

January 11, 2012

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-12-____

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 seven (7) copies of a Cost of Gas (COG) change pursuant to the terms of Rates 88 and 99.

Attachment A is the Rate Summary Sheet (100th Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered February 1, 2012.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.537 per dk since the last filing due to a decrease in the overall market price of gas. Attachment B explains the reasons for the decrease in the market price of gas. There has also been a change in pipeline rates, as shown on Attachment C, increasing the cost of gas \$0.001 per dk. In addition, Montana-Dakota has modified its overall firm transportation capacity, resulting in a system wide change in demand allocation and a decrease of approximately \$0.023 per dk.

The COG tariff sheet, Exhibit A page 1, summarizes the gas cost adjustment, calculated pursuant to the terms of Rate 88, and the surcharge adjustment and market based pricing differential provision that will apply during the month of February 2012.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.559 per dk for residential and firm general service customers, a decrease of \$0.542 per dk for small and large interruptible customers and a decrease of \$0.540 per dk for Air Force interruptible customers from the currently effective rates.

Exhibit B shows the calculation of the current gas cost adjustment that will be applicable to Montana-Dakota's customers for the month of February 2012. The average cost of gas for firm customers, adjusted for losses, is \$4.458.

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 a combination of factors. Attachment B page 2 explains the reasons for the increase in the market price of propane.

Exhibit A, page 2 summarizes the cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of February 2012. The net effect of this filing is an increase of \$1.647 per dk for all customers from the currently effective rates.

Exhibit D shows the calculation of the current cost of gas – propane that will be applicable to Montana-Dakota's customers for the month of February 2012. The average cost of propane for all customers, adjusted for losses, is \$18.114 per dk.

This proposed adjustment, calculated in accordance with Rate 99, will amount to an increase of approximately \$12,188 for propane customers during the month of February, 2012. All of the Montana-Dakota's propane customers in North Dakota may be affected by this proposal. There were 332 propane customers in North Dakota as of December 31, 2011.

These proposed adjustments, calculated in accordance with Rate 88 and 89, will amount to a decrease of approximately \$1,290,500 for natural gas customers during the month of February 2012. All of Montana-Dakota's retail natural gas customers in North Dakota may be affected by this proposal. There were 94,066 natural gas customers in North Dakota as of December 31, 2011.

Please refer all inquiries regarding this filing to:

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

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

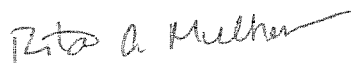
Mr. Daniel S. Kuntz
Associate General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

Montana-Dakota submitted a check for the amount of \$600 in accordance with North Dakota Century Code Section 49-05-05 on December 9, 2010. This payment will cover the filing fee associated with this monthly COG.

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
Regulatory Affairs Manager

Attachment

Attachment A

**Rate Summary Sheet
(Proposed)**



Montana-Dakota Utilities Co.

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

State of North Dakota Gas Rate Schedule

NDPSC Volume 7
 100th Revised Sheet No. 3
 Canceling 99th Revised Sheet No. 3

RATE SUMMARY SHEET

Page 1 of 2

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	\$0.30 per day	\$0.812	\$4.417	\$5.229
Air Force Rate 64	7	\$1,000.00 per month \$135.00 per month			
Minot Air Force Base					
PAR Site					
Firm Service			\$0.138	\$4.417	\$4.555
Interruptible Service - PAR			\$0.120	\$3.580	\$3.700
Interruptible Service - MAFB			\$0.120	\$3.541	\$3.661
Firm General Service Rate 70	13	\$0.52 per day \$1.75 per day			
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet			\$0.597	\$4.417	\$5.014
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$3.580	(Maximum) \$4.451
Optional Seasonal Gas Service Rate 72	15	\$0.52 per day \$1.75 per day			
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet					
Winter Gas Usage			\$0.597	\$4.505	\$5.102
Summer Gas Usage			\$0.597	\$3.561	\$4.158
Transportation Service	24	\$150.00 per month \$725.00 per month			
Small Interruptible Rate 81					
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.016	
Large Interruptible Rate 82					
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.016	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$3.580	(Maximum) \$4.299
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$18.616	\$19.428
Firm General Propane Rate 92	34	\$0.52 per day \$1.75 per day			
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet			\$0.597	\$18.616	\$19.213

Date Filed: January 11, 2012

Effective Date:

Issued By: Tamie A. Aberle
 Regulatory Affairs Manager

Case No.:

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

February 2012

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.

Continued mild weather across much of the US, record levels of gas in storage and strong domestic supply likely contributed to the decrease in the commodity price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of December 30, 2011 were 15.2 percent above the five-year average and 11.4 percent above last year's record storage balance.

The EIA provides various publications on energy issues. The information is available on their website: <http://www.eia.doe.gov>.

The January Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 17.

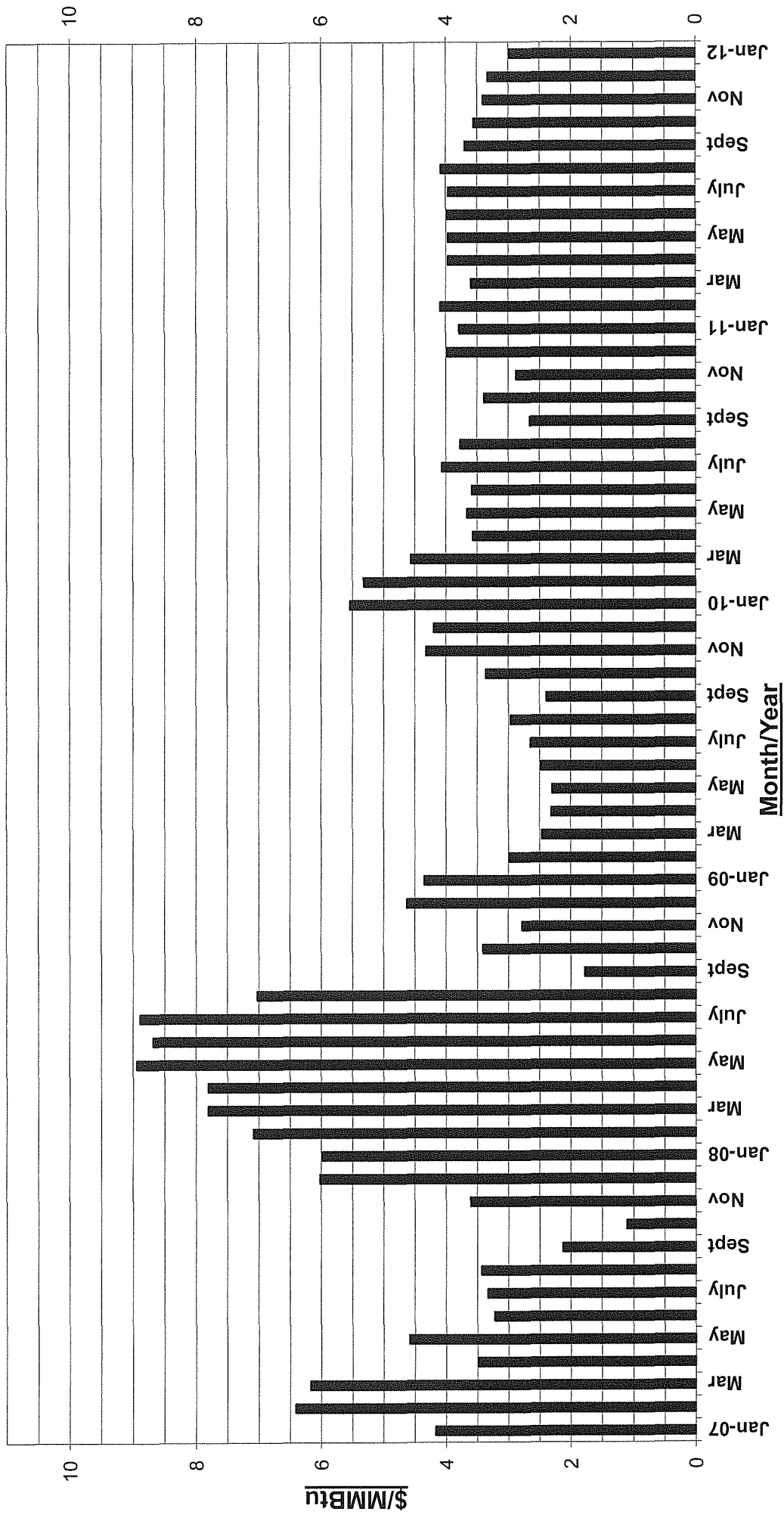
**Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
February 2012**

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 January 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 an increase in the price of propane.

