

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

August 8, 2014

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

Re: Cost of Gas Adjustment
(COG) Rate 88
Case No. PU-14-008

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

Attachment A is the Rate Summary Sheet (128th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered September 1, 2014.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.714 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. 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 \$0.051 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 September 2014.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.664 per dk for residential and firm general customers, a decrease of \$0.715 per dk for small and large interruptible customers and a decrease of \$0.712 per dk for Air Force customers from the currently effective rates.

Exhibit B shows the calculation of the current gas cost adjustment that will be applicable to Montana-Dakota's customers for the month of September 2014. The average cost of gas for firm customers, adjusted for losses, is \$5.388.

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

Montana-Dakota purchases propane supplies from various wholesale suppliers. The cost of propane has decreased since the last COG filing due to a decrease in the market price of propane. Attachment B page 2 explains the reasons for the decrease 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 September 2014. The net effect of this filing is a decrease of \$0.549 per dk for all customers from the currently effective rates.

Exhibit D shows the calculation of the current cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of September 2014. The net effect of this filing is a decrease of \$0.549 per dk for all customers from the currently effective rates.

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

These proposed adjustments, calculated in accordance with Rate 88, will amount to a decrease of approximately \$243,300 for natural gas customers during the month of September 2014. All of Montana-Dakota's retail natural customers in North Dakota may be affected by this proposal. There were 101,889 natural gas customers in North Dakota as of June 30, 2014.

Please refer all inquiries regarding this filing to:

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

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

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

Montana-Dakota mailed a check on February 5, 2014 to the North Dakota Public Service Commission for \$500 pursuant to the requirements of North Dakota Century Code Section 49-05-05. This payment will cover the filing fee associated with the monthly COG filings for March 2014 through January 2015.

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

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

Sincerely,



Tamie A. Aberle
Director of Regulatory Affairs

Attachment

**Rate Summary Sheet
(Proposed)**



Montana-Dakota Utilities Co.

A Division of MDU Resources Group, Inc.

400 N 4th Street
Bismarck, ND 58501

State of North Dakota Gas Rate Schedule

NDPSC Volume 7
128th Revised Sheet No. 3
Canceling 127th 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	\$0.4935 per day	\$0.326	\$5.400	\$5.726
Air Force Rate 64	7	\$2,000.00 per month \$175.00 per month			
Minot Air Force Base					
PAR Site					
Firm Service			\$0.329	\$5.400	\$5.729
Interruptible Service - PAR			\$0.260	\$4.276	\$4.536
Interruptible Service - MAFB			\$0.260	\$4.322	\$4.582
Firm General Service Rate 70	13	\$0.67 per day \$1.90 per day			
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet			\$0.730	\$5.400	\$6.130
Small Interruptible Gas Rate 71	14	\$175.00 per month	(Maximum) \$0.929	\$4.276	(Maximum) \$5.205
Optional Seasonal Gas Service Rate 72	15	\$0.67 per day \$1.90 per day			
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet			\$0.730	\$4.171	\$4.901
Transportation Service	24				
Small Interruptible Rate 81		\$175.00 per month			
Maximum			\$0.485		
Minimum			\$0.102		
Fuel Charge				\$0.019	
Large Interruptible Rate 82		\$1,000.00 per month			
Maximum			\$0.297		
Minimum			\$0.061		
Fuel Charge				\$0.019	
Large Interruptible Gas Rate 85	27	\$1,000.00 per month	(Maximum) \$0.718	\$4.276	(Maximum) \$4.994
Residential Propane Rate 90	32	\$0.4935 per day	\$0.326	\$12.159	\$12.485
Firm General Propane Rate 92	34	\$0.67 per day \$1.90 per day			
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet			\$0.730	\$12.159	\$12.889

Date Filed: August 8, 2014

Effective Date: September 1, 2014

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.: PU-14-008

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

September 2014

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.

Contributing factors to the decrease of the index price were regional below-normal temperatures leading to lower power generation gas demand for this part of the country and abundant supplies. The EIA reported the national storage level as of July 25, 2014, was 21.7 percent below the five-year average and 18.7 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 July Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 19. The August Outlook will be published August 12, 2014.

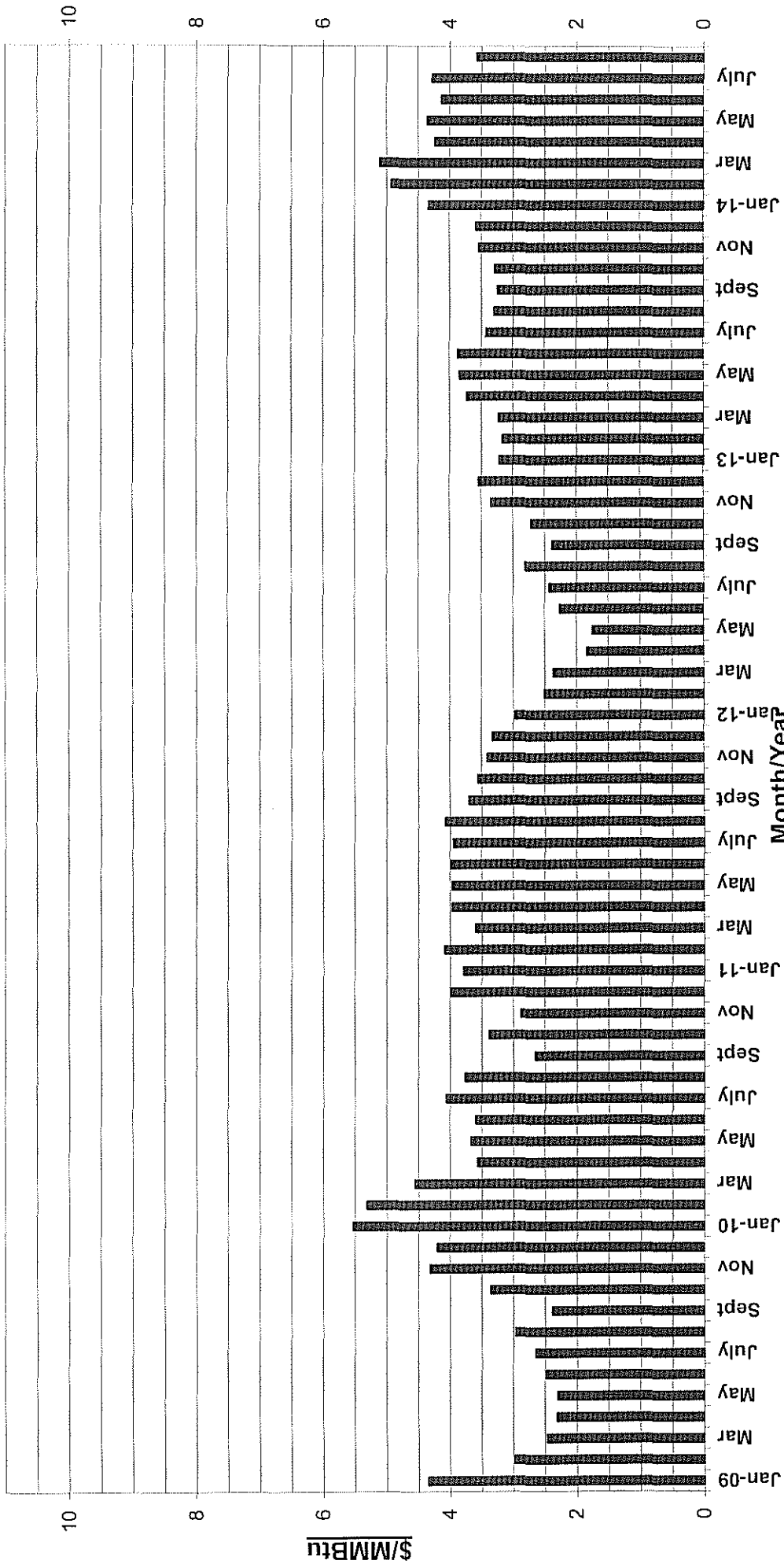
**Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
September 2014**

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 September prices for propane have decreased from the previous level. A change in the price of propane is generally driven by a combination of crude oil prices, weather, and demand and inventory levels. Seasonal usage decreases have resulted in a decrease 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 2009-2014YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2012-\$2.58; 2013-\$3.45; 2014YTD-\$4.37



Independent Statistics & Analysis

U.S. Energy Information
Administration

July 2014

Short-Term Energy Outlook (STEO)

