

RESERVE BASE LENDING AND THE OUTLOOK FOR SHALE OIL AND GAS FINANCE

By Amir Azar

MAY 2017



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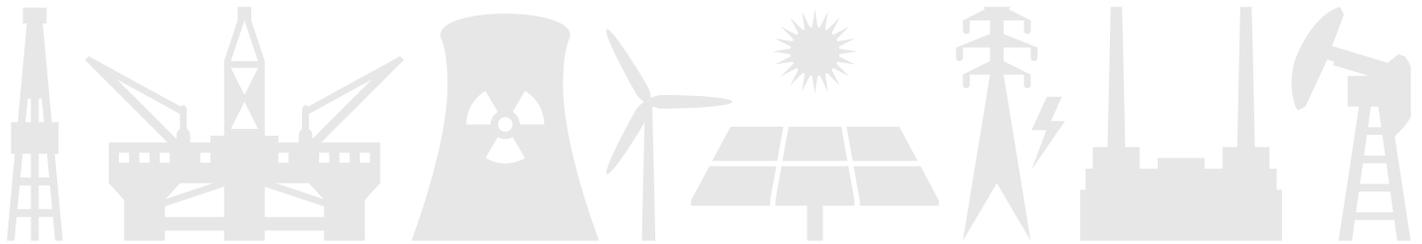
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By Amir Azar*

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EXECUTIVE SUMMARY

US oil production rose 74 percent, from 5.4 million barrels per day in 2009 to 9.4 million barrels per day in 2015,¹ with shale oil driving more than 92 percent of the growth.² The rapid expansion of shale oil and gas production in the United States from 2009 to 2014 has been associated with a period of historically low interest rates and sustained high oil prices. Over that five-year period, easy access to low-cost debt helped fuel the shale revolution; North American exploration and production companies (E&Ps) funded their cash-flow deficits with billions in secured and unsecured debt. Since mid-2014, oil prices have dramatically declined, forcing companies to adjust. An extensive body of literature has examined their resilience in the face of lower oil and gas prices and their ingenuity in protecting profit margins through cost savings and productivity gains.³ Interest rates, however, have remained relatively depressed throughout the price decline, though they have recently started to creep up. Whether the industry, having learned to reduce operating costs in the face of low prices, could overcome the additional challenge of a significant further increase in interest rates remains an unexamined question. While commentators have noted in broad terms the risk of an increase in borrowing costs for shale E&P companies, there has not been any notable in-depth study of the specific ways in which higher interest rates would impact the sector. Such an investigation is the purpose of this paper.

The exposure of shale oil and gas companies to interest-rate fluctuations is tied to their form of financing. Unlike conventional oil and gas companies, which are traditionally deep-pocketed and largely self-financed, shale companies tend to be deeply leveraged. Many small and midsize shale oil and gas exploration and production companies (E&Ps) are typically rated below investment grade by the rating agencies, Standard & Poor's (S&P) and Moody's, which makes their access to debt markets relatively expensive compared with investment-grade companies, especially when low oil prices put profit margins under pressure. In this context, the financing structure known as Reserve Base Lending (RBL) has been particularly instrumental in providing the sector with access to low-cost bank debt financings, allowing the rise and expansion of numerous small and midsize players in shale. While protecting lenders' collateral, RBL structure provides funds for the drilling and expansion of oil and gas reserves.

Unlike the operational improvement of shale oil and gas companies, which has been the object of many studies since the oil price crash, efficiency gains realized on the financial side of the industry have been less widely noted quantitatively. The selloff put the RBL structure to the test in late 2014 and 2015. Although the structure proved generally resilient, the low price of oil and the bankruptcies it triggered in the sector led to a series of improvements in RBL covenant structures. As a result, the banking sector has become more efficient and selective in E&P lending. In particular, RBL credit agreements have been amended to maintain control of the borrower's use of funds by adding anti-cash hoarding, which blocks the companies from withdrawing sizable funds without lenders' approval.

The high-yield debt market's reaction to the oil downturn magnified the importance of RBLs as the most reliable source of liquidity and funding for small and midsize E&Ps. The yield for non-investment-grade energy bonds increased from 5 percent in September 2014 to 15 percent in December 2014 and later to 25 percent in January 2016. Unlike debt capital markets, the banks remained committed to E&Ps, since the flexible nature of RBL structure allowed them to adjust their commitment and to cushion the impact of the oil crash on borrowing base calculations, particularly since most of the banks had originally used more conservative price decks than WTI NYMEX Futures. The persistence of low interest rates helped maintain the banks' commitment to the sector.

Though shale oil and gas operation and production have become more efficient (with efficiency gains reaching up to 50 percent in some basins), higher interest rates could wipe out a substantial portion of these benefits. With interest expenses comprising 25 percent to 33 percent of the total cash cost (lifting cost + cash interest expense) of E&Ps

rated between B and CCC-, a 2 percent increase in London Interbank Offer Rate (LIBOR), coupled with 1.5 percent higher credit spreads, would raise their interest expense per dollar borrowed by 30 percent, eliminating a significant portion of the gains from operational efficiencies. If rate hikes continue at 50 basis points per year, LIBOR will be above 2 percent by the end of 2018. Should it rise to a pre-financial-crisis level of above 5 percent, the cost of unsecured debt for small and even midsize producers could exceed 10–12 percent. Since shale oil production is highly capital intensive, the high cost of debt could drive up total cost of production to an unsustainable level if oil prices further fall and remain low. This high cost of capital would benefit larger players with deep financial reserves and access to debt and equity capital markets at a lower cost. Those in turn might be led to play a much larger role in the shale oil and gas sector.

While the downturn in oil prices served as an opportunity for shale producers to enhance efficiencies and improve their cost structure, a hasty rise of interest rates to the pre-financial crisis level would pose a challenge to funding future drilling and production during a low oil price environment, particularly for small and midsize companies due to the capital-intensive nature of shale.

INTRODUCTION

Although the existence of a vast shale oil resource in the United States has been known for decades, it was the innovation of producing hydrocarbon from the source rock by combining hydraulic fracturing with horizontal drilling that made the oil in nonporous shale technically exploitable.⁴ The process, however, remains capital-intensive. The real catalyst of the shale revolution was thus the 2008 financial crisis and the era of unprecedentedly low interest rates it ushered in, driven by the US Federal Reserve Bank's monetary policy. American entrepreneurship, coupled with low-cost debt, created the conditions for a surge in production that ranks among the biggest oil booms in history.

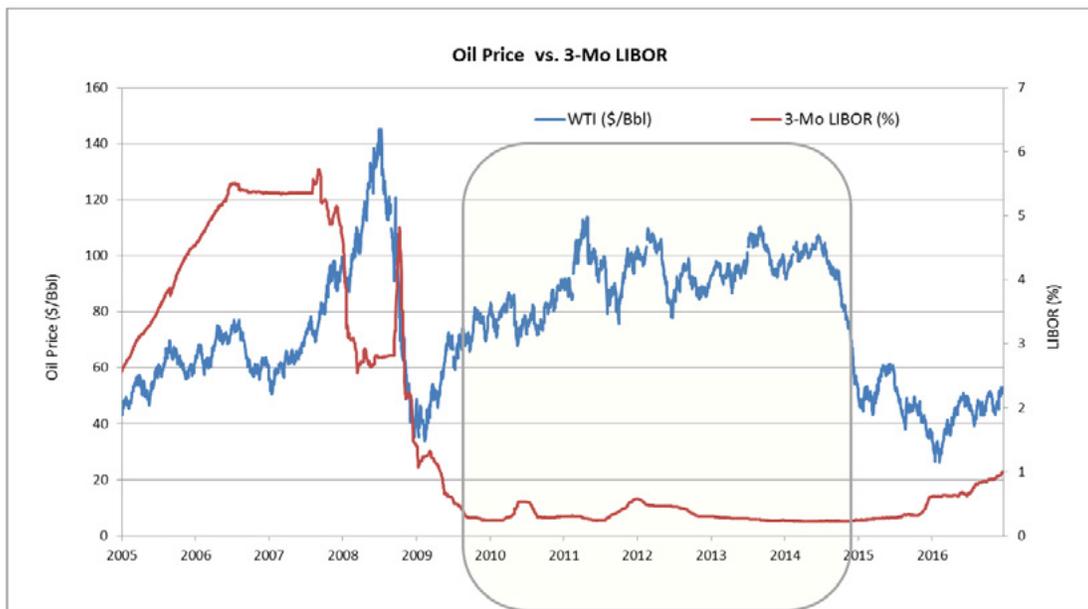
With the 2008 crisis in the rear-view mirror and oil prices rebounding to above \$100 per barrel, markets poured billions of dollars into shale over the next six years. Thus, the oil and gas sector became a major source of growth and employment, which some have argued helped the US economy out of the recession.⁵

Figure 1 shows the decline in the Intercontinental Exchange London Interbank Offered Rate (LIBOR), a widely used benchmark for interest rates. It highlights how the shale boom coincided with a period in which high oil prices and low interest rates were both persistent. Low-cost debt allowed small and midsize oil companies to access high-yield bond markets in an unprecedented way (figure 2).