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

CIG Rocky Mountains Index Monthly Gas Prices 2007-2012YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2010-\$3.92; 2011-\$3.79; 2012YTD - \$2.98



Independent Statistics & Analysis
U.S. Energy Information
Administration

January 2012

Short-Term Energy Outlook

January 10, 2012 Release

Highlights

- This edition of the *Short-Term Energy Outlook* is the first to include forecasts for 2013.
- EIA expects the price of West Texas Intermediate (WTI) crude oil to average about \$100 per barrel in 2012, \$5 per barrel higher than the average price last year. For 2013, EIA expects WTI prices to continue to rise, reaching \$106 per barrel in the fourth quarter of next year. EIA's forecast assumes that U.S. real gross domestic product (GDP) grows by 1.8 percent in 2012 and 2.5 percent in 2013, while world real GDP (weighted by oil consumption) grows by 2.9 percent and 3.8 percent in 2012 and 2013, respectively.
- The forecast of average household heating expenditures for all heating fuels has been lowered from the first forecast for the current winter published in the *October 2011 Outlook*, primarily as a result of the warm first half of this heating season. Average household heating oil expenditures are now expected to increase by 4 percent this winter heating season (October 1 to March 31) compared with last winter. In contrast, natural gas and propane expenditures are projected to decline by 7 percent and 1 percent, respectively, and electricity expenditures are 2 percent lower than last winter's levels.
- EIA expects regular-grade motor gasoline retail prices to average \$3.48 per gallon in 2012, 4 cents per gallon lower than last year, and \$3.55 per gallon in 2013. During the April through September peak driving season each year, prices are forecast to average about 5 cents per gallon higher than the annual average. There is regional variation in the forecast, with average expected prices on the West Coast about 25 cents per gallon above the national average during the April through September period.
- Natural gas working inventories continue to set new record highs and ended December 2011 at an estimated 3.5 trillion cubic feet (Tcf), about 12 percent above the same time last year. EIA's average 2012 Henry Hub natural gas spot

price forecast is \$3.53 per million British thermal units (MMBtu), a decline of almost \$0.50 per MMBtu from the 2011 average spot price. EIA expects that Henry Hub spot prices will average \$4.14 per MMBtu in 2013.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. Absent a significant oil supply disruption, EIA expects the recent tightening of world oil markets to moderate in 2012 and resume in 2013. World oil consumption grows by an annual average of 1.3 million barrels per day (bbl/d) in 2012 and 1.5 million bbl/d in 2013. Supply from non-Organization of the Petroleum Exporting Countries (non-OPEC) countries increases by 0.9 million bbl/d in 2012 and 0.8 million bbl/d in 2013. EIA expects that the market will rely on both inventories and increases in production of crude oil and non-crude liquids in OPEC member countries to meet world demand growth.

There are many significant uncertainties that could push oil prices higher or lower than projected. Should a significant oil supply disruption occur, OPEC members not increase production, or projected non-OPEC projects come online more slowly than expected, oil prices could be significantly higher. If the pace of global economic growth fails to accelerate in Organization for Economic Cooperation and Development (OECD) countries, or if economic growth slows in non-OECD countries, reduced demand could lower prices.

Global Crude Oil and Liquid Fuels Consumption. World oil consumption grew by an estimated 1.0 million bbl/d in 2011 to 88.1 million bbl/d. EIA expects that this growth will accelerate over the next two years, with consumption reaching 89.4 million bbl/d in 2012 and 90.9 million bbl/d in 2013. OECD consumption fell by 420 thousand bbl/d in 2011 and is expected to decline again in 2012 as very modest demand growth in North America will be more than offset by demand decline in Europe. A projected European economic recovery contributes to a small increase in forecast OECD consumption in 2013. Non-OECD countries are expected to account for most of the world's growth over the next two years, with the largest contributions coming from China, the Middle East, and Brazil ([World Liquid Fuels Consumption Chart](#)). EIA expects non-OECD consumption growth will slow slightly, from 1.5 million bbl/d in 2011 to 1.4 million bbl/d in 2012 and to 1.3 million bbl/d in 2013.

Non-OPEC Supply. EIA expects non-OPEC crude oil and liquid fuels production to rise by 910 thousand bbl/d in 2012 and a further 760 thousand bbl/d in 2013. The largest area of non-OPEC growth will be North America, where production increases by 290 thousand bbl/d and 250 thousand bbl/d in 2012 and 2013, respectively, stemming from continuing growth in production from U.S. onshore shale formations

and Canadian oil sands. Other major growth areas include Brazil, where production increases annually by an average of 170 thousand bbl/d over the next two years with increased output from its offshore, pre-salt oil fields, and Kazakhstan, which will commence production in the Kashagan field in 2013 and increase production annually by an average of 125 thousand bbl/d. Production also increases in Colombia, Norway, and China. Notable production declines occur in Russia, Mexico, and Sudan and the United Kingdom.

OPEC Supply. EIA expects that OPEC members' crude oil production will continue to rise over the next two years to accommodate increasing world oil consumption. Projected OPEC crude oil production increases by about 90 thousand bbl/d and 590 thousand bbl/d in 2012 and 2013, respectively. OPEC non-crude petroleum liquids, which are not subject to production targets, increase by 410 thousand bbl/d in 2012 and by 250 thousand bbl/d in 2013. EIA expects that OPEC surplus production capacity will increase from about 2.3 million bbl/d at the end of 2011 to 3.7 million bbl/d at the end of 2013, in part due to the assumed recovery of Libyan production to pre-disruption levels over the forecast period ([OPEC Surplus Crude Oil Production Capacity Chart](#)).

OECD Petroleum Inventories. EIA estimates that commercial oil inventories held in the OECD ended 2011 at 2.64 billion barrels, equivalent to about 56.4 days of forward-cover (days-of-supply), which is the highest end-of-year level in terms of forward-cover since 1994. Projected OECD oil inventories decline slightly over the forecast, with days of forward-cover falling from current levels to 54.9 days at the end of 2013 ([Days of Supply of OECD Commercial Stocks Chart](#)).

Crude Oil Prices. At this time last year, EIA had projected that the WTI crude oil price would average about \$93 per barrel in 2011, rising to an average \$99 per barrel in the fourth quarter 2012. The final average WTI price for 2011 was \$95 per barrel. A monthly average high of \$109.53 per barrel for April followed the disruption in Libyan crude oil production, while a monthly low of \$85.52 for September, stemming from deteriorating expectations of world economic growth, contributed to lower demand growth forecasts. EIA's current forecast for WTI crude oil spot prices averages \$101 per barrel in the fourth quarter 2012, rising to an average of \$106 per barrel in the fourth quarter of 2013 ([West Texas Intermediate Crude Oil Price Chart](#)).

Energy price forecasts are highly uncertain ([Market Prices and Uncertainty Report](#)). WTI futures for March 2012 delivery during the 5-day period ending January 5, 2012 averaged \$101.47 per barrel. Implied volatility averaged 35 percent, establishing the lower and upper limits of a 95-percent confidence interval for the market's expectations of monthly average WTI prices in March 2012 of \$81 per barrel and \$127

per barrel, respectively. Last year at this time, WTI for March 2011 delivery averaged \$91 per barrel and implied volatility averaged 28 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$76 per barrel and \$109 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. In 2011, total U.S. liquid fuels consumption fell by an estimated 310 thousand bbl/d (1.6 percent) from 2010 (U.S. Liquid Fuels Consumption Chart). Motor gasoline consumption accounted for most of the decline for the year, falling by 240 thousand bbl/d (2.7 percent). In contrast, distillate fuel oil consumption rose by 50 thousand bbl/d (1.4 percent). Recovery in industrial output as well as increases in non-petroleum imports were the main reasons for the distillate fuel consumption growth.

