COMMON LEGAL ISSUES IN U. S. SHALE PLAYS

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The most significant emerging resource plays in the United States involve the exploration of carbonaceous (organic-rich) shale formations primarily for the production of natural gas. The Barnett Shale in the Fort Worth Basin in north Texas is probably the best known such play. Using horizontal drilling and a mix of water, sand, and chemicals for hydraulic fracturing, horizontal wells in the Barnett Shale have produced three times as much as traditional vertical wells.[2] In 2008, the Barnett Field produced 4 Bcf/d, making it then the largest gas field in America.[3] The Barnett is estimated to cover 2 million core acres and have 34 Tcf of remaining recoverable reserves.[4]

While the Barnett Shale has been under development for several years,[5] many more recently discovered shale plays are growing in importance – including the Haynesville (est. 750,000 core acres in East Texas and Northwest Louisiana, with an est. 42 Tcf of remaining recoverable reserves), the Fayetteville (est. 400,000 core acres in Arkansas, with an est. 7.8 Tcf of remaining recoverable reserves), the Woodford (est. 480,000 core acres in Oklahoma, with an est. 10.6 Tcf of remaining recoverable reserves), the Marcellus (est. 5,000,000 core acres primarily in New York, Pennsylvania, West Virginia, and Ohio, with an est. 200 Tcf of remaining recoverable reserves),[6] and the Eagle Ford (est. 500,000 core acres in South Texas, with an est. 19 Tcf of remaining recoverable reserves).[7] And these are only the major gas shale plays. The industry is also developing oil shale plays such as the Bakken in North Dakota, Montana, Manitoba, and Saskatchewan. On the U.S. side alone, the Bakken is estimated to hold 3.65 billion barrels of light sweet crude, as well as 1.85 Tcf of associated gas and 148 million barrels of gas liquids.[8]

As of November 9, 2009, 110 horizontal drilling rigs were running in the core areas of the Haynesville Shale, 63 were running in the core areas of the Barnett Shale, 47 in the Fayetteville, 39 in the Marcellus, 24 in the Woodford, and 11 in the Eagle Ford.[9]

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[2] *See* Ben Casselman, *U.S. Gas Fields Go From Bust to Boom*, WALL ST. J., April 30, 2009, at A1.

[3] *See* Anna Driver, *New U.S. Shale Plays Spark Debate About Barnett*, REUTERS, Aug. 14, 2008, http://www.reuters.com/article/rbssOilGasExplorationProduction/idUSN1335858620080814.

[4] Ross Smith Energy Group Ltd., Energy Information Administration, as reported in the; Tom Fowler, *Next Generation Drilling Game Changer or Hype?*, HOUSTON CHRON., November 1, 2009. See map and charts on the following page.

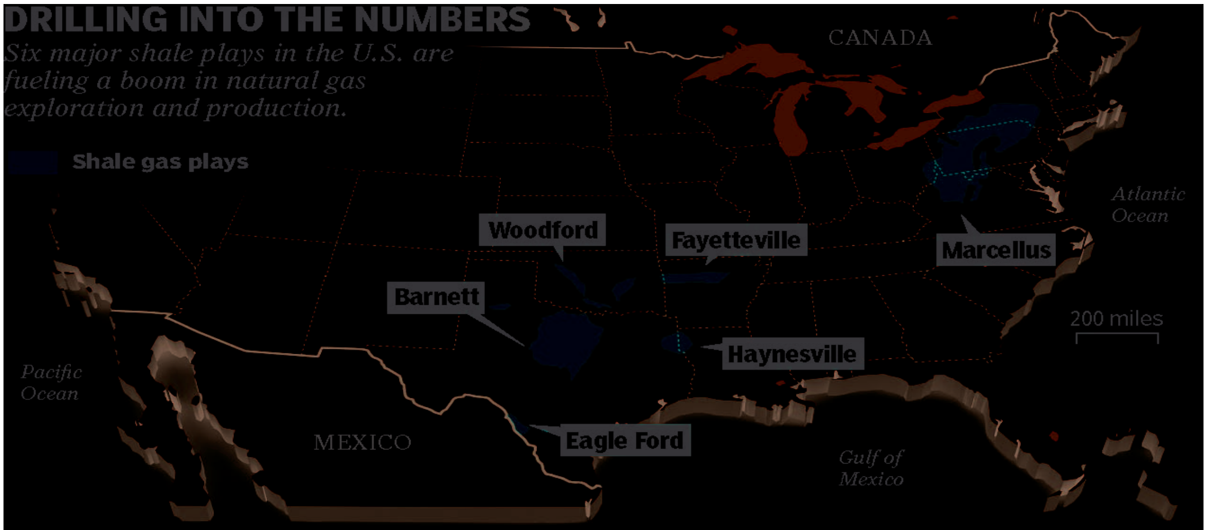
[5] Mitchell Energy began efforts to fracture the Barnett Shale as early as 1982. *See* Tom Fowler, *Stubborn in His Vision,* HOUSTON CHRON., November 15, 2009.