Highlights

- Unrest in Iraq put upward pressure on world oil prices last month, helping North Sea Brent crude oil spot prices reach their highest daily level of the year at just over \$115/barrel (bbl) on June 19. North Sea Brent crude oil spot prices increased from a monthly average of \$110/bbl in May to \$112/bbl in June. This was the 12th consecutive month in which the average Brent crude oil spot price ranged between \$107/bbl and \$112/bbl. EIA projects Brent crude oil prices to average \$110/bbl in 2014 and \$105/bbl in 2015, \$2/bbl and \$3/bbl higher than projected in last month's STEO, respectively. The West Texas Intermediate (WTI) crude oil price discount to Brent is expected to average \$9/bbl and \$10/bbl in 2014 and 2015, respectively.
- During this year's April-through-September summer driving season, regular gasoline retail prices are forecast to average \$3.66/gallon (gal), 8 cents higher than last year. Regular gasoline retail prices are projected to fall from an average of \$3.68/gal during the second quarter to \$3.64/gal during the third quarter as lower refinery margins more than offset higher crude oil prices. EIA expects regular gasoline retail prices to average \$3.54/gal in 2014 and \$3.45/gal in 2015, compared with \$3.51/gal in 2013.
- U.S. total crude oil production, which averaged 7.4 million barrels per day (bbl/d) in 2013, is expected to average 8.5 million bbl/d in 2014 and 9.3 million bbl/d in 2015. The 2015 forecast represents the highest annual average level of oil production since 1972. Natural gas plant liquids production increases from an average of 2.6 million bbl/d in 2013 to 3.0 million bbl/d in 2015. The growth in domestic production has contributed to a significant decline in petroleum imports. The share of total U.S. liquid fuels consumption met by net imports fell from 60% in 2005 to an average of 33% in 2013. EIA expects the net import share to decline to 22% in 2015, which would be the lowest level since 1970.
- Natural gas working inventories on June 27 totaled 1.93 trillion cubic feet (Tcf), 0.67 Tcf (26%) below the level at the same time a year ago and 0.79 Tcf (29%) below the previous five-year average (2009-13). Projected natural gas working inventories reach 3.43 Tcf at the end of October, 0.38 Tcf below the level at the same time last year. EIA expects that the Henry Hub natural gas spot price, which averaged \$3.73 per million British thermal units (MMBtu) in 2013, will average \$4.77/MMBtu in 2014 and \$4.50/MMBtu in 2015.

Global Petroleum and Other Liquids

EIA projects world petroleum and other liquids supply to increase by 1.5 million bbl/d in 2014 and by another 1.2 million bbl/d in 2015, with most of the growth coming from countries outside of the Organization of the Petroleum Exporting Countries (OPEC). Forecast non-OPEC supply grows by 1.7 million bbl/d in 2014 and 1.0 million bbl/d in 2015. The United States and Canada account for much of this growth. Projected world liquid fuels consumption grows by an annual average of 1.1 million bbl/d in 2014 and 1.5 million bbl/d in 2015. Countries outside the Organization for Economic Cooperation and Development (OECD), notably China, drive expected consumption growth.

The escalation of violence in northern Iraq that started in June has introduced significant uncertainty into the Iraq oil production outlook. EIA has reduced Iraq's production forecast from last month's STEO, maintaining production near 3.3 million bbl/d over the forecast, which was Iraq's average production level during the first half of 2014.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 1.3 million bbl/d (1.5%) in 2013, averaging 90.5 million bbl/d for the year. EIA expects global consumption to grow by 1.1 million bbl/d in 2014 and 1.5 million bbl/d in 2015. Projected global oil-consumption-weighted real GDP, which increased by an estimated 2.6% in 2013, grows by 2.8% and 3.4% in 2014 and 2015, respectively.

Non-OECD countries account for nearly all of the expected consumption growth in 2014 and 2015. China is the leading contributor to projected global consumption growth, with consumption increasing by 400,000 bbl/d (3.7%) in 2014 and 430,000 bbl/d in 2015. However, China's economic and oil consumption growth rates have moderated compared with rates before 2012, when annual GDP growth exceeded 9% and oil consumption growth averaged almost 800,000 bbl/d from 2009 through 2011.

EIA expects a decline in OECD consumption in 2014, led by projected consumption declines in both Japan and Europe. EIA expects Japan's oil consumption to fall by an annual average of 130,000 bbl/d in 2014 and 160,000 bbl/d in 2015, as the country continues to increase natural gas and coal consumption in the electricity sector and returns some nuclear power plants to service in 2015. EIA projects that OECD Europe's consumption, which fell by 110,000 bbl/d in 2013, will decline by 120,000 bbl/d in 2014 and then increase by 60,000 bbl/d in 2015. U.S. liquids consumption, which increased by 400,000 bbl/d in 2013, is expected to be largely unchanged in 2014 and then increase by 70,000 bbl/d in 2015.

Non-OPEC Supply. EIA estimates that non-OPEC liquids production grew by 1.4 million bbl/d in 2013, averaging 54.1 million bbl/d for the year. EIA expects non-OPEC liquids production to grow by 1.7 million bbl/d in 2014 and 1.0 million bbl/d in 2015. EIA forecasts production from the United States and Canada to grow by a combined annual average of 1.6 million bbl/d in 2014 and 1.0 million bbl/d in 2015. EIA estimates that the Former Soviet Union's production will rise

by an annual average of 120,000 bbl/d in 2014, led by Russia. However, production in the region declines by 100,000 bbl/d in 2015. The expected completion of phase one of Kazakhstan's Kashagan field has been pushed back to the first half of 2016 because of continued problems delaying the start of commercial production.

Unplanned supply disruptions among non-OPEC producers averaged 0.6 million bbl/d in June, down from an estimated 0.7 million bbl/d in May. South Sudan, Syria, and Yemen accounted for 83% of total non-OPEC supply disruptions. EIA does not assume a disruption to oil supply or demand as a result of ongoing events in Ukraine.

OPEC Supply. EIA estimates that OPEC crude oil production averaged 29.9 million bbl/d in 2013, a decline of 1.0 million bbl/d from the previous year, primarily reflecting increased outages in Libya, Nigeria, and Iraq, along with strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.3 million bbl/d in 2014 and by an additional 0.1 million bbl/d in 2015 to accommodate growing production in non-OPEC countries.

In Libya, force majeure on oil exports from the two largest eastern oil ports (Es-Sidra and Ras Lanuf - combined effective export capacity of 550,000 bbl/d) were lifted after the rebel group blockading the ports agreed to return them to the government. Although the deal is a major step forward, given the fragility of the situation and the failure of past deals, it is highly uncertain if this deal will materialize into a sustained recovery of Libya's eastern exports. In April 2014, a similar deal was made to return control of two smaller eastern ports (Marsa al-Hariga and Zueitina with combined export capacity of 200,000 bbl/d). However, the deal did not lead to a substantial increase in production and exports because instability and sporadic blockades continued. For now, EIA's short-term forecast for Libya remains unchanged, assuming a small recovery in 2015 but still well below the 2012 crude production level of 1.37 million bbl/d.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.7 million bbl/d in June 2014, slightly higher than the previous month because of increased outages in Iraq. The escalation of violence in northern Iraq that started in June has not reduced the availability of exports to the global market, as southern exports have been unaffected and northern exports were halted in early March 2014. The recent events have mainly affected Iraq's crude oil supply to its largest domestic refinery, which had been processing approximately 0.2 million bbl/d of crude oil. The northern Baiji refinery was shut down during the second half of June, reducing northern Iraqi crude oil and petroleum product production. Crude oil production in southern Iraq of roughly 2.8 million bbl/d and in the Iraqi Kurdistan Region of roughly 0.2 million bbl/d has not been disrupted.

Recent events have introduced a high level of uncertainty in Iraq, and as a result, EIA has reduced its forecast production growth in Iraq by about 0.3 million bbl/d in both 2014 and 2015. EIA does not expect Iraq's crude production to exceed 3.3 million bbl/d, its average level during the first half of 2014, during the STEO forecast period. EIA expects Saudi Arabia to maintain a

higher production level through 2014 to offset the loss of Iraq's growth. In 2015, Saudi Arabia's annual production is still projected to decline to accommodate growing output in non-OPEC countries, albeit to a lesser extent than previously expected.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to average 2.0 million bbl/d in 2014 and 2.7 million bbl/d in 2015. These surplus capacity projections are 0.2 million bbl/d and 0.8 million bbl/d lower than last month's STEO, respectively. The reduction in surplus capacity from last month's STEO mainly reflects increased forecast production from Saudi Arabia. These estimates do not include additional capacity that may be available in Iran but is offline because of the effects of U.S. and European Union sanctions on Iran's ability to sell its oil.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.55 billion barrels at the end of 2013, equivalent to roughly 55 days of consumption. Projected OECD oil inventories rise to 2.60 billion barrels at the end of 2014.

