



MONTANA-DAKOTA

UTILITIES CO.

A Division of MDU Resources Group, Inc.

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

April 10, 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-12-008

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 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 (103rd Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered May 1, 2012.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.560 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.

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 May 2012.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.560 per dk for residential, firm general, small and large interruptible customers and a decrease of \$0.557 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 May 2012. The average cost of gas for firm customers, adjusted for losses, is \$3.241.

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 decreased since the last COG filing due to a combination of factors. 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 May 2012. The net effect of this filing is a decrease of \$0.963 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 May 2012. The average cost of propane for all customers, adjusted for losses, is \$12.076 per dk.

Exhibit F shows the calculation of the surcharge adjustment which will apply during the period May 1, 2012 through April 30, 2013. The surcharge is \$0.646 per dk, an increase of \$0.135 per dk for all customers.

These proposed adjustments, calculated in accordance with Rate 88 and 99, will amount to a decrease of approximately \$371,400 for natural gas customers and a decrease of approximately \$3,000 for propane customers during the month of May 2012. All of Montana-Dakota's retail natural gas and propane customers in North Dakota may be affected by this proposal. There were 94,964 natural gas customers and 340 propane customers in North Dakota as of March 31, 2012.

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 \$500 in accordance with North Dakota Century Code Section 49-05-05 on February 9, 2012. This payment will cover the filing fee associated with this monthly COG filing.

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
 103rd Revised Sheet No. 3
 Canceling 102nd 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	\$3.200	\$4.012
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$3.200	\$3.338
Interruptible Service - PAR			\$0.120	\$2.380	\$2.500
Interruptible Service - MAFB			\$0.120	\$2.347	\$2.467
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$3.200	\$3.797
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$2.380	(Maximum) \$3.251
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day			
Winter Gas Usage			\$0.597	\$3.289	\$3.886
Summer Gas Usage			\$0.597	\$2.362	\$2.959
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.010	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.010	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$2.380	(Maximum) \$3.099
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$12.713	\$13.525
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$12.713	\$13.310

Date Filed: April 10, 2012

Effective Date:

Issued By: Tamie A. Aberle
 Regulatory Affairs Manager

Case No.:

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

May 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.

The lack of cold winter weather, national storage levels at record levels and continuing strong domestic supply continue to contribute to the decline in the commodity price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of March 30, 2012 were 60.5 percent above the five-year average and 55.7 percent above last year's storage balance.

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

The April Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 20.

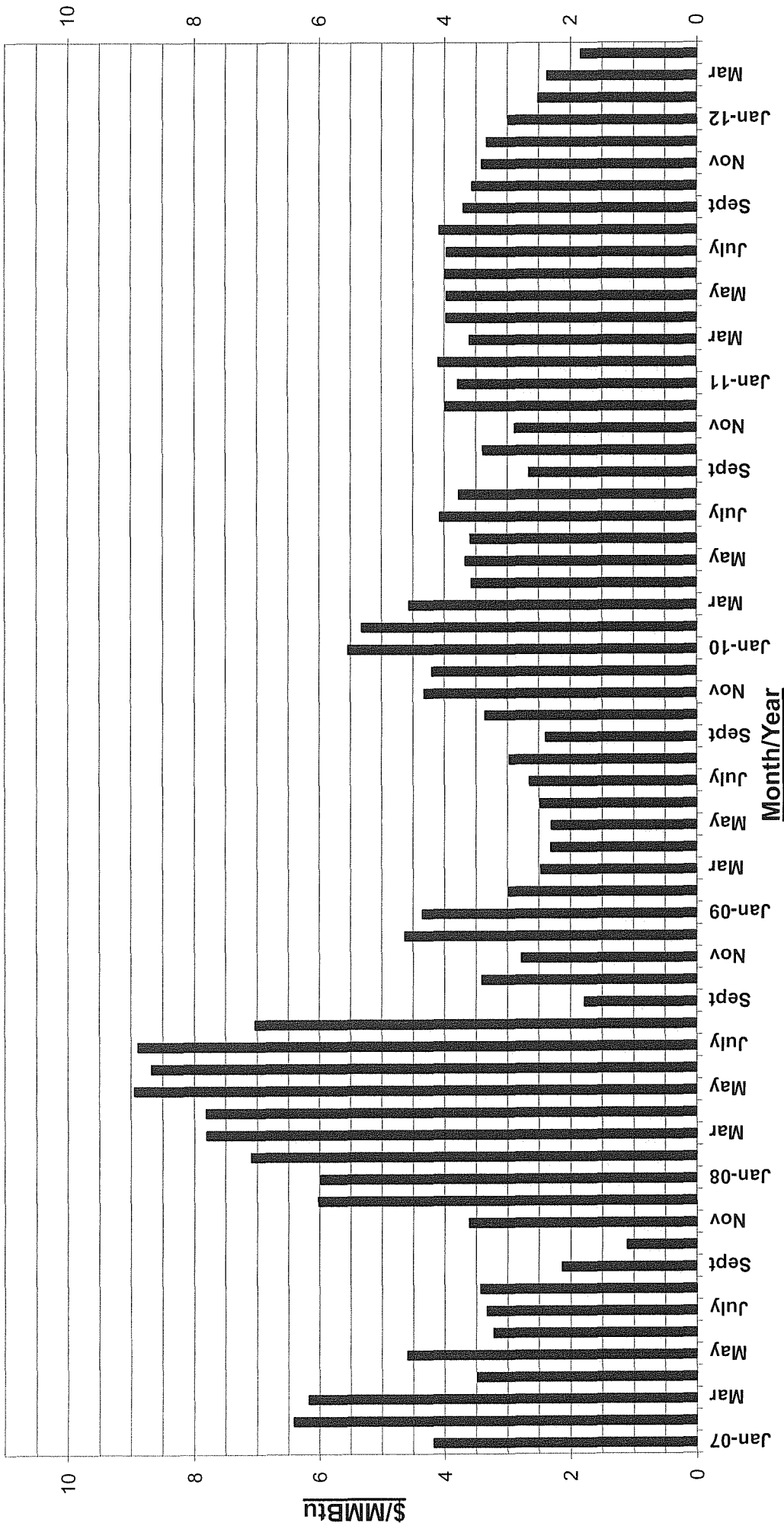
**Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
May 2012**

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 April 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, demand and inventory levels. As seasonal usage decreases, this has 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.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 - \$2.43



Independent Statistics & Analysis

U.S. Energy Information
Administration

April 2012

Short-Term Energy and Summer Fuels Outlook

April 10, 2012 Release

Highlights

- EIA has lowered the forecast 2012 average U.S. refiner acquisition cost of crude oil by \$2 per barrel from last month's *Outlook* to \$112 per barrel, still \$10 per barrel higher than last year's average price. EIA expects the price of West Texas Intermediate (WTI) crude oil to average about \$106 per barrel in 2012, the same as in last month's *Outlook* but \$11 per barrel higher than the average price last year. Constraints in transporting crude oil from the U.S. midcontinent region contribute to the expected discount for WTI relative to other world crude oil prices. EIA expects WTI prices to remain relatively flat in 2013, averaging about \$106 per barrel, while the average U.S. refiner acquisition cost of crude oil averages \$110 per barrel.
- During the April-through-September summer driving season this year, regular gasoline retail prices are forecast to average about \$3.95 per gallon, peaking in May at a monthly average price of \$4.01 per gallon. EIA expects regular gasoline retail prices to average \$3.81 per gallon in 2012 and \$3.73 per gallon in 2013, compared with \$3.53 per gallon in 2011. The June 2012 New York Harbor Reformulated Blendstock for Oxygenate Blending (RBOB) futures contract averaged \$3.28 per gallon for the five trading days ending April 5. Based on the market value of futures and options contracts, there is a 40 percent probability that its price at expiration will exceed \$3.35 per gallon, consistent with a monthly average regular-grade gasoline retail price exceeding \$4.00 per gallon in June.
- The warmer-than-normal weather this past winter contributed to high natural gas working inventories that continue to set new record seasonal highs, with March 2012 ending at an estimated 2.48 trillion cubic feet (Tcf), about 57 percent above the same time last year. EIA's average 2012 Henry Hub natural gas spot price forecast is \$2.51 per million British thermal units (MMBtu), a decline of \$1.49 per MMBtu from the 2011 average spot price. EIA expects that Henry Hub spot prices will average \$3.40 per MMBtu in 2013.

