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Analyst Contacts

Steven Wood +1.212.553.0591
MD-Corporate Finance
steven.wood@moodys.com

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Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
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Oil & Gas - Global

Focus on consolidation, simplification and more infrastructure will drive 2019 returns

» **We expect the medium-term price band for WTI crude will be $50-$70/bbl, and North American natural gas at Henry Hub will average $2.50-$3.50/MMBtu.** Market expectations for continued strong oil demand growth have remained in place, despite concerns about weaker global economic growth, tariffs, and a strong US dollar. The key questions for 2019 are whether OPEC and Russia will maintain production discipline, and what happens when the current agreement expires in June.

» **E&P investors will keep awaiting higher shareholder returns in 2019.** E&P companies have made strides in capital efficiency and commodity prices are higher than in the 2015-16 downturn, but investor sentiment is weak and infrastructure constraints reduce prices that E&Ps receive. The North American E&P and midstream sectors are primed for further consolidation but oil-price volatility may slow M&A activity in 2019.

» **Wide differentials for regional oil and natural gas prices will narrow against the main North American benchmarks in 2019.** Infrastructure coming into service in late 2019 and 2020 will ease bottlenecks in the Permian, western Canada, and other regions, relieving stress on commodity prices. Credit quality is visibly improving for midstream companies after several years—largely thanks to equity investors demanding better returns from companies as consolidation opportunities pick up.

» **The OFS sector faces an inauspicious start for 2019.** While overall earnings will increase by 10%-15% from a relatively low level, most of that growth will likely come only later in 2019 after the heightened oil-price volatility of late 2018. Permian infrastructure constraints will also limit OFS operators' ability to raise prices early in 2019.

» **Distillate margins for refiners will begin expanding from already strong levels in the second half of 2019 and remain strong through at least 2022.** Heavy crude differentials will widen as refiners cut their consumption and reduce production of high sulfur fuel oils ahead of the stricter IMO 2020 requirements on sulfur content in marine fuel. US refiners are better positioned for the shift than their competitors elsewhere.

» **Mexico's energy sector faces risks to business confidence from a new government policy that would shift PEMEX toward refining and away from oil production, and from a proposal to place energy regulation under federal energy ministry oversight.** Asian NOCs will increase capital spending to support growing domestic fuel needs in line with national energy policies, but volatile oil prices, increasing shareholder returns, soft refining margins and evolving fuel-price regulations all pose credit risks.

Oil and natural gas prices will be volatile but range-bound in 2019

Terry Marshall, Senior Vice President

We expect the medium-term price band for West Texas Intermediate (WTI) crude, the main North American benchmark, will be $50-$70 per barrel (bbl). The December 2018 announcement that OPEC and Russia have agreed to cut production by a total 1.2 million bbl/day (bpd) from October 2018 levels helps alleviate concerns about an oversupplied oil market, which had led to a more than 40% drop in crude prices in the past three months. Market expectations for continued strong oil demand growth of 1.4 million bpd have remained in place, despite concerns of slowing demand growth tied to weaker global economic growth, the impact of tariffs and a strong US dollar, especially in the emerging markets. Very high Saudi and Russian production, mixed signals on Iran sanctions, and US presidential pressure on Saudi Arabia to maintain high production levels have all heightened supply volatility. The key questions for 2019 are whether OPEC and Russia will maintain production discipline, and what happens when the current agreement expires in June.

We expect that North American natural gas at Henry Hub—the chief benchmark for US natural gas prices—will average $2.50-$3.50 per million British thermal units (MMBtu). We expect natural gas liquids (NGLs) will trade at roughly 45% of WTI, for a $22-$32/bbl average.

Exhibit 1
Oil and natural gas price estimates

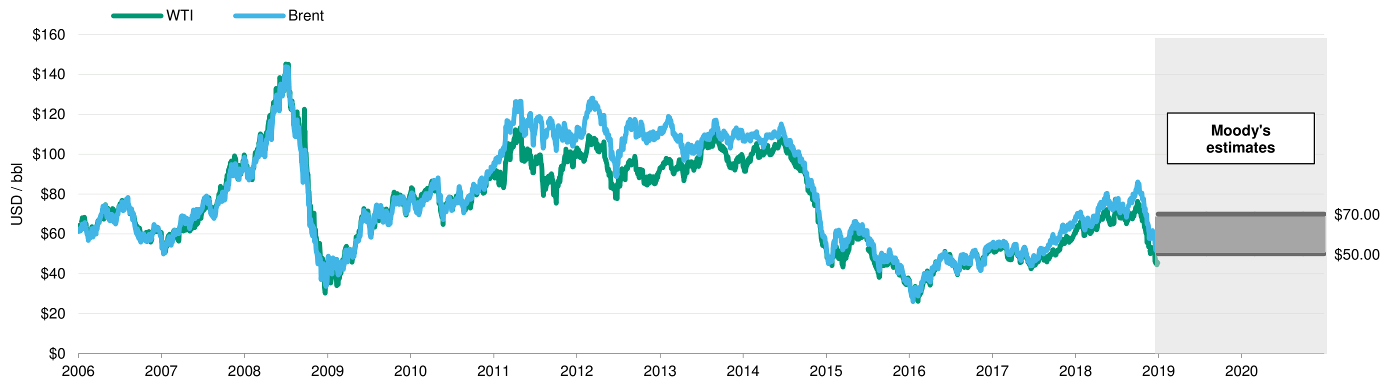
	Medium-term price band
WTI crude*	$50 to $70
Henry Hub natural gas	$2.50 to $3.50
Natural gas liquids	$22 to $32