Crude Oil Prices. North Sea Brent crude oil spot prices averaged \$112/bbl in June, an increase of \$2/bbl from May. This was the 12th consecutive month in which average Brent crude oil spot prices fell within a relatively narrow range of \$107/bbl to \$112/bbl. The escalating conflict in Iraq, continued record-high levels of Chinese crude oil imports in 2014, and ongoing delays to Libyan oil exports have contributed to upward price pressure. The forecast Brent crude oil price averages \$110/bbl in 2014, \$2/bbl higher than estimated for 2014 in last month's STEO, and \$105/bbl in 2015, which is \$3/bbl higher than in last month's STEO.

The WTI crude oil spot price increased from an average of \$102/bbl in May to \$106/bbl in June. Driven in part by the relocation of crude oil to refining centers along the Gulf Coast through new pipelines, crude oil inventory levels at the Cushing, Oklahoma, storage hub, the delivery point for WTI, have fallen by more than half since the start of the year, from 42 million barrels on January 24 to below 21 million barrels on June 27, the lowest level since November 2008. The discount of WTI crude oil to Brent crude oil, which averaged more than \$13/bbl from November 2013 through January 2014, has since fallen to \$6/bbl in June. The U.S. Commerce Department's Bureau of Industry and Security (BIS) recently authorized two companies to export stabilized lease condensate processed in a distillation tower. EIA now expects the discount of WTI to Brent crude oil to average \$9/bbl in the second half of 2014, which is \$1/bbl lower than last month's STEO. EIA expects the discount to average \$10/bbl in 2015.

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 October 2014 delivery, traded during the five-day period ending July 2, averaged \$104/bbl. Implied volatility averaged 14%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in October 2014 at \$92/bbl and \$118/bbl, respectively. Last year at this time, WTI for October 2013 delivery averaged \$98/bbl and implied volatility averaged 21%.

The corresponding lower and upper limits of the 95% confidence interval were \$81/bbl and \$118/bbl.

U.S. Petroleum and Other Liquids

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by 400,000 bbl/d (2.1%) in 2013. Consumption of hydrocarbon gas liquids (HGL) registered the largest gain in 2013, increasing by 150,000 bbl/d (6.4%). Total consumption is expected to fall by 10,000 bbl/d in 2014, with declines in the consumption of residual fuel oil and unfinished oils offsetting increases in distillate fuel and gasoline. Total consumption grows by 70,000 bbl/d in 2015, with HGL consumption increasing by 80,000 bbl/d.

Motor gasoline consumption grew by 90,000 bbl/d (1.1%) in 2013, the largest increase since 2006. Motor gasoline consumption grows by 30,000 bbl/d in 2014 and then falls by 10,000 bbl/d in 2015 as improving fuel economy in new vehicles increasingly offsets highway travel growth. Distillate fuel consumption increased by 90,000 bbl/d (2.5%) last year, reflecting colder weather and economic growth. Consumption of that fuel rises by 120,000 bbl/d and 60,000 bbl/d in 2014 and 2015, respectively.

Liquid Fuels Supply. The forecast for total U.S. crude oil production increases from an estimated 7.4 million bbl/d in 2013 to 8.5 million bbl/d in 2014 and 9.3 million bbl/d in 2015. The highest previous annual average U.S. production level was 9.6 million bbl/d in 1970. Recent U.S. crude oil production growth has consisted primarily of lighter, sweet crude (a description of crude quality, as measured by API gravity and sulfur content) from tight resource formations. Roughly 96% of the 1.8-million-bbl/d growth in production between 2011 and 2013 consisted of sweet grades with lighter API gravity of 40 or above. [EIA analysis of current and forecast crude oil production](#) indicates that U.S. supply of lighter API gravity crude will continue to outpace that of medium and heavier crudes. More than 60% of EIA's forecast production growth for 2014 and 2015 consists of light, sweet grades with API gravity of 40 or above.

HGL production at natural gas liquids plants is projected to rise from 2.6 million bbl/d in 2013 to 3.0 million bbl/d in 2015. About half of this growth is expected to come from ethane production to meet growing demand associated with expanding domestic ethylene production and export capacity.

The growth in domestic production has contributed to a significant decline in petroleum imports. The share of total U.S. liquid fuels consumption met by net imports fell from 60% in 2005 to an average of 33% in 2013. EIA expects the net import share to decline to 22% in 2015, which would be the lowest level since 1970.

Petroleum Product Prices. The U.S. annual average regular gasoline retail price, which averaged \$3.51/gal in 2013, is projected to increase to an average of \$3.54/gal in 2014 before falling to \$3.45/gal in 2015. Diesel fuel prices, which averaged \$3.92/gal in 2013, are projected to average

\$3.93/gal in 2014 and \$3.88/gal in 2015, 3 cents and 10 cents higher than projected in last month's STEO, respectively.

EIA expects that the monthly average regular gasoline retail price will fall from \$3.69/gal in June to \$3.61/gal in September. The September 2014 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged \$3.01/gal for the five trading days ending July 2. Based on the market value of futures and options contracts for this key petroleum component of gasoline, there is a 4% probability that its price at expiration will exceed \$3.35/gal, consistent with a monthly average regular-grade gasoline retail price exceeding \$4.00/gal in September 2014. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas exceeding the national average price by 30 cents/gal or more.

Natural Gas

While this year's natural gas injection season began slowly in April, injections into storage during May and June were very strong. According to preliminary data from EIA's *Weekly Natural Gas Storage Report*, net injections were 100 billion cubic feet (Bcf) or greater for each of the past eight weeks. Over the previous four years, weekly injections during May and June exceeded 100 Bcf on only three occasions. EIA expects injections will slow during July and August as more natural gas goes to the electric power sector to meet air conditioning demand. The strength in storage injections is the result of strong production growth and moderate demand. Marketed production in April set a record high, at 73.5 Bcf/d, according to EIA's most recent data, with the largest increases coming from areas in Texas.

Natural Gas Consumption. EIA expects total natural gas consumption will average 72.4 Bcf/d in 2014, an increase of 1.4% from 2013, led by the industrial sector. In 2015, total natural gas consumption falls by 0.3 Bcf/d as a return to near-normal winter weather contributes to lower residential and commercial consumption. Higher natural gas prices this year contribute to a 1.1% decline in natural gas consumption in the power sector to 22.1 Bcf/d in 2014. EIA expects natural gas consumption in the power sector to increase to 22.8 Bcf/d in 2015 with lower natural gas prices and the retirement of some coal plants.

Natural Gas Production and Trade. EIA expects natural gas marketed production to grow by an average rate of 4.1% in 2014 and 1.2% in 2015. Rapid natural gas production growth in the Marcellus formation has contributed to low natural gas forward prices in the Northeast, and as a result new infrastructure has been proposed to take gas to other market regions. In June, the eastward-flowing Rockies Express Pipeline (REX) began service on its Seneca Lateral pipeline, which will take Marcellus gas westward to the Midwest. REX's parent company, Tallgrass Energy, plans to add bidirectional capability on a significant portion of REX's easternmost segment.

Growing domestic production is expected to continue to put downward pressure on natural gas imports from Canada. EIA projects net imports of 3.7 Bcf/d in 2014 and 3.1 Bcf/d in 2015, which would be the lowest level since 1987. Liquefied natural gas (LNG) imports have fallen over the past several years because higher prices in Europe and Asia are more attractive to sellers than the relatively low prices in the United States. Several companies are planning to build liquefaction capacity to export LNG from the United States. Cheniere Energy's Sabine Pass facility is expected to be the first to liquefy natural gas produced in the Lower 48 states for export. It is scheduled to come online in stages beginning in late 2015.

Natural Gas Inventories. Natural gas working inventories totaled 1,929 Bcf as of June 27, which was 666 Bcf lower than the same time last year and 790 Bcf lower than the previous five-year (2009-2013) average. The injection season began somewhat slowly in April, but picked up in May and June with more than 1 Tcf was added to storage. EIA expects working gas stocks will reach around 3,430 Bcf at the end of October, 380 Bcf lower than at the same time last year.

