4.980
Interruptible Service - PAR			$0.120	$3.963	$4.083
Interruptible Service - MAFB			$0.120	$4.011	$4.131
Firm General Service Rate 70 [1]	13				
Meters rated < 500 cubic feet		$0.52 per day			
Meters rated > 500 cubic feet		$1.75 per day	$0.597	$4.842	$5.439
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71 [2]	14	$100.00 per month	$0.871	$3.963	$4.834
Optional Seasonal Gas [1]					
Service Rate 72	15				
Meters rated < 500 cubic feet		$0.52 per day			
Meters rated > 500 cubic feet		$1.75 per day	$0.597	$4.929	$5.526
Transportation Service [1]	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	
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85 [3]	27	$675.00 per month	$0.719	$3.963	$4.682
Residential Propane Rate 90 [1]	32	$0.30 per day	$0.812	$12.934	$13.746
Firm General Propane Rate 92 [1]	34				
Meters rated < 500 cubic feet		$0.52 per day			
Meters rated > 500 cubic feet		$1.75 per day	$0.597	$12.934	$13.531

1/ Interim increase of 15.678% applicable to amounts billed under Basic Service Charge and Distribution Delivery Charge.
2/ Interim increase of 8.671% applicable to amounts billed under Basic Service Charge and Distribution Delivery Charge.
3/ Interim increase of 9.382% applicable to amounts billed under Basic Service Charge and Distribution Delivery Charge.

Date Filed: November 12, 2013 **Effective Date:**

Issued By: Tamie A. Aberle
Director - Regulatory Affairs **Case No.:**

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

December 2013

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

The major contributing factor to the increase in natural gas prices is likely a result of the increase in demand associated with the start of the seasonal heating. According to the Energy Information Administration (EIA), domestic demand was greater than supply for the first time since April. The EIA reported storage levels nationwide continue to be slightly above the five year average as of November 1, 2013, 1.5 percent above the five-year average and 2.9 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.gov.

The October Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 19. The November Outlook will be published November 13, 2013.

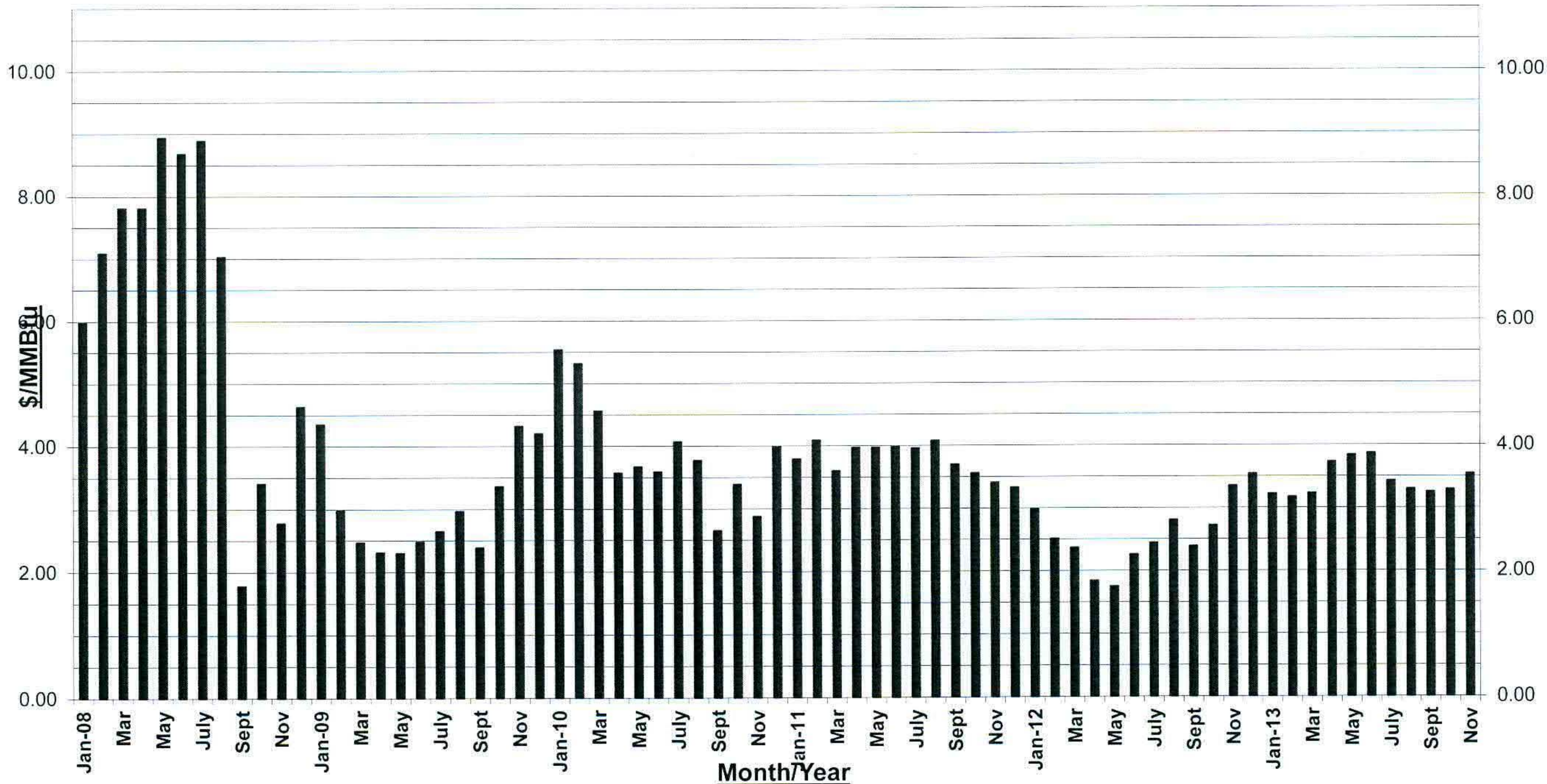
Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
December 2013

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 December 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.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 - $3.44

Independent Statistics & Analysis
U.S. Energy Information Administration

October 2013

Short-Term Energy and Winter Fuels Outlook (STEO)

Highlights

- EIA projects average U.S. household expenditures for natural gas and propane will increase by 13% and 9%, respectively, this winter heating season (October 1 through March 31) compared with last winter. Projected U.S. household expenditures are 2% higher for electricity and 2% lower for heating oil this winter. Although EIA expects average expenditures for households that heat with natural gas will be significantly higher than last winter, spending for gas heat will still be lower than the previous 5-year average (see EIA *Short-Term Energy and Winter Fuels Outlook* slideshow).

- Brent crude oil spot prices fell from a recent peak of $117 per barrel in early September to $108 per barrel at the end of the month as some crude oil production restarted in Libya and concerns over the conflict in Syria moderated. EIA expects the Brent crude oil price to continue to weaken, averaging $107 per barrel during the fourth quarter of 2013 and $102 per barrel in 2014. Projected West Texas Intermediate (WTI) crude oil prices average $101 per barrel during the fourth quarter of 2013 and $96 per barrel during 2014.

