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Oil Price Drop Opens Midstream Investment Opportunities

By Paul Hart, Editor-In-Chief

The impact on the U.S. energy industry of the worldwide crude oil price drop cannot be denied. But results will vary widely by segment and—in the case of some well-positioned midstream players—may create investor opportunities.

Upstream, operators expect to trim 2015 drilling plans and speculation abounds that higher-cost plays will see a significant drop in capex activity as crude prices sag well below the $100 per barrel (bbl) benchmark through the first three quarters of this year.

Downstream is a different matter: A crude price drop is good news. "In an oversupplied oil market, refiners win," Raymond James Equity Research observed in a recent research report. Usually, oil feedstock prices drop faster than petroleum product prices, widening refiners' crack spreads and increasing profitability.

"Demand factors are positive and U.S. crude supply growth should still be sufficient to disconnect WTI [West Texas Intermediate] from Brent. Both dynamics should benefit U.S. refiners," RBC Capital Markets said, reporting on a Dec. 1 investor conference call with its analysts.

But what about midstream?

Prospects for the middle of the industry look less promising than at the first of the year but brighter than the upstream segment, most analysts agree. Midstream's long-term move toward fee-based services, rather than commodity-based pricing structures, will ease revenue declines even if drilling drops. Low commodity prices certainly will impact drilling and resulting new production so, over time, midstream operators that rely solely on fees will feel an impact.

Midstream's biggest firm, Kinder Morgan Inc., this week announced its financial projections for the new year with an upbeat tone.

"We anticipate strong growth in 2015 across our pipeline and storage businesses and currently have a backlog of approximately $18 billion in expansion projects and joint-venture investments that have a high certainty of completion," Chairman and CEO Richard Kinder said in the announcement. "We are generating strong growth even though we have revised our projected WTI crude oil price to $70/bbl. As our track record demonstrates, we own and operate a large, diversified portfolio of stable, primarily fee-based energy assets across North America, which produce substantial cash flow in virtually all types of market conditions, regardless of commodity prices."

Kinder's comments match the corporation's continuing self description as a "toll road" linking upstream producers and downstream consumers.

Overall for the midstream, a lot depends on drilling trends in the near future and prospects for revised 2015 upstream capex plans look weak.

"We don't know if OPEC has ulterior motives to let oil prices drift lower and pinch the global E&P sector, or if reaching a consensus on cuts was just too challenging," Wells Fargo Securities said in report published following the cartel's Nov. 27 meeting in Vienna. "What's clear is that lower cash flows are highly likely to translate into lower E&P spending across a host of regions/countries. A handful of E&P companies have already announced meaningful 2015 capex reductions (vs. 2014) and more are sure to follow with oil prices well below $80/bbl post OPEC's announcement."

Sunil Sibal, Global Hunter Securities MLP and midstream analyst, said in a research report published this week that "weak commodity prices are a headwind for not only the MLPs that have direct commodity exposure but also those that have exposure to crude oil, natural gas and/or NGL volumes flowing through their systems. A persistent weak commodity price environment is likely to result in curtailed activity by E&P producers impacting those volumes."

In mid November, Sibal published two revised, and lower, commodity price scenarios for 2015-2016. His preferred projections at the time were $78-$79/bbl for WTI, $85-$89 for Brent and natural gas at $3.90 per thousand cubic feet (Mcf). An alternate—and more pessimistic—projection pegged WTI at $70/bbl next year, rising to $75/bbl for 2016.

"We further assume that producer volume growth is curtailed in some of the faster-growing shale plays, further impacting cash flows for the midstream players in those basins," he said.

As December began, "post the OPEC decision to maintain production levels at 30 million bbl per day, it seems like this alternate case may most likely end up being closer to the base case for commodity prices," Sibal said in an update to his November report.

The collective impact on midstream's 2015 capex should be more muted—at least early in the year, according to RBC's MLP analyst, T.J. Schultz.

In the RBC conference call, Schultz noted that "most of the 2015 capital budgets for midstream [are] set on committed projects so we would see kind of marginal impact to spending in at least that early part of 2015. The focus point on capex will really be on commentary around project backlogs. This should kind of help ascertain what medium-term capex is real and what falls off the books. This should be somewhat companies specific—different MLPs do have different ways" of handling capex backlogs, he added.

Baird Equity Research is among the research firms that see investor opportunity ahead as midstream stock and unit prices wallow well below highs set earlier in 2014.

