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

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September 30, 2014

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

Re: Cost of Gas Adjustment (COG)
October 2014

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and two (2) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (103rd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (103rd Revised Sheet No. 8), showing the October 2014 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an decrease of $0.0637 per Dk for residential and firm general service customers and an decrease of $0.0637 per Dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for October 2014, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.0637 per Dk for all customers since the last COG filing due to an decrease in the market price of gas.

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, 2014.

Great Plains submitted a check for $600.00 on January 2, 2014 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,

Tamie A. Aberle
Director of Regulatory Affairs

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

103rd Revised Sheet No. 1.1

**RATE SUMMARY SHEET**

Canceling 102nd Revised Sheet No.1.1



| Rate Schedule | Sheet No. | Basic Service Charge | Distribution Delivery Charge | | COG Items | Total Rate/dk |
|---|---|---|---|---|---|---|
| Firm Gas Service - General | 2 | $3.50 per month | First 10 dk | $1.2869 | $6.8844 | $8.1713 |
| | | | Over 10 dk | 1.0646 | | 7.9490 |
| Interruptible Gas Service - General | 3 | $3.50 per month | First 400 dk | $1.1506 | $5.0111 | $6.1617 |
| | | | Next 2,600 dk | 0.9021 | | 5.9132 |
| | | | Over 3,000 dk | 0.7486 | | 5.7597 |
| Interruptible Gas Service - Grain Processing | 4 | $3.50 per month | All dk | $1.2516 | $5.0111 | $6.2627 |
| Transportation Service | 5 | $3.50 per month | First 400 dk | $1.1506 | | $1.1506 |
| | | | Next 2,600 dk | 0.9021 | | 0.9021 |
| | | | Over 3,000 dk | 0.7486 | | 0.7486 |

**Date Filed:** September 30, 2014

**Effective Date:** Service rendered on and after October 1, 2014

**Issued By:** Tamie A. Aberle
Director - Regulatory Affairs

**Case No.:**

# GREAT PLAINS NATURAL GAS CO.

*A Division of MDU Resources Group, Inc.*

## State of North Dakota
## Gas Rate Schedule

NDPSC Volume 2
103rd Revised Sheet No. 8
Canceling 102nd 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 | $0.0662 | $5.1708 | $0.0000 | $5.2370 | $5.1708 | $0.0000 | $5.1708 |
| Accumulated Adj. | 1.4450 | (1.0801) | 1.3462 | 1.7111 | (1.0656) | 0.9696 | (0.0960) |
| Current Adj. | 0.0000 | (0.0637) | 0.0000 | (0.0637) | (0.0637) | 0.0000 | (0.0637) |
| Total Adj. | 1.4450 | (1.1438) | 1.3462 | 1.6474 | (1.1293) | 0.9696 | (0.1597) |
| Total Rate | $1.5112 | $4.0270 | $1.3462 | $6.8844 | $4.0415 | $0.9696 | $5.0111 |

**Date Filed:** September 30, 2014

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**Issued By:** Tamie A. Aberle
Director - Regulatory Affairs

**Case No.:**

**GREAT PLAINS NATURAL GAS CO.**
**WAHPETON**
**COST OF GAS ADJUSTMENT**
**OCTOBER 2014**

| Firm | Billing Determinants | | Rate | Demand Months | Amount | Amount Per dk |
|---|---|---|---|---|---|---|
| FT-A - Zone 1-1 | 8,000 | | $3.3978 | 12 | $326,189 | $0.2315 |
| FT-A - Zone 1-1 | 5,000 | | 3.6918 | 5 | 92,295 | 0.0655 |
| FT-A Seasonal | 2,000 | | 3.6918 | 5 | 36,918 | 0.0262 |
| TFX Seasonal | 2,000 | | 15.1530 | 5 | 151,530 | 0.1075 |
| TFX - Winter | 13,000 | | 15.1530 | 5 | 984,945 | 0.6990 |
| TFX - Summer | 13,000 | | 5.6830 | 7 | 517,153 | 0.3670 |
| LMS Demand 2/ | | | | | | 0.0145 |
| Total Demand Charges | | | | | $2,109,030 | 1.5112 |
| Estimated Weighted Average Commodity Cost | 1,409,081 | 1/ | 4.0270 | | 5,674,369 | 4.0270 |
| Gas Cost Reconciliation Adjustment | | | | | | 1.3462 |
| Total Current Firm Gas Cost | | | | | $7,783,399 | 6.8844 |
| Base Cost of Gas | | | | | | 5.2370 |
| Accumulated Adjustment | | | | | | $1.6474 |

| Interruptible | |
|---|---|
| Estimated Weighted Average Commodity Cost | $4.0270 |
| Gas Cost Reconciliation Adjustment | 0.9696 |
| LMS Demand 2/ | 0.0145 |
| Total Current Interruptible Gas Cost | 5.0111 |
| Base Cost of Gas | 5.1708 |
| Accumulated Adjustment | ($0.1597) |

1/ Three year normalized average Dk sales
2/ Amount divided by 2011-2013 average normalized interruptible sales volumes plus 2011-2013 average normalized firm sales volumes.

| | Billing Determinants | Rate | Demand Months | Amount | Amount Per dk |
|---|---|---|---|---|---|
| LMS Demand | 2,500 | $0.9800 | 12 | $29,400 | $0.0145 |

**GREAT PLAINS NATURAL GAS CO.**
**WAHPETON**
**COST OF GAS ADJUSTMENT**
**OCTOBER 2014**

| **Rates Effective October 1, 2014** | $/Dk | |
|---|---|---|
| FT-A - Zone 1-1 (Category 1) | $3.6918 | Per Dk/Mo. |
| FT-A - Zone 1-1 (Category 3) | 3.3978 | Per Dk/Mo. |
| FT-A - Seasonal | 3.6918 | Per Dk/Mo. |
| TFX | 15.1530 | Per Dk/Mo. |
| TFX Seasonal | 15.1530 | Per Dk/Mo. |
| LMS Demand | 0.9800 | Per Dk/Mo. |
| Estimated Weighted Average Commodity Cost: | 4.0270 | Per Dk |

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

**Base Rate Calculation**

| Firm | | |
|---|---|---|
| Demand 2/ | $0.0662 | Per Dk |
| Commodity | 5.1708 | Per Dk |
| Total Firm Base Cost | $5.2370 | Per Dk |

| Interruptible: | | |
|---|---|---|
| Commodity | $5.1708 | Per Dk |

1/ The Firm Gas Base Cost is based on the FERC Gas Tariff, Third Revised Volume No. 1 of Midwestern Gas Transmission Company, effective July 1, 1981.

