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

705 West Fir Ave.
PO Box 176
Fergus Falls, MN 56538-0176
(218) 736-6935

March 31, 2011

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

Re: Cost of Gas Adjustment (COG)
April 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 (61st Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (61st Revised Sheet No. 8), showing the April 2011 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $0.6944 per mcf for residential and firm general service customers and $0.1345 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for April 2011, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $0.1345 per mcf since the last COG filing due to an increase in the market price of gas. There has been an increase in pipeline charges of $0.5599 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of $0.6944 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
61st Revised Sheet No. 1.1
Canceling 60th 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 | $8.6282 | $9.9022 |
| | | | Over 10 MCF | 1.0540 | | 9.6822 |
| Interruptible Gas Service - General | 3 | $3.50 per month | First 400 MCF | $1.1391 | $3.9247 | $5.0638 |
| | | | Next 2,600 MCF | 0.8931 | | 4.8178 |
| | | | Over 3,000 MCF | 0.7411 | | 4.6658 |
| Interruptible Gas Service - Grain Processing | 4 | $3.50 per month | All MCF | $1.2391 | $3.9247 | $5.1638 |
| 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:** March 31, 2011

**Effective Date:** April 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
61st Revised Sheet No. 8
Canceling 60th 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. | 3.5846 | (1.2298) | 0.3941 | 2.7489 | (1.2153) | (0.1136) | (1.3289) |
| Current Adj. | 0.5599 | 0.1345 | 0.0000 | 0.6944 | 0.1345 | 0.0000 | 0.1345 |
| Total Adj. | 4.1445 | (1.0953) | 0.3941 | 3.4433 | (1.0808) | (0.1136) | (1.1944) |
| Total Rate: | $4.2103 | $4.0238 | $0.3941 | $8.6282 | $4.0383 | ($0.1136) | $3.9247 |

**Date Filed:** March 31, 2011 **Effective Date:** April 1, 2011

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

**Case No.:**

**GREAT PLAINS NATURAL GAS CO.**
**WAHPETON**
**COST OF GAS ADJUSTMENT**
**APRIL 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 | | 17.3762 | 12 | 1,657,064 | 1.1830 |
| Trans Canada - Demand Charge | 7,947 | | 23.7361 | 12 | 2,263,569 | 1.6159 |
| BP Canada - Demand Charge | 7,947 | | 0.9612 | 12 | 91,664 | 0.0654 |
| NOVA - Seasonal | 5,068 | | 17.3762 | 5 | 440,313 | 0.3143 |
| Trans Canada - Seasonal | 5,068 | | 23.7361 | 5 | 601,473 | 0.4294 |
| 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 | | | | | $5,877,423 | 4.2103 |
| Estimated Weighted Average Commodity Cost | 1,400,774 | 1/ | 4.0238 | | 5,636,434 | 4.0238 |
| Gas Cost Reconciliation Adjustment | | | | | | 0.3941 |
| Total Current Firm Gas Cost | | | | | $11,513,857 | 8.6282 |
| Base Cost of Gas | | | | | | 5.1849 |
| Accumulated Adjustment | | | | | | $3.4433 |

| Interruptible | |
|---|---|
| Estimated Weighted Average Commodity Cost | $4.0238 |
| Gas Cost Reconciliation Adjustment | (0.1136) |
| LMS Demand 2/ | 0.0145 |
| Total Current Interruptible Gas Cost | 3.9247 |
| Base Cost of Gas | 5.1191 |
| Accumulated Adjustment | ($1.1944) |

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**
**APRIL 2011**

| **Rates Effective April 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 | 17.3762 | Per dk/Mo. |
| Trans Canada Pipeline Demand Charge | 23.7361 | Per dk/Mo. |
| BP Canada - Demand Charge | 0.9612 | Per dk/Mo. |
| NOVA - Seasonal | 17.3762 | Per dk/Day |
| Trans Canada - Seasonal | 23.7361 | 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: | 4.0238 | 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 | 1.47% |
| Zone 1-2 | $0.0130 | $0.0019 | $0.0149 | 1.98% |
| Zone 2-2 | $0.0130 | $0.0019 | $0.0149 | 0.51% |
| Minimum Rate | $0.0130 | $0.0019 | $0.0149 | |
| IT and AOT | | | | |
| Zone 1-1 | $0.1368 | $0.0019 | $0.1387 | 1.47% |
| Zone 1-2 | $0.1737 | $0.0019 | $0.1756 | 1.98% |
| Zone 2-2 | $0.0834 | $0.0019 | $0.0853 | 0.51% |
| 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: 0.17% for Zone 1-1, 0.22 % for Zone 1-2, and 0.05% 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 | | $0.0265 | |