"With crude oil seeing another leg down following OPEC's decision to stand pat... we advise investors to use the weakness to build positions in higher-quality, infrastructure-oriented names," Baird advised in a research report. "Cyclical names may look more attractive but negative momentum and tax loss selling give us pause for the balance of 2014. We expect this tape to be dominated by resilient top lines, fee-for-service businesses, and large-cap sponsored MLPs.

"MLPs are not a homogeneous asset class; MLPs are a structure. Varying degrees of cyclicality and commodity exposure can be found in the MLP structure," it added.

Tudor, Pickering, Holt & Co. also sees opportunities for midstream investors in the current environment.

"Several of our BUY-rated names have been handed a beatdown as growthy midstream space is less like utes [utilities] and more like contracted, non-discretionary services supporting E&Ps," it said in a report, adding "things aren't so bad" for well-positioned midstream firms at $70/bbl. It advised clients that it was revising its financial models.

A later report, based on the new models, found the “good news is that while the near-term isn’t quite as rosy as a few weeks ago” Tudor’s midstream picks “are still able to support healthy dividend growth rates with no risk for a cut.”

RBC’s Schultz also said in the conference call he “would expect some mid-street MLPs to look at slowing distribution growth as early as 2015 and focus more on building coverage where possible” if low prices linger.

The near-term impacts of the current pricing environment will first be “seen on commodity-exposed MLPs, which in midstream is typically the gathering and processing of stocks and some with NGL exposure,” he added.

“We do know that there are some growing, fee-based cash flow streams from these guys though. The next focus, near term, would be some risk from gathering volumes accrued by rail” with later impacts on pipeline projects and other midstream facilities, Schultz said.

Antero Steady In Sluggish Post-Holiday Energy Trading

By Deon Daugherty, Associate Editor

Analysts were bullish on Monday as they initiated coverage on Antero Midstream Partners LP with an outperform rating and prices in the mid-$30s.

In a Dec. 1 note to investors, Baird Equity Research said the freshly minted MLP has two important traits: “highest quality” in its management and in its assets.

“Highly respected and savvy industry veterans Paul Rady and Glen Warren lead both (Antero Resources and Antero Midstream). There is some key man risk if either of these principals leaves the picture,” Baird said, adding that Antero Resources is drilling at a rate of 50%+ in the Northeast, is hedged through 2017 and has firm takeaway capacity with several offtake agreements.

Baird began its coverage of the new MLP with a $34 price target. Analysts at Raymond James gave Antero a strong buy rating with a $32 price target. Credit Suisse initiated coverage with an outperform rating and a $36 price target.

“(Antero Midstream) is differentiated from most midstream peers in that it does not need to compete either in M&A or the field for (its) volumes, which flow directly from (Antero Resources). Gravy in the story comes from the potential drop-down of water logistics assets at Antero Resources or, longer term, third-party M&A),” Baird said.

Antero’s IPO, which reached $1 billion, hit traders just a week after Shell Midstream Partners generated $1.06 billion with its IPO, the largest in MLP history. Shell’s offering, sponsored by the international Royal Dutch Shell Plc, had expected to raise about $750 million.

Most energy stocks were sluggish on Monday, however. And Antero’s units were no exception, trading at $27 each by mid-afternoon, a decline of more than 2% from the market’s previous close.

Analysts at Raymond James said in a note to investors they expected something of a holiday slump on Friday.

“A particularly steep plunge in oil prices in response to OPEC's (rather unsurprising) decision, combined with lots of U.S. investors out of the office, led to a near-total absence of buyers stepping in. The result: one of the roughest one-day selloffs in energy stocks that anyone has ever seen—and yes, that includes the financial crisis,” they wrote.

Questions Hover Over North America's LNG Export Market

By Leslie Haines, Hart Energy

Brian Forbes, partner at A.T. Kearney, discusses price spreads at Hart Energy's recent North American LNG Export Conference. (Source: Hart Energy)

North America consumes about 6 trillion cubic feet (Tcf) of natural gas annually, but it produces 7 Tcf from conventional and unconventional sources, thereby setting the stage for the opportunity to export LNG.

But the amount exported, the costs of that supply, the exporters' netbacks, are all questions still to be answered. Until that time, first-mover projects with cost advantages will win—and natural gas prices may be "messy." This analysis comes from Brian Forbes, partner at consulting firm A.T. Kearney, who spoke at Hart Energy's recent North American LNG Exports Conference in Houston.

