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

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

March 9, 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 (102nd Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered April 1, 2012.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased $0.093 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, decreasing the cost of gas $0.045 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 April 2012.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of $0.138 per dk for residential and firm general service customers, a decrease of $0.129 per dk for small and large interruptible customers and a decrease of $0.128 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 April 2012. The average cost of gas for firm customers, adjusted for losses, is $3.801.

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.

These proposed adjustments, calculated in accordance with Rate 88, will amount to a decrease of approximately $161,400 for natural gas customers during the month of April 2012. All of Montana-Dakota's retail natural gas customers in North Dakota may be affected by this proposal. There were 94,764 natural gas customers in North Dakota as of February 29, 2012.

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 April 2012. The net effect of this filing is a decrease of $3.842 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 April 2012. The average cost of propane for all customers, adjusted for losses, is $13.174 per dk.

This proposed adjustment, calculated in accordance with Rate 99, will amount to a decrease of approximately $16,500 for propane customers during the month of April, 2012. All of the Montana-Dakota's propane customers in North Dakota may be affected by this proposal. There were 338 propane customers in North Dakota as of February 29, 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
102nd Revised Sheet No. 3
Canceling 101st Revised Sheet No. 3

RATE SUMMARY SHEET

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	$3.760	$4.572
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$3.760	$3.898
Interruptible Service - PAR			$0.120	$2.940	$3.060
Interruptible Service - MAFB			$0.120	$2.904	$3.024
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	$3.760	$4.357
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	14	$100.00 per month	$0.871	$2.940	$3.811
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	$3.849	$4.446
Summer Gas Usage			$0.597	$2.917	$3.514
Transportation Service	24				
Small Interruptible Rate 81		$150.00 per month			
Maximum			$0.427		
Minimum			$0.102		
Fuel Charge				$0.013	
Large Interruptible Rate 82		$725.00 per month			
Maximum			$0.298		
Minimum			$0.061		
Fuel Charge				$0.013	
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	27	$675.00 per month	$0.719	$2.940	$3.659
Residential Propane Rate 90	32	$0.30 per day	$0.812	$13.676	$14.488
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	$13.676	$14.273

Date Filed: March 9, 2012 **Effective Date:**

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

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

April 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 likely contributed to the decrease in the commodity price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of March 2, 2012 were 48.3 percent above the five-year average and 43.6 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 March Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 18.

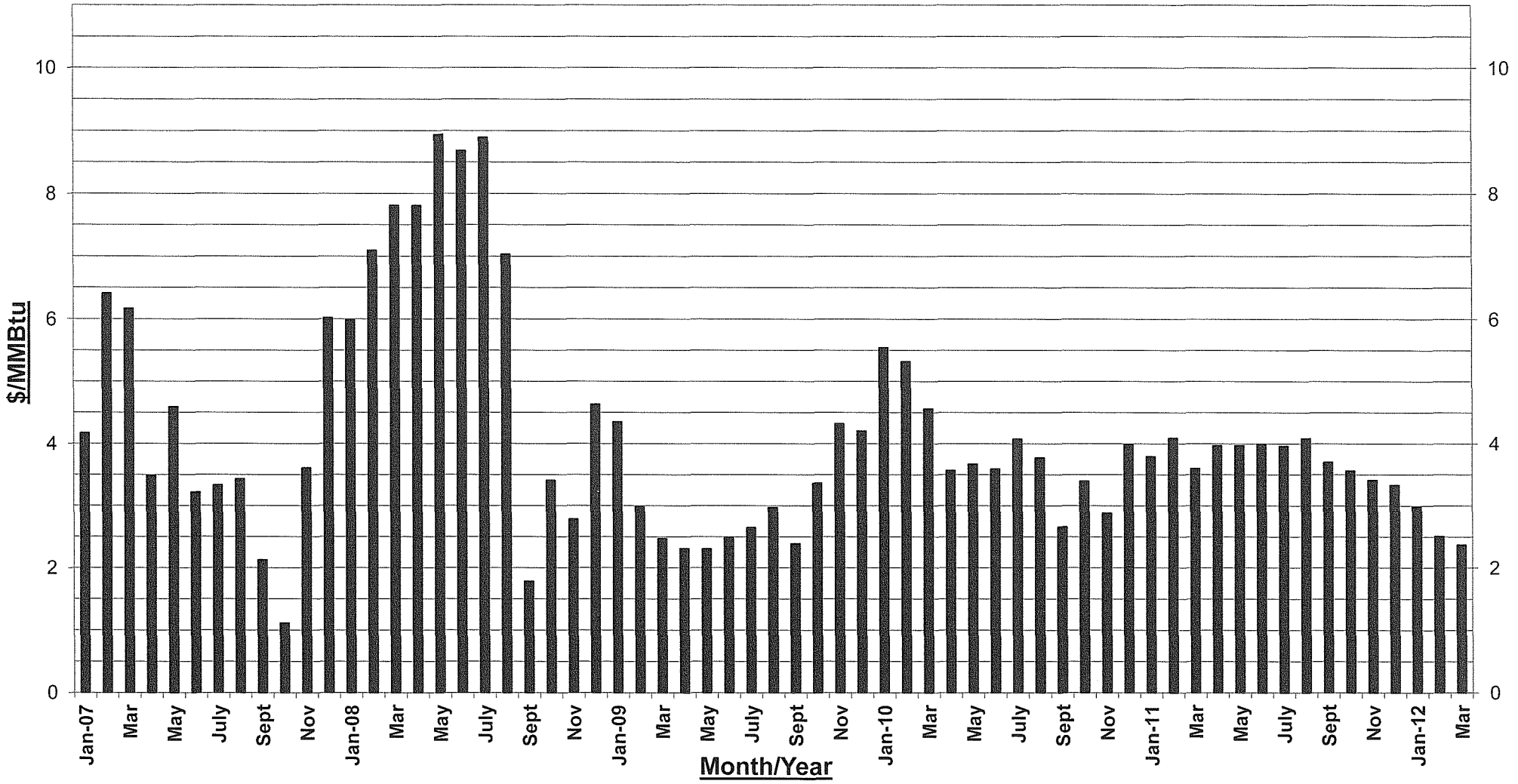
Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
April 2012