The next two years are expected to see only small changes in total liquid fuels consumption, with growth of about 90 thousand bbl/d in 2012 and about half that amount in 2013. Motor gasoline consumption, constrained by slowing driving-age population growth and the improving fuel economy of new vehicles, falls by 20 thousand bbl/d (0.2 percent) annually in both 2012 and 2013. Distillate fuel consumption, however, continues to rise at an average 80 thousand bbl/d (2.0 percent) each year, buoyed by continued growth in industrial output and non-petroleum imports.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by an estimated 90 thousand bbl/d in 2011 to 5.57 million bbl/d. A 370-thousand bbl/d increase in lower-48 onshore production in 2011 was partly offset by a 40-thousand bbl/d decline in Alaska and a 240-thousand bbl/d decline in output in the Federal Gulf of Mexico (GOM). GOM production for 2011 was revised downwards from last month's *Outlook* based on currently available production data reported by the [Bureau of Ocean Energy Management](#).

Forecast total crude oil production increases by 170 thousand bbl/d in 2012 and by a further 80 thousand bbl/d in 2013. Continued increases in lower-48 onshore production of 270 thousand bbl/d in 2012 and 110 thousand bbl/d in 2013 overshadow declines of about 30 thousand bbl/d in Alaskan output each year as well as a decline of 80 thousand bbl/d in GOM production in 2012 (U.S. Crude Oil and Liquid Fuels Production Chart). This rising trend in production continues to be driven by increased oil-directed drilling activity, particularly in onshore shale formations. The number of onshore oil-directed drilling rigs reported by Baker Hughes increased from 777 at the beginning of 2011 to 1,193 on December 29, 2011.

In 2011, three southeastern Pennsylvania refineries – Sunoco’s Marcus Hook and Philadelphia refineries along with ConocoPhillip’s Trainer refinery - that comprise over 50% of the total refining capacity in the Northeast were proposed for sale. Two of these refineries (Marcus Hook and Trainer) have already been idled. Some of the lost capacity is offset by the return to full operations in October 2011 of the 182,000 bbl/d Delaware City, Delaware refinery, owned by PBF Energy Company. The Gulf Coast is likely to be a significant alternate supplier with a recent major capacity addition at Marathon Petroleum Corporation’s Garyville, Louisiana refinery and a planned expansion at Motiva’s Port Arthur, Texas refinery, due to be completed in 2012. In addition, a recent expansion at Conoco Phillip’s Wood River refinery in Illinois may free up some supply that had come to the Midwest from the Gulf Coast. EIA also expects increased gasoline imports into the Northeast. However, reduced short-term product supply flexibility due to longer delivery times and potential transportation bottlenecks for sources outside the region could contribute to higher Northeast prices and price volatility. For a more detailed analysis on Northeast Refining Activity, see EIA’s *Reductions in Northeast Refining Activity: Potential Implications for Petroleum Product Markets*.

For the first time since 1949, the United States was a net exporter of refined petroleum products in 2011, with gross product exports averaging 380 thousand bbl/d more than gross product imports (product exports averaged almost 2.5 million barrels per day less than gross product imports in 2005). EIA expects that the United States will continue to be a net product exporter through the forecast horizon, with net product exports averaging 310 thousand bbl/d in 2012 and 290 thousand bbl/d in 2013.

The share of total U.S. consumption met by total liquid fuel net imports (including both crude oil and refined products), which has been falling since 2005, averaged 45 percent in 2011, down substantially from 49 percent in 2010. EIA expects the total net import share of consumption will remain near 2011 levels in 2012 and 2013, as continued growth in domestic crude oil output exceeding the growth in liquid fuels consumption offsets an expected reduction in the drawdown in domestic commercial and government stocks from the 2011 level of 160 thousand bbl/d.

U.S. Petroleum Product Prices. Regular-grade gasoline retail prices averaged \$3.53 per gallon in 2011, which was \$0.74 per gallon (27 percent) higher than the 2010 average, as higher crude oil costs (\$0.59 per gallon) and refinery gasoline margins (\$0.12 per gallon) pushed retail prices up. EIA expects the regular-grade gasoline retail price to average \$3.48 per gallon in 2012 as slightly higher crude oil prices are more than offset by lower refinery gasoline margins (U.S. Gasoline and Crude Oil Prices Chart). The projected continuing increase in crude oil prices in 2013 contributes

to the increase in the forecast average annual regular-grade gasoline retail price to \$3.55 per gallon in 2013.

EIA expects that on-highway diesel fuel retail prices, which averaged \$3.84 per gallon in 2011, will average \$3.85 per gallon in 2012 and \$3.93 per gallon in 2013 (U.S. Diesel Fuel and Crude Oil Prices Chart).

Between 1990 and 2004, annual average wholesale gasoline prices ranged from 5 cents per gallon to 11 cents per gallon above wholesale diesel prices. Beginning in 2005, wholesale gasoline prices fell below wholesale diesel fuel prices in all years except 2009, as world demand growth for diesel fuel, primarily in the emerging economies, outpaced gasoline demand growth. In 2011 gasoline prices fell below wholesale diesel prices by 16 cents per gallon. EIA expects the gasoline wholesale price to weaken further relative to diesel wholesale prices, averaging 19 cents per gallon below diesel in 2012 and 21 cents per gallon lower in 2013.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 68.2 billion cubic feet per day (Bcf/d) in 2012, an increase of 1.3 Bcf/d (2.0 percent) from 2011. From 2011 to 2012, projected consumption increases in all sectors, with the largest volume increase (0.7 Bcf/d) coming from the electric power sector. Natural gas consumption growth continues into 2013, with projected total consumption averaging 69.1 Bcf/d. Increases in the consumption of natural gas for power generation are likely to continue as domestic production continues to grow and natural gas remains a relatively inexpensive option for generators.

U.S. Natural Gas Production and Imports. Total marketed production grew by an estimated 4.5 Bcf/d (7.4 percent) in 2011, the largest year-over-year volumetric increase in history. This strong growth was driven in large part by increases in shale gas production. EIA expects production to grow by 1.4 Bcf/d (2.2 percent) in 2012 and 0.7 Bcf/d (1.0 percent) in 2013 as low prices reduce new drilling plans and consumption grows at a measured pace. In the face of continued low spot and future prices as well as record high storage levels for this time of year, drillers appear to have begun cutting back on new production plans for 2012. According to Baker Hughes, the natural gas rig count has fallen to 809 as of December 29, 2011, from a 2011 high of 936 in mid-October. However, high initial production rates from new wells, associated natural gas production from oil drilling, and a backlog of uncompleted or unconnected wells contribute to our forecast of further production increases in 2012, albeit at a significantly lower rate than 2011.

Pipeline gross imports are expected to fall by 0.4 Bcf/d (4.1 percent) in 2012 as domestic production grows and displaces Canadian sources. This follows a 0.6 Bcf/d (6.8 percent) decline in gross imports in 2011. Pipeline gross exports are expected to grow by 0.2 Bcf/d (4.5 percent) in 2012 as production grows near the Mexican border area, particularly in the Eagle Ford shale play.

Liquefied natural gas (LNG) imports are expected to decline by 0.2 Bcf/d (26 percent) in 2012 as higher global LNG market prices reduce LNG's competitiveness in the U.S. market. A small amount of LNG will continue to arrive at U.S. terminals in 2012 and 2013 either to take advantage of temporarily high local prices due to cold snaps and disruptions or to fulfill long-term contract obligations.

U.S. Natural Gas Inventories. Working natural gas inventories ended December at 3,472 Bcf, a record high for this time of year. An unusually warm winter so far combined with the domestic production increases throughout the year has contributed to large storage accumulations. Inventory levels at the end of October 2012 and 2013 are expected to set new record highs at about 3,960 Bcf and 3,990 Bcf, respectively. Total natural gas working storage design capacity of active fields was estimated at 4,388 Bcf in April 2011, but regional storage constraints could occur below that level. Unusually warm winters or mild summers could potentially strain available storage capacity over the next two years, leading to temporary shut-in production and lower prices for natural gas.

