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I need hardly say that the oil industry is unique. It is by nature differentiated from every other kind of business or industry ... based upon the law of probabilities. It hardly has so sure or firm a foundation as that. The oil business is based on the logic of chance ... [and] is nothing more or less than a calculus of chances or of risks.

—Sen. Kenneth McKellar (Tenn.) commenting on the inherent risks of the oil and gas industry during a Senate Floor Debate on tax incentives to encourage the exploration and development of minerals, 78 Cong. Rec. 6181-6183 (1920).
CHAPTER 1

INTRODUCTION TO THE U.S. OIL AND GAS INDUSTRY: AN UPSTREAM PERSPECTIVE

A. Setting the Stage

The need for a reliable and affordable energy supply, coupled with the lack of currently available viable “alternative” energy options, means that for the time being oil and natural gas remain the primary means to meet the nation’s, and indeed the world’s, energy needs. The domestic oil and gas industry — also known as the exploration and production (E&P) industry — is a fundamental pillar of the U.S. economy, an integral part of the American way of life, and arguably central to national security. In recent history, it has been highlighted by the stump speeches of the
candidates (including the famous 2008 “Drill, Baby, Drill!” Republican party campaign slogan) and the Keystone Pipeline,\(^1\) exemplified by the fallout after the Deepwater Horizon oil spill,\(^2\) and reinforced by the international effects of the boom and bust of shale (tight oil or nonconventional drilling).

From both a supply-and-demand perspective, the U.S. oil and gas industry is vulnerable to the effects of myriad internal and external factors, ranging from global credit markets\(^3\) to domestic and for-

\(^1\) The Keystone Pipeline system is a pipeline system to transport hydrocarbons from oil sands formations from northeastern Alberta, Canada, to multiple destinations in the U.S. It consists of the “Keystone Pipeline” and “Keystone-Cushing Extension,” both of which are operational, and two proposed expansion segments, “Keystone XL Pipeline” and the “Gulf Coast Project.” In November 2015, perhaps amid wide speculation that the Obama administration would not support construction of pipeline through the U.S., TransCanada Corp., the company behind the Keystone XL Pipeline, asked the U.S. State Department to “pause in its review of the presidential permit application.” See “TransCanada Requests Suspension of U.S. Permit for Keystone XL Pipeline,” WSJ.com, www.wsj.com/articles/transcanada-requests-suspension-of-u-s-permit-for-keystone-xl-pipeline-1446507279 (last visited April 1, 2016).

\(^2\) Deepwater Horizon was an ultra-deepwater semi-submersible offshore oil drilling rig owned by Transocean Ltd. and leased to British Petroleum. On April 20, 2010, while drilling in the Gulf of Mexico, an explosion on the rig caused by a blowout killed several crew members, sank the rig and left the well gushing at the seabed. It was the largest offshore oil spill in U.S. history.

\(^3\) By way of example, reaction of the market to commodity prices has led to a reluctance on the part of many energy lenders to loan additional funds, renegotiate loan terms, enter into forbearance agreements or waive covenant defaults, potentially forcing many E&P companies facing cash-flow crises into bankruptcy.
eign geopolitical events, and from technological developments and limitations\textsuperscript{4} to population growth\textsuperscript{5} and the weather\textsuperscript{6}.

Recent history has been volatile in the E&P industry. 2008 was a “boom” year, with crude oil prices reaching a record high of over $147/barrel in July 2008\textsuperscript{7} and the average wellhead price for natural gas hitting the highest nominal recorded level at $10.82 per thousand cubic feet (Mcf) in June 2008.\textsuperscript{8} On July 2, 2008, Henry Hub prices spiked to $13.68/Mcf.\textsuperscript{9} This resulted in a frenzy of pro-

\begin{footnotesize}
\textsuperscript{5} China is a good example. As recently as 1950, China’s population was a mere 563 million. The population grew dramatically through the following decades to 1 billion in the early 1980s and is expected to reach 1.4 billion by the late 2010s. The population surge has contributed to its high growth rates of economic output and growth in urban areas. A 2006 paper prepared by the Congress of the United States Congressional Budget Office entitled China’s Growing Demand for Oil and Its Impact on U.S. Petroleum Markets concluded that China’s near-term demand for oil is likely to affect U.S. oil markets by causing higher crude oil prices, higher refining costs and greater price volatility. April 2006, CBO Publ. 2561. Between 2009 and 2010, world liquid fuels consumption had China’s year-over-year growth increasing at twice that of the U.S. See U.S. Energy Information Administration, www.eia.gov/forecasts/steo/report/global (last visited Feb. 24, 2016).
\textsuperscript{7} On July 11, 2008, the West Texas Intermediate (WTI) price for crude rose to over $147/barrel.
\textsuperscript{9} Id.
\end{footnotesize}
duction, with the number of active total oil and gas rigs in the U.S. rising in September 2008 to 2,031, the highest count in 22 years.\textsuperscript{10}

However, starting in the second quarter of 2008, a rapid decline in oil and natural gas prices set in, and by December the price of a barrel of crude was sitting at less than $40/barrel. In addition, natural gas wellhead prices had fallen by 45 percent from the June peak to an average of $5.87/Mcf.\textsuperscript{11} By the third week of April 2009, the active total rig count had plummeted to 488 rigs, the lowest rig count since 1940.\textsuperscript{12}

Less than three years later, by December 2011, the number of active rigs in the U.S. had increased to 2,019. Canada peaked at 710 in early 2012.\textsuperscript{13} The average Brent price dropped from $109/barrel (bb) in 2013 to an average of $56/barrel (bb) in 2015. By early 2016, the rig count was down to 517 in the U.S. and 242 in Canada. There seems to be a growing consensus that, at best, E&P will be volatile\textsuperscript{14} in years to come, with booms followed more closely by busts.

Even for those practitioners who experienced the waves of bankruptcies that occurred from the 1980s through 2009, navigating through a modern E&P bankruptcy, workout or financial restructuring may be daunting. The nature of the game has changed,

\begin{footnotesize}
\begin{enumerate}
\item \textit{Id}.
\item \textit{Id}.
\item See, e.g., \textit{Annual Energy Outlook 2015} (and prior years), \textit{available at} www.eia.gov/totalenergy (last visited March 15, 2016).
\item See \textit{Short-Term Energy Outlook} (March 2016), U.S. Energy Information Administration, \textit{available at} www.eia.gov/forecasts/steo/pdf/steo_full.pdf (last visited March 15, 2016) (forecasting Brent crude oil prices to remain lower than previously forecasted, with averages of $34 per barrel in 2016 and $40 per barrel in 2017).
\end{enumerate}
\end{footnotesize}
part due to changing technologies in the industry. Lenders, management, royalty owners, oilfield service providers, general unsecured creditors and equityholders can be overwhelmed by the myriad issues that a troubled E&P company can be facing, as well as the ripple effects in the industry that such trouble causes.