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 March 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 - $2.62

Independent Statistics & Analysis
U.S. Energy Information Administration

March 2012

Short-Term Energy Outlook

March 6, 2012 Release

Highlights

- EIA expects the price of West Texas Intermediate (WTI) crude oil to average about $106 per barrel in 2012, $5 per barrel higher than in the previous *Outlook* and $11 per barrel higher than the average price last year. Supply disruptions in the Middle East and Africa contributed to a significant increase in world crude oil prices during February. EIA has increased the forecast 2012 average cost of crude oil to U.S. refiners from $105 per barrel in last month's *Outlook* to $115 per barrel. Constraints in transporting crude oil from the U.S. midcontinent region contribute to the expected continuing 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 U.S. refiner average cost of crude oil averages $110 per barrel.

- EIA expects regular-grade motor gasoline retail prices to average $3.79 per gallon in 2012 and $3.72 per gallon in 2013, compared with $3.53 per gallon in 2011. During the April through September summer driving season this year, prices are forecast to average about $3.92 per gallon with a peak monthly average price of $3.96 per gallon in May. The June 2012 New York Harbor Reformulated Blendstock for Oxygenate Blending (RBOB) futures contract averaged $3.26 for the five trading days ending March 1. Based on the market value of futures and options contracts, there is a 39 percent probability that its price at expiration will exceed $3.35 per gallon, consistent with a monthly average regular-grade gasoline retail price of roughly $4.00 per gallon in June. The value of futures and options contracts imply a 2 percent probability that its price at expiration will exceed $4.35 per gallon, consistent with a monthly average regular-grade gasoline retail price of approximately $5.00 per gallon.

- The warm weather this winter has resulted in natural gas working inventories that continue to set new record seasonal highs, with February 2012 ending at an estimated 2.44 trillion cubic feet (Tcf), about 41 percent above the same time last year. EIA's average 2012 Henry Hub natural gas spot price forecast is $3.17 per million British thermal units (MMBtu), a decline of about $0.83 per MMBtu

from the 2011 average spot price. EIA expects that Henry Hub spot prices will average $3.96 per MMBtu in 2013.

- EIA expects electricity generation from coal to decline by nearly 5 percent in 2012 as generation from natural gas increases by about 9 percent. EIA forecasts that electricity generation from coal will increase by 3.8 percent in 2013, as projected coal prices to the power sector fall slightly while natural gas prices increase, and coal regains some of its power sector generation share.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA expects increases in global consumption to outpace production growth in countries outside of the Organization of the Petroleum Exporting Countries (OPEC) during the forecast period. World liquid fuels consumption grows by an annual average of 1.1 million barrels per day (bbl/d) in 2012 and 1.4 million bbl/d in 2013. Supply from non-OPEC countries increases by 0.7 million bbl/d in 2012 and by 0.8 million bbl/d in 2013. EIA expects that the market will rely on both inventories and increases in crude oil and non-crude liquids production from OPEC members to meet world demand growth.

Significant 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 current disruptions intensify, new non-OPEC projects come online more slowly than expected, or OPEC members do not increase production. On the demand side, if the pace of global economic growth fails to recover in countries belonging to the Organization for Economic Cooperation and Development (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 0.8 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 89.0 million bbl/d in 2012 and 90.3 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).

Non-OPEC Supply. EIA expects non-OPEC crude oil and liquid fuels production to rise by 690 thousand bbl/d in 2012 and by a further 750 thousand bbl/d in 2013. The largest area of forecast non-OPEC growth will be North America, where production increases by 360 thousand bbl/d and 190 thousand bbl/d in 2012 and 2013,

respectively, resulting from continued production growth from U.S. onshore shale 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, production increases annually by an average of 120 thousand bbl/d over the next two years, with increased output from its offshore, pre-salt oil fields. Production also increases in Colombia and China 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 over the last two months, leaving an average of around 1 million bbl/d offline in February. 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 now projects that total production from Sudan and South Sudan, which averaged about 430 thousand bb/d in 2011, will average 200 thousand bbl/d in 2012 and recover to 370 thousand bbl/d in 2013.

