Shale Basins Demonstrate Maxim: Reduced Drilling Begets Higher Prices

Natural gas prices in the various North American shale basins rose about 50 cents, or close to 20%, year-to-year from Jan. 1, 2012 to Jan. 1, 2013, moving mainly from the $2.80s to the $3.30s per MMBtu. At the same time, operating rigs in the same basins dropped 21%, according to surveys conducted throughout the year for NGI's Shale Daily.

As companies repositioned rigs throughout 2012, moving from dry gas plays to the liquids-rich plays and then to oil, they also worked fewer rigs as borne out by lower fourth quarter profit projections by drilling service firms, Schlumberger Ltd. and Baker Hughes Inc. The companies blame the fall-off in part on a slowdown in North American drilling activity (see Shale Daily, Dec. 19). Part of the reason for the rig decline, however, is that drillers are making better use and producing more with fewer rigs. The key will be the year-end production totals, which analysts have variously predicted will be flat to down or up slightly from 2011.

National Oilwell Varco Inc., the largest oilfield equipment... cont’ pg. 14

Besting Expectations, Pennsylvania Producers Pay $206M in Impact Fees

Originally published by NGI's Shale Daily: Sept. 12, 2012

The Pennsylvania Public Utility Commission (PUC) said Monday that natural gas producers have paid most of about $206 million owed under the drilling impact fee enacted under Act 13, surging past the $180 million the state thought it would take in this year from its new omnibus Marcellus shale law.

According to the PUC, the 58 producers affected by the fee have collectively paid $197.6 million, or about 96% of the total amount due, $205.9 million. Most of the producers, 35 in all, have paid their entire obligation, while six have paid a portion of their fees and 17 haven't paid anything yet.

Chesapeake Appalachia LLC paid the largest impact fee bill at $30.8 million, followed by Talisman Energy USA Inc. at $26.4 million... cont’ pg. 15

Miss-Understood Lime 'Unconventional Conventional' Play

Originally published by NGI's Shale Daily: November 29, 2012

What explorers know about the Mississippian Lime formation could fill a book. What they don't know about the Midcontinent play could fill a few more, industry experts said Wednesday.

The best way to describe the potentially 20-million acre formation is an "unconventional conventional," said Petro River Oil Ltd. Co-CEO Ruben Alba. Thousands of conventional wells already had been drilled hit-and-miss into the Kansas/Oklahoma formation before... cont’ pg. 16
EAGLE FORD SHALE

Eagle Ford an Oil Production Barn Burner, Say Analysts

Originally published by NGI’s Shale Daily: November 20, 2012

The Eagle Ford Shale of South Texas is likely the biggest potential driver of U.S. oil production growth for the next five to 10 years with production on track to pass 1 million b/d by the middle of next year and 1.7 million b/d by the end of 2015, analyst at Raymond James & Associates said in a note Monday.

"The potential of the play is probably best exemplified by its rapidly increasing rig count, which grew from 63 rigs in January 2010 to over 250 rigs, currently," Raymond James said. "We expect to see rapid production growth as these rigs translate into production. Importantly, even though the rig count clearly isn't growing at the same linear rate as it has over the past several years, we expect production efficiencies, longer laterals and pad drilling to continue to drive production gains."

According to NGI's Shale Daily Unconventional Rig Count, there were 241 rigs active in the Eagle Ford last week, a 5% increase from a year ago.

Eagle Ford output has grown from 8,000 b/d in January 2010 to more than 900,000 b/d currently, including condensate and natural gas liquids (NGL), they said. And that growth might have been greater were it not for infrastructure constraints that have kept some production from market, the analysts added.

Oil, of course, has drawn producers to the Eagle Ford during a period of particularly low prices for dry gas. But liquids associated with natural gas and oil production are a big part of the Eagle Ford story, too. NGLs have made the Eagle Ford a boom region for the gas processing industry.

Liquids content is expressed as gallons per 1,000 cubic feet of gas, or GPM. A rating above 2 or 3 GPM is generally considered to be high, or liquids-rich, Raymond James noted. But in the Eagle Ford, production can be 5-6 GPM, which represents 1,280-1,400 Btu/cubic foot of energy content, on average. Raymond James said some producers in the Eagle Ford are seeing GPMs as high as 7 or 8.

The buildout of gas processing infrastructure to handle all of the rich gas is well under way in the Eagle Ford, and the new plants are particularly efficient compared with previous generations of processing. They are particularly good at recovering ethane, the analysts noted.

"We estimate that ethane (C2) recoveries at such plants are materially above 90%; propane recovery is between 95% and 99% (bias toward the upper band of the range, and normal and isobutane (C4s) or heavier are almost fully recovered," the analysts said. "Moreover, new plants often have a greater degree of efficiency as it relates to rejecting ethane while retaining as much propane as possible. In a world of 30 cent/gallon ethane and 90 cent/gallon propane, this can be a critical factor in supporting the profitability of processing."

The analysts said they've seen a good deal of ethane rejection -- 100,000-125,000 b/d -- across the Midcontinent and the Rockies in light of the fact that ethane prices have dropped 65% since the beginning of the year while natural gas is up 25%.

"Given the high percent of ethane in the standard Eagle Ford y-grade barrel, what does this mean for gas processors? The uplift from processing and fractionating is still profitable," the analysts said. "We estimate that the uplift from processing gas, including the cost of shrink/plant fuel and quality degradation is currently $1.58/Mcf of gas.

"...[R]egardless of the low price of ethane, propane and the heavier end of the [NGL] barrel support gas processing and fractionation margins. When considering the forward curve for purity products, we believe that gas processing and NGL fractionation will remain advantaged despite backwardation of the heavy end of the barrel."

However, the analysts said the uplift from processing Eagle Ford gas will trend down as oil prices decline next year.

On the oil side of the production ledger, the outlook for the infrastructure that handles crude, that is to say refineries, is more uncertain. There is plenty of refinery capacity in the Eagle Ford region, but the problem is it was mainly designed to handle heavier, sour imported crudes. Therefore, Eagle Ford crude must move to the larger Gulf Coast refining complex, driving its price to $5-7/bbl below that for Louisiana Light Sweet crude, the analysts said.

There is talk of converting some of the Eagle Ford capacity to run a lighter crude slate, but doing this is more complicated, costly and time-consuming than many realize, Raymond James said.

However, the analysts wrote that "ultimately, the Eagle Ford stands to be one of the best opportunities to move America closer toward energy independence, and its attractive geographic proximity to the heart of America's refinery and North American petrochemical industry doesn't hurt either."

EXPORTS

LNG Exports Depend Upon Shale Gas Staying Power, Study Finds

Originally published by NGI’s Shale Daily: December 10, 2012

Exporting liquefied domestic natural gas to world markets would generate a net benefit to the U.S. economy, and the more liquefied natural gas (LNG) that's exported, the greater the benefit, according to a macroeconomic analysis of the impact of LNG exports commissioned by the U.S. Department of Energy (DOE) and released for public comment Wednesday.

"Across all these scenarios [considered by the study], the U.S.
was projected to gain net economic benefits from allowing LNG exports. Moreover, for every one of the market scenarios examined, net economic benefits increased as the level of LNG exports increased. In particular, scenarios with unlimited exports always had higher net economic benefits than corresponding cases with limited exports，“ NERA Economic Consulting said in the summary of its 216-page report.

But one of the main keys to successful exports is cheap shale gas and lots of it for a long time. Without low domestic prices U.S. LNG won't be competitive in the world market. Based on the report if U.S. LNG exports are restricted, it’s more likely to be because of economics rather than government policy.

Under a low natural gas price case, which includes "high" estimated ultimate recoveries (EUR) from shale plays, exports are feasible. "However, under a low shale gas outlook (low shale EUR), international demand has to increase along with a tightening of international supply for the U.S. to be an LNG exporter," NERA said.

On the same day the NERA study was released, the Energy Information Administration (EIA) weighed in on LNG exports (see Shale Daily, Dec. 7). In its Annual Energy Outlook for 2013 (AEO2013), the EIA said that due to rising shale gas development, the United States is expected to become a net exporter of LNG starting in 2016, and a net exporter of gas (including via pipelines) in 2020. It projects that LNG exports will rise to about 1.6 Tcf by 2027, almost double the 0.8 Tcf projected last year in the AEO2012. The agency anticipates that the United States will become less dependent on foreign energy over the forecast period. Overall, energy imports will fall to 9% in 2040, compared with 19% in 2011 and 30% in 2005, the EIA said.