Although E&P companies seek bankruptcy protection for a number of reasons, experience teaches us that most are the result of liquidity crises primarily due to cyclical price fluctuations, often compounded by leverage that originally seemed manageable. The drop in the value of reserves reduces availability under debt instruments. Cash flow from production is adversely affected by production declines. The decrease in revenue and limited access to lending further decreases the ability to fund the CAPEX necessary to retain acreage and, most importantly, to counter decreased production. However, even without a drop in hydrocarbon prices, with the inherent “calculus of chances or of risks,”15 and with the growth in the number of small to mid-sized independent E&P companies16 over the past several decades, an E&P bankruptcy can occur at any time.

Bankruptcy cases involving an E&P company raise unique issues that result from the interplay among the Bankruptcy Code, federal and state laws, a variety of regulatory structures governing the E&P industry, and the political and practical reality of the E&P industry’s significance on national, regional and local levels. These materials rely heavily on the Texas experience, as Texas is the country’s largest producer of oil and gas, but the decisions and laws of other states, such as California, Colorado, Louisiana, North Dakota, Oklahoma, Ohio, Pennsylvania and Wyoming, are also referenced. This manual is intended to give those practitioners with experience

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15 As stated by Sen. McKellar and cited in the manual’s introduction.
16 “Independent” refers to the nonintegrated nature of an E&P company, meaning that it receives nearly all of its revenues from production at the wellhead. These companies have no downstream marketing or refining operations.
in the highly specialized areas of oil and gas, financial restructuring and bankruptcy law a better understanding of what happens when those worlds collide. The goal is to discuss basic principles, as well as the issues that are unique to E&P bankruptcies and that arise in many of them.

Excerpted from When Gushers Go Dry: The Essentials of Oil & Gas Bankruptcy, Second Edition
in addition to other payments such as delay rentals\textsuperscript{18} or a shut-in royalty.\textsuperscript{19} Courts most often treat oil and gas leases as having elements of both conveyances and contracts.\textsuperscript{20}

1. **Nature of an Oil and Gas Lease**

The nature of an oil and gas lease is determined by the language of the granting clause as interpreted under state law.\textsuperscript{21} This interpretation affects process perfection of liens, assignability, cure obligations and timing. Leases can terminate for a number of reasons, including:

- the lack of production in paying quantities;
- the failure to pay delay rentals;
- in some cases, the failure to pay royalties;
- the failure to drill within the primary term; and
- the failure to continuously drill that causes the release of undeveloped portions of the lease.

Even within these general “termination events,” the terms of actual leases will vary. For example, one lease may prevent termination if a well is drilled but not completed, while another may require actual production.

\textsuperscript{18} See Glossary at Chapter 7.
\textsuperscript{19} Id.
\textsuperscript{20} As is discussed in this section, the extent to which an oil and gas lease is considered to be a “true lease,” a “contract,” “deed” or other instrument of conveyance varies by state.
Generally speaking, states follow one of two theories regarding the ultimate right to ownership of subsurface minerals: the “ownership in place” theory or the “non-ownership” theory. Under the ownership-in-place theory, the oil and gas under the ground is a fee simple absolute estate in land, giving the holder of such rights ownership of the oil and gas in place, subject to divestiture. Under this theory, the entire real property “bundle of sticks” is bestowed upon the owner, including the right to present possession of the oil and gas in place; the right to search for, develop and produce minerals; the right to profits; the obligation for costs; the right to lease or sell the mineral interest; and the right to enjoy benefits under an oil and gas lease. In addition, the ownership-in-place theory includes an implied right to reasonable use of the surface to realize the benefits of the mineral estate. The ownership theory is the majority rule in the U.S. and is followed in Texas, New Mexico, Colorado, Ohio and Kansas, among other states.

Under the non-ownership theory, the owner of the mineral estate has an exclusive right to explore for, develop and produce oil and gas, but does not have a present right to possession of the oil and gas in place. Such a theory is more akin to a profit à prendre (profit) (California), or a license, which is a real property interest allowing the holder of the profit to remove a part of the substance of the land. Like states adopting the ownership-in-place theory, the mineral estate is dominant in non-ownership states, meaning that there is an implied right to reasonable use of the surface. Okla-

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22 Id.
25 Id.
26 See, e.g., Wall v. Shell Oil Co., et al., 209 Cal. App. 2d 504, 510 (1962). Rights incident to mineral ownership include the right to search, develop and produce minerals (right to profits and obligations of costs), right to lease or sell those rights (the “executive” right), and the right to benefits under an oil or gas lease (right to bonus, delay rentals, shut-in royalties, royalties).
homa, Louisiana, California, Wyoming and Pennsylvania are non-ownership-theory states.

The primary difference between the ownership-in-place theory and non-ownership theory from a real property law standpoint is the present right of possession. The present right of possession is the defining factor between a corporeal interest (carries with it the right of possession and cannot be abandoned) and an incorporeal interest (does not have a right of possession, just use, and can be abandoned). Oil and gas rights in the states following the non-ownership theory are subject to loss by abandonment or, in the case of Louisiana, codified prescription for non-use.

Although the classification of the rights created by an oil and gas lease vary, in general states that follow the ownership-in-place theory characterize the interest granted by a lease to be a fee simple determinable estate in the oil and gas in place. This is because the typical language creates an interest to continue indefinitely (the “fee simple” part) subject to the occurrence (or lack of an occurrence) of a specified event (the “determinable” part), which is usually the lack of production, failure to pay delay rentals or, in some cases, the failure to pay royalties or continuously drill. Under Louisiana’s Civil Law regime, a landowner does not own the

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27 Oklahoma does not follow the ownership-in-place theory. In Oklahoma, “no title vests until the oil or gas is reduced to possession,” making the lease “a grant of an incorporeal hereditament.” Cuff v. Koslosky, 25 P.2d 290, 291-92 (Okla. 1933); see also Lima Oil & Gas Co. v. Pritchard, 218 P. 863, 865-66 (Okla. 1923).
29 See 2 Kuntz § 2.4.
30 The characterization of the rights created by an oil and gas lease in ownership-in-place states begins with the language of the lease, although in such states it is rare that characterization issues arise anymore. 1-2 Williams & Meyers, Oil and Gas Law § 203 (LexisNexis, Matthew Bender 2015) (hereinafter “Williams and Myers”). Such is not the case in non-ownership states.
31 Where the bargaining power of a lessor allows for it, some leases include a “termination upon failure to pay royalty” clause. Due to the heavy consequences for
oil and gas in place, thus there is no “mineral estate” from which to carve a leasehold interest. Instead, a mineral servitude is imposed upon the land, giving its holder the right to explore for, develop and produce oil and gas. The mineral lease creates a real right, but it is not subject to prescription of non-use.32 The Civil Law regime’s strong policy in favor of beneficial usage of land results in a codified prescriptive period for non-use, which is 10 years.33 Good-faith operations for the exploration, development and production of oil and gas will prevent the prescriptive period from running.34

