GREAT PLAINS
NATURAL GAS CO.
A Division of MDU Resources Group, Inc.

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February 25, 2011

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

Re: Cost of Gas Adjustment (COG)
March 2011

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and seven (7) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (60th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (60th Revised Sheet No. 8), showing the March 2011 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.2725 per mcf for residential and firm general service customers and $0.3059 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for March 2011, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.3059 per mcf since the last COG filing due to a decrease in the market price of gas. There has been an increase in pipeline charges of $0.0334 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of $0.2725 per mcf for residential and firm general service customers.

Attachment C explains the reasons for the change in the market price of gas.

Attachment D shows the calculation of the balancing account since April 30, 2010.

Great Plains submitted a check for $600.00 on January 10, 2011 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment covers the $50.00 filing fee associated with this month's COG filing.

Great Plains respectfully requests this filing be accepted as being in full compliance with the filing requirements of this Commission.

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

Sincerely,

Rita A. Mulkern

Rita A. Mulkern
Regulatory Affairs Manager

Attachments

# Attachment A

# GREAT PLAINS NATURAL GAS CO.

*A Division of MDU Resources Group, Inc.*

## State of North Dakota
## Gas Rate Schedule

NDPSC Volume 2
60th Revised Sheet No. 1.1
Canceling 59th Revised Sheet No.1.1


**RATE SUMMARY SHEET**

| Rate Schedule | Sheet No. | Basic Service Charge | Distribution Delivery Charge | | COG Items | Total Rate/MCF |
|---|---|---|---|---|---|---|
| Firm Gas Service - General | 2 | $3.50 per month | First 10 MCF | $1.2740 | $7.9338 | $9.2078 |
| | | | Over 10 MCF | 1.0540 | | 8.9878 |
| Interruptible Gas Service - General | 3 | $3.50 per month | First 400 MCF | $1.1391 | $3.7902 | $4.9293 |
| | | | Next 2,600 MCF | 0.8931 | | 4.6833 |
| | | | Over 3,000 MCF | 0.7411 | | 4.5313 |
| Interruptible Gas Service - Grain Processing | 4 | $3.50 per month | All MCF | $1.2391 | $3.7902 | $5.0293 |
| Transportation Service | 5 | $3.50 per month | First 400 MCF | $1.1391 | | $1.1391 |
| | | | Next 2,600 MCF | 0.8931 | | 0.8931 |
| | | | Over 3,000 MCF | 0.7411 | | 0.7411 |

**Date Filed:** February 25, 2011

**Effective Date:** March 1, 2011

**Issued By:** Tamie A. Aberle
Regulatory Affairs Manager

**Case No.:**

# GREAT PLAINS NATURAL GAS CO.

*A Division of MDU Resources Group, Inc.*

## State of North Dakota
## Gas Rate Schedule

NDPSC Volume 2
60th Revised Sheet No. 8
Canceling 59th Revised Sheet No. 8

## COST OF GAS

| Summary: | Firm | | | | Interruptible | | |
|---|---|---|---|---|---|---|---|
| | Est. Wtd. Demand Costs | Average Commodity | GCR Adj. | Est. Wtd. Total Firm | Average Commodity | GCR Adj. | Total Int. |
| Base Rate | $0.0658 | $5.1191 | $0.0000 | $5.1849 | $5.1191 | $0.0000 | $5.1191 |
| Accumulated Adj. | 3.5512 | (0.9239) | 0.3941 | 3.0214 | (0.9094) | (0.1136) | (1.0230) |
| Current Adj. | 0.0334 | (0.3059) | 0.0000 | (0.2725) | (0.3059) | 0.0000 | (0.3059) |
| Total Adj. | 3.5846 | (1.2298) | 0.3941 | 2.7489 | (1.2153) | (0.1136) | (1.3289) |
| Total Rate: | $3.6504 | $3.8893 | $0.3941 | $7.9338 | $3.9038 | ($0.1136) | $3.7902 |

**Date Filed:** February 25, 2011 **Effective Date:** March 1, 2011

**Issued By:** Tamie A. Aberle
Regulatory Affairs Manager

**Case No.:**

**GREAT PLAINS NATURAL GAS CO.**
**WAHPETON**
**COST OF GAS ADJUSTMENT**
**MARCH 2011**

| Firm | Billing Determinants | | Rate | Demand Months | Amount | Amount Per dk |
|---|---|---|---|---|---|---|
| FT-A | 7,841 | | $3.4671 | 12 | $326,226 | $0.2329 |
| FT-A - Zone 1-1 | 500 | | 3.4671 | 5 | 8,668 | 0.0062 |
| FT-A - Zone 1-2 | 4,500 | | 4.5871 | 5 | 103,210 | 0.0737 |
| FT-A Seasonal | 3,000 | | 3.7671 | 5 | 56,507 | 0.0403 |
| TFX Seasonal | 3,000 | | 15.1530 | 5 | 227,295 | 0.1623 |
| NOVA - Demand Charge | 7,947 | | 17.1450 | 12 | 1,635,016 | 1.1672 |
| Trans Canada - Demand Charge | 7,947 | | 17.4700 | 12 | 1,666,009 | 1.1893 |
| BP Canada - Demand Charge | 7,947 | | 0.9612 | 12 | 91,664 | 0.0654 |
| NOVA - Seasonal | 5,068 | | 17.1450 | 5 | 434,454 | 0.3102 |
| Trans Canada - Seasonal | 5,068 | | 17.4700 | 5 | 442,690 | 0.3160 |
| BP Canada - Seasonal | 5,068 | | 0.9612 | 5 | 24,357 | 0.0174 |
| BP Canada Winter Surcharge | 5,068 | | 3.0417 | 5 | 77,077 | 0.0550 |
| LMS Demand 2/ | | | | | | 0.0145 |
| Total Demand Charges | | | | | $5,093,173 | 3.6504 |
| Estimated Weighted Average Commodity Cost | 1,400,774 | 1/ | 3.8893 | | 5,448,030 | 3.8893 |
| Gas Cost Reconciliation Adjustment | | | | | | 0.3941 |
| Total Current Firm Gas Cost | | | | | $10,541,203 | 7.9338 |
| Base Cost of Gas | | | | | | 5.1849 |
| Accumulated Adjustment | | | | | | $2.7489 |

| Interruptible | |
|---|---|
| Estimated Weighted Average Commodity Cost | $3.8893 |
| Gas Cost Reconciliation Adjustment | (0.1136) |
| LMS Demand 2/ | 0.0145 |
| Total Current Interruptible Gas Cost | 3.7902 |
| Base Cost of Gas | 5.1191 |
| Accumulated Adjustment | ($1.3289) |

1/ Three year normalized average Dk sales.
2/ Amount divided by 2009 interruptibles sales volumes plus three year normalized firm Dk Sales. 2,073,950

| | Billing Determinants | Rate | Demand Months | Amount | Amount Per dk |
|---|---|---|---|---|---|
| LMS Demand | 2,500 | $1.0000 | 12 | $30,000 | $0.0145 |