Natural Gas Prices. Natural gas spot prices averaged \$4.59/MMBtu at the Henry Hub in June. EIA expects spot prices will remain near current levels until the start of the next winter heating season. Projected Henry Hub natural gas prices average \$4.77/MMBtu in 2014 and \$4.50/MMBtu in 2015.

Natural gas futures prices for October 2014 delivery (for the five-day period ending July 2) averaged \$4.40/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for October 2014 contracts at \$3.37/MMBtu and \$5.76/MMBtu, respectively. At this time last year, the natural gas futures contract for October 2013 averaged \$3.62/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$2.69/MMBtu and \$4.88/MMBtu.

Coal

Coal Supply. EIA expects U.S. coal production will grow 2.7% to 1,011 million short tons (MMst) in 2014, driven by higher consumption. In 2015, forecast U.S. coal production falls by 0.9% to 1,002 MMst.

Coal Consumption. EIA projects total coal consumption growth of 2.8% to 951 MMst in 2014 because of higher electricity demand and power sector natural gas prices nearly 30% above their 2013 level. Total coal consumption is projected to fall by 2.8% in 2015, as retirements of coal power plants rise in response to the implementation of the Mercury and Air Toxics Standards, electricity sales growth slows to 0.1%, and natural gas prices fall relative to coal prices.

Coal Exports. In April, coal exports were 16.6% (1.6 MMst) lower compared with last year, with steam coal exports falling by 1.5 MMst (33.4%). Coal exports are projected to total 99 MMst in

2014, primarily because of slowing world coal demand growth and increasing coal output in other coal-exporting countries. In 2015, projected exports fall to 95 MMst.

Coal Prices. Annual average coal prices to the electric power industry fell over the past two years, from \$2.39/MMBtu in 2011 to \$2.35/MMBtu in 2013. Monthly average coal prices have increased by 10 cents per MMBtu since the beginning of the year, with the April price averaging \$2.40/MMBtu. EIA expects average delivered coal prices to increase over the forecast period, with prices of \$2.39/MMBtu in 2014 and \$2.41/MMBtu in 2015.

Electricity

A large proportion of U.S. conventional hydroelectric output is produced in states west of the Mississippi River, especially in the Pacific Northwest. The level of hydroelectric generation is heavily influenced by precipitation patterns, and the western states have experienced widely divergent levels of rainfall and snowfall in recent months. A higher-than-normal snowpack in the Rocky Mountains contributed to an 11.6% increase in year-to-date (January-April) hydroelectric generation in the Mountain Census Division, compared with the same period in 2013. Low precipitation levels in the Pacific Northwest earlier this year were offset by a very wet March, leading to relatively flat year-to-date change in hydroelectric generation in Oregon and Washington. In contrast, exceptional drought in California has caused a 46.6% year-to-date decline in that state's hydroelectric generation.

Electricity Consumption. EIA estimates that total consumption of electricity during the first half of 2014 was 2.5% higher than during the same period last year. This increased consumption occurred primarily in the residential and commercial sectors during the first quarter of the year as a result of colder temperatures in the eastern half of the United States. Retail sales of electricity to the industrial sector during the first half are estimated to be down 1.0% from last year. A 5.1% year-over-year increase in cooling degree days during the second half of 2014 and projected improvements in energy efficiency contribute to the forecast of 0.6% growth in total electricity consumption during the remainder of 2014. EIA expects little change in electricity consumption in 2015.

Electricity Generation. EIA projects that total U.S. electricity generation in 2014 will grow by 1.6% from last year to an average of 11,300 gigawatthours per day. Recently rising costs for natural gas have driven power generators to use relatively more coal for supplying electricity. During the first half of 2014, EIA estimates that 40.0% of total generation was fueled by coal, compared with 39.0% during the first half of last year. In contrast, the share of generation supplied by natural gas fell from 26.1% last year to 24.8% during the first half of 2014. EIA expects that coal's share of generation will fall to an average of 38.8% in 2015 while the natural gas fuel share rises to 27.5%.

Electricity Retail Prices. EIA expects the U.S. residential annual average electricity price to increase by 3.1% this year, which would be the highest growth rate since 2008, primarily in response to higher fuel costs for power generation. The largest price increases occur in the Northeast region. Projected residential prices increase by an additional 2.4% during 2015.

Renewables and Carbon Dioxide Emissions

Electricity and Heat Generation from Renewables. EIA projects total renewables use for electricity and heat generation will grow by 2.9% in 2014. Conventional hydropower generation is projected to fall by 0.8%, while nonhydropower renewables rise by 4.9%. In 2015, total renewables consumption for electric power and heat generation increases by 4.0%, as a result of a 3.5% increase in hydropower and a 4.2% increase in nonhydropower renewables.

EIA projects that wind power capacity will increase by 8.6% in 2014 and 13.9% in 2015. Electricity generation from wind is projected to contribute 4.5% of total electricity generation in 2015.

EIA expects continued robust growth in solar electricity generation, although the amount of utility-scale generation remains a small share of total U.S. generation at about 0.5% in 2015. While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity doubled in 2013. EIA expects that utility-scale solar capacity will increase by 88% between the end of 2013 and the end of 2015; about 70% of this new capacity is being built in California. However, customer-sited photovoltaic capacity growth, which the STEO does not forecast, is expected to exceed utility-scale solar growth between 2013 and 2015, according to *EIA's Annual Energy Outlook 2014*.

Liquid Biofuels. Ethanol production increased from an average of 907,000 bbl/d in March to an estimated 949,000 bbl/d in June, which was the highest monthly level of the year and included the highest weekly level ever recorded at 972,000 bbl/d for the week ending June 13. Ethanol production is forecast to average 932,000 bbl/d in 2014 and 940,000 bbl/d in 2015. Biodiesel production averaged 89,000 bbl/d in 2013 and is forecast to average 80,000 bbl/d in 2014 and 84,000 bbl/d in 2015.

Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide (CO₂) emissions from fossil fuels increased by 2.2% in 2013 from the previous year. Emissions are forecast to rise by 1.7% in 2014, and then to decline by 0.9% in 2015. The increase in emissions in 2013 and 2014 reflects growth in coal consumption for electric power generation. Coal emissions are projected to decline by 2.6% in 2015.

On June 4, the 24th allowance auction was held for the Regional Greenhouse Gas Initiative (RGGI). RGGI involves nine northeastern and mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont). Each allowance permits one short ton of CO₂ emissions. The clearing price was \$5.02 per short ton,

and more than 18 million allowances were sold to 43 bidders. The average clearing prices in prior-year auctions were \$1.93 per short ton in 2012 and \$2.92 per short ton in 2013.

U.S. Economic Assumptions

Recent Economic Indicators. Economic growth slowed in the first quarter of 2014, with recent economic indicators showing signs of improvement later in the year. The Bureau of Economic Analysis (BEA) reported that real gross domestic product (GDP) fell at an annualized rate of 2.9% from the fourth quarter of 2013 to the first quarter of 2014. This was a revision from BEA's first and second estimates, which reported an annualized increase of 0.1% and an annualized decrease of 1.0%, respectively. The first revision was associated with a significant decline in inventory investment, while the latest was more broad-based with downward revisions in consumer spending and trade.

Recent employment indicators are more positive; the U.S. Bureau of Labor Statistics (BLS) reported that the four-week moving average of initial seasonally adjusted unemployment insurance claims for the week ending June 28 was 315,000. According to BLS, the U.S. economy added 288,000 jobs in June, and the unemployment rate fell to 6.1%. New orders for durable goods contracted in May, according to the U.S. Census Bureau (Census), as new orders fell 1%, compared with the 0.8% increase reported in April. BEA also reported that real personal consumption expenditures fell 0.1% between April and May, following a 0.2% drop from March to April. Census reported that sales of new single-family homes rose 18.6% from April to May, a level 16.9% above the May 2013 sales estimate.

EIA used the June 2014 version of the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO. This GI forecast does not reflect recent macroeconomic data, such as the second downward revision to first quarter real U.S. GDP growth.

Production and Income. Forecast real GDP grows by 2.2% in 2014 and by 2.9% in 2015, down from the 2.4% and 3.1% increases, respectively, forecast in last month's STEO. Weaker real GDP growth in this month's forecast reflects BEA's first downward revision to first-quarter real GDP growth and a downward revision in 2015 real disposable income growth to 3.1% from 3.6% forecast in last month's STEO. Total industrial production grows by 3.4% in 2014 and 3.0% in 2015. Growth in industrial production in the manufacturing sector is lower than in total industrial production in 2014, at 3.3%, but moves higher in 2015 to 3.4%.