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 |

Northern Natural Gas Company
FERC Gas Tariff
Sixth Revised Volume No. 1

Second Revised Sheet No. 50
Superseding
First Revised Sheet No. 50

RATE SCHEDULE TF

| RESERVATION RATES | MARKET-TO-MARKET TF12 Base | MARKET-TO-MARKET TF12 Variable | MARKET-TO-MARKET TF5 | FIELD-TO-FIELD/MARKET DEMARCATION 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 | 0.0383 | 0.0214 | | | 0.0175 | 0.0000 | 0.0383 | 0.0214 |
| Field | Market | 0.0383 | 0.0214 | 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 $0.0005 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.

Northern Natural Gas Company
FERC Gas Tariff
Sixth Revised Volume No. 1

Second Revised Sheet No. 51
Superseding
First Revised Sheet No. 51

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 | 0.0383 | 0.0214 | | | 0.0175 | 0.0000 | 0.0383 | 0.0214 |
| Field | Market | 0.0383 | 0.0214 | 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 $0.0005 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**
**April 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 April monthly price for the AECO Index is expected to increase slightly 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).

Winter weather continued over much of the lower 48 states necessitating gas usage to meet space heating demand contributing to the expected increase in the index price. The year over year comparison indicates the anticipated April AECO price will be approximately equal to the previous April index price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of March 18, 2011 were 2.2 percent above the five-year average and 0.7 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 14.


*Independent Statistics & Analysis*
U.S. Energy Information Administration

# Short-Term Energy Outlook

March 2011

March 8, 2011 Release

## Highlights

- West Texas Intermediate (WTI) and other crude oil spot prices have risen about $15 per barrel since mid-February partly in response to the disruption of crude oil exports from Libya. Continuing unrest in Libya as well as other North African and Middle Eastern countries has led to the highest crude oil prices since 2008. As a result, EIA has raised its forecast for the average cost of crude oil to refiners to $105 per barrel in 2011, $14 higher than in the previous *Outlook*. However, EIA has raised its 2011 forecast for WTI by only $9 per barrel to $102 per barrel because of the projected continued price discount for this type of crude compared with other crudes. EIA projects a further small increase in crude oil prices in 2012, with the refiner acquisition cost for crude oil averaging $106 per barrel and WTI averaging $105 per barrel. EIA's forecast assumes U.S. real gross domestic product (GDP) grows 3.3 percent in 2011 and 2.8 percent in 2012, while world real GDP (weighted by oil consumption) grows by 3.8 percent and 3.7 percent in 2011 and 2012, respectively.

- The recent rapid increase in spot crude and gasoline prices has led to a significant rise in retail product prices. Motorists currently experiencing a jump in pump prices will likely see further increases from now through the spring since the recent increase in crude oil prices has not yet been fully passed through to gasoline prices. EIA expects the retail price of regular-grade motor gasoline to average $3.56 per gallon in 2011, 77 cents per gallon higher than the 2010 average and about 40 cents above the projected price in the previous *Outlook*. EIA projects gasoline prices to average about $3.70 per gallon during the peak driving season (April through September) with considerable regional and local variation. There is also significant uncertainty surrounding the forecast, with the current market prices of futures and options contracts for gasoline suggesting a 25-percent probability that the national monthly average retail price for regular gasoline could exceed $4.00 per gallon during summer 2011. Rising crude oil prices are the primary reason for higher retail prices, but higher refining margins are also expected to be a contributing factor.

- EIA estimates that natural gas working inventories ended February 2011 at 1.7 trillion cubic feet (Tcf), slightly below the 2010 end-of-February level. Inventories are expected to remain relatively high through 2011. The projected Henry Hub natural gas spot price averages $4.10 per million Btu (MMBtu) in 2011, $0.29 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.

## Global Crude Oil and Liquid Fuels

*Crude Oil and Liquid Fuels Overview.* EIA expects continued tightening of world oil markets over the next two years, particularly in light of the recent events in North Africa and the Middle East, the world's largest oil producing region. The current situation in Libya increases oil market uncertainty because, according to various reports, much of the country's 1.8-million bbl/d total liquids production has been shut in and it is unclear how long this situation will continue. The market remains concerned that the unrest in the region could continue to spread.