**GREAT PLAINS NATURAL GAS CO.**
**WAHPETON**
**COST OF GAS ADJUSTMENT**
**MARCH 2011**

| **Rates Effective March 1, 2011** | $/Dk | |
|---|---|---|
| FT-A - Zone 1-1 | $3.4671 | Per dk/Mo. |
| FT-A - Zone 1-2 | 4.5871 | Per dk/Mo. |
| FT-A - Seasonal | 3.7671 | Per dk/Mo. |
| TFX Seasonal | 15.1530 | Per dk/Mo. |
| NOVA - Demand Charge | 17.1450 | Per dk/Mo. |
| Trans Canada Pipeline Demand Charge | 17.4700 | Per dk/Mo. |
| BP Canada - Demand Charge | 0.9612 | Per dk/Mo. |
| NOVA - Seasonal | 17.1450 | Per dk/Day |
| Trans Canada - Seasonal | 17.4700 | Per dk/Mo. |
| BP Canada - Seasonal | 0.9612 | Per dk/Mo. |
| BP Canada Winter Surcharge | 3.0417 | Per dk/Mo. |
| LMS Demand | 1.0000 | Per dk/Mo. |
| Estimated Weighted Average Commodity Cost: | 3.8893 | Per dk |

| **Base Rate Effective September 1, 1981** | | |
|---|---|---|
| Demand Charge | $0.8100 | Per Mcf/Mo. |
| Commodity Charge | 5.1191 | Per Mcf |

| **Base Rate Calculation** | | |
|---|---|---|
| Firm | | |
| Demand 1/ | $0.0658 | Per Mcf |
| Commodity | 5.1191 | Per Mcf |
| Total Firm Base Cost | $5.1849 | Per Mcf |
| | | |
| Interruptible: | | |
| Commodity | $5.1191 | Per Mcf |

1/ Demand base rate calculation: 4,768 X 12 X $0.8100 / 707,222

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

| Rate Schedule | Base Tariff Rate |
|---|---|
| Category 1 (Contract Term of Less than 3 Years) | |
| Monthly Reservation Rates | |
| FT-A | |
| Zone 1-1 Maximum Rate | $3.7671 |
| Zone 1-1 Minimum Rate | $0.0000 |
| Zone 1-2 Maximum Rate | $4.8871 |
| Zone 1-2 Minimum Rate | $0.0000 |
| Zone 2-2 Maximum Rate | $2.1400 |
| Zone 2-2 Minimum Rate | $0.0000 |
| Category 2 (Contract Term of 3 Years to less than 5 Years) | |
| Monthly Reservation Rates | |
| FT-A | |
| Zone 1-1 Maximum Rate | $3.6171 |
| Zone 1-1 Minimum Rate | $0.0000 |
| Zone 1-2 Maximum Rate | $4.7371 |
| Zone 1-2 Minimum Rate | $0.0000 |
| Zone 2-2 Maximum Rate | $1.9900 |
| Zone 2-2 Minimum Rate | $0.0000 |
| Category 3 (Contract Term of 5 or more Years) | |
| Monthly Reservation Rates | |
| FT-A | |
| Zone 1-1 Maximum Rate | $3.4671 |
| Zone 1-1 Minimum Rate | $0.0000 |
| Zone 1-2 Maximum Rate | $4.5871 |
| Zone 1-2 Minimum Rate | $0.0000 |
| Zone 2-2 Maximum Rate | $1.8400 |
| Zone 2-2 Minimum Rate | $0.0000 |

| Rate Schedule | Base Tariff Rate | Adjustment Under Section 19 1/ | Rate After Current Adjustment | Fuel and Loss Retention Percentages 2/ |
|---|---|---|---|---|
| Commodity Rates | | | | |
| FT-A – Maximum Rates | | | | |
| Zone 1-1 | $0.0130 | $0.0019 | $0.0149 | 1.92% |
| Zone 1-2 | $0.0130 | $0.0019 | $0.0149 | 2.23% |
| Zone 2-2 | $0.0130 | $0.0019 | $0.0149 | 0.31% |
| Minimum Rate | $0.0130 | $0.0019 | $0.0149 | |
| IT and AOT | | | | |
| Zone 1-1 | $0.1368 | $0.0019 | $0.1387 | 1.92% |
| Zone 1-2 | $0.1737 | $0.0019 | $0.1756 | 2.23% |
| Zone 2-2 | $0.0834 | $0.0019 | $0.0853 | 0.31% |
| Minimum Rate | $0.0130 | $0.0019 | $0.0149 | |

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of $0.0019 per Dekatherm shall be added to other charges under Company's Rate Schedules.

2/ Fuel and Losses Retention Percentages shall be applicable to all transportation rate schedules.

Transportation Fuel and Loss Retention Percentages are inclusive of the following percentages for Gas Lost and Unaccounted For: 0.16% for Zone 1-1, 0.18% for Zone 1-2, and 0.02% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted for percentages.

| Rate Schedule | Base Tariff Rate | Adjustment Under Section 27 1/ | Rate After Current Adjustment |
|---|---|---|---|
| LMS – Monthly Demand Rate | $1.0000 | | $1.0000 |
| LMS – Daily Overrun Rate | $0.1737 | | $0.1737 |
| LMS – Load Management Cost Reconciliation Adjustment | | $0.0453 | |

1/ Pursuant to Section 27 of the General Terms and Conditions of this Tariff, a mechanism is established to reconcile through surcharges or credits to the Rate Schedule LMS rate, as appropriate, differences between the cost to maintain Company's line pack gas and the amounts Company receives or pays for such gas arising out of the purchase and sale of such gas.

| Rate Schedule | Maximum Commodity Rate Per Dekatherm, Per Day | Minimum Commodity Rate Per Dekatherm, Per Day |
|---|---|---|
| PAL | $0.1737 | $0.0000 |

RATE SCHEDULE TF

| | MARKET-TO-MARKET | | | FIELD-TO-FIELD/MARKET DEMARCATION |
|---|---|---|---|---|
| | | TF12 | | |
| RESERVATION RATES | TF12 Base | Variable | TF5 | TFF |
| Base Tariff Rates 1/ | | | | |
| Summer (Apr-Oct) | 5.683 | 5.683 | -0- | 5.473 |
| Winter (Nov-Mar) | 10.230 | 13.866 | 15.153 | 9.853 |

| COMMODITY RATES 2/ TF12 Base, TF12 Var., TF5 & TFF | | Market Area 3/ | | Field Mileage 5/ Rate per 100 miles | | Carlton Surcharge 4/ | | Out-of Balance 3/ | |
|---|---|---|---|---|---|---|---|---|---|
| Receipt Point | Delivery Point | Maximum | Minimum | Maximum | Minimum | Maximum | Minimum | Maximum | Minimum |
| Market | Market | 0.0384 | 0.0215 | | | 0.0175 | 0.0000 | 0.0384 | 0.0215 |
| Field | Market | 0.0384 | 0.0215 | 0.0122 | 0.0040 | 0.0175 | 0.0000 | | |
| Market | Field | | | 0.0122 | 0.0040 | | | | |
| Field | Field | | | 0.0122 | 0.0040 | | | 0.0295 | 0.0109 |

1/ The minimum reservation rate is equal to zero.
2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
3/ Maximum and Minimum rates include ACA of $0.0019 and the Market Area Electric Compression charge of $0.0006 where applicable.
4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
5/ Where Applicable, Field Area Electric Compression charge of $0.0000 and ACA will be added to the mileage based rates.

