ONRR Year In Review

Fiscal Year 2009 in Review

Overview:

For Fiscal Year (FY) 2009, October 2008 through September 2009, the domestic oil and gas markets experienced significant commodity value volatility, driven down early in the year in large part because of lower demand caused by the severe economic downturn. To a lesser extent, production volumes also experienced volatility. This volatility is reflected in volume and value data for production on Federal and Indian lands reported to MMS by Sales year. [1] Geopolitical risk, an economic downturn, supply disruptions, rising and falling demand, financial market technical factors, and localized weather events continue to drive much of the volatility.

Crude oil prices continued the dramatic fall that began in July 2008 until March 2009 and then experienced a strong recovery. New York Mercantile Exchange (NYMEX) West Texas Intermediate (WTI) values averaged $57.76 per barrel for FY 2009, more than 45 percent lower than the FY 2008 average of $107.70. The per barrel price for WTI ranged from a high of $98.53 on October 1, 2008 to a low of $33.87 on December 19, 2008. Significant variations in the price difference (basis) between the Gulf of Mexico and onshore Federal oil production continued to exist due to variations in supply, demand, and quality. Federal oil volumes subject to royalty payments were still down for the first quarter of FY 2009 following damage caused by Hurricanes Gustav and Ike. Oil volumes returned to pre-hurricane levels by the second quarter and remained steady as pipeline and platform infrastructure from hurricane damage was repaired. The SPR program resumed shipments in April 2009 with contracts through December 2009. However, the allocated SPR volumes were significantly lower than previous initiatives, representing only 2 percent of offshore royalty production.

Natural gas prices saw a slightly steeper drop than oil prices in FY 2009. Prices leveled off a bit by April but then fell again in the fourth quarter, never experiencing the recovery seen in crude oil prices. Daily prices at Henry Hub averaged $4.45 per MMBtu in FY 2009, more than 50 percent lower than the FY 2008 average of $8.98, with a high of $7.64 on October 3, 2008, to an eight year low of $1.85 on September 5, 2009. Variations in the price basis between the Gulf of Mexico and onshore Federal gas production, and between producing and consuming areas, continued to exist due to pipeline constraints and differences in transportation costs and local economics. However, both the completion of the Rockies Express Pipeline (REX) pipeline, which strengthened Rockies prices, and pipelines accessing mid-continent shale gas production, which weakened the Henry Hub, narrowed the basis in late FY 2009. Federal royalty gas volumes steadily increased throughout the year following the post hurricane production drop experienced in the fall of 2008.

Overall U.S. coal production decreased during FY 2009. U.S. coal-fired generation was down 13 percent for the year, or roughly 100 million tons, with coal prices declining as well. Coal prices rose slightly when production cutbacks were first announced at the onset of the fiscal year but then dipped again. When the coal sales value per ton reported to MMS is compared to the Platts' values, a slight divergence is seen. This is due to the fact that Platts reports spot prices, while reporting to MMS includes both long-term legacy contract prices and spot prices.

U.S. coal production totaled over 1 billion tons, with about 50 percent of the total coming from Federal and Indian lands. Over 80% of Federal and Indian production is mined in the Powder River Basin of northeast Wyoming and southeast Montana.

Increased geothermal leasing activity in several western states led to a dramatic increase in geothermal bonus payments. Once production begins on these leases, a similar increase in geothermal royalty revenues is expected.

Disbursements made by MMS decreased from $23.4 billion in FY 2008 to $10.7 billion in FY 2009. This decrease is primarily the result of fewer offshore lease sales and lower bonus bids in FY 2009 compared to FY 2008. In FY 2009, bonus revenues totaled less than $2 billion where as in FY 2008, bonus revenues totaled more than $10 billion with four large Gulf of Mexico and Alaska offshore sales that brought in over $9.5 billion in bonus bids.