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 and was further curtailed in February by a strike at the country's largest oil field. 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. In Syria, damage to a major pipeline that feeds one of the country's two refineries has exacerbated the country's production problems. EIA now expects Syria to produce 260 thousand bbl/d in 2012 and recover to 360 thousand bbl/d in 2013, still below the country's pre-crisis production level of 400 thousand bbl/d.

Disruptions stemming from technical issues have temporarily curbed production in the United Kingdom and Canada, 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. Projected OPEC crude oil production increases by about 490 thousand bbl/d and 560 thousand bbl/d in 2012 and 2013, respectively. EIA's forecast does not factor in any potential effects that the impending European Union embargo and other sanctions may have on Iran's crude oil production because it is too early to assess the country's ability to place its supply elsewhere. However, EIA estimates that Iran's crude oil production has fallen since mid-2011 and is projected to continue to decline through the forecast period. OPEC non-crude petroleum liquids (condensates,

natural gas liquids, coal-to-liquids, and gas-to-liquids), which is not covered by OPEC's production quotas, will increase by 220 thousand bbl/d in 2012 and by 60 thousand bbl/d in 2013.

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 OPEC surplus production capacity will increase from about 2.4 million bbl/d in January 2012 to 3.7 million bbl/d at the end of 2013, as Libyan production capacity recovers to pre-disruption levels, allowing other OPEC producers to scale back production (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 56.9 days of forward-cover (days-of-supply). Although the December 2011 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 1994 because of a decline in OECD consumption last year. Projected OECD oil inventories decline slightly over the forecast, with OECD inventories falling to 2.57 billion barrels, or 55.4 days of forward-cover, at the end of 2013 (Days of Supply of OECD Commercial Stocks Chart).

Crude Oil Prices. EIA's forecast of the WTI spot price is higher than last month's *Outlook*, averaging about $106 per barrel in both 2012 and 2013 (West Texas Intermediate Crude Oil Price Chart), compared with $100 and $104 per barrel for 2012 and 2013, respectively, in the previous *Outlook*. The projected WTI price discount to the average U.S. refiner acquisition cost of crude oil narrows over the forecast from about $10 per barrel in the second quarter of 2012 to $4 per barrel by the fourth quarter of 2013, as physical pipeline capacity constraints diminish. The projected average refiner acquisition cost (RAC) of crude oil averages $115 per barrel in 2012 and $110 per barrel in 2013.

Energy price forecasts are highly uncertain (Market Prices and Uncertainty Report). WTI futures for May 2012 delivery during the 5-day period ending March 1, 2012 averaged $108.60 per barrel. Implied volatility averaged 30 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in May 2012 at $88 per barrel and $134 per barrel, respectively. Last year at this time, WTI for May 2011 delivery averaged $101 per barrel and implied volatility averaged 36 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $79 per barrel and $129 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. In 2011, total U.S. liquid fuels consumption fell by 340 thousand bbl/d (1.8 percent) from the 2010 average level (U.S. Liquid Fuels Consumption Chart). Motor gasoline consumption accounted for much of that decline, shrinking by 260 thousand bbl/d (2.9 percent). In contrast, distillate fuel oil consumption rose by 50 thousand bbl/d (1.3 percent), brought about by recovery in industrial output and freight transport.

Even with forecast U.S. real gross domestic product growth of 2.2 percent in 2012 and 2.4 percent in 2013, the next two years are expected to see only small changes in total liquid fuels consumption, with a decline of about 60 thousand bbl/d (0.3 percent) in 2012 and an increase of 110 thousand bbl/d (0.6 percent) in 2013. Motor gasoline consumption, constrained by slowing growth in the driving-age population and the improving fuel economy of new vehicles, is forecast to fall by 60 thousand bbl/d in 2012 and decline by 10 thousand bbl/d in 2013. Distillate fuel consumption, however, continues to rise.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by an estimated 120 thousand bbl/d to 5.60 million bbl/d in 2011. A 390-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 230-thousand bbl/d decline in output in the Federal Gulf of Mexico (GOM).

Forecast U.S. total crude oil production increases by 230 thousand bbl/d in 2012 and by a further 90 thousand bbl/d in 2013. Continued increases in lower-48 onshore crude oil production of 340 thousand bbl/d in 2012 overshadow declines averaging about 20 thousand bbl/d in Alaskan output and a 90-thousand bbl/d decrease 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 shale formations. The number of onshore oil-directed drilling rigs reported by Baker Hughes increased from 777 at the beginning of 2011 to 1,293 on March 2, 2012.

Since the idling of two refineries late last year, the East Coast lost another important source of supply last month when HOVENSA closed its St. Croix refinery in the U.S. Virgin Islands. The market transition on the East Coast thus far has been relatively smooth. However, if Sunoco's Philadelphia refinery closes in July 2012, as Sunoco has announced may occur if no buyer is found, the Northeast could be significantly affected, as replacing the additional lost volumes will be complicated by reduced access to distribution systems. Adequate refining capacity is available outside of the East Coast to replace product supplies, but logistical constraints to delivering product

to the Northeast in the short term may present significant challenges. 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 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 remain near 2011 levels in 2012 and 2013.