[6] For a discussion of basic principles on the nature of the lessee's interest, implied duties, and calculation of royalty in the Marcellus Shale states, see George A. Bibikos and Jeffrey C. King, *A Primer on Oil and Gas Law in the Marcellus Shale States*, 4 TEX. J. OF OIL, GAS AND ENERGY LAW 2, (2008-2009).

[7] Ross Smith Energy Group Ltd., *supra*, note 4.

[8] *See* Jeannie Stell, *Bakken Breakout*, Oil and Gas Investor, October 2009.

[9] Ross Smith Energy Group Ltd. See map on the following page.



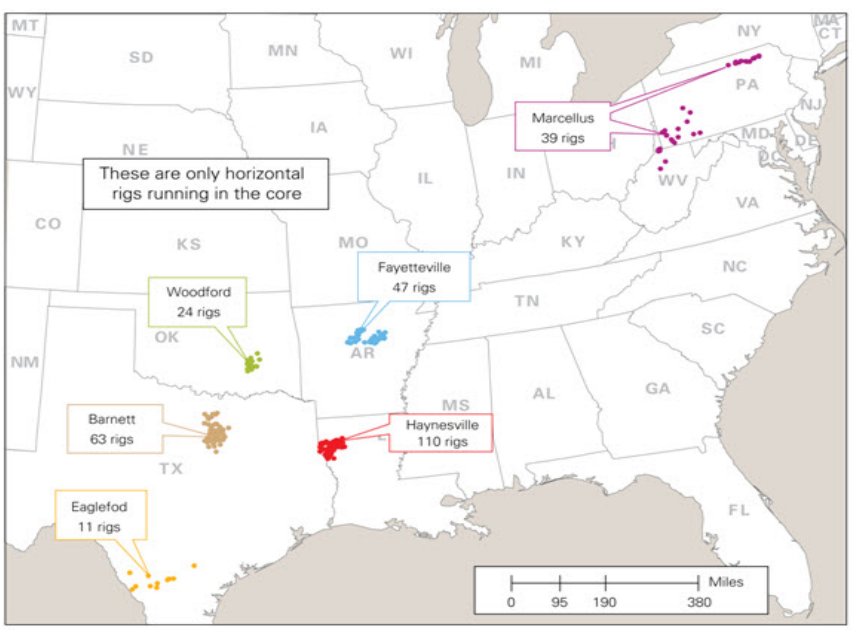
	Barnett	Woodford	Fayetteville	Marcellus	Haynesville	Eagle Ford
Core acres*	**2,000,000**	**480,000**	**400,000**	**5,000,000**	**750,000**	**500,000**
Locations drilled	5800	600	1000	100	150	20
Remaining recoverable gas (trillion cubic feet)	**33.9**	**10.6**	**7.8**	**199.2**	**42.1**	**19**
Median break even**	$5.18	$6.97	$4.69	$3.74	$4.49	$3.88

*Areas known to be productive; non-core areas are still being explored, or have proven less productive.

**Price per million British thermal units.

Source: Ross Smith Energy Group, Energy Information Administration

ALBERTO CUADRA : CHRONICLE



Source: Ross Smith Energy Group Ltd.