Starting in June 2014, the oil market suffered what turned out to be the steepest and longest-lasting price correction in its history. The oil price fell from above \$90 per barrel in 3rd quarter 2014 to \$40 per barrel in 1st quarter 2015 and later to \$30 per barrel in 1st quarter 2016. Although the price collapse caused some turmoil in the shale oil patch, the industry managed remarkably well in a lower price environment. Thanks to cost savings and improvement in efficiency and productivity, the average well-head break-even⁶ price of the shale oil industry fell from \$80 per barrel in 2013 to \$35 per barrel in 2016.⁷ As companies cut spending in response to lower prices, the rig count in shale oil and gas fields initially plummeted, reducing US oil production from 9.4 million barrels per day in 2015 to 8.9 million barrels per day in 2016. US shale oil production initially fell to 4.2 million barrels per day in 2016 from its peak at 4.9 million barrels per day in 2015, but the pace of decline was mitigated by slowed reductions in cost and improvements in drilling techniques.⁸

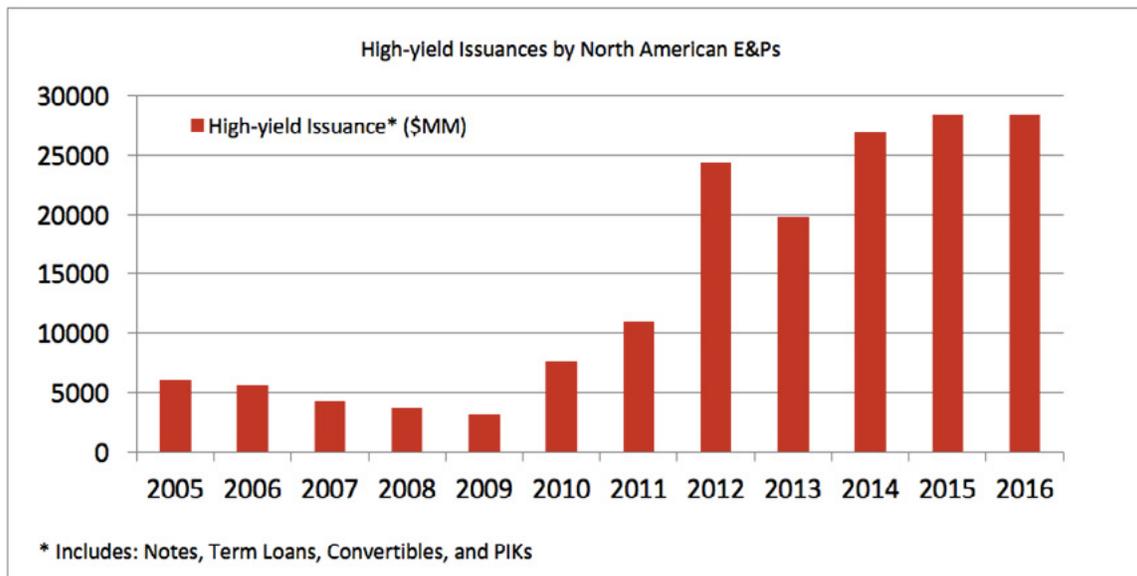
Even as oil prices plummeted, low interest rates, the industry's other enabler, have persisted through much of the market downturn. But with global economic growth showing signs of life, the outlook for rising interest rates is now improving. Already, US interest rates have started to creep up with Federal Fund Rate rising from a range of zero to 0.25 percent in between 2008 and 2014 to its current level at 0.75 percent. The Federal Reserve expects to raise rates three more times in 2017, to 1.5 percent. It signaled it will raise rates to 2 percent in 2018 and 3 percent in 2019.⁹ Whether the shale oil and gas industry, having adjusted to a lower price environment, can now also weather higher interest rates and an increase in borrowing costs is unclear.

Figure 1: High oil price period coincided with low LIBOR between 2009 and 2014



Source: Bloomberg

Figure 2: High-yield E&P issuance increased rapidly



Source: S&P Capital IQ

This essay aims to assess the general outlook for US shale oil and gas in a higher-interest-rate environment, a topic that has until now received surprisingly little attention compared with shale operational costs and efficiencies. To do so, the paper examines for the first time North American exploration and production (E&P) companies from a compiled financial perspective, with a focus on the impact of the collapse of oil prices to below \$50 per barrel. Financial data from the top 63 E&Ps with S&P ratings between A and CCC have been compiled in order to identify industry-wide trends and behavior patterns. Financial and credit metrics are considered in aggregate for the purpose of analyzing sectorial trends, not to evaluate individual companies or assess their corporate strategies at the company level.

The analysis begins with debt and leverage ratios as they climbed between 2005 and 2015, driven by ongoing cash-flow deficits and low interest rates. This is followed by a discussion of the impact of the 2014 oil crash on corporate reserves and balance sheets.

The study then focuses on the role of the Reserve Base Lending (RBL) structure in creating a structural platform for the growth of small and midsize oil producers. It discusses borrowing-base calculations and analyzes the strengths and weaknesses of various RBL structures, ranging from a “covenant-lite” general working-capital structure, in which the company enjoys full flexibility in withdrawals and usage of the borrowed funds, to a highly “covenanted” structure, where the banks exercise tight control over withdrawal amounts and usage of the funds. This move to more stringent lending practices is driven by concerns about future losses as well as the Office of the Comptroller of the Currency’s (OCC) regulations and guidelines, after many small and midsize E&Ps already filed for bankruptcy, and as others are barely staying afloat.

AN OVERVIEW OF NORTH AMERICAN E&PS' FINANCIAL POSITIONS AND TREND

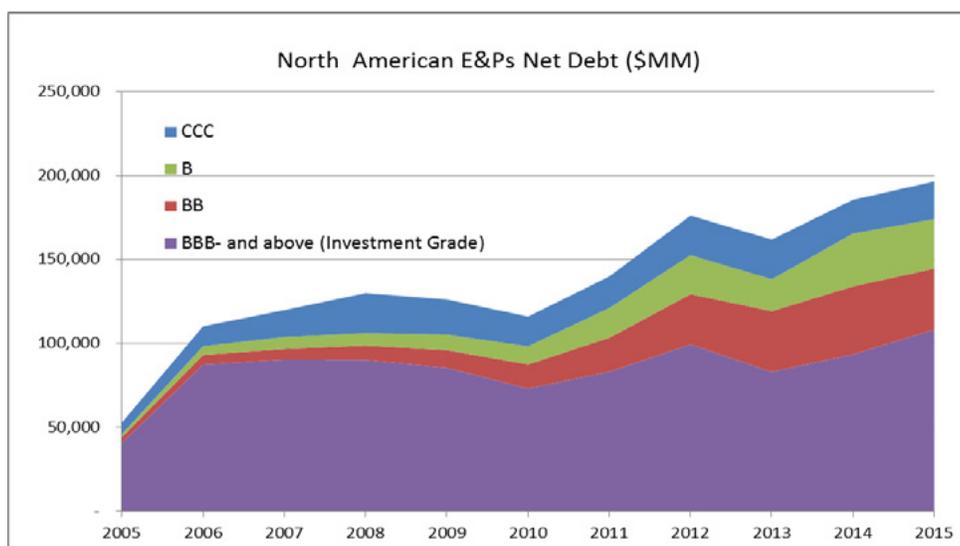
This section provides an overview of financial metrics of North American E&Ps on a macro level compiled basis between 2005 and 2015. The selected financial metrics provide an insight on industry-wide trends regarding debt, leverage, and cash flow. Of the 63 E&Ps whose data have been compiled in this paper, those deemed in the investment-grade category (graded BBB and above by S&P) generally represent the larger E&Ps, while those in the non-investment-grade category (BB+ to CCC) represent small and midsize E&Ps, which typically use RBLs to fund their drilling and production activities. The financial metrics are from the companies' audited annual financial reports, extracted from Capital IQ.¹⁰

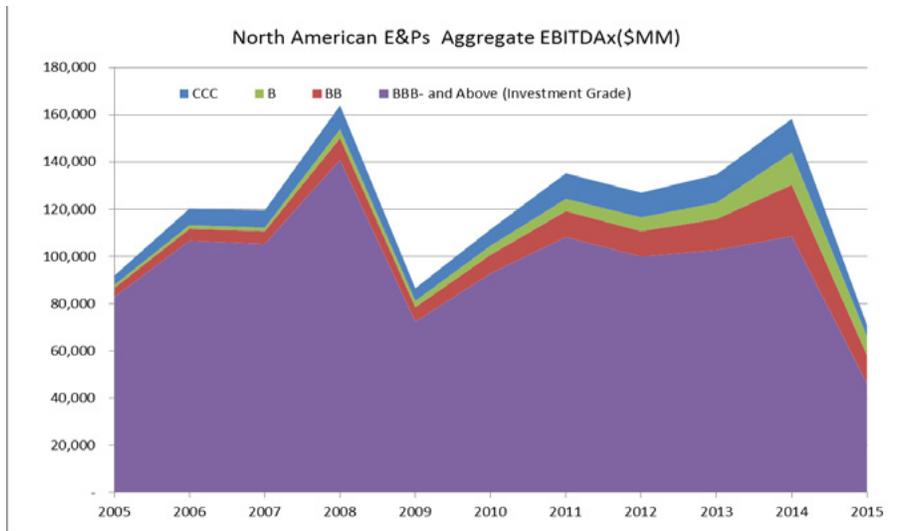
Debt and Leverage and the 2014 Crash

The E&P sector entered the current down cycle with a historically high aggregate leverage, as the debt markets flooded the oil and gas sector with cheap money, an indirect result of the Fed's low-interest-rate policy. As shown in figure 3, aggregate net debt of E&P companies in North America was close to \$200 billion. By 2014, net debt had already exceeded \$175 billion—a 250 percent increase from its 2005 level. Meanwhile, the aggregate annual EBITDA¹¹ (a proxy for cash flow) increased only 68 percent, from \$95 billion in 2005 to \$160 billion in 2014. Therefore, even before the 2014 oil crash, the E&P companies' aggregate debt increase had outpaced their EBITDA and cash-flow generation, resulting in higher leverage ratios across the sector. In 2015, aggregate EBITDA fell to \$70 billion due to oil crash.