U.S. Petroleum Product Prices. Regular-grade gasoline retail prices averaged $3.53 per gallon in 2011, $0.74 per gallon (27 percent) higher than the 2010 average. The price increase in 2011 largely reflected higher crude oil costs ($0.60 per gallon) and higher refinery gasoline margins ($0.10 per gallon). EIA expects the regular-grade gasoline retail price to increase to an average of $3.79 per gallon in 2012 due to higher crude oil prices (U.S. Gasoline and Crude Oil Prices Chart), and regular-grade gasoline prices this summer are expected to average close to $4.00 per gallon in May. Forecast regular-grade gasoline prices decline to an average of $3.72 per gallon in 2013.

EIA expects that on-highway diesel fuel retail prices, which averaged $3.84 per gallon in 2011, will average $4.15 per gallon in 2012, and $4.11 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. EIA expects gasoline wholesale prices to remain lower than diesel wholesale prices, with gasoline prices averaging 17 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 68.9 billion cubic feet per day (Bcf/d) in 2012, an increase of 2.1 Bcf/d (3.1 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 0.5 percent and 0.1 percent, respectively, in 2012, reflecting a downward revision in projected consumption from last month's *Outlook*.

Projected consumption of natural gas in the electric power sector grows by close to 9 percent in 2012, primarily driven by the relative advantages of natural gas over coal for power generation in a growing number of economic dispatch decisions. Consumption in the electric power sector peaks in the third quarter of 2012, when electricity demand for air conditioning is highest.

Growth in total natural gas consumption continues into 2013, with forecast consumption averaging 69.3 Bcf/d (U.S. Natural Gas Consumption Chart). Consumption in the residential and commercial sectors increases in 2013 because of the forecast return to near-normal temperatures next winter. The increase in consumption in these sectors more than offsets a decline in power sector natural gas burn stemming from the projected increase in natural gas prices relative to coal prices later this year and next.

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 and 2013, 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 fell to 691 as of March 2, 2012, 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. However, fewer horizontal natural gas wells, particularly in areas such as the Haynesville Shale, contribute to small short-term production declines through June 2012. These declines reverse later in the year as prices rise, wet natural gas production rises, and associated gas production from oil wells increases.

Pipeline gross imports are expected to fall by 0.6 Bcf/d (7.0 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 is often a marginal source of supply. Pipeline gross exports grew by 1.0 Bcf/d in 2011, driven by increased exports to Mexico, and are expected to continue to grow, although 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 at terminals in the United States 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 February 24, 2012, according to EIA's *Weekly Natural Gas Storage Report*, working inventories totaled 2,513 Bcf, 756 Bcf greater than last year's level. EIA expects the winter heating season, which goes through March 31, will end with working inventories of about 2,270 Bcf, which would be highest end-of-March level on record. 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 five-year average during this year's winter heating season. EIA expects inventory levels at the end of October in both 2012 and 2013 will set new record highs as well (U.S. Working Natural Gas in Storage Chart).

U.S. Natural Gas Prices. Natural gas spot prices averaged $2.50 per MMBtu at the Henry Hub in February 2012, down $0.17 per MMBtu from the January 2012 average and the lowest average monthly price since February 2002. Abundant storage levels, as well as ample production, have contributed to the recent low prices. EIA expects that the Henry Hub spot price will begin to recover soon and will average $3.17 per MMBtu in 2012, and $3.96 per MMBtu in 2013, down $0.18 per MMBtu and $0.11 per MMBtu from last month's *Outlook*, respectively (U.S. Natural Gas Prices Chart).

Natural gas futures prices for May 2012 delivery (for the 5-day period ending March 1, 2012) averaged $2.69 per MMBtu, and the average implied volatility was 42 percent (Market Prices and Uncertainty Report). The lower and upper bounds for the 95-percent confidence interval for May 2012 contracts are $1.96 per MMBtu and $3.69 per MMBtu. At this time last year, the May 2011 natural gas futures contract averaged $3.98 per MMBtu and implied volatility averaged 33 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $3.09 per MMBtu and $5.11 per MMBtu.

Coal

U.S. Coal Consumption. Electric power sector coal consumption is forecast to decline by nearly 5 percent in 2012 as generation from natural gas, nuclear, and wind increases (U.S. Coal Consumption Chart). EIA expects electric power sector coal consumption to drop below 900 million short tons (MMst) for the first time since 1996. 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 1.9 percent in 2013 as the economic competitiveness of coal-fired generation improves.

U.S. Coal Supply. EIA expects coal production to decline by 4.4 percent in 2012 as domestic consumption and exports fall (U.S. Coal Production Chart). Production declines are expected in all coal-producing regions, with the largest occurring in the Interior region (19.3 MMst). EIA projects that secondary inventories will rise in 2012, but decline in the following year, primarily in the electric power sector, as consumption grows (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 99 MMst in both 2012 and 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 2013 will be about 3 percent lower than the 2011 average price.