- EIA expects electricity generation from coal to decline by about 10 percent in 2012 as generation from natural gas increases by about 17 percent. EIA forecasts that electricity generation from coal will increase by about 7 percent and generation from natural gas fall by 3 percent in 2013 as projected coal prices to the power sector fall slightly while natural gas prices increase, allowing coal to regain some of its power sector generation share.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA expects global liquid fuels consumption will increase by 0.89 million barrels per day (bbl/d) in 2012, while total liquids supply increases by 1.81 million bbl/d, 0.85 million bbl/d from countries outside of the Organization of the Petroleum Exporting Countries (OPEC) and 0.97 million bbl/d of crude oil and non-crude liquids from OPEC-member countries. The larger increase in total supply compared with consumption growth is misleading, however, as the 2011 balance between supply and consumption resulted in a supply shortfall of 0.77 million bbl/d that contributed to a decline in world inventories, including the coordinated drawdown in government-held stocks in countries belonging to the Organization for Economic Cooperation and Development (OECD) last summer. Consequently, the change in the supply-demand balance for 2012 reflects the increase in supply over last year that is forecast to maintain stocks near current levels.

Several uncertainties could push oil prices higher or lower than projected. A number of non-OPEC countries are currently undergoing supply disruptions. Oil prices could be higher than projected in this *Outlook* if their recoveries from the disruptions are slower than forecast, additional disruptions occur, or supply growth is lower than expected. Additionally, although the effects of the impending European Union embargo and other sanctions targeting Iranian crude oil imports are still uncertain, heightened market anxiety surrounding a potentially significant supply disruption could further bolster oil prices. On the demand side, if the pace of global economic growth fails to recover in countries belonging to the OECD, or if economic growth slows in non-OECD countries, prices could be lower.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by an estimated 0.79 million bbl/d to 87.9 million bbl/d in 2011. EIA expects that this growth will accelerate over the next two years, with consumption reaching 88.8 million bbl/d in 2012 and 90.1 million bbl/d in 2013. Non-OECD countries will account for essentially all of the world's consumption growth over the next two years, with the largest contributions coming from China, the Middle East, and Central and South America (World Liquid Fuels Consumption Chart). OECD liquid fuels consumption is projected to decline by about 400 thousand bbl/d in 2012, with Europe

and the United States accounting for almost all the decline. In 2013, forecast OECD liquid fuels consumption is expected to recover slightly by 100 thousand bbl/d, driven by higher consumption in the United States.

Non-OPEC Supply. EIA expects non-OPEC crude oil and liquid fuels production to rise by 850 thousand bbl/d in 2012 and by a further 840 thousand bbl/d in 2013. The largest area of non-OPEC growth will be North America, where production increases by 560 thousand bbl/d and 180 thousand bbl/d in 2012 and 2013, respectively, resulting from continued production growth from U.S. onshore shale and other tight oil formations and Canadian oil sands. EIA expects that Kazakhstan, which will commence commercial production in the Kashagan field in the next year, will increase its total production annually by an average of 170 thousand bbl/d in both 2012 and 2013. In Brazil, output rises annually by an average of 130 thousand bbl/d over the next two years, with increased output from its offshore, pre-salt oil fields. Production also rises in China and Colombia over the next two years, while production declines in Russia, Mexico, and the North Sea.

Several notable disruptions to non-OPEC production commenced or intensified since the beginning of this year. In the former Sudan, an unresolved dispute between Sudan and the newly independent South Sudan over transit fees and other issues caused the latter to shut in all of its production at the end of January. EIA projects that total production from Sudan and South Sudan, which averaged about 430 thousand bbl/d in 2011, will average 190 thousand bbl/d in 2012 and recover to 440 thousand bbl/d in 2013 (Sudan and South Sudan Country Analysis Brief).

In Yemen and Syria, civil conflict continues to compromise a considerable portion of each country's oil output. Yemen's production is already impaired by an ongoing outage to the Marib pipeline. EIA projects that Yemen's production will average 180 thousand bbl/d in 2012, and 200 thousand bbl/d in 2013, down from the country's pre-crisis production level of around 260 thousand bbl/d (Yemen Country Analysis Brief). Due to heightened unrest, EIA expects Syria to produce 260 thousand bbl/d in 2012 and 360 thousand bbl/d in 2013, still below the country's pre-crisis production level of 400 thousand bbl/d.

Moderate disruptions stemming from technical issues have temporarily curbed production at some oil fields in Canada, Brazil, and China, but production is expected to recover in the near future.

OPEC Supply. EIA expects that OPEC members' crude oil production will continue to rise over the next two years to accommodate the projected increase in world oil demand and to counterbalance supply disruptions. Projected OPEC crude oil

production increases by about 720 thousand bbl/d in 2012 and then falls by 150 thousand bbl/d in 2013. OPEC non-crude petroleum liquids (condensates, natural gas liquids, coal-to-liquids, and gas-to-liquids), which are not covered by OPEC's production quotas, are forecast to increase by 240 thousand bbl/d in 2012, and by 70 thousand bbl/d in 2013.

EIA expects Iran's crude production to fall by about 500 thousand bbl/d by the end of 2012, from its previous level of 3.55 million bbl/d at the end of 2011. Iran's decline in output began to accelerate during the last quarter of 2011 and has continued. EIA believes that the acceleration reflects a lack of investment, which is needed to offset natural production declines. A number of foreign companies that were investing in Iran's upstream have halted their activities as a result of previous sanctions against Iran that have made it difficult to do business with the country. EIA's forecast does not factor in any potential effects of the more recent sanctions targeting Iran's central bank and the impending European Union embargo on Iran's crude oil production, because it is too early to assess Iran's ability to place its supply elsewhere.

OPEC members serve as the "swing" producers in the world market because only OPEC producers possess surplus or "spare" oil production capacity. EIA expects that the forecast decline in Iran's output of 500 thousand bbl/d in 2012 and an additional 200 thousand bbl/d in 2013 will be offset by increased production in other OPEC member countries. EIA projects that OPEC surplus production capacity will average 2.9 million bbl/d in 2012 and rise to 3.6 million bbl/d in 2013 (OPEC Surplus Crude Oil Production Capacity Chart).

OECD Petroleum Inventories. EIA estimates that commercial oil inventories held in the OECD ended 2011 at 2.59 billion barrels, equivalent to about 56.0 days of forward-cover (days-of-supply) (Days of Supply of OECD Commercial Stocks Chart). Projected OECD oil inventories increase slightly, to 2.62 billion barrels and 56.8 days of forward cover, by the end of 2012. Although the forecast December 2012 inventory is slightly lower than the 2.66-billion-barrel level at the end of December 2010, the days of forward-cover are at the highest end-of-year level since 1991 because of a decline in OECD consumption.

Crude Oil Prices. The projected U.S. refiner acquisition cost of crude oil averages \$112 per barrel in 2012 and \$110 per barrel in 2013. EIA's forecast of the WTI spot price is the same as in last month's *Outlook*, averaging about \$106 per barrel in both 2012 and 2013 (West Texas Intermediate Crude Oil Price Chart). The projected WTI price discount to the average U.S. refiner acquisition cost of crude oil narrows over the forecast from about \$7 per barrel in the second quarter of 2012 to \$4 per barrel by the fourth quarter of 2013, as physical pipeline capacity constraints diminish.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for June 2012 delivery during the 5-day period ending April 5, 2012 averaged \$104 per barrel. Implied volatility averaged 26 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in June 2012 at \$88 per barrel and \$123 per barrel, respectively. Last year at this time, WTI for June 2011 delivery averaged \$109 per barrel and implied volatility averaged 30 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$90 per barrel and \$132 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total U.S. liquid fuels consumption fell by an estimated 850 thousand bbl/d (4.5 percent) in the first quarter of 2012 from the same period last year (U.S. Liquid Fuels Consumption Chart). Motor gasoline and distillate fuel consumption accounted for much of that decline, shrinking by 240 thousand bbl/d (2.8 percent) and 260 thousand bbl/d (6.7 percent), respectively. EIA expects more moderate year-over-year declines in motor gasoline consumption, averaging about 40 thousand bbl/d over the next 9 months. In contrast, projected distillate fuel oil consumption recovers from the very warm winter with year-over-year growth averaging about 80 thousand bbl/d.