The United States would benefit most from exports if it were able to produce "large quantities" of shale gas at low cost, if global demand for LNG increases rapidly and if LNG supplies from other regions are limited, NERA said.

"If the promise of shale gas is not fulfilled and costs of producing gas in the U.S. rise substantially, or if there are ample supplies of LNG from other regions to satisfy world demand, the U.S. would not export LNG," the study said. "Under these conditions, allowing exports of LNG would cause no change in natural gas prices and do no harm to the overall economy."

The long-awaited independent study is the second part of DOE's two-part analysis of the impact of LNG exports on domestic natural gas prices and the U.S. economy. The first part was conducted by DOE's Energy Information Administration and released in January (see Daily GPI, Jan. 20). DOE would not disclose the name of the firm conducting the macroeconomic analysis; however, NERA’s name was recently linked to a news service (see Daily GPI, Nov. 21). Release of the NERA study had been delayed, and in the months leading up to the U.S. presidential election it became apparent to many that it would not be released until after election day.

The NERA study looked at "a wide range of different assumptions about levels of exports, global market conditions, and the cost of producing natural gas in the U.S.," the firm said. "...[M]arket scenarios ranged from relatively normal conditions to stress cases with high costs of producing natural gas in the U.S. and exceptionally large demand for U.S. LNG exports in world markets...Export limits were set at levels that ranged from zero to unlimited in each of the scenarios.

"In all of these cases, benefits that come from export expansion more than outweigh the losses from reduced capital and wage income to U.S. consumers, and hence LNG exports have net economic benefits in spite of higher domestic natural gas prices. This is exactly the outcome that economic theory describes when barriers to trade are removed."

Not all of the scenarios examined yielded conditions that would generate exports of LNG from the United States. Under the study’s U.S. reference and international reference cases (status quo conditions at home and abroad), "there is no feasible level of exports possible from the U.S.," NERA said.

Domestic gas prices would rise with LNG exports, the study found. "But the global market limits how high U.S. natural gas prices can rise under pressure of LNG exports because importers will not purchase U.S. exports if U.S. wellhead price rises above the cost of competing supplies. In particular, the U.S. natural gas price does not become linked to oil prices in any of the cases examined."

The research found that at the time when LNG exports could begin (2015), the increase generated in natural gas prices would range from zero to 33 cents/Mcf in 2010 dollars.

"The largest price increases that would be observed after five more years of potentially growing exports could range from 22 cents to $1.11/Mcf," the study found. "The higher end of the range is reached only under conditions of ample U.S. supplies and low domestic natural gas prices, with smaller price increases when U.S. supplies are more costly and domestic prices higher."

Domestic gas prices would not rise to levels in countries that
pay oil parity-based prices for LNG imports, the study found. "U.S. exports will drive prices down in regions where U.S. supplies are competitive so that even export prices will come down at the same time that U.S. prices will rise."

While exports would be a net benefit to the U.S. economy, not all participants in the nation's economy would benefit equally, and some would be harmed, the study found. In general, the winners would be the shareholders of natural gas companies.

"Like other trade measures, LNG exports will cause shifts in industrial output and employment and in sources of income," the study found. "Overall, both total labor compensation and income from investment are projected to decline, and income to owners of natural gas resources will increase.

"...[T]hrough retirement savings an increasingly large number of workers share in the benefits of higher income to natural resource companies whose shares they own. Nevertheless, impacts will not be positive for all groups in the economy. Households with income solely from wages or government transfers, in particular, might not participate in these benefits."

Commercial interests that would be impacted by LNG exports are confined to narrow segments of industry, according to the study. "About 10% of U.S. manufacturing, measured by value of shipments, has both energy expenditures greater than 5% of the value of its output and serious exposure to foreign competition. Employment in industries with these characteristics is about one-half of one percent of total U.S. employment."

The overall level of employment in the country would likely not be affected; however, some workers would likely be pulled to industries associated with gas production and export from other industries. "In no scenario [in the study] is the shift in employment out of any industry projected to be larger than normal rates of turnover of employees in those industries."

The trade group Industrial Energy Consumers of America (IECA) gave a nod to the report but made it clear Wednesday that it's not a fan of its findings. "Once export applications are approved, there is no putting the genie back in the bottle," said IECA President Paul Cicio. "The export application approvals are for 20-30 year time periods and a lot can happen. For this reason it is important that policy makers thoughtfully evaluate the implications."

IECA said at first glance it found four "weaknesses" in the report:

• It doesn't compare the economic benefits of exporting natural gas versus using it as a domestic jobs creator.
• It "unfortunately" uses EIA Annual Energy Outlook 2011 demand forecast assumptions, which say electricity demand for natural gas will decrease by 2020, and that there will be only a small increase in industrial demand.
• It does not "adequately address," the EPA and Bureau of Land Management regulations on natural gas drilling that could negatively impact production, nor does it address forthcoming EPA regulations that will drive demand.
• It does not address the implications of removing the intangible drilling costs tax provision that allows the industry to deduct expenses and generate the cash flow to invest in drilling.

The report was harshly criticized by Dow Chemical Co. CEO Andrew Liveris.

"The report issued by the DOE on...LNG exports is flawed, misleading and based on outdated, inaccurate and incomplete economic data," Liveris said. "The report fails to give due consideration to the importance of manufacturing to the U.S. economy. Manufacturing is the largest user of natural gas in the U.S. and creates more jobs and more value to the U.S. economy from natural gas than any other sector."

Liveris took out his calculator to make his point. "The value of every unit of energy used by the manufacturing sector is multiplied by as many as 20 times from the production of thousands of high-value products though the value chain," he said. "Compare this to the one-time value created by exporting energy as liquefied natural gas. Furthermore, for every manufacturing job created on the factory floor, five to eight more are created in the larger economy."

However, the Institute for Energy Research (IER) praised the study’s findings. "The report confirms what everyone knows: exporting American-made products creates American jobs and grows our economy. It does not matter if we are exporting wheat, airplanes or natural gas," said IER President Thomas Pyle. "We are at no risk of running out of natural gas, especially if the federal government ends its de facto moratorium on exploration and development of new areas."

As of Nov. 21, about 20 parties had applied for authorization to export domestically sourced LNG, some to nations that are parties to free trade agreements (FTA) with the United States, some to non-FTA countries and some to both, according to DOE’s latest applications summary. Exports to FTA countries are presumed to be in the public interest. However, DOE so far has only granted Cheniere Energy’s Sabine Pass LNG project authorization to export to the much larger group of non-FTA countries. The newly released NERA analysis bolsters the case of those seeking non-FTA export authorizations.
North American Unconventionals Shifting Global Energy Trade, Says IEA

Originally published by NGI's Shale Daily: November 13, 2012

The United States will become the top producer of oil globally within five years, a net exporter of natural gas by 2020 and an oil exporter by close to 2030, all thanks to its massive unconventional resources, the International Energy Agency (IEA) said Monday in its annual flagship publication, the World Energy Outlook (WEO).

"North America is at the forefront of a sweeping transformation in oil and gas production that will affect all regions of the world, yet the potential also exists for a similarly transformative shift in global energy efficiency," said IEA Executive Director Maria van der Hoeven.

"The global energy map is changing, with potentially far-reaching consequences for energy markets and trade," the WEO report noted. "It is being redrawn by the resurgence in oil and gas production in the United States and could be further reshaped by a retreat from nuclear power in some countries, continued rapid growth in the use of wind and solar technologies and by the global spread of unconventional gas production."

Ultimately recoverable resources, the measure of long-term fossil fuel production potential used in the WEO, "are considerably higher than proven reserves. As market conditions change and technology advances, some of these resources are set to move into the proven category, providing further reassurance that the resource base will not constrain production for many decades to come."

"In particular, large volumes of unconventional oil and gas are expected to be proven in many parts of the world, diversifying the geographical distribution of reserves. The costs of supply will undoubtedly be higher than in the past, as existing sources are depleted and companies are forced to turn to more difficult sources to replace lost capacity."

Energy developments in the United States "are profound and their effect will be felt well beyond North America -- and the energy sector," noted IEA's report. "The recent rebound in U.S. oil and gas production, driven by upstream technologies that are unlocking light tight oil and shale gas resources, is spurring economic activity -- with less expensive gas and electricity prices giving industry a competitive edge -- and steadily changing the role of North America in global energy trade."