2/ Demand base rate calculation:

| | | | |
|---|---|---|---|
| Demand Charge | | 0.81 | Per MCF/Mo. |
| Convert mcf to dk | x | 0.99 | Therm Factor |
| | | 0.82 | Per Dk/Mo. |
| Capacity | x | 4,768 | |
| Months | x | 12 | |
| | | 46,814.13 | |
| Volumes | / | 707,222 | |
| | | 0.0662 | Per Dk |

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 | $3.6918 |
| Zone 1-1 Minimum Rate | $0.0000 |
| Zone 1-2 Maximum Rate | $4.7894 |
| Zone 1-2 Minimum Rate | $0.0000 |
| Zone 2-2 Maximum Rate | $2.0972 |
| 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 | $3.5448 |
| Zone 1-1 Minimum Rate | $0.0000 |
| Zone 1-2 Maximum Rate | $4.6424 |
| Zone 1-2 Minimum Rate | $0.0000 |
| Zone 2-2 Maximum Rate | $1.9502 |
| 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 | $3.3978 |
| Zone 1-1 Minimum Rate | $0.0000 |
| Zone 1-2 Maximum Rate | $4.4954 |
| Zone 1-2 Minimum Rate | $0.0000 |
| Zone 2-2 Maximum Rate | $1.8032 |
| Zone 2-2 Minimum Rate | $0.0000 |

| Rate Schedule | Base Tariff Rate | Fuel and Loss Retention Percentages 2/ |
|---|---|---|
| Commodity Rates 1/ | | |
| FT-A – Maximum Rates | | |
| Zone 1-1 | $0.0127 | 0.08% |
| Zone 1-2 | $0.0127 | 0.10% |
| Zone 2-2 | $0.0127 | 0.02% |
| Minimum Rate | $0.0127 | |
| IT and AOT | | |
| Zone 1-1 | $0.1341 | 0.08% |
| Zone 1-2 | $0.1702 | 0.10% |
| Zone 2-2 | $0.0816 | 0.02% |
| Minimum Rate | $0.0127 | |

1/ Pursuant to Section 19 of the General Terms and Conditions, the maximum and minimum commodity rates shall be increased to include the Commission-authorized Annual Charge Adjustment unit rate as published on the Commission's Web Site located at http://www.ferc.gov.

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: 0.01% for Zone 1-1, 0.01% for Zone 1-2, and 0.00% 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 | $0.9800 | | $0.9800 |
| LMS – Daily Overrun Rate | $0.1702 | | $0.1702 |
| LMS – Load Management Cost Reconciliation Adjustment | | $0.0116 | |

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 Rate Per Dekatherm | Minimum Rate Per Dekatherm |
|---|---|---|
| PAL | | |
| NPL, OPL, and APL Service: | | |
| Daily Commodity Rate | $0.1702 | $0.0000 |
| RPL Service: | | |
| Daily Reservation Rate | $0.1702 | $0.0000 |

RATE SCHEDULE TF

| | MARKET-TO-MARKET | | | FIELD-TO-FIELD/MARKET DEMARCATION |
|---|---|---|---|---|
| RESERVATION RATES | TF12 Base | TF12 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 | 0.0364 | 0.0195 | | | 0.0175 | 0.0000 | 0.0364 | 0.0195 |
| Field | Market | 0.0364 | 0.0195 | 0.0122 | 0.0040 | 0.0175 | 0.0000 | | |
| Market | Field | | | 0.0122 | 0.0040 | | | | |
| Field | Field | | | 0.0122 | 0.0040 | | | 0.0276 | 0.0090 |

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 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/ The Maximum and Minimum rates include the Market Area Electric Compression charge of $0.0005 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.
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, the Field Area Electric Compression charge of $0.0000 and the ACA unit surcharge as set forth on FERC's website at http://www.ferc.gov will be added to the mileage based rates.

RATE SCHEDULES TFX and LFT

| | MARKET-TO-MARKET | | FIELD-TO-FIELD | |
|---|---|---|---|---|
| RESERVATION RATES | Apr-Oct | Nov-Mar | Apr-Oct | 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 | 0.0364 | 0.0195 | | | 0.0175 | 0.0000 | 0.0364 | 0.0195 |
| Field | Market | 0.0364 | 0.0195 | 0.0122 | 0.0040 | 0.0175 | 0.0000 | | |
| Market | Field | | | 0.0122 | 0.0040 | | | | |
| Field | Field | | | 0.0122 | 0.0040 | | | 0.0276 | 0.0090 |

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

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 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/ The Maximum and Minimum rates include the Market Area Electric Compression charge of $0.0005 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.
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, the Field Area Compression charge of $0.0000 and the ACA unit surcharge as set forth on FERC's website at http://www.ferc.gov will be added to the mileage based rates.
6/ In addition to the Maximum and Minimum rates, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.

RATE SCHEDULES TF, TFX, LFT, GST, TI, & FDD

Fuel Percentages/Electric Compression Rates

| | Percentages |
|---|---|
| FUEL PERCENTAGES: | 1/ |
| Market Area (including Out-of-Balance) | 0.97% |
| Field Area | 2/ 3/ 5/ 6/ |
| UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance) | 0.09% 4/ 5/ |
| FDD Storage Fuel | 1.76% |

| | Electric Compression |
|---|---|
| COMMODITY RATES: | 1/ |
| Market Area | $0.0005 |
| Field Area | $0.0000 |

1/ Northern will adjust its Fuel percentages and electric compression commodity rates in accordance with Sections 53A and 53B, respectively, of the General Terms and Conditions of this Tariff.

2/ Fuel shall be determined by Mileage Indicator Districts (MIDS) for the Field Area.

3/ Fuel charged in the Field and Market Areas for a pooling transaction or for processing plant transactions will not exceed the fuel charged on a unified Field-to-Market transaction having the same initial Field receipt point and ultimate Market delivery point, i.e., the total fuel collected for transactions that go into and out of pooling points or processing plants in either the Field Area or the Market Area will be no greater than the fuel collected on the total path between the original receipt point and the ultimate delivery point, subject to the shipper(s) providing Northern the requisite information.

4/ The Unaccounted For percentage utilizes the most recent twelve-month period ending December 31, 2013.

5/ Sheet No. 54A identifies the specific transportation transactions exempt from fuel and unaccounted-for retention charges.

6/ The Out-of-Balance Fuel Percentage for deliveries in MIDS 1-7 shall be the applicable Section 1 Mainline Fuel percentage, and for deliveries in MIDS 8-16B shall be the applicable Section 2 Mainline Fuel percentage.

In the event facilities have been abandoned, Northern shall have the right to file to reduce the applicable MID fuel percentage(s) on a common basis for all transactions affected by the abandonment to reflect the reduction in use for the remainder of the PRA period. In the event such abandoned facilities (gas compressors) have been replaced with electric compressors installed after October 1, 1998, and Northern reduces the applicable MID fuel percentages, Northern has the right to file to increase the applicable electric compression commodity rate.

RATE SCHEDULES FDD, PDD, IDD, ILD & SMS

| | | |
|---|---|---|
| **Rate Schedule FDD** | | |
| Maximum Reservation Fee | 1.7140 | 1/ |
| Maximum Capacity Fee | 0.3567 | 1/ |
| Injection Charge - Firm | 0.0149 | |
| Withdrawal Charge - Firm | 0.0149 | |
| Annual Rollover Fee | 0.3567 | 1/ |
| **Rate Schedule PDD** | | |
| Maximum Capacity Fee | 0.3567 | 1/ |
| Maximum Monthly Inventory Charge | 0.0887 | 1/ |
| Injection Charge | 0.0149 | |
| Withdrawal Charge | 0.0149 | |
| Annual Rollover Fee | 0.3567 | 1/ |
| **Rate Schedule IDD** | | |
| Maximum Monthly Inventory Charge | 0.0887 | 1/ |
| Injection Charge | 0.0149 | |
| Withdrawal Charge | 0.0149 | |
| Annual Rollover Fee | 0.3567 | 1/ |
| **Rate Schedule ILD** | | |
| Maximum Charge | 11.7500 | |
| Minimum Charge | 0.5044 | |
| Performance Obligation Charge | 2.0000 | |
| **Rate Schedule SMS** | | |
| Reservation Fee | 2.1800 | |
| Commodity Rate | 0.0208 | |

1/ Minimum Rate is zero.