Despite assumed growth in U.S. real disposable income of 1.7 percent in 2013, forecast motor gasoline consumption will continue to be constrained by high gasoline prices, slowing growth in the driving-age population, and the improving average fuel economy of new vehicles, and declines by a further 20 thousand bbl/d in 2013. Distillate fuel consumption increases by 130 thousand bbl/d (3.3 percent) in 2013, buoyed by an assumed near-normal winter and relatively strong growth in manufacturing output.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by an estimated 180 thousand bbl/d (3.2 percent) to 5.66 million bbl/d in 2011, an upward revision of about 60 thousand bbl/d from last month's *Outlook*. A 440-thousand bbl/d increase in lower-48 onshore production in 2011 was partly offset by a 40-thousand-bbl/d production decline in Alaska and a 230-thousand bbl/d production decline in the Federal Gulf of Mexico (GOM).

Forecast U.S. total crude oil production increases to 6.02 million bbl/d in 2012, an upward revision of 190 thousand bbl/d from last month's *Outlook*, and the highest level of production since 1998. Growth in lower-48 onshore crude oil production of 450 thousand bbl/d in 2012 overshadows declines averaging about 30 thousand bbl/d

in Alaskan output and 50 thousand bbl/d in GOM production (U.S. Crude Oil and Liquid Fuels Production Chart). The rise in production is driven by increased oil-directed drilling activity, particularly in onshore tight oil formations. The number of onshore oil-directed drilling rigs reported by Baker Hughes increased from 777 at the beginning of 2011 to 1,329 on April 5, 2012.

The share of total U.S. consumption met by total liquid fuel net imports (including both crude oil and products) has been falling since 2005, and averaged 45 percent in 2011, down from 49 percent in 2010. EIA expects that the total net import share of consumption will be 43 percent in both 2012 and 2013.

Summer Transportation Fuels Outlook

U.S. Gasoline and Diesel Fuel Prices. EIA expects that regular-grade gasoline retail prices, which averaged \$3.71 per gallon last summer, will average \$3.95 per gallon during the current summer (April through September) driving season, a year-over-year increase of 6.3 percent. The projected monthly average regular retail gasoline price peaks this summer at \$4.01 per gallon in May. Diesel fuel prices, which averaged \$3.94 per gallon last summer, are projected to average \$4.21 per gallon this summer, with monthly prices peaking at \$4.25 per gallon in the middle of the driving season. 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 25 cents per gallon or more.

Because taxes and retail distribution costs are generally stable, movements in gasoline and diesel prices are driven primarily by changes in both crude oil prices and wholesale margins. The retail price projections reflect higher prices for the average refiner acquisition cost of crude oil, which averages about \$114 per barrel (\$2.71 per gallon) this summer compared with the \$104 per barrel (\$2.48 per gallon) average of last summer. Crude oil prices that differ from our forecast would be reflected in the price of motor fuels. Each dollar per barrel of sustained change in crude oil prices relative to the forecast translates into approximately a 2.4-cent-per-gallon change in product prices, absent the consideration of factors specific to the gasoline and diesel fuel markets.

EIA expects wholesale gasoline margins (the difference between the wholesale price of gasoline and the refiner acquisition cost of crude oil) will average 56 cents per gallon this summer, about the same as last summer, but 8 cents per gallon higher than the previous 5-summer average of 48 cents per gallon (U.S. Gasoline and Crude Oil Prices Chart). Forecast wholesale diesel margins are 1 cent per gallon above last

summer's level and 10 cents per gallon higher than the previous 5-summer average of 54 cents per gallon (U.S. Diesel Fuel and Crude Oil Prices Chart).

As in the case of crude oil, the market's expectation of uncertainty in monthly average gasoline prices is reflected in the pricing and implied volatility of futures and options contracts. New York Harbor reformulated gasoline blendstock for oxygenate blending (RBOB) futures contracts for June 2012 delivery over the 5-day period ending April 5, averaged \$3.28 per gallon. The probability the RBOB futures price will exceed \$3.35 per gallon (consistent with a U.S. average regular gasoline retail price above \$4.00 per gallon in June 2012) is about 40 percent, while the probability it will exceed \$3.85 per gallon (consistent with a U.S. average regular gasoline retail price above \$4.50 per gallon) in June 2012 is about 5 percent.

While retail gasoline prices have generally followed the rise in crude oil prices, refinery closures in the Philadelphia area and other parts of the Atlantic Basin may have a further impact on prices. This *Outlook* assumes the Sunoco Philadelphia refinery continues to operate. If the Sunoco Philadelphia refinery closes, price impacts are highly uncertain. If certain areas cannot be adequately supplied in the short term, prices can spike. For a more detailed analysis on Northeast refining issues, see EIA's "[*Potential Impacts of Reductions in Refinery Activity on Northeast Petroleum Product Markets*](#)."

The projected increase in gasoline prices this year suggests that vehicle fueling costs for the average U.S. household will be about \$250 higher in 2012 than they were in 2011. According to the 2009 National Household Travel Survey ([Transportation Energy Data Book](#), Tables 4.1 and 8.6), U.S. households drove an average 19,850 miles with an average passenger car fuel efficiency of 22.5 miles per gallon. Assuming no change in travel or average fuel economy, the increase in the average annual gasoline retail price (all grades) from \$2.83 per gallon in 2010 to \$3.58 per gallon in 2011 and a projected \$3.87 per gallon in 2012 implies an increase in average annual household expenditures on gasoline from \$2,501 in 2010 to \$3,159 in 2011 and to \$3,410 in 2012.

Motor Gasoline. During this summer season (April through September), projected motor gasoline consumption declines by 0.5 percent from last summer. Finished motor gasoline is supplied by four sources: domestic refinery output, fuel ethanol blending, net imports of gasoline and gasoline blending components, and primary inventories. EIA expects that domestic refinery production, including blending output, will decline 0.6 percent from last summer. Fuel ethanol blending into gasoline is projected to change little from last summer's level of about 850 thousand bbl/d, which is about 9.6 percent of total gasoline consumption. Forecast total gasoline net

imports are projected to average 340 thousand bbl/d, a decrease of 9 percent from the previous summer.

At the onset of the summer driving season (April 1) total gasoline stocks, at 221.3 million barrels, are 6.4 million barrels above the level of a year ago, and 5.1 million barrels more than the previous 5-year average for beginning-of-season stocks (U.S. Gasoline and Distillate Inventories Chart). Stock withdrawals have not been a significant motor gasoline supply source for the summer season in recent years, having averaged less than 50 thousand bbl/d during the previous 5 summer seasons. This summer, total gasoline stocks are projected to be drawn down by an average of 27 thousand bbl/d, compared with an average 7 thousand bbl/d build last summer.

Diesel Fuel. Projected consumption of distillate fuel, which includes diesel fuel and heating oil, will average 3.85 million bbl/d this summer, up 2.3 percent from last summer. That growth is buoyed by continued strength in manufacturing output and foreign trade.