Note: *We assume a $5.00 premium for Brent crude
Source: Moody's Investors Service (estimates)

While we will see only a gradual increase in rig activity in 2019, oilfield services (OFS) costs will likely rise over the medium term. Higher oil prices will encourage more production activity, which will stimulate already rising OFS prices, raising the breakeven cost of the marginal barrel and potentially raising medium-term oil prices. In North America, strong demand from shale producers is driving up pricing for high-caliber “super spec” drilling rigs, and for various production services. In Texas, strong economic growth and low unemployment have led to widespread labor shortages, escalating labor cost inflation. International activity is picking up in certain markets. But it will take higher oil prices to develop the more expensive conventional barrels that are ultimately needed to meet increasing global demand and offset natural production declines.

Prices toward the upper end of the oil price-band will encourage increased supply as US production grows and OPEC countries reduce their compliance with their production quotas. Shale oil production in particular features relatively low extraction costs and short time lags from drilling to production, and shale's drilling efficiencies have increased substantially over the past few years. US shale producers are paying increasing attention to capital discipline and return-focused performance, but even at current lower prices, we believe US shale production will continue to grow, increasing global production and keeping a lid on prices. We believe prices will remain largely within our expected range (see Exhibit 2)—although they will be volatile—amid increases in US shale production, reduced but still significant global supplies, and potential declining compliance with agreed production cuts, especially if growth in demand is more tepid.

Exhibit 2
WTI crude prices will stay within $50-$70/bbl band



Source: US Energy Information Administration; Moody's Investors Service (estimates)

We expect the Brent-WTI differential to narrow toward $5.00/bbl during 2019, down from around $8.00/bbl in late 2018. The wider-than-normal differential reflected OPEC production cuts and other supply disruptions outside of North America, sanctions on Iran, and increased US exports. Rising US and Canadian production and insufficient North American pipeline capacity had widened the WTI discount in 2018.

Meanwhile, natural gas demand is likely to increase with US exports of liquefied natural gas, as well as dry gas to Mexico; growing demand from US Gulf Coast petrochemical plants; and continuing growth in gas-fired power demand. Abundant US supplies of natural gas from shale, along with rapidly increasing associated gas from shale oil production, will limit US natural gas prices (see Exhibit 3). However, storage levels below historical averages mean prices could continue to spike to levels above our band, based on unexpectedly severe winter weather.

Exhibit 3
North American natural gas prices will stay within $2.50-$3.50/MMBtu band through 2020

Source: US Energy Information Administration; Moody's Investors Service (estimates)

NGL prices will move with WTI crude prices, but will spike on infrastructure bottlenecks and demand volatility, as they did briefly in 2018. Construction of new fractionation and NGL pipeline capacity will ease the threat of bottlenecks, but short-term fluctuations in demand such as maintenance downtime at ethane crackers could lead to occasional price spikes. NGLs will benefit from additional export capacity, while ethane prices will rise as new Gulf Coast crackers increasingly process ethane into ethylene. Strong propane demand and export growth are also propping up NGL composite prices.

E&P companies struggle to improve shareholder returns

Amol Joshi, Vice President - Senior Analyst

E&P investors looking for higher shareholder returns will continue to wait in 2019, despite strides in capital efficiency and higher commodity prices since the 2015-16 downturn. E&P revenues correlate closely to oil and gas prices, but profitability depends on numerous other factors, including operating costs, product mix and quality, transportation costs and financial policy. While profitability influences valuation and shareholder returns, supply/demand imbalances and market sentiment can make investor returns volatile.

E&P companies in 2019 will continue to exercise spending discipline and focus on capital efficiency. While labor inflation has increased their operating costs, rising production has largely contained their costs per unit. Higher demand for OFS has raised the costs of drilling and completing onshore wells, but efficiencies have helped most E&P companies offset some of these higher capital costs.

Still, elevated oil prices through most of 2018 did not benefit many producers in the Permian, the dominant US producing basin. Permian-based E&P companies had increased production beyond what midstream companies could take away, and higher transportation costs will continue to hurt profitability in 2019, while insufficient takeaway capacity could stifle E&P growth plans. Such constraints have soured investors' expectations over near-term earnings potential. Investor sentiment has weakened—especially at the end of 2018—amid increased commodity-price volatility, US production growth, renewed economic uncertainty, and tariff wars.

Even if such risks do not worsen in 2019, tepid investor appetite will make companies less inclined to try and raise capital, and could even temporarily dampen E&P consolidation. But plenty of companies still have small production and reserve bases, and are seeking relevance in the capital markets. Such companies will be inclined to consolidate and improve investor returns by eliminating costs. The pace of consolidation that began in mid-2016 still has not reached that of previous cycles.