Close to 2020, the United States is projected to become the largest global oil producer (overtaking Saudi Arabia until the mid-2020s) and starts to see the impact of new fuel-efficiency measures in steadily changing the role of North America in global energy trade." The result is a continued fall in U.S oil imports, to the extent that North America becomes a net oil exporter around 2030. This accelerates the switch in direction of international oil trade toward Asia, putting a focus on the security of the strategic routes that bring Middle East oil to Asian markets."

The United States now imports about one-fifth of its total energy needs, but it is projected to become "all but self-sufficient in net terms -- a dramatic reversal of the trend seen in most other energy-importing countries."

The massive jump in domestic oil and gas production "will mean a sea-change in global energy flows." In its new scenario, the WEO's central scenario, the "United States becomes a net exporter of natural gas by 2020 and is almost self-sufficient in energy, in net terms, by 2035. North America emerges as a net oil exporter, accelerating the switch in direction of international oil trade, with almost 90% of Middle Eastern oil exports being drawn to Asia by 2035."

Remaining technically recoverable resources of global conventional gas, including proven reserves, reserves growth and undiscovered resources, now is estimated at more than 460 Tcm, or 16,234 Tcf, an increase of around 60 Tcm (2,118 Tcf) from the 2011 WEO. For shale gas, remaining resources are estimated at 200 Tcm, or 7,062 Tcf, which includes the latest U.S. Energy Information Administration estimates of 81 Tcm (2,860 Tcf) for tight gas and 47 Tcm (1,659 Tcf) for coalbed methane (CBM) (see Shale Daily, June 27).

Oil production (net processing gains) rises from 84 million b/d in 2011 to 92 million b/d in 2020 and 97 million b/d in 2035. Crude oil production, which is the largest single component of oil production, is forecast to fall slightly between 2011 and 2035, with "sharp increases" in natural gas liquids output because of rising gas production and unconventional oil -- mostly oilsands in Canada.

By 2015, U.S. oil production is forecast to increase to 10 million b/d then jump to 11.1 million b/d by 2020, overtaking frontrunner Saudi Arabia and second-place Russia, the WEO noted. The U.S. lead should last for a short while before Saudi Arabia ramps up oil output to 11.4 million b/d over the 2020-2030 decade, outpacing U.S. output. By 2035, U.S. oil production is expected to slip to 9.2 million b/d, lower than Saudi Arabia's estimated 12.3 million b/d and behind Iraq, which is seen moving into second place. Russia would become the third largest oil exporter. By then real oil prices are forecast to reach $125/bbl, but the United States likely won't be relying much on foreign energy, the IEA noted.

Overall, natural gas resources are expected to hit 790 Tcm [27,898 Tcf] by 2035, "or more than 230 years of production at current rates," the WEO noted. Unconventional gas would account for "nearly half of the increase in global gas production to 2035."

The prospects for unconventional production worldwide still are uncertain, IEA noted, and "depend, particularly, on whether governments and industry can develop and apply rules that effectively earn the industry a 'social license to operate' within each jurisdiction, so satisfying already clamorous public concerns about the related environmental and social impacts."

Among the OECD regions, North American gas production is projected to continue to expand, thanks mainly to U.S. shale gas. Total domestic gas production grows from an estimated 650 Bcm (22.95 Tcf) in

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**US Oil and Gas Production**

Source: IEA's World Energy Outlook 2012

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Chesapeake Caves to Shareholders; Utica Acreage For Sale

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Ahead of the annual shareholder meeting on Friday, Chesapeake Energy Corp. acquiesced to demands of major shareholder groups and Carl Icahn, who now holds 7.8% of the stock, and said four existing independent directors would resign from the board. The company also has put up for sale 337,481 net acres in its prized Utica/Point Pleasant Shale, which would give it less than one million acres in the play.

Shareholders reacted positively, sending shares up 6.03% (94 cents) to close at $16.52, versus $15.58 on Friday. More than 37.6 million shares exchanged hands, versus average volume of 30.4 million.

Chesapeake said its decision to oust nearly half of its nine-member board followed "extensive discussions" with Icahn and representatives of Southeastern Energy Management, the largest shareholder with 13.6% of the stock.

Three of the new directors are to be proposed by Southeastern and one seat would be proposed by Icahn or someone he designates.

Robert W. Baird & Co.'s senior analyst Michael Hall said the board shakeup "will go a long way in addressing the market's lack of confidence around Chesapeake's corporate governance and likely usher in a new culture of increased conservatism."

Meanwhile, Treflis energy analysts on Monday cut their price target on Chesapeake by almost one-third to $19.12 from an April target of $27.81.

The announcement "is the culmination of a continuing effort by Chesapeake's board to address shareholder concerns and better position the company for the future," said CEO Aubrey McClendon. "I am fully supportive of these measures and remain focused on executing Chesapeake's strategy."

One shareholder is retiring this year and Chesapeake already announced that it would replace that vacated seat with the still-to-be-named independent nonexecutive chairman through a selection process that is nearing completion, the company noted. McClendon was stripped of the chairman title in early May (see Shale Daily, May 2).

The new chairman is to have "no previous substantive relationship with Chesapeake" and would be "confirmed by the reconstituted board and will be acceptable to Southeastern and Mr. Icahn," Chesapeake stated. McClendon then is to relinquish the position of chairman but would continue to run the company and serve as a director.

The new board's composition, including the independent nonexecutive chairman, is to be announced by June 22. The size of the board would remain at nine directors.

Icahn acquired his big stake in Chesapeake late last month and has put up for sale 337,481 net acres in its prized Utica/Point Pleasant Shale, which would give it less than one million acres in the play.

"We appreciate the board's willingness to listen to shareholders and to respond appropriately," said Icahn. "Under Aubrey's leadership, Chesapeake has assembled great assets and I am confident I can help the company create significant shareholder value from these assets. We enjoyed a very good relationship when I acquired almost 6% of the company's stock in late 2010 and I look forward to a similarly constructive relationship now," (see Shale Daily, Dec. 22, 2010).

Southeastern CEO O. Mason Hawkins said the steps taken by Chesapeake to "reconstitute" the board "will enhance oversight and provide greater accountability."

In another move that acquiesces to large shareholder group demands, Chesapeake's board announced that if the amendment to the bylaws to implement majority voting in director elections is approved by shareholders on Friday, it would be implemented immediately and applied to the results of the annual meeting.

"The board will also seek relief from the Oklahoma statute mandating classified boards of directors for certain Oklahoma incorporated public companies so that shareholders will have the opportunity to elect the entire board of directors at the 2013 annual meeting of shareholders."

Chesapeake's lead independent director Pete Miller, who also is CEO of National Oilwell Varco, said the actions would "further enhance Chesapeake's corporate governance for the benefit of all shareholders. We greatly appreciate the substantial contributions of all of our directors but recognize our shareholders' desire for change."

The Utica/Point Pleasant acreage for sale, which encompasses 510,847 gross acres, is mostly in the wet gas/oil window of the play, land that Chesapeake had planned to target in its move to a more liquids position. Eighty percent already is held by production (HPB).

As of May, Chesapeake had 1.3 million net acres in the Utica Shale (Pennsylvania and Ohio combined), according to figures compiled by NGI's Shale Daily. The latest sale would leave the company with an estimated 963,000 net acres in the prospective play.

The "rationale for selling" is because capital spending has been cut, "altering the company's plans to develop all of its highly prospective Utica acreage," Chesapeake stated. "Utica/Point Pleasant development will be focused where Chesapeake's land ownership is more concentrated."

The Utica land is limited to the Cincinnati, Utica, Point Pleasant and Trenton intervals, according to Chesapeake. About 270,500 net acres are HBP by shallower zones (Queenston and Clinton counties) or held by storage, it said.

Chesapeake now has two operated wells in the acreage for sale. One well is a stratigraphic test that was drilled this year and is temporarily plugged. The second is an exploratory well also drilled this year that is scheduled to be hydraulically fractured in July. There also are five nonoperated wells across the leasehold that were drilled between 1995 and 2005, all vertical completions in naturally fractured Utica intervals with "minimal production volumes," Chesapeake noted.