- The weekly U.S. average regular gasoline retail price fell by 18 cents per gallon during September, ending the month at $3.43 per gallon. EIA's forecast for the regular gasoline retail price averages $3.34 per gallon in the fourth quarter of 2013. The annual average regular gasoline retail price, which was $3.63 per gallon in 2012, is expected to be $3.52 per gallon in 2013 and $3.40 per gallon in 2014.

- Natural gas working inventories ended September at an estimated 3.52 trillion cubic feet (Tcf), 0.17 Tcf below the level at the same time a year ago and 0.04 Tcf above the previous five-year average (2008-12). EIA expects that 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 $4.00 per MMBtu in 2014.

- Despite a rise in natural gas prices from their 2012 level, stable coal prices and an increase in electricity generation from coal contribute to only modest increases in retail electricity prices. EIA expects residential electricity prices to increase by 2% in 2013 and 1% in 2014.

Projected Winter Fuel Expenditures by Fuel and Region

The average household winter heating fuel expenditures discussed in this STEO provide a broad guide to changes compared with last winter. However, fuel expenditures for individual households are highly dependent on local weather conditions, market size, the size and energy efficiency of individual homes and their heating equipment, and thermostat settings (see Winter Fuels Outlook table). Forecast temperatures are close to last winter nationally, with the Northeast about 3% colder and the West 3% warmer.

Natural Gas. About one-half of U.S. households use natural gas as their primary heating fuel. EIA expects households heating with natural gas to spend an average of $80 (13%) more this winter than last winter. The increase in natural gas expenditures represents a 14% increase in the average U.S. residential price from last winter, with consumption that is slightly lower than last winter nationally. The projected changes in residential natural gas prices this winter range from a 10% increase in the West to a 15% increase in the Northeast. Several factors contribute to this regional variation, including differences in weather patterns, regional changes in production and pipeline capacity, and differences in regulatory constraints in passing price changes through to customers.

Heating Oil. EIA expects households heating primarily with heating oil to spend an average of about $46 (2%) less this winter than last winter, reflecting a 5% decrease in prices and a 3% increase in consumption. Although winter temperatures are expected to be similar to last winter nationally, weather in the Northeast is expected to be 3% colder than last winter. Reliance on heating oil is highest in the Northeast, where about 25% of households depend on heating oil for space heating, compared with 6% of households nationally. The state of New York, which accounts for about one-third of the region's heating oil market, has required the use of ultra-low sulfur heating oil since July 2012. A number of other states will begin to move away from higher-sulfur heating oil in the coming years.

Propane. About 5% of all U.S. households heat with propane. EIA expects households heating primarily with propane to spend more this winter, but the projected increase varies across regions. EIA expects that households heating with propane in the Midwest will spend an average of $120 (9%) more this winter than last winter, reflecting prices that are about 10% higher and consumption that is 1% lower than last winter. Households in the Northeast are expected to spend an average of $206 (11%) more this winter with average prices that are about 8% higher and consumption that is 3% higher than last year.

Electricity. Households heating primarily with electricity can expect to spend an average of $18 (2%) more this winter with 2% higher prices but consumption slightly lower than last winter. About 39% of all U.S. households rely on electricity as their primary heating source, ranging from 14% in the Northeast to 63% in the South.

Wood. The use of cord wood and wood pellets as the primary residential space heating fuel has increased by 39% since 2004, to about 2.5 million households in 2012. About 8% of households use wood as a secondary source of heat, making wood second only to electricity as a supplemental heating fuel. About 20% of New England homes (1.1 million) used wood for space heating, water heating, or cooking in 2009 (EIA, Residential Energy Consumption Survey, 2009), which is nearly twice the national rate. Almost half of all rural households in New England used wood compared with only 12% of the area's urban households that used the fuel.

Global Crude Oil and Liquid Fuels

Estimated global liquid fuels supply disruptions in September averaged 3.0 million barrels per day (bbl/d), which is unchanged from the revised August estimate and remains at the highest level since at least January 2011. However, some of Libya's production restarted in the second half of September after coming to a near-halt earlier in the month. EIA expects Libya's production to remain at its current level for October, although output still remains considerably below the precrisis level. EIA expects total unplanned outages from both OPEC and non-OPEC countries to decline in October.

Global Liquid Fuels Consumption. EIA projects global consumption to grow by 1.0 million bbl/d in 2013 and by another 1.2 million bbl/d in 2014, with China, the Middle East, Central & South America, and other countries outside of the Organization for Economic Cooperation and Development (OECD) accounting for essentially all consumption growth. Projected OECD liquid fuels consumption declines by 0.2 million bbl/d in 2013 and 0.1 million bbl/d in 2014. The declines in OECD consumption are largely due to lower consumption in Europe and Japan.

Non-OECD Asia, particularly China, is the leading contributor to projected global consumption growth. EIA estimates that liquid fuels consumption in China will increase by 420,000 bbl/d in 2013 and by a further 430,000 bbl/d in 2014, compared with average annual growth of about 510,000 bbl/d from 2003 through 2012. China's steady growth in oil demand has led it to become the world's largest net oil importer, exceeding the United States in September 2013. EIA forecasts this trend to continue through 2014.

Non-OPEC Supply. Forecast non-OPEC liquid fuels production increases by 1.5 million bbl/d in both 2013 and 2014. Growing non-OPEC liquid fuels production contributes to a decline in the call on OPEC crude oil and global stocks (world consumption less non-OPEC production and OPEC non-crude oil production), which falls from an average of 30.2 million bbl/d in 2013 to 29.6 million bbl/d in 2014.

The largest area of non-OPEC supply growth is North America, where production increases by 1.4 million bbl/d and 1.1 million bbl/d in 2013 and 2014, respectively, resulting from continued production growth in U.S. onshore tight oil formations and from Canadian oil sands. EIA expects smaller production growth from a number of other areas, including Central & South America, Asia & Oceania, and Africa. In Central & South America, forecast liquid fuels supply increases by 0.1 million bbl/d and 0.2 million bbl/d in 2013 and 2014, respectively, mainly driven by increases in Brazil's offshore, pre-salt oilfields output. EIA expects total liquid fuels supply in Asia & Oceania to increase by 0.2 million bbl/d in 2014, led by Malaysia.

Kazakhstan's Kashagan oilfield is the largest to be discovered in the past 35 years. The project's operator expects commercial production to start in October. While the oilfield has significant potential, technical challenges and high development costs may limit its expansion and EIA expects field production to reach just 25,000 bbl/d by the end of 2013.

EIA made upward revisions of 0.2 million bbl/d to estimated non-OPEC outages in both July and August, putting outages at 1.0 million bbl/d and 0.8 million bbl/d, respectively. The change resulted from downward revisions to China's production for both months because of flooding in southwestern and northern China that curbed output from the major Changqing and Daqing fields.

Of the estimated 3.0 million bbl/d of global unplanned supply disruptions in September, approximately 0.6 million bbl/d occurred among non-OPEC producers. Total non-OPEC supply disruptions have fallen since July largely because of a decline in outages in Canada, Brazil, and Colombia. In September, Syria, Yemen, South Sudan, and China accounted for all non-OPEC supply disruptions, although EIA expects outages in the latter two countries to decline in October.