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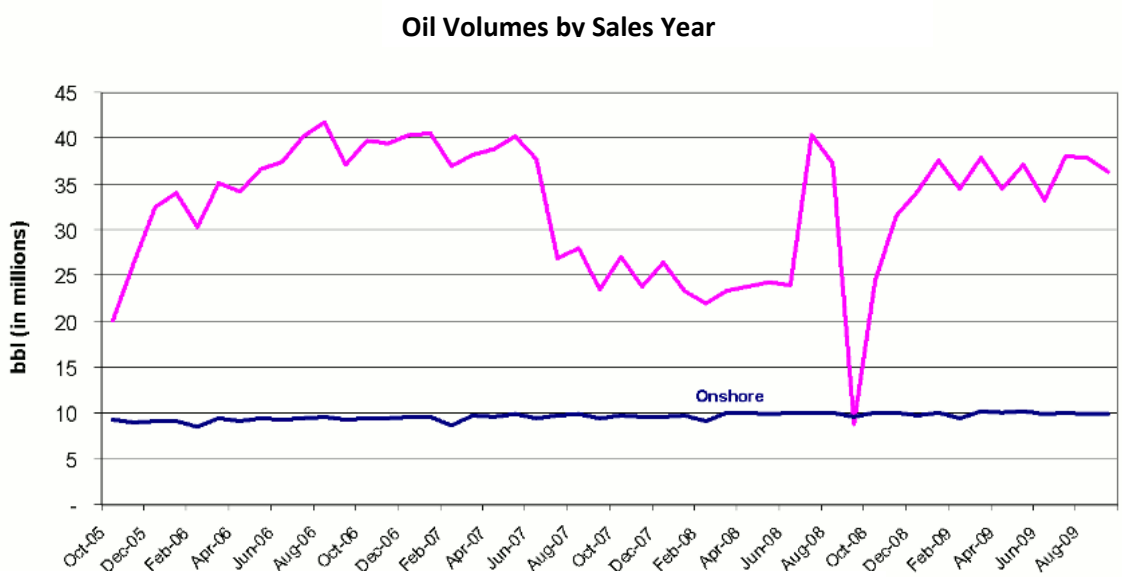
[1] Sales year data provides a "snap shot" view of reported sales of mineral commodities, excluding adjustments for the current year, as of the report publication date. It offers a "point in time" view of the reported royalty revenue data sets that are useful for data analysis and/or trending purposes.

Oil Volume Observations:



Onshore and offshore total sales volumes based on sales year (without prior period adjustment)

Offshore oil production has been trending upward since late 2004. Many of the larger deep-water fields are ramping-up production leading to an overall Gulf of Mexico production increase despite declining production rates from many older, smaller fields. Some of these projects include new fields in the Southern Green and Mississippi Canyons as well as other deep-water areas. Chevron's Tahiti Field in the Southern Green Canyon started its first oil production in May 2009. Daily production from Tahiti is expected to plateau at 125,000 barrels of oil per day. [2] BP's Thunder Horse Field in the Mississippi Canyon ramped up its production by bringing on new wells after its first production in mid 2008. By March 2009, Thunder Horse produced over 300,000 barrels of oil equivalent per day from seven well s.[3]

Of note are the significant impacts of Gulf of Mexico hurricanes in recent years, including Hurricane Ivan in late 2004, Hurricanes Katrina and Rita in late 2005, and Hurricanes Ike and Gustav in late 2008. The 2009 hurricane season was mild and did not significantly threaten Gulf of Mexico oil production. The Strategic Petroleum Reserve (SPR) program resumed shipments in April 2009, at a volume of approximately 26,000 barrels per day representing only two percent of the total offshore oil royalty production through the nine month duration of the contracts. These contracts, issued to "top off" the SPR at its capacity of 727 billion barrels, expired in December 2009.

Onshore crude oil production remained steady in 2009 with falling production rates from older onshore fields being offset by:

- increasing oil production from North Dakota's Bakken shale on the Fort Berthold Indian Reservation,
- increasing condensate production from onshore gas fields, and
- Enhanced Oil Recovery projects.