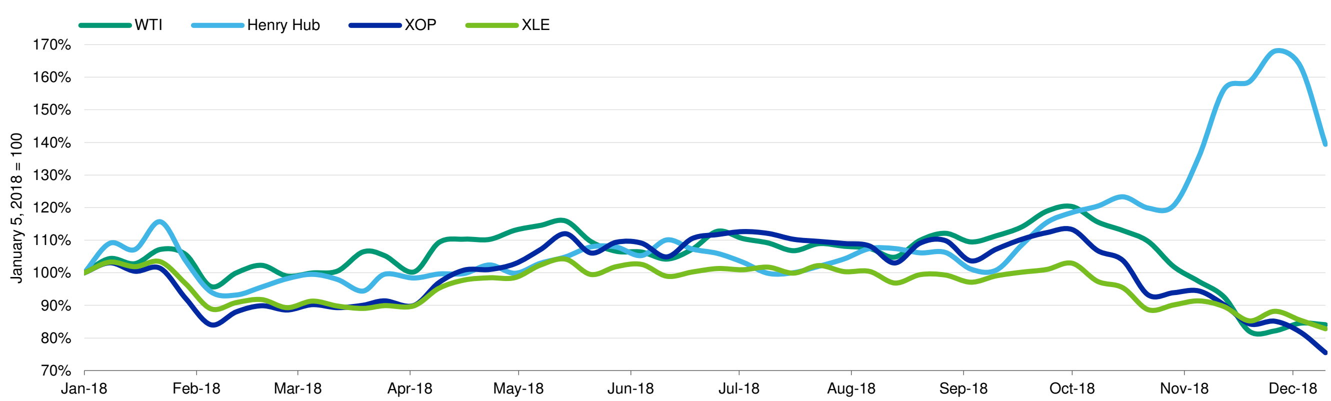
New midstream infrastructure will eventually ease takeaway constraints and normalize pricing differentials. The wide 2018 discounts for Permian and Western Canadian Select crude should gradually narrow through 2019. Meanwhile, capital spending has fallen as a percentage of retained cash flow since 2016. In 2015, E&P companies had continued spending heavily on capital projects even as oil prices crashed; by comparison, companies today are far likelier to rein in capital spending if prices and cash flow drop, thus preventing a meltdown scenario.

Natural gas prices rallying in late 2018 also did not immediately boost investor confidence or returns. In December 2018, futures contracts for natural gas sold at more than $4.00/MMBtu for winter delivery, but futures prices retreat for deliveries later in 2019, reflecting the abundant US supply. Not only are natural gas-focused companies increasing production, but oil-focused companies are also producing large amounts of associated gas, especially in the Permian and STACK.

E&P companies are now inclined to return excess cash flow to shareholders rather than re-investing—a significant shift from the 2010-14 mindset of production growth at any cost. But this trend has still not translated into overall shareholder returns, whether for exchange-traded funds such as the E&P focused XOP, or the broader energy-focused XLE (see Exhibit 4).

Exhibit 4

Investor returns are disconnected from commodity prices



Source: FactSet

The focus on capital efficiency since 2017 has helped increase netbacks and reduce finding and development costs, benefiting E&P capital efficiency—which we measure with our leveraged full-cycle ratio—and profitability. Higher prices should ultimately enhance shareholder returns, but only when investors feel assured that falling prices will be temporary, and that surging prices will persist for longer.

Consolidation will accelerate among upstream and midstream shale companies

Elena Nadtotchi, Vice President - Senior Credit Officer

North American shale producers are poised to continue to consolidate and optimize acreage portfolios in 2019 to help maximize efficiency and returns on capital. The midstream sector, which many smaller companies entered in 2017-18, is also getting ready for a wave of consolidation, particularly in the Permian Basin, and companies are making structural adjustments for future deal-making. But the volatility of oil prices means companies may delay M&A decisions, slowing the pace of consolidation in 2019. The consolidation trend is credit positive for both shale producers and the midstream companies that aim to serve them.

Investors increasingly demand that shale producers generate capital-efficient growth and improve returns. To do so, many companies strive to reduce development costs by adopting new, scale-dependent drilling processes, and by improving their operational efficiency by reducing general and administrative costs and improving supply-chain management. Such efficiencies require shale producers to expand their complementary acreage footprints continuously through asset swaps and acquisitions, creating economies of scale and allowing more of an industrial approach to shale oil production. This push to expand acreage will also foster consolidation as shale producers become increasingly specialized and geographically focused, generating strong capital returns. Small and even mid-sized companies outside of the core shale plays will increasingly struggle to attract growth capital.

The consolidation trend for shale producers is taking place within the fast-growing Permian, but also in other shale regions. Concho Resources' (Baa3 stable) all-equity acquisition of RSP Permian in March 2018 and Diamondback Energy's (Ba1 stable) all-equity purchase of Energen in November offered a preview of the trend. QEP Resources (Ba3 review for downgrade) is now building up a Permian-focused portfolio and divesting assets in the Williston and Uinta basins. Outside of the Permian, Chesapeake Energy (B2 review for upgrade) in October announced plans to acquire WildHorse Resource Development (B2 review for upgrade), citing both its adjacent Eagle Ford acreage and its oil-weighted production profile. Buying Newfield Exploration (Ba1 positive) gives Encana (Ba1 positive) an opportunity to add SCOOP/STACK operations to its Permian and Montney/Duvernay plays.