The forecast for total world oil consumption grows by an annual average of 1.6 million bbl/d through 2012. Supply from non-Organization of the Petroleum Exporting Countries (non-OPEC) countries grows about 0.2 million bbl/d this year, then falls slightly in 2012. Consequently, EIA expects that 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 projected world demand growth. Onshore commercial oil inventories in the Organization for Economic Cooperation and Development (OECD) countries remained high in 2010, but floating oil storage fell sharply. EIA expects that OECD oil inventories will decline to the lower bound of the previous 5-year range by the end of 2012.

There are many reasons for market uncertainty that could push oil prices higher or lower than current expectations. Among the uncertainties are: the continued unrest in producing countries and its potential impact on supply; decisions by key OPEC member countries regarding their production response to the global recovery in oil demand and recent supply losses; 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.

*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 reductions in demand during the prior two years and surpassed the 2007

consumption level of 86.3 million bbl/d. EIA expects that world liquid fuels consumption will grow by 1.5 million bbl/d in 2011 and by an additional 1.7 million bbl/d in 2012. Non-OECD countries will make up almost all of the growth in consumption over the next 2 years, with the largest demand increases coming from China, Brazil, and the Middle East. EIA expects that, among the OECD regions, only North America will show growth in oil consumption over the next two years, offsetting declines in OECD Europe and Asia.

*Non-OPEC Supply.* EIA projects that non-OPEC crude oil and liquid fuels production will increase by 170,000 bbl/d in 2011, then decline slightly in 2012. Increases in non-OPEC oil production during 2011 will be concentrated in a few countries, particularly China and Brazil, where EIA expects annual average production growth of 140,000 and 170,000 bbl/d, respectively. In 2012, EIA expects Canadian production growth to average 170,000 bbl/d while China and Brazil grow by 140,000 and 110,000 bbl/d, respectively. Other non-OPEC production is expected to decline. EIA expects that Mexico's production will fall by about 220,000 bbl/d in 2011, followed by a further decline of 80,000 bbl/d in 2012. Similarly, production from the North Sea will fall by 210,000 bbl/d and 170,000 bbl/d in 2011 and 2012, respectively. EIA expects the former Soviet Union republics to increase production by 320,000 bbl/d in 2011, followed by a production decrease of 180,000 bbl/d in 2012 mainly driven by decreases in Russia, whose West Siberian fields are expected to decline significantly. Projected U.S. crude oil and liquid fuels production declines by 100,000 bbl/d in 2011 and by a further 160,000 bbl/d in 2012.

*OPEC Supply.* EIA expects that lost crude oil production from Libya will be made up for by both drawdown of inventories and increases in production from other OPEC countries. Forecast OPEC crude oil and non-crude liquids production increase by 0.1 million bbl/d and by 0.7 million bbl/d in 2011, respectively. Continuing growth in global demand for oil and limited growth in supplies originating from non-OPEC countries contribute to an increase in OPEC crude oil production of 1.9 million bbl/d in 2012. EIA expects growth in OPEC non-crude liquids production to slow to 0.3 million bbl/d in 2012. EIA has revised its projected OPEC surplus capacity downward, compared with the last *Outlook*, as assumptions underlying these projections changed in light of the unrest in Libya. As a result, EIA projects that OPEC surplus capacity will fall from an average 4.4 million bbl/d in 2010 to 4.1 million bbl/d in 2011, followed by a further decline to 3.1 million bbl/d in 2012.

*OECD Petroleum Inventories.* Onshore commercial oil inventories in the OECD countries remained high in 2010, but reports indicate that floating oil storage fell sharply. EIA expects that OECD onshore inventories will decline over the forecast period. Projected OECD stocks fall by about 111 million barrels in 2011, followed by

an additional 38 million barrel decline in 2012. Days of supply (total inventories divided by average daily consumption) drops from a relatively high 57 days at the end of 2010 to 55 days by the end of 2011, which is close to the middle of the previous 5-year range.

*Crude Oil Prices.* WTI crude oil spot prices averaged $88.58 per barrel in February, slightly lower than the January average, while over the same time period the estimated average cost of all crude oil to U.S. refineries increased by about $4.50 per barrel to $92.50. 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 $105 per barrel in December 2011 and remain at about that level through 2012.