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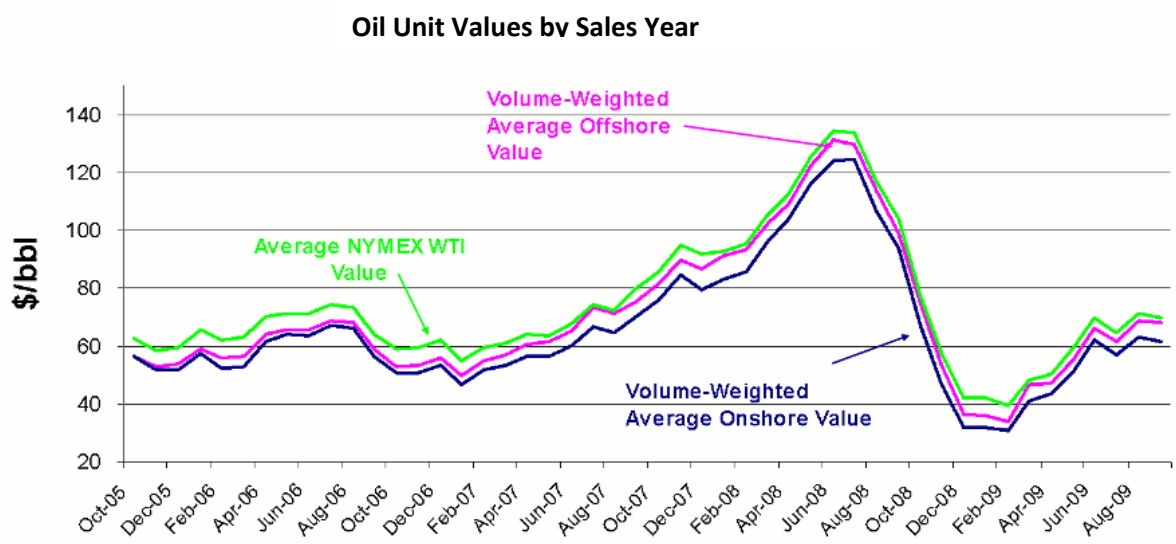
[2] http://www.chevron.com/news/Press/release/?id=2009-05-06

[3] http://www.oilonline.com/News/NewsArticles/DrillingCompletions/articleType/ArticleView/articleId/2132 8/Thunder-Horse-at-full-gallop.aspx

Oil Value Observations:



Monthly values are calculated by dividing monthly reported sales volume using sales year data (without prior period adjustments) for both RIV and RIK transactions

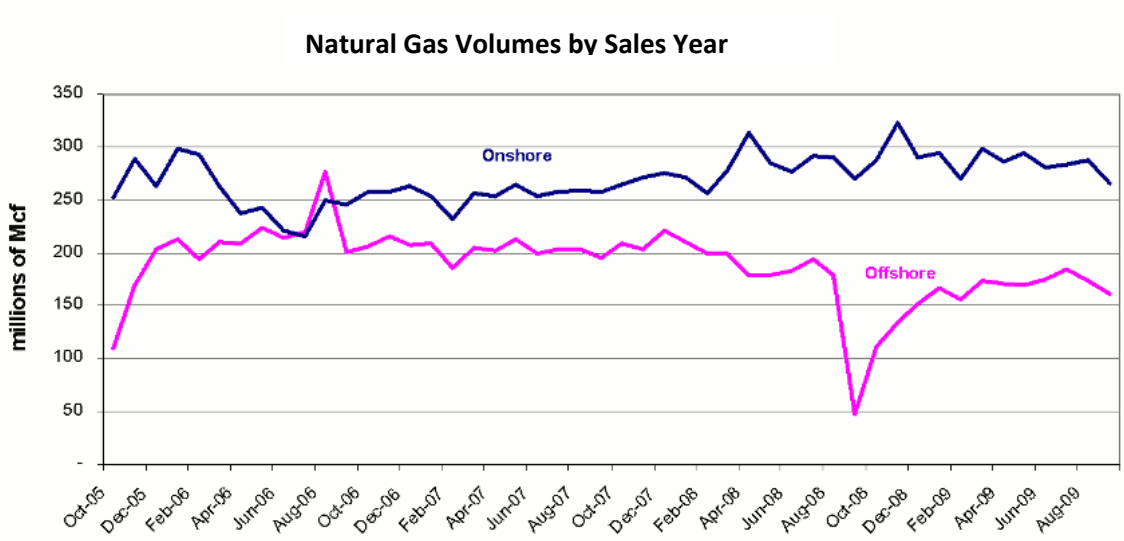
When the oil sales value per unit reported to MMS is compared to the NYMEX WTI value, a slight divergence is seen. This is due to the fact that much of the Federal production is heavy sour; these oil types receive a significant discount from WTI in the marketplace due to low API gravity and high sulfur content. The discount relates to the limited product yield and/or additional sulfur removal refinery considerations for these barrels versus the light sweet production.