OPEC Supply. EIA projects total OPEC liquid fuels production to decline by 0.8 million bbl/d in 2013 and by an additional 0.3 million bbl/d in 2014. The declines in 2013 mostly reflect supply outages among some OPEC producers, along with an overall decrease in Saudi Arabia's production in response to the increase in non-OPEC supply. Over the first three months of 2013, Saudi Arabia's crude oil production averaged 830,000 bbl/d lower than the same period last year. However, Saudi Arabia's crude oil production rose from 9.1 million bbl/d in March to 10.2 million bbl/d in August, in part to offset recent global supply disruptions. EIA expects Saudi Arabia and other OPEC members to begin cutting back as some of the disrupted production comes back online and non-OPEC supply continues to grow.

Overall OPEC crude oil unplanned disruptions in September averaged 2.4 million bbl/d, an increase of 0.2 million bbl/d over the previous month attributed solely to Libya. Widespread protests at key oil installations in Libya resulted in an average of 1.2 million bbl/d offline in September. The situation improved somewhat in the latter half of September after oilfields and loading ports in western Libya restarted operations. Libya's outage volume at the end of the month stood at 930,000 bbl/d.

Planned maintenance work started on Iraq's southern export terminals in September, contributing to an almost 450,000 bbl/d month-over-month decrease in total crude oil output. EIA excludes this volume from unplanned outage estimates. EIA estimates that unplanned crude oil disruptions in Iraq were 260,000 bbl/d in September, stemming mostly from persistent attacks on the Kirkuk-Ceyhan pipeline between Iraq and Turkey.

Total OPEC surplus crude oil production capacity in the third quarter of 2013 averaged 1.7 million bbl/d, which is 0.3 million bbl/d below the year-ago level and 1.4 million bbl/d lower than the historical 2010-12 average. EIA projects OPEC surplus capacity will increase to an average of 2.4 million bbl/d in the fourth quarter of 2013, and 4.2 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 offline because of the effects of U.S. and European Union 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 roughly 58 days of supply. OECD oil inventories are projected to end 2013 at 2.58 billion barrels and end 2014 at 2.57 billion barrels (56 days of supply).

Crude Oil Prices. Brent crude oil spot prices fell from a recent peak of $117 per barrel in early September to $108 per barrel at the end of the month. EIA expects the Brent crude oil price to continue to weaken as non-OPEC supply grows, averaging $107 per barrel during the fourth quarter of 2013 and $102 per barrel in 2014.

The forecast WTI crude oil spot price, which averaged $106 per barrel during September, averages $101 per barrel during the fourth quarter of 2013 and $96 per barrel during 2014. The discount of WTI crude oil to Brent crude oil, which averaged $18 per barrel in 2012 and then fell to $3 per barrel in July 2013, averaged $5 per barrel during September. EIA expects the WTI discount to average $6 per barrel during the fourth quarter of 2013 and during 2014.

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 January 2014 delivery traded during the five-day period ending October 3, 2013, averaged $102 per barrel. Implied volatility averaged 20%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in January 2014 at $85 per barrel and $121 per barrel, respectively. Last year at this time, WTI for January 2013 delivery averaged $92 per barrel and implied volatility averaged 31%. The corresponding lower and upper limits of the 95% confidence interval were $70 per barrel and $121 per barrel.

U.S. Crude Oil and Liquid Fuels

After reaching $3.68 per gallon on July 22, 2013, U.S. regular gasoline retail prices fell to $3.43 per gallon on September 30, 2013. The largest declines in retail gasoline prices before Labor Day were seen along the West Coast, with ample inventories and an absence of refinery outages such as those that occurred during the summer of 2012. EIA expects regular gasoline retail prices to average $3.34 per gallon during the fourth quarter of 2013.

U.S. Liquid Fuels Consumption. In 2012, total liquid fuels consumption declined by 390,000 bbl/d (2.1%). Total liquid fuels consumption for the first three quarters of 2013 rose 110,000 bbl/d (0.6%) compared with the same period last year, led by increases in liquefied petroleum gas and distillate consumption. Motor gasoline and jet fuel consumption, however, remained relatively flat, reflecting moderate growth in travel activity offset by continued efficiency growth for both fuels. These patterns extend to the fourth quarter, resulting in overall liquid consumption growth of 0.7% for the year as a whole. In 2014, total consumption of liquid fuels remains close to its 2013 level. EIA continues to expect gasoline consumption to decline in 2014 by 0.4% as continued improvements in new-vehicle fuel economy boost overall fuel efficiency growth, which outpaces growth in highway travel. Distillate consumption rises by 2.1% in 2014, buoyed by growth in industrial production, in the imports of goods, and an increase in coal production.

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 7.5 million bbl/d in 2013 and 8.5 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 liquid fuel net imports fell to 7.4 million bbl/d in 2012, and EIA expects net imports to continue declining to an average of 5.3 million bbl/d by 2014. Similarly, the share of total U.S. consumption met by liquid fuel net imports peaked at more than 60% in 2005 and fell to an average of 40% in 2012. EIA expects the net import share to decline to 28% 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 \$3.53 per gallon during September, will average \$3.34 per gallon during the fourth quarter of 2013. Led by falling crude oil prices, the projected U.S. annual average regular gasoline retail price falls from \$3.63 per gallon in 2012 to an average of \$3.52 per gallon in 2013 and \$3.40 per gallon in 2014. Diesel fuel prices, which averaged \$3.97 per gallon in 2012, are projected to average \$3.93 per gallon in 2013 and \$3.76 per gallon in 2014.

Natural Gas

Under the baseline winter weather scenario, EIA expects end-of-October working gas inventories will total 3,830 billion cubic feet (Bcf) and end March 2014 at 1,890 Bcf. The projected 1,940 Bcf inventory drawdown during this winter is similar to the previous five-winters (October 2008 – March 2013) average of 1,940 Bcf. Because storage withdrawals are primarily used to meet winter heating demand, changes in weather can significantly alter winter drawdowns. This year's Winter Fuels Outlook projects a drawdown of 2,340 Bcf in the cold-winter scenario (heating degree days 10% higher than projected), and 1,560 Bcf in the warm-winter scenario (10% fewer heating degree days). In the cold-winter scenario, storage inventories exit the heating season with a projected 1,450 Bcf at the end of March. However, this cold-winter scenario ending stock level is still higher than the average 1,271 Bcf end-of-winter stocks during the previous decade (2000-2009), reflecting increases in storage capacity as well as production over the last few years.

U.S. Natural Gas Consumption. EIA expects that natural gas consumption, which averaged 69.7 Bcf/d in 2012, will average 70.0 Bcf/d and 69.4 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 22.1 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 70.0 Bcf/d in 2013 and to 70.4 Bcf/d in 2014. Natural gas pipeline gross imports, which have fallen over the past five years, are projected to fall by 0.3 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 September 27, working gas stocks totaled 3,487 Bcf, which is 155 Bcf less than at the same time last year, and 49 Bcf greater than the previous five-year (2008-12) average for that week. EIA projects inventories will total 3,830 Bcf at the end of the injection season, and 1,890 Bcf at the end of March 2014, the end of the winter heating season.

U.S. Natural Gas Prices. Natural gas spot prices averaged $3.62 per MMBtu at the Henry Hub in September, up 19 cents from the previous month's price. While prices declined from April through August, they began increasing last month in anticipation of winter heating demand. 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 $4.00 per MMBtu in 2014.