**Great Plains Natural Gas Co.**
**Market Conditions for Wahpeton's Natural Gas**
**October 2014**

The principal gas sources of natural gas for Wahpeton, North Dakota are from the mid-continent area of the United States. The pricing for the majority of this gas is the Northern Natural Gas Co. Ventura, Iowa point which is an actively traded market point in North America. The October monthly price for the NNG-Ventura Index is expected to trade within the same range as the previous month index. The NNG-Ventura Index is based on negotiated trades during the last five business days of the month, commonly known as bid week, and reported by Platt's Inside FERC's Gas Market Report published the beginning of each month.

As we transition from summer to fall, a couple of items have caused the October index to remain in the same range as the previous month, such as a decrease in the gas usage for power generation offset by some space heating demand across the country and storage levels remaining below last year and the five year average offset by stronger national supply resulting in the difference in the storage balance continuing to shrink from previous years. The EIA reported storage levels nationwide as of September 19, 2014 were 12.5 percent below the five-year average and 11.4 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 17.

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

September 2014

# Short-Term Energy Outlook (STEO)

## Highlights

- Driven in large part by falling crude oil prices, U.S. regular gasoline retail prices fell to an average of $3.49/per gallon (gal) in August, 12 cents below the July average and 21 cents below the average in June. U.S. regular gasoline retail prices are projected to continue to decline to an average of $3.18/gal in December, 12 cents lower than projected in last month's STEO. EIA expects U.S. regular gasoline retail prices, which averaged $3.51/gal in 2013, to average $3.46/gal in 2014 and $3.41/gal in 2015, 4 cents lower and 6 cents lower than last month's STEO, respectively.

- Weakening global demand and increased Libyan oil exports contributed to a drop in the North Sea Brent crude oil spot price to an average of $102 per barrel (bbl) in August, $5/bbl lower than the July average and $10/bbl below the average in June. For the first time in 14 months, average Brent spot prices fell outside the relatively narrow $5/bbl range between $107/bbl and $112/bbl. EIA projects that Brent crude oil prices will average $103/bbl in fourth-quarter 2014 and $103/bbl in 2015, $5/bbl and $2/bbl lower than forecast in last month's STEO, respectively. The WTI discount to Brent, which averaged $11/bbl in 2013, is expected to average $8/bbl in both 2014 and 2015.

- Total U.S. crude oil production averaged an estimated 8.6 million barrels per day (bbl/d) in August, the highest monthly production since July 1986. Total crude oil production, which averaged 7.5 million bbl/d in 2013, is expected to average 9.5 million bbl/d in 2015, 0.2 million bbl/d higher than projected in last month's STEO. If achieved, the 2015 forecast would be the highest annual average crude oil production since 1970. Natural gas plant liquids production increases from an average of 2.6 million bbl/d in 2013 to 3.1 million bbl/d in 2015. The growth in domestic liquids production has contributed to a significant decline in petroleum imports. The share of total U.S. petroleum and other liquids consumption met by net imports fell from 60% in 2005 to an average of 32% in 2013. EIA expects the net import share to decline to 21% in 2015, which would be the lowest level since 1968.

- Natural gas spot prices fell 15% from an average of $4.59/million British thermal units (MMBtu) in June to $3.91/MMBtu in August even as natural gas stock builds continued to outpace historical norms. Natural gas working inventories on August 29 totaled 2.71 trillion cubic feet (Tcf), 0.47 Tcf (15%) below the level at the same time a year ago and 0.50 Tcf (15%) below the previous five-year average (2009-13). Projected natural gas working

inventories reach 3.48 Tcf at the end of October, 0.34 Tcf below the level at the same time last year. EIA expects that the Henry Hub natural gas spot price, which averaged $3.73 per MMBtu in 2013, will average $4.46/MMBtu in 2014 and $3.87/MMBtu in 2015.

## Global Petroleum and Other Liquids

EIA estimates that global oil inventories grew by 0.5 million bbl/d in August. The recent inventory builds are somewhat atypical for this time of year and signal a relatively loose global crude oil market compared with conditions over the past three years. Weaker oil demand and lower refinery runs in European and Asian countries within the Organization for Economic Cooperation and Development (OECD) this year have reduced market tightness. Nevertheless, these conditions may be temporary and the risk for tighter markets in the future remains elevated due to persistently high supply disruptions and relatively low surplus crude oil production capacity.

Geopolitical risks to near-term supply have abated since June, when Libya's production and exports were at a minimal level and violence in northern Iraq escalated causing northern production (outside of Iraqi Kurdistan) to come to a near-halt. Iraq's southern crude oil exports still remain unaffected by the unrest in northern Iraq. In Libya, crude oil exports restarted in August at the country's two major eastern ports, Es Sidra and Ras Lanuf, after being blocked by protestors for about a year. However, the situation in Libya is still very precarious as the security situation remains volatile, with a significant possibility of intermittent disruptions.

EIA projects world petroleum and other liquids supply to increase by 1.6 million bbl/d in 2014 and by 1.3 million bbl/d in 2015, with most of the growth coming from countries outside of the Organization of the Petroleum Exporting Countries (OPEC). Forecast non-OPEC supply grows by 1.8 million bbl/d in 2014 and 1.2 million bbl/d in 2015. The United States accounts for much of this growth. Projected world liquid fuels consumption grows by an annual average of 1.0 million bbl/d in 2014 and 1.3 million bbl/d in 2015. Non-OECD countries, notably China, drive expected consumption growth.

**Global Petroleum and Other Liquids Consumption**. Global consumption grew by 1.3 million bbl/d (1.5%) in 2013, averaging 90.5 million bbl/d for the year. EIA expects global consumption to grow by 1.0 million bbl/d in 2014 and 1.3 million bbl/d in 2015. Projected global oil-consumption-weighted real GDP, which increased 2.7% in 2013, grows by 2.7% and 3.3% in 2014 and 2015, respectively.

Non-OECD consumption is projected to grow by 1.3 million bbl/d in 2014 and 1.2 million bbl/d in 2015, accounting for nearly all forecast global consumption growth during that period. China is the leading contributor to projected global consumption growth, with consumption increasing by 0.37 million bbl/d (3.5%) in 2014 and 0.43 million bbl/d in 2015.

EIA expects a 0.21-million-bbl/d decline in OECD consumption in 2014, led by projected consumption declines in both Japan and Europe. Japan's consumption, which fell by 0.16 million bbl/d in 2013, is projected to continue to decline by an annual average of 0.13 million bbl/d in 2014 and 0.16 million bbl/d in 2015. The projected decline reflects Japan's effort to reduce its share of oil in the electricity sector, replacing it with natural gas, coal, and nuclear power as the country returns some nuclear power plants to service in 2015. OECD Europe's consumption, which fell by 0.12 million bbl/d in 2013, is projected to decline by a further 0.12 million bbl/d in 2014 and by 0.03 million bbl/d in 2015. U.S. consumption, which increased by 0.47 million bbl/d in 2013, is expected to be mostly flat in 2014 and then increase by 0.15 million bbl/d in 2015.