Figure 4 depicts both large investment-grade (BBB- and above) as well as small and midsize non-investment-grade (BB, B, CCC, or below) E&Ps following the same trend. While E&P investment-grade net debt more than doubled, their aggregate EBITDA increased by only 30 percent between 2005 and 2014. During the same period, non-investment-grade E&Ps increased their net debt by 730 percent, while their EBITDA increased by only 420 percent.

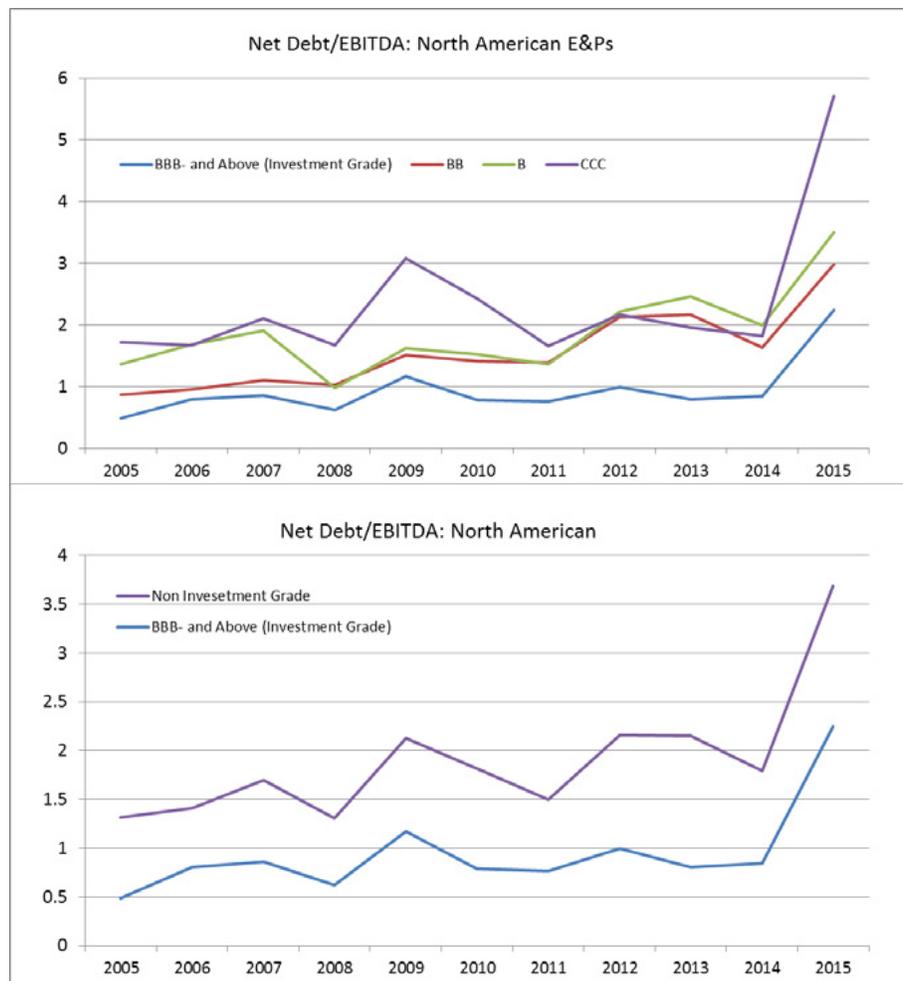
Figure 3: Net debt increased between 2005 and 2014 while EBITDA fluctuated with oil price (Cont.)





Data Source: Capital IQ, Financial Reporting

Figure 4: Leverages increased for both Investment Grade and Non-Investment-Grade



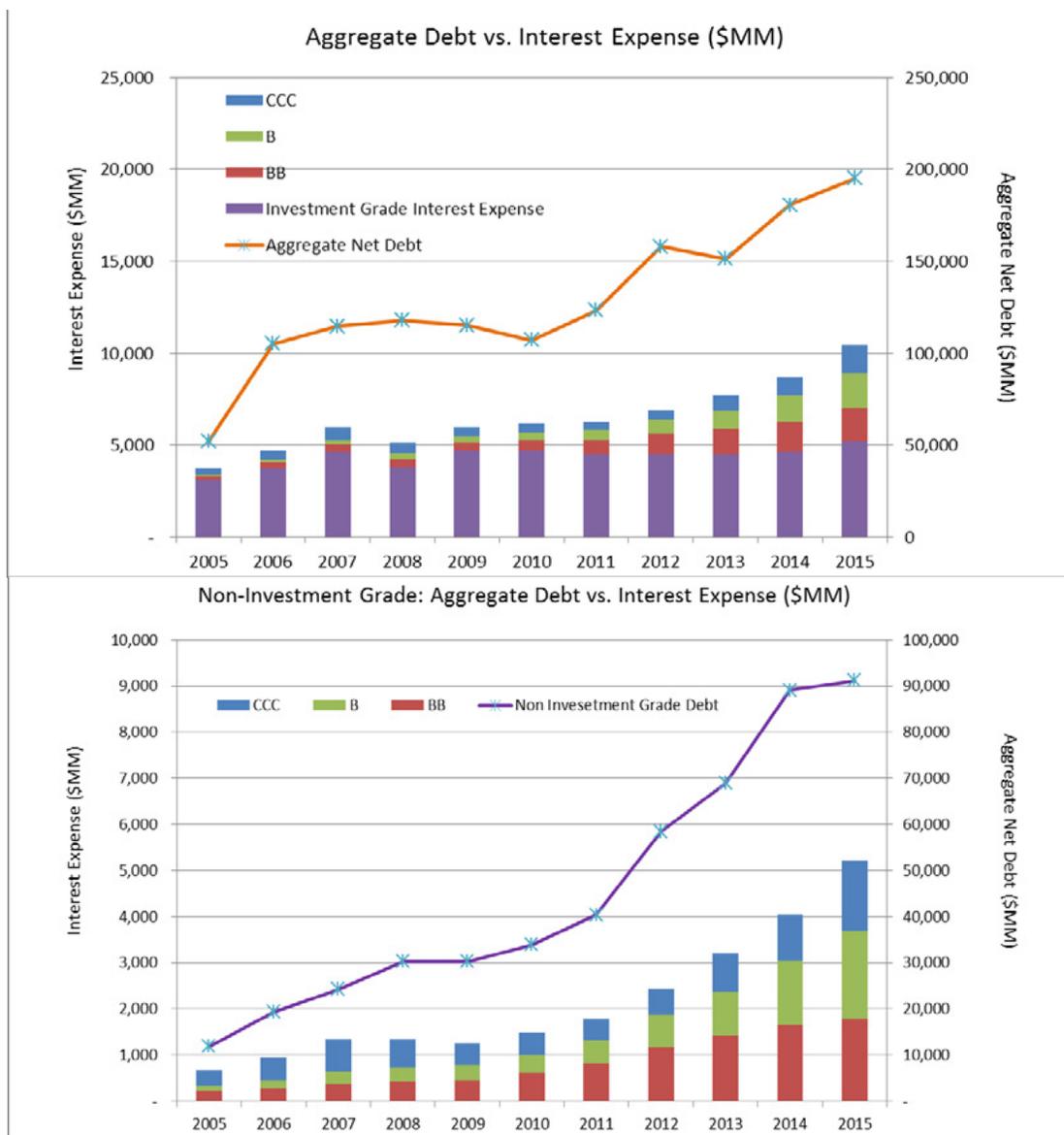
Data Source: Capital IQ, Financial Reporting

Though the small and midsize E&Ps were more aggressive, both investment-grade and non-investment-grade companies increased their debt and leverage ratios between 2005 and 2014. Leverage ratios then spiked across the industry when oil prices began to plummet.

Decline in Borrowing Cost

While E&P debt climbed to a historical high, interest costs in proportion to the amount borrowed declined, driven by the low-interest-rate environment. As shown in figure 5, between 2005 and 2015, E&P aggregate debt increased by 300 percent, from \$50 billion to \$200 billion, while interest expense increased only 150 percent, from \$4 billion to \$10 billion. Therefore, debt increased twice as fast as interest expense, indicating a gradual decline in borrowing cost. Simply put, low interest rates incentivized higher debt to boost the return per share.