A further distinction dictated by state law is whether rights to oil and gas are considered real or personal property.35 From this crucial distinction flow important consequences. The determining factor here is not possession, but duration. If an interest is a freehold estate, a life estate or a fee estate, it is real property. All other interests are personal property.36

The typical oil and gas lease conveys an interest in real property due to the potentially perpetual duration (e.g., “this lease shall remain in force for a term of three (3) years from the date hereof, and as long thereafter as operations are conducted upon said land....”). In most oil and gas-producing states, including Texas, Colorado37 and New Mexico, the leasehold interest created by an oil and gas

33 A caveat to this rule is that mineral servitudes in favor of the U.S., the State of Louisiana or any of their respective agencies or subdivisions are imprescriptible while owned by the government. La. R.S. § 31:149.
34 La. R.S. § 31:29.
35 For a more thorough discussion of the real vs. personal property nature of oil and gas, see Williams and Meyers, supra.
36 Id.
37 Hagood v. Heckers, 182 Colo. 337, 347-348, 513 P. 2d 208 (Colo. 1973), cited with approval in Maralex Resources v. Chamberlain, 320 P. 3d 399 (Colo. App. 2014) (“Accordingly, as implicitly accepted in Hagood, we conclude that an oil and gas lessee has an interest in real property.”). Id. at 403.
lease is interpreted according to contract principles, but is also the instrument by which the mineral estate owner conveys a real property right to the E&P company to explore for, develop and produce minerals. In Oklahoma, an oil and gas lease is a real property interest for some purposes, but not for others.\(^3\) However, in states such

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\(^3\) In Oklahoma, an oil and gas lease is a leasehold estate for a term of years, which is a statutory “chattel real” pursuant to Title 60, Sec. 26 Okla. Stat. As such, it has been described as a “hybrid estate deriving its legal characteristics from both real and personal property, yet it is actually neither. It is, in essence, and also an interest in land.” *Continental Supply Co. v. Marshall*, 152 F.2d 300, 305 (10th Cir. Okla. 1945) cert. denied, sub nom. Fed. Ntl. Bank v. Continental Supply Co., 327 U.S. 803, 66 S.Ct. 962, 90 L.Ed.2d 1028 (citing *Duff v. Keaton*, 33 Okl. 92, 124 P. 291 (Okla. 1912); *Rich v. Doneghey*, 71 Okl. 204, 177 P. 86 (Okla. 1918); *Nicholson Corp. v. Ferguson*, 114 Okl. 16, 243 P. 195 (Okla. 1925); *Tiffany on Real Property, 3rd Ed.,* Vol. 2, Sec. 589). Oklahoma leases have been classified as real property for purposes of mortgaging the oil and gas in place and the land itself (*Continental Supply Co.*, 152 F.2d at 307; *White v. McVey*, 168 Okl. 19, 31 P.2d 850 (Okla. 1934)); vendor’s liens (*Casper v. Neubert*, 489 F.2d 543 (10th Cir. 1973); *Galer Oil Co. v. Pryor*, 172 Okl. 302, 47 P.2d 97, 102 (Okla. 1935)); the statute of frauds (*Woodworth v. Franklin*, 85 Okl. 27, 204 P. 452 (Okla. 1921)); *r/hrg denied*; the formalities of conveyance (*Bentley v. Zelma Oil Co.*, 76 Okl. 116, 184 P. 131 (Okla. 1919)); *Davis v. Lewis*, 187 Okl. 91, 100 P.2d 994 (Okla. 1940); *Tupeker v. Deaner*, 46 Okl. 328, 148 P. 853 (Okla. 1915)); homestead laws pertaining to conveyances of real property (*Carter Oil Co. v. Popp*, 70 Okl. 232, 174 P. 747 (Okla. 1918)); measuring damages for breach of covenants in real estate transactions (23 Okla. Stat. § 25; *Nicholson Corp. v. Ferguson*, 114 Okl. 16; 243 P. 195 (Okla. 1925)); an exception in a deed of conveyance reserving to the grantor the oil and gas (*Rich v. Doneghey*, 71 Okl. 204, 177 P. 86 (Okla. 1918); *Hudson v. Smith*, 171 Okl. 79, 41 P.2d 861 (Okla. 1935)); *Ewert v. Robinson*, 289 F. 740 (8th Cir. 1923); a pledge of unaccrued royalty as security by the lessor of an oil and gas lease (*McCully v. McCully*, 184 Okl. 264, 86 P.2d 786 (Okla. 1939)). An Oklahoma oil and gas lease is not characterized as an interest in real property for purposes of the statute creating a judgment creditor’s lien (*First National Bank v. Dunlap*, 122 Okl. 288, 254 P. 729 (Okla. 1927)); Probate Code procedural provisions relating to the oil and gas lease or conveyance thereof by a guardian, executor or administrator of an estate (*Duff v. Keaton*, 33 Okl. 92, 124 P. 291 (Okla. 1912)); *Kolachny v. Galbreath*, 26 Okla. 772, 110 P. 902 (Okla. 1910)); *Cabin Valley Mining Co. v. Hall*, 53 Okl. 760, 155 P. 570 (Okla. 1916)); the statute which requires foreclosure suits be filed in the county where the property is located (*Widick v. Phillips Petr. Co.*, 173 Okl. 325, 49 P.2d 132 (Okla. 1935)); *ad valorem* taxes, when separate *ad valorem* taxes were levied apart from the fee title (*State v. Shamblin*, 185 Okl. 126, 90 P.2d 1053 (Okla. 1939); *State v.*
as Kansas, oil and gas leases are not considered interests in real property. In Ohio, there is a historical split in authority as to the nature of an oil and gas lease. However, recent Ohio case law and statutory authority support the view that an oil and gas lease now grants to the lessee an ownership in the minerals. In Pennsylvania, the courts have ruled that the terms of the instrument determine the nature of the interest conveyed. However, once the lease is held by production, a fee simple determinable is created. In Louisiana, a mineral lease is defined as a “contract” by which the lessee is granted the right to explore for and produce minerals, although Louisiana courts recognize this as an interest in realty.