At some point in the future, companies will trade LNG cargoes globally and a vibrant spot market will develop, he said. Asian buyers might buy North American LNG and swap it for African or Middle Eastern cargoes.

The price spread between supply and the cost of shipping to global markets is the key. "If you do the analysis, the landed cost of U.S. LNG compares favorably to Australia and Africa in most cases; with Russia we are pretty close. This opens up quite a bit if you allow global trading," he said.

Location is key

However, it's not as important how much LNG you sell, as it is where you sell it, Forbes said, although the best markets are to Asian buyers. For example, shipping LNG from the proposed Kitimat project in British Columbia to South Korea costs $1.05/Mcf, whereas from Sabine Pass off the Louisiana coast, shipping cost rises to $2.41/Mcf. Liquefaction costs depend heavily on how much infrastructure exists at a site and the cost and extent of power generation needed on site.

A big question for U.S. producers is the effect of exports on domestic gas prices. Forbes said he expects U.S. prices to rise once LNG exports start but markets will be "messy" in his words, until price equilibrium is reached.

"You could end up with $6 or $7 gas but it might take a year, or maybe six months," he said. "It's hard to predict. If more shale fields are in the money and thus have access to more capital, you will see us over drill for gas. This will contribute to that messy equilibrium. The U.S. stays competitive if it stays closer to 6 Tcf of exports, so you want to be one of the first projects built and with fully committed demand."

With increased competition worldwide on the LNG production side, it is not clear how much LNG will come out of the U.S. A.T. Kearney has run various scenarios, he said.

"Our projections show that by 2020, the U.S. will be a fairly significant exporter, likely to place 3- to 6 Tcf a year. If you can process the gas and ship it at the cheapest option, you win," he said.

Exporting 3 Tcf annually translates to about 8 Bcf/d, he said. For context, the EIA reports gas production from seven key regions now totals a bit more than 43 Bcf/d (the seven: Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara, Permian and Utica). The Marcellus Shale alone produces about 15 Bcf/d.

Point of no demand

Forbes said by 2030, the U.S. gas market will balance with both consumption and production of about 9 Tcf annually. Australia would be producing 6 Tcf and consuming 2 Tcf by then. Certainly those projects in the front of the line, with approvals in place and groundbreaking having occurred, will be competitive and likely have the lowest costs.

"When do we reach that point when so much LNG is being exported that it gets harder to build demand? I think up to 3-4 Tcf, the market isn't at equilibrium, but once we get to 3-4 Tcf the market starts to understand and it gets harder to build demand," he said.

Forbes suggested one way to increase LNG demand is to export it for powering gas-fired desalinization projects, as water scarcity becomes a bigger concern worldwide.

"If Australia figures out how to lower their costs, if Russia gets its act together, the cost will go lower and the economics are different," he said. "If China figures out how to drill its shales by 2025 … well, we've made a lot of money in the meantime. LNG netbacks depend on the cost of natural gas supply and that's not going to be $4 forever."

Alaska Has Big Plans For LNG Partnership

By Caryn Livingston, Assistant Editor

The biggest question facing the Alaska LNG project is whether it can be cost-competitive, said Audie Setters of the Alaska Department of Natural Resources at the North American LNG Exports conference. Source: Hart Energy

The North Slope in Alaska has huge potential for gas development, and the state is looking for a way to benefit from that alongside private corporations.

The most promising route to accomplishing that is the Alaska LNG project, said Audie Setters, executive LNG supply manager with the Alaska Department of Natural Resources.

The Alaska LNG project is a partnership between BP Plc, ExxonMobil Corp., ConocoPhillips and Alaska that aims to take advantage of undeveloped North Slope natural gas. Currently, oil producers working in Prudhoe Bay in the North Slope area put recovered CO_2 back into the reservoir because there is no cost-effective way to transport or treat it. The Prudhoe Bay area, combined with the nearby Point Thompson Field, contain an estimated 35 trillion cubic feet of natural gas. The project aims to utilize that by building a gas treatment facility in the area.

The project will include "three 6 million-tonne LNG trains, so we'll have the capacity of about 18 [million] to 20 million tonnes of LNG when that's all said and done," Setters told attendees at Hart Energy's recent North American LNG Exports conference in Houston. "We'll have three storage tanks and we'll have two LNG berths."