Figure 5: E&Ps' aggregate debt growth outpaced aggregate interest expense

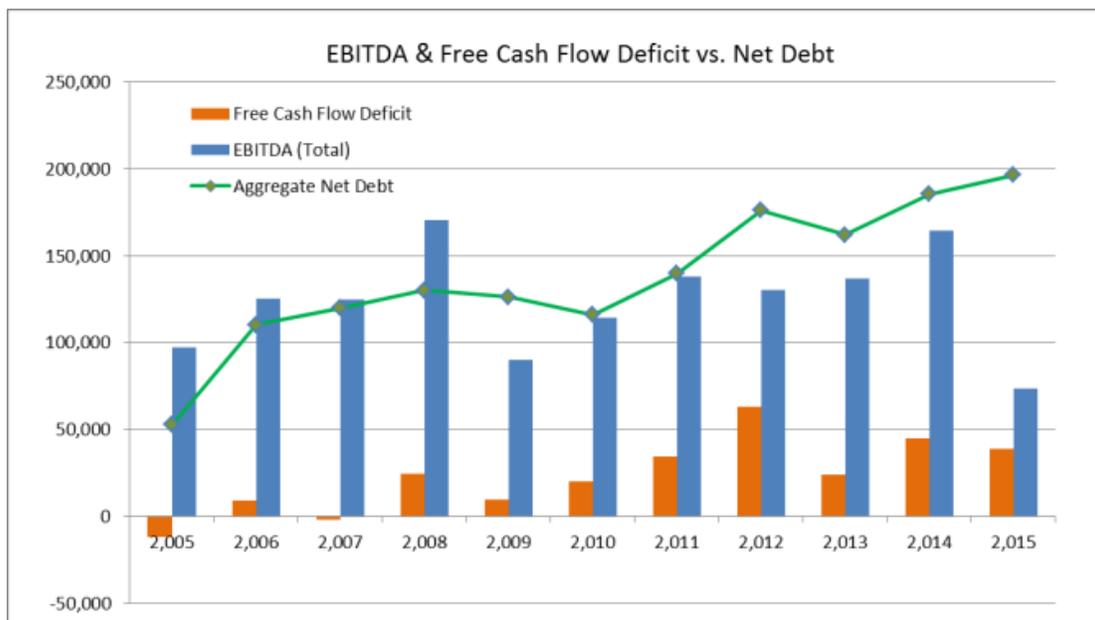


Data Source: Capital IQ, Financial Reporting

Cash-Flow Deficit, a New Norm

With easy access to low-cost debt, the industry became accustomed to outspending its cash flow to fund growth projects—largely with new debt rather than a more balanced mix of debt and equity. Figure 6 shows North American E&P cash-flow deficits, which reached a peak in 2012 as US natural gas prices plummeted; small and midsize E&Ps were more dependent on debt to fund their growth. The figure shows the gradual increase in aggregate debt, which was used to fund free cash-flow deficit.

Figure 6: E&Ps cash flow deficit was funded by debt



Data Source: Capital IQ, Financial Reporting

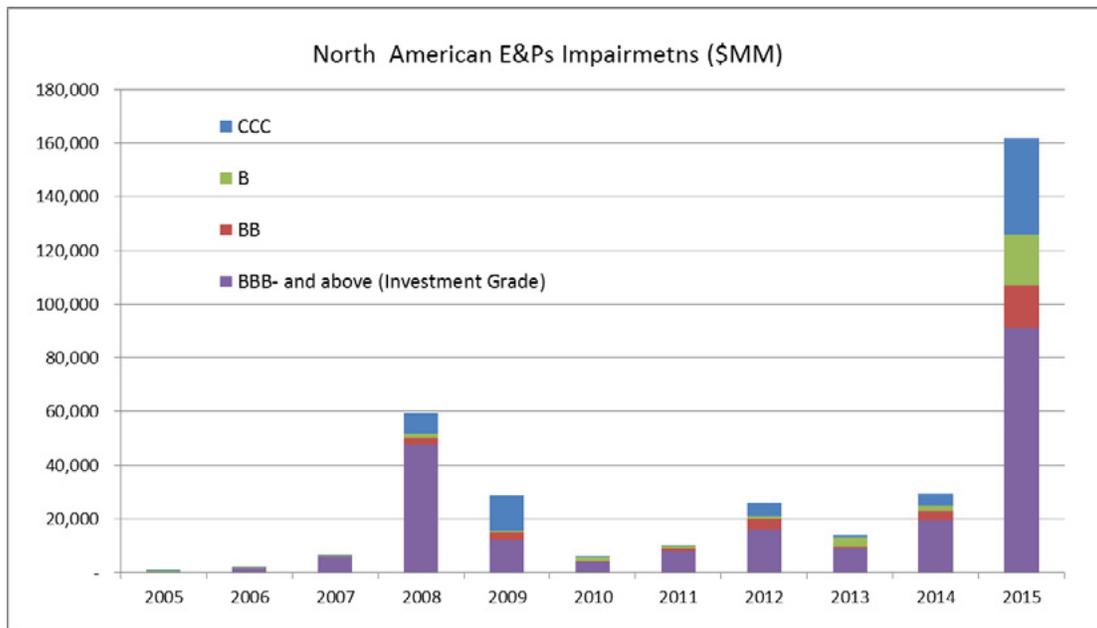
The Oil Crash and Its Impact on Book Value of Oil and Gas Reserves

The price of oil collapsed from above \$90 per barrel in the third quarter of 2014 to \$50 a barrel in the fourth quarter of 2014, following OPEC's November 2014 decision to forgo oil supply cuts and opt instead for a policy of market-share defense. The persistent low oil prices triggered revisions and impairments in companies' oil and gas reserves, wiping out sizable portions of companies' reserves, and therefore their equity, with asset impairments exceeding \$160 billion.¹²

In addition to its impact on revenue and cash flow, the low oil price affected the volume of the reserves and the dollar amounts of property, plant, and equipment (PP&E)¹³ booked on the companies' balance sheets. The reserve revisions are based on SEC rules that allow companies to book only reserves scheduled to be developed or produced within five years. In a low-price environment, corporate cuts in capital spending push the development of certain reserves beyond the SEC's five-year window, thus trimming reserve volumes.¹⁴

Impairment charges¹⁵ are driven by accounting rules and the ceiling test that requires evaluating the book value of reserves using a defined average of the commodity's value for the prior twelve-month period. Although a noncash charge, an impairment could heavily impact companies' balance sheets, particularly for small and midsize companies that use a full-cost¹⁶ method in booking their exploration costs. In many cases, large impairments wiped out the whole book equity value of the company. As shown in figure 7, the sustained low oil price environment wiped out more than \$160 billion of book equity value of E&Ps in North America alone.

Figure 7: With collapse of oil prices, more than \$160 billion of book equity was wiped out by impairments



Data Source: Capital IQ, Financial Reporting

RESERVE BASE LENDING (RBL) STRUCTURE AND BORROWING BASE DETERMINATION

The low-oil-price environment heavily impacted non-investment-grade, small and midsize North American oil and gas producers. To better understand the phenomenon, one should take into account the reserve base lending (RBL) structure, the most important source of debt financing and growth for these stakeholders. Unlike large investment-grade companies that have easy access to debt and equity markets to fund their growth, many non-investment-grade companies need to use a combination of equity and borrowings under RBLs to fund their capital spending. RBL structure is a bank-syndicated revolver credit facility¹⁷ secured by the company's proved oil and gas reserves. Oil and gas reserves are classified into three categories: proved reserves, probable reserves, and possible reserves. Bank lenders only extend credit against a company's proved reserves. As the collateral is oil and gas reserves of the company, RBL financing requires engagement of an independent reserve and production engineer to support the bank's calculations in determining the borrowing base, which is the maximum credit that could be made available to the borrower by a lender, calculated based on the company's reserves.

The "proved reserves" category is itself broken down into three different sub-categories reflecting different levels of risk associated with the production and valuation of the reserves: proved developed producing (PDP), proved developed nonproducing (PDNP) and proved undeveloped (PUD). As the producing reserves have the lowest risk, the Advance Rate (1-risk factor) for PDP ranges from 99 percent to 95 percent. The PDNP Advance Rate ranges from 65 percent to 75 percent; and PUDs have the highest risk as a substantial amount of capital expenditure is needed to bring PUDs to production, reflecting a risk factor of 50 percent to 60 percent. Typically, PDP/PDNP/PUD risk factors are at the independent engineer's discretion within a bank's internal risk policy.

Table 1: Borrowing Base by Reserve Type

Reserve Type	Advance Rate (%)	Borrowing Base (\$)
Proved		
PDP	AR1: 95%-99%	$PDB_{(BB)} = AR1 * PDP_{(PV9)}$
PDNP	AR2: 65%-75%	$PDNB_{(BB)} = AR2 * PDNP_{(PV9)}$
PUD	AR3: 50%-60%	$PUD_{(BB)} = AR3 * PUD_{(PV9)}$
Total Proved		$PDB_{(BB)} + PDNB_{(BB)} + PUD_{(BB)}$
Probable	N/A	No borrowing base credit extended
Possible	N/A	No borrowing base credit extended

The borrowing base calculation methodology is based on the net present value (PV9) of future cash flows from oil and gas production under each lender's assumed price deck and the appetite of the sector.

Figure 8 and figure 9 show the range of banks' price deck in 3Q 2014, right before the oil price collapse, and the 3Q 2016 price decks. The data is collected and published by Macquarie Tristone's Quarterly Energy Lender Price Survey.¹⁸ The difference between the highest and lowest price decks could be substantial. The high price deck typically tracks the NYMEX Futures. As shown, the majority of banks' oil and gas price decks incorporate discounts from the NYMEX Futures.

Figure 8: 3Q2014 Banks' Price Decks



Figure 9: 3Q2016 Banks' Price Decks



Source: Macquarie Tristone's Quarterly Energy Lender Price Survey

The borrowing base redetermination process is generally done on a semiannual basis,¹⁹ starting with a reserve report that includes lease operating cost, taxes, required capital spending, and production under the company's price assumptions, primarily based off the NYMEX Futures.²⁰ Since the banks' price assumption is lower than that of the NYMEX Futures, they re-evaluate production and cost calculations under their own price decks. Many large banks have in-house engineers; however, the majority of the banks active in the sector hire independent engineering consultancies to assess the engineering reports. Using the bank's price deck and the cost structure, the engineer performs an analysis to determine the borrowing base—the maximum dollar amount to be extended to the borrower.

In addition to determining the valuation of reserves under the base case scenario, banks typically prefer to evaluate borrowing base under stressed (sensitivity) price scenario, which is considerably below the NYMEX Futures and the bank's base case. Under this scenario, independent engineers take into account the impact of low prices on future production as well as production cost.