RATE SCHEDULES TFX and LFT

| RESERVATION RATES | MARKET-TO-MARKET Apr-Oct | MARKET-TO-MARKET Nov-Mar | FIELD-TO-FIELD Apr-Oct | FIELD-TO-FIELD Nov-Mar |
|---|---|---|---|---|
| Base Tariff Rates 1/ | $5.683 | $15.153 | $5.473 | $9.853 |

| COMMODITY RATES 2/ TFX and LFT | | Market Area 3/ | | Field Mileage 5/ Rate per 100 miles | | Carlton Surcharge 4/ | | Out-of-Balance 3/ | |
|---|---|---|---|---|---|---|---|---|---|
| Receipt Point | Delivery Point | Maximum | Minimum | Maximum | Minimum | Maximum | Minimum | Maximum | Minimum |
| Market | Market | 0.0384 | 0.0215 | | | 0.0175 | 0.0000 | 0.0384 | 0.0215 |
| Field | Market | 0.0384 | 0.0215 | 0.0122 | 0.0040 | 0.0175 | 0.0000 | | |
| Market | Field | | | 0.0122 | 0.0040 | | | | |
| Field | Field | | | 0.0122 | 0.0040 | | | 0.0295 | 0.0109 |

| GULF COAST | Reservation 1/ Maximum | Reservation 1/ Minimum | Commodity 6/ Maximum | Commodity 6/ Minimum | Out-of-Balance 6/ Maximum | Out-of-Balance 6/ Minimum |
|---|---|---|---|---|---|---|
| MOPS Gathering | 1.0514 | 0.0000 | 0.0019 | 0.0019 | 0.0019 | 0.0019 |
| MOPS Transmission | 1.5337 | 0.0000 | 0.0019 | 0.0019 | 0.0019 | 0.0019 |
| Tivoli - Downstream | 0.6827 | 0.0000 | 0.0019 | 0.0019 | 0.0019 | 0.0019 |
| Other Gulf Coast | 4.8169 | 0.0000 | 0.0019 | 0.0019 | 0.0019 | 0.0019 |

1/ The minimum reservation rate is equal to zero.
2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
3/ Maximum and Minimum rates include ACA of $0.0019 and the Market Area Electric Compression charge of $0.0006 where applicable.
4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
5/ Where applicable, Field Area Compression charge of $0.0000 and ACA will be added to the mileage based rates.
6/ Maximum and Minimum rates include ACA of $0.0019.

**Great Plains Natural Gas Co.**
**Market Conditions for Wahpeton's Natural Gas**
**March 2011**

The principal gas sources of natural gas for Wahpeton, North Dakota are from the large Western Canadian Sedimentary Basin (WCSB). The pricing point for much of this gas is the Alberta Energy Company (AECO-C), one of the largest and most liquid volume points in North America. The March monthly price for the AECO Index is expected to decrease from the previous month index. The AECO Index is based on the weighted average one month spot price at AECO-C and Nova Inventory Transfer (N.I.T.) as reported by Natural Gas Exchange (NGX).

Unusually colder weather over the past several weeks had increased residential and commercial heating demand while shutting in significant natural gas production, leading to higher storage inventory withdrawals. However, the market has begun to factor in the downturn in demand expected as the winter season ends which has resulted in lower prices in the near term. The Energy Information Administration (EIA) reported storage levels nationwide as of February 18, 2011 were 6.7 percent below the five-year average and 7.4 percent below last year's balance.

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

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 15.

www.eia.doe.gov
Energy Information Administration

February 2011

# Short-Term Energy Outlook

February 8, 2011 Release

## Highlights

- EIA expects the price of WTI crude oil to average about $93 per barrel in 2011, $14 higher than the average price last year. For 2012, EIA projects that WTI prices will continue to rise, averaging $98 per barrel. EIA's forecast assumes U.S. real gross domestic product (GDP) grows 3.0 percent in 2011 and 2.8 percent in 2012, while world real GDP (weighted by oil consumption) grows by 3.9 percent and 4.0 percent, respectively, in 2011 and 2012.

- EIA expects regular-grade motor gasoline retail prices to average $3.15 per gallon in 2011, 37 cents per gallon higher than the 2010 average, and $3.30 per gallon in 2012, with prices forecast to average about 5 cents per gallon higher in each year during the peak driving season (April through September). There is regional variation in the forecast, with average expected prices on the West Coast about 25 cents per gallon above the national average during the peak driving season. There is also significant uncertainty surrounding the forecast, with the current market prices of futures and options contracts for gasoline suggesting a 35 percent probability that the national monthly average retail price for regular gasoline could exceed $3.50 per gallon during summer 2011 and about a 10 percent probability that it could exceed $4.00 per gallon. Rising crude oil prices are the primary reason for higher retail prices, but higher refining margins are also expected to contribute.

- EIA estimates that natural gas working inventories ended January 2011 at 2.3 trillion cubic feet (Tcf), about 30 billion cubic feet (Bcf) or 1 percent below the 2010 end-of-January level. Inventories are expected to remain high through 2011. The projected Henry Hub natural gas spot price averages $4.16 per million Btu (MMBtu) for 2011, $0.22 per MMBtu lower than the 2010 average. EIA expects the natural gas market to begin to tighten in 2012, with the Henry Hub spot price increasing to an average of $4.58 per MMBtu.

- EIA forecasts average household expenditures for space-heating fuels to total $991 during this 2010-2011 winter season, $24 higher than last year. EIA projects higher expenditures for heating oil and propane, flat expenditures for electricity, but lower expenditures for natural gas. A forecast of milder weather in the South and the West compared with the 2009-2010 winter leads to lower fuel consumption in those areas.

## Global Crude Oil and Liquid Fuels

*Crude Oil and Liquid Fuels Overview.* EIA expects a continued tightening of world oil markets over the next two years. World oil consumption grows by an annual average of 1.5 million barrels per day (bbl/d) through 2012 while the growth in supply from non-Organization of the Petroleum Exporting Countries (non-OPEC) countries averages about 0.3 million bbl/d this year and remains flat in 2012. Consequently, EIA expects the market will rely on both inventories and significant increases in the production of crude oil and non-crude liquids in OPEC member countries to meet world demand growth. While on-shore commercial oil inventories in the Organization for Economic Cooperation and Development (OECD) countries remained high last year, floating oil storage fell sharply in 2010, and EIA expects that OECD oil inventories will decline over the forecast period to close to the middle of the previous 5-year range by the end of 2012.

There are many significant uncertainties that could push oil prices higher or lower than current expectations. Among the uncertainties are decisions by key OPEC member countries regarding their production response to the global recovery in oil demand; the rate of economic recovery, both domestically and globally; fiscal issues facing national and sub-national governments; and China's efforts to address concerns regarding its growth and inflation rates. In addition, even though Egypt is not a major supplier of crude oil or natural gas to world markets, the recent unrest in that country raises the concern that unrest could spread to other countries in the region with a larger role in supplying world energy markets or that key transit routes for energy and other goods could be disrupted.