U.S. Natural Gas Prices. At this time last year, EIA had projected that the Henry Hub natural gas spot price would average \$4.02 per MMBtu in 2011, rising to an average \$4.50 per MMBtu in 2012. The final average Henry Hub spot price for 2011 was \$4.00 per MMBtu. The current forecast for 2012 natural gas prices is significantly lower than at this time last year, as continued growth in production and a very warm start to the winter have contributed to record-high natural gas inventories. EIA now expects the Henry Hub spot price will average \$3.53 per MMBTU in 2012. In 2013, the forecast spot price rises to an average of \$4.14 per MMBtu.

Natural gas futures prices for March 2012 delivery (for the 5-day period ending January 5, 2012) averaged \$3.05 per MMBtu, and the average implied volatility was 40 percent (Market Prices and Uncertainty Report). The lower and upper bounds for the 95-percent confidence interval for March 2012 contracts are \$2.29 per MMBtu and \$4.06 per MMBtu. At this time last year, the March 2011 natural gas futures contract averaged \$4.39 per MMBtu and implied volatility averaged 43 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.21 per MMBtu and \$6.02 per MMBtu.

Coal

U.S. Coal Consumption. Coal consumption for electricity generation fell by 30 million short tons (MMst) (3.1 percent) in 2011. Electric power sector coal consumption is forecast to decline by an additional 2.1 percent in 2012 as generation from natural gas, nuclear and wind increases and electricity consumption remains flat. EIA expects the decline in electric power sector coal consumption to continue in 2013, although at a slower rate, as increases from other sources continue to displace coal-fired electricity generation.

U.S. Coal Supply. U.S. coal production remained at nearly the same level for a second consecutive year in 2011, as production growth in the Appalachian and Interior regions offset declines in the Western region (U.S. Coal Production Chart). The significant increase in coal exports in 2011 was balanced by lower domestic consumption and a drawdown in inventories. EIA expects coal production to decline by 2 percent in 2012 as domestic consumption and exports fall. Coal production in the Western region, which is primarily used for power generation, is projected to grow slightly in 2012 while production from the Appalachian and Interior regions declines. EIA forecasts that the decline in production will continue in 2013 as consumption falls and inventory withdrawals continue. EIA expects the drawdown of inventories at electric power plants will continue at a slower rate in 2012 and 2013 (U.S. Electric Power Sector Coal Stocks Chart).

U.S. Coal Trade. U.S. coal exports of 107 MMst in 2011 were the highest since 1991. EIA expects U.S. coal exports will remain higher than recent levels but stay below the 2011 level, as supply from other major coal-exporting countries recovers from disruptions. Forecast U.S. coal exports are at 98 MMst in 2012 and 2013.

U.S. Coal Prices. Delivered coal prices to the electric power sector have increased steadily over the last 10 years and this trend continued in 2011, with an average delivered coal price of \$2.40 per MMBtu (6.0 percent increase). Looking forward, several factors are exerting downward pressure on the average delivered coal price, including lower demand for coal to generate electricity, lower natural gas prices, and concerns about the effects of the U.S. Environmental Protection Agency's (EPA) Cross-State Air Pollution Rule (CSAPR) and the timing of its implementation. EIA forecasts the average delivered coal price to remain close to its 2011 level in 2012 and 2013.

Electricity

U.S. Electricity Consumption. EIA expects total U.S. consumption of electricity will rise slightly during 2012 and then grow by 1.6 percent during 2013 (U.S. Total

Electricity Consumption Chart). Cooling degree-days throughout the United States during 2010 and 2011 were about 18 percent higher than the 30-year average. The National Oceanic and Atmospheric Administration projects summer temperatures in 2012 will be very close to the 30-year normal. As a result, less electricity is consumed for air conditioning, pushing electricity sales to the residential sector down by 0.5 percent this year. An increase in the growth rate in the number of households drives a 2.1 percent increase in residential electricity consumption during 2013. Increasing growth in economic activity over the next two years should contribute to 0.8-percent growth in retail sales of electricity to the industrial sector during 2012 and 1.7-percent growth in 2013.

U.S. Electricity Generation. On December 21, 2011, EPA finalized its Mercury and Air Toxics Standards (MATS) rule regarding maximum achievable control technology for power plants. On December 30, the U.S. Court of Appeals in the District of Columbia issued a stay on the implementation of the EPA's Cross-State Air Pollution Rule (CSAPR), which was originally scheduled to become effective January 1, 2012. Both CSAPR and MATS introduce extra uncertainty into EIA's projections of the mix of fuels used for electricity generation. The timing and pace of change in industry generation dispatch patterns remains unclear. EIA expects coal to fuel 42.2 percent of total generation this year and 41.5 percent in 2013, down from a share of 43 percent during 2011. In contrast, the share of generation fueled by natural gas is forecast to rise from 24.4 percent in 2011 to 25.4 percent in 2012 and 25.8 percent in 2013 (U.S. Electricity Generation Chart).

U.S. Electricity Retail Prices. After having risen by 2.1 percent between 2010 and 2011, EIA expects average U.S. residential electricity prices to rise only 0.6 percent in 2012 and then stay flat in 2013 (U.S. Residential Electricity Prices Chart).

Renewables and Carbon Dioxide Emissions

U.S. Renewables. The time period from 2011 to 2013 presents a complex landscape in terms of renewable energy projections. A 30-percent grant available for renewables that could be taken in lieu of both an investment tax credit (ITC) and a production tax credit (PTC) expired at the end of 2011. Both the PTC and ITC for wind expire for projects built after 2012, and these credits for other eligible renewables at the end of 2013. Solar energy is not eligible for the PTC but has its own ITC that is reduced from 30 percent to 10 percent at the end of 2016.

After growing 12 percent in 2011, EIA expects the total renewable energy supply to decline by 2.3 percent in 2012 as a 13-percent decline in hydropower from the 2011

level offsets growth in other renewable energy supplies. In 2013, renewable energy supply is projected to increase by 2.1 percent.

Wood and wood waste is second only to hydropower in terms of the total energy supplied by renewable sources. After declining by 1.6 percent between 2010 and 2011, it is projected to grow in 2012 and 2013 by 1.7 percent and 2.2 percent, respectively.

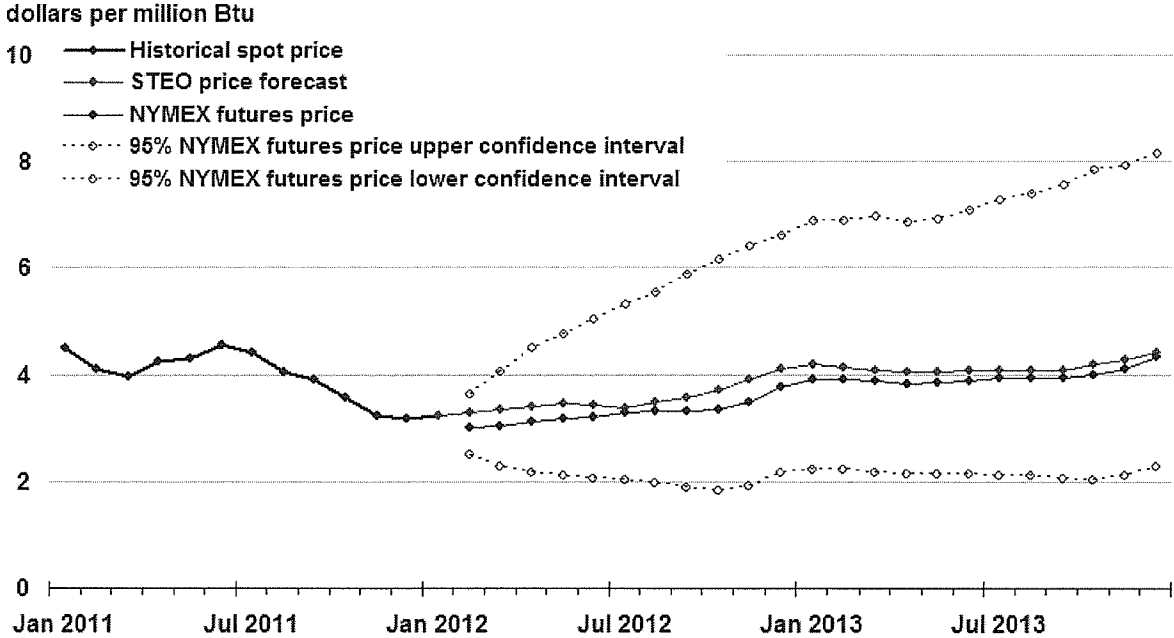
While wind energy has shown robust growth in recent years (24 percent between 2010 and 2011), its growth is projected to slow relative to recent rates. It is projected to grow 9.4 percent in 2012 and 11.3 percent in 2013, as capacity added by the end of 2012 is available for the entire year in 2013.