Electricity

U.S. Electricity Consumption. EIA expects total U.S. consumption of electricity will fall slightly during 2012, and then grow by 1.9 percent during 2013 (U.S. Total Electricity Consumption Chart). Growth in retail sales of electricity to the commercial and industrial sectors during 2012 of 0.7 percent and 0.8 percent, respectively, will be offset by a 2.1 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 January and February was about 9 percent lower than during the same months of 2011, primarily because of the 17-percent decline in heating degree-days nationwide. Similarly, the projected 15-percent year-over-year decline in U.S. cooling degree-days this year is expected to lead to reduced electricity demand this summer. The total number of U.S. households is expected to grow by 1.4 percent during 2013, which would be the highest growth rate since 1998.

U.S. Electricity Generation. Recent data show that the trend in displacing coal with natural gas as a generation fuel has accelerated in response to the current low price of natural gas delivered to electric generators. U.S. generation fueled by natural gas in December 2011 was 11.6 percent higher than in December 2010. In contrast, coal-fired

generation declined by 20.7 percent over the same period. EIA expects this fuel displacement pattern to continue at least through the first half of 2012, causing the annual average share of total generation fueled by natural gas to rise from 24.8 percent in 2011 to 27.1 percent for 2012. As delivered natural gas prices begin increasing later this year, in response to higher demand and flattening growth in production, EIA expects the trend in fuel displacement will reverse slightly in 2013, with natural gas' share of U.S. generation falling back to an annual average of 26.1 percent (U.S. Electricity Generation Chart).

U.S. Electricity Retail Prices. The price of natural gas delivered to electric generators is estimated to have averaged about $3.30 per MMBtu in February 2012, which would be its lowest nominal value in 10 years. EIA expects these low fuel costs to be passed through to residential electricity consumers over the next two years. Average U.S. residential electricity prices are forecast to rise by 0.4 percent in 2012, and then fall by 0.9 percent in 2013 (U.S. Residential Electricity Prices Chart). These growth rates compare with an average annual increase of 2.6 percent during the past five years.

Renewables and Carbon Dioxide Emissions

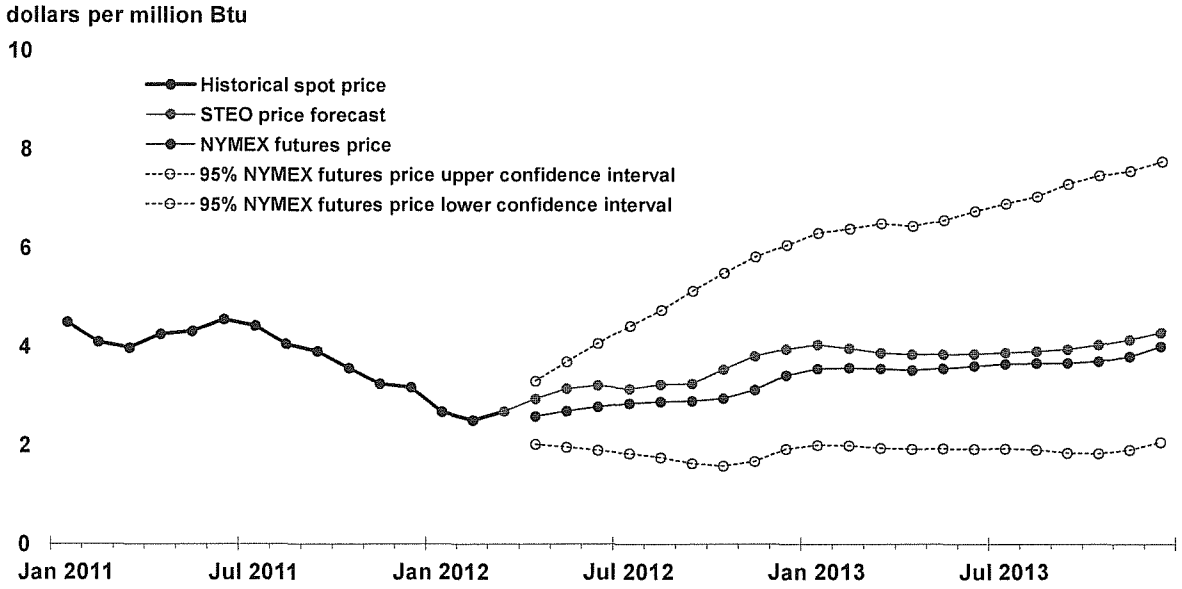
U.S. Renewables. After a banner year in 2011, U.S. hydropower production is assumed to return to long-term average production levels in 2012 and beyond. The strong growth in hydropower combined with growth in other renewables led to a 14 percent increase in total renewable energy supply in 2011. EIA expects the total renewable energy supply to decline by 3.8 percent in 2012 as the reduction in hydropower production offsets continued growth in other renewables (U.S. Renewable Energy Supply Chart). In 2013, renewables supply increases 1.4 percent as non-hydropower renewables continue to increase.