These transactions are generally equity-funded, not debt-financed, and bring many operating benefits, including longer-life drilling inventory, efficiencies and synergy opportunities, and greater capital and operating flexibility. Smaller geographic footprints pose concentration risks to credit quality, however, so these companies must balance those risks by delivering higher capital returns and reducing debt leverage.

Consolidation for shale producers may spark consolidation in the midstream sector as well— particularly for the highly competitive and fragmented Permian segment, where smaller gathering and transportation (G&T) companies struggle to keep pace with the rapid growth in production. Rising demand for supporting infrastructure such as pipelines and water management systems will also facilitate consolidation among midstream operators, many of them newly established businesses backed by private-equity capital.

Under pressure to secure market access and finance construction of new infrastructure, many G&T companies took on competitively priced long-term contracts with E&P producers and shippers that will likely make them less attractive near-term acquisition targets for larger midstream companies. G&T systems rely fully on the cash flow they generate by moving oil and gas through their systems. Smaller midstream operators will seek consolidation deals and joint ventures in 2019, possibly with the help of private-equity sponsors, to scale up and optimize their operations, and to fund significant investment in pipeline infrastructure to capture more of the production growth.

We will likely see more ambitious transportation deals in 2019 along the lines of BCP Raptor, LLC's (B3 stable) June 2018 announcement that it will invest in the $2 billion Permian Highway Pipeline natural gas pipeline project led by Kinder Morgan, Inc. (KMI, Baa2 stable). Blackstone, the private equity group that bought BCP Raptor in 2017, backs the G&T deal, which will add considerable Permian takeaway capacity and increase volumes for BCP.

Differentials will drop as infrastructure comes on line

James Wilkins, Vice President - Senior Analyst

Paresh Chari, Vice President - Senior Analyst

Wide differentials for oil and natural gas sold in various North American basins will decline against the region's main benchmark prices in 2019, with more takeaway infrastructure freeing the movement of hydrocarbons to customers and end markets.

The Permian Basin, which has accounted for the largest increment of growth in US oil production in 2017-18, faces takeaway constraints for oil, natural gas liquids and natural gas. The constraints resulted in high basis differentials in 2018, with WTI Midland crude selling sometimes at prices more than $14/bbl beneath Cushing, and Waha natural gas sometimes $2.00/MMBtu below spot prices at Henry Hub. Insufficient long-haul pipeline takeaway capacity to the US Gulf Coast and export markets have left producers to look for new markets, and existing markets served by other producing areas have been oversupplied. Natural gas prices in the Rockies plunged to more than $1.00/MMBtu below Henry Hub in 2018, with excess Permian natural gas flooding US West Coast and other markets typically supplied by Rockies production.

Midstream takeaway infrastructure spending lagged E&P capital spending in 2017-18, but many midstream projects coming into service in late 2019 and 2020 will provide relief to basin takeaway capacity constraints and the strain on commodity prices. The EPIC, Cactus II and Gray Oak pipelines will begin shipping oil from the Permian in 2019, reducing basis differentials and supporting increased development and higher production volumes in the prolific basin. The Gulf Coast Express and other pipelines will boost Permian natural gas takeaway capacity in the second half of 2019, which has been a bottleneck for oil production, and will also narrow the natural gas differentials in neighboring regions such as the Rockies. Increased natural gas supplies will benefit new power plants, increasing industrial demand and liquefied natural gas (LNG) exports; additional pipelines will improve prices for natural gas from the Marcellus and Utica basins.

Very high crude inventories in the province of Alberta created extraordinarily wide Canadian heavy oil differentials in November-December 2018, amid significant refinery downtime and full pipeline egress out of Canada. Alberta's (Aa1 negative) December 2018 move to curtail production by 325,000 bbl/day (bpd) while high inventories persist immediately helped narrow Albertan heavy oil's wide discount to WTI. But while the curtailment quickly helped boost prices, it does not change the region's long-term risk of low margins; without additions in long-term pipeline takeaway capacity, Alberta crude prices will remain volatile and cheaper than WTI.

The lack of takeaway capacity will keep the heavy oil discount to WTI wide in 2019 and beyond. But on top of the Alberta government's action to boost prices, several companies are taking steps that will narrow differentials. More companies are shipping crude by rail: Cenovus Energy (Ba1 stable) is ramping up shipments by rail to 100,000 bpd under a three-year rail contract, and Alberta will purchase additional railway cars to ship another 120,000 bpd out of the province. Canadian Natural Resources' (Baa2 stable) and Alberta's Sturgeon refinery will start processing heavy oil early 2019, consuming about 80,000 bpd. Enbridge's (Baa3 positive) Line 3 replacement pipeline, which could enter service as soon as the fourth quarter of 2019, and would add an incremental 370,000 bpd of capacity. While Line 3R would help differentials considerably, there will be no lasting improvement without this and other significant new pipeline egress, which has proven very difficult to implement.