Additionally, an 800-mile, 42-inch high-pressure pipeline with eight compression stations is planned to carry LNG away from the plant. The project also comes with a hefty price tag—an estimated $45 billion to $65 billion—much more than a similar project would run in the Lower 48. The price doesn't worry Setters, though.

"Buyers are always going to require long-term contracts, and we would require long-term contracts," he said. "And just because you build capacity in the Lower 48 doesn't mean any gas is going to go through it. So that remains to be seen."

Setters emphasized that because the state is a project partner, there would be a special interest in avoiding price volatility.

"The state is approaching the project conservatively. We're going to have long-term contracts, 15- to 20-year contracts," he said. "[In] a project like this with a state selling its own share, we need to mitigate the downside."

However, the project still has a long way to go before it enters into any serious conversations with buyers about contractual commitments. With a FEED decision not expected until early 2016 and a final investment decision (FID) not expected until 2018, other LNG projects are far ahead in terms of timing. According to Setters, some projects around Kitimat, British Columbia, have already entered the FEED stage. In other ways, though, the Alaska LNG project has the edge in reaching a FID.

"I would say that in terms of native title issues, we're in a better place, just because we've worked through a lot of the native title issues" during the last 40 years, Setters said.

The project also benefits from its proximity to conventional reservoirs. "We're not having to drill wells for 20 years to support production for the LNG liquefaction projects," he said. "All the gas is in conventional reservoirs—all the gas is there. We wouldn't be producing it."

Other major issues many LNG projects face are backlash from environmental groups and problems when dealing with regulatory agencies, but the Alaska LNG project shouldn't confront those issues, either. According to Setters, the new project will be "living within the footprint of the existing infrastructure that's there" and won't cause a significant impact on the environment. Then, because the state is a partner in the project, supportive state officials and national representatives have indicated they plan to extend "enough support to keep this at the top of the regulatory agenda, and every indication is that the DOE [U.S. Department of Energy] and FERC [Federal Energy Regulatory Commission] are very, very much behind the project."

The only real issue, Setters said, is the same facing every LNG project in development today.

"At the end of the day, to get an LNG project off the ground in this environment, it's going to come down to cost, cost, cost. We've got to put something together that is competitive in this market, and we've got to be one of the leading low-cost producers. So we think we have the fiscal structure, we think we have the resource, the size, the scale and the proximity to the markets in Asia to make this a very competitive project."

Frac Spread: Tough Outlook For Hydrocarbon Markets

By Frank Nieto, Senior Editor

If the past few years have been a period of NGL prices decoupling from crude and natural gas prices, the last few weeks have shown that these products are still linked. However, the recent price crashes in each market have had their own reasons for losing value that are separate from their connections.

The decrease in crude prices has been the biggest story in the commodities market recently. West Texas Intermediate (WTI) has dropped below $70 per barrel (/bbl) as production has exceeded demand for much of the second half of this year. The situation was made worse last week when OPEC announced that it will not halt production despite the already severe price drop. It is assumed that some OPEC members are attempting to undercut U.S. production to halt the development of unconventional domestic reserves, but the move could backfire.

“We believe the richer OPEC countries, led by the Saudis, are playing a dangerous game of chicken as the drop in crude prices has increased the probability of heightening geopolitical turmoil across the Middle East, which could boomerang against the richer OPEC countries (Saudi Arabia, UAE and Kuwait) before it significantly impacts U.S. shale production. Economic and political instabilities are growing in oil producing countries such as Libya, Nigeria, Venezuela, Angola, Algeria, not to mention the fragile geopolitics in Iraq and Iran and the deteriorating economy in Russia,” according to En*Vantage’s *Weekly Energy Report* for Dec. 4.

The report noted that as crude prices have decreased, gasoline demand has increased in the U.S. and that China is aggressively buying crude supplies, which supports a price turnaround.

“We realize that market sentiment remains very bearish and the deflationary environment can breed more downside as consumers delay purchases, but it seems very unreasonable that the market is placing no price risk premium to crude oil prices. The richer OPEC countries seem willing to place a big bet that their neighboring countries can withstand lower oil prices and still keep their political houses in order. This bet seems very risky to us,” the report said. It will take some time for crude prices to recover, but a turnaround could begin as soon as early 2015 when refinery turnarounds begin to take place and demand for gasoline increases.

The number of moving parts involved in crude markets makes it more difficult to predict where the market is headed, but that isn’t the cash in the natural gas market. Gas prices fell below $3.50 per million Btu (/MMBtu) at both Conway and Mont Belvieu because of mild temperatures that have limited heating demand. This is on top of the limited cooling demand that was experienced this past summer that resulted in storage levels to build back up close to their five-year average after they had drastically fallen after a very frigid winter.