Some discounts are especially deep, in particular onshore production fields as this production can be very heavy. Heavy crude is suitable for limited use in applications such as asphalt or roofing-material production. These onshore fields also are affected by the increased supply and import of Canadian crude, as these barrels displace domestic production.

Both onshore and offshore values reported to MMS may also include deductions for transportation and pipeline quality considerations resulting in a reduction in unit value. Royalty regulations allow these deductions and they typically range from $1 to $2 per barrel offshore and under $1 onshore.

Early FY 2009 oil prices continued the downturn that began mid July 2008 following the dramatic rise in prices starting in 2007. Prices stabilized in mid February and began a strong yet stable recovery through the remainder of the year.

Natural Gas Volume Observations:



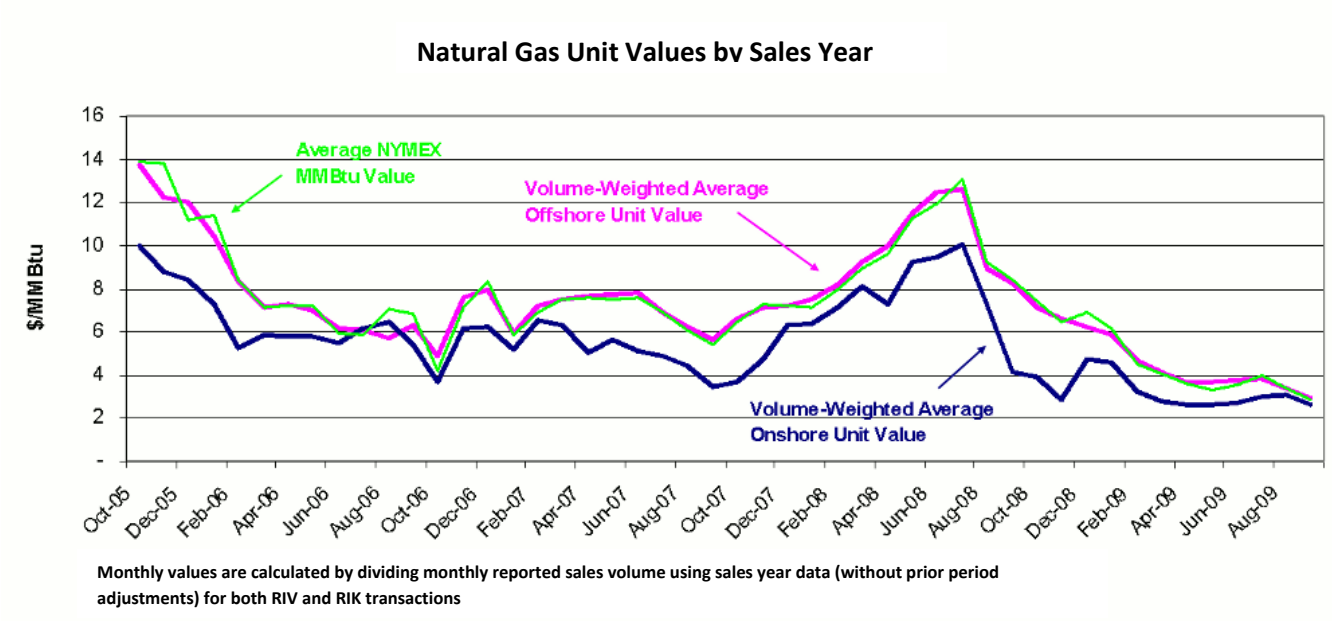
Onshore and offshore total sales volumes based on sales year (without prior period adjustment)

Overall, offshore gas production is steadily declining, especially on the shelf portion of the Gulf of Mexico. FY 2009 offshore volumes were down more than 12.5 percent from FY 2008, primarily due to the 2008 hurricanes. Although production

levels have recovered somewhat, they have not returned to pre-hurricane production levels. Production from the deepwater Independence Hub somewhat lessened this decline, although much of this production is subject to royalty relief. Some of the new deepwater oil projects also have significant associated gas production which may help offset future gas production declines.