Natural gas futures prices for January 2014 delivery (for the five-day period ending October 3, 2013) averaged $3.83 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for January 2014 contracts at $2.91 per MMBtu and $5.04 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for January 2013 averaged $3.84 per MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $2.77 per MMBtu and $5.31 per MMBtu.

Coal

Coal production, based on preliminary data for the first eight months, is down 3% from the same period last year. Production was down in nearly every coal-producing region (Illinois Basin (ILB) production was up 3%), but the largest decline was in the Appalachian region. Coal production in the Appalachian region was down 7% with Central Appalachian Basin (CAP) production down 12%. A recent report released by the Kentucky Energy and Environment Cabinet (KEEC) showed that employment at the state's coal mines was at it's the lowest level since the data was first collected in 1927. In the two years since July 2011, the KEEC reported that employment at eastern Kentucky (CAP) mines fell by nearly 42%. Western Kentucky (ILB) mines saw employment fall only 2 % over the same time period. There are signs that the shift in production will continue as several power generators have announced plans to shift from CAP coal to cheaper, though higher in sulfur content, ILB coal. Retrofitting of coal-fired generating units with flue-gas desulfurization (FGD), or scrubbers, contributes to this shift to higher-sulfur coal.

U.S. Coal Supply. Coal production in the first half of 2013 was 488 million short tons (MMst), 20 MMst (3.9%) lower than in the same period of 2012. EIA projects higher production in all regions during the second half of 2013 with total coal production of 1,012 MMst in 2013. Coal production is forecast to grow by 3.1% in 2014 to 1,043 MMst as inventories stabilize and consumption increases.

Inventory draws are expected to meet most of the growth in consumption in 2013. Total coal inventories fell by 19 MMst during the first half of 2013. EIA forecasts an additional 10 MMst of inventory withdrawals over the second half of 2013.

U.S. Coal Consumption. EIA estimates that total coal consumption for the first half of 2013 was 446 MMst, or 36 MMst (8.8%) 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 936 MMst (a 5.1% increase over 2012). Consumption grows at about half that rate (2.8%), to 962 MMst in 2014.

U.S. Coal Exports. EIA estimates that first-half 2013 exports totaled 61 MMst, which was 5 MMst lower than the same period last year. 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 105 MMst in 2014. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, increasing coal output 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. 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 \$2.33 per MMBtu in 2013. EIA forecasts average delivered coal prices of \$2.34 per MMBtu in 2014.

Electricity

The electricity industry retired 10.5 gigawatts (GW) of coal-fired generating capacity during 2012. Most of this capacity consisted of older, inefficient units, which generators found uneconomical to run as a result of low natural gas prices and slow growth in electricity demand. Coal capacity retirements have continued into 2013, albeit at a slower pace, with 1.4 GW reported to EIA through July. Despite the retirements, coal-fired generation during the first seven months of 2013 was 7.5% higher than the same period last year as generators utilized existing capacity at higher rates in response to rising natural gas prices.

U.S. Electricity Consumption. EIA expects U.S. retail sales of electricity to the residential sector to grow by 0.4% in 2013 and fall by 1.0% in 2014. About two-thirds of households in the South Census region use electricity as their primary heating source. Heating degree days in this region during the upcoming winter months (October-March) are expected to be slightly higher than last winter. Growth in the total number of households, leads to a 1.0% winter-over-winter increase in residential electricity sales in the South region.

U.S. Electricity Generation. EIA expects total U.S. electricity generation will grow by 0.1% in 2013 and by 0.4% in 2014. Despite the retirement of coal-fired generating capacity, higher prices for natural gas delivered to electric generators drive a projected 6.1% increase in coal generation this year while natural gas-fired generation falls by 9.8%. The addition of new capacity leads to a 14% increase in generation from renewable energy sources other than hydropower during 2013, and contributes about 6% of total generation.

U.S. Electricity Retail Prices. The rising cost of generation fuels, particularly natural gas, contributes to a projected increase in the residential price of electricity. During the upcoming winter months, EIA expects the U.S. residential electricity price to average 11.9 cents per kilowatthour, which is 2.3% higher than the winter of 2012-13.

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 4.5% in 2013. While hydropower declines by 1.5%, nonhydropower renewables used for electricity and heat generation grow by an average of 8.3% in 2013. In 2014, the growth in renewables consumption for electric power and heat generation is projected to continue at a rate of 2.3%, as a 0.9% increase in hydropower is combined with a 3.1% increase in nonhydropower renewables.

EIA estimates that wind capacity will increase by 2.5% this year to about 61 GW and will total more than 66 GW in 2014. EIA has lowered the 2014 capacity projection for wind by 3.5% from last month's STEO, under the assumption that some wind power projects will be delayed to the following year. Recently updated Internal Revenue Service guidance on production tax credits (PTC) has clarified that all projects that begin construction by the end of 2013 and enter service by the end of 2015 will qualify for the PTC. Electricity generation from wind is projected to increase by 19% in 2013 and by 2.4% in 2014, contributing more than 4% of total electricity generation.

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 0.3% by 2014. 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 79% in 2013 and 80% in 2014.

U.S. Liquid Biofuels. The ethanol industry is beginning to show some recovery from last year's drought when fuel ethanol production fell from an average 900,000 bbl/d in the first half of 2012 to an average of 820,000 bbl/d from July 2012 through March 2013. Ethanol production averaged 850,000 bbl/d during September 2013 and is forecast to average 880,000 bbl/d during 2014. 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 128 million gallons (98,000 bbl/d) in July 2013. Biodiesel production is forecast to average about 82,000 bbl/d in 2013 and 87,000 bbl/d in 2014.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels declined by 4.0% in 2012, and projects increases of 1.7% in 2013 and 0.9% 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