Commodity Derivatives and Hedging

In order to proactively manage price volatility, many oil and gas companies put hedges in place by entering into commodity derivatives. Counterparties on these derivative instruments (swaps, collars, and puts) are usually highly rated financial institutions. Hence, lenders take into account hedged volumes and pricings in calculating the

borrowing base. Lenders use the average derivative price for the portion of the production that is hedged. As in the majority of such cases, the price of the hedged position is higher than the bank's price deck, so hedges contribute positively to borrowing base calculations. Therefore, commodity derivatives are essential elements in protecting the borrowing base against price drops.

RBL Facility and Covenant Structure

Most RBL facilities have a five-year tenor with a bullet maturity²¹ date and are governed by credit agreements that require semiannual redetermination as well as borrower restrictions with leverage and liquidity covenants. Semiannual redetermination protects lenders from adverse price movements, since lenders adjust and reduce the size of the borrowing base given new prices. If a company has already drawn the facility beyond the most recently calculated borrowing base limit, it typically has six months to repay the excess borrowings.

Leverage²² and liquidity²³ covenants restrict borrowers from taking excessive financial risk. Usually, leverage covenant is debt to EBITDAX²⁴ <4.0x, and liquidity covenant >1.0x. In addition to leverage and liquidity covenants, credit agreements usually require a 25 percent reduction of the borrowing base for unsecured note and second-lien issuances. Although the banks hold the first lien on reserves, this covenant protects lenders from aggressive debt issuances that could in turn increase the interest expense to an unhealthy level that would jeopardize debt repayments. Following the 2014 price collapse, to further protect lenders, additional covenants were introduced, including anti-cash-hoarding language, deposit account control agreement (DACA), and minimum hedge requirements.

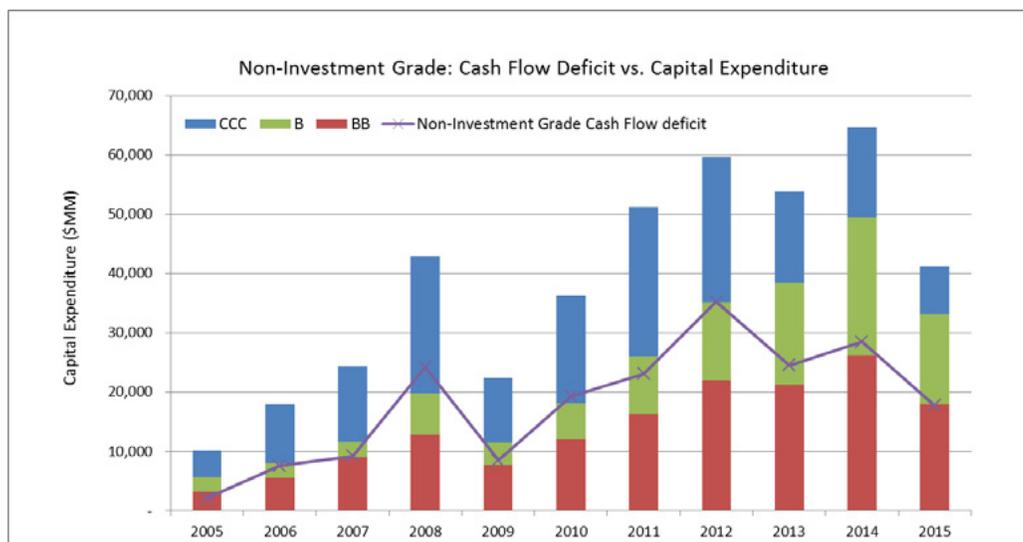
OCC's Repayment Analysis Processes

The Office of the Comptroller of the Currency's (OCC) Oil and Gas Lending Handbook recommends repayment analysis tests to determine that the cash flow available for debt repayment (CFDR) from the reserves is sufficient to repay the debt within a reasonable time period. CFDR is calculated as revenues less lease operating expenses, less production and ad valorem taxes, less general and administration expense, less interest expense. According to the OCC, a reasonable repayment period for an RBL is 60 percent of the economic life of the proved reserves, and 75 percent of the total economic reserve life for all secured debt. The repayment test must use a fully funded borrowing base commitment, rather than the current outstanding. Unlike borrowing base redetermination—which uses unlevered cash flow to establish a net present value (NPV) for the proved reserve—the repayment test uses levered cash flow, which takes into account in its repayment capability the company's capital structure and interest expenses.

RBLs IN PRACTICE

Historically, RBL facilities have been the core driver of reserve and production growth for non-investment-grade E&P companies through organic and/or acquisition-driven growth. Free cash-flow deficit is funded by draws under the RBL revolver facility, followed by note issuance to repay the balance on the RBL. Figure 10 shows aggregate cash-flow deficit movement versus capital expenditures. The trend of outspending cash flow peaked in 2012, caused by low natural gas prices and the E&P industry's shift to more oil-based assets with higher acquisition and development costs. As the negative free cash flow was largely funded by debt, we observe a gradual increase in aggregate debt (figure 6).

Figure 10: Outspending the cash flow to fund the capital expenditure peaked in 2012



Data Source: Capital IQ, Financial Reporting

Organic Growth

Under an organic growth scenario, the company already owns the reserves and uses the funds from the revolver facility to drill, develop, and produce the reserves. Through the drilling process, companies generally prove more reserves, thereby allowing the company to replace the produced barrels, and, in many cases, increase the reserve base. The produced barrels generate the cash flow to cover operational and interest expenses and theoretically repay the borrowings under the RBL facility. However, to fund future capex, the company needs to borrow again under the revolver, and the cycle repeats.

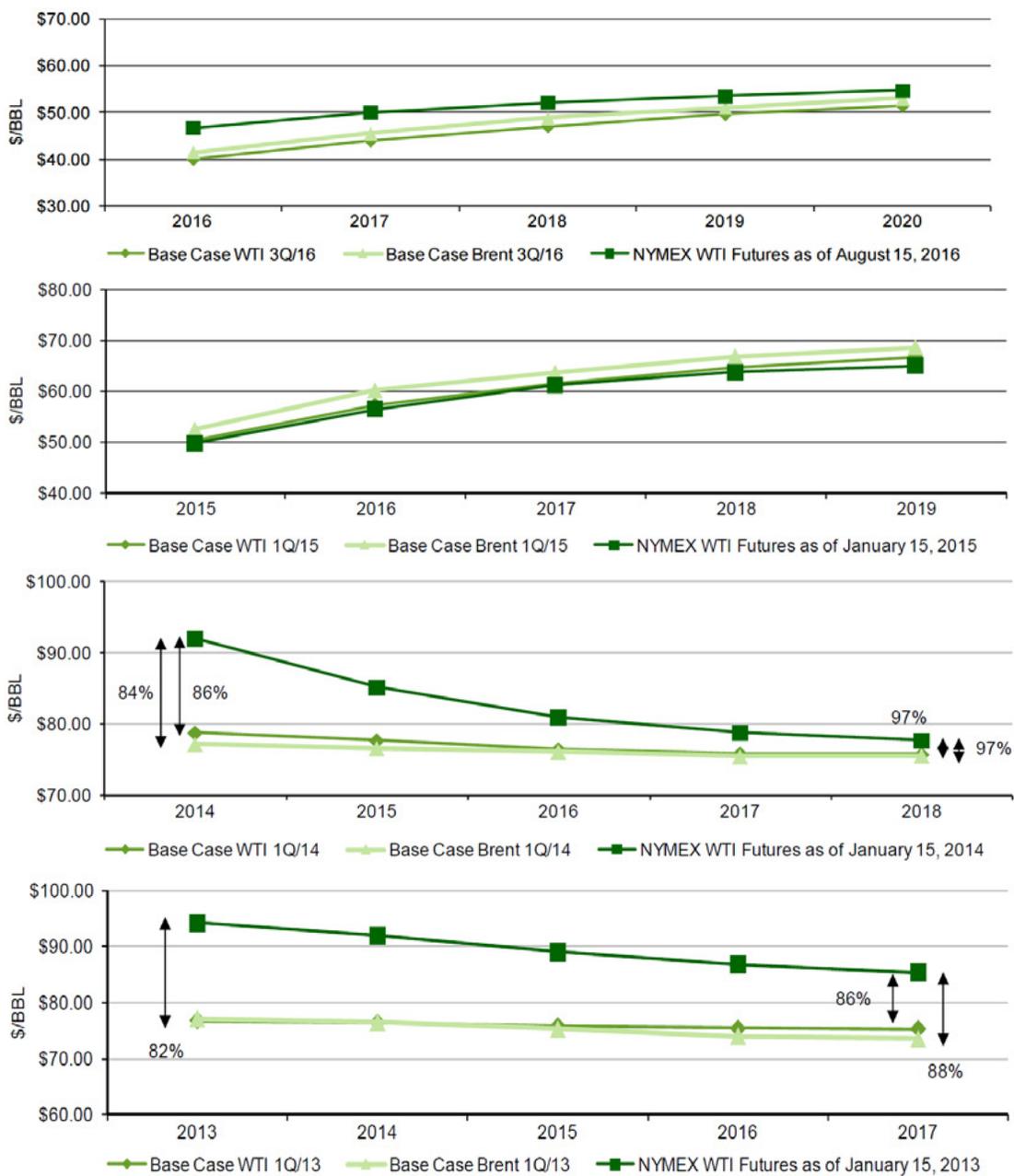
Acquisition-Driven Growth

A more common use of RBL throughout the oil boom period was acquisition financing. Under this scenario, the acquisition is funded largely by debt in multiple steps. First, the company uses a portion of its RBL to fund the acquiring assets. With the acquired reserve and updated reserve engineering reports, the company upsizes its RBL facility to include the acquired assets. In the second step, the company accesses the high-yield debt market to issue unsecured notes or second-lien term loans. The proceeds repay and lower the balance on the RBL. To protect the banks' collateral, credit agreements typically require a reduction in borrowing base equal to 25 percent of issued unsecured notes and second-lien term loans. More conservative companies use a combination of debt and equity issuance to maintain lower leverage in order to protect their balance sheet. The third step consists of using the availability under the RBL to fund drilling and production of the acquired and legacy reserves. Under this scenario and similarly in the organic growth scenario, the company operates with negative free cash flow, funding the capex by borrowing under the upsized RBL facility.