Expenditures. Private real fixed investment growth averages 3.9% and 8.5% in 2014 and 2015, respectively, led by industrial and transportation equipment in 2014 and by a broad array of equipment categories in 2015. Real consumption expenditures grow faster than real GDP in 2014 at 2.7%, but fall below the real GDP growth rate in 2015 at 2.6%. Durable goods expenditures drive consumption spending in both years. Export growth is 3.3% and 4.8% over

the same two years, while import growth is 2.8% in 2014 and 5.2% in 2015. Total government expenditures fall by 0.9% in 2014, but increase by 0.3% in 2015.

U.S. Employment, Housing, and Prices. Projected growth in nonfarm employment averages 1.7% in 2014 and 1.8% in 2015. This is accompanied by a gradually declining unemployment rate that reaches 5.9% at the end of 2015. The employment growth in 2014 and 2015 is slower than projected last month and the declines in the unemployment rate are about the same. Housing starts grow an average of 14.3% and 28.2% in 2014 and 2015, respectively. Both consumer and producer price indexes continue to increase at a moderate pace, as wages continue to show modest gains.

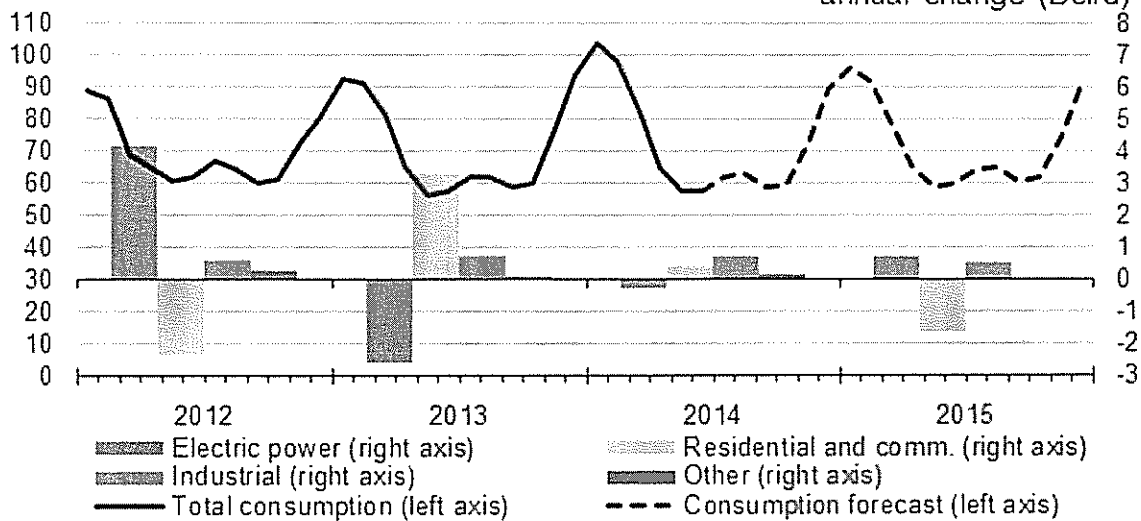
This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views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

U.S. Natural Gas Consumption

billion cubic feet per day (Bcf/d)



annual change (Bcf/d)



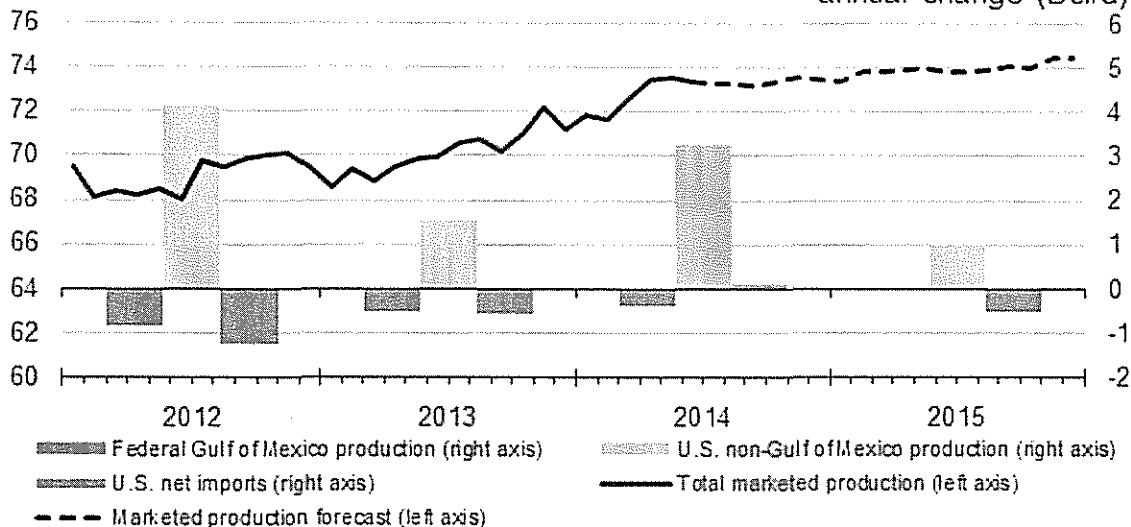
Source: Short-Term Energy Outlook, July 2014.

U.S. Natural Gas Production and Imports

billion cubic feet per day (Bcf/d)

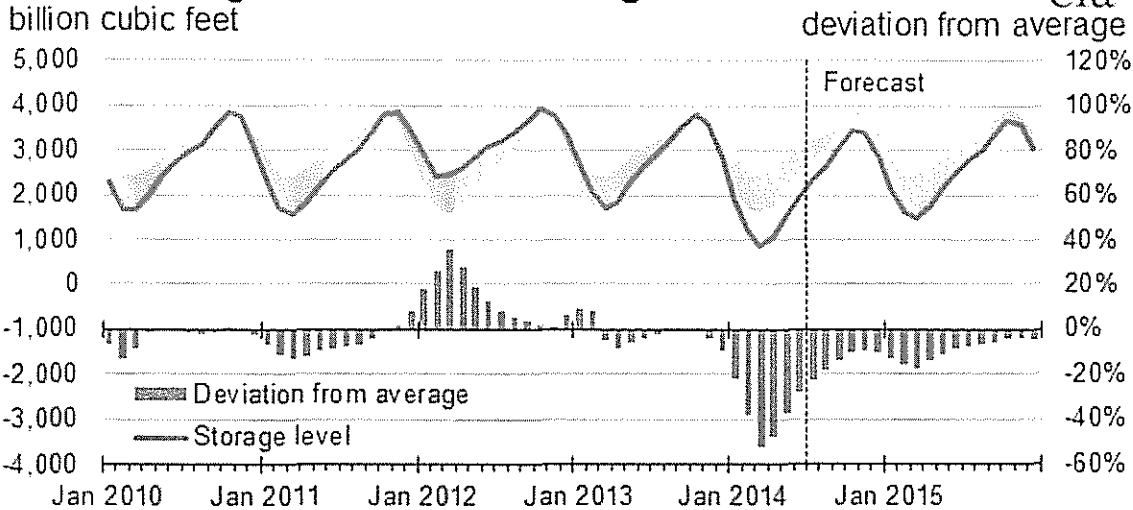


annual change (Bcf/d)



Source: Short-Term Energy Outlook, July 2014.

U.S. Working Natural Gas in Storage

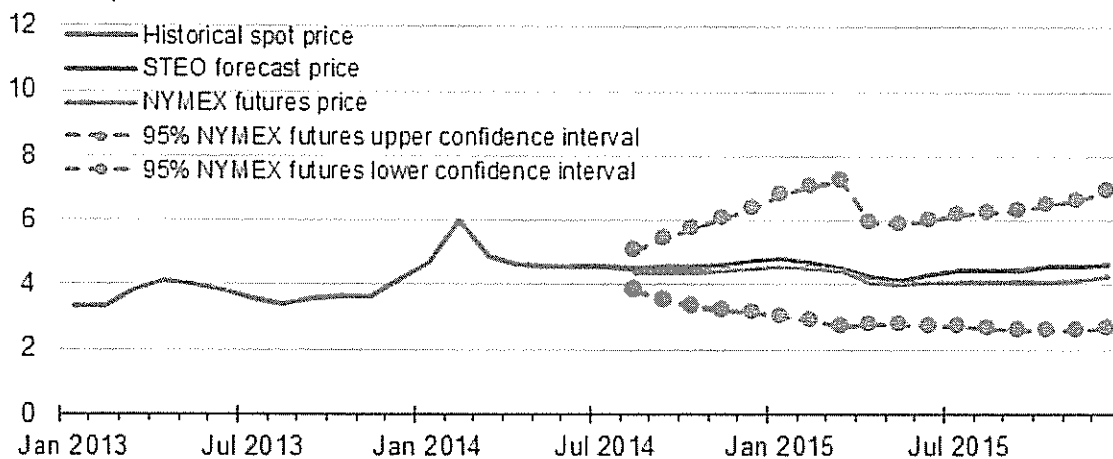


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2009 - Dec. 2013.