The solar energy supply is projected to grow by 6.7 percent and 8.5 percent in 2012 and 2013, respectively, reaching a total of 0.13 quadrillion Btu in 2013. About 80 percent of the near-term growth in central-station solar energy (both solar photovoltaic and solar thermal) is from projects being developed in the southwestern United States where resources are abundant and of high quality. However, on a Btu basis, 89 percent of solar energy in 2010 was related to residential consumption in the form of photovoltaic and solar thermal collectors. This percentage is projected to decline as more central power station projects come on line.

In terms of liquid renewable fuels, EIA expects fuel ethanol production to grow from an average of 907 thousand bbl/d in 2011 to 929 thousand bbl/d in 2012 and 934 thousand bbl/d in 2013. EIA estimates that biodiesel production in 2011 averaged about 56 thousand bbl/d (860 million gallons total annual production). Forecast biodiesel production grows slightly higher to 62 thousand bbl/d in 2012 and 75 thousand bbl/d in 2013.

U.S. Energy-Related CO₂ Emissions. Fossil fuel emissions are projected to remain flat in 2012 and 2013, as increasing emissions from natural gas are offset by declines in coal emissions (U.S. Carbon Dioxide Emissions Growth Chart).

Henry Hub Natural Gas Price



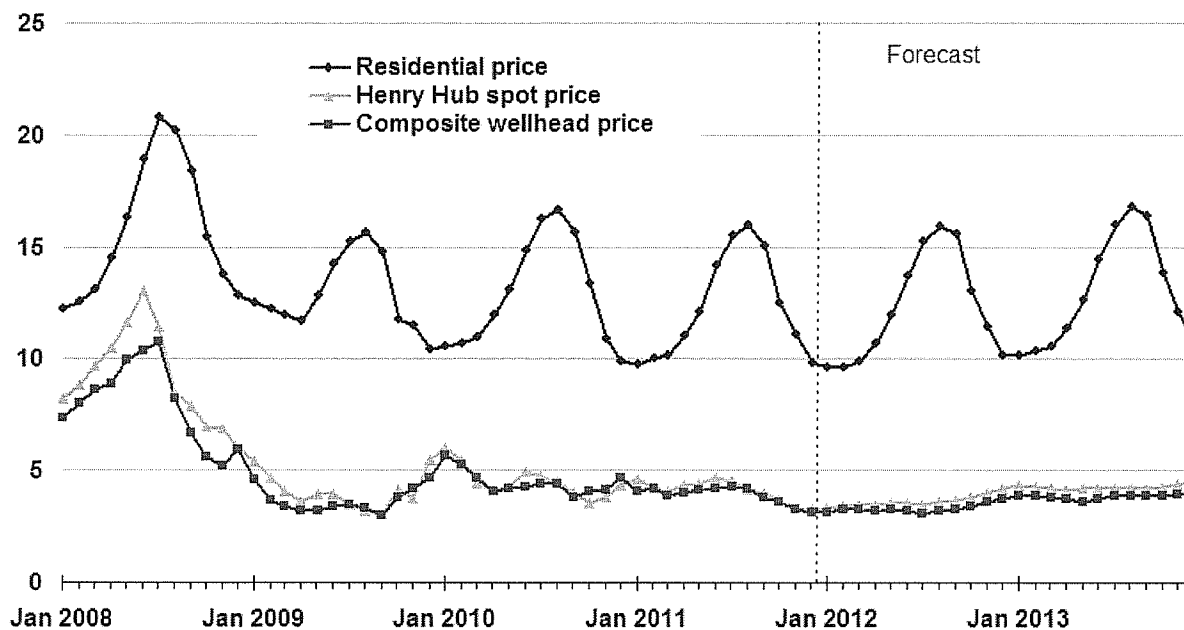
Note: Confidence interval derived from options market information for the 5 trading days ending January 5, 2012
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: Short-Term Energy Outlook, January 2012