Banks' Price Decks and RBL Resiliency

As discussed earlier, RBL structure allows each lending bank to determine the borrowing base using its own price deck and risk factors. Price decks used by the majority of banks are typically lower than NYMEX Futures prices, providing additional cushion against oil drops. Figure 11 illustrates the movements of banks' average price decks with respect to WTI and Brent. As seen, the banks' price decks were substantially more conservative, especially during the earlier years, which had the highest impact in borrowing base calculations given the 9 percent discount factor.

Figure 11: Banks' Price Decks vs. NYMEX WTI Futures



Source: Macquarie Tristone's Quarterly Energy Lender Price Survey

Banks' conservatism on price decks prior to the oil price crash proved instrumental in supporting their borrowers during the downtime. When spot oil collapsed to below \$40 per barrel and five-year futures traded below \$60 per barrel, the banks maintained a price deck that was slightly below the oil futures and occasionally even above the NYMEX Futures prices. By using price decks close to NYMEX Futures, banks showed strong support for their clients in borrowing base redeterminations. As shown above, the current average banks' price deck is just slightly below the NYMEX Futures.

In addition to pricing, the size of these credit facility revolvers for most small and midsize E&Ps are determined through a borrowing base calculation, which is directly correlated to oil and gas future pricings. In 2014, the majority of lender banks' price decks were noticeably below the NYMEX Futures at the time, providing a substantial cushion against the fall of oil and gas prices in calculating borrowing base. As shown above, this time around, most of the banks' price decks were on par with NYMEX Futures, allowing no cushion. Therefore, further declines in oil prices would directly impact the borrowing capacity of oil producers.

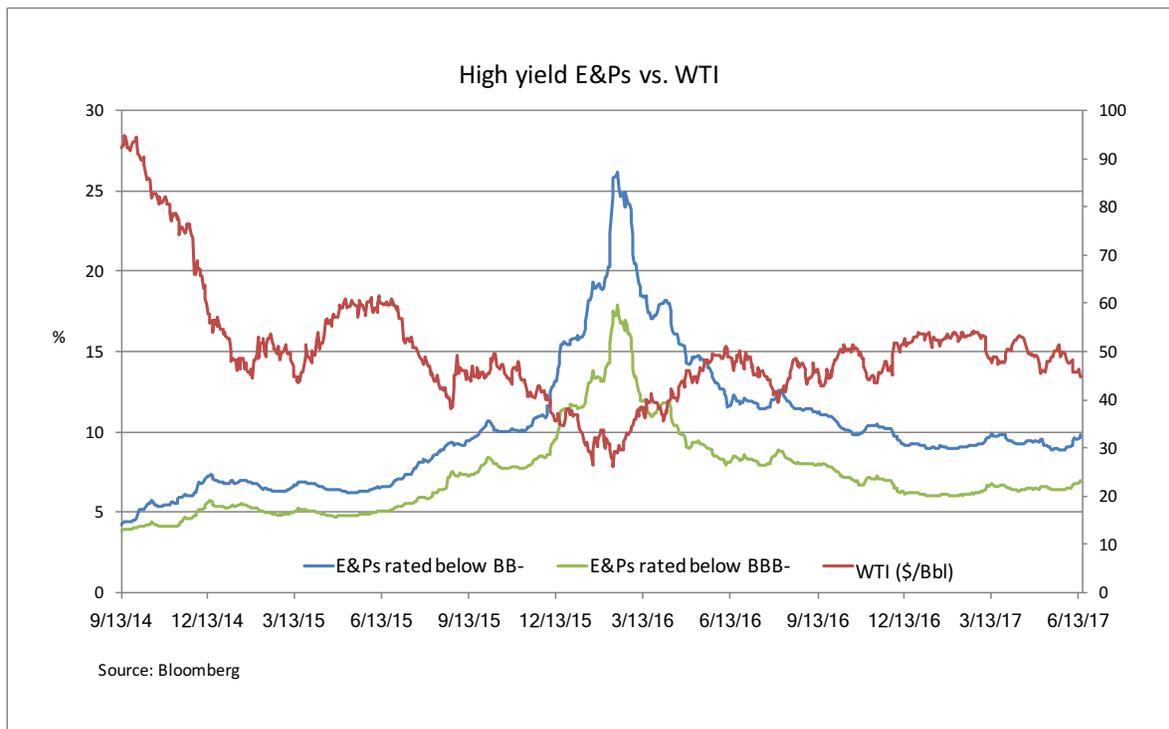
Oil Crash and Access to Capital Market

The generosity of debt and equity capital markets toward oil and gas companies ended abruptly in the fourth quarter of 2014, as markets had little appetite for oil and gas issuers. While larger companies could still appease their investors with convertibles and preferred shares, the sky was gloomier for small and midsize E&Ps.

The figure below shows the yields for oil and gas non-investment-grade companies versus the global high-yield market. As shown, the average high yield for small and midsize E&Ps spiked to 25 percent, practically shutting them out of the high-yield debt market. Limited access²⁵ to the high-yield debt market proved detrimental for highly levered E&Ps, since they relied on debt to maintain their drilling and production. Suffering from a classic "debt overhang" case scenario, highly levered companies lost their access to the equity market as well. By second quarter 2016, more than 58 small and midsize E&Ps filed for bankruptcy.²⁶

The high-yield debt market reactions to the oil downturn magnified the importance of RBLs as the most reliable source of liquidity and funding for non-investment-grade E&Ps. The yield for non-investment-grade energy bonds increased from 5 percent in September 2014 to 15 percent in December 2014, and later to 25 percent in January 2016.²⁷ Unlike debt capital markets, banks remained committed to E&Ps because the flexible nature of RBL structure allowed banks to adjust their commitment and to cushion the impact of an oil crash on borrowing base calculations, particularly since most of the banks had originally used more conservative price decks than WTI NYMEX Futures.

Figure 12: Following oil drop to below \$30/Bbl, average yield for oil and gas speculative grade peaked

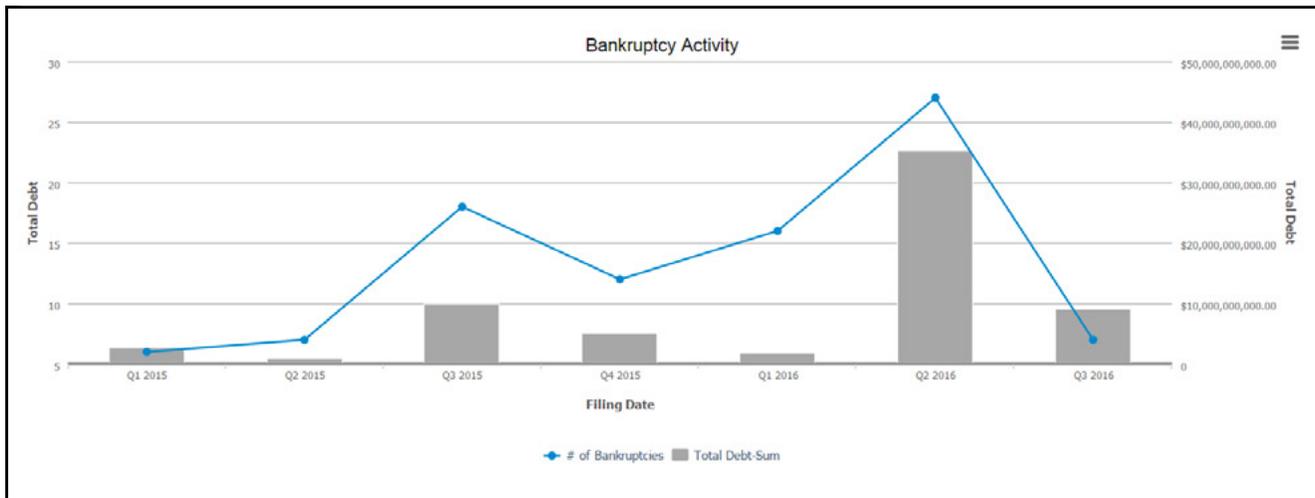


Source: S&P Presentation on Global Oil Market, November 2016

Adjusting to Low Prices: Low Oil a New Reality

The collapse of oil to below \$50 per barrel in 4Q 2014 exposed many small and midsize North American companies to a declining reserve base. The large number of those that made acquisitions at the peak found themselves having overpaid for high-cost reserves, largely with debt. With the continued low price environment in 2015, the equity value of many oil producers was wiped out, putting them on the verge of bankruptcy. As Saudi Arabia flooded the market with oil,²⁸ North American oil companies responded by cutting capital expenditures, canceling future developments, and lowering the operating cost to the extent that they could while maintaining existing production. Although the industry has become more efficient with the lowering of cost, due to shale's sharp decline rate, ongoing capital spending is required to maintain production at the same level. For many companies, getting funds proved to be impossible, forcing them into bankruptcy, as shown in figure 13.