Whether a lease is a “renewal” or an “extension” can affect other rights. Under Texas law, the analysis of whether “renewal or extension” language reaches new leases taken on the same lands is highly fact-specific. In Sunac Petroleum Corp. v. Parkes, the

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40 Compare In re Gasoil Inc., 59 B.R. 804 (Bankr. N.D. Ohio 1986) (holding that oil and gas leases create leaseholds in nonresidential real property), with In re Frederick Petroleum Corp., 98 B.R. 762 (S.D. Ohio 1989) (holding that oil and gas leases create a license and noting that exact nature of lessee’s interest in oil and gas leases is unclear in Ohio).

41 Baxter v Reserve Energy Exploration Co., 2015 Ohio App. LEXIS 5341 (11th App. Dist. Ohio 2015) (the lessee/grantee acquires ownership of all the minerals in place that the lessor/grantor owned and purported to lease); Kramer v. PAC Drilling Oil & Gas LLC, 197 Ohio App. 3d 554 (9th App. Dist. Ohio 2011) (fee simple determinable); see also Chesapeake Exploration LLC v. Buell, 144 Ohio St. 3d 490 (2015) (leases of oil and gas rights create an interest in real estate), and O.R.C. 5301.09 (same).


43 La. R.S. § 31:114.

44 416 S.W.2d. 798, 803 (1967).
Texas Supreme Court held that a new lease is not a “renewal or extension” if the new lease was entered into after the old lease had already expired, new consideration exists to support the new lease, the new lease was executed under different circumstances, and the new lease contains different terms. An analysis of whether “new” leases taken on lands covered by previous leases, or whether other documents intended to be ratifications, revivers, extensions or renewals would be covered under such a provision, must be undertaken on a case-by-case basis.

2. Division Orders

A division order is a “snapshot” of how the proceeds of production will be divided up and is based on the calculation of various royalty interests in a well. Ideally, each holder of any royalty interest will have signed or otherwise agreed to the division order. From a lender or investor’s perspective, a division order is the foundation for calculating the value of the reserves held by an E&P company. It is important to note that consent to a division order can be withdrawn and that the holder of a royalty interest can challenge its percentage, the allocation of costs and/or the method of calculation of payment.

3. Landowners: Mineral Owners, Surface Owners, Royalty Owners

In common law states, real property is severable between the surface and mineral estates. In the simplest of scenarios, there is one owner of both the surface and the entire mineral estate and, thus, one owner with whom an E&P company would have to negotiate.

45 Division orders are at the well and not the lease level.
in leasing and enjoying the full benefits of the leasehold estate.\textsuperscript{46} However, given severability and the free alienability of the rights in the “bundle of sticks,” it is often the case that the lease is granted from one or more mineral interest owners, but such individuals do not own the surface estate. Furthermore, because the right to explore for, develop and produce oil and gas, or to grant oil and gas leases, is itself one of the “bundles of sticks” associated with the mineral estate, that right can be conveyed independently. As a result, an owner of an interest in the mineral estate may have no right to grant leases or to explore for minerals himself.\textsuperscript{47}

One of the benefits of the bargain that a lessor receives in granting an oil and gas lease is the right to receive a royalty. A royalty is a right to receive a payment that represents the lessor’s share of proceeds of production (or, in some cases, the right to take, in-kind, the production itself).\textsuperscript{48} There are different types of royalties, each conveying to its owner a different set of rights.\textsuperscript{49} A \textit{landowner royalty} is that typically retained by the lessor in conveying the oil and gas lease. In pre-printed “Producer’s-88” forms, the royalty is 1/8 of oil and gas. However, more modern leases often grant a higher royalty, with the high end of 1/4 of the proceeds of production. A \textit{non-participating royalty} is a right to receive a percentage of the

\textsuperscript{46} In theory, an E&P company need only concern itself with the mineral owner(s) because the mineral estate is dominant and the surface is subject to reasonable use. In practice, however, there are many issues that affect surface use, and an E&P must almost always directly negotiate with the surface owner(s) as well.
\textsuperscript{47} This right is known as the “executive right.” See Glossary at Chapter 7.
\textsuperscript{48} See Williams and Meyers.
\textsuperscript{49} There is a substantial body of case law discussing various aspects of royalties, including the distinction between a mineral interest and a royalty interest; among an interest “in royalty,” “of royalty” (\textit{e.g.}, a 1/8 interest in a 1/8 royalty is equal to 1/16 of the proceeds of production) and a “royalty interest” (\textit{e.g.}, a straight 1/8 royalty); and how various royalties are calculated. Although interesting, and a subject that may arise in an oil and gas bankruptcy case (for example, reconciling a claim for incorrectly paid royalties or failure to pay minimum royalty requires an understanding of these nuances), such topics do not warrant broad discussion here. For a more in-depth discussion on issues related to royalty payments, see Williams and Meyers.
proceeds of production, but without a commensurate right to lease or otherwise bargain for such percentage.\textsuperscript{50} Such a royalty arises when a mineral interest owner owns no executive rights, but has a right to a payment from production. The common factor among all royalty interests is that they are not cost-bearing — meaning that they are free and clear of the costs of production. Some royalty interests bear a share of the post-production costs.\textsuperscript{51} All royalty interests burden the leasehold estate in that they are netted from the proceeds of production prior to the E&P company receiving its share of revenue. While there are general “rules,” an agreement that conveys a royalty interest is a contract. As there is no prohibition on modifying “generally accepted” treatment, each lease must be evaluated to determine the economic benefits and burdens.\textsuperscript{52}

There is also no set definition as to how to calculate the base amount of a royalty. Examples include a royalty based on market value, “amount realized,” “gross proceeds,” “at the well,” “at the point of sale,” “before payout (BPO)” or “after payout (APO)” of drilling expenses. One common factor is that litigation over calculation of royalties increases as production decreases.

4. Leasehold Interest Owners: Operators, Non-Operators, Overriding Royalty Owners

The leasehold interest, also called the working interest,\textsuperscript{53} is the right to “work” the land covered by the lease in the exploration,
development and production of oil and gas, with the obligation to pay costs. A distinction should be made between the leasehold interest/working interest owner(s) and the “lessee.” The “lessee” is the named party on the lease to whom the lease was granted. It is common practice in the oil and gas industry for a party (sometimes a lease broker) to take a lease in its name, and then to transfer all or part of the leasehold interest to other parties. Thus, while the named lessee may (or may not) own a working interest in the lease, the holder or holders of the working interest may not appear anywhere on the face of the lease. To determine working interest record title, it is necessary to search the public county records and, often, to hire an attorney to render a leasehold title opinion.