Energy price forecasts are particularly uncertain (Energy Price Volatility and Forecast Uncertainty). WTI futures for May 2011 delivery over the 5-day period ending March 3 averaged $101 per barrel and implied volatility averaged 36 percent. This makes the lower and upper limits of the 95-percent confidence interval $79 per barrel and $129 per barrel, respectively. Last year at this time, WTI for May 2010 delivery averaged $80 per barrel with the limits of the 95-percent confidence interval at $65 per barrel and $99 per barrel. Based on WTI futures and options prices, the probability that the monthly average price of WTI crude oil will exceed $110 per barrel in December 2011 is about 36 percent. Conversely, the probability that the monthly average December 2011 WTI price will fall below $90 per barrel is about 34 percent.

## U.S. Crude Oil and Liquid Fuels

*U.S. Liquid Fuels Consumption.* Total consumption of petroleum and non-petroleum liquid fuels increased by 380,000 bbl/d (2.0 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 160,000 bbl/d (4.5 percent), and motor gasoline, which increased by 40,000 bbl/d (0.4 percent). Projected total U.S. liquid fuels consumption increases by 130,000 bbl/d (0.7 percent) in 2011, and by a further 190,000 bbl/d (1.0 percent), to 19.5 million bbl/d, in 2012. As in 2010, 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 110,000 bbl/d in 2011 and by a further 130,000 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 10,000 bbl/d in 2012 because of maturing Alaskan oil fields. EIA expects production from the Federal Gulf of Mexico (GOM) to fall by 240,000 bbl/d in 2011 and by a further 200,000 bbl/d in 2012. These production declines in Alaska and the GOM are partially offset by projected increases in lower-48 non-GOM production of 190,000 bbl/d and 70,000 bbl/d in 2011 and 2012, respectively.

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 9.7 million bbl/d in 2011 and 10.0 million bbl/d in 2012, comprising 50 percent and 52 percent of total consumption, respectively.

EIA expects slow growth in fuel ethanol production over the next 2 years. Ethanol production increases by a projected 40,000 bbl/d, to 900,000 bbl/d in 2011, followed by an additional 10,000 bbl/d increase in 2012.

***U.S. Petroleum Product Prices.*** Projected regular-grade gasoline retail prices rise from a national average of $2.78 per gallon in 2010 to $3.56 per gallon in 2011 and $3.57 per gallon in 2012, although there is considerable variation within and between regions. The forecast for on-highway diesel fuel retail prices, which averaged $2.99 per gallon in 2010, averages $3.81 per gallon and $3.82 per gallon in 2011 and 2012, respectively.

The projected monthly average regular gasoline price peaks this year at $3.75 per gallon in June. New York Harbor RBOB (reformulated gasoline blendstock for oxygenate blending) futures contracts for July 2011 delivery over the 5-day period ending March 3 averaged $2.97 per gallon and implied volatility averaged 33 percent. The probability the RBOB futures price will exceed $3.30 per gallon (consistent with a U.S. average regular gasoline retail price above $4 per gallon) in July 2011 is about 25 percent.

## Natural Gas

***U.S. Natural Gas Consumption.*** EIA expects that total 2011 natural gas consumption will remain close to 2010 levels. Forecast residential and commercial consumption in 2011 should be lower than reported 2010 levels by 1.2 percent and 2.7 percent, respectively, reflecting 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*) that were implemented in the middle of 2010 to provide more accurate data on seasonal patterns of natural gas use. Industrial

consumption rises from 18.1 billion cubic feet per day (Bcf/d) in 2010 to 18.8 Bcf/d in 2011 as the natural-gas-weighted industrial production index increases 4.0 percent year-over-year.

Total consumption grows 1.0 percent in 2012, from 66.6 Bcf/d to 67.2 Bcf/d. Increases in natural gas consumption in the electric power sector and the industrial sector are partially offset by slight declines in residential and commercial consumption. EIA expects electric power sector and industrial sector consumption in 2012 to grow by 2.8 percent and 1.5 percent, respectively.

***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 63.8 Bcf/d in December. Year-over-year growth in 2011 slows 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 0.5 Bcf/d in the GOM.

The latest EIA data for monthly natural gas production in the *Natural Gas Monthly* show an increase in production in the lower-48 States in December 2010, continuing an increase from the previous month. However, modest declines are expected through 2011 because of a falling gas-directed drilling rig count in response to lower prices. The number of rigs drilling for natural gas, as reported by Baker Hughes Inc., increased from a low of 665 in July 2009 to 973 in April 2010. The natural gas rig count stayed relatively unchanged from April through October 2010. However, since October 2010 the rig count has fallen, dropping to 906 rigs as of February 25. 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 in 2012, led by strong growth in the electric power sector, contributes to higher prices and to an economic incentive for producers to resume drilling. Total domestic natural gas production increases by 0.9 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. Federal GOM production remains flat in 2012.