The bid date for the Ohio sale is July 11 with an effective date of sale July 1. A closing date is tentatively set for Aug. 17.
Bakken Fracking In a Lull, But 2013 Looms Big

Originally published by NGI's Shale Daily: December 20, 2012

In the midst of continued oil/natural gas production growth, albeit at a slower pace, North Dakota's drilling activity has slowed significantly and the amount of hydraulic fracturing (fracking) even more so, according to the state's top oil/gas official. Activity is projected to increase again next year, however, with continuing technology advances.

Department of Mineral Resources (DMR) Director Lynn Helms said there has been a marked increase in the number of wells that sat idle because they were waiting for fracking services.

"What this indicates is that operators continue to drill a significant number of wells as a means of retaining leases, but they postpone the major investment of hydraulic fracturing," Helms told a webcast audience Monday. "That investment has become a significant part of Bakken well costs."

According to Smith Bits data and NGI's Shale Daily calculations for the week ending Dec. 14, Whiting O&G and Continental Resources Inc., each with 23 rigs, were the most active operators in the Bakken/Sanish/Three Forks region, followed by Statoil ASA and Hess Corp., both with 16 rigs, and Petro-Hunt LLC and ExxonMobil Corp., with 11 and 10 rigs, respectively. In total there were 211 rigs drilling in the region, which was up 10 rigs from one year ago.

The average well in the Bakken, where 95% of the state's oil/gas production is centered, costs $9-11 million, according to Helms. Fracking averages nearly half of that cost, or about $5 million, he said.

"In October, there was a significant amount of wells that operators decided to postpone, or slow down the fracturing services on, in an effort to conserve capital, or use it for drilling rather than hydraulic fracturing," he said.

"Nevertheless, the companies say that starting in January, with new capital budgets, they plan to ramp drilling back up toward about 200 rigs [from the current 180]. We talked to some of the biggest Bakken drillers, such as Continental Resources, which plans to drill 60 more wells next year than it did this year."

Helms said other major players, such as Hess and Whiting, have indicated that they, too, will increase the number of wells they drill next year. "So we believe that shortly after the first of the year, we will begin to see the rig count increase again, and we will see a lot of mobilization of hydraulic fracturing crews to try to catch up with the increased drilling rig count," Helms said.

The growth recently has continued to be in oil production, with natural gas staying relatively flat. According to Helms, that as an outgrowth of dry gas producers outside the Bakken reducing their production "pretty substantially" in the face of low gas prices. In contrast, Bakken gas is still "fetching a very good price," and production increased there, he said.

Behind the number of drilling rigs, wells and permits being issued, improved efficiencies and technological advances are greatly increasing the productivity of the operators, Helms said. Where the big operators have been getting 10-12 wells drilled annually for each rig in action, that number is expected to increase to 14 by the end of 2013, he said.

"The operators continue to find better drill rigs, better drilling systems and increase that efficiency in the drilling arena. That means the hydraulic fracturing folks are going to have to get very busy to keep up with that."

Helms said the Bakken's biggest driller, Continental Resources, will have drilled 270 wells by the end of this year, and it expects to drill 310-320 wells in 2013. "They have a very intense program, and they are very focused on the Three Forks formation."
Texas Judge: Flaming Water a Hoax, Conspiracy Against Range

Originally published by NGI's Shale Daily: February 21, 2012

A Texas couple that has sued Range Resources Corp. for allegedly contaminating its drinking water with hydraulic fracturing (fracking) on Thursday lost a bid for dismissal of the company's countersuit, which alleges that the couple participated in a conspiracy to defame Range.

In response to a lawsuit filed by landowners Steven and Shyla Lipsky, Range last year told the 43rd District Court in Parker County, TX, that the Lipskys and environmental consultant Alisa Rich of Wolf Eagle Environmental conspired to incriminate the company for the occurrence of natural gas in the couple's well water. The company has maintained -- and the Railroad Commission of Texas (RRC) has found (see Shale Daily, Feb. 10, 2011) -- that the gas in the Lipskys' well came from the Strawn Formation and not the deeper Barnett Shale targeted by Range's Barnett Shale gas well.

On Thursday the 43rd Judicial District Court in Texas sided with Range in denying the Lipsky's motion to dismiss Range's countersuit.

"The court references with concern the actions of Mr. Steven Lipsky, under the advice or direction of Ms. Alisa Rich, to intentionally attach a garden hose to a gas vent -- not to a water line -- and then light and burn the gas from the end nozzle of the hose," wrote presiding judge Trey E. Loftin. "This demonstration was not done for scientific study but to provide local and national news media a deceptive video, calculated to alarm the public into believing the water was burning."

Range maintains in its lawsuit (see Shale Daily, July 20, 2011) that Rich conspired with the Lipskys' to do an end-run around the RRC, which already was investigating the alleged well contamination, to gain an audience with the Environmental Protection Agency (EPA), which Rich believed would be more sympathetic to their cause.

"Rich's actions, with which the Lipskys agreed, approved, and/or acquiesced, resulted in losses to Range, and therefore its shareholders, in an amount in excess of $3 million...in expenditures and other harm to its business reputation," the company said.

Loftin said in his order Thursday that Rich deliberately sought to stir up EPA Region 6 administrators.

"There is further evidence that Rich knew the regional EPA administration and provided or assisted in providing additional misleading information (including the garden hose video) to alarm the EPA. Moreover, the emails in question [between Rich and the Lipskys] which refer to this deceptive garden hose demonstration as a 'strategy' appear to support that a 'meeting of the minds' took place and that a reasonable trier of fact could believe, together with other evidence, that the elements of a conspiracy to defame Range exist."

Range said in its countersuit against the Lipskys that instances of flaming well water purported to be documented by Lipsky actually involved the ignition of natural gas at the end of a garden hose that was connected to a well vent specifically intended to release naturally occurring gas from the Lipsky water well.

Further, Range said the Lipskys have enjoyed a break in ad valorem taxes on their multi-million-dollar property of about $44,000 per year due to the property's devaluation based on the couple's well water contamination claims.

While Range was later exonerated by Texas regulators, the EPA cited the company for the alleged well water contamination in December 2010 (see Shale Daily, Dec. 9, 2010). Range is still fighting the EPA.

"We're pleased with the decision and look forward for a jury to hear the case," Range spokesman Matt Fitzarella said Friday.

Since the Range case, the controversy over the potential link between fracking and aquifer/well water contamination has moved to Wyoming, where EPA has come the under scrutiny of state regulators and federal lawmakers for its preliminary findings that fracking may have contaminated water in that state (see Shale Daily, Feb. 16; Feb. 10).

Resurgence of the Permian Basin Driven by Innovation, Prices

Originally published by NGI's Shale Daily: July 25, 2012

Ten years ago the Permian Basin, first drilled nearly a century ago, was considered passe for oil and gas exploration. Today, however, a new generation of explorers and midstream operators has made the basin one of the hottest tickets on the reservoir circuit and there are no signs that the lights will be dimming anytime soon.

The massive stretch of prairie land straddles more than 50 counties in West Texas and southeastern New Mexico in an area about 250 miles wide and 300 miles long. The basin and its subsasins of tight sands and shale, stacked on top of one another, contain thick deposits of rocks that have squeezed out more than 40 billion bbl of oil since wildcatters first tapped into reservoirs. For today's explorers, there's never been anything like the rejuvenated Permian, which has come out from down under through technology, innovation, and, oh yes, oil prices.

Today hundreds of old and new companies are ramping up activity in the area nearly 100 years after the first commercial Permian oil well was drilled and completed to a depth of 2,498 feet in 1921 in Mitchell County, TX. Production reached a peak of about 715 million bbl in 1974 before starting on a 30-year decline to a low of 307 million bbl in 2004. Production is again climbing with the Texas portion alone reaching 284 million bbl in 2011.
The Texas Permian accounted for about two-thirds of the state's 437 million bbl of crude oil output in 2011, and about 17% of the total 2 billion bbl of U.S. oil production, according to University of Texas of the Permian Basin statistics.

A good indication of activity is in the number of new drilling permits issued. Last year the Railroad Commission of Texas (RRC) issued 9,347 new drilling permits for Permian Basin operators, well ahead of 2010, when it issued 6,928 and triple the 3,369 issued in 2009. About 133,000 total wells in the Texas Permian are on the RRC proration schedule, a list of wells that are on schedule to produce and on which operators submit monthly production reports to the commission. About 22,000 are listed as active injection/disposal wells and 82,000 of which are listed as active producing wells.