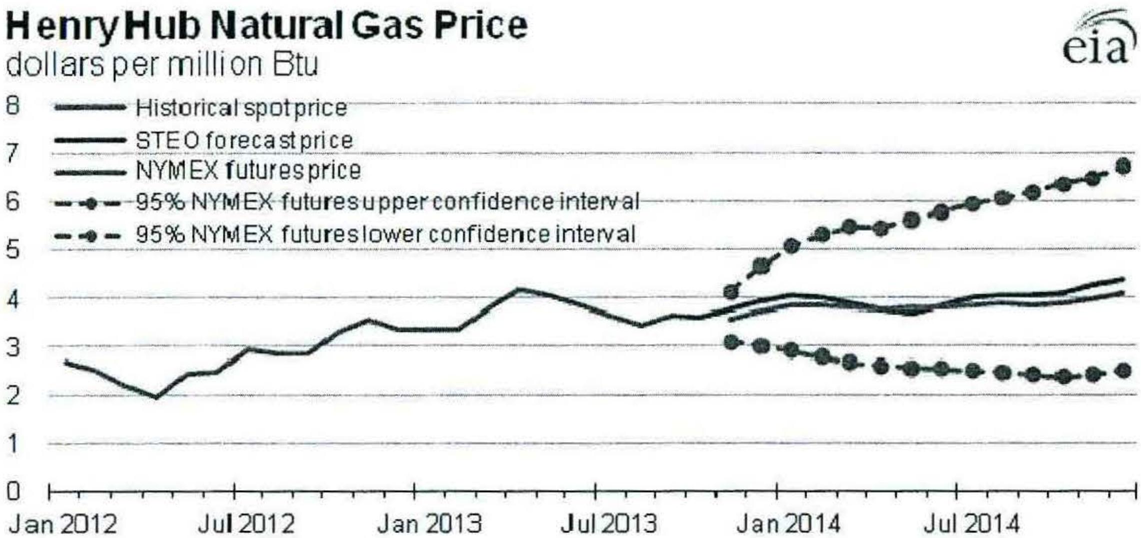
EIA uses the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO. The GI simulation used in this STEO includes recent revisions to the National Income and Product Accounts (NIPA) by the U.S. Bureau of Economic Analysis (BEA). It also assumes that the spending cuts mandated in the Budget Control Act of 2011 (sequestration) are replaced by a combination of tax and spending changes that are implemented in 2014. In addition, the GI forecast does not make any assumptions about the economic impacts of a government shutdown, but 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. Bureau of Economic Analysis reported that real disposable personal income rose 0.3% from July to August 2013, while real consumption expenditures rose 0.2% over the same time period. The U.S. Department of Labor also reported that initial weekly unemployment insurance claims were 308,000 in the week ending September 28, 2013, an increase of 1,000 from the previous week's figure, but still lowering the 4-week moving average to 305,000. The U.S. Census Bureau reported that new orders for manufactured durable goods rose 0.1% in August, following a revised 8.1% decrease in July.

U.S. Production and Income. Forecast U.S. real GDP grows by 1.6% in 2013 and 2.6% in 2014. Year-on-year real GDP growth begins to accelerate in the second half of 2014, eventually rising to 3.0% in the fourth quarter of 2014. Forecast real disposable income increases 0.5% in 2013 and 3.2% in 2014. Total industrial production grows almost one percentage point faster than real GDP in 2013 at 2.3%, and its projected growth of 3.0% in 2014 is still well above the growth rate of real GDP.

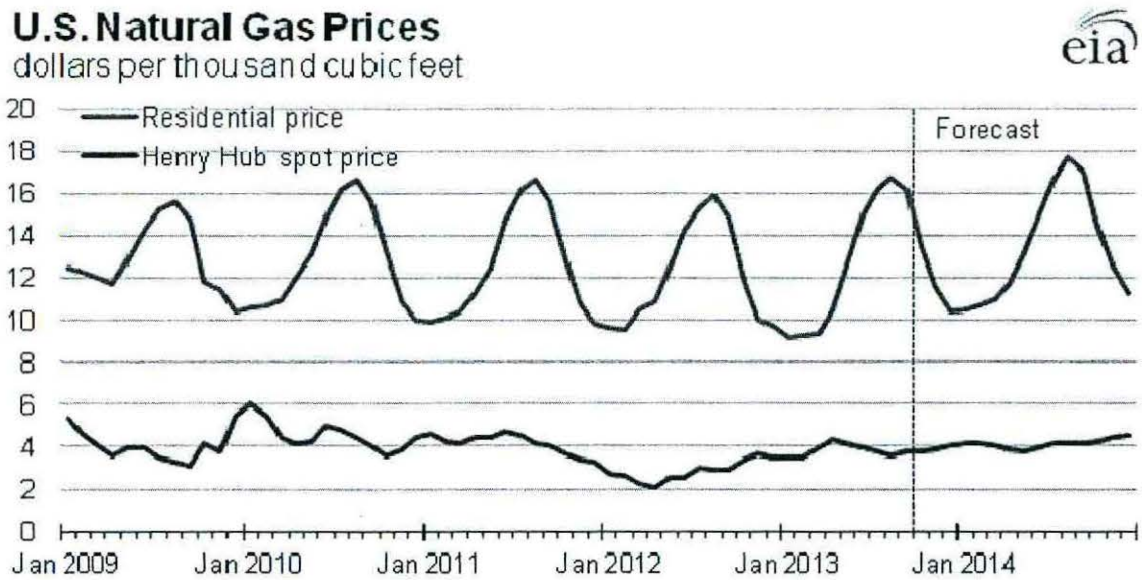
U.S. Expenditures. Private real fixed investment growth averages 4.6% and 8.0% over 2013 and 2014, respectively. Real consumption expenditures grow faster than real GDP in 2013, at 1.9%, but slows below the rate of real GDP growth in 2014, at 2.5%. Export growth triples from 1.7% to 5.1% over the same two years. Government expenditures fall 3.0% in 2013, and rise by 0.1% in 2014.

U.S. Employment, Housing, and Prices. The unemployment rate in the forecast averages 7.6% over 2013, and gradually falls to 6.9% at the end of 2014. This is accompanied by nonfarm employment growth averaging 1.7% in both 2013 and 2014. Consistent with an improving housing sector, housing starts grow an average of 20% and 29% in 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.



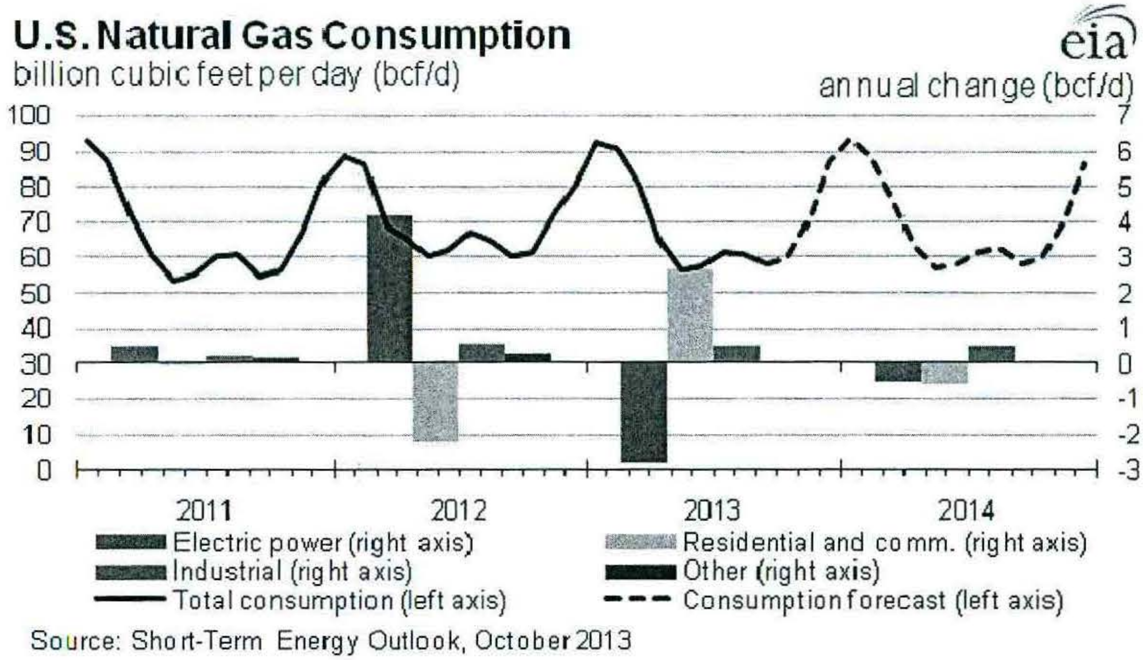
Note: Confidence interval derived from options market information for the 5 trading days ending October 3, 2013. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, October 2013