Many independent U.S. oil and gas companies are making large investments in shale plays. Notable examples include Chesapeake,[10] EOG, PetroHawk, Anadarko, XTO, EXCO, Range, Devon, Swift, Carrizo, Cabot, Plains, and many more. The growing importance of shale plays to the industry is also reflected in a number of large recent foreign investments in these areas. Examples include the 2008 transaction in which Statoil ASA of Norway acquired a 32.5% interest in Appalachian (Marcellus Shale) leases of Chesapeake for more than $3.3 billion, the August, 2009 acquisition by British company BG Group Plc of a 50% interest in various holdings of EXCO Resources Inc. in the Haynesville Shale for more than $1 billion, and the May, 2009 acquisition by Italian company Eni SpA of a 27.5% interest in core Barnett Shale acreage in Tarrant and Denton Counties, Texas, from Quicksilver Resources Inc., for $280 million.

This article will highlight many significant legal issues arising from the emergence of shale plays in the U.S. Topics include issues resulting from operations in urban areas (including relations with surface owners and government regulation), acquisition and divestiture issues (including confidentiality agreement issues, issues with undeveloped acreage, issues when existing production is involved, additional due diligence issues, and issues in a typical shale farmout), pipeline issues, and other, miscellaneous issues.[11]

OPERATIONS IN URBAN AREAS

Some emerging shale plays include densely populated urban areas, giving rise to legal issues that are not as frequently encountered in rural oil and gas development.[12] For example, the Barnett Shale is projected to have over one thousand wells within the city limits of Fort Worth, Texas.[13] An operator engaged in urban drilling should be aware of the unique legal issues affecting its relationship with surface owners, its interactions with all levels of government, and its potential exposure to liability caused by new technologies used in urban drilling.

Relations with Surface Owners. Urban surface owners are concerned with pollution, safety, and noise attributable to urban drilling. Many surface owners in an urban setting do not own the minerals under their land. As a result, the surface owner may gain nothing from oil and gas exploration and subsequent production, but may have to put up with many of the inconveniences of such operations.[14]

Generally in the U.S., the mineral estate is the dominant estate, but its dominance over the surface estate is not unfettered. In Texas, for example, the dominance of the mineral estate is limited by the accommodation doctrine, which provides

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10 In October, 2009, Chesapeake told analysts it expects to spend $4.7 billion on drilling in 2010, an estimated 40% more than in 2009 –mostly in the gas shale areas. Tom Fowler, *Next Generation Drilling Game Changer or Hype?*, HOUSTON CHRON., November 1, 2009.

11 Some of the issues discussed in this article (such as certain contractual and due diligence issues) will be familiar to many oil and gas practitioners, as they are not unique to shale plays. Because they are quite commonly encountered in shale plays, however, we believe that a review of such issues in the context of this article is appropriate.

12 For a detailed exploration of this issue, *see* Billie Ann Maxwell, *Texas Tug of War: A Survey of Urban Drilling and the Issues an Operator Will Face*, 4 TEX. J. OF OIL, GAS AND ENERGY LAW 337, 349 (2008-2009).

13 THE PERRYMAN GROUP, BOUNTY FROM BELOW: THE IMPACT OF DEVELOPING NATURAL GAS RESOURCES ASSOCIATED WITH THE BARNETT SHALE ON BUSINESS ACTIVITY IN FORT WORTH AND THE SURROUNDING 14-COUNTY AREA 23, (2007), a*vailable at:* http://www.bseec.org/images/PerrymanStudy.pdf.

14 *See* Maxwell, supra note 12, at 339.

that operators must accommodate surface owners if drilling operations would interfere with existing surface uses and a reasonable alternative on the property exists for the operator.[15] In addition, the Texas legislature has responded to concerns of surface owners by passing a law requiring the operator to notify the surface owner after the operator is granted a drilling permit to drill on the surface owner's land.[16] The increased sophistication of urban lessors may lead to more leases with surface use agreements and surface restoration clauses, altering the default Texas rule that the mineral lessee may utilize and cause reasonable surface damages without making restitution to the surface owner.

Some shale plays lie in states such as Colorado that seem to regard the surface and mineral estates as equals.[17] These areas will require a greater degree of surface accommodation and will possibly lead to more frequent and detailed surface agreements between operators and surface owners.