Source: Short-Term Energy Outlook, July 2014.

Henry Hub Natural Gas Price

dollars per million Btu

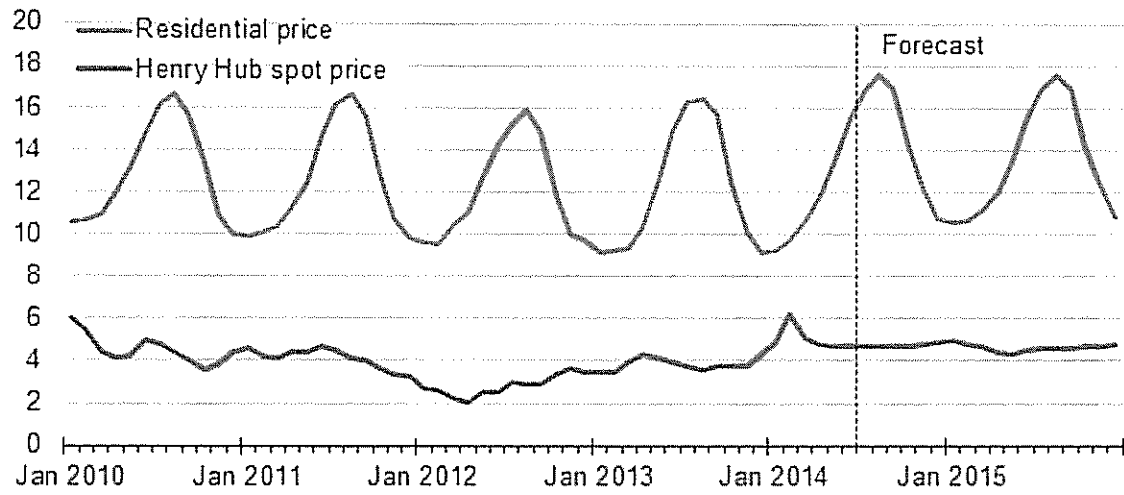


Note: Confidence interval derived from options market information for the 5 trading days ending Jul. 2, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, July 2014.

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, July 2014.

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS TARIFF SHEET
NORTH DAKOTA GAS
EFFECTIVE SEPTEMBER 2014

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$5.388	\$4.159	\$4.160	\$4.141
Prior Gas Cost	6.052	4.869	4.875	4.853
Current Gas Cost Adjustment	(\$0.664)	(\$0.710)	(\$0.715)	(\$0.712)
<u>Surcharge Adjustment:</u>				
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
<u>Market Based Pricing Differential</u>				
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	<u>(\$0.664)</u>	<u>(\$0.710)</u>	<u>(\$0.715)</u>	<u>(\$0.712)</u>
Gas Cost Level	\$5.388	\$4.159	\$4.160	\$4.141
Plus: Surcharge	0.024	0.024	0.116	0.181
Total Gas Cost Level in Tariff Rates	<u>\$5.412</u>	<u>\$4.183</u>	<u>\$4.276</u>	<u>\$4.322</u>

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE TARIFF SHEET
NORTH DAKOTA PROPANE
EFFECTIVE SEPTEMBER 2014

Cost of Gas - Propane

Current Propane Cost (Exhibit A)	\$10.978
Prior Propane Cost	<u>11.527</u>
Current Propane Cost Adjustment	<u><u>(\$0.549)</u></u>

Surcharge Adjustment

Current Adjustment	\$1.193
Prior Adjustment	<u>1.193</u>
Change in Surcharge Adjustment	\$0.000

Market Based Pricing Differential

Current Adjustment	(\$0.012)
Prior Adjustment	<u>(0.012)</u>
Change in Margin Sharing Provision	\$0.000
Net Increase (Decrease) in Gas Costs	<u><u>(\$0.549)</u></u>

Propane Cost Level	\$10.978
Plus: Surcharge	<u>1.193</u>
Total Propane Cost Level in Rates	<u><u>\$12.171</u></u>

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
RESIDENTIAL AND GENERAL SERVICE
EFFECTIVE SEPTEMBER 2014**

	Amount
Total Gas Costs 1/	\$79,269,318
Residential and General Service dk Requirements 2/	14,778,002
Average Cost of Gas per dk	\$5.364
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.388
Less: Gas Cost Level in Rates 3/	6.052
Current Gas Cost Adjustment	(\$0.664)

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 May 31, 2014, adjusted for losses at .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-14-008 effective August 1, 2014:

Cost of Purchased Gas	\$6.025
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$6.052

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
OPTIONAL SEASONAL - RATE 72
EFFECTIVE SEPTEMBER 2014

Total Gas Costs 1/	\$79,269,318
Less: Annual MDDQ Costs	<u>18,087,631</u>
Total Gas Costs excluding MDDQ	\$61,181,687
Firm Service Requirements 1/	14,778,002
Other Gas Costs per Dk (excluding MDDQ)	\$4.140
<u>Summer - June - September</u>	
Summer Seasonal Rate, adjusted for losses 2/	4.159
Less: Gas Cost Level in Rates 3/	<u>4.869</u>
Current Gas Cost Adjustment	<u><u>(\$0.710)</u></u>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-14-008 effective August 1, 2014:

	<u>Summer</u>
Cost of Purchased Gas	\$4.847
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.869

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
INTERRUPTIBLE
EFFECTIVE SEPTEMBER 2014**

	Amount
Total Gas Costs 1/	\$28,957,434
Interruptible Service dk Requirements	6,993,666
Average Cost of Gas per dk	\$4.141
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.160
Less: Gas Cost Level in Rates 2/	4.875
Current Gas Cost Adjustment	(\$0.715)

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-14-008 effective August 1, 2014:

Cost of Purchased Gas	\$4.853
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.875

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
EFFECTIVE SEPTEMBER 2014**

	Amount
Total Gas Costs 1/	\$2,153,950
Air Force Interruptible dk Requirements	520,209
Average Cost of Gas per dk	\$4.141
Less: Gas Cost Level in Rates 2/	4.853
Current Gas Cost Adjustment	(\$0.712)

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-14-008 effective August 1, 2014:
Cost of Purchased Gas \$4.853

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
September 2014 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.	921.000	N.A.	N.A.	921.000
MINIMUM	RATE PER EQV. DKT PER MO	0.000	N.A.	N.A.	0.000
COMMODITY CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
MINIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
SCHEDULED OVERRUN CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	32.112	N.A.	N.A.	32.112
MINIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	30.279	N.A.	N.A.	30.279
MINIMUM	RATE PER DKT	0.000	N.A.	N.A.	0.000

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 2.560%, CONSISTING OF 2.275% FOR THE CURRENT PERCENTAGE AND 0.285% 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 1.727 CENTS, CONSISTING OF 1.407 CENTS FOR THE CURRENT RATE AND 0.320 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."

Issued On: May 8, 2014
 Docket Number: RP14-118-003
 FERC Order Date: May 14, 2014

Effective On: May 1, 2014

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FTN-1					
RESERVATION CHARGE					
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)					
MAXIMUM	RATE PER EQV. DKT PER MO.	24.274	N.A.	N.A.	24.274
MINIMUM	RATE PER EQV. DKT PER MO.	1.263	N.A.	N.A.	1.263
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	0.798	N.A.	N.A.	0.798
MINIMUM	RATE PER DKT	0.042	N.A.	N.A.	0.042

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NOTICE OF CURRENTLY EFFECTIVE RATES

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

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

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 0.642%, CONSISTING OF 0.684% FOR THE CURRENT PERCENTAGE AND (0.042%) 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 (0.140) CENTS, CONSISTING OF 0.000 CENTS FOR THE CURRENT RATE AND (0.140) 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.