From the leasehold title standpoint, in the simplest of scenarios, one E&P company owns a 100 percent working interest in a lease on a given tract, and therefore, owns the full bundle of sticks to explore for and produce oil and gas. Although this is often the case, it is just as common that more than one E&P company or individual investors each own a working interest percentage. Because oil and gas exploration is extremely capital-intensive, this arrangement allows an E&P company to mitigate risk, reducing the financial impact of drilling unsuccessful wells, and is an alternative for developing an area on a limited budget. In such a situation, a joint operating agreement (JOA) will typically govern operations on

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E&P industry, including lease operating expenses (LOE), capital expenditures (CAPEX) and, for the larger capital outlays associated with drilling and completion of the well (usually over a certain threshold as defined in the joint operating agreement (JOA)), an Authority for Expenditure (AFE) is prepared by the operator for approval by non-operating working interest owners. The concept of working interest is inextricably linked with that of net revenue interest (NRI), which is the right to receive revenue from an oil and gas lease.

A JOA is not the only means to jointly determine the rights and responsibilities of the operator and the non-operators. For example, in states such as Oklahoma and Wyoming that have instituted forced pooling, the pooling order issued by the state regulatory agency often governs relationships among working interest owners. In Oklahoma, a pooling order is a “bare bones” operating agreement. *Leede Oil & Gas Inc., v. Corp. Com’n of State of Okla.*, 747 P.2d 294, 296
the lease. A JOA can cover a single well or the development of a larger area. There are several model forms, but the most common is that promulgated by the American Association of Professional Landmen (AAPL).

Under a JOA, one party will be designated as the “operator” and, as such, will undertake certain duties, such as serving as the primary interlocutor for purposes of communicating with, and being accountable to, the state regulatory agency/agencies; seeing that the wells on the lease are drilled and completed in accordance with the lease obligations and as a “reasonably prudent operator” would;55 selling production; paying royalties; billing the non-operators for their proportional share of the costs (called the “joint interest billings” or “JIBs”); and distributing to the non-operators their proportional share of the revenue. Although it is sometimes the case that an operator owns its own rigs and undertakes the drilling itself, more often than not the drilling rigs are owned and operated by drilling contractors. Operators have the right to contract (and sub-contract) on behalf of all the working interest owners for various aspects of the drilling and completion. Thus, typically an operator’s

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55 This is the standard of care for operators in Texas, but other oil and gas-producing states have a similar standard of care. For example, Oklahoma enacted the “Energy Litigation Reform Act,” which states that “[a] person is bound as a reasonably prudent operator,” which means that the operator will perform duties that “an operator acting reasonably would have undertaken given the circumstances at the time, without being required to subordinate its own business interests, but with due regard to the interests of all affected parties, including the operator....” Title 52 Okla. Stat. § 902(1). This standard applies to private agreements, statutes and governmental orders. Id. For a discussion of the standard of care in Colorado, see, e.g., North York Land Associates v. Byron Oil Industries, 695 P.2d 1188, 1190-1191 (Colo. App. 1984). See also Garman v. Conoco Inc., 886 P. 2d 652 (Colo. En Ban. 1994) “In Colorado we have recognized four implied covenants in oil and gas leases: to drill; to develop after discovery of oil and gas in paying quantities; to operate diligently and prudently; and to protect leased premises against drainage.” Id. at 659.
duties during a cycle consist of producing oil and gas (including contracting with vendors, other contractors and subcontractors, and incurring all of the upfront costs of drilling and completing), billing the non-operators for their proportionate share of the costs, selling the production, gathering the revenue from production, paying royalty owners their share of the proceeds of production, and proportionally distributing the resulting revenue to itself and the non-operators.

If JIBs are a significant source of cash flow, which could be the case where the debtor is the operator and the other non-operating working interest owners own a substantial percentage of the working interest in a given well or lease, inquiry should be made about whether there are subcontractors threatening to file liens against the JIB obligor. If so, it is possible that the JIB obligor will suspend payment of JIBs until mineral liens are released, whether or not the JIB obligor is entitled by law to make such a demand. Where the E&P debtor is the JIB obligor (i.e., the non-operator) operators will be concerned about whether the debtor will be unable to pay its proportionate share of drilling, completion and LOEs. There are provisions in most standard JOAs aimed at protecting the operator in the event a non-operator becomes a debtor in bankruptcy, such as the operator’s right to net (recoup or set off) the debtor’s production revenues against overdue JIB payments and the creation of liens to protect against nonpayment. In addition, mineral subcontractor liens can be filed against the debtor’s working interest if vendors are not being paid. In most cases, the operator sees to it that vendors are paid.

Beyond issues of whether the royalty interest bears production costs or post-production costs, other issues relating to the characterization of royalty interests are being raised — particularly with regard to overriding royalty interests (ORRIs) and net profit interests (NPIS) — including whether (1) an NPI or ORRI is treated as
a real or personal property conveyance; (2) an agreement to convey
an NPI or ORRI is treated as an executory contract; (3) the pro-
ceeds of production are subject to competing claims; and (4) the
conveyance could be recharacterized as a financing arrangement.

a. Real or Personal Property
In Texas, a conveyance of an NPI or ORRI should be treated in
bankruptcy as a conveyance of real property. In Louisiana, by con-
trast, characterization of an assignment of an ORRI or the retention
of an ORRI depends on the nature of the contractual actual rela-
tionship from which the royalty is created.56

b. Executory Contract
In In re Foothills Tex Inc.,57 the Delaware Bankruptcy Court ana-
lyzed whether a conveyance of an ORRI under Texas law would be
treated as an executory contract, regardless of whether the ORRI
was an interest in real property.58 The court reached the conclusion
that where the assignee had no obligation to pay any costs or ex-
penses associated with the lease, it was not executory.

c. Sale vs. Financing Transaction
In ATP Oil & Gas59 Texas Bankruptcy Judge Marvin Isgur denied
a Motion for Summary Judgment as to whether an ORRI should
be recharacterized as a debt financing rather than a conveyance of
real property. The decision was governed by Louisiana law, but
the analysis would be applicable in Texas. The court analyzed the

56 Tidelands Royalty B. Corp. v. Gulf Oil Corp., 804 F.2d 1344 (5th Cir. 1986).
57 Foothills Tex. Inc. v. MTGLQ Investors L.P. (In re Foothills Tex. Inc.), 476 B.R.
58 The Bankruptcy Code does not define “executory contract.” However, it is gen-
erally accepted that, at a minimum, an executory contract is one where perfor-
mance remains on both sides such that a failure would be a material breach.
59 NGP Capital Res. Co. v. ATP Oil & Gas Corp. (In re ATP Oil & Gas Corp.),
conveyance document to determine whether the transaction was (1) inconsistent with an ORRI under Louisiana law and (2) consistent with a loan under Louisiana law.