*Global Crude Oil and Liquid Fuels Consumption.* World crude oil and liquid fuels consumption grew by an estimated 2.4 million bbl/d in 2010, to 86.7 million bbl/d, the second largest annual increase in at least 30 years. This growth more than offset the losses of the previous two years and surpassed the 2007 level of 86.3 million bbl/d reached prior to the economic downturn. EIA expects that world liquid fuels consumption will grow by 1.5 million bbl/d in 2011 and by an additional 1.6 million bbl/d in 2012. Non-OECD countries make up almost all of the growth in consumption

over the next 2 years, with the largest contributions coming from China, Brazil, and the Middle East. Among the OECD regions, EIA expects that only North America will show oil consumption growth over the next 2 years, which will be offset by continued declines in OECD Europe and Asia.

*Non-OPEC Supply.* EIA projects non-OPEC crude oil and liquid fuels production will increase by 310,000 bbl/d in 2011, then decline slightly in 2012. Increases in non-OPEC oil production will be concentrated in a few countries, particularly in China and Brazil, where EIA expects each to show annual average production growth of 170,000 bbl/d in 2011. In 2012, EIA expects Canadian production growth to average 170,000 bbl/d while China and Brazil grow by 130,000 and 110,000 bbl/d, respectively. Other non-OPEC production is expected to decline. EIA expects Mexico's production will fall by about 210,000 bbl/d in 2011, followed by a further decline of 80,000 bbl/d in 2012. Similarly, production from the North Sea falls by 220,000 bbl/d and 160,000 bbl/d in 2011 and 2012, respectively. Projected U.S. crude oil production declines by 50,000 bbl/d in 2011 and by a further 190,000 bbl/d in 2012.

*OPEC Supply.* Forecast OPEC crude oil production increases by 0.4 million bbl/d in 2011, followed by a further increase of 1.2 million bbl/d in 2012. These production increases are in response to the increase in global demand for oil and limited growth in supplies originating in non-OPEC countries. Non-crude liquids production is expected to increase by 0.7 and 0.4 million bbl/d in 2011 and 2012, respectively. EIA expects that OPEC surplus production capacity will remain above 4 million bbl/d during the next 2 years.

*OECD Petroleum Inventories.* Onshore commercial oil inventories in the OECD countries remained high last year, but reports indicate floating oil storage fell sharply. Now that floating storage has been reduced, EIA expects that OECD onshore inventories will decline over the forecast period. Projected OECD stocks fall by about 55 million barrels in 2011, followed by an additional 60 million barrel decline in 2012. Days-of-supply (total inventories divided by average daily consumption) drops from 57 days to 55 days between December 2010 and the end of 2012, which is close to the middle of the previous 5-year range.

*Crude Oil Prices.* WTI crude oil spot prices averaged $89 per barrel in January, about the same as the December average, while over the same time period the estimated average cost of all crude oil to U.S. refineries increased by about $1 per barrel. Growing volumes of Canadian crude oil imported into the United States contributed to record-high storage levels at Cushing, Oklahoma, and a price discount for WTI compared with similar quality world crudes such as Brent crude oil. Projected WTI

spot prices rise to an average of $95 per barrel in December 2011 and continue to increase to $99 per barrel by the fourth quarter of 2012.

Energy price forecasts are uncertain (Energy Price Volatility and Forecast Uncertainty). WTI futures for April 2011 delivery over the 5-day period ending February 3 averaged $93 per barrel, and implied volatility averaged 30 percent. This makes the lower and upper limits of the 95-percent confidence interval $76 per barrel and $114 per barrel, respectively, for WTI delivered in April 2011. Last year at this time, WTI for April 2010 delivery averaged $75 per barrel and implied volatility averaged 34 percent, with the limits of the 95-percent confidence interval at $60 per barrel and $94 per barrel. Based on WTI futures and options prices, the probability that the monthly average price of WTI crude oil will exceed $100 per barrel in December 2011 is about 44 percent. Conversely, the probability that the monthly average December 2011 WTI price will fall below $85 per barrel is about 32 percent.

## U.S. Crude Oil and Liquid Fuels

***U.S. Liquid Fuels Consumption.*** Total consumption of petroleum and non-petroleum liquid fuels increased by 360,000 bbl/d (1.9 percent) to 19.1 million bbl/d in 2010 (U.S. Liquid Fuels Consumption Growth Chart). The major sources of this consumption growth were distillate fuel oil (diesel fuel and heating oil), which grew by 140,000 bbl/d (3.8 percent), and motor gasoline, which increased by 60,000 bbl/d (0.6 percent). Projected total U.S. liquid fuels consumption increases by 140,000 bbl/d (0.8 percent) in 2011 and a further 170,000 bbl/d (0.9 percent), to 19.5 million bbl/d, in 2012. Motor gasoline and distillate fuel account for much of the growth in consumption.

***U.S. Liquid Fuels Supply and Imports.*** Domestic crude oil production, which increased by 150,000 bbl/d in 2010 to 5.51 million bbl/d, declines by 50,000 bbl/d in 2011 and by a further 190,000 bbl/d in 2012 (U.S. Crude Oil Production Chart). The 2011 forecast includes production declines in Alaska of 60,000 bbl/d in 2011 and an additional decline of 20,000 bbl/d in 2012 because of the ongoing decline in production from the maturing Alaskan oil fields. EIA expects production from the Federal Gulf of Mexico (GOM) to fall by 250,000 bbl/d each year over the next 2 years. The production declines in Alaska and the GOM are partially offset by projected increases in lower-48 non-GOM production of 250,000-bbl/d in 2011 and 80,000 bbl/d in 2012.

Liquid fuel net imports (including both crude oil and refined products) fell from 57 percent of total U.S. consumption in 2008 to 49 percent in 2010, primarily because of the decline in consumption during the recession, and rising domestic production. EIA forecasts that liquid fuel net imports will average 9.6 million bbl/d in 2011 and 10.0

million bbl/d in 2012, comprising 50 percent and 51 percent of total consumption, respectively.

EIA expects slow growth in fuel ethanol production over the next 2 years. Ethanol production increases by a projected 50,000 bbl/d to 910,000 bbl/d in 2011 and then grows by an additional 10,000 bbl/d in 2012.

***U.S. Petroleum Product Prices.*** Projected regular-grade gasoline retail prices rise from an average of $2.78 per gallon in 2010 to $3.15 per gallon in 2011 and $3.30 per gallon in 2012. There is regional variation in the forecast, with average expected prices on the West Coast about 25 cents per gallon above the national average.

On-highway diesel fuel retail prices, which averaged $2.99 per gallon in 2010, will average $3.43 per gallon and $3.51 per gallon, respectively, in 2011 and 2012. Rising crude oil prices are the primary reason for higher retail prices, but higher gasoline and distillate refining margins are also expected to contribute to higher retail prices.