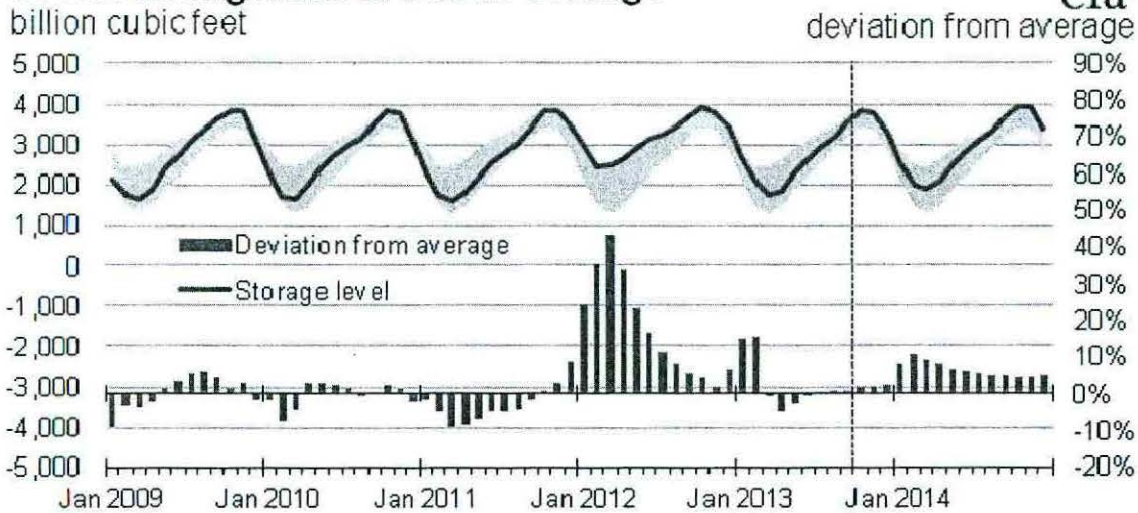


Source: Short-Term Energy Outlook, October 2013

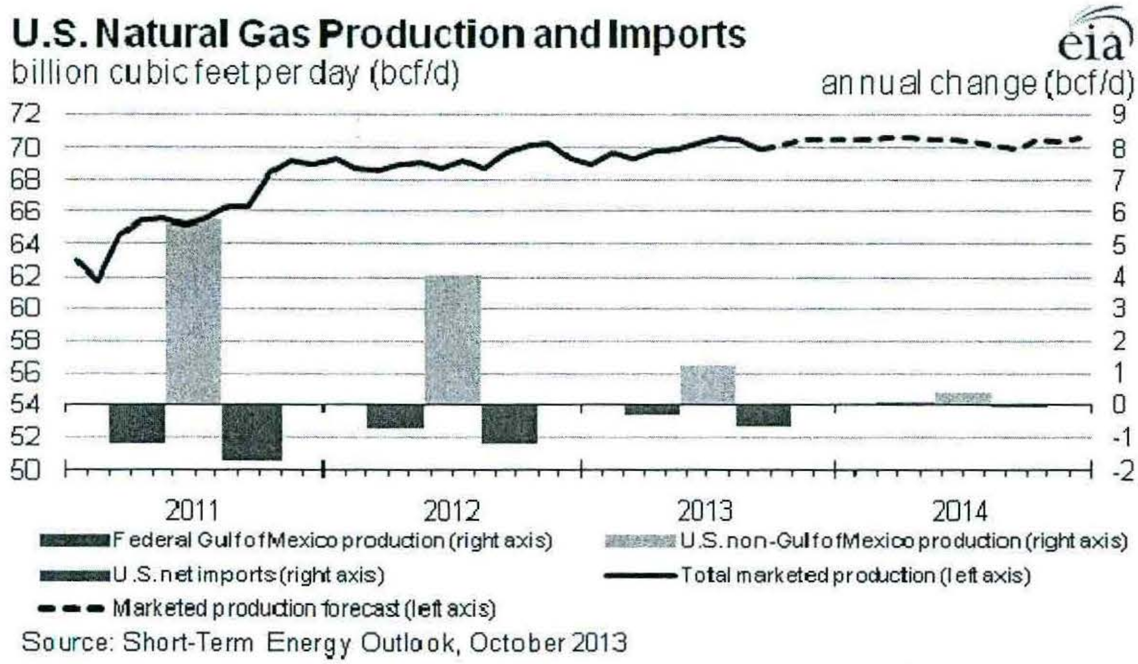
http://www.eia.gov/forecasts/steo/images/Fig5.png


U.S. Natural Gas Consumption
billion cubic feet per day (bcf/d)
eia
annual change (bcf/d)
100
90
80
70
60
50
40
30
20
10
0
7
6
5
4
3
2
1
0
-1
-2
-3
2011
2012
2013
2014
Electric power (right axis)
Residential and comm. (right axis)
Industrial (right axis)
Other (right axis)
Total consumption (left axis)
Consumption forecast (left axis)
Source: Short-Term Energy Outlook, October 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, October 2013


U.S. Natural Gas Production and Imports
billion cubic feet per day (bcf/d)
annual change (bcf/d)
eia
72
70
68
66
64
62
60
58
56
54
52
50
9
8
7
6
5
4
3
2
1
0
-1
-2
2011
2012
2013
2014
Federal Gulf of Mexico production (right axis)
U.S. non-Gulf of Mexico production (right axis)
U.S. net imports (right axis)
Total marketed production (left axis)
Marketed production forecast (left axis)
Source: Short-Term Energy Outlook, October 2013

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

NorthWestern Energy Docket No. D2012.9.94

On September 28, 2012, NorthWestern Energy filed an application to increase natural gas rates in Montana with the Montana Public Service Commission. On March 20, 2013, the Montana Public Service Commission issued an interim order authorizing NorthWestern to implement an interim increase effective April 1, 2013.

On May 7, 2013, the Montana PSC issued its Final Order authorizing NorthWestern to increase its rates effective June 1, 2013. NorthWestern refunded to customers the difference between the current level of interim rates that had been in effect since April 1, 2013 and the final rates approved in its Final Order for service rendered on or after June 1, 2013 through a Natural Gas Delivery Services Rebate.

On September 16, 2013, NorthWestern filed to expire the Natural Gas Delivery Services Rebate and filed new adjusted final natural gas rates to be effective September 20, 2013.