An estimated 439 drilling rigs were working the Permian for the week ended July 13, 2012. Those 439 rigs represented 23.2% of the total rigs drilling in the United States at the time, a figure that is significantly higher than it normally is this time of year. NGI's Shale Daily took a look back at the historical Permian rig count over the last 10 years, and from 2002-2010, the Permian rig count represented 11-15% of the total U.S. rig count for the second week of July.

The George Mitchell-led horizontal drilling/hydraulic fracturing (fracking) combo that turned the North American natural gas markets upside down got twisted about in the conventional Permian play, demonstrating how technology and engineering reign supreme.

Innovations in the venerable Spraberry oilfield, a conventional play in the Midland, TX, area are a prime example of how everything old has become new again. Conventional wells for decades typically were drilled straight down into one or two zones. However, operators began to experiment with their drilling techniques, still drilling their conventional wells but with a twist: adding multi-stage fracturing techniques.

In unconventional drilling, horizontal laterals may be drilled up to 8,000 feet, with several fracturing stages along the way. Conventional verticals can be drilled deeper, possibly opening up more oil and gas zones, which may be fracked several times. The wellbores in some Spraberry wells have begun to look more like the lateral section of a horizontal. As tight reservoirs were combined and commingled through staged fracturing in the vertical drilling, the Spraberry commingled with the Wolfcamp formation to become the "Wolfberry" and the Bone Spring became the "Wolfbone."

Unconventional drilling techniques also have opened up tight formations in the rich shale on the western edge of the basin. The Delaware subbasin's Avalon, Wolfcamp and Bone Spring shales straddle land near Hobbs, NM, and four West Texas counties. Today the three formations are a big target for unconventional oil and NGLs.

Apache Corp.'s John Christmann, regional vice president of the Permian Basin division, began to put people on the ground in the Permian area in May 2011. The producer's workforce in a year's time has grown from 345 to close to 800. Apache's leasehold is considered the second largest behind Occidental Petroleum Corp.

"In 2010 we were running five rigs," Christmann said in June. Today Apache is running around 34 rigs, almost a seven-fold increase over a two-year period. Two years ago the company had drilled 20 horizontal wells, mostly in the Central Basin; today it's drilled more than 120. The total well count has tripled to almost 760 from 263.

"I tell you, the more we work these assets, the more excited we get," Christmann said. "Everything is working technically, and there are more and more horizontal candidates coming at us from all different locations. So today we see 35,518 [drilling] locations” versus about 5,000 when he arrived a year ago. "When you look at that, we do know..."
there's a lot behind us and there's a lot underneath us."

The Permian "could be the most incrementally impactful trend" for the exploration and production (E&P) sector over the next five years, which means there's a big need to get incremental infrastructure up and moving, according to U.S. Capital Advisors LLC (USCA).

Today at least $5 billion of new infrastructure projects have been announced and more are likely to be launched over the coming months. As a companion report to a recent one by USCA on the Permian's exploration and production activity (see Shale Daily, June 12), analysts Becca Followill and James Carreker took a deeper look at the infrastructure needs for natural gas, oil and natural gas liquids (NGL) operators in the basin to determine what's going to be needed as production continues to ramp up in various parts of the play.

USCA's report, which overlays forecasts of hydrocarbon production against current and planned infrastructure, also provides maps and summaries of companies' regional assets. The big infrastructure needs are for crude oil and natural gas liquids (NGL), according to USCA analysts. Infrastructure for crude oil is "tight" and will be until early in the second half of 2014, when four "major" pipelines, new or expanded, are to more than double takeaway capacity from its current 725,000 b/d. New capacity is expected to eliminate bottlenecks through 2018.

Oil gathering infrastructure still will be lacking in some of the wide open prairie, said Followill. "Generally, drilling is occurring in areas with established infrastructure, but we identified several significant areas of activity with little or no pipeline infrastructure."

NGL pipeline capacity also is squeezed. Two systems now being built should add 400,000 b/d of capacity by the second half of 2014. "Both are expandable, so we don't see additional projects announced," said Followill.

Don't look for any new natural gas pipeline projects in the near-term, but gas processing expansions are a possibility. Gas production peaked at around 9.5 Bcf/d and today it's about half that.

"Permian gas production is down 50% from the early 1970s highs, so plenty of capacity abounds," said Followill. Gas processing capacity in aggregate appears to be sufficient at around 4 Bcf/d, "but with the Permian spanning 10 million acres, it's all about location and plant vintage. Look for more processing to be announced." USCA is estimating another 1 Bcf/d will be needed down the line.

Federal Reserve Bank of Dallas economists Robert W. Gilmer and Jesse B. Thompson III said in June moving NGLs to the 1 million b/d market on the Gulf Coast has posed the "greatest problems" for basin growth. However, with its "rich infrastructure in place," the basin "enjoys the advantage of expanding on existing transportation systems rather than starting from scratch." New gathering systems and fractionation capacity is under way in the Avalon shale, with a rail terminal and several pipelines under construction that would move product to Houston, they said.

The Permian Basin's "tight labor markets are the stuff of legend," said the economists. Finding workers in the Delaware subbasin was difficult "before the shift to shale began and they remain so." The labor shortages "in the lucrative oil sector drive local wage increases, leaving other segments to compete for workers." The "frenetic activity level is increasing," said the economists. While overall drilling activity in some unconventional plays may have "cooled in recent months, the Permian Basin has picked up the pace."

Lease auctions in New Mexico and Texas point to heightened interest in the Permian. On Wednesday, July 18 a lease auction conducted by the U.S. Bureau of Land Management's state office in Santa Fe, NM, resulted in bids on 14 parcels in New Mexico that brought in more than $25.6 million and 15 parcels in Texas that attracted $2.7 million. The highest bids all were for New Mexico parcels in the Permian Basin.

Charles D. Ray of Midland, TX, offered to pay a total of $10.08 million for an 800-acre parcel of land ($12,600/acre) in Lea County, NM. Adventure Exploration Partners II LLC of Midland bid almost $7.3 million total for 640 acres with an $11,400/acre bid for some New Mexico Permian acreage. The third-highest bid of $2.11 million was made by Midland-based Marshall & Winston Inc. for 319.7 acres at $6,600/acre.

The land auctions by the Texas General Land Office (GLO) over the past couple of years also show where the money is being spent. A GLO auction in April 2011 brought one bid of $9.9 million: $3,264/acre for 30,000 acres, which compared with an average bid of $906/acre in the same area just six months before.

This past April the GLO auction brought no bids close to the $9.9 million bid, but GLO tabulated high bids for several Permian leaseholds: $456,000 on 80 acres (Heritage Land Services LLC); $397,680 on 240 acres (Double Nickel Oil and Gas LLC); $367,200 on 240 acres (LE Norman Operating LLC); $324,800 on 320 acres by Magnum Operating LLC; $210,000 on 120 acres (Comstock Oil & Gas); $202,080 on 80 acres (Permian Basin Land Associates Inc.); $200,160 on 160 acres (Clayton Williams Energy Inc.); and $189,571 on 151.5 acres (Double Nickel). Several went for more than $100,000.

According to analysis conducted by NGI's Shale Daily, there are 439 rigs operating in the Permian currently. The top five operators are Apache with 34 rigs, COG Petroleum with 33 rigs, Occidental (32 rigs), Pioneer Natural (30 rigs) and Cimarex Energy (14 rigs). The top five contractors in the basin are Patterson-UTI Energy (48 rigs), Helmerich & Payne (32 rigs), Nabors Drilling (26 rigs), Capstar Drilling (19 rigs) and Big Dog Drilling (18 rigs).
industry is at mid-cycle operating rates. In addition, the investment for on-purpose propylene production will improve the downstream propylene envelope integration and provide a platform for margin improvements."

The Gulf Coast investment plan included four milestones:

- Restart an ethylene cracker at the St. Charles Operations site near Hahnville, LA, by the end of 2012, which "is progressing on time";
- Improve ethane feedstock flexibility for an ethylene cracker at the Louisiana Operations site in Plaquemine, LA, in 2015;
- Construct a world-scale ethylene production plant in the U.S. Gulf Coast, for start-up in 2017 for long-term growth in the performance plastics segment; and
- Construct a world-scale on-purpose propylene production facility at its Texas operations for start-up in 2015.