**Non-OPEC Petroleum and Other Liquids Supply.** EIA estimates that non-OPEC production grew by 1.4 million bbl/d in 2013, averaging 54.1 million bbl/d for the year. EIA expects non-OPEC production to grow by 1.8 million bbl/d in 2014 and 1.2 million bbl/d in 2015. The United States is the leading contributor to forecast non-OPEC supply growth, increasing by 1.4 million bbl/d in 2014 and 1.2 million bbl/d in 2015. EIA estimates that Eurasia's production will increase by less than 0.1 million bbl/d in 2014, with increased production from Russia and Kazakhstan offsetting declines in other countries, and stay relatively flat in 2015. This forecast assumes the current economic sanctions on Russia do not affect Russian oil production in the short term.

Unplanned supply disruptions among non-OPEC producers averaged nearly 0.6 million bbl/d in August, slightly lower than the estimated July level. South Sudan, Syria, and Yemen accounted for more than 85% of total non-OPEC supply disruptions. EIA does not assume a disruption to oil supply or demand as a result of ongoing events in Ukraine.

**OPEC Petroleum and Other Liquids Supply**. EIA estimates that OPEC crude oil production averaged 29.9 million bbl/d in 2013, a decline of 1.0 million bbl/d from the previous year, primarily reflecting increased outages in Libya, Nigeria, and Iraq, along with strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.3 million bbl/d in 2014 and by 0.1 million bbl/d in 2015 to accommodate growing production in non-OPEC countries.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.4 million bbl/d in August 2014, 0.1 million bbl/d lower than the previous month mainly because of decreased outages in Libya. Libya's production increased to 0.5 million bbl/d in August, 0.3 million bbl/d higher than the second quarter 2014 average, but still well below the 1.4 million bbl/d the country produced before the major blockades started in mid-2013. Almost all of Libya's export terminals are able to export crude as protestors agreed to stop the blockades, and production has restarted in some of Libya's largest eastern oil fields. However, some of the major issues that incited the widespread protests over the past year remain unresolved. As a result, EIA does not expect Libya's oil production to recover to its preblockade level over the forecast period.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to average 2.2 million bbl/d in 2014 and 2.7 million bbl/d in 2015. These estimates do not

include additional capacity that may be available in Iran but is offline because of the effects of U.S. and European Union sanctions on Iran's ability to sell its oil.

**OECD Petroleum Inventories.** EIA estimates that OECD commercial oil inventories totaled 2.55 billion barrels at the end of 2013, equivalent to roughly 55 days of consumption. Projected OECD oil inventories rise to 2.58 billion barrels at the end of 2014.

**Crude Oil Prices.** North Sea Brent crude oil spot prices averaged $102/bbl in August, a decrease of $5/bbl. Or 4.7%, from July. Brent crude oil prices were driven downward in large part because of weakening global oil demand as well as growing Libyan oil exports. August was the first in 13 consecutive months in which average Brent crude oil spot prices fell outside the relatively narrow range of $107/bbl to $112/bbl. The forecast Brent crude oil price averages $106/bbl in 2014, $2/bbl lower than in last month's STEO, and $103/bbl in 2015, $2/bbl lower than in last month's STEO.

The monthly average WTI crude oil spot price fell from a high of $106/bbl in June to $97/bbl in August. Driven in part by new pipelines delivering crude oil to refining centers along the Gulf Coast, crude oil inventory levels at the Cushing, Oklahoma, storage hub, the futures market's delivery point for WTI, fell below 18 million barrels on July 25, the lowest level since October 2008. Crude oil inventories then built for four consecutive weeks to reach 20.7 million barrels on August 22. After falling to an annual low of $3/bbl in July, the discount of WTI crude oil to Brent crude oil increased to $5/bbl in August. While record high refinery runs contributed to the WTI discount falling to $3/bbl in July, the discount widened in August while refinery runs remained elevated. EIA now expects WTI crude oil prices to average $93/bbl in the fourth quarter of 2014, $5/bbl lower than in last month's STEO, and $95/bbl in 2015. The discount of WTI to Brent crude oil is forecast to widen from current levels, averaging $10/bbl in the fourth quarter of 2014 and $8/bbl in 2015.

Energy price forecasts are highly uncertain, and the current values of futures and options contracts suggest that prices could differ significantly from the forecast levels (*Market Prices and Uncertainty Report*). WTI futures contracts for December 2014 delivery, traded during the five-day period ending September 4, averaged $93/bbl. Implied volatility averaged 16%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in December 2014 at $81/bbl and $107/bbl, respectively. Last year at this time, WTI for December 2013 delivery averaged $106/bbl and implied volatility averaged 25%. The corresponding lower and upper limits of the 95% confidence interval were $86/bbl and $131/bbl.

## U.S. Petroleum and Other Liquids

After reaching a summer peak of $3.70/gal in late June, U.S. average regular gasoline retail prices fell to $3.45/gal on August 25, the lowest price on the Monday before Labor Day since 2010. Gasoline prices have fallen from their summer peak in late June primarily because of

lower crude oil prices, which in addition to reduced geopolitical risk premiums to Iraqi and Libyan oil exports, have been driven downward because of weakening global oil demand indicators in combination with growing international oil supplies. EIA expects that U.S. regular gasoline retail prices will continue to fall through the end of the year, reaching $3.18/gal in December, which would mark the lowest monthly average since January 2011.

**Liquid Fuels Consumption.** EIA has revised total 2013 U.S. petroleum and other liquids consumption upwards by 74,000 bbl/d to 18.96 million bbl/d. Upward revisions in motor gasoline (69,000 bbl/d), special naphthas (66,000 bbl/d), and hydrocarbon gas liquids (HGL) (47,000 bbl/d) were offset by a 113,000 bbl/d reduction in unfinished oils consumption. Total U.S. petroleum and other liquids consumption rose by 470,000 bbl/d (2.5%) in 2013, the largest annual increase since 2004. Motor gasoline consumption rose by 160,000 bbl/d (1.9%). High petrochemical demand and a very wet corn crop late in the year contributed to a 100,000 bbl/d (8.5%) increase in propane consumption last year.

Total consumption is expected to fall slightly, by 0.2%, in 2014. A year-over-year increase in total consumption of 170,000 bbl/d during the first quarter is expected to be more than offset by an average 150,000 bbl/d decline during the second half of the year. Propane consumption retreats from last year's growth, falling by an average of 110,000 bbl/d this year. Distillate fuel consumption is projected to increase by an average of 160,000 bbl/d (4.2%) in 2014.

Total consumption grows by 150,000 bbl/d in 2015 to average 19.08 million bbl/d, an increase of 100,000 bbl/d from last month's STEO. HGL consumption, primarily ethane and propane, increases by 120,000 bbl/d next year, while distillate consumption is 70,000 bbl/d higher.