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 DECEMBER 2013

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
Gas Cost Adjustment:				
Gas Cost Level (Exhibit B)	$4.830	$4.917	$3.847	$3.830
Prior Gas Cost	4.641	4.726	3.677	3.660
Current Gas Cost Adjustment	$0.189	$0.191	$0.170	$0.170
Surcharge Adjustment:				
Current Adjustment	$0.024	$0.024	$0.116	$0.181
Prior Adjustment	0.024	0.024	0.116	0.181
Change in Surcharge Adjustment	$0.000	$0.000	$0.000	$0.000
Market Based Pricing Differential				
Current Adjustment	($0.012)	($0.012)	$0.000	$0.000
Prior Adjustment	(0.012)	(0.012)	0.000	0.000
Change in Margin Sharing Provision	$0.000	$0.000	$0.000	$0.000
Net Increase (Decrease) in Gas Costs	**$0.189**	**$0.191**	**$0.170**	**$0.170**
Gas Cost Level	$4.830	$4.917	$3.847	$3.830
Plus: Surcharge	0.024	0.024	0.116	0.181
Total Gas Cost Level in Tariff Rates	$4.854	$4.941	$3.963	$4.011

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

Cost of Gas - Propane	
Current Propane Cost (Exhibit F)	$13.723
Prior Propane Cost	12.075
Current Propane Cost Adjustment	$1.648
Surcharge Adjustment	
Current Adjustment	($0.777)
Prior Adjustment	(0.777)
Change in Surcharge Adjustment	$0.000
Market Based Pricing Differential	
Current Adjustment	($0.012)
Prior Adjustment	(0.012)
Change in Margin Sharing Provision	$0.000
Net Increase (Decrease) in Gas Costs	**$1.648**
Propane Cost Level	$13.723
Plus: Surcharge	(0.777)
Total Propane Cost Level in Rates	**$12.946**

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

	Amount
Total Gas Costs 1/	$70,862,062
Residential and General Service dk Requirements 2/	14,738,364
Average Cost of Gas per dk	$4.808
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.830
Less: Gas Cost Level in Rates 3/	4.641
Current Gas Cost Adjustment	**$0.189**

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 September 30, 2013, adjusted for losses at .45%.
3/ Gas Cost Level in Current Tariff Rates Case No. PU-13-008 effective October 1, 2013:

Cost of Purchased Gas	$4.620
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$4.641

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

Total Gas Costs 1/	$70,862,062
Less: Annual MDDQ Costs 1/	13,478,010
Total Gas Costs excluding MDDQ	$57,384,052
Firm Service Requirements 1/	14,738,364
Other Gas Costs per Dk (excluding MDDQ)	$3.894
Winter - October - May	
Annual MDDQ Costs 1/	$13,478,010
Winter Firm Service Requirements	13,459,236
MDDQ Costs per Winter Dk	$1.001
Add: Other Gas Costs per Dk	3.894
Winter Seasonal Rate	$4.895
Winter Seasonal Rate, adjusted for losses 2/	$4.917
Less: Gas Cost Level in Rates 3/	4.726
Current Gas Cost Adjustment	**$0.191**

1/ Exhibit B, page 1.
2/ Loss factor of .45%.
3/ Gas Cost Level in Current Tariff Rates Case No. PU-13-008 effective October 1, 2013:

	Winter
Cost of Purchased Gas	$4.705
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$4.726

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

	Amount
Total Gas Costs 1/	$13,415,286
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	$3.830
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.847
Less: Gas Cost Level in Rates 2/	3.677
Current Gas Cost Adjustment	**$0.170**

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 October 1, 2013:

Cost of Purchased Gas	$3.660
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$3.677

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

	Amount
Total Gas Costs 1/	$3,370,334
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	$3.830
Less: Gas Cost Level in Rates 2/	3.660
Current Gas Cost Adjustment	**$0.170**

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 October 1, 2013:
Cost of Purchased Gas $3.660

Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
December 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	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.	737.928
MINIMUM	RATE PER EQV. DKT PER MO	0.000	N.A.	N.A.	0.000
COMMODITY CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	3.120	N.A.	N.A.	3.120
MINIMUM A/B/C/	RATE PER DKT	3.120	N.A.	N.A.	3.120
SCHEDULED OVERRUN CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	30.884	N.A.	N.A.	30.884
MINIMUM A/B/C/	RATE PER DKT	3.120	N.A.	N.A.	3.120
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	24.261	N.A.	N.A.	24.261
MINIMUM	RATE PER DKT	0.000	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 2.766%, CONSISTING OF 3.057% 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 1.230 CENTS, CONSISTING OF 1.300 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.

C/ SHIPPER MUST REIMBURSE TRANSPORTER FOR THE ACA SURCHARGE. SUCH SURCHARGE SHALL BE THE ACA UNIT CHARGE SPECIFIED IN THE ANNUAL NOTICE ISSUED BY THE FERC ENTITLED "FY [YEAR] GAS ANNUAL CHARGES CORRECTION FOR ANNUAL CHARGES UNIT CHARGE."

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FTN-1					
RESERVATION CHARGE					
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)					
MAXIMUM	RATE PER EQV. DKT PER MO.	47.491	N.A.	N.A.	47.491
MINIMUM	RATE PER EQV. DKT PER MO.	1.589	N.A.	N.A.	1.589
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	1.561	N.A.	N.A.	1.561
MINIMUM	RATE PER DKT	0.052	N.A.	N.A.	0.052

8NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FS-1					
CAPACITY RESERVATION CHARGE					
MAXIMUM	RATE PER EQV. DKT PER MO.	2.102	N.A.	N.A.	2.102
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	0.000
CAPACITY DELIVERABILITY CHARGE					
MAXIMUM	RATE PER EQV. DKT PER MO.	190.602	N.A.	N.A.	190.602
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	0.000
INJECTION CHARGE					
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
WITHDRAWAL CHARGE					
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
SCHEDULED OVERRUN CHARGE					
INJECTION					
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
WITHDRAWAL					
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	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 0.996%, CONSISTING OF 1.163% 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 0.131 CENTS, CONSISTING OF 0.098 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.

Exhibit B
Page 8 of 14

STATEMENT OF RATES
2/ 3/

Rate Schedule	Long-Term Base Tariff Rate (per 100 Dth-Miles) 1/
T-1 and T-1B	
Daily Reservation Rate - Port of Morgan, MT to Ventura, IA	
Maximum	\$0.0286
Minimum	\$0.0000
Daily Reservation Rate - Ventura, IA to North Hayden, IN	
Maximum	\$0.0307
Minimum	\$0.0000
Commodity Rate - Port of Morgan, MT to North Hayden, IN	
Maximum	\$0.0004
Minimum	\$0.0004

1/ Applicable to any Rate Schedule T-1 U.S. Shippers Service Agreement or any Rate Schedule T-1B Service Agreement with a primary term of at least twelve consecutive months.

2/ The Settlement Rates, pursuant to Articles II and VII of the September 27, 2012, Stipulation at Docket Nos. RP06-72-000, et al., remain in effect until such rates are superseded by new rates placed into effect consistent with the provisions of the Stipulation.

3/ Rates in this section are subject to the revenue retrieval provision pursuant to Article V.A of the September 27, 2012, Stipulation at Docket Nos. RP06-72-000, et al.