Midstream credit quality will finally improve through structural simplification

Andrew Brooks, Vice President - Senior Credit Officer

Credit quality is visibly improving for midstream energy companies after several years of stagnation—largely and ironically thanks to pressure from equity markets. Equity investors have increasingly demanded higher returns from midstream companies, having grown weary of the sector's debt-laden balance sheets, organizational structures lacking transparency, dilutive financing schemes, and the diversion of ever-expanding amounts of cash to general partners. The high cost of equity capital has led much of the midstream sector to begin transforming its predominant master limited partnership (MLP) structure into simplified corporate (C-corp) structures, while reducing distributions to investors, including eliminating Incentive Distribution Rights (IDRs), and paring back debt leverage—efforts that will improve the sector's credit quality as the shift continues in 2019 and beyond.

Over the first half of the decade, the rapid construction of midstream infrastructure to accommodate surging shale development effectively papered over the increase in leverage that midstream operators incurred to finance this growth. Midstream MLPs routinely paid out virtually 100% of their free cash flow, depending almost completely on externally sourced capital to fund this growth.

However, as new project opportunities slowed following 2015's crash in crude prices, much of the midstream sector was exposed as over-levered; at times, some companies barely covered their fixed distribution obligations to investors, with badly weakened counterparty credit exposure and double-digit yields on equity. However, unlike the upstream and oilfield services sectors, for which the oil-price downturn eviscerated cash flow and credit, midstream companies continued to generate strong cash flow. But midstream companies typically distributed that cash flow almost entirely to equity owners without addressing the heavy debt on their balance sheets.

While a limited few MLPs simplified their organizational structures earlier in the decade, the midstream sector's renewed attention to credit quality developed slowly following Kinder Morgan's late 2014 simplification of its corporate structure through a general partner/limited partner (GP/LP) merger that also eliminated its burdensome IDRs. A year later KMI slashed its dividend by 75%. In 2017-18 a host of midstream MLPs went through similar simplifications—continuing with GP/LP mergers, if not always ending their MLP structures altogether; eliminating IDRs, which had so burdened their costs of equity; and retaining greater amounts of cash flow.

Many midstream operators today aspire to funding growth with higher retained cash flow, with distribution coverage increasing in some instances to well over 1.5x. Midstream companies in 2019 will continue to fund growth projects with debt from banks and the capital markets, while contributing equity through higher retained earnings. By using excess cash coverage as the equity component to fund this growth, midstream companies are seeking to change from the earlier model that sourced equity capital from the market, paid out big distributions to equity, then returned to the equity market through new equity offerings. This model had become expensive and inefficient, and disliked by equity investors. Midstream companies are also paying stricter attention to their balance sheets and reducing debt leverage—but primarily doing so by increasing EBITDA, rather than reducing debt.

The midstream energy sector may be finally on the cusp of improved credit quality in 2019 after several years of a largely sideways movement—although this improvement also reflects a certain self-interest, and not only just more creditor-friendly behavior or bowing to equity-investor demands. Increased consolidation opportunities in midstream are also more likely in the near future, and participation in that consolidation would be difficult to finance with over-levered balance sheets and uneconomic costs of capital. For 2019 and beyond, midstream companies will try and get back into fighting trim to help them more competitively engage in M&A deals, and to fend off competing forces such as private equity, which has aggressively barged into the sector with enormous financial resources.

Oilfield services grinds forward slowly from weak level

Sajjad Alam, Vice President - Senior Analyst

The OFS sector faces an inauspicious start for 2019 after recording steady gains in revenue, utilization and pricing during most of 2018. While we expect that overall earnings will increase by 10%-15% from a relatively low level, most of that growth will likely come only later in 2019 after the heightened oil-price volatility of late 2018. Infrastructure constraints in the Permian Basin will also limit OFS operators' ability to raise prices early in 2019.

While E&P companies grew cautious after a precipitous 40% decline in WTI prices between early October and the end of 2018, we still expect low single-digit growth in E&P spending in 2019. E&P companies have dramatically reduced their cost structures since 2015, and today most companies can break even, reinvest enough to sustain production, and even grow modestly in most regions with oil prices at $50-$55/bbl. Producers will most likely start 2019 on a cautious note, but then gradually boost spending later in the year as the global oil supply/demand picture becomes clearer, and more infrastructure becomes available in the Permian—the busiest region for OFS activity during 2017-18.

US onshore markets still present more growth opportunities than other OFS markets. E&P companies and oil majors have committed much of their capital in expanding unconventional production, and current prices should support their ongoing development. The strong producer focus on low-risk, flexible and quick-payback shale assets in a low and volatile price environment should lift utilization and pricing in the OFS sector in 2019 while infrastructure hurdles gradually dissipate.

With Brent crude prices above $60/bbl during most of 2018, international land markets have become more active, particularly in Latin America. We expect this growth trend will continue through 2019, although the pace of growth will likely be slow with the recent price decline and continued competitive pressures.