**Liquid Fuels Supply.** The forecast for total U.S. crude oil production increases from an estimated 7.45 million bbl/d in 2013 to 8.53 million bbl/d in 2014 and 9.53 million bbl/d in 2015. The 2014 and 2015 forecasts are 0.07 million bbl/d and 0.25 million bbl/d higher than in last month's STEO, respectively. The highest previous annual average U.S. production level was 9.6 million bbl/d in 1970. Oil production from the Gulf of Mexico is expected to increase from 1.25 million bbl/d in 2013 to 1.67 million bbl/d in 2015, with 11 projects starting this year. Six projects began production in the first half of 2014: Na Kika Phase 3, Mars B, Dalmatian, Entrada, Atlantis Phase 2, and Tubular Bells. Additional wells are expected to come online in the fourth quarter of 2014 from the Cardamom Deep, South Deimos/West Boreas, Hadrian South, Jack/St. Malo, and Lucius projects.

HGL production at natural gas liquids plants is projected to increase from 2.6 million bbl/d in 2013 to 3.1 million bbl/d in 2015. Most of this growth is expected to come from additional ethane and propane production that will meet growing demand associated with expanding domestic ethylene and propylene production and export capacity.

The growth in domestic production has contributed to a significant decline in petroleum imports. The share of total U.S. liquid fuels consumption met by net imports fell from 60% in

2005 to an average of 32% in 2013. EIA expects the net import share to decline to 21% in 2015, which would be the lowest level since 1968.

**Petroleum Product Prices.** EIA expects that the monthly average regular gasoline retail price will fall from the recent peak of $3.69/gal in June to $3.41/gal in September, before falling to $3.18/gal in December. The U.S. annual average regular gasoline retail price, which averaged $3.51/gal in 2013, is projected to average $3.46/gal in 2014 and $3.41/gal in 2015, 4 cents and 6 cents lower than in last month's STEO, respectively. Diesel fuel prices, which averaged $3.92/gal in 2013, are projected to fall to an average of $3.86/gal in 2014 and $3.82/gal in 2015, 2 cents and 5 cents lower than projected in last month's STEO, respectively. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas falling above or below the national average price by 30 cents/gal or more.

## Natural Gas

Industrial natural gas consumption has grown steadily since 2009, as relatively low prices have been attractive to consumers who use natural gas as a feedstock for chemical production. Ammonia-based fertilizer and methanol plants that use natural gas as a feedstock are among the most natural gas-intensive industrial end users. Low gas prices and proximity to shale resources have led to proposals for several methanol and ammonia plants. Two methanol plants are currently under construction and set to begin service this year— a small facility in Pampa, Texas and one in Geismar, Louisiana. Two large facilities coming online in 2015, a methanol plant in Clear Lake, Texas, and a fertilizer/urea plant in Wever, Iowa, will support continued growth in industrial demand. Many large plants use more than 0.1 billion cubic feet per day (Bcf/d) of natural gas. EIA projects growth in industrial demand will continue through 2015, with consumption averaging 21.3 Bcf/d in 2014 and 22.1 Bcf/d in 2015.

**Natural Gas Consumption.** EIA expects total natural gas consumption will average 72.6 Bcf/d in 2014, an increase of 1.8% from 2013 led by the industrial sector. In 2015, total natural gas consumption increases 0.2% as continued industrial sector growth offsets lower residential and commercial consumption. Higher natural gas prices this year contribute to a 2.0% decline in natural gas consumption in the power sector to 21.9 Bcf/d in 2014. EIA expects natural gas consumption in the power sector to increase to 22.8 Bcf/d in 2015.

**Natural Gas Production and Trade.** EIA expects natural gas marketed production to grow by an annual rate of 5.3% in 2014 and 2.1% in 2015. STEO projects that strong increases already seen in the Lower 48 states this year will continue, offsetting declines in the Gulf of Mexico. As of June, the most recent month for which EIA data are available, marketed production was 4.6 Bcf/d greater than it was in June 2013. Rapid natural gas production growth in the Marcellus formation has contributed to low natural gas forward prices in the Northeast, and as a result new infrastructure has been proposed to flow gas to other market regions. In June, the eastward-flowing Rockies Express Pipeline (REX) began service on its Seneca Lateral, which flows

Marcellus gas westward to the Midwest. REX's parent company, Tallgrass Energy, plans to add bi-directional capability on a significant portion of REX's easternmost segment.

Growing domestic production is expected to continue to put downward pressure on natural gas imports from Canada, and spur exports to Mexico. Exports to Mexico have been increasing in recent months because of growing demand from Mexico's electric power sector and flat Mexican production. Mexico has been an outlet for U.S. production, particularly from the Eagle Ford Shale in South Texas.

Liquefied natural gas (LNG) imports have fallen over the past four years because higher prices in Europe and Asia are more attractive to sellers than the relatively low prices in the United States. This month's STEO revises the forecast for 2015 LNG net imports to reflect Cheniere Energy's Sabine Pass export terminal beginning service in 2015. EIA now expects the United States will be a net exporter of LNG in 2015. LNG exports are still a very small part of the total picture, however, and overall the United States will remain a net importer of natural gas because of pipeline imports from Canada.

**Natural Gas Inventories.** Natural gas working inventories totaled 2,709 Bcf as of August 29, which was 471 Bcf lower than the same time last year and 495 Bcf lower than the previous five-year (2009-13) average. The injection season began somewhat slowly in April, but has continued at a strong pace, with injections averaging above the five-year average throughout most of the injection season. EIA expects working gas stocks will reach 3,477 Bcf at the end of October, 339 Bcf lower than at the same time last year.

**Natural Gas Prices.** Natural gas prices fell from $4.05/MMBtu in July to $3.91/MMBtu in August as storage injections continue to outpace historical norms. EIA expects spot prices will remain below $4/MMBtu through October, before rising with winter heating demand. Projected Henry Hub natural gas prices average $4.46/MMBtu in 2014 and $3.87/MMBtu in 2015.

Natural gas futures prices for December 2014 delivery (for the five-day period ending September 4) averaged $4.07/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for December 2014 contracts at $3.09/MMBtu and $5.35/MMBtu, respectively. At this time last year, the natural gas futures contract for December 2013 averaged $3.87/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $2.98/MMBtu and $5.04/MMBtu.

## Coal

Electric power sector coal inventories fell to 133 million short tons (MMst) at the end of June, 38 MMst lower compared with the same time last year. Coal inventories in the Midwest and South, two regions that rely heavily on coal-fired generation, are down 19% and 29%, respectively, when compared with last year. Midwestern electric generators have recently cited

continuing problems with rail coal deliveries to power plants. One utility in Wisconsin is concerned that it may have to cease or curtail operations at a coal plant and in Minnesota one utility states that it has begun curtailing output at a large coal-fired plant to conserve fuel. Coal car loadings have fallen in 8 of the past 9 weeks, and although year-to-date rail coal shipments are up by 0.1%, this has been insufficient to maintain stocks. Some Southern generators are reportedly turning to shipments of imported coal to meet their needs.