The projected monthly average regular gasoline price peaks this year at $3.24 per gallon in July. New York Harbor RBOB (reformulated gasoline blendstock for oxygenate blending) futures contracts for July 2011 delivery over the 5-day period ending February 3 averaged $2.65 per gallon and implied volatility averaged 30 percent. The probability the RBOB futures price will exceed $2.80 per gallon (and the U.S. average regular gasoline retail price exceed $3.50 per gallon) in July 2011 is about 35 percent. The probability the RBOB futures price will exceed $3.30 per gallon (and the gasoline retail price exceed $4.00 per gallon) in July 2011 is about 10 percent.

## Natural Gas

***U.S. Natural Gas Consumption.*** EIA expects that total natural gas consumption will remain flat from 2010 to 2011. Reported residential and commercial consumption are expected to decline by 0.3 percent and 2.4 percent, respectively, primarily because of changes to EIA's methodology for collecting and reporting natural gas consumption data (see *Changes in Natural Gas Monthly Consumption Data Collection and the Short-Term Energy Outlook*). Industrial consumption rises from 18.0 billion cubic feet per day (Bcf/d) in 2010 to 18.3 Bcf/d in 2011 as the natural-gas weighted industrial production index increases 2.4 percent year over year.

Total consumption grows 1 percent in 2012, from 66.2 Bcf/d to 66.8 Bcf/d. Increases in natural gas consumption in the electric power sector (2.9 percent) and industrial sector (1.2 percent) are partially offset by slight declines in residential and commercial consumption. EIA expects electric power sector and industrial sector consumption to grow by 2.9 percent and 1.2 percent, respectively, in 2012.

*U.S. Natural Gas Production and Imports.* Total marketed natural gas production grew strongly throughout 2010 (4.4 percent), increasing from 59.7 Bcf/d in January to an estimated 63.7 Bcf/d in December. Year-over-year growth in 2011 is expected to slow considerably to just 0.8 percent as an increase of 1.0 Bcf/d in the lower-48 states is partially offset by a decline of 0.4 Bcf/d in the GOM.

The latest EIA data for monthly natural gas production in the *Natural Gas Monthly*, showed an increase in lower-48 states' production for November 2010, reversing October's decline. Modest declines are expected to resume and continue through 2011, however, because of a falling drilling rig count in response to lower prices. The number of rigs drilling for natural gas reported by Baker Hughes Inc. increased from a low of 665 in July 2009 to 973 in April 2010. Over the following 6 months the natural gas rig count stayed relatively unchanged. However, over the last 3 months the rig count has fallen, dropping to 911 rigs as of February 4. The large price difference between petroleum liquids and natural gas on an energy-equivalent basis contributes to an expected shift towards drilling for liquids rather than for dry gas.

Increasing consumption, especially in the electric power sector, contributes to higher prices and more economic incentive for producers to resume drilling. Total domestic natural gas production increases 1.1 percent in 2012. Lower-48 production is expected to increase throughout 2012 from 55.0 Bcf/d in January to 57.4 Bcf/d in December, which would be strong growth, but significantly less than during 2010. Federal GOM production declines slightly, by 0.4 percent (0.02 Bcf/d) in 2012.

EIA expects gross pipeline imports of 8.7 Bcf/d in 2011 and 8.2 Bcf/d in 2012, year-over-year decreases of 4.2 and 5.5 percent, respectively. Projected imports of liquefied natural gas (LNG) average 1.1 Bcf/d in 2011, a 4.4-percent decrease from 2010 levels. LNG imports in 2012 grow modestly to 1.2 Bcf/d. High domestic production, high inventories, and low U.S. prices relative to European and Asian markets should continue to discourage LNG imports.

*U.S. Natural Gas Inventories.* On January 28, 2011, working natural gas in storage stood at 2,353 Bcf, slightly below last year's level at this time (U.S. Working Natural Gas in Storage Chart). At the end of the winter heating season (March 31, 2011), EIA expects that about 1,651 Bcf of working natural gas will remain in storage, which is a downward revision of about 120 Bcf from last month's Outlook. Colder-than-normal weather east of the Rocky Mountains in January contributed to a larger-than-expected draw on inventories. EIA expects near-record high inventories to continue through most of 2011. Falling production and greater consumption contribute to lower inventories in the second half of 2012.

*U.S. Natural Gas Prices.* The Henry Hub spot price averaged $4.49 per MMBtu in January, 2011, $0.24 per MMBtu greater than the average spot price in December 2010 (Henry Hub Natural Gas Price Chart). EIA expects that the Henry Hub spot price will average $4.16 per MMBtu in 2011, a drop of $0.22 per MMBtu from the 2010 average. EIA expects the natural gas market to begin to tighten in 2012, with the Henry Hub spot price increasing to an average of $4.58 per MMBtu.

Uncertainty over future natural gas prices is slightly lower this year compared with last year at this time. Natural gas futures for April 2011 delivery (for the 5-day period ending February 3) averaged $4.39 per MMBtu, and the average implied volatility over the same period was 34 percent. This produced lower and upper bounds for the 95-percent confidence interval for April 2011 contracts of $3.40 per MMBtu and $5.66 per MMBtu, respectively. At this time last year, the natural gas April 2010 futures contract averaged $5.35 per MMBtu and implied volatility averaged 46 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $3.80 per MMBtu and $7.50 per MMBtu.

## Electricity

*U.S. Electricity Consumption.* EIA expects total U.S. consumption of electricity in 2011 to remain at about the same level as consumption during 2010. Retail sales of electricity to the residential sector this year will fall 2.0 percent in response to the assumed 16-percent decline in cooling degree-days. Consumption should grow by 2.5 percent during 2012 (U.S. Total Electricity Consumption Chart). During 2012, EIA's assumption of a relatively strong increase in the number of households leads to a 2.3-percent increase in residential electricity sales. Continued robust growth in manufacturing output should drive growth in industrial electricity sales of 1.7 percent during 2011 and 2.3 percent in 2012.

*U.S. Electricity Generation.* Projected total generation by the electric power sector decreases by 0.2 percent in 2011, which is the same year-over-year decline as projected in last month's *Outlook*. However, EIA has lowered its projections for growth in hydroelectric power this year to 0.9 percent compared to 6.0 percent in the last *Outlook*. This downward revision in hydro generation will be offset by natural gas-fired generation, which is now expected to grow slightly during 2011. During 2012, EIA expects a 2.5-percent increase in total electric power sector generation, which will be fueled primarily by increased generation from coal, natural gas, and non-hydropower renewables (U.S. Electric Power Sector Generation Growth Chart).

*U.S. Electricity Retail Prices.* EIA expects the U.S. retail price for electricity distributed to the residential sector to rise slightly (0.6 percent) during 2011, after a

small increase of 0.7 percent during 2010. The U.S. residential price increases by about 0.7 percent in 2012. These price increases are relatively small compared with the average annual growth rate of 3.5 percent over the period of 2000-2009 (U.S. Residential Electricity Prices Chart). The effect of lower generation fuel costs should be more evident in retail electricity prices for the industrial sector, which are expected to fall about 2 percent this year after a similar rise last year. Projected industrial electricity prices should rise 0.8 percent in 2012.