Offshore markets could see slightly more capital allocation from upstream companies after four consecutive years of steep cuts. We expect that offshore OFS activity and customer orders will increase sequentially, but pricing and earnings recovery will remain elusive. Producers are still deferring offshore exploration, appraisal, and large-scale development decisions, while on the supply side, overcapacity has posed a persistent threat for rig, vessel, remotely operated vehicles, helicopter, manufacturing and seismic specialists. Most of the incremental drilling and development activity in 2019 will occur in shallow-water markets such as the North Sea and the Persian Gulf, while deepwater activity will primarily target projects that are low risk, can leverage existing infrastructure, or have relatively short cycle times. A number of large offshore gas development projects will also increase OFS activity in 2019.

The health of the OFS sector is still quite weak. While earnings are improving, a large subset of companies are still carrying excessive amounts of debt, and any sustained drop in crude prices will create stress. With US unemployment at record lows, OFS companies and their E&P customers are all seeing significant inflation in labor costs. Most OFS companies also need to reinvest in their operations to boost service capacity and meet customer demand. So even if OFS companies book more revenue in 2019, they may not generate significant discretionary cash flow and boost financial flexibility, which makes the sector's recovery a long, drawn-out process.

IMO 2020 mandates will benefit US refiners but pose hazards for late adopters

Arvinder Saluja, Vice President - Senior Analyst

Distillate margins for refiners will likely begin expanding from today's already strong levels in the second half of 2019, ahead of the International Maritime Organization's adoption of stricter IMO 2020 requirements on sulfur content in marine fuel, and will remain strong through at least 2022. Differentials of heavy crude will also widen as refiners cut their consumption and reduce production of high sulfur fuel oils (HSFO). US refiners are better positioned to take advantage of the shift than refiners globally in general.

Stricter government regulations to help protect the environment will require refiners around the world to produce low-sulfur transportation fuels. The new IMO 2020 emission standards, which take effect on January 1, 2020, will reduce the maximum amount of sulfur permitted in fuel for shipping vessels to 0.5% by mass, from 3.50% today.

Many marine shippers are looking into alternatives, such as putting scrubbers on vessels that would allow them to continue using HSFO or switching to LNG as a fuel. Installing scrubbers is expensive and time-consuming, and also leads to environmental concerns about increased sulfur emissions into the ocean or on land. Switching to LNG, while cleaner, also incurs significant upfront costs, but the biggest constraint is its availability as a bunker fuel. Probably no more than 10% of the total 60,000-ship global merchant marine fleet will be using these alternatives when the mandate takes effect, and the rest will initially switch to marine gasoil or a new very-low-sulfur fuel oil, according to the International Energy Agency. Incremental demand for marine gasoil to replace HSFO could rise by more than 3 million bpd for 2-3 years starting in 2020, leading to higher refinery utilization, distillate prices and refinery margins, and to lower residual fuel prices.

Many US refineries are already high-complexity, so the IMO 2020 sulfur restrictions allow them to benefit from wider light/heavy differentials while producing fewer residuals and more IMO-compliant fuel and other distillates. Valero Energy (Baa2 stable) and Marathon Petroleum (Baa2 stable) stand to gain the most, while Phillips 66 (A3 negative) also benefits from its high distillate yield, and PBF Holding (Ba3 stable) from its usage of heavy sour crudes.

By contrast, many non-US refiners elsewhere produce large amounts of HSFO today. IMO 2020 raises the risk of economic stress and shut-in production for many refiners that were slow to make upgrades and now have little time left to adapt to IMO 2020. But persistently wide light/heavy differentials should make investments in coking and other conversion capabilities attractive. Companies that act quickly will have the greatest advantage, while latecomers may find that their investments are too late to capture acceptable returns. Valero plans to invest $975 million on its Port Arthur Coker Project, which it expects will increase its heavy sour crude processing capability beginning in 2022.

IMO 2020 implies one emerging risk for refiners, however: the possibility that the US government or some shipping organizations will seek a delay or phased implementation of IMO 2020. We are expecting no significant delay in implementation and a two-thirds compliance with the mandate. But with gasoline demand at peak levels and inventories high today, refiners are depending on distillates to improve their overall margins. Any improvement for distillates will not happen without the successful enforcement of IMO 2020, or if phased or delayed implementation of IMO 2020 becomes significantly more likely.

Mexico faces significant uncertainty with new administration

Nymia Almeida, Senior Vice President

The new government's energy policy in Mexico (A3 stable) will focus more on self-sufficiency for fuel, an agenda that threatens to shift national oil company (NOC) Petroleos Mexicanos (PEMEX, Baa3 stable) toward refining, which would compromise its standalone credit quality, and by extension Mexico's revenue from energy production. Placing Mexico's energy regulators under federal energy ministry oversight would further erode business confidence in Mexico's energy sector.

The new government has already signaled that it understands the importance both of PEMEX and oil production, disclosing in December 2018 in the federal budget for the Ministry of Energy that it would inject MXN25 billion (less than $1.3 billion) in capital into PEMEX in 2019. But despite the signal of very high government support, the possible addition of some $5.6 billion in debt on top of another $4.4 billion maturing in 2019 makes it crucial that PEMEX maintain access to the international capital markets. Significant operating expenses in 2019 will make it harder for PEMEX to stabilize crude production and reserves.