Figure 13: Bankruptcy filings peaked in 2nd quarter 2016



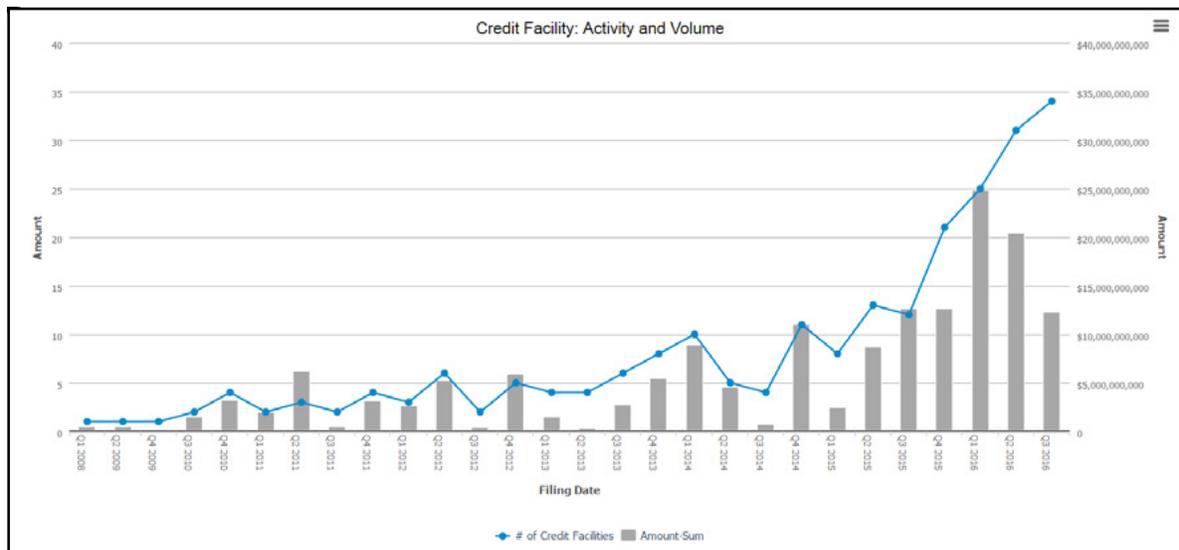
Data Source: Petroleum Listing Services (PLS)

Covenants and Amendments

For highly leveraged companies with substantial fixed production costs, the disappearance of half their EBITDAX as a result of low oil prices meant a breach of leverage covenants. The leverage covenants are typically calculated as total debt divided by last twelve month (LTM) EBITDAX. Consequently, in the first and second quarters of 2015, a large wave of amendment requests from these companies came toward the banks to waive or redefine the leverage covenants. Depending on the company's position, the requests included raising the covenant level from 4.0x to above 5.5x. In many cases, companies that had large unsecured notes outstanding requested their covenants be revised to take into account only secured debt (balance on the revolver) rather than total debt.

These covenant reliefs provided an opportunity for these producers to improve their EBITDAX by lowering the cost and repaying a portion of their debt by divesting noncore assets. In addition to asset sales to fix their balance sheets, many companies offered unsecured and junior note holders cash and/or second- or third-lien secured debt positions in exchange for a haircut on the notes. As the unsecured notes were traded at heavy discounts—in some cases below 30 cents on the dollar—exchanging the notes for a secured position below the RBL facility for a moderate haircut seemed a rational decision for many investors. Lowering the debt helped the borrower both on leverage (debt/EBITDAX) and coverage covenants (interest expenses/EBITDAX).

Figure 14: Requests for covenant relieves and amendments



Data Source: Petroleum Listing Services (PLS)

Cash Hoardings and Inclusion of Anti-Hoarding Language

The first half of 2015 was a divergence point that separated the borrowers who concentrated their efforts on keeping the company afloat and fixing their balance sheets on the one hand, and the borrowers who decided to prepare for bankruptcy and restructuring on the other. With expectations low, oil would linger, and given insufficient cash flow to maintain operations and production, these borrowers moved forward with “cash hoarding,” drawing all the availability on their RBL facility and keeping the cash to cover operational and legal costs throughout the bankruptcy process.²⁹ In some instances, companies filed for bankruptcy within days of fully drawing on their RBL revolver facility.³⁰

The cash-hoarding phenomenon caught banks by surprise, as credit agreements provided no lien on the companies’ cash or limitation on withdrawals. Although RBL funds were originally designed to be used for working capital and capital expenditure so as to improve the underlying reserve, cash hoarding was instead used to pay for restructuring companies and bankruptcy legal fees on top of exorbitant operational and administrative expenses. It was in 2016 that the banks started introducing anti-cash-hoarding and restricted cash account to credit agreements through renegotiation processes in exchange for easing the leverage and coverage covenants that companies needed.³¹

Minimum Hedging Requirements

Prior to oil crash in 2014, mandatory hedging was unusual unless done in the context of protecting against downside in highly levered acquisition or second lien transactions. As a matter of fact, the bigger issue for lenders was maximum volume hedged. Lenders are concerned if a borrower enters into swap contracts covering notional volumes that are at or near the borrower’s expected production levels, because, if production declines, the company may become “over-hedged.” If, however, there is no production to sell and hence no revenues to net against, the company will be forced to pay such swap obligations out of its own cash reserves. To mitigate this risk, lenders invariably impose limitations on the notional volumes that may be hedged, typically between 80–90 percent anticipated production from proved developed and producing reserves (PDP).³²

Commodity derivatives proved to be instrumental in cushioning many E&Ps from an immediate hard fall. Many companies with strategies to hedge more than 50 percent of their production were able to substantially protect their cash flow drainage

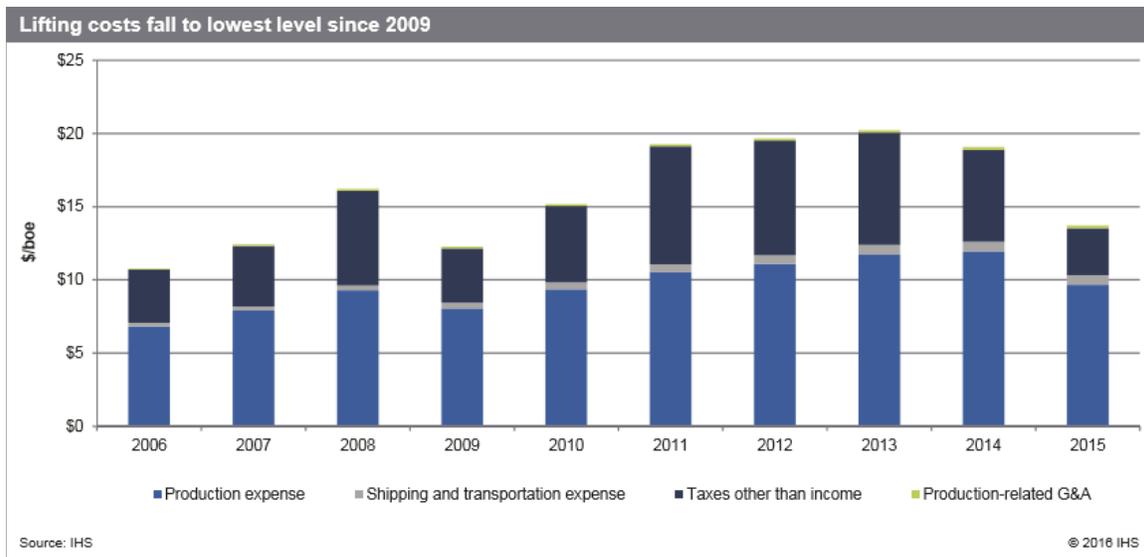
from the impact of low oil prices. More importantly, since RBL structure takes into account oil and gas derivatives in calculations of borrowing base capacity, these companies were able to maintain a strong liquidity position. Following the 2014 oil crash, many lenders began to require that portions of production be hedged. Minimum hedge requirements are designed to lower the lenders' risk against price volatilities, particularly for borrowers with relatively higher operating costs.³³

Following the 2014 oil crash, many lenders began to require that portions of production be hedged. Minimum hedge requirements are designed to lower the lenders' risk against price volatilities, particularly for borrowers with relatively higher operating costs.³⁴

Limitation on Second-Lien and Third-Lien Debt

As discussed earlier, the OCC's repayment test recommends a reasonable repayment period of 60 percent of the reserve's economic life for RBL, and 75 percent of the reserve's economic life for total secured debt. In practice, the test restricts excessive borrowing by ensuring that the levered cash flow is adequate to repay the debt. In 2011–15, many E&Ps used second- and third-lien debt to fund capital spending and cover their negative free cash flows.³⁵ Although this practice may not directly impact first-lien lenders, the additional debt and associated interest expenses limit the company's cash available for debt repayment.