Distillate fuel is supplied by four sources: domestic refinery output, biodiesel blending, primary inventories, and net imports. EIA expects refinery output of distillate fuel will average 4.52 million bbl/d this summer, up 1.0 percent from last summer. Biodiesel has been a small but growing part of the distillate pool. Biodiesel blending averaged 62 thousand bbl/d last summer and is forecast to average about 61 thousand bbl/d this summer. Projected distillate fuel net exports average 580 thousand bbl/d this summer, down from the record 680 thousand bbl/d last summer. In contrast, the United States was a net importer of distillate fuel, averaging 120 thousand bbl/d, during the summers of 2000 through 2007.

Distillate inventories are projected to start the summer at 135.4 million barrels, down from 148.5 million barrels last year. Distillate inventories typically build during the summer season in preparation for the heating season. This summer, the build is forecast to average 88 thousand bbl/d, far more than the 28 thousand bbl/d recorded last summer but similar to the previous 5-year average summer build of 90 thousand bbl/d. End-of-summer stocks are 151 million barrels, down slightly from the 154 million barrels recorded last summer, but unchanged from the previous 5-year end-of-summer average.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 69.6 billion cubic feet per day (Bcf/d) in 2012, an increase of 2.8 Bcf/d (4.2 percent) from 2011. EIA expects that large gains in electric power use will offset

declines in residential and commercial use. Because of the much-warmer-than-normal winter this year, EIA expects residential and commercial consumption to fall by 3.9 percent and 2.7 percent, respectively, in 2012, reflecting a downward revision in projected consumption from last month's *Outlook*. Currently, the National Oceanic and Atmospheric Administration (NOAA) expects heating degree-days to total 4,020 for 2012, 5.3 percent less than in last month's *Outlook*, and about 11 percent below the 30-year normal level.

Projected consumption of natural gas in the electric power sector grows by about 16 percent in 2012, primarily driven by the increasing relative cost advantages of natural gas over coal for power generation in some regions. Consumption in the electric power sector peaks in the third quarter of 2012, at 30.6 Bcf/d, when electricity demand for air conditioning is highest. This compares with 27.7 Bcf/d in the third quarter of 2011.

Growth in total natural gas consumption continues into 2013, with forecast consumption averaging 70.5 Bcf/d (U.S. Natural Gas Consumption Chart). A forecast of closer-to-normal winter temperatures drives increases in residential and commercial consumption of 7.3 percent and 4.7 percent, respectively. The increase in consumption in these sectors, as well as an increase in industrial consumption, more than offsets a 3.4-percent decline in power-sector natural gas burn.

U.S. Natural Gas Production and Imports. Total marketed production of natural gas grew by an estimated 4.8 Bcf/d (7.9 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. While EIA expects year-over-year production growth to continue in 2012, the projected increases occur at a much lower rate than in 2011 as low prices reduce new drilling plans. According to Baker Hughes, the natural gas rig count was 647 as of April 5, 2012, down from a 2011 high of 936 in mid-October. So far, the lower rig count has not impacted production levels, partly reflecting improved drilling efficiency. While fewer horizontal natural gas rigs, particularly in areas of dry production such as the Haynesville Shale, probably indicate declines in these areas, these losses are more than offset in the short term by other production from wet plays.

Pipeline gross imports are expected to fall by 0.7 Bcf/d (7.2 percent) in 2012 as domestic supply displaces Canadian sources. The warm winter in the United States also adds to the year-over-year decline in imports, particularly to the Northeast, where imported natural gas can serve as additional supply in times of very cold weather. Pipeline gross exports grew by 1.0 Bcf/d in 2011, driven by increased exports to Mexico, and are expected to continue to grow, at a slower rate, in 2012 and 2013.

Liquefied natural gas (LNG) imports are expected to fall by 0.3 Bcf/d (28 percent) in 2012. EIA expects that an average of about 0.7 Bcf/d will arrive in the United States (mainly at the Everett LNG terminal in New England and the Elba Island terminal in Georgia) in both 2012 and 2013, either to fulfill long-term contract obligations or to take advantage of temporarily high local prices due to cold snaps and disruptions.

U.S. Natural Gas Inventories. Working natural gas inventories continue to set new seasonal record highs as a very warm winter has contributed to much-lower-than-normal inventory draws. As of March 30, 2012, according to EIA's *Weekly Natural Gas Storage Report*, working inventories totaled 2,479 Bcf, 887 Bcf greater than last year's level and 934 Bcf above the 5-year (2007-2011) average. In the last 20 years, end-of-March inventories have not risen over 1,700 Bcf, and prior to that, rose above 2,100 Bcf just once, in 1983. With only a few exceptions, weekly inventory withdrawals have been smaller than the previous 5-year average during this year's winter heating season, and though the end of March is technically the end of the heating season, net inventory injections began the week ending March 16. EIA expects that inventory levels at the end of October 2012 will set a new record high as well (U.S. Working Natural Gas in Storage Chart).

U.S. Natural Gas Prices. Natural gas spot prices averaged \$2.18 per MMBtu at the Henry Hub in March 2012, down \$0.32 per MMBtu from the February 2012 average and the lowest average monthly price since April 1999. Abundant storage levels, as well as ample production, have contributed to the recent low prices. EIA expects natural gas prices will average \$2.51 per MMBtu in 2012, a downward revision from \$3.17 per MMBtu expected in last month's *Outlook*. EIA revised its forecast for 2013 down to \$3.40 per MMBtu, from \$3.96 per MMBtu in last month's *Outlook*. Prices remain low as production and supplies remain robust (U.S. Natural Gas Prices Chart).

Natural gas futures prices for June 2012 delivery (for the 5-day period ending April 5, 2012) averaged \$2.27 per MMBtu, and the average implied volatility based on options and futures prices was 48 percent (*Market Prices and Uncertainty Report*). Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for June 2012 contracts at \$1.60 per MMBtu and \$3.21 per MMBtu, respectively. At this time last year, the June 2011 natural gas futures contract averaged \$4.29 per MMBtu and implied volatility averaged 34 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.37 per MMBtu and \$5.47 per MMBtu.

Coal

U.S. Coal Consumption. EIA forecasts that electric power sector coal consumption will be well below 900 million short tons (MMst) in both 2012 and 2013. Power sector natural gas prices have fallen significantly, leading generators in several regions to increase the share of natural gas-fired generation. EIA expects this trend to continue in 2012 with power sector coal consumption falling by 10 percent (U.S. Coal Consumption Chart). Projected power sector coal prices fall slightly next year while natural gas prices increase. In response, EIA expects that electric power sector coal consumption will increase by 5 percent in 2013 as the economic competitiveness of coal-fired generation improves.

U.S. Coal Supply. EIA forecasts coal production to decline by 7.6 percent in 2012 as domestic consumption and exports fall (U.S. Coal Production Chart). Production declines greater than 20 MMst are expected in each of the three coal-producing regions (Appalachia, Interior and Western). EIA projects that secondary inventories will increase in 2012, with electric power sector stocks exceeding 200 MMst, and inventories will remain at these levels in 2013 (U.S. Electric Power Sector Coal Stocks Chart).

U.S. Coal Trade. EIA expects U.S. coal exports to remain strong but be below the 107 MMst exported in 2011. Forecast U.S. coal exports are 100 MMst in 2012 and 98 MMst in 2013. U.S. coal exports averaged 56 MMst in the decade preceding 2011.

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 (5.8 percent increase from 2010). However, EIA expects the decline in demand for coal to generate electricity will put downward pressure on coal prices and contribute to the shut-in of higher-cost production. Several companies have recently announced the curtailment of operations, particularly in Appalachia, where production costs at some older mines are high. EIA forecasts the average delivered coal price in 2012 will be about 1.0 percent lower than the 2011 average price. EIA predicts the 2013 average delivered coal price to be \$2.30 per MMBtu, or 3.2 percent lower than the previous year's price.