U.S. Natural Gas Prices

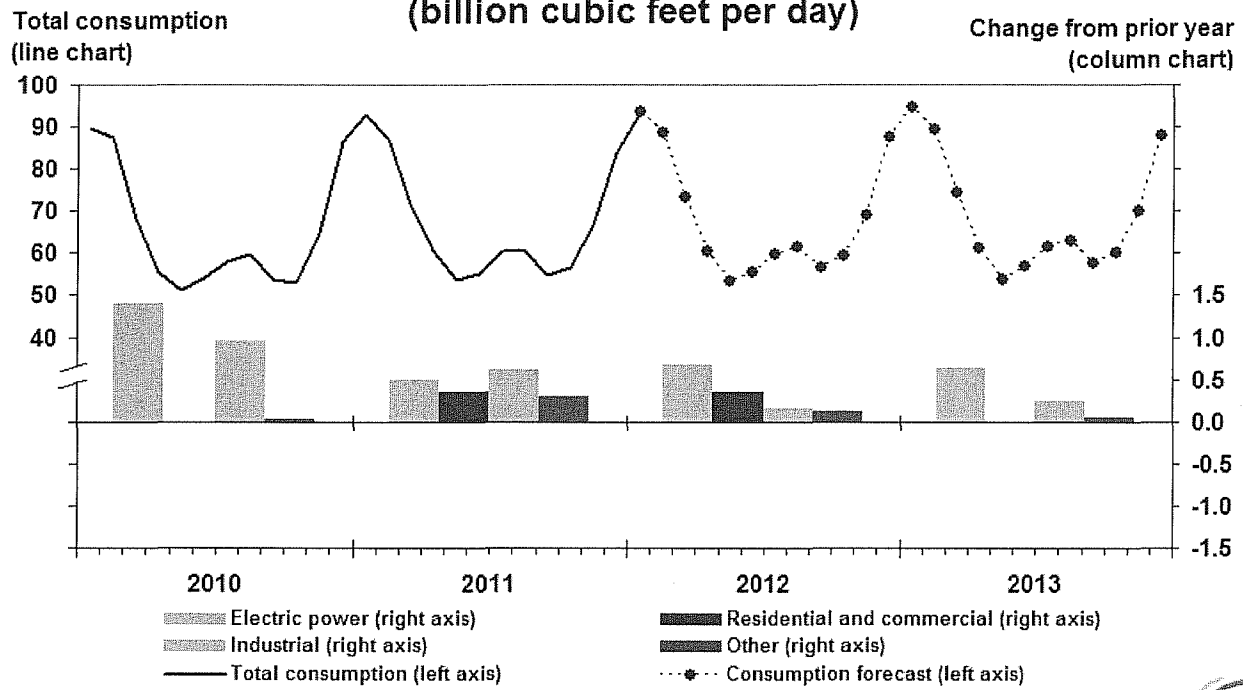
dollars per thousand cubic feet



Source: Short-Term Energy Outlook, January 2012



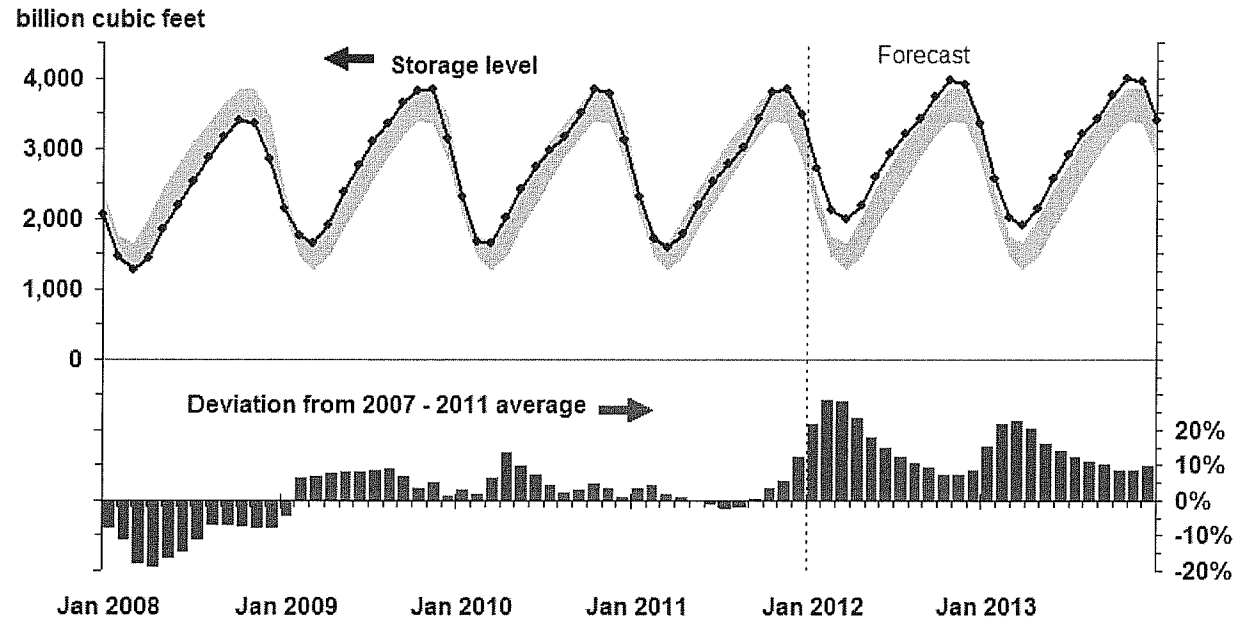
U.S. Natural Gas Consumption (billion cubic feet per day)



Source: Short-Term Energy Outlook, January 2012



U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2007 - Dec. 2011.

Source: Short-Term Energy Outlook, January 2012



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

Foothills Pipe Lines Ltd.

On October 31, 2011, TransCanada filed new rates for the Foothills Pipe Lines Ltd. System with the National Energy Board to be effective January 1, 2012.

NOVA Gas Transmission Ltd.

TransCanada filed new rates for the Alberta System with the National Energy Board to be effective January 1, 2012.

Approximate impact on Montana-Dakota's cost of gas: 0.001 cents per dk

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS TARIFF SHEET
NORTH DAKOTA GAS
EFFECTIVE FEBRUARY 2012

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$4.458	\$4.546	\$3.516	\$3.500
Prior Gas Cost	5.017	5.107	4.058	4.040
Current Gas Cost Adjustment	(\$0.559)	(\$0.561)	(\$0.542)	(\$0.540)
<u>Surcharge Adjustment:</u>				
Current Adjustment	(\$0.032)	(\$0.032)	\$0.064	\$0.041
Prior Adjustment	(0.032)	(0.032)	0.064	0.041
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<u>Market Based Pricing Differential</u>				
Current Adjustment	(\$0.009)	(\$0.009)	\$0.000	\$0.000
Prior Adjustment	(0.009)	(0.009)	0.000	0.000
Change in Margin Sharing Provision	\$0.000	\$0.000	\$0.000	\$0.000
Net Increase (Decrease) in Gas Costs	(\$0.559)	(\$0.561)	(\$0.542)	(\$0.540)
Gas Cost Level	\$4.458	\$4.546	\$3.516	\$3.500
Plus: Surcharge	(0.032)	(0.032)	0.064	0.041
Total Gas Cost Level in Tariff Rates	\$4.426	\$4.514	\$3.580	\$3.541

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE TARIFF SHEET
NORTH DAKOTA PROPANE
EFFECTIVE FEBRUARY 2012

Cost of Gas - Propane

Current Propane Cost (Exhibit D)	\$18.114
Prior Propane Cost	<u>16.467</u>
Current Propane Cost Adjustment	<u><u>\$1.647</u></u>

Surcharge Adjustment

Current Adjustment	\$0.511
Prior Adjustment	<u>0.511</u>
Change in Surcharge Adjustment	\$0.000

Market Based Pricing Differential

Current Adjustment	(\$0.009)
Prior Adjustment	<u>(0.009)</u>
Change in Margin Sharing Provision	\$0.000

Net Increase (Decrease) in Gas Costs

\$1.647

Propane Cost Level	\$18.114
Plus: Surcharge	<u>0.511</u>
Total Propane Cost Level in Rates	<u><u>\$18.625</u></u>

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
RESIDENTIAL AND GENERAL SERVICE
EFFECTIVE FEBRUARY 2012**

	Amount
Total Gas Costs 1/	\$61,642,412
Residential and General Service dk Requirements 2/	13,890,396
Average Cost of Gas per dk	\$4.438
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.458
Less: Gas Cost Level in Rates 3/	5.017
Current Gas Cost Adjustment	(\$0.559)

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

2/ Normalized dk sales for the twelve months ended November 30, 2011, adjusted for losses at .45%

3/ Gas Cost Level in Current Tariff Rates Case No. PU-11-8 effective December 1, 2011:

Cost of Purchased Gas	\$4.994
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.017

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
OPTIONAL SEASONAL - RATE 72
EFFECTIVE FEBRUARY 2012**

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$61,642,412
Less: Annual MDDQ Costs 1/	<u>11,830,932</u>
Total Gas Costs excluding MDDQ	\$49,811,480
Firm Service Requirements 1/	13,890,396
Other Gas Costs per Dk (excluding MDDQ)	\$3.586
Summer Seasonal Rate, adjusted for losses 2/	3.602
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,830,932
Winter Firm Service Requirements	12,582,858
MDDQ Costs per Winter Dk	\$0.940
Add: Other Gas Costs per Dk	<u>3.586</u>
Winter Seasonal Rate	\$4.526
Winter Seasonal Rate, adjusted for losses 2/	\$4.546
Less: Gas Cost Level in Rates 3/	<u>5.107</u>
Current Gas Cost Adjustment	<u><u>(\$0.561)</u></u>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-11-8 effective December 1, 2011:

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$4.123	\$5.084
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$4.142	\$5.107

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
INTERRUPTIBLE
EFFECTIVE FEBRUARY 2012**

	Amount
Total Gas Costs 1/	\$12,258,526
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$3.500
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.516
Less: Gas Cost Level in Rates 2/	4.058
Current Gas Cost Adjustment	(\$0.542)

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-11-8 effective December 1, 2011:

Cost of Purchased Gas	\$4.040
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.058

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
EFFECTIVE FEBRUARY 2012

	<u>Amount</u>
Total Gas Costs 1/	<u>\$3,079,727</u>
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$3.500
Less: Gas Cost Level in Rates 2/	<u>4.040</u>
Current Gas Cost Adjustment	<u><u>(\$0.540)</u></u>

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

2/ Gas Cost Level in Current Tariff Rates Case No. PU-11-8 effective December 1, 2011:
Cost of Purchased Gas \$4.040

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
February 2012 PGA**

Williston Basin Interstate Pipeline Company - Exhibit B, pages 6 - 8 for Schedules FT-1, FTN-1, and FS-1.

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

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

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

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

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

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

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES

RATE SCHEDULE FT-1						

RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	737.928	N.A.	N.A.	N.A.	737.928
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
COMMODITY CHARGE						
MAXIMUM A/B/	RATE PER DKT	3.120	0.180	N.A.	N.A.	3.300
MINIMUM A/B/	RATE PER DKT	3.120	0.180	N.A.	N.A.	3.300
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.180	N.A.	N.A.	31.064
MINIMUM A/B/	RATE PER DKT	3.120	0.180	N.A.	N.A.	3.300
VOLUMETRIC CAPACITY RELEASE CHARGE						
MAXIMUM	RATE PER DKT	24.261	N.A.	N.A.	N.A.	24.261
MINIMUM	RATE PER DKT	0.000	N.A.	N.A.	N.A.	0.000

-
- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 3.261%, CONSISTING OF 3.450% FOR THE CURRENT PERCENTAGE AND (0.189%) 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 1.098 CENTS, CONSISTING OF 0.962 CENTS FOR THE CURRENT RATE AND 0.136 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.