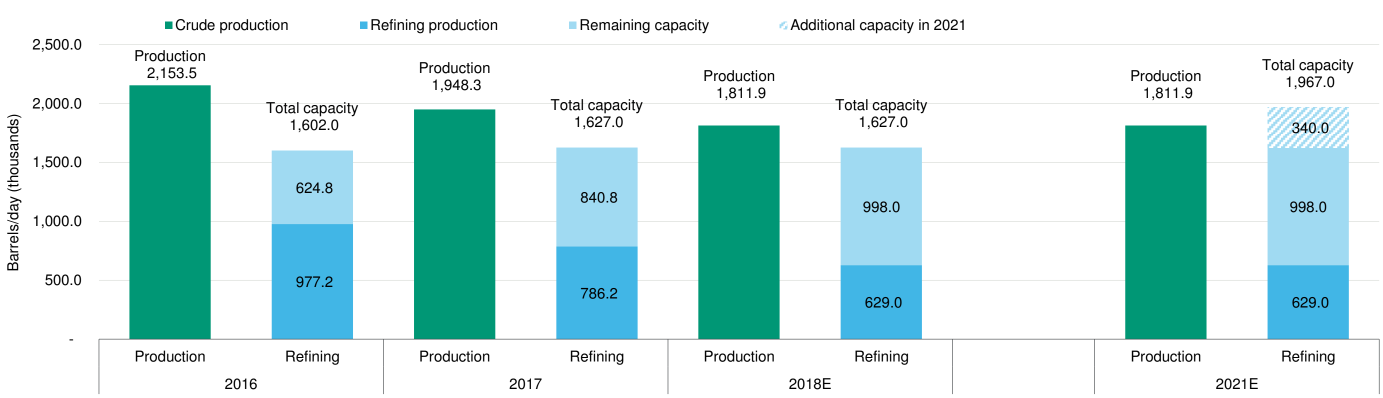
While our investment-grade rating for PEMEX assumes very high implicit support from the Mexican government, President Andres Manuel López Obrador's nationalistic vision for Mexico's energy sector entails both increased state control and greater limits on private involvement in Mexico's oil sector, implying a radical departure from the 2013 energy reform. A congressional proposal to place Mexico's oil and electricity regulators beneath the oversight of the federal energy ministry would end their political independence. Lower regulatory autonomy, transparency and impartiality would reduce the appetite for private investment in the petroleum and power sectors in Mexico, which in turn could increase the country's already high dependence on imported fuel, natural gas, and eventually oil as well.

PEMEX needs that investment badly today, since its oil production and reserve life have declined over the last 15 years. Since 2016, PEMEX's efficiency has improved slightly, while liquidity has strengthened and PEMEX has slowed additions to its debt, but the company is not making money from its E&P after capital costs and reserve replacement, and still posts losses in refining. PEMEX also pays the federal government 70% of its EBITDA, which restricts its capital investment.

A new government decision to cap fuel prices or shift toward more fuel refining would weaken PEMEX's credit quality, turning Mexico from a crude exporter to an exporter of lower-margin fuel. The government's goals suggest that Mexico's fuel refining capacity would exceed its crude production by 2021 (see Exhibit 5), which PEMEX probably cannot increase significantly based on natural declines and insufficient capital, even with the big new government commitment to E&P investment in 2019.

Exhibit 5

Steady crude production in Mexico would likely fall short of refining capacity by 2021



Source: PEMEX; Moody's Investors Service

To help make Mexico self-sufficient in fuel, especially gasoline, President López Obrador has proposed spending some $10 billion or more to expand PEMEX's refining capacity by more than 20%. But doing so would turn Mexico into a net oil importer, with no clear view about whether PEMEX or the government would pay for the refining push.

Mexico today has enough market access to borrow money, and can choose whether to support PEMEX or install a new energy model, but its decision will affect its debt metrics—and ultimately PEMEX's rating. Since the new government's cash on hand will not be enough to cover its refining ambitions, the endeavor would force either the government or PEMEX to borrow in 2019 and possibly increasingly starting in 2020. Any sovereign downgrade would not automatically mean a PEMEX downgrade, but would make it more likely.

Asian NOCs will face dilemma over investment plans amid volatile oil prices

Rachel Chua, Assistant Vice President - Analyst

Asian NOCs plan to increase capital spending in 2019 to support growing domestic fuel needs in line with national energy policies, after years of rationalizing their capital investments. But these companies will have to balance their growth ambitions in an environment of volatile oil prices, increasing shareholder returns, soft refining margins and evolving fuel price regulations, which pose risks to their free cash flow generation and credit metrics.