5. Oilfield Service Providers

As indicated above, exploring for, developing and producing oil and gas requires a large quantity of goods and services to be provided to the oilfield during each phase of site preparation, drilling, completion and production. Services include seismic testing, surveying, preparation of plats, staging of the area (clearing trees, or leveling the ground, for example), mobilization of the drilling rig, mud logging, supplying casing and pipe, hydraulic fracturing or “fracking,” enhanced recovery treatments, well stimulation, wireline logging, coring and other testing techniques, and even housing and accommodations services for on-site personnel. The operator is responsible for contracting with each of these vendors. It is often, though not always, the case that this relationship is governed by a single master service agreement (MSA), supplemented by work or purchase orders on an individual-project basis.

E&P companies wish to maintain a good relationship with oilfield service providers. In addition, it should not be overlooked that these entities comprise a large segment of the local culture and economy. They play a pivotal role during a bankruptcy process, both in terms of their roles as creditors and in terms of the potential leverage they hold from needed post-petition drilling activities potentially necessary to maximize the value of the estate.

Recognizing the importance of this industry to its state and local economies and the risks involved, most oil and gas-producing states provide for a lien in favor of oilfield service providers, simi-

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60 Id.
lar to a mechanic’s and materialman’s lien. These liens, which usually attach to the lease on which work was performed, relate back to the date of the first work on the property and can trump mortgages on the property. Even where mineral lien claimants are not first-lien-holders, mineral lien claimants are important stakeholders who should be included from day one in evaluating exit strategies. Beyond statutory liens, § 503(b)(9) of the Bankruptcy Code gives unpaid suppliers a priority right to be paid for goods delivered in the 20 days before the company files for bankruptcy. After the Sem-Crude bankruptcy, some states strengthened the ability of producers to have “springing” liens that defeat contractual liens securing loan debt.

Given the changing nature of an E&P company’s assets, it is possible (and often probable) that service companies may have liens that are senior to the lenders. As a result, it is common in DIP financing to “carve out” priority status over such liens — at least, at the interim stage. Such liens can also complicate sales, with fights over allocation of value at the sale-approval stage rather than post-closing.

6. Joint Development Agreements

A “joint development agreement” is the generic term used to describe any number of different arrangements whereby risk and reward are shared between or among E&P companies. Examples of joint development agreements are areas of mutual interest (AMI) agreements, joint exploration agreements and farm-outs/farm-ins. These agreements are common in the industry and, for purposes of bankruptcy law, are typically executory contracts.61

7. **Surface Use Agreements**

A surface use agreement (SUA) is an agreement between the operator and the owner of the surface above the minerals. While the right to access the minerals is dominant, surface use agreements are often required where there is common ownership of the surface and the minerals. Surface use agreements are executory contracts. Issues that can arise with SUAs include:

1. assignability;
2. calculation of any cure obligations; and
3. identifying restrictions on drilling and related costs.

8. **Midstream Contracts**

The purchasers of production include pipelines, gatherers and refiners. These entities, in the so-called “midstream,” purchase oil and gas from the operator for distribution and resale or, more likely, further processing. There are two general forms of gas gathering and processing agreements.

A “service based” agreement is where a processor processes a producer’s gas to remove the natural gas liquids (NGLs) in consideration of the payment of a cash fee and the producer’s retention of a portion of the gas as plant and (if necessary) compressor fuel, as well as a percentage of the NGLs extracted. In a service-based processing agreement, the producer receives the remainder of the NGLs extracted and any residue gas.

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A “sale based” agreement is where the producer sells gas to a processor at the well head, a central delivery point in the field or the inlet of the plant. The price paid by the processor is either an index price or, in recent years, a price per MMBTU equal to a percentage of the proceeds received by the processor upon its sale of the NGLs extracted from the producer’s gas and the residue gas after processing. Absent a specific provision, a producer whose gas is sold before processing is not obligated to pay royalties on NGLs. From the perspective of a midstream operator, these agreements contain significant commodity price risk. From the midstream operator’s perspective, fee-based and cost-of-service agreements may be preferred.

9. Taxing Authorities

In addition to the Internal Revenue Service (IRS), there are multiple state, city, county, school district, utility district and improvement district authorities that have taxing authority. A severance tax is unique to the oil and gas industry, and most states with oil and gas production impose such a tax. It consists of a fixed percentage tax on oil and gas production for each working interest owner’s pro rata share of production, including the royalty owner. Imposition of a tax, creation or perfection of a statutory tax lien or special assessment on real property do not violate the automatic stay in bankruptcy.63

10. Federal and State Regulatory Agencies

On the federal level, the Bureau of Ocean Energy Management (BOEM) and its sister agency, the Bureau of Safety and Environmental Enforcement, are the U.S. Department of the Interior exec-

utive agencies responsible for management of the nation’s mineral resources on the outer continental shelf (OCS), formerly under the purview of the Minerals Management Service.64 BOEM also accounts for revenue from federal offshore mineral leases and onshore mineral leases on federal and American Indian lands.65 The Bureau of Land Management (BLM) (also under the U.S. Department of the Interior) reviews and approves permits and licenses from companies to explore, develop and produce oil and gas on federal lands.66

Similarly, each state has a regulatory agency that oversees the environmental and safety aspects of its E&P industry. A sampling of such agencies includes: the Texas Railroad Commission,67 the Oklahoma Corporation Commission,68 the Colorado Oil & Gas Conservation Commission,69 the North Dakota Industrial Commission,70 the California Department of Conservation71 and the Louisiana Office of Conservation.72

64 OCS leases are described in 43 U.S.C. §§ 1331-1356(a) (2006).
65 See www.boemre.gov, www.boem.gov and www.bsee.gov (last accessed March 15, 2016). The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) was previously known as the Minerals Management Service (MMS). It was renamed on June 18, 2010, by U.S. Department of the Interior Secretarial Order No. 3302. In the aftermath of the Deepwater Horizon blowout and subsequent oil spill, BOEMRE is currently undertaking “an aggressive overhaul of the offshore oil and natural gas regulatory process” that involves dividing the former three missions of MMS — promoting resource development, enforcing safety regulations and maximizing revenues from offshore operations — into three distinct independent agencies, the Office of Natural Resources Revenue within the Department of the Interior’s Office of Policy, Management and Budget, the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE).
67 See www.rrc.state.tx.us.
68 See www.occ.state.ok.us.
69 Colo. Rev. Stat. § 34-60-104, 106 and 109; see also cogcc.state.co.us.
70 See www.nd.gov/ndic.
71 See www.conservation.ca.gov/index/oilgas/Pages/Index.aspx.
72 See dnr.louisiana.gov/cons/conserv.ssi.
C. The Basics of Oil and Gas Valuation