EIA expects gross pipeline imports of 8.4 Bcf/d in 2011 and 8.2 Bcf/d in 2012, year-over-year decreases of 5.6 and 2.3 percent, respectively. Projected imports of liquefied natural gas (LNG) average 1.2 Bcf/d in 2011, a 3-percent decrease from 2010 levels. LNG imports in 2012 remain relatively flat. High domestic production combined with 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 February 25, 2011, working natural gas in storage stood at 1,745 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 1,549 Bcf of working natural gas will remain in storage, a downward revision of about 102 Bcf from last month's *Outlook*. Cold temperatures and production freeze-offs in February contributed to a larger-than-expected draw on inventories. EIA expects that inventories, though somewhat below their 2010 levels for the first half of the year, still will remain relatively robust. Slower growth in 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 $4.09 per MMBtu in February 2011, $0.40 per MMBtu less than the average spot price in January 2011 (Henry Hub Natural Gas Price Chart). EIA expects that the Henry Hub spot price will average $4.10 per MMBtu in 2011, a drop of $0.29 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 May 2011 delivery (for the 5-day period ending March 3) averaged $3.98 per MMBtu, and the average implied volatility over the same period was 33 percent. This produced lower and upper bounds for the 95-percent confidence interval for May 2011 contracts of $3.09 per MMBtu and $5.11 per MMBtu, respectively. At this time last year, the natural gas May 2010 futures contract averaged $4.77 per MMBtu and implied volatility averaged 39 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $3.57 per MMBtu and $6.39 per MMBtu.

## Electricity

*U.S. Electricity Consumption.* EIA expects an increase of 0.5 percent in total U.S. consumption of electricity during 2011 (U.S. Total Electricity Consumption Chart). Retail sales of electricity to the residential sector this year will fall 1.7 percent in response to the assumed 16-percent decline in cooling degree-days compared to the hot summer of 2010. During 2012, total U.S. electricity consumption should grow by 2.0 percent. EIA projects that retail sales of electricity to the residential sector will grow by 1.8 percent in 2012, while electricity sales to the commercial and industrial sectors grow by 2.3 and 2.0 percent, respectively.

*U.S. Electricity Generation.* EIA projects that total generation by the electric power sector will increase slightly during 2011, rising by 24 gigawatthours per day (0.2

percent) (U.S. Electric Power Sector Generation Growth Chart). Preliminary estimates by EIA indicate that wind power capacity grew by at least 3,657 megawatts during 2010, which is the lowest capacity addition since 2006. Capacity is expected to grow at a similar pace this year, boosting wind generation by 43 gigawatthours per day (16 percent) during 2011. During 2012, EIA expects a 2.1-percent increase in total electric power sector generation, fueled primarily by increased coal and natural gas generation.

***U.S. Electricity Retail Prices.*** During 2010, retail prices for electricity distributed to the residential sector averaged 11.58 cents per kilowatthour, about the same level as in 2009. EIA expects residential prices to rise by 1.0 percent in 2011, followed by an increase of 0.5 percent in 2012 (U.S. Residential Electricity Prices Chart). The effect of lower generation fuel costs in 2011 should be more evident in retail prices for electricity distributed to the industrial sector, which EIA projects will fall 1.6 percent during 2011 and then rise 0.2 percent next year.

## 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 during the hot summer. EIA projects that coal consumption in the electric power sector will increase only slightly in 2011, as slow growth in power demand and increases in generation from hydropower and wind power reduce the need for coal-fired generation. In 2012, coal consumption in the electric power sector grows by 2.6 percent (U.S. Coal Consumption Growth Chart).

***U.S. Coal Supply.*** Coal production in 2010 grew by only 1 percent despite the nearly 5-percent increase in total 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). EIA projects that coal production in 2011 will increase just slightly as total coal consumption shows little change (U.S. Annual Coal Production Chart). The projected increase in coal consumption in 2012 leads to a forecast 3.3-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. Metallurgical coal exports nearly doubled in the first three-quarters of 2010 compared with the same period of 2009, and metallurgical coal's share of total coal exports has grown from 52 percent in 2008 to 69 percent in 2010. Supply disruptions in several key coal exporting countries (Australia, Colombia, Indonesia, and South Africa) have greatly affected the amount of coal available on the world market. Consequently, EIA expects U.S. coal

exports to increase by 7.7 percent in 2011. In 2012, U.S. coal exports are forecast to fall back to more recent levels (about 80 million short tons) as supply from other major coal-exporting countries recovers.