Issued On: September 1, 2011
 Docket Number: RP11-2476-001
 FERC Order Date: September 28, 2011

Effective On: October 1, 2011

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES

RATE SCHEDULE FTN-1						

RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	47.491	N.A.	N.A.	N.A.	47.491
MINIMUM	RATE PER EQV. DKT PER MO.	1.589	N.A.	N.A.	N.A.	1.589
VOLUMETRIC CAPACITY RELEASE CHARGE						
MAXIMUM	RATE PER DKT	1.561	N.A.	N.A.	N.A.	1.561
MINIMUM	RATE PER DKT	0.052	N.A.	N.A.	N.A.	0.052

Issued On: September 30, 2010
 Docket Number: RP10-1378-000
 FERC Order Date: November 1, 2010

Effective On: September 30, 2010

NOTICE OF CURRENTLY EFFECTIVE RATES

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

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

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 0.998%, CONSISTING OF 1.264% FOR THE CURRENT PERCENTAGE AND (0.266%) 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 0.491 CENTS, CONSISTING OF 0.673 CENTS FOR THE CURRENT RATE AND (0.182) 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: August 31, 2011
 Docket Number: RP11-2477-000
 FERC Order Date: September 23, 2011

Effective On: October 1, 2011

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

PART 4.1
4.1 - Statement of Rates
T-1 and T-1B - Long Term Base Tariff Rates
v.1.0.0 Superseding v.0.0.0

STATEMENT OF RATES
2/ 3/

Rate Schedule -----	Long-Term Base Tariff Rate (per 100 Dth-Miles) 1/ -----
T-1 and T-1B	
Daily Reservation Rate - Port of Morgan, MT to Ventura, IA	
Maximum	\$0.0321
Minimum	\$0.0000
Daily Reservation Rate - Ventura, IA to North Hayden, IN	
Maximum	\$0.0345
Minimum	\$0.0000
Commodity Rate - Port of Morgan, MT to North Hayden, IN	
Maximum	\$0.0004
Minimum	\$0.0004

- 1/ Applicable to any Rate Schedule T-1 U.S. Shippers Service Agreement or any Rate Schedule T-1B Service Agreement with a primary term of at least twelve consecutive months.
- 2/ The Settlement Base Rates, pursuant to the Stipulation at Docket No. RP06-72-000, et al., remain in effect until such rates are superseded by new base rates placed into effect consistent with the provisions of the Stipulation.
- 3/ Rates in this section are subject to the revenue retrieval provision pursuant to Article X of the Stipulation at Docket No. RP06-72-000, et al.

NOVA Gas Transmission Ltd.

Table of Rates, Tolls and Charges
Page 1 of 2

Service	Rates, Tolls and Charges		
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month based on a three year term (Price Point "B") & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) \$ 179.94/10 ³ m ³		
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D ³	Refer to Attachment "2" for applicable FT-D Demand Rate per month based on a one year term (Price Point "Z") & Surcharge for each Group 1 or Group 2 Delivery Point. Average FT-D Demand Rate for Group 1 Delivery Points \$ 5.44/GJ FT-D Demand Rate for Group 2 Delivery Points ¹ \$ 2.39/GJ FT-D Demand Rate for Group 3 Delivery Points ² \$ 2.87/GJ		
4. Rate Schedule STFT	STFT Bid Price = Minimum of 100% of the applicable FT-D Demand Rate based on a one year term (Price Point "Z") for each Group 1 Delivery Point		
5. Rate Schedule FT-DW	FT-DW Bid Price = Minimum of 125% of the applicable FT-D Demand Rate based on a three year term (Price Point "Y") for each Group 1 Delivery Point		
6. Rate Schedule FT-P ³	Refer to Attachment "3" for applicable FT-P Demand Rate per month		
7. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10³m³/day)</u>	
	1-5 years	10.85	
	6-10 years	9.07	
	15 years	8.13	
	20 years	7.22	
8. Rate Schedule LRS-2	LRS-2 Rate per month	\$ 50,000	
9. Rate Schedule LRS-3	LRS-3 Demand Rate per month	\$ 129.55/10 ³ m ³	
10. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
11. Rate Schedule IT-D ³	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point		
12. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
13. Rate Schedule PT	<u>Schedule No</u>	<u>PT Rate</u>	<u>PT Gas Rate</u>
	9009-01001-1	\$ 660.00/d	50.0 10 ³ m ³ /d
14. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2011462247	\$ 27.00 / month	
	2011462241	\$ 7.00 / month	
	2011462238	\$ 20.00 / month	
	2011462242	\$ 3.00 / month	
	2011462243	\$ 1.00 / month	
	2011462244	\$ 32.00 / month	
	2011462240	\$ 1.00 / month	
	2011462245	\$ 1,985.00 / month	
	2011462252	\$ 3.00 / month	
	2011462239	\$ 56.00 / month	
	2011462248	\$ 135.00 / month	
	2011462249	\$ 75.00 / month	
	2011462246	\$ 11.00 / month	
	2011462250	\$ 207.00 / month	
	2011466606	\$ 204.00 / month	
	2011463220	\$ 392.00 / month	
	2003004522	\$ 83,333.00 / month	
	2011476052 / 2011476054	\$ 0.0783 / GJ subject to \$ 717,000.00 Minimum Annual Charge	
	2011475772	\$ 9,250.00 / month	
	2011475056	\$ 0.095 / GJ and \$ 1,000.00 / month	
	2011476092	\$ 0.095 / GJ and \$ 1,000.00 / month	
	2011494569	\$ 0.095 / GJ and \$ 1,000.00 / month	

NOVA Gas Transmission Ltd.

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

Group 1 Delivery Point Number	Group 1 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" (\$/GJ)	IT-D Rate per Day (\$/GJ)
2000	ALBERTA-B.C. BORDER	5.51	0.1986
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	2.39	0.0861
31110	ALLIANCE EDSON INTERCONNECT APN	2.39	0.0861
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	2.39	0.0861
3002	BOUNDARY LAKE BORDER	3.44	0.1242
1958	EMPRESS BORDER	5.30	0.1911
3886	GORDONDALE BORDER	3.44	0.1242
6404	MCNEILL BORDER	5.30	0.1911

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	2.39	0.0861	
31003	AGRIUM CARSELAND SALES APS	2.39	0.0861	
31002	AGRIUM FT. SASK SALES APN	2.39	0.0861	Yes
31004	AGRIUM REDWATER SALES APN	2.39	0.0861	
31005	AINSWORTH SALES APGP	3.39	0.1226	
31006	AIR LIQUIDE SALES APN	3.39	0.1226	
31007	ALBERTA ENVIROFUELS SALES APN	3.39	0.1226	Yes ²
31008	ALBERTA HOSPITAL SALES APN	3.39	0.1226	Yes
3868	ALBERTA-MONTANA	3.44	0.1242	
3059	ALLISON CREEK SALES	2.39	0.0861	
31009	ALTASTEEL SALES APN	3.39	0.1226	Yes ²
3562	AMOCO SALES (BP SALES TAP)	2.39	0.0861	
31012	APL JASPER SALES APN	3.39	0.1226	Yes
3488	ARDLEY SALES	2.39	0.0861	
3135	AURORA SALES	2.39	0.0861	
3423	BASHAW WEST SALES	2.39	0.0861	
31013	BAYMAG SALES APS	2.39	0.0861	
31014	BEAR CREEK COGEN SALES APGP	3.39	0.1226	
3068	BEAVER HILLS SALES	2.39	0.0861	
3933	BIG EDDY INTERCONNECTION	2.39	0.0861	
3067	BIGSTONE SALES	2.39	0.0861	
3468	BLEAK LAKE SALES	2.39	0.0861	
3164	BRAINARD LAKE SALES	2.39	0.0861	
3918	BUFFALO CREEK INTERCONNECTION	2.39	0.0861	
31015	BURDETT COGEN SALES APS	2.39	0.0861	
3204	CABIN SALES	2.39	0.0861	
3109	CALDWELL SALES	2.39	0.0861	
31016	CALGARY ENERGY CENTRE SALES APS	2.39	0.0861	Yes
3634	CANOE LAKE SALES	2.39	0.0861	
3165	CANOE LK SLS #2	2.39	0.0861	
3866	CARBON INTERCONNECTION	2.39	0.0861	
3484	CARIBOU LAKE SALES	2.39	0.0861	
3157	CARIBOU LK SOUTH SL	2.39	0.0861	
3106	CARMON CREEK SALES	2.39	0.0861	
3101	CAROLINE SALES	2.39	0.0861	
31017	CARSELAND COGEN SALES APS	2.39	0.0861	
3495	CAVALIER SALES	2.39	0.0861	
31018	CHAIN LAKES COOP SALES APS	2.39	0.0861	
3907	CHANCELLOR INTERCONNECTION	2.39	0.0861	
3151	CHEECHAM W. #2 SALES	2.39	0.0861	
3622	CHEECHAM WEST SALES	2.39	0.0861	
6014	CHEVRON AURORA SALES	2.39	0.0861	
31019	CHEVRON FT. SASK SALES APN	3.39	0.1226	Yes

NATURAL GAS TARIFF

NorthWestern
Energy

Canceling 26th Revised Sheet No. 80.1
25th 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	\$ 103.60
10,001 to 30,000	\$ 148.95
>30,000	\$ 330.50

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for
Maximum Daily Delivery Quantity (MDDQ) \$ 0.8469517

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum \$ 0.0064180
Minimum \$ 0.0017935
GTAC Amortization \$ (0.0011145)

Balancing Penalty Rate Higher of \$25.00/ Dekatherm Or
150% of Market Price

PLUS:

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

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

MINIMUM BILL: Per respective contracts.