The value of an E&P company’s oil and gas leases is typically in its reserves — that is, the hydrocarbons that have yet to be produced, but are economically viable to extract. Ownership interests in reserves can take many forms, including overriding royalty interests, royalty interests and working interests. Because the production rates of individual wells decline over time, the asset base of an E&P company (the reserves) must be continually updated through drilling new wells in the same formations or by acquiring new leases or “proving up” formation. Ideally, each E&P will have a well schedule showing the state, county, drilling status, spud date, completion date, reservoir formation, the American Petroleum Institute (API) number and whether the well is operated or non-operated. An additional schedule tying wells to leases (i.e., identifying which wells are drilled on which lease(s)) will be crucial for valuation purposes, analysis of the liens affecting the various properties, and for understanding the rights of various secured creditors and the distribution to all creditors. Although these seem like obvious requirements, because oil and gas accounting is primarily on a well-basis and security interests and other rights are determined on a lease basis

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73 The foundation for this section was derived from the 2007 Petroleum Resource Management System (PRMS), available at www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf, which was jointly sponsored by the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC) and the Society of Petroleum Evaluation Engineers (SPEE), as well as Alex W. Howard and Alan B. Harp, Jr., “Oil and Gas Company Valuations,” 28 Business Valuation Review 1, p. 30-35 (2009) (hereinafter cited as “Howard and Harp”), providing a practical overview of oil and gas valuation.

74 A company will also have a net revenue interest (NRI) in a given lease or well. This is the share of production proceeds (once severed and sold), but does not describe the interest in the oil and gas in the ground (i.e., the “reserves”). For additional discussion of the interplay between “overriding interests,” “working interests,” “non-operating interests” and “carried interests” in the Colorado context, see AEC Industries v. Survivor Oil, 7 P.3d 1052 (Colo. App. 1999). For application of the Colorado definition of “overriding interest” in a bankruptcy context, see In re Delta Petroleum, 2015 WL 1577990 (Bankr. D. Del. 2015).
(and because a debtor’s records may be in less-than-perfect order), there may not be a comprehensive schedule containing all of the required information in one location. Successful navigation of an oil and gas bankruptcy case requires inventorying, organizing and assessing early in the case.

An E&P company’s reserves are valued by petroleum engineers and petroleum geologists, in accordance with certain industry standards, and the resulting reports are known as “reserve reports.” Reserve reports are typically updated periodically, and are conducted for various reasons, including Securities and Exchange Commission (SEC) purposes, as a requirement for a bank or other financing, for merger and acquisition (M&A) transactions, and for special purposes, such as valuation determinations during bankruptcy. Because mineral liens are lease-specific and valuation is often conducted on a well basis (i.e., the value of production attributable to particular wells), a standard reserve report may not be the only tool needed to value the assets of the company.

The purpose of the study influences the inputs, and this can dramatically affect the resulting value. For the oil and gas bankruptcy

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75 The SPE, AAPG, WPC and SPEE work together to formulate and publish, for example, definitions of reserve categories, evaluation guidelines and standards believed suitable for use throughout the oil and gas industry.

76 Pricing is one example of an input that will vary depending on the reserve report’s purpose. For SEC reporting purposes, the SEC has traditionally required that prices in effect at the evaluation date (typically year-end) are held constant throughout the long-term projection period. However, for a non-SEC case report, a distinct price deck would be used, such as the NYMEX strip pricing, which, given its taking into account price fluctuations, made the SEC case overly conservative or overly robust in comparison. New SEC rules in effect since 2010 now require the use of a first-of-the-month 12-month average price. Also significant is the new SEC rule allowing the use of “reliable technologies” to establish reserves estimates, rather than the limitation of specific field tests. For an overview of the new rules, see www.sec.gov/info/smallbus/secg/oilgasreporting-secg.htm (last accessed March 15, 2016).
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practitioner, it is critical to keep this in mind. A list of key considerations useful in a bankruptcy case follows:77

- What price deck is being used? (SEC case? NYMEX strip? Other “management” case?)
- How do projected volumes compare with historical production volumes? If these are materially different, why?
- Are proved undeveloped locations included in the valuation? If not, is it worth considering having a separate valuation undertaken that models the unproved reserves and acreage values?
- What is the going rate for lease bonuses in the geographical area of each lease?
- What are the drilling, lease operating expense (LOE) and capital expenditure (CAPEX) assumptions?
- How are plugging and abandonment costs being estimated?
- Which percentage discount (PV-10? PV-15? PV-20?) most closely approximates the fair market value?
- How diversified is the production by well, by field and by region? (The more concentrated the production, the higher the risk, because if only a few wells represent a significant portion of cash flow, a risk adjustment is warranted.)
- Are there secondary or tertiary recovery techniques being used or contemplated to increase production?

77 Several items from this list were adopted from Howard and Harp, p. 32.
• What are the mechanical procedures that have “routinely been successful” (workovers, fracking jobs, retreatments) in “analogous reservoirs”?  

• What is the value of the seismic data on a given area?

Reserves fall into one of several categories, based on the uncertainty associated with recovery of the hydrocarbons. At the highest level, reserves are either proved or unproved. Within each category are several further subcategories. Proved reserves comprise proved developed producing (PDP), proved developed non-producing (PDNP) and proved undeveloped (PUD). Unproved reserves are further broken down into probable (PROB or 2P) and possible (POSS or 3P) reserves. A brief description of each category follows:  

Proved: Proved reserves are those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods and government regulations. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate.

• Proved Developed Producing (PDP): These are the most valuable reserves because they are the least risky. PDPs are the least risky because they are the most “proved”; that is, they are the quantities of hydrocarbons that are expected with reasonable certainty to be commercially recoverable from a given date forward, from known reservoirs and under defined economic conditions. If using probabilistic

79 See id.
methods, at least a 90 percent probability should exist for PDP reserves.

- **Proved Developed Non-Producing (PDNP):** Additional completion work is needed before these reserves can be produced. These reserves include shut-in (SI) or behind pipe (BP) reserves. SI reserves are expected to be recovered from completion intervals that (1) were open at the time of the reserve estimate but are not producing, (2) were shut in for market conditions or pipeline conditions, or (3) are not capable of production for mechanical reasons. BP reserves are expected to be recovered from completion intervals not yet open but still behind casing in existing wells. These are usually producing, but from another completion interval. Additional completion work is needed before these reserves can be produced.