EIA expects fuel ethanol production to grow from an average of 910 thousand bbl/d in 2011 to 920 thousand bbl/d in 2012, and to 930 thousand bbl/d in 2013. 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 64 thousand bbl/d in 2012 and 65 thousand bbl/d in 2013.

U.S. CO_2 Emissions. After declining by 2.0 percent in 2011, fossil fuel emissions are projected to fall an additional 0.4 percent in 2012, but increase by 0.9 percent in 2013. After falling by 2.1 percent last year, petroleum emissions continue to decline slightly in 2012, and then increase by 0.4 percent in 2013. Natural gas emissions rise in both

2012 and 2013. Coal emissions fall in 2012 by 3.4 percent, but rise by 1.9 percent in 2013 (U.S. Carbon Dioxide Emissions Growth Chart).

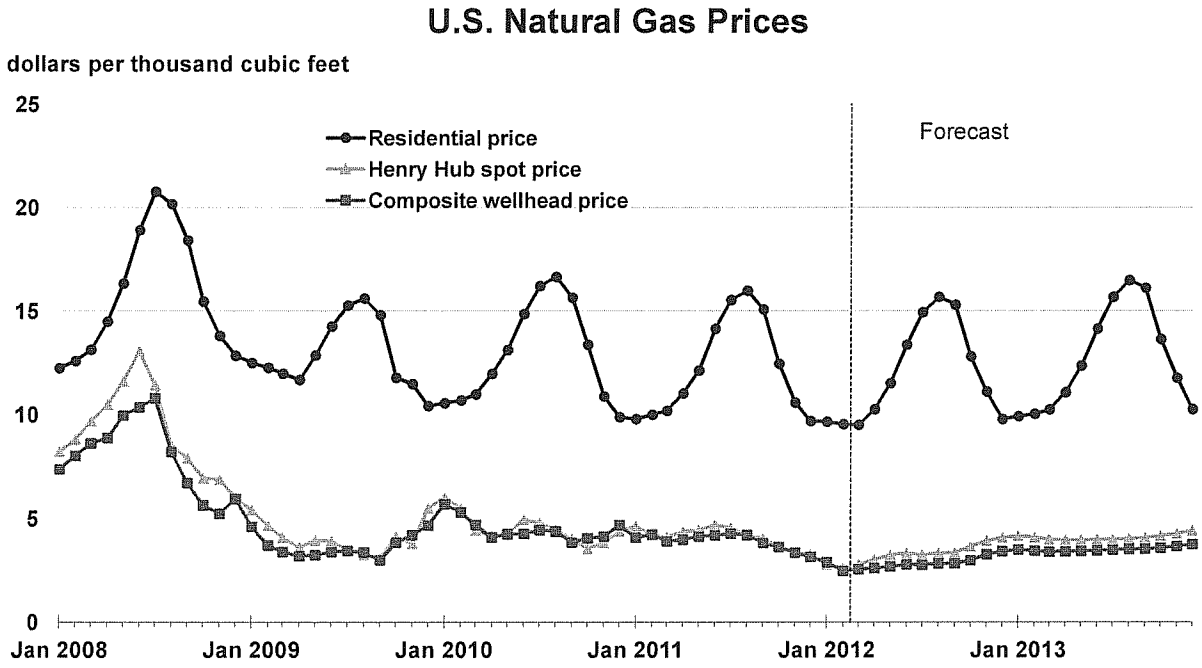
Henry Hub Natural Gas Price



Note: Confidence interval derived from options market information for the 5 trading days ending March 1, 2012
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

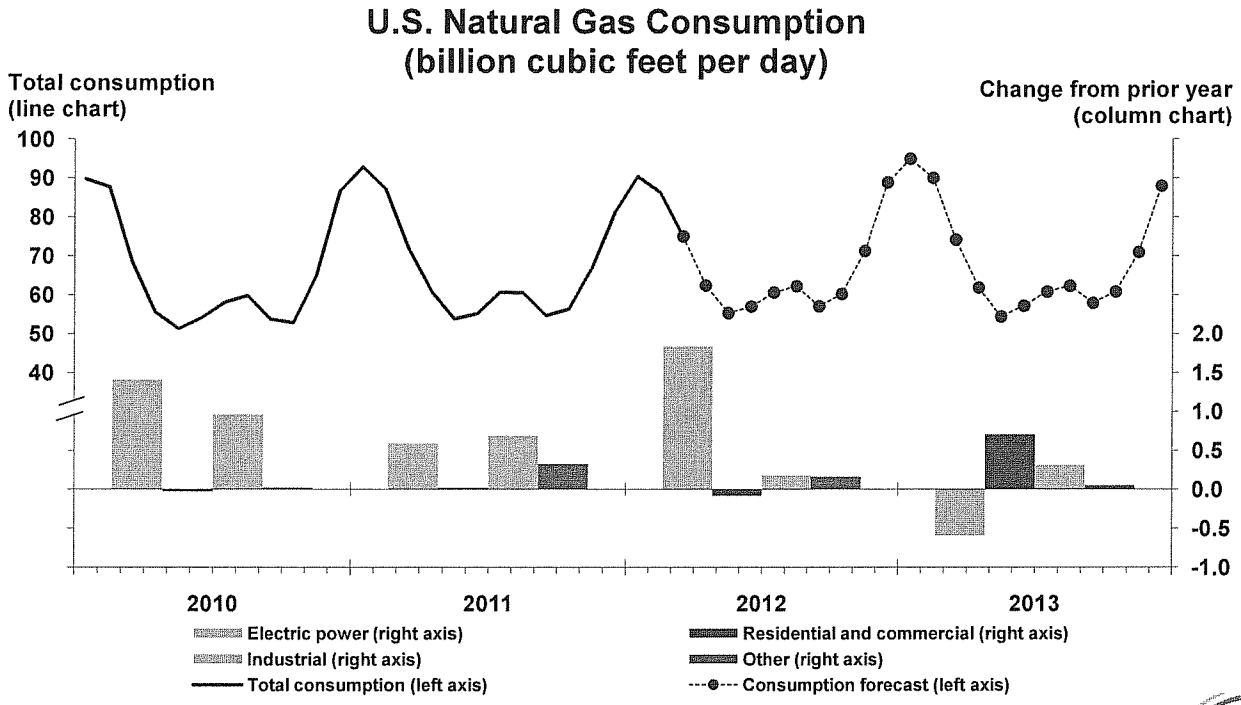
Source: Short-Term Energy Outlook, March 2012