Electricity

U.S. Electricity Consumption. EIA expects total U.S. consumption of electricity will fall slightly during 2012, and then grow by 2.3 percent during 2013 (U.S. Total Electricity Consumption Chart). Growth in retail sales of electricity to the commercial and industrial sectors during 2012 will be offset by a 3.2-percent decline in residential

sector consumption. Residential consumption falls this year as a result of milder weather compared with last year. EIA estimates that U.S. residential electricity consumption during the first quarter of this year was about 8 percent lower than during the same period in 2011, primarily because of the 22-percent decline in heating degree-days nationwide. Similarly, the projected 17-percent year-over-year decline in U.S. cooling degree-days during the second and third quarters this year is expected to reduce residential electricity consumption by 5 percent this summer.

U.S. Electricity Generation. The price of natural gas delivered to electric generators averaged \$3.67 per million Btu in January, which is the lowest price since 2002. These low prices continue to drive substantial displacement of coal by natural gas for fueling electricity generation. Furthermore, a projected year-over-year decline in hydroelectric generation in the western U.S. contributes to higher levels of generation from natural gas this year. EIA projects that the share of total generation fueled by natural gas will rise from an average 24.8 percent in 2011 to an average of 29.2 percent in 2012. The 4.4 percentage point increase is the largest annual change in natural gas's fuel share since record-keeping began in 1949. The share of total generation produced using coal falls from 42.2 percent in 2011 to 38.3 percent in 2012 (U.S. Electricity Generation Chart).

U.S. Electricity Retail Prices. EIA forecasts average U.S. residential electricity prices to rise by 0.9 percent in 2012, and then fall by 1.4 percent in 2013 (U.S. Residential Electricity Prices Chart). The rising costs of transmitting and distributing electricity to retail customers offset some of the declining fuel costs. In addition, some of the increase in electricity prices this year is due to the forecast of a milder summer, which lowers average household consumption and raises the contribution of fixed electricity costs to the per kilowatt-hour average price.

Renewables and Carbon Dioxide Emissions

U.S. Renewables. After growing 14 percent in 2011, total renewable energy supply is projected to decline by 2.7 percent in 2012 (U.S. Renewable Energy Supply Chart). This decrease is the result of hydropower resource levels beginning a return to the long-term average, with supply falling by 0.4 quadrillion Btu (12 percent). The decline in hydropower from the 2011 level offsets growth in other renewable energy supplies. Renewables supply increases slightly in 2013 as hydropower continues to decline (4.3 percent) and non-hydropower renewables grow by 2.8 percent, which is modest compared with recent experience.

Under current law, federal production tax credits for wind-powered generation will not be available for turbines that begin operating after the end of 2012. Wind-

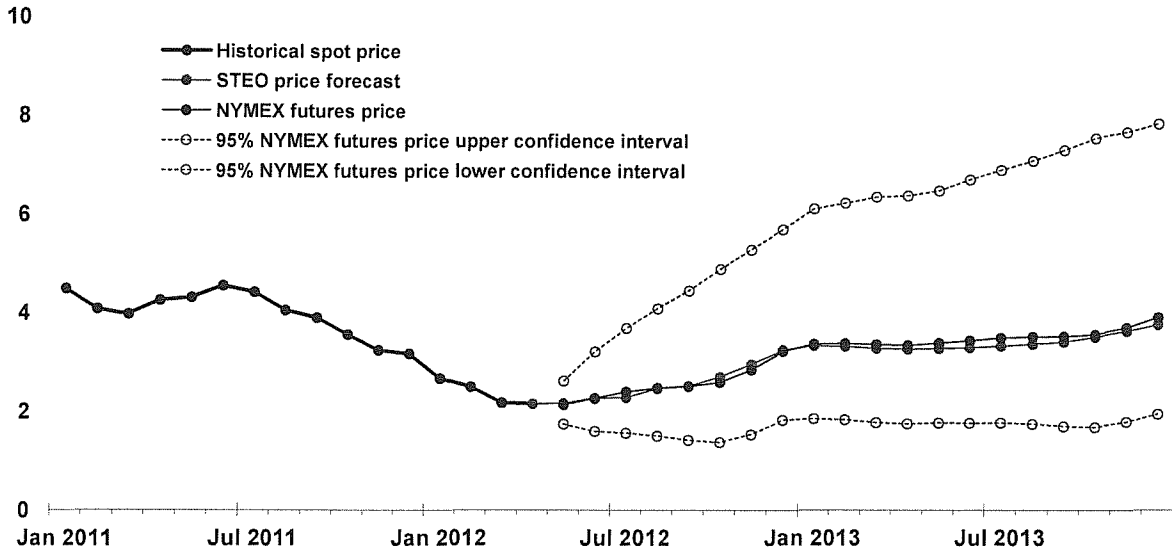
powered generation, which grew by 26 percent in 2011, is forecast to grow an additional 14 percent in 2012 and 5 percent in 2013. Of the 1,739 megawatts (MW) of capacity that has been reported to EIA as possibly coming on line in 2013 only 49 MW is currently under construction. The project under construction is in Ohio, where there is a renewable portfolio standard (RPS) that requires 2.4 percent of covered energy to come from renewable sources by 2014, up from 0.2 percent in 2009. Most of the States with approved, pending, or planned projects also have RPS requirements. Production credits for other eligible renewables, such as closed-loop biomass and geothermal generation, expire at the end of 2013. Solar energy (at both the corporate and residential level) is eligible for investment tax credits that will remain at 30 percent throughout the forecast period.

In terms of liquid renewable fuels, EIA expects fuel ethanol production to fall slightly, from an average of 910 thousand bbl/d in 2011 to an average of 900 thousand bbl/d in both 2012 and 2013. This forecast assumes that E15 (gasoline blended with 15 percent ethanol by volume) does not yet reach the market. Consequently, U.S. ethanol production is projected to exceed the volume that can easily be used in the U.S. liquid fuels pool, so the Nation will continue to be a net exporter of ethanol over the next two years. EIA estimates that biodiesel production in 2011 averaged about 61 thousand bbl/d (939 million gallons of total annual production). Forecast biodiesel production averages 56 thousand bbl/d in 2012, and 65 thousand bbl/d in 2013.

U.S. CO₂ Emissions. After declining by 1.9 percent in 2011, fossil fuel emissions are projected to further decline by 1.9 percent in 2012, but increase by 2.1 percent in 2013. Petroleum emissions decline slightly in 2012 (0.5 percent) and then rise by 0.6 percent in 2013, while natural gas emissions rise by 4.6 percent and 1.1 percent in 2012 and 2013, respectively. Coal emissions decline in 2012 by 8.2 percent, but rise by 4.8 percent in 2013 (U.S. Carbon Dioxide Emissions Growth Chart).

Henry Hub Natural Gas Price

dollars per million Btu

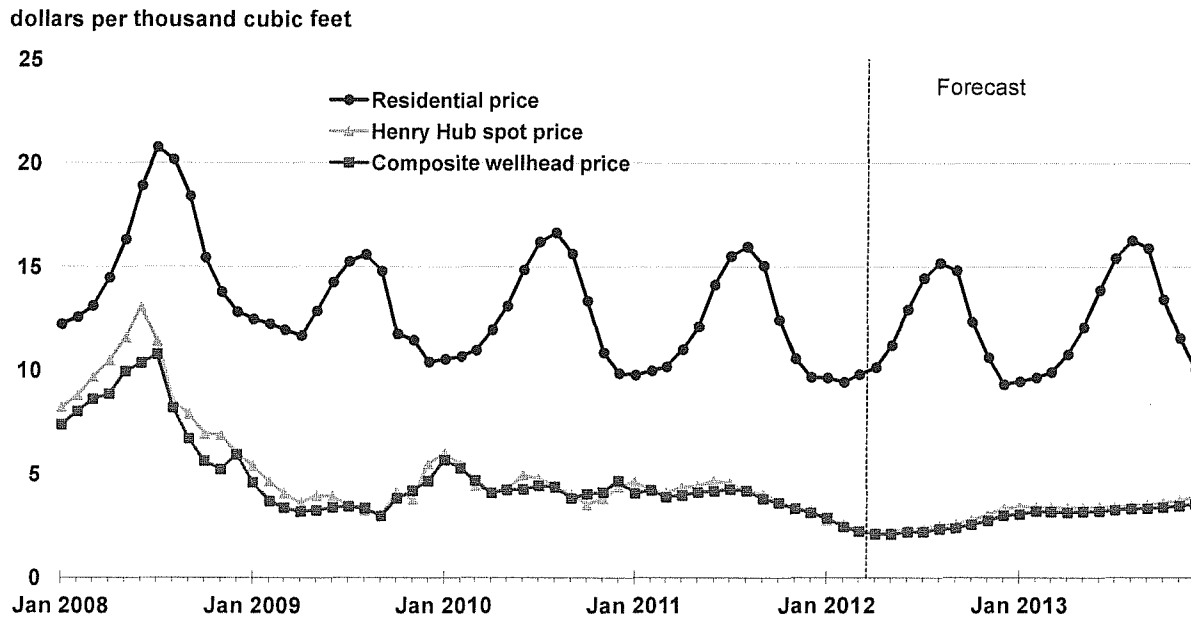


*Note: Confidence interval derived from options market information for the 5 trading days ending April 5, 2012
Intervals not calculated for months with sparse trading in "near-the-money" options contracts*