Issued On: May 8, 2014
 Docket Number: RP14-118-003
 FERC Order Date: May 14, 2014

Effective On: May 1, 2014

Northern Border Pipeline Company
FERC Gas Tariff
Second Revised Volume No. 1

PART 4.1
4.1 - Statement of Rates
T-1 and T-1B - Long Term Base Tariff Rates
v.2.0.0 Superseding v.1.0.0

STATEMENT OF RATES
2/ 3/

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

- 1/ Applicable to any Rate Schedule T-1 U.S. Shippers Service Agreement or any Rate Schedule T-1B Service Agreement with a primary term of at least twelve consecutive months.
- 2/ The Settlement Rates, pursuant to Articles II and VII of the September 27, 2012, Stipulation at Docket Nos. RP06-72-000, et al., remain in effect until such rates are superseded by new rates placed into effect consistent with the provisions of the Stipulation.
- 3/ Rates in this section are subject to the revenue retrieval provision pursuant to Article V.A of the September 27, 2012, Stipulation at Docket Nos. RP06-72-000, et al.

Service	Rates, Tolls and Charges		
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month based on a three year term (Price Point "B") & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) \$ 216.98/10 ³ m ³		
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D ¹	Refer to Attachment "2" for applicable FT-D Demand Rate per month based on a one year term (Price Point "Z") & Surcharge for each Group 1 or Group 2 Delivery Point Average FT-D Demand Rate for Group 1 Delivery Points \$ 5.23/GJ FT-D Demand Rate for Group 2 Delivery Points \$ 4.19/GJ FT-D Demand Rate for Group 3 Delivery Points \$ 5.02/GJ		
4. Rate Schedule STFT	STFT Bid Price = Minimum of 100% of the applicable FT-D Demand Rate based on a one year term (Price Point "Z") for each Group 1 Delivery Point		
5. Rate Schedule FT-DW	FT-DW Bid Price = Minimum of 125% of the applicable FT-D Demand Rate based on a three year term (Price Point "Y") for each Group 1 Delivery Point		
6. Rate Schedule FT-P ¹	Refer to Attachment "3" for applicable FT-P Demand Rate per month		
7. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10³m³/day)</u>	
	1-5 years	11.29	
	6-10 years	9.44	
	15 years	8.46	
	20 years	7.51	
8. Rate Schedule LRS-3	LRS-3 Demand Rate per month \$ 129.55/10 ³ m ³		
9. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
10. Rate Schedule IT-D ¹	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point		
11. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
12. Rate Schedule PT	<u>Schedule No.</u>	<u>PT Rate</u>	<u>PT Gas Rate</u>
	9009-01001-1	\$ 660.00/d	50.0 10 ³ m ³ /d
13. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2014612719	\$ 2.00	/ month
	2014612718	\$ 2.00	/ month
	2014612720	\$ 2,174.00	/ month
	2014612725	\$ 20.00	/ month
	2014612724	\$ 129.00	/ month
	2014612723	\$ 71.00	/ month
	2014612722	\$ 15.00	/ month
	2014612721	\$ 283.00	/ month
	2014612717	\$ 212.00	/ month
	2011475772	\$ 9,250.00	/ month
	2014613454	\$ 650.00	/ month
	2003004522	Applicable IT-R and IT-D Rate	
	2011476052 / 2011476054	\$ 0.1376 \$ 717,000.00	/ GJ subject to Minimum Annual Charge
	2011475056 / 2011476092 / 2011476049 / 2011476050	\$ 0.095 \$ 1,000.00	/ GJ and / month
14. Rate Schedule CO ₂	<u>Tier</u>	<u>CO₂ Rate (\$/10³m³)</u>	
	1	528.30	
	2	418.06	
	3	272.20	

1. Service under rate Schedule FT-D, FT-P and IT-D for delivery stations identified in Attachment 2, and stations identified on rate Schedule OS No. 2011476092 and No. 2011476049, are subject to the ATCO Pipelines Franchise Fees pursuant to paragraph 15.13 of the General Terms and Conditions.

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	5.18	0.1874
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	4.19	0.1514
31110	ALLIANCE EDSON INTERCONNECT APN	4.19	0.1514
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	4.19	0.1514
3002	BOUNDARY LAKE BORDER	4.19	0.1514
1958	EMPRESS BORDER	5.35	0.1935
3886	GORDONDALE BORDER	4.19	0.1514
6404	MCNEILL BORDER	5.35	0.1935

Group 2 Delivery Point Number	Group 2 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" (\$/GJ)	IT-D Rate per Day (\$/GJ)	Subject to ATCO Pipelines Franchise Fees ¹
31000	A.T. PLASTICS SALES APN	4.19	0.1514	Yes
31001	ADM AGRI INDUSTRIES SALES APN	4.19	0.1514	Yes
3880	AECO INTERCONNECTION	4.19	0.1514	
31003	AGRIUM CARSELAND SALES APS	4.19	0.1514	
31002	AGRIUM FT. SASK SALES APN	4.19	0.1514	Yes
31004	AGRIUM REDWATER SALES APN	4.19	0.1514	
31005	AINSWORTH SALES APGP	4.19	0.1514	
31006	AIR LIQUIDE SALES APN	4.19	0.1514	
3214	AKUINU RIVER WEST SALES	4.19	0.1514	
31007	ALBERTA ENVIROFUELS SALES APN	4.19	0.1514	Yes ²
31008	ALBERTA HOSPITAL SALES APN	4.19	0.1514	Yes
3868	ALBERTA-MONTANA BORDER	4.19	0.1514	
3059	ALLISON CREEK SALES	4.19	0.1514	
31009	ALTASTEEL SALES APN	4.19	0.1514	Yes ²
3562	AMOCO SALES (BP SALES TAP)	4.19	0.1514	
31012	APL JASPER SALES APN	4.19	0.1514	Yes
3488	ARDLEY SALES	4.19	0.1514	
3237	ASPEN SALES	4.19	0.1514	
3216	AURORA NO 2 SALES	4.19	0.1514	
3135	AURORA SALES	4.19	0.1514	
3423	BASHAW WEST SALES	4.19	0.1514	
31013	BAYMAG SALES APS	4.19	0.1514	
31014	BEAR CREEK COGEN SALES APGP	4.19	0.1514	
3068	BEAVER HILLS SALES	4.19	0.1514	
3268	BENBOW SOUTH SALES	4.19	0.1514	
3933	BIG EDDY INTERCONNECTION	4.19	0.1514	
3067	BIGSTONE SALES	4.19	0.1514	
3468	BLEAK LAKE SALES	4.19	0.1514	
3225	BOTHA SALES	4.19	0.1514	
3259	BOULDER CREEK SALES	4.19	0.1514	
3164	BRAINARD LAKE SALES	4.19	0.1514	
3918	BUFFALO CREEK INTERCONNECTION	4.19	0.1514	
31015	BURDETT COGEN SALES APS	4.19	0.1514	
3265	BURNT TIMBER SALES	4.19	0.1514	
3204	CABIN SALES	4.19	0.1514	
3109	CALDWELL SALES	4.19	0.1514	
31016	CALGARY ENERGY CENTRE SALES APS	4.19	0.1514	Yes
3634	CANOE LAKE SALES	4.19	0.1514	
3165	CANOE LAKE SALES NO 2	4.19	0.1514	
3866	CARBON INTERCONNECTION	4.19	0.1514	
3484	CARIBOU LAKE SALES	4.19	0.1514	
3157	CARIBOU LAKE SOUTH SALES	4.19	0.1514	
3106	CARMON CREEK SALES	4.19	0.1514	
3101	CAROLINE SALES	4.19	0.1514	
31017	CARSELAND COGEN SALES APS	4.19	0.1514	
3495	CAVALIER SALES	4.19	0.1514	
31018	CHAIN LAKES COOP SALES APS	4.19	0.1514	
3907	CHANCELLOR INTERCONNECTION	4.19	0.1514	
3151	CHEECHAM WEST NO 2 SALES	4.19	0.1514	
3622	CHEECHAM WEST SALES	4.19	0.1514	
6014	CHEVRON AURORA SALES	4.19	0.1514	
31019	CHEVRON FT. SASK SALES APN	4.19	0.1514	Yes
3097	CHICKADEE CREEK SALES	4.19	0.1514	
3305	CHIGWELL NORTH SALES	4.19	0.1514	
3496	CHIPEWYAN RIVER SALES	4.19	0.1514	
3163	CHRISTINA LAKE NORTH SALES	4.19	0.1514	

NATURAL GAS TARIFF

**NorthWestern
Energy**

Canceling $\frac{35^{th}}$ Revised Sheet No. 80.1
 $\frac{34^{th}}$ Revised Sheet No: 80.1

Schedule No. T-FIG-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	\$ 120.40	(1)
10,001 to 30,000	\$ 173.05	(1)
>30,000	\$ 384.05	(1)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for
Maximum Daily Delivery Quantity (MDDQ) \$ 0.9840814 (1)

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum \$ 0.0074572 (1)

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)

Docket No. D2013.12.83
Tariff Letter No. 237-G
By Operation of Law

Effective for service rendered on or after
January 1, 2014

PUBLIC SERVICE COMMISSION
Aleisha Salem Secretary

GAS RATE SCHEDULE

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

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

Date Filed: January 24, 2001

Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is \$2.398 per dekatherm.