- **Proved Undeveloped (PUD):** Hydrocarbons are expected to be recovered from new wells on undrilled acreage or existing wells requiring reworking or other major expenditure. PUDS are typically not “booked” until it is clear the major expenditure will be funded or completed in the near term.

*Unproved.* Unproved reserves are based on geoscience and/or engineering data similar to that used in estimates of proved reserves, but technical or other uncertainties preclude such reserves being classified as proved. Unproved reserves may be further categorized as probable reserves and possible reserves.

- **Probable Reserves (PROB or 2P):** Probable reserves are calculated off of the proved reserve values, but are assigned an additional “risk factor.” Probable reserves are those that are

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80 Depending on the type of reserves being estimated, unproved reserves should not be overlooked, as they can be valuable assets. For example, in the early stages of a new play, much value could potentially exist in the unproved reserves, even if value cannot be determined by a more traditional reserve analysis.
less likely to be recovered than proved reserves, but more certain to be recovered than possible reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50 percent probability that the actual quantities will be recovered.

- Possible Reserves (POSS or 3P):81 Possible reserves are also calculated off of the proved reserves values. The total quantities ultimately recovered from the project have a low probability of exceeding the sum of proved plus probable plus possible (3P), which is equivalent to the high estimate scenario. Thus, they are assigned an additional “risk factor” indicating that there is a 10 percent chance that reserves are greater than estimated and a 90 percent chance that they will be smaller.

Although it is the primary evaluation tool used to determine value, it is important to understand that a reserve report is not an appraisal of fair market value.82 Rather, it is an estimate of the “gross quantities expected to be produced from wells, net of the company’s ownership interest, using estimates of future prices, operating expenses and capital expenditure.”83 It is a discounted cash flow model for the E&P company’s reserves on a pre-income-tax basis. Depending on the nature and type of the oil and gas asset, a fair market value report or other expert report assessing the value of undeveloped acreage may be necessary.

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81  Probable reserves are called “3P” reserves when aggregated with proved and probable reserves.
82  Market value is typically defined as “an amount which would be applied to particular properties under consideration which probably could be sold by one who desires to sell but is under no urgent necessity to sell to a buyer who desires to buy but is under no urgent necessity to buy, in an arm’s-length transaction with both parties having reasonable knowledge of the facts.”
83  Howard and Harp, p. 32.
D. Oil and Gas Financing

The use and extension of credit is part of the everyday fabric of the oil and gas business. Traditional oil and gas lending is reserves-based, or “RBL.” This means the collateral for the loan is the value of the reserves, and repayment comes from the revenue derived from production proceeds. In the U.S., loans are based on the basis of PDP, with some additional value given the PDNP and little value to PUDs. There is little or no value, from a lending perspective, ascribed to unproved locations. The risks for lenders are volatile market prices (as influenced by a number of internal and external factors), dependence upon technical and operational assumptions in determining value, and depletion.

Adding to these risks is the ability of borrowers to draw down the full amount available on their RBLs and then file for bankruptcy. Lenders are generally required to honor such drawdowns up to the available amount, subject solely to compliance with specified conditions, which are generally limited to (1) no default and (2) accuracy of representations and warranties. Even though most RBL agreements will include a “no material adverse effect” condition, reliance on such a condition as a basis to refuse a revolver draw is difficult as the occurrence of a “material adverse effect” is usually a very high standard. Thus, even in a period of sustained financial distress, including potential bankruptcy, lenders may still be required to provide additional financing. This may result in pre-bankruptcy companies essentially “parking” cash on their balance sheet to be used during the bankruptcy process. However, some RBL lenders have recently prevented companies from using the RBL as such by incorporating anti-hoarding language into the RBL, whereby a dollar limit is set on the amount of cash that can be held on the balance sheet. Additionally, some RBL lenders require drawdowns to go into a control account with a lien attached to the account.
In a falling-price environment, regulators become proactive in reviewing such loans and related reserves. Reserve borrowing base “price decks” will be reviewed more frequently, lenders will perform periodic stress testing at various price floors, and efforts will be undertaken to confirm the perfection of liens. Regulators will also evaluate concentrations in service companies viewed as being most at risk in the short-term.

Depletion is a concept that arises in the context of valuation of reserves. Because the volume of hydrocarbons recoverable from a given well is fixed, as hydrocarbons are produced, there are fewer to produce in the future and, all else being equal, less profit to be gained. Depletion is an important concept and one that is often (in the opinion of these authors) without complete understanding. Although few people would argue against the fact that the volume of recoverable hydrocarbons is finite, that is not necessarily to say that the depletion of a given well or wells equates to the diminution of value of the leasehold. New drilling and implementation of secondary or tertiary recovery techniques are two examples of ways that the value of a leasehold can increase over time, even while producing.

In most, though not all, scenarios, the primary lender takes a blanket security interest in all of the oil and gas leases, including the production, proceeds, accounts, general intangibles, etc. However, unlike lending to a commercial real estate company, an E&P com-

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85 In the oil and gas-lending business, “price deck” refers to the current and future price estimates a lender and its engineering function will use to calculate a borrower’s borrowing base and collateral value.
pany’s assets are ever-changing. An E&P may have an interest in a lease as to certain depths and, subsequent to the loan, acquire interests in other depths; a borrower may enter into a “farmout” agreement either before or after the loan and “earn” acreage from the primary working interest owner by drilling; a lease may expire as to certain acreage not held by production (HBP); a lease may be unitized or pooled only as to certain depths; or the mortgage itself may be limited only as to certain depths in a given lease. Secured lenders therefore may be left vulnerable to having lost or limited their security interests for failing to systematically review the borrower’s interests in leases and for keeping current their perfection with new filings, particularly if the collateral description is arguably limited to a particular lease or if the borrower has acquired acreage or even the right to acquire acreage in another county. Every lender should have an accurate schedule of leasehold interests by lease identifier (usually an internal lease number), lease description (lessor, lessee, recording date, book/page, state and county), any depth severances, working interest percentage, whether the E&P is the operator or the non-operator, and whether the lease is pooled or unitized, and if so, the pooling or unit designation information and pooling or unit depth-severances, if any.

It is also important for lenders to have a schedule of all operating agreements, as a security interest may be contractually subordinated to any liens granted in the operating agreement.86

86 See, e.g., In re Century Management Corp., 119 F.3d 409 (6th Cir. 1997) (under Louisiana law, investors that hold unperfected reciprocal liens on debtor’s lease through operating agreement have priority over perfected secured interest).