Where federal lands are involved, some concern has also been raised about attempts by the federal government to impose regulations on surface use and the 10th Amendment issues implicated by such attempts – particularly in Pennsylvania where the federally-owned Allegheny National Forest covers more than a half-million acres.[18]

Recently, some operators have been faced with litigation based on allegations of nuisance caused by noise and odors arising from urban drilling.[19]

Government Regulation of Urban Oil and Gas Operations. Oil and gas operations in Texas highlight the way operators must negotiate with different levels of government while operating urban wells. In Texas, state and local governments regulate oil and gas development. The Texas Railroad Commission oversees oil and gas matters for the state of Texas and is the state governmental authority that issues drilling permits.[20] The Railroad Commission also regulates important areas such as spacing and density of wells.[21]

Local governments, through their police powers, also regulate oil and gas exploration and production through zoning and city ordinances.[22] These ordinances may restrict surface locations to accommodate housing or require permits to drill within city limits.[23] Local governments are allowed to restrict operations under their police powers and such regulations are presumptively reasonable and valid, particularly if they do not completely ban operations.[24] Local governments have also passed city ordinances aimed at lowering

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[15] *See* Getty Oil Co. v. Jones, 470 S.W.2d 618, 622 (Tex. 1971); Sun Oil Co. v. Whitaker, 483 S.W.2d 808, 812 (Tex. 1972).

[16] TEX. NAT. RES. CODE ANN. § 91.753.

[17] *See* Gerrity Oil & Gas Corp. v. Magness, 946 P.2d 913, 927 n.8 (Colo. 1997).

[18] *See* Robert J. Keir, *The Battle for the ANF is Really a States Rights Issue*, *Landman 2*, September 2009, at 13.

[19] *See* Justiss v. Natural Gas Pipeline Co. of America., No. 65759 (Dist. Ct., Lamar County, Tex. Jan. 30, 2009).

[20] *See* 16 TEX. ADMIN. CODE § 3.5.

[21] *See id*.

[22] *See* Maxwell, *supra* note 12, at 349.

[23] Barnett Shale Energy Education Council, City Ordinances, *available at:* http://www.bseec.org/index.php/content/facts/city_ordinances.

[24] A Texas court recently ruled that a city owed a mineral rights owner more than $16,000,000 when a city ordinance completely banned drilling and thereby rendered the owner's mineral rights valueless. *Trail Enters. v. City of Houston*, 2008 Tex. App. LEXIS 2575 (Tex. App.—Waco 2008, pet. filed).

noise levels of producing wells which will affect operations in urban settings.[25]

In the area of transportation of natural gas, operators in the Barnett Shale deal with federal law (interstate pipelines), state law (intrastate pipelines), and local government regulations affecting the transportation of natural gas.[26] Whether local governments are preempted by state and federal law from regulating pipelines is undecided, but in one case involving such a challenge, the court found that only one small aspect of a city ordinance was preempted.[27]

Environmental aspects of shale exploration also give rise to regulation. For example, hydraulic fracturing uses large amounts of fresh water that returns to the surface as unusable waste water.[28] Some state and local officials are concerned about the amount of fresh water used in shale plays, as exemplified by Pennsylvania's[29] and New York's[30] recent consideration of new water use laws in response to the quantity of water used in the Marcellus Shale. Also, the proximity of shale plays to densely populated urban areas heightens environmental concerns about the effect of waste water on the safety of city water supplies. Such concerns prompted the CEO of Chesapeake Energy Corporation, the only leasehold owner in the New York City watershed, to announce recently that it will not drill within its 5000 acres of leasehold in the watershed, focusing instead on "more promising areas for gas development in the state."[31] Operators in the Barnett Shale are investigating a process to turn the waste water into safe,

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[25] *See* Barnett Shale Energy Education Council, *supra* note 23.

[26] *See* Maxwell, *supra* note 12, at 350.

[27] Tex. Midstream Gas Services v. City of Grand Prairie, 2008 U.S. Dist. LEXIS 95991 (N.D. Tex. 2008).

[28] *See* John A. Sullivan, *STW, GE Drilling Wastewater Venture Used in Shale Plays*, *OIL AND GAS INVESTOR.COM*, June 23, 2008, *available at: http://www.oilandgasinvestor.com/Headlines/WebJune/item3840.php.*

[29] In early 2009, the Pennsylvania Department of Environmental Protection ("DEP") revised its permitting procedures for High-TDS wastewater, with a particular focus on fracturing wastewater. DEP's new permitting strategy for treatment facilities seeks to prohibit new sources of High-TDS wastewater by January 1, 2011.