Service	Rates, Tolls and Charges
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month based on a three year term (Price Point "B") & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) $ 216.99/10^3m^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 $ 5.70/GJ FT-D Demand Rate for Group 2 Delivery Points [1] $ 3.34/GJ FT-D Demand Rate for Group 3 Delivery Points [2] $ 4.00/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	Contract Term — Effective LRS Rate ($/$10^3m^3$/day) 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 $ 129.55/10^3m^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	Schedule No — PT Rate — PT Gas Rate 9009-01001-1 — $ 660.00/d — 50.0 10^3m^3/d
14. Rate Schedule OS	Schedule No. — Charge 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 — $ 0.1097 / 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

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	5.74	0.2076
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	3.34	0.1207
31110	ALLIANCE EDSON INTERCONNECT APN	3.34	0.1207
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	3.34	0.1207
3002	BOUNDARY LAKE BORDER	3.55	0.1283
1958	EMPRESS BORDER	5.64	0.2041
3886	GORDONDALE BORDER	3.55	0.1283
6404	MCNEILL BORDER	5.64	0.2041

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	3.34	0.1207	
31003	AGRIUM CARSELAND SALES APS	3.34	0.1207	
31002	AGRIUM FT. SASK SALES APN	3.34	0.1207	Yes
31004	AGRIUM REDWATER SALES APN	3.34	0.1207	
31005	AINSWORTH SALES APGP	3.39	0.1226	
31006	AIR LIQUIDE SALES APN	3.39	0.1226	
3214	AKUINU RIVER WEST SALES	3.34	0.1207	
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	3.55	0.1283	
3059	ALLISON CREEK SALES	3.34	0.1207	
31009	ALTASTEEL SALES APN	3.39	0.1226	Yes[2]
3562	AMOCO SALES (BP SALES TAP)	3.34	0.1207	
31012	APL JASPER SALES APN	3.39	0.1226	Yes
3488	ARDLEY SALES	3.34	0.1207	
3216	AURORA NO 2 SALES	3.34	0.1207	
3135	AURORA SALES	3.34	0.1207	
3423	BASHAW WEST SALES	3.34	0.1207	
31013	BAYMAG SALES APS	3.34	0.1207	
31014	BEAR CREEK COGEN SALES APGP	3.39	0.1226	
3068	BEAVER HILLS SALES	3.34	0.1207	
3933	BIG EDDY INTERCONNECTION	3.34	0.1207	
3067	BIGSTONE SALES	3.34	0.1207	
3468	BLEAK LAKE SALES	3.34	0.1207	
3225	BOTHA SALES	3.34	0.1207	
3164	BRAINARD LAKE SALES	3.34	0.1207	
3918	BUFFALO CREEK INTERCONNECTION	3.34	0.1207	
31015	BURDETT COGEN SALES APS	3.34	0.1207	
3204	CABIN SALES	3.34	0.1207	
3109	CALDWELL SALES	3.34	0.1207	
31016	CALGARY ENERGY CENTRE SALES APS	3.34	0.1207	Yes
3634	CANOE LAKE SALES	3.34	0.1207	
3165	CANOE LAKE SALES NO 2	3.34	0.1207	
3866	CARBON INTERCONNECTION	3.34	0.1207	
3484	CARIBOU LAKE SALES	3.34	0.1207	
3157	CARIBOU LAKE SOUTH SALES	3.34	0.1207	
3106	CARMON CREEK SALES	3.34	0.1207	
3101	CAROLINE SALES	3.34	0.1207	
31017	CARSELAND COGEN SALES APS	3.34	0.1207	
3495	CAVALIER SALES	3.34	0.1207	
31018	CHAIN LAKES COOP SALES APS	3.34	0.1207	
3907	CHANCELLOR INTERCONNECTION	3.34	0.1207	
3151	CHEECHAM WEST NO 2 SALES	3.34	0.1207	
3622	CHEECHAM WEST SALES	3.34	0.1207	
6014	CHEVRON AURORA SALES	3.34	0.1207	
31019	CHEVRON FT. SASK SALES APN	3.39	0.1226	Yes
3097	CHICKADEE CREEK SALES	3.34	0.1207	
3305	CHIGWELL NORTH SALES	3.34	0.1207	
3496	CHIPEWYAN RIVER SALES	3.34	0.1207	

NATURAL GAS TARIFF

NorthWestern Energy

	34^{th}	Revised	Sheet No.	80.1
Canceling	33^{rd}	Revised	Sheet No.	80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge	
5,001 to 10,000	$ 120.20	(I)
10,001 to 30,000	$ 172.80	(I)
>30,000	$ 383.45	(I)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	$ 0.9826075	(I)

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	$ 0.0074460	(I)
Minimum	$ 0.0017935	
GTAC Amortization	$ (0.0013032)	
Balancing Penalty Rate	Higher of $25.00/ Dekatherm Or 150% of Market Price	

PLUS:

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

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

MINIMUM BILL: Per respective contracts.

(continued)

GAS RATE SCHEDULE

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

NG00-001

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
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

Division	Receipt Point	Delivery Point	Monthly Customer Charge	Maximum Demand Charge 6/	Minimum Demand Charge 6/	Maximum Transportation Charge 2/	Minimum Transportation Charge 2/	Fuel Reimbursement Quantity Percentage 3/
TC (Casper) Firm Transportation	MLI	MLI	$0.00	$9.50	$0.00	$0.1040	$0.0010	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 DECEMBER 2013

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2013	$12,209,780	$530,223	$3,397,692
November	9,744,553	444,791	2,765,388
December	5,993,668	347,507	1,336,947
January 2014	408,817	172,599	(341,514)
February	(2,341,550)	86,463	(1,521,407)
March	(2,810,156)	71,786	(2,295,013)
April	(2,864,778)	70,076	(2,119,421)
May	(1,987,834)	116,434	(1,231,930)
June	(215,523)	210,127	(43,613)
July	3,656,808	416,856	1,131,309
August	7,498,293	621,654	2,309,843
September	10,486,910	780,639	3,283,724
October	12,067,172	864,705	3,470,295
13 month average	$3,988,166	$364,143	$780,177
Rate of Return	8.791%	8.791%	8.791%
Return	$350,600	$32,012	$68,585
Return Requirement	$475,948	$43,457	$93,106

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 DECEMBER 2013

Cost of Purchased Propane	$95,626
Gallons Purchased	76,501
Projected dk Sales	7,000
Propane Cost per Dk	$13.661
Average Cost of Propane as Adjusted for Losses @ 99.55%	13.723
Less: Propane Cost Level in Rates 1/	12.075
Current Propane Cost Adjustment	$1.648

1/ Propane Cost Level in Current Rates - Case No. PU-13-008, effective October 1, 2013.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2013									**$268,918**
August	($171,535)	$0	$6	($171,529)	283,161	($0.113)	($31,997)	($139,532)	129,386
September	(10,802)	387,468 2/	2	376,668	259,134	(0.113)	(29,282)	405,949	535,335
Balance @ September 30, 2013									**$535,335**

1/ Interest calculated at the 90 day Treasury Note rate.
2/ Adjustment to correct gas costs for the period December 2010 - August 2013 due to a billing error.

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

	(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, 2013									**$162,872**
August	($8,729)	$0	$4	($8,725)	32,348	($0.115)	($3,719)	($5,006)	157,866
September	(2,593)	0	1	(2,592)	33,833	(0.115)	(3,891)	1,299	159,165
Balance @ September 30, 2013									**$159,165**

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

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, 2013									**$86,961**
August	($1,327)	$0	$2	($1,325)	4,039	($0.377)	($1,522)	$197	87,158
September	(5,633)	0	1	(5,632)	4,641	(0.377)	(1,750)	(3,882)	83,276
Balance @ September 30, 2013									**$83,276**

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