eia



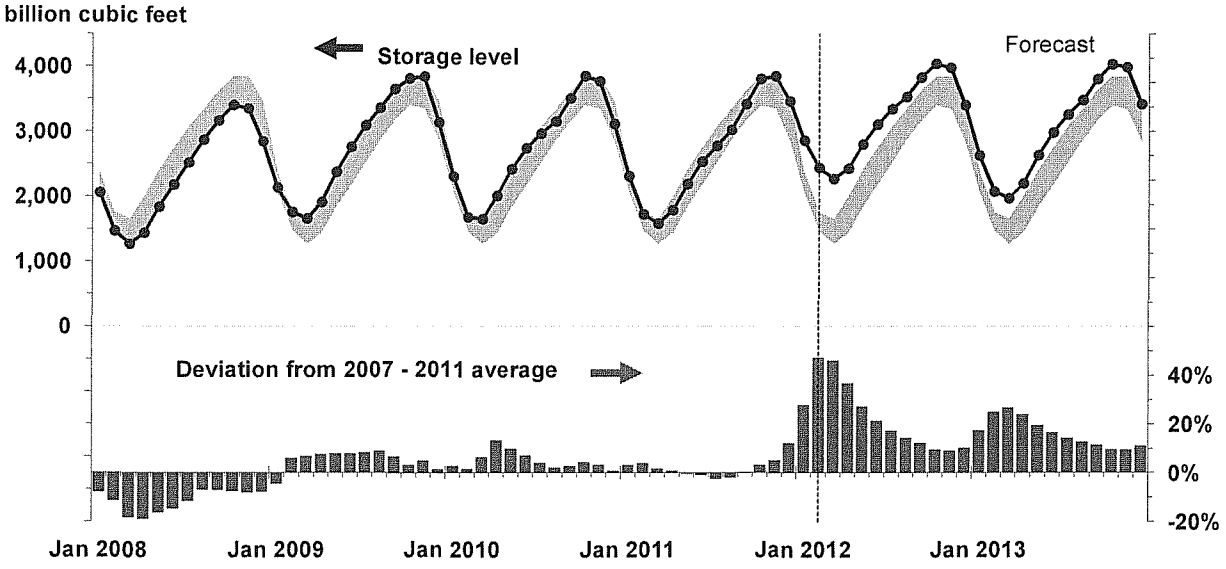
Source: Short-Term Energy Outlook, March 2012

eia



Source: Short-Term Energy Outlook, March 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, March 2012

eia

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

Williston Basin Interstate Pipeline Company Docket No. RP12- 444-000

On March 1, 2012, Williston Basin filed its semi-annual fuel and electric power reimbursement adjustment with the FERC in Docket No. RP12-444-000, reflecting revisions to the fuel and electric power components of Williston Basin's transportation and storage rates to be effective April 1, 2012.

Approximate impact on Montana-Dakota's cost of gas: (4.5) cents per dk

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

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
Gas Cost Adjustment:				
Gas Cost Level (Exhibit B)	$3.801	$3.890	$2.876	$2.863
Prior Gas Cost	3.939	4.027	3.005	2.991
Current Gas Cost Adjustment	($0.138)	($0.137)	($0.129)	($0.128)
Surcharge Adjustment:				
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
Market Based Pricing Differential				
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	**($0.138)**	**($0.137)**	**($0.129)**	**($0.128)**
Gas Cost Level	$3.801	$3.890	$2.876	$2.863
Plus: Surcharge	(0.032)	(0.032)	0.064	0.041
Total Gas Cost Level in Tariff Rates	$3.769	$3.858	$2.940	$2.904