Source: Short-Term Energy Outlook, April 2012

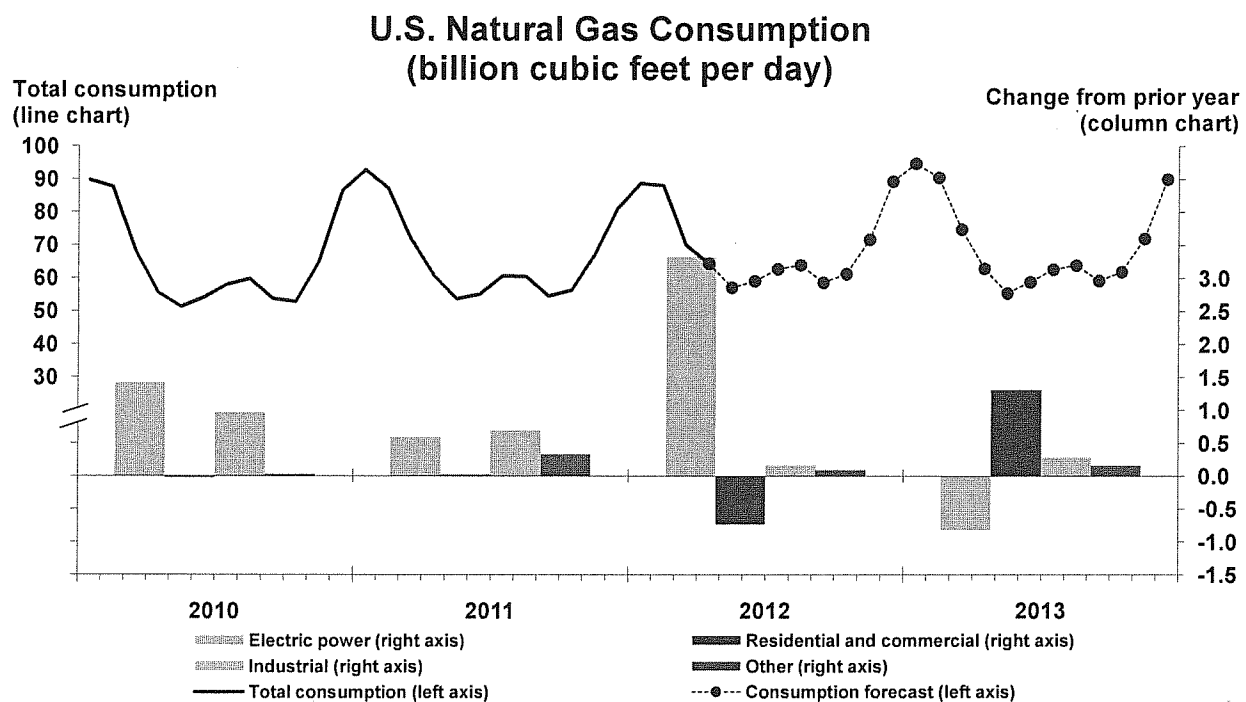


U.S. Natural Gas Prices



Source: Short-Term Energy Outlook, April 2012

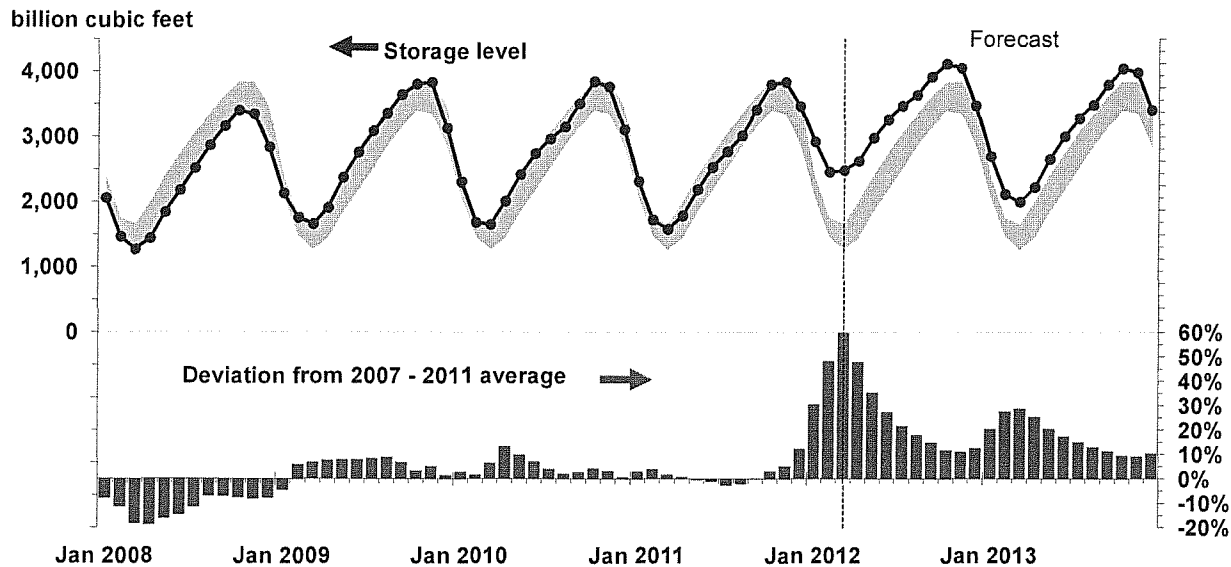




Source: Short-Term Energy Outlook, April 2012



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, April 2012



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

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$3.241	\$3.330	\$2.316	\$2.306
Prior Gas Cost	3.801	3.890	2.876	2.863
Current Gas Cost Adjustment	(\$0.560)	(\$0.560)	(\$0.560)	(\$0.557)
<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	<u>(\$0.560)</u>	<u>(\$0.560)</u>	<u>(\$0.560)</u>	<u>(\$0.557)</u>
Gas Cost Level	\$3.241	\$3.330	\$2.316	\$2.306
Plus: Surcharge	(0.032)	(0.032)	0.064	0.041
Total Gas Cost Level in Tariff Rates	<u>\$3.209</u>	<u>\$3.298</u>	<u>\$2.380</u>	<u>\$2.347</u>

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

<u>Cost of Gas - Propane</u>	
Current Propane Cost (Exhibit D)	\$12.076
Prior Propane Cost	<u>13.174</u>
Current Propane Cost Adjustment	<u><u>(\$1.098)</u></u>
<u>Surcharge Adjustment</u>	
Current Adjustment (Exhibit F)	\$0.646
Prior Adjustment	<u>0.511</u>
Change in Surcharge Adjustment	\$0.135
<u>Market Based Pricing Differential</u>	
Current Adjustment	(\$0.009)
Prior Adjustment	<u>(0.009)</u>
Change in Margin Sharing Provision	\$0.000
Net Increase (Decrease) in Gas Costs	<u><u>(\$0.963)</u></u>
Propane Cost Level	\$12.076
Plus: Surcharge	<u>0.646</u>
Total Propane Cost Level in Rates	<u><u>\$12.722</u></u>