## Coal

***U.S. Coal Consumption.*** EIA estimates that coal consumption in the electric power sector grew by nearly 5 percent in 2010, primarily the result of higher electricity consumption because of the very warm summer. EIA projects that coal consumption in the electric power sector will decrease by 0.7 percent in 2011, as increases in generation from natural gas, nuclear, and wind back out coal. In 2012, projected electricity generation increases by 2.5 percent and coal consumption in the electric power sector grows by 3.4 percent (U.S. Coal Consumption Growth Chart).

***U.S. Coal Supply.*** Coal production during the first 6 months of 2010 fell by 2.5 percent from the same period last year despite a 5.4-percent increase in U.S. coal consumption. A drawdown in stocks, particularly in the electric power sector, met the demand increase (U.S. Electric Power Sector Coal Stocks Chart). Estimated coal production increases in the second half of 2010 contributed to 2010 annual growth of 1.0 percent. EIA projects coal production in 2011 will remain relatively flat as coal consumption shows little change (U.S. Annual Coal Production Chart). The projected increase in coal consumption in 2012 leads to a forecast 3.6 percent increase in coal production.

***U.S. Coal Trade.*** Strong global demand for coal, particularly metallurgical coal used to produce steel, resulted in sharp increases in U.S. coal exports in 2010 to an average of 7.3 percent of production. Metallurgical coal exports nearly doubled in the first half of 2010 compared with the first half of 2009, and metallurgical coal's share of total coal exports has grown from 52 percent in 2008 to almost 70 percent in 2010. Flooding in Australia has greatly affected the amount of metallurgical coal available on the world market, and EIA expects U.S. metallurgical coal exports to increase in 2011 by 7.3 percent. In 2012, forecast U.S. coal exports fall back to more recent levels (about 80 million short tons) as other major coal-exporting countries increase their supply to the global coal market.

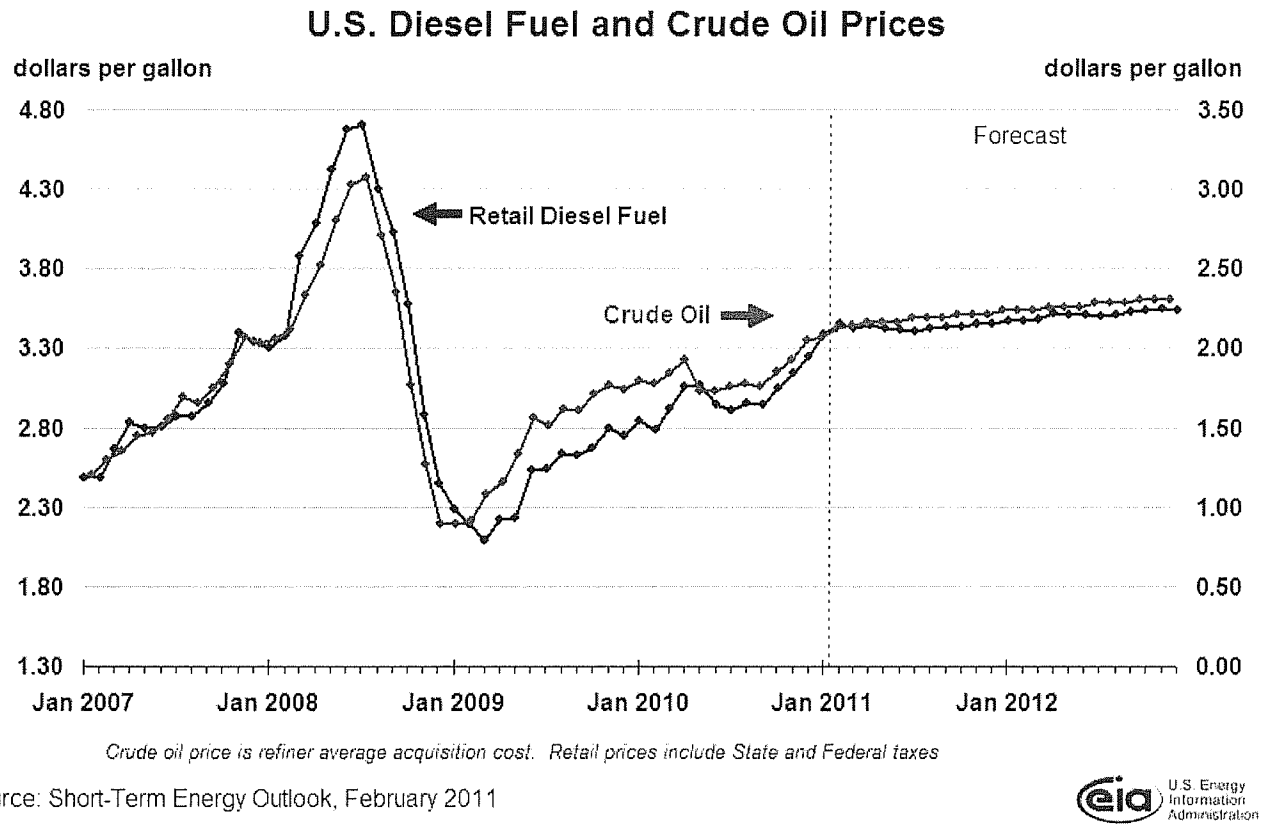
***U.S. Coal Prices.*** Coal prices have been rising relatively steadily over the last 10 years reflecting longer-term power sector coal contracts initiated during a period of high

energy prices, rising transportation costs, and increased consumption. However, EIA expects that the power sector coal price will show little change over 2011 and 2012 as coal competes with natural gas for market share in the power sector. The projected power sector-delivered coal price, which averaged $2.26 per MMBtu in 2010, averages $2.23 per MMBtu in both 2011 and 2012.

**U.S. Carbon Dioxide Emissions**

EIA estimates that fossil-fuel $CO_2$ emissions increased by 3.6 percent in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). Coal- and natural gas-related $CO_2$ emissions rose as a result of increased usage of both fuels for electricity generation and higher consumption of natural gas in the industrial sector.

Projected increases for consumption of petroleum--primarily in the transportation sector--and natural gas are offset by declines in coal consumption in the electric power sector in 2011. As a result, forecast fossil-fuel $CO_2$ emissions remain relatively flat in 2011. The forecast resumption of growth in electricity generation and improvement in economic growth in 2012 contribute to a 2.0-percent increase in fossil-fuel $CO_2$ emissions. Projected fossil-fuel $CO_2$ emissions in 2012 remain below the levels seen since 1999 and 4.3 percent below 2005 emissions.