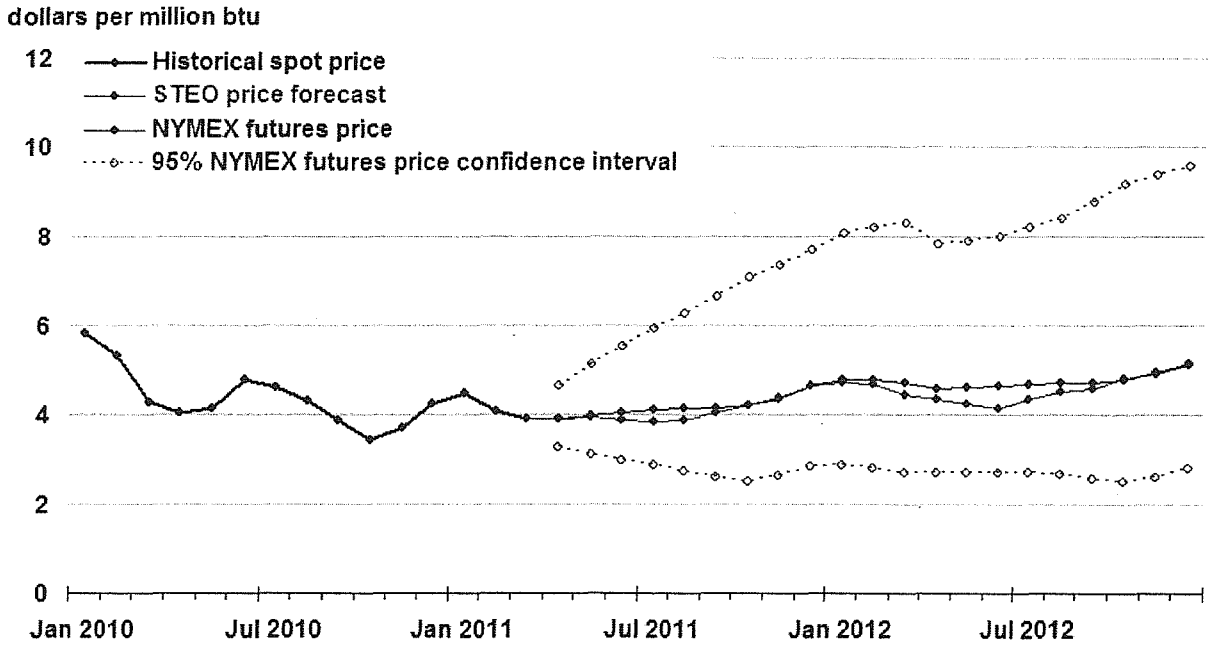
*U.S. Coal Prices.* Coal prices have been rising relatively steadily over the last 10 years, reflecting longer-term power sector coal contracts initiated during a period of high energy prices, rising transportation costs, and increased consumption. However, EIA expects that the power sector coal price will decline slightly in 2011 and 2012 as coal competes with natural gas for market share. The projected power sector delivered coal price, which averaged $2.26 per MMBtu in 2010, averages $2.23 per MMBtu and $2.21 per MMBtu in 2011 and 2012, respectively.

## U.S. Carbon Dioxide Emissions

EIA estimates that fossil-fuel $CO_2$ emissions increased by 3.7 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.

Forecast fossil-fuel $CO_2$ emissions remain relatively flat in 2011, as projected increases in consumption of petroleum, primarily in the transportation sector, and natural gas, primarily in the industrial sector, offset declines in natural gas consumption in both the residential and commercial sectors in 2011. The expected resumption of growth in electricity generation and the improvement in economic growth in 2012 contribute to a 1.8-percent increase in fossil-fuel $CO_2$ emissions.