According to the company’s 3Q2012 10-Q filing, Dow uses derivatives of crude oil and natural gas as a feedstock in its ethylene facilities. The company's cost of purchased feedstocks and energy in 3Q2012 decreased $1.2 billion compared with the same quarter last year, a decline of 20%. The cost of purchased feedstocks decreased primarily due to lower feedstocks and energy prices in the United States due to increased supply of shale gas and natural gas liquids as well as lower naphtha and condensate prices in Europe. Year to date, the cost of purchased feedstocks and energy was down $2.1 billion from the same period last year, a decrease of 12%.

Last year Dow launched a four-point plan to integrate domestic operations into "feedstock opportunities" through U.S. shale gas (see Shale Daily, April 25, 2011). At that time Dow, the largest U.S. chemical manufacturer, and a subsidiary of Range Resources Corp. signed a memorandum of understanding for Range to deliver ethane supplied from the Marcellus Shale in Pennsylvania to Dow's existing chemical operations in Louisiana.

As a result of these investments, the company's exposure to purchased ethylene and propylene is expected to decline, offset by increased exposure to ethane and propane feedstocks. The first project to come online will be the restart of an ethylene cracker in St. Charles, LA, which is expected to be completed by the end of 2012. The company also announced investments in a new on-purpose propylene production unit (expected start-up in 2015) and a new ethylene production unit (expected start-up in 2017), both located in Freeport, TX (see Shale Daily, April 20). As a result, Dow's ethylene production capabilities are expected to increase by as much as 20%.

NATURAL GAS LIQUIDS

Energy Transfer Looks to Liquids with Sunoco Buy

Originally published by NGI’s Shale Daily: May 1, 2012

Producers have eschewed dry gas in favor of more lucrative oil and liquids-rich production, and midstream operators are following them. Energy Transfer Partners LP (ETP) is buying Sunoco Inc. for $5.3 billion in a deal intended give it oil and liquids business and a presence in the Marcellus Shale.

The combined company would be one of the largest and most diversified energy partnerships in the country through expansion of ETP's geographic footprint and strengthening of its presence in the transportation, terminaling and logistics of crude oil, natural gas liquids (NGL) and refined products, the companies said Monday.

"This transaction, which will be immediately accretive, represents the next step in Energy Transfer Partners' transformation into a more diversified enterprise with an integrated and expanded footprint," said CEO Kelcy Warren. "As we have said in the past year, our goal is to derive more of our distributable cash flow from the transportation of heavier hydrocarbons like crude oil, NGLs, and refined products. With this transaction, we make a major move in that direction, bringing our cash flow mix related to the combined enterprise's pipeline businesses to approximately 70% natural gas and 30% heavier hydrocarbons."

The natural gas price collapse has shrunk gas producer margins, and basis differentials have collapsed as well, a fact not lost on ETP.

"...[W]e've got to get a healthier mix of the movement of crude with natural gas," Warren told financial analysts during a conference call Monday. "The primary reason for that is look at what's happened to basis differentials in natural gas...They're almost nonexistent. That's OK; they will return; they will come back. They always do.

"The margins for movement of crude now are good. We think they're going to be good for quite a while...We think this is the right thing for us to do."

The acquisition would add 107,000 b/d of NGL throughput to ETP's current NGL throughput of 576,000 b/d and also add 1 million bbl of NGL storage capacity to the 33 million bbl ETP currently has. On the crude side, ETP would gain 5,400 miles of crude oil pipelines, infrastructure that spans the Marcellus region of Ohio, Pennsylvania and beyond in the Northeast.
"ETP has an interest in growing its Marcellus Shale-related activity, and I am pleased that the combined enterprise will retain a strong Pennsylvania presence," said Sunoco CEO Brian P. MacDonald.

ETP is to acquire Sunoco in a unit and cash transaction valued at $50.13/share. The deal comes weeks after the closing of ETP general partner owner Energy Transfer Equity LP's (ETE) acquisition of Southern Union Co., which created a midstream company with more than 44,000 miles of interstate natural gas pipelines and an estimated 30.7 Bcf/d of transportation capacity (see Shale Daily, June 17, 2011).

Given the industry-wide shift to liquids and crude, ETP has been eyeing natural gas pipeline assets in its portfolio that could be converted to crude service, particularly some of the Southern Union assets, and Sunoco's expertise could help with that, Warren said.

"There are...[natural gas] assets that were part of the Southern Union acquisition that are much more trinkule in nature; they span longer distances. They're not needed for the demand of our customers...So we are exploring converting [to crude oil service] some of those lines from the Gulf Coast to the Midwest, to other parts of the country," Warner said.

ETP has pipeline operations in Alabama, Arizona, Arkansas, Colorado, Florida, Louisiana, Mississippi, New Mexico, Utah and West Virginia, and owns what it claims is the largest intrastate pipeline system in Texas. It currently has natural gas operations that include 23,500 miles of gathering and transportation pipelines, treating and processing assets, and three storage facilities in Texas. ETP also holds a 70% interest in Lone Star NGL, a joint venture that owns and operates NGL storage, fractionation and transportation assets in Texas, Louisiana and Mississippi.

Besides owning the general partner of ETP, ETE also owns the general partner of Regency Energy Partners LP. ETE as of March is the parent of Southern Union. The ETE family of companies owns 45,000 miles of natural gas and NGL pipelines.

Sunoco Inc. owns the general partner interest of Sunoco Logistics Partners LP, a master limited partnership that owns pipeline, terminaling and crude oil acquisition and marketing assets.

Sunoco Logistics has 2,500 miles of refined products pipelines in the Northeast, Midwest and Southwest and equity interests in four refined products pipelines. It has 5,400 miles of crude oil pipelines mainly in Oklahoma and Texas. Its terminal facilities consist of 42 million shell barrels of refined products and crude oil capacity (including 22 million shell barrels of capacity at the Nederland Terminal on the Gulf Coast of Texas and approximately 5 million shell barrels at the Eagle Point terminal on the banks of the Delaware River in New Jersey). The crude oil acquisition and marketing business is principally conducted in Oklahoma and Texas and consists of about 190 crude oil transport trucks and 120 crude oil truck unloading facilities.

Sunoco Logistics and MarkWest Liberty Midstream & Resources LLC last year announced the Mariner West project, which would carry Marcellus Shale ethane from Pennsylvania to Canadian markets.

Midstream peer company Enterprise Products Partners has been focused on growing its business on the back of increasing NGL production (particularly ethane) from the nation's shale plays (see Shale Daily, March 21). Enterprise and two partners recently announced plans to construct an NGL pipeline from the Denver-Julesburg Basin in Weld County, CO, to Skellytown, TX. Enterprise is also behind the proposed 125,000 b/d Appalachia-to-Texas (Atex Express) ethane pipeline.

The ETP-Sunoco merger consideration, which consists of $25 in cash and 0.5245 of an ETP common unit, or approximately 50% cash and 50% ETP common units, represents a 29% premium to the 20-day average closing price of Sunoco shares as of April 27. By acquiring Sunoco, ETP will also own Sunoco's general partner interest and the incentive distribution rights (IDR) in Sunoco Logistics Partners as well as Sunoco's 32.4% interest in Sunoco Logistics Partners' limited partner units and Sunoco's branded retail business with about 4,900 retail locations in the United States.

Sunoco shareholders can elect to receive, for each Sunoco common share they own, either $50.00 in cash, 1.0490 ETP common units or a combination of $25.00 in cash and 0.5245 ETP common units. The aggregate cash paid and common units issued will be capped so that the cash and common units will each represent 50% of the aggregate consideration. Upon closing, Sunoco shareholders are expected to own 20% of ETP common units. In addition, $965 million of Sunoco's existing notes will remain outstanding.

Standard & Poor's Ratings Services (S&P) affirmed ETP's "BBB-" corporate credit rating and revised its outlook to "stable" from "negative," and placed the "BBB" corporate credit rating on Sunoco Inc. on CreditWatch with "positive" implications. The "BBB" corporate credit rating on Sunoco Logistics Partners was placed on CreditWatch with "negative" implications, and the "BB" corporate credit rating on ETE was affirmed and its "stable" outlook maintained.

S&P said the deal would extend ETP's scale and enhance its position across the gas, oil and NGL value chain. "The contribution from ETP's challenged intrastate natural gas business will also notably decrease and be replaced by Sunoco's more stable crude oil and refined products transportation assets," the ratings agency said.

Sunoco Inc. will run Sunoco Logistics Partners LP, according to the deal announcement. ETP will own 80% of the combined company and Sunoco will own 20%. ETP's cash consideration is up to $2.18 billion, which includes $1 billion of Sunoco debt and $1.18 billion in cash. ETP will also pay Sunoco shareholders a special dividend of $50.13/share.