**Coal Supply.** EIA estimates that coal production for the first eight months of this year (658 MMst) was slightly lower (5 MMst) than production over the same period last year. EIA expects that U.S. coal production will grow 1.4% to 998 MMst in 2014, driven by higher consumption and a need to replenish consumer inventories, particularly at power producers. In 2015, forecast U.S. coal production increases slightly by 0.5% to 1,002 MMst.

**Coal Consumption.** EIA projects total coal consumption growth of 2.0% to 943 MMst in 2014 because of higher electricity demand and power sector natural gas prices more than 20% above their 2013 level. Total coal consumption is projected to fall by 2.6% in 2015, as retirements of coal power plants rise in response to the implementation of the Mercury and Air Toxics Standards, electricity sales growth slows to 0.4%, and natural gas prices fall relative to coal prices.

**Coal Trade.** EIA estimates that coal exports for the first six months of this year were 17.2% (10.5 MMst) lower compared with last year, with tonnage declines for steam coal exports more than double those of metallurgical coal. Coal exports are projected to decline to 96 MMst in 2014 from 118 MMst in 2013, primarily because of slowing world coal demand growth, lower international coal prices, and increasing coal output in other coal-exporting countries.

Coal imports for the first six months of this year increased by 43% (1.8 MMst) compared with last year. Rail congestion, coupled with falling global coal prices, has made imports an attractive alternative to domestic coal, especially to power plants in the East. EIA expects coal imports to total 12.8 MMst in 2014 and fall slightly to 10.8 MMst in 2015.

**Coal Prices.** Annual average coal prices to the electric power industry fell over the past few years, from $2.39/MMBtu in 2011 to $2.35/MMBtu in 2013. EIA expects the average delivered coal prices to be $2.36/MMBtu in 2014 and remain at that level in 2015.

## Electricity

Preliminary data indicate that power generators added 4.35 gigawatts (GW) of new capacity during the first half of 2014. This rate of new capacity builds is 40% below the rate of capacity additions during the same period last year. Power plants fueled by natural gas accounted for more than half of the new capacity coming online so far this year, with the remainder primarily composed of renewable generating capacity. No coal-fired generating capacity was completed

during the first half of 2014, compared with 1.51 GW in 2013. Two coal plants with a total capacity of 0.58 GW are scheduled to begin operations this year. Preliminary data indicate that at least 0.95 GW of coal-fired capacity has been retired so far this year. A much larger number of coal plants are expected to retire during 2015.

**Electricity Consumption.** After cold weather during the first quarter of this year and relatively close to normal summer temperatures, EIA projects growth of 1.9% in U.S. retail sales of electricity to the residential sector in 2014. As forecast temperatures return to normal in 2015, EIA expects residential electricity sales will decline by 0.7% next year. Relatively modest economic growth compared with last year has led to slower growth in the electricity sales to the commercial sector. U.S. commercial electricity sales are expected to average 0.9% higher in 2014 than sales last year and then grow by 0.4% in 2015. EIA expects U.S. industrial electricity sales to remain flat during 2014 and grow by 2.2% in 2015 after two years of declines.

**Electricity Generation.** EIA projects that average daily U.S. electricity generation in 2014 will grow by 100 gigawatthours per day (0.9%) from last year. Changes in relative fuel costs have altered the mix of plants used to generate electricity. Power sector natural gas prices this year are expected to be more than 20% higher than prices last year, while the prices of coal delivered to the power sector are expected remain flat. Rising natural gas costs lead to a reduction in the fuel's share of total generation from 27.4% in 2013 to 26.7% this year. In contrast, coal's share of total generation rises from 39.1% in 2013 to 40.1% this year. In 2015, EIA expects the power sector's price of natural gas will fall by 12%. This lower price, combined with the scheduled retirements of coal capacity, should push up natural gas's fuel share next year to 27.6% and reduce coal's fuel share to 38.8%.

**Electricity Retail Prices.** Residential electricity prices have risen in most states so far this year, compared with the same period in 2013. EIA expects the U.S. residential price to average 12.5 cents per kilowatthour in 2014, which is 3.1% higher than the average last year. The increase in average prices will be highest in the New England states, at 7.8%. Average U.S. residential electricity prices grow at a slower rate of 1.7% in 2015.

## Renewables and Carbon Dioxide Emissions

Almost 50% of the new utility-scale power generation capacity added during the first half of 2014 uses renewable energy sources. Solar-powered capacity grew about 1,150 megawatts (MW) during the first six months of 2014 compared with 690 MW added during the same period last year. The electricity industry has added 675 MW of wind capacity this year, which is more than double the amount added during the first half of 2013.

**Electricity and Heat Generation from Renewables.** EIA projects that total renewables use for electricity and heat generation will grow by 2.1% in 2014. Conventional hydropower generation is projected to fall by 4.2%, while nonhydropower renewables rise by 5.5%. In 2014, nonhydropower renewables generation in the electric power sector surpasses hydropower on

an annual basis for the first time. In 2015, total renewables consumption for electric power and heat generation increases by 4.4%, as a result of a 4.5% increase in hydropower and a 4.4% increase in nonhydropower renewables.

EIA projects that wind power capacity will increase by 9.2% in 2014 and 16.2% in 2015. Electricity generation from wind is projected to contribute 4.6% of total electricity generation in 2015.

EIA expects continued robust growth in solar electricity generation, although the amount of utility-scale generation remains a small share of total U.S. generation at about 0.6% in 2015. While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity doubled in 2013. EIA expects that utility-scale solar capacity will increase by 104% between the end of 2013 and the end of 2015, with about two-thirds of this new capacity built in California. However, customer-sited photovoltaic capacity growth, which the STEO does not forecast, is expected to exceed utility-scale solar growth between 2013 and 2015, according to EIA's *Annual Energy Outlook 2014*.

**Liquid Biofuels.** Ethanol production increased from an average of 907,000 bbl/d in March to average about 940,000 bbl/d over the past 3 months, which are among the highest monthly levels ever recorded, and included the highest weekly level ever recorded at 972,000 bbl/d for the week ending June 13. Ethanol production is forecast to average 929,000 bbl/d in 2014 and 934,000 bbl/d in 2015. Biodiesel production averaged 87,000 bbl/d in 2013 and is forecast to average 80,000 bbl/d in 2014 and 84,000 bbl/d in 2015.

**Energy-Related Carbon Dioxide Emissions.** EIA estimates that carbon dioxide emissions from fossil fuels increased by 2.4% in 2013 from the previous year. Emissions are forecast to rise by 1.3% in 2014, and then to decline by 0.6% in 2015. The increase in total emissions in 2013 and 2014 reflects increases in emissions from coal of 4.2% and 2.1%, respectively. The price of natural gas to electric power generators rose on average by $0.91/MMBtu in 2013 and is projected to rise by $0.93/MMBtu in 2014, contributing to an increase in coal use. Coal emissions are projected to decline by 2.5% in 2015.

## U.S. Economic Assumptions

**Recent Economic Indicators.** Economic growth improved substantially in the second quarter of 2014. The U.S. Bureau of Economic Analysis (BEA) reported that second quarter real gross domestic product (GDP) grew at an annualized rate of 4.2% from the first quarter of 2014, which reflects an upward revision of 0.2% from its previous estimate. Second quarter growth was associated with increases in private inventory investment and exports, along with greater state and local government spending and higher nonresidential fixed investment.