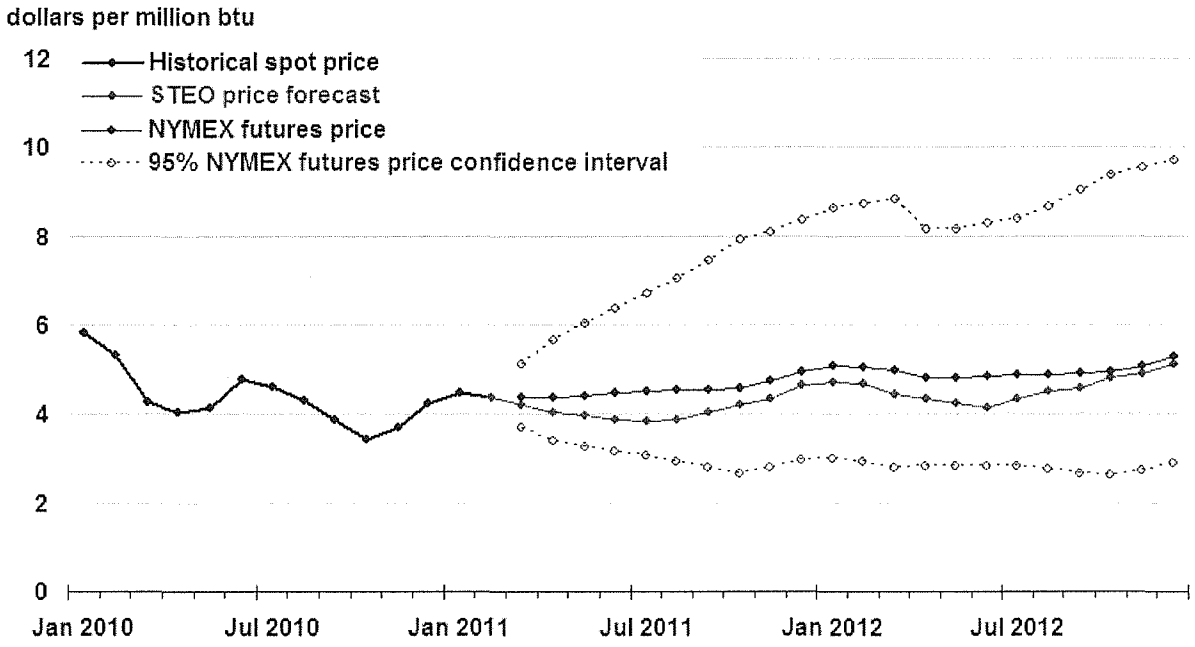



*Crude oil price is refiner average acquisition cost. Retail prices include State and Federal taxes*

Source: Short-Term Energy Outlook, February 2011

U.S. Energy Information Administration

# Henry Hub Natural Gas Price



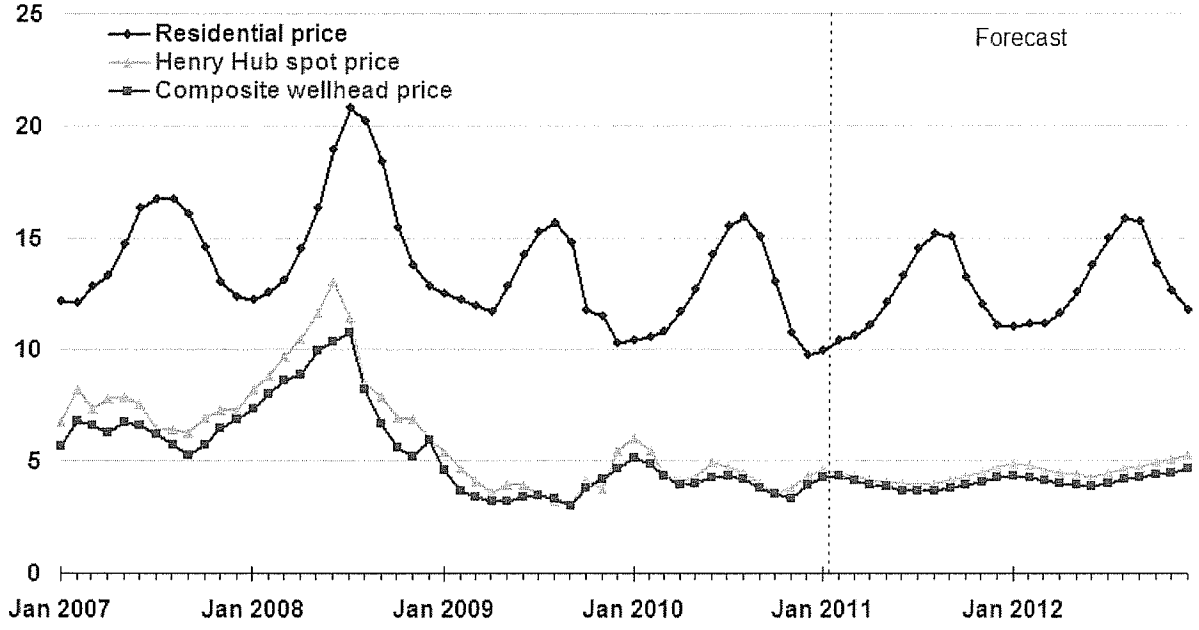

*Note: Confidence interval derived from options market information for 5 trading days ending February 3, 2011*
*Intervals not calculated for months with sparse trading in "near-the-money" options contracts*