In fact, storage levels are so high that even with two solid withdrawals to start the winter heating season, prices fell heavily at both hubs. The Conway price was down 25% to $3.34/MMBtu and the Mont Belvieu price fell 16% to $3.42/MMBtu.

The downturn in NGL prices is related to both of these depressed markets, but also has its own reasons for falling, especially the light NGL markets.

Ethane prices have deteriorated because of both planned and unplanned cracker turnarounds that have caused a tremendous storage overhang. The Conway price fell 15% to 16 cents per gallon (/gal) the week of Nov. 26 and the Mont Belvieu price dropped 1% to 20 cents/gal. The Mont Belvieu price was the lowest it has been since August 2005, while the Conway price was the lowest it has been since it was 13 cents/gal the week of Jan. 29, 2014.

The industry is approaching full capacity, but will take time to work off storage. A new headwind has emerged for ethane as lower propane and butane prices as propane is now the most preferred ethylene feedstock, though this shouldn’t result in a change in the petrochemical industry in the short-term, according to En*Vantage.

“It is doubtful that ethylene producers will significantly increase propane cracking with winter just beginning. But, the market fears that if the status quo does not change by spring then ethane cracking could be affected by increased propane cracking,” the company said.

Propane cracking is estimated between 300,000 bbl/d and 350,000 bbl/d and LPG exports remain firm, but the lack of heating demand caused prices to fall 7% at both hubs. The Mont Belvieu price was down to 69 cents/gal, its lowest price since it was 68 cents/gal the week of July 8, 2009. The Conway price of 72 cents/gal was the lowest it has been since it was also 68 cents/gal the week of Dec. 12, 2012.

The theoretical NGL bbl fell 6% to $29.22/bbl with a 15% increase in margin to $17.02/bbl at Conway while the Mont Belvieu price dropped 7% to $28.16/bbl with a 3% gain in margin to $15.66/bbl.

The margin increase at both hubs was based on improvements in ethane, but this is a statistical anomaly as ethane margins remain firmly negative and the increase is being rejected throughout the country aside from contractual and technical reasons.

The most profitable NGL to make at both hubs was C_{5+} at $1.08/gal at Conway and $1.03/gal at Mont Belvieu. This was followed, in order, by isobutane at 76 cents/gal at Conway and 59 cents/gal at Mont Belvieu; butane at 68 cents/gal at Conway and 57 cents/gal at Mont Belvieu; propane at 41 cents/gal at Conway and 38 cents/gal at Mont Belvieu; and ethane at negative 7 cents/gal at Conway and negative 3 cents/gal at Mont Belvieu.

Natural gas storage levels fell 22 billion cubic feet to 3.41 trillion cubic feet (Tcf) the week of Nov. 28 from 3.432 Tcf the previous week, according to the most recent information from the Energy Information Administration. This was 6% below the 3.637 Tcf posted last year at the same time and 10% below the five-year average of 3.782 Tcf.

Storage levels are expected to face challenges the second week of December as the National Weather Service's forecast anticipates warmer-than-normal temperatures throughout the country, which should lower heating demand.

Mont Belvieu	Eth	Pro	Norm	Iso	Pen+	NGL Bbl
Nov. 26 - Dec. 2, '14	19.52	69.30	92.10	93.07	141.20	**$28.16**
Nov. 19 - 25, '14	19.70	74.65	99.55	101.53	152.20	**$30.18**
Nov. 12 - 18, '14	21.94	80.74	107.52	110.50	150.16	**$31.77**
Nov. 5 - 11, '14	23.14	84.84	108.92	110.08	157.90	**$33.03**
November '14	23.50	88.90	111.20	112.90	164.60	**$34.22**
October '14	21.83	94.21	113.04	114.47	176.33	**$35.53**
3rd Qtr '14	23.19	103.92	123.69	128.39	212.20	**$40.27**
2nd Qtr '14	29.26	106.55	124.12	130.23	222.81	**$42.31**
1st Qtr '14	34.50	129.51	137.62	141.49	212.60	**$46.16**
4th Qtr '13	26.76	119.81	142.56	145.02	210.66	**$44.03**
Nov. 27 - Dec. 3, '13	25.92	119.90	138.73	142.13	213.30	**$43.82**