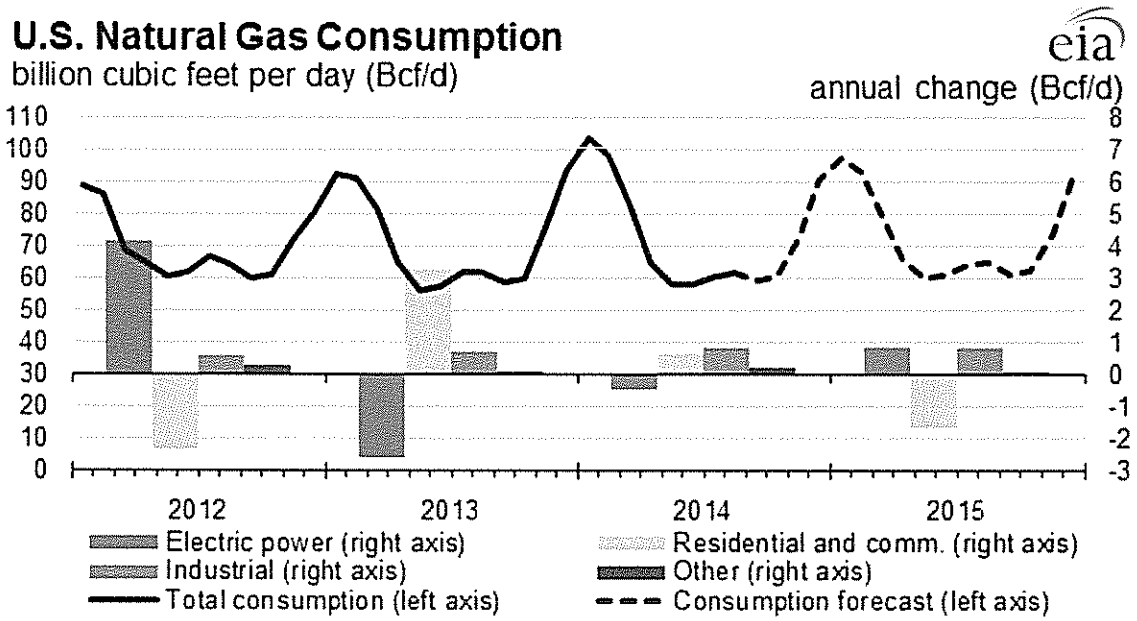
The U.S. Bureau of Labor Statistics (BLS) reported that the four-week moving average of initial unemployment insurance claims for the week ending August 30 was 302,750, an increase of 3,000 from the previous week's moving average.

EIA used the August 2014 version of the IHS macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

**Production and Income.** Forecast real GDP growth in 2014 was revised upwards from an average 1.7% in last month's STEO to 2.1%. For 2014, the increase reflects the upward revision in real GDP growth in the second quarter of 2014. Real disposable income grows by 2.5% in 2014, down from the 3.1% forecast last month. In 2015, both real GDP and disposable income increase by 2.8%. Total industrial production grows at 3.9% in 2014 and 3.4% in 2015. Growth in industrial production in the manufacturing sector averages 3.5% in both 2014 and 2015.

**Expenditures.** Private real fixed investment growth averages 4.8% and 7.3% in 2014 and 2015, respectively, led by industrial and transportation equipment in 2014 and by a broad array of equipment categories in 2015. Real consumption expenditures grow faster than real GDP in 2014 at 2.3%, but fall below the real GDP growth rate in 2015 at 2.7%. Durable goods expenditures drive consumption spending in both years. Export growth is 2.7% and 5.4% over the same two years, while import growth is 3.5% in 2014 and 4.9% in 2015. Total government expenditures fall 0.4% in 2014, but increase by 0.3% in 2015.

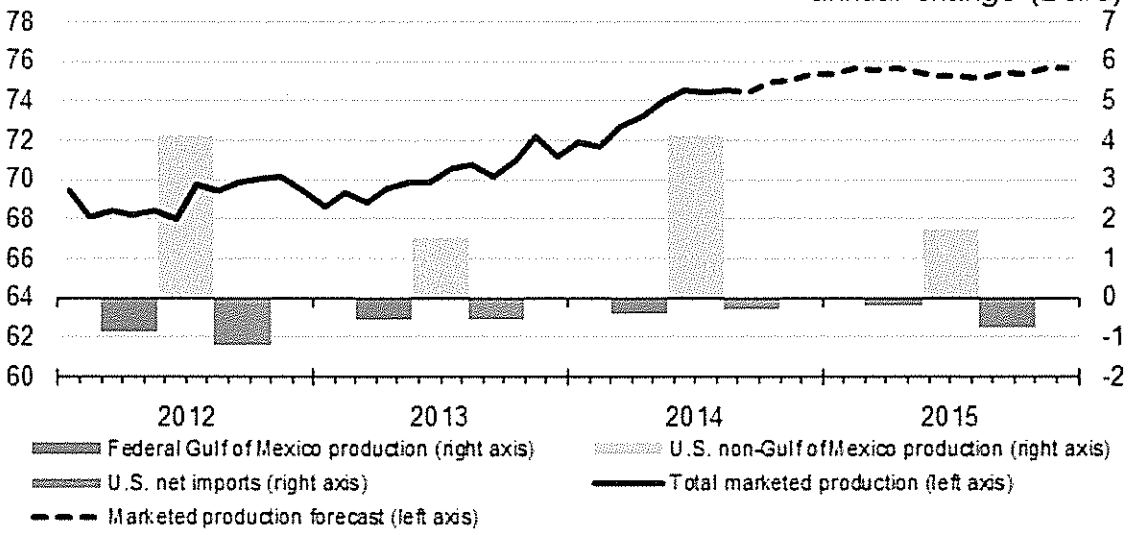
**U.S. Employment, Housing, and Prices.** Projected growth in nonfarm employment averages 1.8% in 2014 and 1.9% in 2015. This is accompanied by a gradually declining unemployment rate that reaches 5.7% at the end of 2015. Housing starts grow an average of 11.4% and 26.8% in 2014 and 2015, respectively. Both consumer and producer price indexes increase at a moderate pace, and wages continue to show modest gains.




Source: Short-Term Energy Outlook, September 2014.