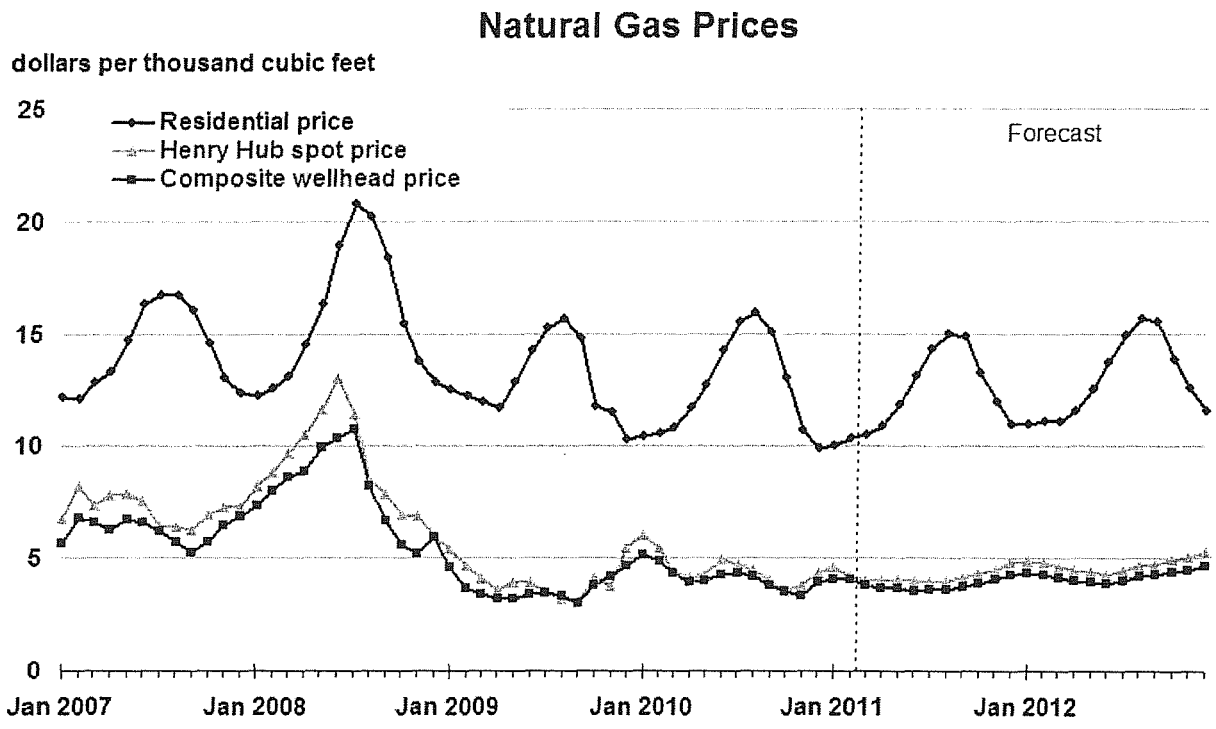
# Henry Hub Natural Gas Price




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

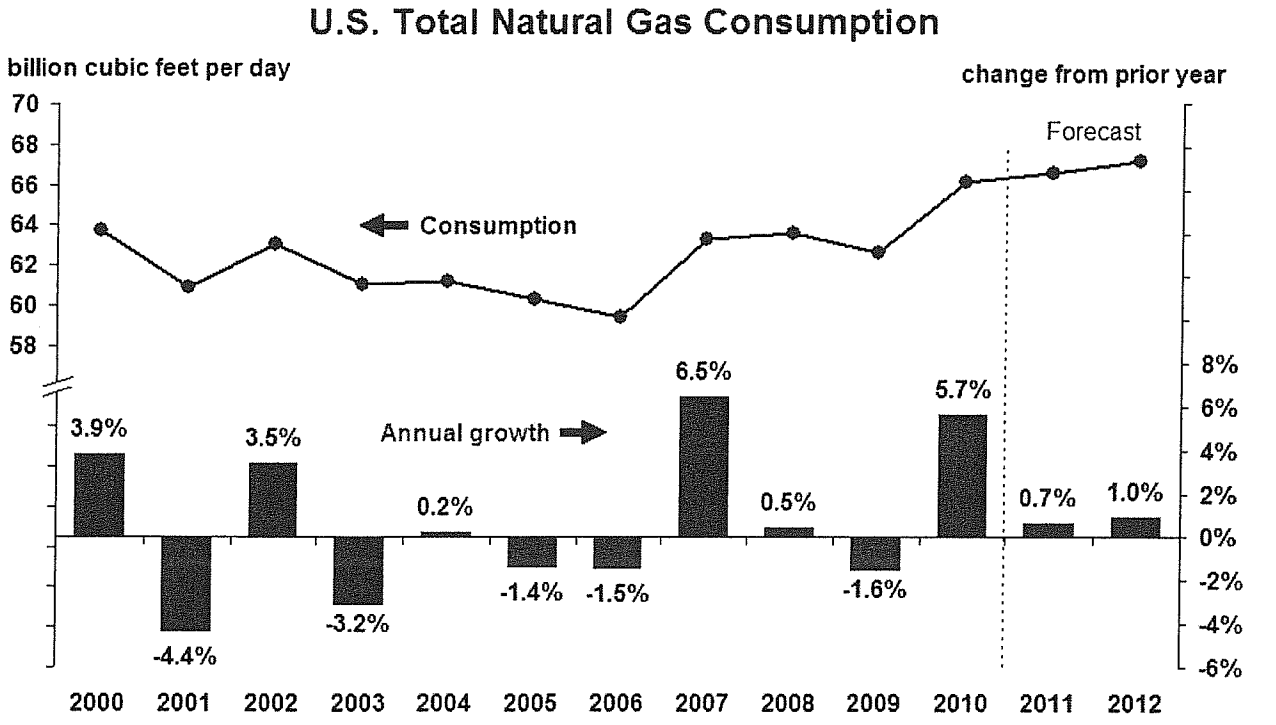
Source: Short-Term Energy Outlook, March 2011