Conway, Group 140	Eth	Pro	Norm	Iso	Pen+	NGL Bbl
Nov. 26 - Dec. 2, '14	15.50	71.57	102.83	108.97	145.20	**$29.22**
Nov. 19 - 25, '14	18.25	76.98	108.50	114.63	151.63	**$31.20**
Nov. 12 - 18, '14	21.20	87.16	117.00	122.78	148.02	**$33.31**
Nov. 5 - 11, '14	21.27	92.24	113.96	124.60	154.06	**$34.23**
November '14	20.00	95.80	113.00	129.00	156.50	**$34.68**
October '14	19.40	97.19	113.57	133.12	169.66	**$35.78**
3rd Qtr '14	20.38	104.99	123.51	140.07	207.90	**$40.18**
2nd Qtr '14	26.26	105.44	121.26	163.00	221.62	**$42.62**
1st Qtr '14	25.46	169.48	132.08	147.10	216.86	**$49.93**
4th Qtr '13	20.19	122.54	144.49	147.58	205.01	**$43.33**
Nov. 27 - Dec. 3, '13	18.20	119.83	136.50	136.57	206.63	**$42.08**

Data Provided by Bloomberg. Individual product prices in cents per gallon.
NGL barrel in $/42 gallons

Mont Belvieu	Eth	Pro	Norm	Iso	Pen+	NGL Bbl
Nov. 19 - 25, '14	19.70	74.65	99.55	101.53	152.20	**$30.18**
Nov. 12 - 18, '14	21.94	80.74	107.52	110.50	150.16	**$31.77**
Nov. 5 - 11, '14	23.14	84.84	108.92	110.08	157.90	**$33.03**
Oct. 29 - Nov. 4, '14	22.34	89.62	110.82	112.78	167.60	**$34.31**
October '14	21.83	94.21	113.04	114.47	176.33	**$35.53**
September '14	23.16	106.29	125.24	127.18	205.79	**$40.15**
3rd Qtr '14	23.19	103.92	123.69	128.39	212.20	**$40.27**
2nd Qtr '14	29.26	106.55	124.12	130.23	222.81	**$42.31**
1st Qtr '14	34.50	129.51	137.62	141.49	212.60	**$46.16**
4th Qtr '13	26.76	119.81	142.56	145.02	210.66	**$44.03**
Nov. 20 - 26, '13	25.54	119.30	143.40	146.20	210.60	**$43.85**

Conway, Group 140	Eth	Pro	Norm	Iso	Pen+	NGL Bbl
Nov. 19 - 25, '14	18.25	76.98	108.50	114.63	151.63	**$31.20**
Nov. 12 - 18, '14	21.20	87.16	117.00	122.78	148.02	**$33.31**
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4th Qtr '13	20.19	122.54	144.49	147.58	205.01	**$43.33**
Nov. 20 - 26, '13	18.20	119.48	142.28	143.43	205.58	**$42.45**

Data Provided by Bloomberg. Individual product prices in cents per gallon.
NGL barrel in $/42 gallons

Current Frac Spread (Cents/Gal)				
Date: December 5, 2014	Conway	Change from Last Week	Mont Belvieu	Change from Last Week
Ethane	15.50		19.52	
Shrink	22.14		22.67	
Margin	-6.64	41.65%	-3.15	57.08%
Propane	71.57		69.30	
Shrink	30.59		31.33	
Margin	40.98	13.71%	37.97	1.87%
Normal Butane	102.83		92.10	
Shrink	34.64		35.47	
Margin	68.19	9.73%	56.63	-1.06%
Isobutane	108.97		93.07	
Shrink	33.27		34.06	
Margin	75.70	7.98%	59.01	-3.10%
Pentane+	145.20		141.20	
Shrink	37.04		37.93	
Margin	108.16	5.98%	103.27	-3.44%
NGL $/Bbl	29.22	-6.35%	28.16	-6.72%
Shrink	12.20		12.49	
Margin	17.02	14.45%	15.66	2.51%
Gas ($/mmBtu)	3.34	-25.28%	3.42	-16.18%
Gross Bbl Margin (in cents/gal)	38.40	15.66%	35.69	3.01%
NGL Value in $/mmBtu (Basket Value)				
Ethane	0.85	-15.07%	1.07	-0.91%
Propane	2.48	-7.03%	2.41	-7.17%
Normal Butane	1.11	-5.23%	0.99	-7.48%
Isobutane	0.68	-4.94%	0.58	-8.33%
Pentane+	1.87	-4.24%	1.82	-7.23%
Total Barrel Value in $/mmbtu	7.00	-6.90%	6.88	-6.41%
Margin	3.66	20.06%	3.46	5.80%

Price, Shrink of 42-gal NGL barrel based on following: Ethane, 36.5%; Propane, 31.8%; Normal Butane, 11.2%; Isobutane, 6.2%; Pentane+, 14.3%, Fuel, frac, transport costs not included. Conway gas based on NGPL Midcontinent zone, Mont Belvieu based on Houston Ship Channel.
Shrink is defined as Btus that are removed from natural gas through the gathering and processing operation.