Sunoco shareholders can elect to receive, for each Sunoco common share they own, either $50.00 in cash, 1.0490 ETP common units or a combination of $25.00 in cash and 0.5245 ETP common units. The aggregate cash paid and common units issued will be capped so that the cash and common units will each represent 50% of the aggregate consideration. Upon closing, Sunoco shareholders are expected to own 20% of ETP common units. In addition, $965 million of Sunoco's existing notes will remain outstanding.

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The deal has been approved by each company's board of directors and is expected to close in the third or fourth quarter, subject to approval of Sunoco shareholders and regulatory approvals. Following the closing, Sunoco and Sunoco Logistics Partners will operate under the ETE umbrella of companies. By acquiring Sunoco, ETP will own Sunoco's general partner interest, limited partner interest and the incentive distribution rights in Sunoco Logistics Partners. Sunoco Logistics Partners will continue to be traded on the New York Stock Exchange as a separate publicly traded MLP.

**DUVERNAY SHALE**

Encana, PetroChina Strike Partnership in Duvernay Shale

*Originally published by NGI's Shale Daily: December 17, 2012*

Encana Corp. on Thursday struck a C$2.18 billion joint venture (JV) agreement to explore and develop close to half a million acres of the Duvernay Shale with a subsidiary of PetroChina International Ltd.

Under the agreement, Phoenix Duvernay Gas would gain a noncontrolling 49.9% stake in Encana's 445,000 acres in the Duvernay.

Encana is to be paid $1.18 billion when the transaction closes and another C$1 billion over the next four years in the form of a drilling carry for half of Encana's share of development capital. Over the carry period, the JV partners plan to invest C$4 billion in new drilling, completion and processing facilities.

Encana, which would remain the operator and hold the majority stake, estimates that the Duvernay JV lands contain about 9 billion...
boe initially in place.

"Phoenix's investment demonstrates the tremendous value that Encana has created in this early life liquids-rich play, and enables us to accelerate the pace at which the full production potential of our Duvernay lands can be achieved," said Encana CEO Randy Eresman. "A transaction of this magnitude keeps us on track to create a more diversified commodity portfolio and maintain our balance sheet strength."

Encana so far has drilled nine wells into the Duvernay, has five producing wells and currently has two rigs actively drilling more prospects. With the JV, the Calgary producer expects to more than double its planned pace of development in the play beginning early next year.

"The Duvernay project will combine Phoenix's integrated upstream and downstream capabilities and financial resources with Encana's proven resource play hub expertise," said Phoenix CEO Zhiming Li. "This joint venture will build a foundation for the successful development of the Duvernay play and help to diversify our business portfolio. Encana is our ideal long term partner for the development of our future natural gas business."

Encana and PetroChina majority stakeholder China National Petroleum Corp. last year had agreed to jointly develop Encana's gassy Cutbank Ridge leasehold, which straddles British Columbia and northwest Alberta, but that partnership deal, estimated to be worth about US$5.4 billion, failed to be completed (see Shale Daily, June 22, 2011).

The Duvernay has perhaps become a more credible development in the eyes of investors after ExxonMobil Corp. in October agreed to pay US$3.1 billion for Celtic Exploration Ltd., which has holdings in the Montney, Duvernay and other Canadian formations (see Shale Daily, Oct. 18). ExxonMobil plans to develop the Celtic leaseholds with its majority owned Canadian company Imperial Petroleum Ltd.

Canadian regulators this month also signaled they would clear select foreign investments in the oil and gas sector after approving a merger between Malaysia's national oil company Petronas Carigali Canada Ltd. and Progress Energy Resources Corp. (see Shale Daily, Aug. 1).

"Having entered into several JV transactions in 2012, these types of arrangements have become an important part of Encana's business model," Encana officials said. "Joint ventures help the company to achieve a highly efficient deployment of capital throughout its vast exploration and development asset base as Encana transitions to a more diversified portfolio of commodities."

"These relationships have the potential to increase natural gas demand as a number of Encana's partners are actively exploring opportunities to export liquefied natural gas, while some are industrial consumers looking to transition to natural gas as fuel for their operations. An example is a recent agreement with Nucor Energy Holdings, which is designed to support Nucor's increased use of natural gas for its facilities, such as its direct reduced iron facility currently under construction in Convent, LA."

Nucor in November agreed to take a half-stake in some of Encana's U.S. natural gas wells to guard against an expected increase in U.S. gas prices. The agreement builds on an earlier and smaller onshore gas drilling agreement with Encana that was clinched in 2010 by increasing the number of gas wells. It also offers the Charlotte, NC-based steel manufacturer more protection against volatile gas prices, which are among its biggest operational costs.

Including the proceeds from the Phoenix transaction, Encana expects to end the year with cash balances of more than US$3 billion, which is ahead of its a June target of US$2.5 billion. In addition, "confirmed" carry capital committed to Encana from joint ventures and other third party agreements for 2013 is now about US$750 million, and covers about half of Encana's projected costs in those areas, it said.

Encana to date has increased its hedge position for 2013 to about 1.5 Bcf/d at an average price of US$4.39/Mcf.

"Our enhanced risk management position combined with our significant expected cash balance for the end of the year puts us in a solid position to execute on our plans for 2013," said Eresman. "We expect these joint venture arrangements will help us achieve higher capital efficiencies, which will enable us to reduce the amount of capital that we initially projected to spend next year."
Natural gas prices climb in 2012 as unconventional rig count slips

Continued from Page 1

supplier in North America, also said in contrast to U.S. offshore activity, the land drilling market has stalled. In a third quarter conference call, Varco executives said, “All across North America, everybody’s hesitating. A new parsimoniousness is sweeping through the complex” as companies slow drilling or draw from their equipment backlogs, according to CFO Clay Williams (see Shale Daily, Oct. 26).

The picture was brighter for the producers doing the drilling. January 2012 shale basin gas prices ranged from $2.81 to $2.93, with most landing somewhere in the $2.80s, except for Marcellus Northeast, which came in at $2.46 due to transportation constraints. All points ended the year in the upper $3.30s, with Marcellus NE not quite catching up at $3.31, as shown in NGI’s Shale Daily SPI Price Table.

Marcellus NE suffered through the first part of the year from lack of sufficient pipeline capacity. Several times June through August prices in the region dropped below $1.00/MMBtu. The situation eased in late August with an upgrade on Tennessee Gas Pipeline in the region and later in the year with several large capacity additions.

The Piceance and Green River basins picked up the highest end of the year prices, coming in at $3.40/MMBtu. The Fayetteville and Marcellus Southwest PA/WV both registered $3.39, with the Haynesville coming along at $3.38. Toward the lower end were the...
Act 13 impact fee implementation nets Pennsylvania millions

Continued from Page 1

and Range Resources Appalachia LLC at $23.7 million. All three, which account for 39% of the total amount, have paid their impact fee bills in full.

Only two other producers had impact fees of more than $10 million: SWEPI LP, a Royal Dutch Shell plc subsidiary, at $15.3 million; and Anadarko E&P Co. LP at $15.0 million.

"While these figures are indeed staggering by any measure, it also serves as a stark reminder that we must ensure that we have common sense policies in place, especially local zoning uniformity at the center of Act 13, which encourage economic growth, job creation and additional revenue," Marcellus Shale Coalition President Kathryn Klaber said Monday.

Using spud data reports provided by the state Department of Environmental Protection (DEP), the PUC determined that 4,034 horizontal and 419 vertical wells were subject to the impact fee. These wells were spud in 2011 or earlier, but for the PUC's fee calculation purposes the first year for all of the wells will be considered as 2011.

Chesapeake accounted for the highest number of horizontal wells (615) subject to the fee, followed by Talisman (526), Range (473), SWEPI (306) and Anadarko (299).

Nearly half of the vertical wells subject to the impact fee were drilled by Atlas Resources LLC, which had 214. Cabot Oil & Gas Corp. had the second-highest number of vertical wells at 38. Most of the other producers with vertical wells had fewer than 10.

Pennsylvania had estimated that the impact fee would net about $180 million in 2012, increasing to $211 million in 2013 and $264 million in 2014 (see Shale Daily, April 30).