eia



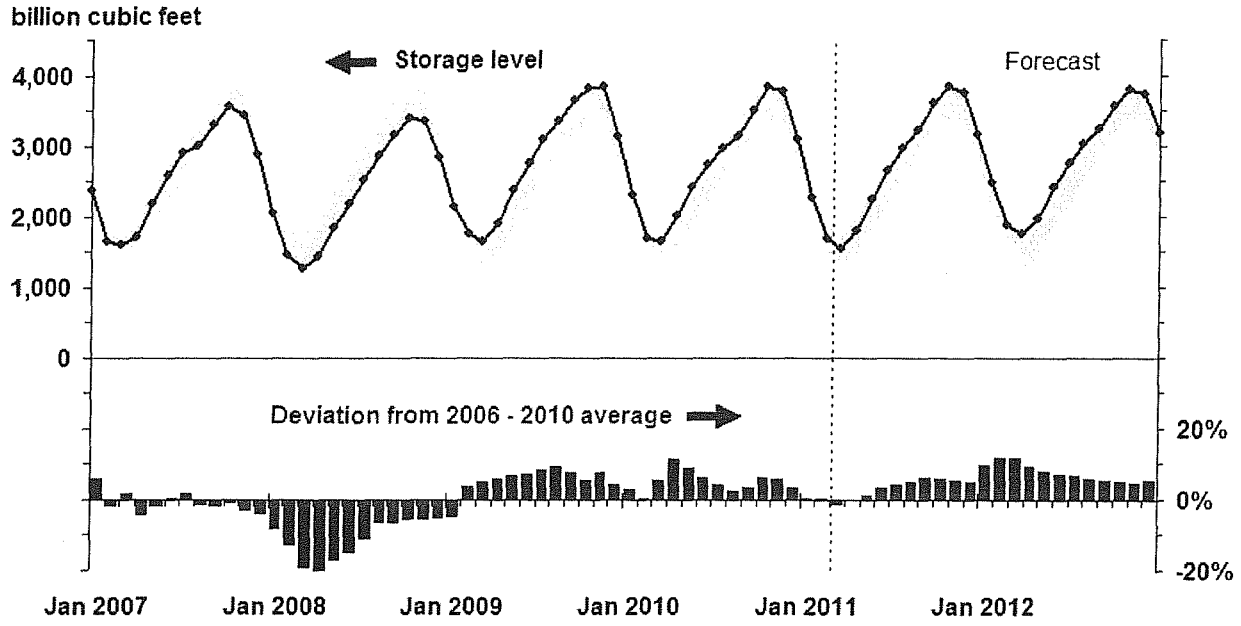

Source: Short-Term Energy Outlook, March 2011

eia




Source: Short-Term Energy Outlook, March 2011

# 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, March 2011

eia

**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 |
| February | (63,560) | 0 | 2,033 | (61,527) | 48,059 | 0.3941 | 18,940 | | (80,467) | 226,464 |
| **Balance @ February 28, 2011** | | | | | | | | | | **$226,464** |

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) |
| February | 3,038 | 0 | (56) | 2,982 | 28,670 | (0.1136) | (3,257) | 6,239 | 2,098 |
| **Balance @ February 28, 2011** | | | | | | | | | **$2,098** |

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).