Current Frac Spread (Cents/Gal)

Date: November 28, 2014	Conway	Change from Last Week	Mont Belvieu	Change from Last Week
Ethane	18.25		19.70	
Shrink	29.64		27.05	
Margin	-11.39	-53.01%	-7.35	0.19%
Propane	76.98		74.65	
Shrink	40.95		37.37	
Margin	36.03	-24.28%	37.28	-7.39%
Normal Butane	108.50		99.55	
Shrink	46.35		42.31	
Margin	62.15	-13.93%	57.24	-7.20%
Isobutane	114.63		101.53	
Shrink	44.52		40.64	
Margin	70.11	-12.09%	60.89	-8.40%
Pentane+	151.63		152.20	
Shrink	49.57		45.25	
Margin	102.06	1.94%	106.95	5.74%
NGL $/Bbl	31.20	-6.34%	30.18	-5.00%
Shrink	16.33		14.90	
Margin	14.87	-15.17%	15.28	-2.21%
Gas ($/mmBtu)	4.47	3.47%	4.08	-7.69%
Gross Bbl Margin (in cents/gal)	33.20	-16.50%	34.65	-2.68%
NGL Value in $/mmBtu (Basket Value)				
Ethane	1.00	-13.92%	1.08	-10.21%
Propane	2.67	-11.68%	2.59	-7.54%
Normal Butane	1.17	-7.26%	1.08	-7.41%
Isobutane	0.71	-6.64%	0.63	-8.12%
Pentane+	1.96	2.44%	1.96	1.36%
Total Barrel Value in $/mmbtu	7.52	-7.53%	7.35	-5.78%
Margin	3.05	-20.00%	3.27	-3.27%

Price, Shrink of 42-gal NGL barrel based on following: Ethane, 36.5%; Propane, 31.8%; Normal Butane, 11.2%; Isobutane, 6.2%; Pentane+, 14.3%, Fuel, frac, transport costs not included. Conway gas based on NGPL Midcontinent zone, Mont Belvieu based on Houston Ship Channel.

Shrink is defined as Btus that are removed from natural gas through the gathering and processing operation.

NGL Energy Partners Acquires Remaining Interest In Grand Mesa Pipeline

NGL Energy Partners LP executed a definitive membership interest purchase agreement with Rimrock Midstream LLC for Rimrock's 50% interest in Grand Mesa Pipeline, LLC. NGL now owns 100% of the pipeline system.

Grand Mesa Pipeline LLC completed a successful open season on Oct. 3, 2014, securing multiple significant long-term shipper commitments. The system will include over 550 miles of new crude oil transportation pipeline, multiple truck injection bays, over 1.0 million barrels of operational storage and at least two origination points near Lucerne and Kersey in Weld County, Colo. The system is in active development and scheduled to commence service in Q4 2016. Rimrock will construct and operate the pipeline system.

The acquisition further strengthens NGL's diversified midstream business, adding significant fee-based revenue backed by long-term contracts. The Grand Mesa Pipeline will help further develop the crude and condensate-rich Denver Julesburg and Wattenberg fields and provide additional options for transporting crude oil to U.S. markets and refineries in the Midwest, including the Cushing, Okla., hub. NGL will have ownership in two long-haul crude oil pipelines that terminate into NGL's Cushing Terminal Facility which provides additional revenue opportunities for NGL, its shippers and refinery customers. A significant portion of the committed crude oil volumes will be tied to Grand Mesa via gathering systems, reducing the need for trucked volumes.

Williams' Geismar Plant In Final Stages Of Commissioning

Williams Partners LP announced its expanded Geismar plant is in the final stages of commissioning and now expects ethylene production for sale to begin in December.