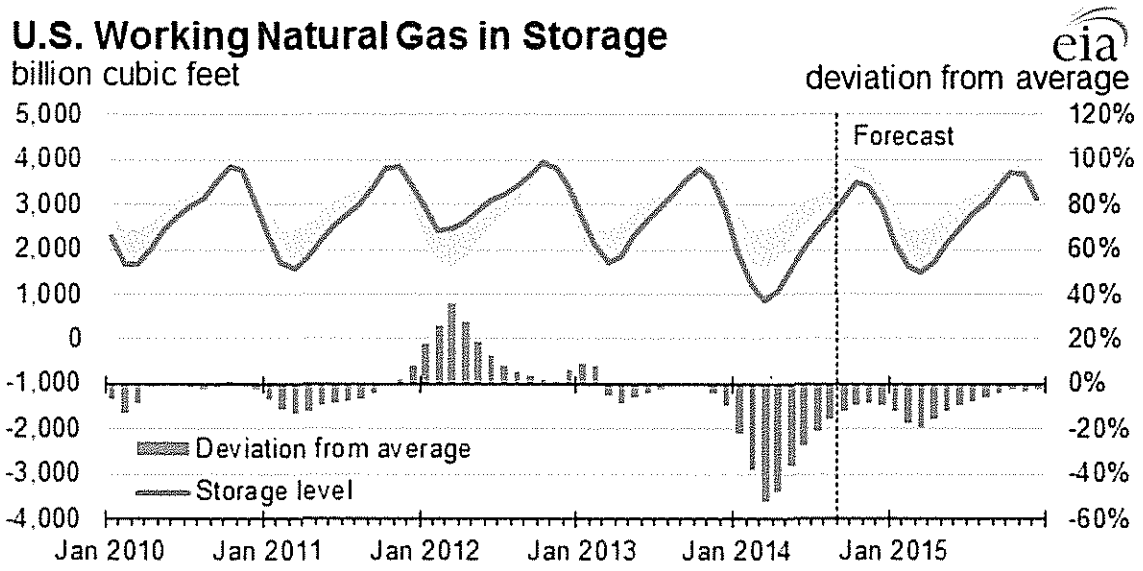
## U.S. Natural Gas Production and Imports

billion cubic feet per day (Bcf/d) — annual change (Bcf/d)




Source: Short-Term Energy Outlook, September 2014.

## U.S. Working Natural Gas in Storage

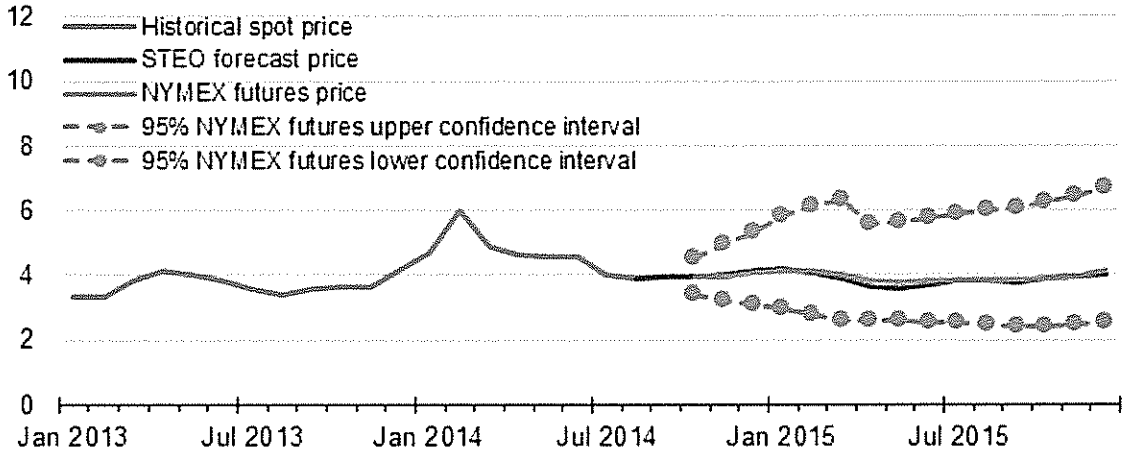



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2009 - Dec. 2013.

Source: Short-Term Energy Outlook, September 2014.

## Henry Hub Natural Gas Price

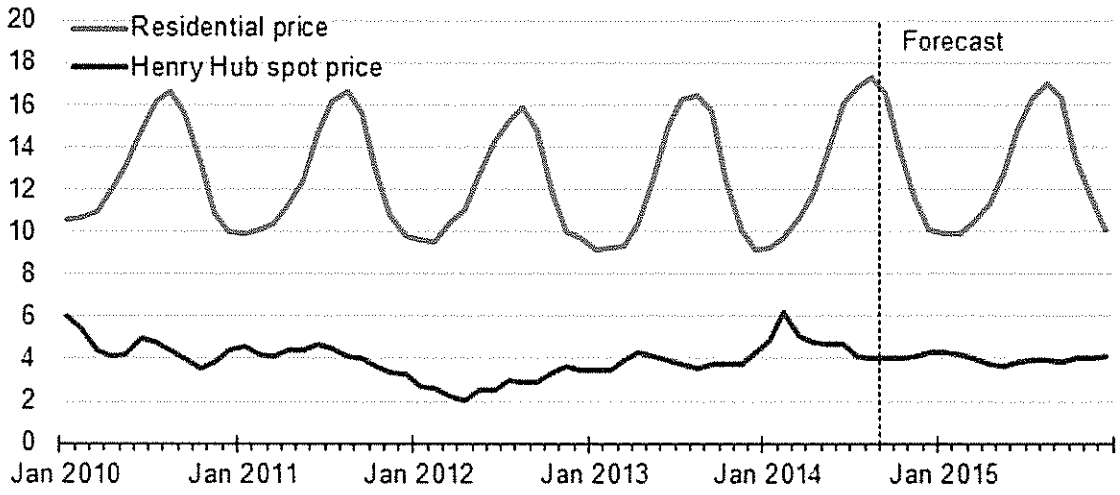
dollars per million Btu




Note: Confidence interval derived from options market information for the 5 trading days ending Sep. 4, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, September 2014.

**U.S. Natural Gas Prices**
dollars per thousand cubic feet




Source: Short-Term Energy Outlook, September 2014.

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, 2014** | | | | | | | | | **$404,569** |
| May 2014 | ($15,520) | 0 | $2,700 | ($12,820) | 18,641 | $0.9614 | $17,921 | ($30,741) | 373,828 |
| June | ($1,551) | 0 | $2,475 | 924 | 9,300 | 1.3462 | $10,015 2/ | (9,092) | 364,736 |
| July | $13,177 | 0 | $2,399 | 15,576 | 6,189 | 1.3462 | $8,331 | 7,245 | 371,981 |
| August | $13,687 | 0 | $2,437 | 16,124 | 5,378 | 1.3462 | $7,240 | 8,884 | 380,865 |
| Total | $9,793 | 0 | $10,011 | $19,804 | 39,508 | | $43,507 | ($23,704) | |
| **Balance @ August 31, 2014** | | | | | | | | | **$380,865** |

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 6,507.2 dk at $0.9614 and 2,792.4 dk at $1.3462.

Attachment D
Page 1 of 2

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, 2014** | | | | | | | | | | **$388,932** |
| May 2014 | ($22,536) | 0 | $2,691 | ($19,845) | 42,002 | $0.0274 | $1,151 | | ($20,996) | 367,936 |
| June | ($17,420) | 0 | $2,515 | (14,905) | 19,772 | 0.9696 | $5,999 | 2/ | ($20,903) | 347,033 |
| July | ($3,815) | 0 | $2,344 | (1,471) | 11,279 | 0.9696 | 10,936 | | (12,407) | 334,626 |
| August | ($6,429) | 0 | $2,239 | (4,190) | 13,996 | 0.9696 | 13,571 | | (17,761) | 316,865 |
| Total | ($50,200) | 0 | $9,789 | ($40,411) | 87,049 | | $31,657 | | ($72,067) | |
| **Balance @ August 31, 2014** | | | | | | | | | | **$316,865** |

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 13,980.6 dk at $0.0274 and 5,791.7 dk at $0.9696.