The PUC will set the rate for wells drilled this year on Jan. 31, 2013 using a tiered structure set according to the average price of natural gas on New York Mercantile Exchange for the last day of the preceding 12 months and adjusted for the Consumer Price Index. The payments for the 2012 fee are due April 1, 2013.

The fee lasts for the first 15 years of the life of a well and decreases annually.

Although the PUC data was not broken down by county, it is believed that Bradford County will receive the most impact fee money because it led unconventional production during the first half of 2012 (see Shale Daily, Aug. 27). Other counties that should receive sizeable portions of the impact fee pot include Susquehanna, Lycoming, Tioga, Washington, Greene, Wyoming, Westmoreland, Clinton and Fayette counties.

According to the DEP's spud reports, the Catherine Conner 1 well -- a vertical well drilled in Toby Township, which is in Clarion County -- is the oldest active unconventional well to be affected by the impact fee. It was spud by Donna Bricker on Nov. 29, 1979 and is targeting the Genesee/Burket Shale, which is just above the Marcellus.

The DEP said the oldest active unconventional well targeting the Marcellus is the Hunter 1 well in Washington County's Hopewell Township. It was spud by JM Best Inc. on June 18, 1982.

Bricker and JM Best have each been levied $10,000 impact fees by the PUC. So far neither has paid the amount due. Bricker, a farmer in the Parker area of Clarion County, could not be reached for comment Tuesday.

"We have mailed each name on the list we received from the [DEP] information about the impact fee and what they need to do to either pay the fee or be exempt from it," PUC spokeswoman Jennifer Kocher told NGI's Shale Daily on Tuesday. "If the well is producing less than 90,000 cubic feet of gas a year, it also meets the definition of a stripper well.

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<th>Producer Name</th>
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* List calculated from data received by the Pennsylvania Department of Environmental Protection & adjusted by the Pennsylvania Public Utility Commission
** Indicates a producer disputing well status

Source: Compiled by NGI's Shale Daily from State reports
meaning they do not have to pay the fee. We are hoping to talk with each of the people on the list to clear up these kinds of issues."

Act 13, which was signed into law by Gov. Tom Corbett in February, amended Title 58 (oil and gas) of the Pennsylvania Consolidated Statutes and empowered the PUC to collect the fee on behalf of local governments (see Shale Daily, Feb. 15). The law gives Pennsylvania's counties the choice to collect an annual per-well fee from operators. The fee is set annually based on the price of gas and declines over 15 years but is set at $50,000 for all unconventional horizontal gas wells drilled through 2011. The revenue from the program is split between state and local governments, with the local share split between counties and the municipalities in those counties. ■

**Shallowness of Miss Lime keeps drilling costs low**

*Continued from Page 1*

the unconventional operators began to claim stakes a few years ago. However, there's still a heck of a lot to learn about the carbonate play, a panel of experts told a packed audience at the Mississippi Lime Congress 2012 in Oklahoma City.

There are a lot of things operators know for sure about the carbonate formation play, which extends from northern Oklahoma into parts of Kansas and Nebraska, even if they haven't quite settled on a name. The Mississippian Lime, Mississippi Lime, Miss Lime, Mississippian Carbonate -- the list goes on. One of its attractions is the cost -- it's a shallow formation at 450-600 feet with low pressure. That means that drilling costs are low -- less horsepower is needed to drill. And the costs are a lot less than in some plays: from spud to release, wells cost around $2.5 million.

Are all of the 20 million acres going to be productive? Probably not, said Petro River Co-CEO Daniel Smith, Alba's partner. "We are able to go in and make good wells." But some have brought in "8 b/d of oil and 8,000 barrels of water...Others are 1,500 b/d-plus wells. We know they are out there...The beautiful thing about the Mississippi Lime is that it's not an unconventional reservoir. It's always produced conventionally and it's got thousands of wells. It was not fractured...So what we are seeing is a hybrid, an unconventional conventional."

The play has its share of big operators, like Encana Corp., Chesapeake Energy Corp., Apache Corp., Royal Dutch Shell plc, as well as a lot of smaller, family-owned operations (see Shale Daily, Aug. 6). According to data compiled by NGI's Shale Daily from company documents, Chesapeake is currently the largest net acreage holder in the play with 2 million acres. Rounding out the top five are SandRidge Energy (1.85 million), Tug Hill Operating (788,000), Apache ($800,000) and Devon Energy ($450,000).

The carbonate is thick, in some places up to 2,000 feet, which "provides a challenge," said Roxanna Oil Co. President Julie Garvin. "There's a tremendous variability through the section. Another variability is in the flow rates. In general, we have seen reported [initial production] rates from 100 b/d to 1,000 b/d...Very variable."

Even with the uncertainty of what has been reported, large and small exploration and production companies have been undeterred. About 700 unconventional wells now have been drilled, and there are more than 600 active permits, said Garvin. "By my estimates, we can easily expect 10-20 billion bbl of recoverable oil from the Mississippi Lime."

"It has the source rock but there is extreme lateral variability," said Garvin, whose company has been exploring the trend since 2007. The play is building by fits and starts using horizontal drilling and hydraulic fracturing, from along the Kansas-Oklahoma border, where the "core horizontal drilling really took off," and has since moved to the south to the Sooner Trend and east of the Nemeha Ridge. There also is a push to the north, west of the Kansas Uplift.

"If you think about all of the potential extensions, we come up with 20 million acres of potential play areas," Garvin said. "It's why there is a conference about a single reservoir."

Roxanna, which had been looking for a shale play when it began studying the Mississippian, has been drilling into the formation's Sooner Trend, said Garvin. "We have had wells in the same section, with one well that makes 5 b/d and has 100 barrels of water. And then we have a well with completely different results next to it."

Looking at the source rocks isn't enough, she said. Years ago small operators may have drilled deeply into the formation and come up empty. Today, "we are trying to target the highest fracture but the highest in-place resource, laterally and vertically." A "biggie" for operators is to increase the flow rates through better completion designs.

"We are moving away from open hole fractures. These days we are thinking of physics, and the how fluids flow...

"There is a multi-phase flow, with gas, oil and water -- three fluid types -- all competing for space." Only now have operators begun to achieve a level of expertise on how far to drill horizontally and how much to fracture the rocks.

Alba, who formerly worked for Halliburton Co., said "everybody's going to have a different approach on how to complete reservoirs...The key thing for us is that it is the same geological system, the same..."
migration on a reserves basis." Whether the Mississippian wells are drilled horizontally or vertically isn't pertinent. "Both of them are right. We have to derisk the play and some ways to do that are through 3-D seismic; which might indicate that it's more important to vertically delineate in one place or horizontally drill in another. "There's no doubt about it that hydrocarbons are there...It's a unique characteristic in coming up with completion techniques."

He told the audience that he'd studied "quite a few reservoirs," but the "oil in place here is truly tremendous. I wonder what I'm doing in Kansas quite often. But I'm a hydrocarbon hunter and I believe they're here to be extracted. We are at a point in the industry where we can tackle low-pressure hydrocarbon systems."

North America's explorers "did a great job on the shales," Alba said. "We have gone through the structure in North America in dealing with deep drilling the Utica, the Marcellus...Barnett. Kansas is a very different place with carbonate chemistry and the environment. We don't realize how much actual reserves there are on the North American continent."

"We know about carbonate chemistry," as the industry has in the past focused its attention on some formations in the Rockies. "The low-pressure reservoir systems bring their own challenge. They have to be drawn down. That's what we're excited about. The water cuts, how to identify the lamination areas, porosity systems that are occurring in saturations over time."

The Mississippian Lime, Alba said, "is not fully saturated; the oil is sitting on the top and water is on the bottom," which has confused some of the early drillers. "We have to know how to keep from drilling horizontals in the water systems and we have to stay in the oil systems..."

Early explorers "did what they thought was best at the time," he said. "There are a lot of hydrocarbons in Kansas," the first producers, mostly "mom-and-pop producers...just did it very slowly. Given what we know today about the reservoir, we can improve upon it...I believe as an industry we have more gas in the U.S. than we can shake a stick at. But I believe places like this can help us overcome and achieve energy independence. This is a great region to come to develop hydrocarbon reserves."

The formation can't be treated the same as other types of unconventional plays, Smith said. "Some wells, you put a lot of fracs on them like shale wells, and they get better and better. You probably can't do that here. If you drill too far, you may not make anything and think there's no oil there. But there is oil there, you've got to figure out how to get to it...Those are some of the operational issues we're dealing with."