"Some of these commissioning activities have taken longer than originally planned, but as we have stated throughout this process, safety is our number one priority," said John Dearborn, SVP of NGL and petchem services. "And I want to thank our Geismar team for its focus on safety throughout this complex expansion and rebuild effort."

Capacity at the Geismar plant is now 1.95 billion pounds of ethylene per year. Williams Partners' share of the total capacity of the expanded plant is approximately 1.7 billion pounds per year.

ONEOK Acquires Permian NGL Pipeline Assets

ONEOK Partners LP completed the acquisition of NGL pipelines and related assets from affiliates of Chevron Corp. for approximately $800 million.

ONEOK Partners now owns an 80% interest in the West Texas LPG Pipeline Limited Partnership and 100% interest in the Mesquite Pipeline, which collectively consist of approximately 2,600 miles of NGL gathering pipelines extending from the Permian Basin in southeastern New Mexico to East Texas and Mont Belvieu, Texas. ONEOK Partners is the operator of both pipelines. The remaining 20% of West Texas LPG is owned by Martin Midstream Partners L.P.

"The West Texas LPG and Mesquite NGL pipelines will integrate into our existing natural gas liquids segment's portfolio of assets and provide fee-based earnings to the partnership," said Terry K. Spencer, president and chief executive officer of ONEOK Partners. "With the closing of this transaction, we welcome the approximately 75 employees currently operating these assets to the ONEOK Partners team. We look forward to working with all of them and assisting them with their transition to ONEOK Partners."

Supermajors Trending Toward MLPs?

By Deon Daugherty, Associate Editor

Despite the recent decisions of Royal Dutch Shell, Noble Energy and Hess Corp. to move their midstream assets into MLP IPOs, an executive at the supermajor of the supermajors says the timing isn't right for the world's largest publically traded oil company to follow suit.

Jeff Woodbury, ExxonMobil's vice president of investor relations and secretary at the Irving, Texas-based company, said during the company's 3Q earnings call on Oct. 31 that the company has already "divested or monetized" all of its non-strategic assets.

"The remaining assets that we've got in place are very strategic to the integrated model that we have between the upstream, downstream or our chemical business," Woodbury told analysts on the call. "The MLPs are generally used as a financing mechanism to raise cash and fund business growth. As you know, with our financial flexibility, we have very low cost of capital. While I will never say no, I would tell you that just the cost-benefit trade-offs for MLPs are unattractive for us given our low cost of capital."

2013 was a record year for companies making public MLP offerings, and 2014 is hot on its heels with more than a dozen—including Shell's $1.06 billion IPO—and word that Hess Corp., along with several others, have plans for their own in the works.

Shell Midstream Partners owns the pipelines that move oil onshore from the Gulf of Mexico; the lines also transport refined products from U.S. refineries to primary centers of demand on the East Coast.

MLPs have gained steady popularity among midstream companies in recent years. The tax-advantaged status of the structure allows the partnership to skip corporate income tax by flowing income to its partners, or unitholders, who are then responsible for the taxes.

Enbridge Reviewing Plan To Dropdown Liquid Pipeline Assets

Enbridge Inc. is reviewing a potential restructuring plan that would involve the transfer of its directly held U.S. liquids pipeline assets to Enbridge Energy Partners LP (EEP), a U.S. affiliate of Enbridge.

"Enbridge's recent restructuring announcement is a clear message that Enbridge is seriously considering further drop-down transactions to EEP. Enbridge's U.S. liquids pipeline systems are extensive and include very strategic assets such as the Flanagan South, Spearhead, Seaway, Toledo and Southern Access Extension pipelines. In addition, EEP and Enbridge have jointly funded several major expansions of the Lakehead pipeline system in the Great Lakes region of the U.S., said Mark A. Maki, president of Enbridge Management.

Maki noted that the company's U.S. pipeline systems are largely underpinned by low-risk commercial frameworks, such as cost of service or ship-or-pay commitments.

"The potential dropdown of Enbridge's U.S. liquids pipelines systems would add substantial new sources of long-lived and growing cash flows to EEP's already exceptional portfolio of liquids pipeline systems. The restructuring plan under consideration by Enbridge once again demonstrates the strategic alignment and support of our sponsor Enbridge, and its commitment to enhancing the value of EEP for all of our investors," concluded Maki.

An independent committee of the board is currently reviewing and considering the terms of the previously announced proposed transfer to EEP of Enbridge's 67% interest in the U.S. segment of the Alberta Clipper Pipeline, which, if approved, is expected to be completed by year end.

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