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

	Amount
Total Gas Costs 1/	\$45,707,740
Residential and General Service dk Requirements 2/	14,167,591
Average Cost of Gas per dk	\$3.226
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.241
Less: Gas Cost Level in Rates 3/	3.801
Current Gas Cost Adjustment	(\$0.560)

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 February 29, 2012, adjusted for losses at .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective April 1, 2012:

Cost of Purchased Gas	\$3.784
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.801

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

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$45,707,740
Less: Annual MDDQ Costs 1/	<u>11,821,667</u>
Total Gas Costs excluding MDDQ	\$33,886,073
Firm Service Requirements 1/	14,167,591
Other Gas Costs per Dk (excluding MDDQ)	\$2.392
Summer Seasonal Rate, adjusted for losses 2/	2.403
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,821,667
Winter Firm Service Requirements	12,804,570
MDDQ Costs per Winter Dk	\$0.923
Add: Other Gas Costs per Dk	<u>2.392</u>
Winter Seasonal Rate	\$3.315
Winter Seasonal Rate, adjusted for losses 2/	\$3.330
Less: Gas Cost Level in Rates 3/	<u>3.890</u>
Current Gas Cost Adjustment	<u><u>(\$0.560)</u></u>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective April 1, 2012:

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$2.945	\$3.872
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$2.958	\$3.890

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

	Amount
Total Gas Costs 1/	\$8,077,455
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$2.306
Average Cost of Gas as Adjusted for Losses @ 99.55%	2.316
Less: Gas Cost Level in Rates 2/	2.876
Current Gas Cost Adjustment	(\$0.560)

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

2/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective April 1, 2012:

Cost of Purchased Gas	\$2.863
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$2.876

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

	Amount
Total Gas Costs 1/	\$2,029,312
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$2.306
Less: Gas Cost Level in Rates 2/	2.863
Current Gas Cost Adjustment	(\$0.557)

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-12-008 effective April 1, 2012:
Cost of Purchased Gas \$2.863

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
May 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 1.690%, CONSISTING OF 1.967% FOR THE CURRENT PERCENTAGE AND (0.277%) FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR TRANSPORTATION. THE APPLICABLE RATE IS 0.856 CENTS, CONSISTING OF 0.732 CENTS FOR THE CURRENT RATE AND 0.124 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.

Issued On: March 1, 2012
 Docket Number: RP12-444-000
 FERC Order Date: March 27, 2012

Effective On: April 1, 2012

NOTICE OF CURRENTLY EFFECTIVE RATES

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

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

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 0.852%, CONSISTING OF 0.777% FOR THE CURRENT PERCENTAGE AND 0.075% FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR STORAGE. THE APPLICABLE RATE IS 0.205 CENTS, CONSISTING OF 0.000 CENTS FOR THE CURRENT RATE AND 0.205 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

Issued On: March 1, 2012
 Docket Number: RP12-444-000
 FERC Order Date: March 27, 2012

Effective On: April 1, 2012

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

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>	
	2012302568	\$ 22.00	/ month
	2012302633	\$ 8.00	/ month
	2012302635	\$ 14.00	/ month
	2012302571	\$ 2.00	/ month
	2012302570	\$ 1.00	/ month
	2012302644	\$ 2,082.00	/ month
	2012302639	\$ 2.00	/ month
	2012302641	\$ 55.00	/ month
	2012302505	\$ 126.00	/ month
	2012302608	\$ 70.00	/ month
	2012302575	\$ 19.00	/ month
	2012302497	\$ 226.00	/ month
	2012302643	\$ 203.00	/ month
	2003004522	\$ 83,333.00	/ month
	2011476052 / 2011476054	\$ 0.0783	/ GJ subject to Minimum Annual Charge
	2011475772	\$ 717,000.00	/ month
	2011475056	\$ 9,250.00	/ month
		\$ 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	
3214	AKUINU RIVER WEST SALES	2.39	0.0861	
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 28th Revised Sheet No. 80.1
27th 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	\$ 100.20
10,001 to 30,000	\$ 144.10
>30,000	\$ 319.75

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for
Maximum Daily Delivery Quantity (MDDQ) \$ 0.8193411

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum \$ 0.0062088

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: January 26, 2012
Docket No.: D2011.12.97, Final Order No. 7191a
Tariff Letter No. 205-G

Effective for service rendered on or after
January 1, 2012

PUBLIC SERVICE COMMISSION
Alestra Zolman 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 MAY 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	9,767,572	426,234	1,229,961
January 2012	6,908,042	318,632	(365,795)
February	4,284,312	46,778	(1,378,772)
March	6,373,802	40,749	(1,969,660)
April	6,138,357	12,743	(1,787,077)
May	6,825,775	42,661	(1,053,791)
June	7,990,595	100,655	(50,243)
July	9,276,536	165,013	1,004,016
August	10,518,068	227,387	2,039,040
September	11,347,887	561,247	2,854,551
October	11,207,100	543,504	3,115,622
13 month average	<u>\$9,108,711</u>	<u>\$294,711</u>	<u>\$709,824</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$800,747	\$25,908	\$62,401
Return Requirement	<u>\$1,091,953</u>	<u>\$35,330</u>	<u>\$85,094</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 MAY 2012

Cost of Purchased Propane	\$37,267
Gallons Purchased	33,879
Projected dk Sales	3,100
Propane Cost per Dk	\$12.022
Average Cost of Propane as Adjusted for Losses @ 99.55%	12.076
Less: Propane Cost Level in Rates 1/	<u>13.174</u>
Current Propane Cost Adjustment	<u><u>(\$1,098)</u></u>

1/ Propane Cost Level in Current Rates - Case No. PU-12-008, effective April 1, 2012.

**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)
December	6,351	0	(1)	6,350	1,811,727	(0.032)	(57,975)	64,325	(89,700)
January 2012	(75,086)	0	(3)	(75,089)	1,909,213	(0.032)	(61,095)	(13,994)	(103,694)
February	(673,857)	0	(8)	(673,865)	1,950,923	(0.032)	(62,430)	(611,435)	(715,129)
Balance @ February 29, 2012									<u>(\$715,129)</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	(4,161)	0	1	(4,160)	71,035	0.064	4,546	(8,706)	74,222
December	(22,361)	0	1	(22,360)	97,320	0.064	6,229	(28,589)	45,633
January 2012	(2,234)	0	1	(2,233)	93,302	0.064	5,971	(8,204)	37,429
February	(50,484)	0	2	(50,482)	82,314	0.064	5,268	(55,750)	(18,321)
Balance @ February 29, 2012									<u><u>(\$18,321)</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)
December	(12,123)	0	(1)	(12,124)	52,081	0.041	2,135	(14,259)	(61,638)
January 2012	160	0	(2)	158	63,119	0.041	2,588	(2,430)	(64,068)
February	(41,949)	0	(5)	(41,954)	68,854	0.041	2,823	(44,777)	(108,845)
Balance @ February 29, 2012									<u>(\$108,845)</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.