Asian NOCs will largely focus their capital projects on adding refining capacity and increasing upstream production. Fuel demand continues to grow in Asia, particularly in China, India and Indonesia, which collectively account for more than 80% of the region's demand growth. Indonesia's Pertamina (Persero) (P.T.) (Baa2 stable) plans downstream capital spending of $2.0 billion-$2.5 billion in 2019 to reduce petroleum imports, which currently make up 40% of consumption. Others, such as India's Oil and Natural Gas Corporation (Baa1 stable) and Thailand's PTT Public Company Limited (Baa1 stable), will spend to boost upstream production to help reduce reliance on crude imports and replenish hydrocarbon reserves.

Chinese NOCs will continue to invest heavily in natural gas production and transmission, given the government's target to increase natural gas in its primary energy mix to improve air quality. But China's import of natural gas will continue to increase over the next two to three years, since its incremental domestic supply will still lag double-digit consumption growth.

Shareholders will also demand stronger returns from the Asian NOCs after their strong performance in 2018 and a largely supportive operating environment, with oil prices settling into our medium-term price band. Shareholders will likely seek higher dividends to make up for distribution cuts in 2015-17, when oil prices were low. Petroliam Nasional Berhad (A1 negative) will pay a one-off special dividend of MYR30 billion (USD7.2 billion) to the Malaysian government (A3 stable) in 2019 on top of its annual dividend payment of at least MYR24 billion.

Asian refining earnings will contract in 2019 as higher regional crude prices drive up feedstock costs, and retail fuel price regulation in some countries will strain marketing profits. We expect the benchmark Singapore complex refining margin to stay benign at $5.50/bbl through the end of 2019. The governments of India and Indonesia have asked their fuel retailers to sell gasoline and diesel to consumers at subsidized prices without reimbursement, and the re-emergence of fuel subsidies could extend to more Asian countries, thereby dampening profits. Indian oil marketing companies began absorbing a $2.10/bbl price cut in October 2018, and Indonesia has yet to revisit its regulated fuel prices, last adjusted in March 2016, when the Dubai crude price was $35.20, roughly half its average price in 2018. In China, an oversupply of refined products following years of capacity additions will also weigh on domestic margins.

Moody's related publications

Sector in-depth reports:

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- Oilfield Services and Drilling - North America: High debt levels constrain credit quality in 2019 and beyond, amid modest margins, October 29, 2018
- Oil and Gas - Global: As prices rally, credit quality still hinges on spending decisions and global risks, October 26, 2018
- Exploration and Production - North America: Temporary pipeline takeaway constraints slows growth in Permian production, October 10, 2018
- Oil and Gas – North America: Industry faces $240 billion of maturities through 2023; issuance slowly returning, October 5, 2018
- Oil and Gas – Global: Frequently asked investor questions, July 31, 2018
- Exploration and Production – North America: Credit quality strengthens for oil producers, but remains weak compared to 2013-14, June 11, 2018
- Oil and Gas - Global: National oil companies adopt tighter spending strategies as oil prices recuperate, May 17, 2018
- Oil and Gas – Global: Frequently asked investor questions, May 11, 2018
- Oil and Gas Industry – Global: Oil industry will focus on disciplined spending and M&A opportunities in 2018, January 2, 2018

Sector comments:

- Oil and Gas - Global: Rating actions trend positive in 2018 as industry recovery continues, December 11, 2018
- Oil & Gas – North America: Oil prices up, but will settle into $50-$70 range through 2020, October 3, 2018

Outlooks:

- Oil and Gas - Global: 2019 outlooks mostly positive as firmer prices take hold (slides), December 10, 2018
- Oil & Gas, Base Metals & Steel, Pulp & Paper - Latin America: 2019 outlooks mostly stable; pulp/paper is positive (slides), December 13, 2018
- Refining and Marketing – Global: Favorable distillate fundamentals and crude differentials will fuel EBITDA growth, October 30, 2018
- Integrated Oil and Gas - Global: Expectation of moderate fall in EBITDA in 2019 keeps outlook stable, September 26, 2018
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- Independent Exploration & Production – Global: Producers thriving after bust, growing EBITDA amid capital efficiency focus, April 25, 2018

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Analyst Contacts

Terry Marshall *Senior Vice President* terry.marshall@moodys.com	+1.416.214.3863
Elena Nadtotchi *VP-Sr Credit Officer* elena.nadtotchi@moodys.com	+1.212.553.7991
Paresh Chari *VP-Senior Analyst* paresh.chari@moodys.com	+1.416.214.3837
Sajjad Alam *VP-Senior Analyst* sajjad.alam@moodys.com	+1.212.553.1150
Nymia Almeida *Senior Vice President* nymia.almeida@moodys.com	+52.55.1253.5707
Steven Wood *MD-Corporate Finance* steven.wood@moodys.com	+1.212.553.0591
Amol Joshi, CFA *VP-Senior Analyst* amol.joshi@moodys.com	+1.212.553.7267
James Wilkins *VP-Senior Analyst* james.wilkins@moodys.com	+1.212.553.0528
Andrew Brooks *VP-Sr Credit Officer* andrew.brooks@moodys.com	+1.212.553.1065
Arvinder Saluja, CFA *VP-Senior Analyst* arvinder.saluja@moodys.com	+1.212.553.1639
Rachel Chua *AVP-Analyst* rachel.chua@moodys.com	+65.6398.8313

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