Despite falling natural gas prices, onshore gas production remained relatively constant, increasing more than three percent over FY 2008. During the first half of the year, production was running well ahead of last year's rates while falling later in the year. The late-year decline may be attributable to the weakness in natural gas prices. Whether this lower production trend continues into FY 2010 depends on the extent the lower prices dampen drilling and further expansion of pipeline infrastructure projects.

Natural Gas Value Observations:

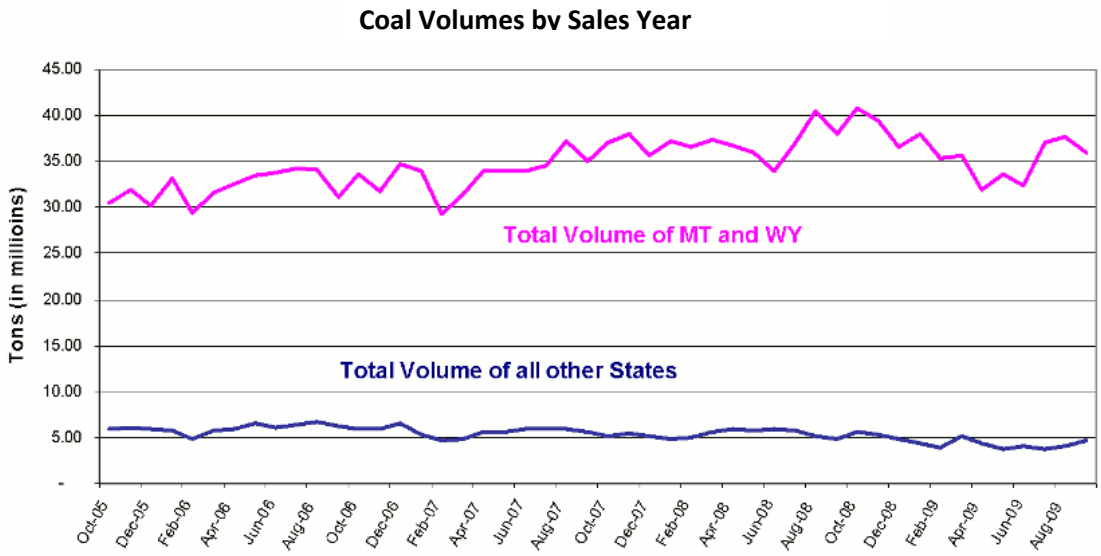


FY 2009 natural gas values continued the late FY 2008 decline through the majority of the year. Contributing to the decline was natural gas industrial demand destruction caused by the high prices and a general economic downturn. Prices moved upward in the last part of September as technical factors and the influence of passive investment in financial markets put upward pressure on physical and financial gas prices. Nonetheless, gas prices are still the lowest seen since 2001.

Offshore Gulf of Mexico values closely follow the average NYMEX Henry Hub value with some slight variance due to differences in local price indices and allowances for transportation and processing costs.

Onshore values typically trend lower than the NYMEX value because of limited onshore pipeline infrastructure and the remote locations of many onshore fields. Local onshore pricing indices show this differential when compared against the NYMEX Henry Hub value. Several significant pipeline projects underway are designed to move more gas from these discounted markets to more populated demand centers with stronger index values. Construction of the REX pipeline was completed to Clarington, Ohio in early November, moving gas from Wyoming and Colorado. REX greatly improved the price basis between the Rockies, the Mid-Continent, and the consuming East. TransCanada has proposed the 310-mile Bison pipeline that would run from Gillette, Wyoming, through southeastern Montana and North Dakota feeding other pipelines serving the Midwest. El Paso Corporation's proposed Ruby pipeline would run from Opal, Wyoming, to Malin, Oregon serving the West Coast. These and other proposed pipeline projects to move more natural gas out of the Rockies should continue to maintain or improve the Rockies basis with the consuming regions.