**MONTANA-DAKOTA UTILITIES CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
PROPANE
TO BE EFFECTIVE MAY 1, 2012 THROUGH APRIL 30, 2013**

(Over)/under recovered gas costs @ February 29, 2012 \$34,370

Less: Projected recovery from rates already established

	Volume	Rate	Amount
March	5,288	\$0.511	2,702
April	4,300	\$0.511	2,197
	9,588		4,899

Additional recovery required \$29,471

Projected sales volumes (dk)

May 2012	3,100		
June	1,900		
July	1,100		
August	1,100		
September	1,100		
October	1,700		
November	3,300		
December	6,400		
January 2013	8,300		
February	6,400		
March	6,900		
April	4,300		
Total			45,600

Total (over)/under recovered gas cost adjustment
to be effective May 1, 2012 through April 30, 2013 \$0.646

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

	(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 @ February 28, 2011									<u>\$38,742</u>
March 2011	\$1,300	\$0	\$2	\$1,302	7,409	(\$0.666)	(\$4,935)	\$6,237	44,979
April	(7,548)	0	22	(7,526)	4,590	(0.666)	(3,057)	(4,469)	40,510
May	(3,298)	0	(19) 2/	(3,317)	3,258	0.511	(88) 3/	(3,229)	37,281
June	6,066	0	1	6,067	1,972	0.511	1,007	5,060	42,341
July	(6,520)	0	1	(6,519)	1,065	0.511	544	(7,063)	35,278
August	(2,128)	0	1	(2,127)	1,113	0.511	569	(2,696)	32,582
September	4,227	0	0	4,227	1,139	0.511	582	3,645	36,227
October	23,169	0	1	23,170	1,731	0.511	885	22,285	58,512
November	(2,538)	0	0	(2,538)	3,505	0.511	1,791	(4,329)	54,183
December	(6,633)	0	0	(6,633)	6,792	0.511	3,470	(10,103)	44,080
January 2012	2,050	0	1	2,051	6,274	0.511	3,205	(1,154)	42,926
February	(5,318)	0	3	(5,315)	6,342	0.511	3,241	(8,556)	34,370
	<u>\$2,829</u>	<u>\$0</u>	<u>\$13</u>	<u>\$2,842</u>	<u>45,190</u>		<u>\$7,214</u>	<u>(\$4,372)</u>	
Balance @ February 29, 2012									<u>\$34,370</u>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Includes (\$20) adjustment related to April interest.

3/ Reflects 1,489.2 Dk @ (\$0.666) and 1,768.8 Dk @ \$0.511.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
PROPANE

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>March 2011</u>				
Cost of Gas - Actual	\$16.13872	\$16.06162	\$16.13872	
Cost of Gas - Recovered	15.91900	15.91900	15.91900	
(Over) Under recovery per dk	<u>\$0.21972</u>	<u>\$0.14262</u>	<u>\$0.21972</u>	
dk billed	0	4,244	3,165	7,409
(Over) Under recovery	<u>\$0</u>	<u>\$605</u>	<u>\$695</u>	<u>\$1,300</u>
<u>April 2011</u>				
Cost of Gas - Actual	\$12.50131	\$16.13872	\$12.50131	
Cost of Gas - Recovered	15.91900	15.91900	15.91900	
(Over) Under recovery per dk	<u>(\$3.41769)</u>	<u>\$0.21972</u>	<u>(\$3.41769)</u>	
dk billed	0	2,238	2,352	4,590
(Over) Under recovery	<u>\$0</u>	<u>\$492</u>	<u>(\$8,040)</u>	<u>(\$7,548)</u>
<u>May 2011</u>				
Cost of Gas - Actual	\$16.37475	\$12.50131	\$16.37475	
Cost of Gas - Recovered	14.82100	15.91900	15.91900	
(Over) Under recovery per dk	<u>\$1.55375</u>	<u>(\$3.41769)</u>	<u>\$0.45575</u>	
dk billed	1,769	1,736	(247)	3,258
(Over) Under recovery	<u>\$2,748</u>	<u>(\$5,934)</u>	<u>(\$112)</u>	<u>(\$3,298)</u>
<u>June 2011</u>				
Cost of Gas - Actual	\$19.11978	\$16.37475	\$19.11978	
Cost of Gas - Recovered	14.82100	14.82100	14.82100	
(Over) Under recovery per dk	<u>\$4.29878</u>	<u>\$1.55375</u>	<u>\$4.29878</u>	
dk billed	0	878	1,094	1,972
(Over) Under recovery	<u>\$0</u>	<u>\$1,364</u>	<u>\$4,702</u>	<u>\$6,066</u>
<u>July 2011</u>				
Cost of Gas - Actual	\$4.43768	\$19.11978	\$4.43768	
Cost of Gas - Recovered	14.82100	14.82100	14.82100	
(Over) Under recovery per dk	<u>(\$10.38332)</u>	<u>\$4.29878</u>	<u>(\$10.38332)</u>	
dk billed	0	309	756	1,065
(Over) Under recovery	<u>\$0</u>	<u>\$1,330</u>	<u>(\$7,850)</u>	<u>(\$6,520)</u>
<u>August 2011</u>				
Cost of Gas - Actual	\$15.24035	\$4.43768	\$15.24035	
Cost of Gas - Recovered	14.82100	14.82100	14.82100	
(Over) Under recovery per dk	<u>\$0.41935</u>	<u>(\$10.38332)</u>	<u>\$0.41935</u>	
dk billed	0	240	873	1,113
(Over) Under recovery	<u>\$0</u>	<u>(\$2,494)</u>	<u>\$366</u>	<u>(\$2,128)</u>

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
PROPANE

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>September 2011</u>				
Cost of Gas - Actual	\$18.99521	\$15.24035	\$18.99521	
Cost of Gas - Recovered	14.82100	14.82100	14.82100	
(Over) Under recovery per dk	<u>\$4.17421</u>	<u>\$0.41935</u>	<u>\$4.17421</u>	
dk billed	0	140	999	1,139
(Over) Under recovery	<u>\$0</u>	<u>\$59</u>	<u>\$4,168</u>	<u>\$4,227</u>
<u>October 2011</u>				
Cost of Gas - Actual	\$31.24630	\$18.99521	\$31.24630	
Cost of Gas - Recovered	14.82100	14.82100	14.82100	
(Over) Under recovery per dk	<u>\$16.42530</u>	<u>\$4.17421</u>	<u>\$16.42530</u>	
dk billed	0	430	1,301	1,731
(Over) Under recovery	<u>\$0</u>	<u>\$1,793</u>	<u>\$21,376</u>	<u>\$23,169</u>
<u>November 2011</u>				
Cost of Gas - Actual	\$15.72154	\$31.24630	\$15.72154	
Cost of Gas - Recovered	16.46700	14.82100	14.82100	
(Over) Under recovery per dk	<u>(\$0.74546)</u>	<u>\$16.42530</u>	<u>\$0.90054</u>	
dk billed	1,775	(179)	1,909	3,505
(Over) Under recovery	<u>(\$1,322)</u>	<u>(\$2,935)</u>	<u>\$1,719</u>	<u>(\$2,538)</u>
<u>December 2011</u>				
Cost of Gas - Actual	\$15.32406	\$15.72154	\$15.32406	
Cost of Gas - Recovered	16.46700	16.46700	16.46700	
(Over) Under recovery per dk	<u>(\$1.14294)</u>	<u>(\$0.74546)</u>	<u>(\$1.14294)</u>	
dk billed	0	2,841	3,951	6,792
(Over) Under recovery	<u>\$0</u>	<u>(\$2,118)</u>	<u>(\$4,515)</u>	<u>(\$6,633)</u>
<u>January 2012</u>				
Cost of Gas - Actual	\$18.11327	\$15.32406	\$18.11327	
Cost of Gas - Recovered	16.46700	16.46700	16.46700	
(Over) Under recovery per dk	<u>\$1.64627</u>	<u>(\$1.14294)</u>	<u>\$1.64627</u>	
dk billed	0	2,968	3,306	6,274
(Over) Under recovery	<u>\$0</u>	<u>(\$3,392)</u>	<u>\$5,442</u>	<u>\$2,050</u>
<u>February 2012</u>				
Cost of Gas - Actual	\$14.83160	\$18.11327	\$14.83160	
Cost of Gas - Recovered	18.11400	16.46700	16.46700	
(Over) Under recovery per dk	<u>(\$3.28240)</u>	<u>\$1.64627</u>	<u>(\$1.63540)</u>	
dk billed	3,153	3,122	67	6,342
(Over) Under recovery	<u>(\$10,348)</u>	<u>\$5,140</u>	<u>(\$110)</u>	<u>(\$5,318)</u>

1/ Consumed in current month.
2/ Consumed in prior month.
3/ True-up of prior month volumes.