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

NG-00-001

STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

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

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

<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	1.153%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.1040	\$0.0010	1.153%
	MLI	DSE	\$225.00	\$0.00	\$0.00	\$0.1978	\$0.0020	3.579%
Interruptible Transportation 4/	MLI	MLI	\$0.00	\$0.00	\$0.00	\$0.0844	\$0.0010	1.153%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.0844	\$0.0010	1.153%
Administrative Fee 5/			\$325.00					

1/ Casper Division service area is defined on Sheet Nos. 3 and 4 of this Tariff.

2/ All charges are per therm.

3/ For fuel, lost and unaccounted for gas, the Company shall be entitled to retain the stated percentage of all therms received for transportation, unless otherwise agreed in writing. On or before March 1 of each year, the Company shall file with the Commission an application to revise the stated percentage to be effective June 1 of that year through May 31 of the following year. The Company shall calculate the stated percentage using not less than twelve (12) consecutive months of actual data.

4/ Interruptible Transportation Service is not available to DSE customers. The Customer Charge will be charged only for those months gas actually flows.

5/ In addition to the transportation charges stated above, Shippers are responsible for the monthly administrative fee as stated, applicable to each meter located at the customer location. For Interruptible Transportation Shippers, the Administrative Fee will be charged only for those months gas actually flows. Firm Transportation Shippers will be charged each month, regardless of gas flow.

6/ Per Dth of MDTQ per month.

Abbreviations (as defined in the General Terms and Conditions of this Tariff):

MLI Mainline System Interconnect
MLE Mainline System End-user
DSE Distribution System End-user

MDTQ Maximum Daily Transportation Quantity

Date Issued: February 28, 2014
By: Michael Noone

Date Effective: June 1, 2014
Title: President and CEO

**MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS
EFFECTIVE SEPTEMBER 2014**

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2013	\$11,873,285	\$524,021	\$3,373,058
November	10,083,032	468,480	2,743,332
December	2,713,665	282,335	1,290,628
January 2014	1,718,601	140,548	(516,571)
February	(7,802,409)	0	(1,585,437)
March	(8,760,334)	17,312	(2,249,296)
April	(8,193,736)	55,269	(2,031,162)
May	(5,576,042)	204,090	(1,264,517)
June	(1,937,654)	387,617	(45,040)
July	2,327,896	592,503	1,426,408
August	6,752,039	794,722	2,902,379
September	10,850,601	977,813	4,121,995
October	12,240,876	1,039,679	4,355,394
13 month average	<u>\$2,022,294</u>	<u>\$421,876</u>	<u>\$963,167</u>
Rate of Return	7.881%	7.881%	7.881%
Return	\$159,377	\$33,248	\$75,907
Return Requirement	<u>\$222,473</u>	<u>\$46,411</u>	<u>\$105,958</u>

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

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

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE
NORTH DAKOTA
EFFECTIVE SEPTEMBER 2014

Cost of Purchased Propane	\$10,929
Gallons Purchased	10,929
Projected dk Sales	1,000
Propane Cost per Dk	\$10.929
Average Cost of Propane as Adjusted for Losses @ 99.55%	10.978
Less: Propane Cost Level in Rates 1/	<u>11.527</u>
Current Propane Cost Adjustment	<u><u>(\$0.549)</u></u>

1/ Propane Cost Level in Current Rates - Case No. PU-14-008, effective May 1, 2014.

**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									<u>\$268,918</u>
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
October	91,702	0	15	91,717	509,627	0.024	(28,445) 3/	120,162	655,497
November	(43,397)	46,049 4/	27	2,679	1,155,975	0.024	27,743	(25,064)	630,433
December	448,098	0	25	448,123	2,259,276	0.024	54,223	393,900	1,024,333
January 2014	218,746	0	22	218,768	3,260,430	0.024	78,250	140,518	1,164,851
February	(243,381)	(98,337) 5/	30	(341,688)	2,668,333	0.024	64,040	(405,728)	759,123
March	2,821,004	0	20	2,821,024	2,727,677	0.024	65,465	2,755,559	3,514,682
April	(316,839)	0	55	(316,784)	1,876,237	0.024	45,030	(361,814)	3,152,868
May	(777,340)	0	49	(777,291)	1,120,204	0.024	26,885	(804,176)	2,348,692
June	319,741	0	48	319,789	551,428	0.024	13,233	306,556	2,655,248
Balance @ June 30, 2014									<u>\$2,655,248</u>

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.

3/ Reflects 296,905.6 Dk @ (\$0.113) and 212,721.2 Dk @ \$0.024.

4/ Adjustment to correct gas costs for the period February 2013 - October 2013 for revisions to volume calculations.

5/ Adjustment to correct prior misallocation between states.

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

	<u>(Over) Under</u>	<u>Refunds &</u>		<u>Total Net</u>	<u>Actual Dk</u>	<u>Adjustment</u>	<u>Total</u>	<u>Net Change-</u>	<u>Cumulative</u>
	<u>Recovery</u>	<u>Other</u>	<u>Interest 1/</u>	<u>Additions</u>	<u>Sales</u>	<u>Per Dk</u>	<u>Adjustment</u>	<u>Additions less</u>	<u>Balance</u>
							<u>Amount</u>	<u>Adjustment</u>	
Balance @ July 31, 2013									<u>\$162,872</u>
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
October	9,049	0	4	9,053	55,674	0.116	(4,732) 2/	13,785	172,950
November	19,660	6,105 3/	7	25,772	126,614	0.116	14,687	11,085	184,035
December	67,199	0	7	67,206	203,609	0.116	23,618	43,588	227,623
January 2014	86,756	0	5	86,761	165,685	0.116	19,220	67,541	295,164
February	8,193	4,502 4/	8	12,703	157,100	0.116	18,224	(5,521)	289,643
March	239,148	0	8	239,156	149,744	0.116	17,371	221,785	511,428
April	56,003	0	8	56,011	119,450	0.116	13,856	42,155	553,583
May	(48,683)	0	9	(48,674)	89,162	0.116	10,344	(59,018)	494,565
June	23,527	0	10	23,537	50,737	0.116	5,885	17,652	512,217
Balance @ June 30, 2014									<u>\$512,217</u>

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

2/ Reflects 48,442.5 Dk @ (\$0.115) and 7,230.6 Dk @ \$0.116.

3/ Adjustment to correct gas costs for the period February 2013 - October 2013 for revisions to volume calculations.

4/ Adjustment to correct prior misallocation between states.

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2013									<u><u>\$86,961</u></u>
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
October	1,205	0	2	1,207	6,585	0.181	(2,484) 2/	3,691	86,967
November	3,672	1,691 3/	3	5,366	29,839	0.181	5,401	(35)	86,932
December	4,326	0	4	4,330	52,750	0.181	9,547	(5,217)	81,715
January 2014	63,099	0	2	63,101	88,671	0.181	16,050	47,051	128,766
February	(50,998)	2,212 4/	3	(48,783)	86,357	0.181	15,631	(64,414)	64,352
March	133,077	0	2	133,079	73,450	0.181	13,295	119,784	184,136
April	30,408	0	3	30,411	60,313	0.181	10,917	19,494	203,630
May	(30,439)	0	3	(30,436)	38,279	0.181	6,929	(37,365)	166,265
June	14,106	0	3	14,109	17,955	0.181	3,249	10,860	177,125
Balance @ June 30, 2014									<u><u>\$177,125</u></u>

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

2/ Reflects 6,585.1 Dk @ (\$0.377).

3/ Adjustment to correct gas costs for the period February 2013 - October 2013 for revisions to volume calculations.

4/ Adjustment to correct prior misallocation between states.