Coal Volume Observations:



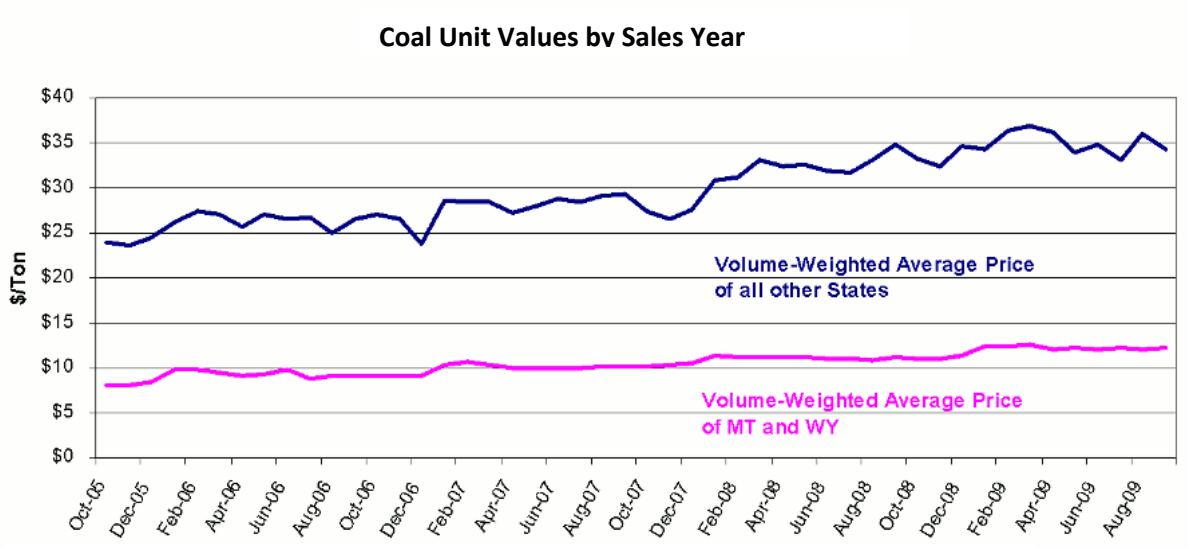
Onshore and offshore total sales volumes based on sales year (without prior period adjustment)

Low electricity generation spurred high coal inventories throughout the year, representing a roughly 25 percent increase over 2008 inventories. Coal producers nationwide dealt with record-high stockpiles and waning demand for steam coal, a trend that follows economic indicators and other energy markets. These near-capacity stockpiles constrained utility generators' ability to take advantage of depressed coal prices. A mild summer also exacerbated the situation and provided little relief to bloated stockpiles.

Powder River Basin coal production hit its lowest point in four years during the third quarter of the fiscal year as Wyoming's largest mines continued ratcheting down production to match continued weak demand for coal. The low point marked the third consecutive quarterly decline, bookending a first half that saw production fall ten million tons below the 212 million tons mined during the same period in 2008. Plans to develop and open mining operations were curtailed or cancelled. Powder River Basin coal markets remained suppressed as sulfur allowances continued at historic lows throughout the fiscal year.

The use of Colorado coal fell 22 percent during the fiscal year, and Utah coal fell 8 percent. The Colorado-Utah region's difficult geology and tougher regulatory environment in the wake of the fatal Crandall Canyon accident in 2007 constrained supply, but demand fell at a greater rate. As well, coal demand in the Colorado-Utah region hit a ceiling of inventory space. The two states had the highest stockpiles in the country, with Utah coal stockpiles increasing over 32 percent during the fiscal year, at 4.8 million tons. Colorado stockpiles were up 29 percent.

Coal Value Observations:



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The sharp drop in natural gas prices during the fiscal year captured market shares from coal. Electric utilities switched from coal to gas as natural gas prices fell more quickly than coal. One reason for the switch is that about 50 percent of natural gas is purchased on the spot market, while up to 90 percent of coal is bought through annual or multi-year contracts.

Despite Powder River Basin coal production falling to the lowest point in 13 quarters, prices continued to fall. Lower electricity demand and competition from other generating fuels have led utilities to curtail their use of coal even as stockpiles increase. Record-low gas prices sent coal prices on a downward trend as well. Some utilities resold coal on the market as they were unable to safely store the coal at their plants.

Colorado and Utah coal prices decreased due to lack of demand and an influx of resold coal hitting the market, forcing producers to discount prices in order to compete. The difficult geology for Western bituminous coal producers kept them from oversupplying their markets – as other regions did – but anemic industrial demand and a cool summer made for excessive stockpiles.