Source: Short-Term Energy Outlook, February 2011

U.S. Energy Information Administration

# Natural Gas Prices

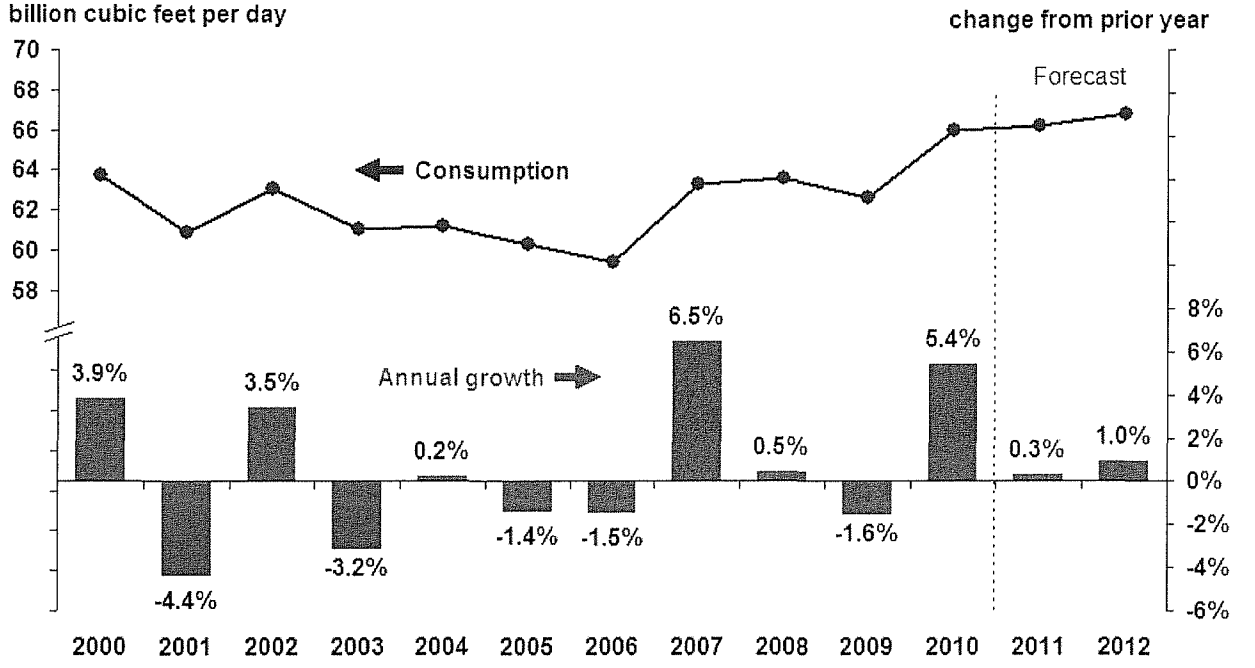
dollars per thousand cubic feet




Source: Short-Term Energy Outlook, February 2011

U.S. Energy Information Administration

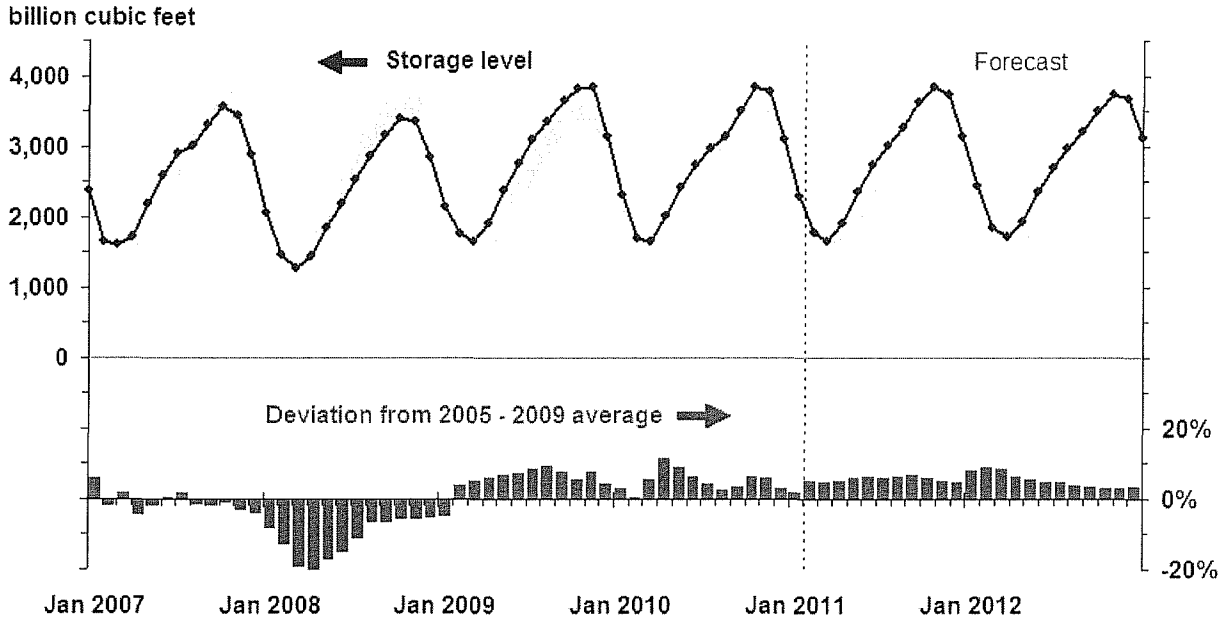
# U.S. Total Natural Gas Consumption




Source: Short-Term Energy Outlook, February 2011

U.S. Energy Information Administration

# U.S. Working Natural Gas in Storage




*Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2006 - Dec. 2010*

Source: Short-Term Energy Outlook, February 2011

U.S. Energy Information Administration

**GREAT PLAINS NATURAL GAS 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 Mcf Sales | Adjustment Per Mcf | Total Adjustment Amount | Net Change-Additions less Adjustment | Cumulative Balance |
|---|---|---|---|---|---|---|---|---|---|
| **Balance @ April 30, 2010** | | | | | | | | | **$114,988** |
| May | $29,734 | $0 | $723 | $30,457 | 12,466 | $0.2343 | $2,921 | $27,536 | 142,524 |
| June | 11,277 | 0 | 917 | 12,194 | 8,311 | 0.3941 | 2,356 2/ | 9,838 | 152,362 |
| July | 20,585 | 0 | 982 | 21,567 | 6,200 | 0.3941 | 2,444 | 19,123 | 171,485 |
| August | 86,747 | 0 | 1,115 | 87,862 | 5,953 | 0.3941 | 2,347 | 85,515 | 257,000 |
| September | 92,220 | 0 | 1,725 | 93,945 | 6,368 | 0.3941 | 2,509 | 91,436 | 348,436 |
| October | 34,666 | 0 | 2,373 | 37,039 | 8,070 | 0.3941 | 3,181 | 33,858 | 382,294 |
| November | 23,805 | 0 | 2,602 | 26,407 | 17,808 | 0.3941 | 7,018 | 19,389 | 401,683 |
| December | (6,120) | 0 | 2,728 | (3,392) | 38,100 | 0.3941 | 15,015 | (18,407) | 383,276 |
| January 2011 | (60,299) | 0 | 2,587 | (57,712) | 47,283 | 0.3941 | 18,633 | (76,345) | 306,931 |
| **Balance @ January 31, 2011** | | | | | | | | | **$306,931** |

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 5,750.5 dk @ $0.2343 and 2,560.2 dk @ $0.3941.

**GREAT PLAINS NATURAL GAS 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 Mcf Sales | Adjustment Per Mcf | Total Adjustment Amount | Net Change-Additions less Adjustment | Cumulative Balance |
|---|---|---|---|---|---|---|---|---|---|
| **Balance @ April 30, 2010** | | | | | | | | | **($30,590)** |
| May | $576 | $0 | ($199) | $377 | 10,944 | ($0.7419) | ($8,120) | $8,497 | (22,093) |
| June | (8,617) | 0 | (146) | (8,763) | 11,808 | (0.1136) | (6,678) 2/ | (2,085) | (24,178) |
| July | (8,501) | 0 | (169) | (8,670) | 10,612 | (0.1136) | (1,205) | (7,465) | (31,643) |
| August | (1,507) | 0 | (224) | (1,731) | 9,466 | (0.1136) | (1,075) | (656) | (32,299) |
| September | 422 | 0 | (230) | 192 | 13,953 | (0.1136) | (1,585) | 1,777 | (30,522) |
| October | 4,873 | 0 | (219) | 4,654 | 26,958 | (0.1136) | (3,062) | 7,716 | (22,806) |
| November | 4,335 | 0 | (170) | 4,165 | 36,122 | (0.1136) | (4,104) | 8,269 | (14,537) |
| December | 6,272 | 0 | (119) | 6,153 | 29,056 | (0.1136) | (3,301) | 9,454 | (5,083) |
| January 2011 | (971) | 0 | (58) | (1,029) | 17,350 | (0.1136) | (1,971) | 942 | (4,141) |
| **Balance @ January 31, 2011** | | | | | | | | | **($4,141)** |

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 8,493.0 dk @ ($0.7419) and 3,315.3 dk @ ($0.1136).