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

Cost of Gas - Propane	
Current Propane Cost (Exhibit D)	$13.174
Prior Propane Cost	17.016
Current Propane Cost Adjustment	($3.842)
Surcharge Adjustment	
Current Adjustment	$0.511
Prior Adjustment	0.511
Change in Surcharge Adjustment	$0.000
Market Based Pricing Differential	
Current Adjustment	($0.009)
Prior Adjustment	(0.009)
Change in Margin Sharing Provision	$0.000
Net Increase (Decrease) in Gas Costs	**($3.842)**
Propane Cost Level	$13.174
Plus: Surcharge	0.511
Total Propane Cost Level in Rates	**$13.685**

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

	Amount
Total Gas Costs 1/	$53,297,337
Residential and General Service dk Requirements 2/	14,084,654
Average Cost of Gas per dk	$3.784
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.801
Less: Gas Cost Level in Rates 3/	3.939
Current Gas Cost Adjustment	**($0.138)**

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 January 31, 2012, adjusted for losses at .45%

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

Cost of Purchased Gas	$3.921
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$3.939

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

Summer - June - September	
Total Gas Costs 1/	$53,297,337
Less: Annual MDDQ Costs 1/	11,821,667
Total Gas Costs excluding MDDQ	$41,475,670
Firm Service Requirements 1/	14,084,654
Other Gas Costs per Dk (excluding MDDQ)	$2.945
Summer Seasonal Rate, adjusted for losses 2/	2.958
Winter - October - May	
Annual MDDQ Costs 1/	$11,821,667
Winter Firm Service Requirements	12,758,830
MDDQ Costs per Winter Dk	$0.927
Add: Other Gas Costs per Dk	2.945
Winter Seasonal Rate	$3.872
Winter Seasonal Rate, adjusted for losses 2/	$3.890
Less: Gas Cost Level in Rates 3/	4.027
Current Gas Cost Adjustment	**($0.137)**

1/ Exhibit B, page 1.
2/ Loss factor of .45%.
3/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective March 1, 2012:

	Summer	Winter
Cost of Purchased Gas	$3.077	$4.009
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	$3.091	$4.027

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

	Amount
Total Gas Costs 1/	$10,028,416
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	$2.863
Average Cost of Gas as Adjusted for Losses @ 99.55%	2.876
Less: Gas Cost Level in Rates 2/	3.005
Current Gas Cost Adjustment	**($0.129)**

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 March 1, 2012:

Cost of Purchased Gas	$2.991
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$3.005

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

	Amount
Total Gas Costs 1/	$2,519,453
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	$2.863
Less: Gas Cost Level in Rates 2/	2.991
Current Gas Cost Adjustment	**($0.128)**

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 March 1, 2012:
Cost of Purchased Gas $2.991

Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
April 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.

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

8NOTICE 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.

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.

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) $ 179.94/10^3m^3
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point
3. Rate Schedule FT-D [3]	Refer to Attachment "2" for applicable FT-D Demand Rate per month based on a one year term (Price Point "Z") & Surcharge for each Group 1 or Group 2 Delivery Point. Average FT-D Demand Rate for Group 1 Delivery Points $ 5.44/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	Contract Term — Effective LRS Rate ($/$10^3m^3$/day) 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 $ 129.55/10^3m^3
10. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point
11. Rate Schedule IT-D [3]	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point
12. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service
13. Rate Schedule PT	Schedule No — PT Rate — PT Gas Rate 9009-01001-1 — $ 660.00/d — 50.0 10^3m^3/d
14. Rate Schedule OS	Schedule No. — Charge 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 $ 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.

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

	28th	Revised	Sheet No.	80.1
Canceling	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)

GAS RATE SCHEDULE

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

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

Date Filed: January 24, 2001

Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is $2.398 per dekatherm.

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

NG-00-001

STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5
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

Division	Receipt Point	Delivery Point	Monthly Customer Charge	Maximum Transportation Charge 2/	Minimum Transportation Charge 2/	Fuel Reimbursement Quantity Percentage 3/
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 APRIL 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	5,460,714	160,620	(1,381,754)
March	3,932,935	51,599	(1,971,583)
April	3,844,976	34,014	(1,788,274)
May	4,000,917	35,536	(1,054,500)
June	4,827,513	73,342	(50,581)
July	6,601,442	158,125	1,003,863
August	8,414,450	244,646	2,039,069
September	10,199,948	606,874	2,854,728
October	10,910,435	632,668	3,115,863
13 month average	$7,895,703	$314,456	$709,296
Rate of Return	8.791%	8.791%	8.791%
Return	$694,111	$27,644	$62,354
Return Requirement	$946,537	$37,697	$85,030

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 APRIL 2012

Cost of Purchased Propane	$56,393
Gallons Purchased	46,994
Projected dk Sales	4,300
Propane Cost per Dk	$13.115
Average Cost of Propane as Adjusted for Losses @ 99.55%	13.174
Less: Propane Cost Level in Rates 1/	17.016
Current Propane Cost Adjustment	($3.842)

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

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2011									**($589,074)**
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)
Balance @ January 31, 2012									**($103,694)**

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2011									**$48,803**
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
Balance @ January 31, 2012									**$37,429**

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2011									**$82,096**
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)
Balance @ January 31, 2012									**($64,068)**

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.