Figure 15: Lifting cost declines as operational efficiencies improves



Source: IHS Herold 2016 Global Upstream Review

FUTURE CHALLENGES

Operational Efficiencies versus Higher Interest Expense

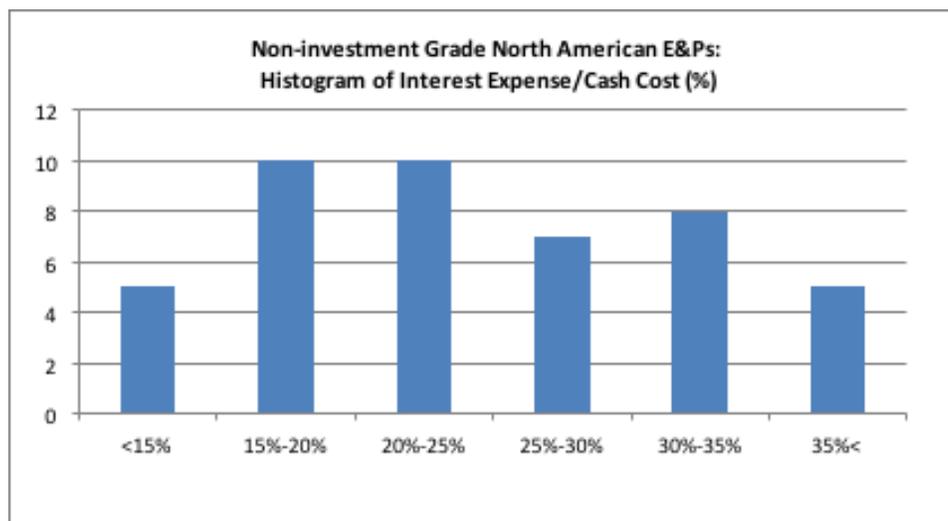
North American E&Ps are significantly more efficient today than in 2014 in almost all basins where shale oil is produced. Lease operating expense (LOE) in production costs has been declining per unit of production.³⁶ Figure 15 shows how average lifting costs declined from the peak of \$20 per BOE in 2013 to less than \$14 per BOE in 2015. In other words, a 30 percent reduction in lifting cost was the industry's response to the downturn. The reduction in production costs allowed continued production from shale reserves even at prices below \$40 a barrel. Today, with oil around \$50 per barrel, many producers maintain healthy cash margins.

However, the current equilibrium could be challenged. With the expectation the Fed will continue to increase rates, oil hovering at \$50 a barrel, and higher credit spreads, small and midsize North American E&Ps may face the same old challenge of high cost of capital. As shown earlier in figure 1, in 2007, the LIBOR rate averaged above 500 bps (5 percent) compared with today's LIBOR rate, which is around 100 bps (1 percent).

Quantitatively speaking, many highly levered, lower-rated E&Ps with an S&P rating ranging from B+ to CCC- are more sensitive to interest rate increases. Typically, as shown in figure 16, these companies' interest expense ranges between 20 percent and 35 percent of their total cash cost (lifting cost + cash interest expense).³⁷ Borrowing rate for companies' reserve base lending (RBL) revolver facility is LIBOR plus the company's risk premium (LIBOR + risk premium). Risk premiums for small and midsize oil and gas companies have been increasing from precrash level in 2014. Generally speaking, the increase in risk premiums ranges between 100bps and 150bps,³⁸ elevating risk premium spreads to above 4 percent in many cases.

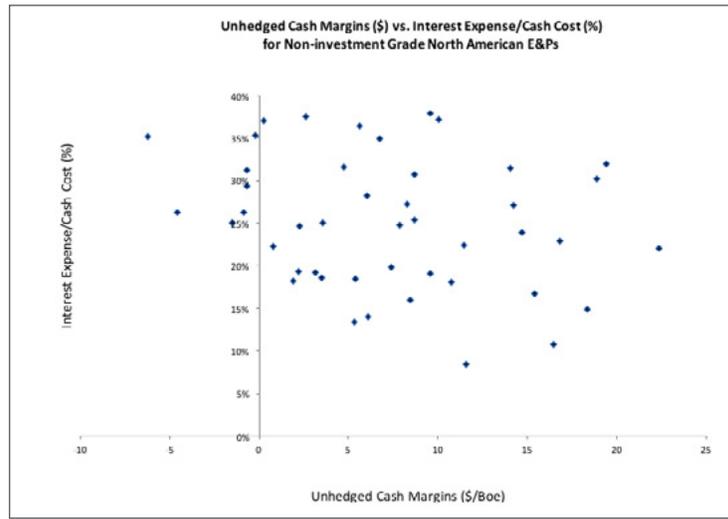
As shown in figure 17, many North American E&Ps have high ratio of interest expense to cash cost coupled with low unhedged cash margins as of FY2015. Therefore, these companies are vulnerable to increase in interest expense. With current secured revolver facility borrowing cost of 3.5 percent to 5 percent and weighted average cost of unsecured notes ranging from 7 percent to 10 percent, a 2 percent increase in LIBOR coupled with 1.0 percent higher risk premiums would have a significant impact on the borrowing cost of these companies, raising the interest expenses per dollar borrowed by 30 percent from the low levels in 2014.

Figure 16: Interest Expense/Cash Cost range for North American Non-investment-Grade E&Ps



Source: Based on author's calculations using public filings and Citi's Oil and Gas Credit Research (2Q2016)

Figure 17: Low Unhedged Cash Margins coupled with high interest expense/cash cost makes many small and midsize E&Ps vulnerable to increase in interest expense

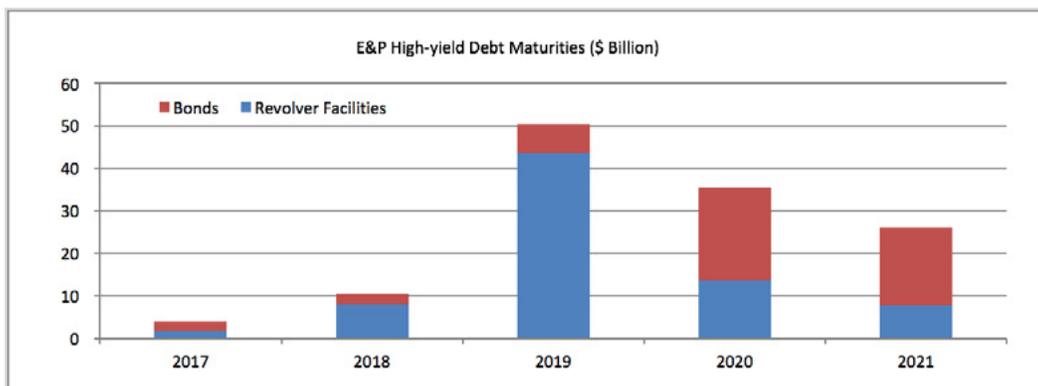


Source: Based on author's calculations using public filings and Citi's Oil and Gas Credit Research (2Q2016)

Upcoming Maturities and Debt Refinancings

Many oil and gas companies have been taking advantage of low interest rates in the last few years. However, as shown in figure 18, more than \$50 billion of non-investment-grade E&P debt is scheduled to mature in 2019, in particular more than \$43 billion in credit facilities with banks. These are five-year revolver facilities that were refinanced in 2014 with historically low pricings.³⁹ While there is still strong demand for oil and gas debt, one could expect that lenders may require higher risk premiums, which, combined with higher LIBOR, would put substantial upward pressure on interest expenses. It should be noted that if the oil prices remain stable above \$50–\$55 per barrel, it provides an opportunity for many companies to refinance their revolver facilities, extending the maturities to 2022.

Figure 18: Maturities schedule for high-yield notes and revolver facilities



Data Source: Petroleum Listing Services (PLS)

The question remains whether the rate hike is the beginning of a gradual trend of increasing rates to the pre-financial-crisis level. A rapid rate hike to the pre-financial-crisis level of 5 percent LIBOR would increase interest expense by more than 50 percent for unsecured notes and 100 percent for secured revolver debt. Therefore, with a series of rate hikes, interest expense for many companies rated B+ to CCC- and below could escalate to an unsustainable level under the current oil price environment.

CONCLUSION

Low interest rates coupled with high oil prices have been the catalyst for the expansion of shale oil. Low oil prices and the subsequent bankruptcies in the North American E&P sector made banks more efficient and selective, triggering a series of improvements in RBL covenant structures, including anti-cash hoarding clauses, restricted cash, and minimum hedge requirements as well as limitations on additional liens on reserves. With the volatile nature of the high-yield-debt capital market, RBLs proved to be the most reliable source of liquidity for non-investment-grade oil and gas producers.

With more \$25 billion of North American E&P high-yield debt coming due in the next few years and the upward pressure on credit spreads, the ultimate direction of small and midsize E&Ps in North America depends on future interest rates. While technological and operational efficiencies have reduced lifting costs by 50 percent in some basins, the challenge lies ahead, since access to low-cost debt is essential for many small and midsize oil producers. If rate hikes continue at 50 bps per year, LIBOR will be above 2 percent by the end of 2018. LIBOR at 2 percent, coupled with 150 bps (1.5 percent) higher credit spreads, would result in a more than 30 percent increase in companies' new debt interest expense, wiping out a significant portion of gains made from operational efficiencies. If LIBOR rises to a pre-financial-crisis level of above 5 percent, the cost of unsecured debt for small and even midsize producers could exceed 10–12 percent. Since shale oil production is highly capital intensive, during low oil price environment, the high cost of debt drives up total cost of exploration and production to an unsustainable level for highly-levered small and midsize E&Ps. This high cost of capital could result in a market environment in favor of larger players with access to debt and equity capital markets at a lower cost.

If oil prices remain above \$55–\$60 a barrel for a sustained period, improved cash margins would allow small and midsize producers to absorb the increase in the funding cost. The production freeze/cut agreement between OPEC and non-OPEC producers has put an upward pressure on prices. A high oil scenario coupled with a slow, gradual increase in rates would be the best-case scenario for North American E&Ps.

The worst-case scenario for North American oil and gas producers would be further drops in oil price coupled with a gradual increase in interest rates to the pre-financial-crisis level. This combination would drive many more North American producers out of business. Low oil would shrink borrowing capacities, impeding necessary capital spending to maintain production while high interest rates devour companies' cash flows.

In short, the oil downturn has put substantial pressure on non-investment-grade North American E&Ps. While operational efficiencies have lowered cash costs, many small and midsize oil producers are still sensitive to higher cost of capitalization. With oil hovering around \$50 a barrel and credit spreads rising from their pre-oil-crash lows, the fate of small and midsize producers depends heavily on the direction of interest rates and the Fed's policies over the next few years.

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