(continued)

Staff Approved: July 27, 2011
Accepted as filed. No Commission action required.
Tariff Letter No. 194-G

Effective for service rendered on or after
August 1, 2011

PUBLIC SERVICE COMMISSION
Aleisha Soem Secretary

GAS RATE SCHEDULE

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

SD P.U.C. Section No. 3
Original Sheet No. 1
Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is \$2.398 per dekatherm.

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

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
Third Revised Sheet No. 12
Cancels Second Revised Sheet No. 12

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

<u>Division</u>	<u>Receipt Point</u>	<u>Delivery Point</u>	<u>Monthly Customer Charge</u>	<u>Maximum Transportation Charge 2/</u>	<u>Minimum Transportation Charge 2/</u>	<u>Fuel Reimbursement Quantity Percentage 3/</u>
TC (Casper)						
Firm						
Transportation	MLI	MLI	\$0.00	\$0.1040	\$0.0010	0.885%
	MLI	MLE	\$145.00	\$0.1040	\$0.0010	0.885%
	MLI	DSE	\$225.00	\$0.1978	\$0.0020	2.425%
Interruptible						
Transportation 4/	MLI	MLI	\$0.00	\$0.0844	\$0.0010	0.885%
	MLI	MLE	\$145.00	\$0.0844	\$0.0010	0.885%
Administrative						
Fee 5/			\$325.00			

- 1/ Casper Division service area is defined on Sheet Nos. 3 and 4 of this Tariff.
- 2/ All charges are per therm.
- 3/ For fuel, lost and unaccounted for gas, the Company shall be entitled to retain the stated percentage of all therms received for transportation, unless otherwise agreed in writing. On or before March 1 of each year, the Company shall file with the Commission an application to revise the stated percentage to be effective June 1 of that year through May 31 of the following year. The Company shall calculate the stated percentage using not less than twelve (12) consecutive months of actual data.
- 4/ Interruptible Transportation Service is not available to DSE customers. The Customer Charge will be charged only for those months gas actually flows.
- 5/ In addition to the transportation charges stated above, Shippers are responsible for the monthly administrative fee as stated, applicable to each meter located at the customer location. For Interruptible Transportation Shippers, the Administrative Fee will be charged only for those months gas actually flows. Firm Transportation Shippers will be charged each month, regardless of gas flow.

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

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

Date Issued: March 1, 2011
By: William N. Cantrell

Date Effective: June 1, 2011
Title: President and CEO

**MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS
EFFECTIVE FEBRUARY 2012**

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2011	\$14,843,510	\$727,522	\$3,066,232
November	12,931,691	618,119	2,523,623
December	11,049,164	495,536	1,231,694
January 2012	6,808,276	263,697	(365,982)
February	4,138,595	112,706	(1,381,629)
March	2,664,732	22,118	(1,971,207)
April	2,622,184	7,651	(1,787,759)
May	2,791,762	12,486	(1,053,926)
June	3,753,825	71,772	(49,988)
July	5,413,835	176,415	1,004,441
August	8,136,983	350,469	2,039,632
September	10,261,761	677,733	2,855,285
October	11,336,005	738,372	3,116,438
13 month average	<u>\$7,442,486</u>	<u>\$328,815</u>	<u>\$709,758</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$654,269	\$28,906	\$62,395
Return Requirement	<u>\$900,541</u>	<u>\$39,786</u>	<u>\$85,881</u>

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

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE
NORTH DAKOTA
EFFECTIVE FEBRUARY 2012

Cost of Purchased Propane	\$133,440
Gallons Purchased	80,873
Projected dk Sales	7,400
Propane Cost per Dk	\$18.032
Average Cost of Propane as Adjusted for Losses @ 99.55%	18.114
Less: Propane Cost Level in Rates 1/	<u>16.467</u>
Current Propane Cost Adjustment	<u><u>\$1.647</u></u>

1/ Propane Cost Level in Current Rates - Case No. PU-11-8, effective November 1, 2011.

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2011									<u>(\$589,074)</u>
August	\$229,854	\$119,111 2/	(\$5) 3/	\$348,960	257,122	(\$0.023)	(\$5,914)	\$354,874	(234,200)
September	153,237	(52,739) 4/	(70) 5/	100,428	263,383	(0.023)	(6,058)	106,486	(127,714)
October	(21,312)	0	(2)	(21,314)	389,643	(0.032)	(10,319) 6/	(10,995)	(138,709)
November	(43,536)	0	(1)	(43,537)	881,908	(0.032)	(28,221)	(15,316)	(154,025)
Balance @ November 30, 2011									<u>(\$154,025)</u>

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

2/ Reflects correction to restate June gas costs to include correct dk volumes.

3/ Includes interest associated with June gas cost adjustment.

4/ Adjustment to correct gas costs for the period July 2009 - August 2011 due to incorrect pipeline border station metered volumes and adjustment for the period December 2010 - June 2011 to reflect the correct allocation of the volumes associated with the Billings Landfill.

5/ Includes interest associated with the September gas cost adjustments.

6/ Reflects 238,784.1 Dk @ (\$0.023) and 150,875.5 Dk @ (\$0.032).

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2011									<u><u>\$48,803</u></u>
August	\$10,522	\$0	\$1	\$10,523	30,906	(\$0.010)	(\$309)	\$10,832	59,635
September	14,424	20,058 2/	32 3/	34,514	33,439	(0.010)	(334)	34,848	94,483
October	(12,066)	0	1	(12,065)	54,461	0.064	(510) 4/	(11,555)	82,928
November	(4,162)	0	1	(4,161)	71,035	0.064	4,546	(8,707)	74,221
Balance @ November 30, 2011									<u><u>\$74,221</u></u>

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

2/ Adjustment to correct gas costs for the period July 2009 - August 2011 due to incorrect pipeline border station metered volumes and adjustment for the period December 2010 - June 2011 to reflect the correct allocation of the volumes associated with the Billings Landfill.

3/ Includes interest associated with the September gas cost adjustments.

4/ Reflects 53,993.4 Dk @ (\$0.010) and 467.7 Dk @ \$0.064.

**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, 2011									<u>\$82,096</u>
August	\$7,880	(\$62,107) 2/	\$0	(\$54,227)	4,781	\$0.031	\$148	(\$54,375)	27,721
September	11,054	(72,081) 3/	(7) 4/	(61,034)	4,781	0.031	148	(61,182)	(33,461)
October	(2,569)	0	(1)	(2,570)	11,572	0.041	358 5/	(2,928)	(36,389)
November	(9,963)	0	0	(9,963)	25,050	0.041	1,027	(10,990)	(47,379)
Balance @ November 30, 2011									<u>(\$47,379)</u>

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

2/ Reflects correction to restate June gas costs to include correct dk volumes.

3/ Adjustment to correct gas costs for the period July 2009 - August 2011 due to incorrect pipeline border station metered volumes and adjustment for the period December 2010 - June 2011 to reflect the correct allocation of the volumes associated with the Billings Landfill.

4/ Includes interest associated with the September gas cost adjustments.

5/ Reflects 11,571.6 Dk @ \$0.031.