Specifically, DEP is proposing that by 2011, any new treatment facility that accepts fracturing wastewater should be able to reduce TDS levels in that wastewater to 500mg/L in order to obtain a permit to operate. In the interim, the agency will not issue permits for new sources of High-TDS wastewater unless the applicant proposes to install adequate treatment for TDS on or before January 1, 2011. Existing sources of High-TDS wastewater will be able to continue to operate under their existing permit limits and conditions until such time as they propose to expand or to increase their existing daily discharge load of any pollutant of concern. These new permitting standards could raise costs in the region for wastewater treatment.

[30] The New York Department of Environmental Conservation ("DEC") is in the process of reviewing its oil and gas regulatory program to address the "potential environmental impacts of large fluid volumes needed for gas well development by high-volume hydraulic fracturing." Topics being reviewed for potential inclusion in the DEC permitting process include: impacts of large volume water withdrawals on stream flow, public water supply, and fish and wildlife; as well as hydraulic fracturing fluid composition, storage and transportation, reuse potential, and treatment options.

[31] *See* Stephen Payne, *Chesapeake Reports It Will Not Drill Gas Wells Within New York City Watershed, OIL AND GAS INVESTOR.COM*, October 28, 2009, *available at: http://www.oilandgasinvestor.com/Headlines/2009/WebOctober/item47510.php.*

reusable water that can be returned to city aquifers.[32] Some operators are even finding ways to recycle water to eliminate discharge. Such water recycling has the additional benefit of improving production economics.[33]

SELECTED ACQUISITION AND DIVESTITURE ISSUES

The emergence of shale plays in the United States has sparked massive "land grabs" by companies seeking to obtain valuable leasehold acreage in areas that are prospective for production from shale formations. While much of that leasehold acreage has been acquired by the major operators of shale wells, substantial areas have been acquired, or were already held, by companies without the resources or expertise to develop the shale formations. In many cases, companies already held significant leasehold positions by virtue of production from established formations in lands overlapping the shale plays. These include producing formations lying both shallower and deeper than the shale plays.[34] As a result, there has been substantial acquisition and divestiture activity in these emerging resource areas. Some of the deals we have seen involve sales of all, or a substantial undivided part, of the seller's entire leasehold position in the area (sometimes reserving the subsurface depths in which the seller has existing production). However, more common since the onset of the financial crisis in late 2008 have been joint exploration agreements and farmouts, often where all, or a large part, of the consideration is the agreement by the buyer/farmee to carry the seller/farmor for the drilling costs (and sometimes the completion costs) in one or more expensive wells to develop the shale formation. The following sections of this article highlights certain issues that are common in these acquisitions and divestitures of shale assets.

Confidentiality Agreement Issues

The process of entering into an acquisition or divestiture of oil and gas assets almost always begins with an invitation to review confidential and proprietary information of the seller. Often, such confidential and proprietary information will be contained in a seller's physical data room or outlined in an offering memorandum. As a result, a Confidentiality Agreement is executed between the seller and the interested potential buyer/farmee, to provide for the protection of this information and to prevent disclosure to third parties by the potential buyer or its representatives.

There are certain provisions not generally found in a Confidentiality Agreement that a seller in an oil and gas transaction covering a shale play should consider adding, particularly where the seller (i) will continue in business subsequent to the closing of the transaction, (ii) intends to continue to operate in the same area, including operation and production of subsurface depths and horizons that are shallower or deeper than the shale play being sold and/or farmed out by seller, or (iii) desires to participate with the potential buyer in the development of the shale play.

Nonsolicitation. The seller may want to consider adding express restrictions regarding contact by the potential buyer or its representatives with employees of the seller. These restrictions are to prevent the potential buyer from hiring away the seller's employees. Specifically, such a provision should provide that for a specified period of time, the potential buyer agrees not to solicit for hire the seller's employees except for

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[32] *See* Sullivan, *supra* note 28.

[33] *See* Judy Maksoud, *Operators Reduce Water Discharge from Marcellus Drilling*, OIL AND GAS INVESTOR.COM, October 23, 2009, *available at: http://www.oilandgasinvestor.com/Headlines/2009/WebOctober/item47275.php.*

[34] *See, e.g.*, Peggy Williams, *Marcellus Shale*, OIL AND GAS INVESTOR, August 2009.

impersonal solicitations (such as advertisements to the general public).

Non-Compete Area. A seller that intends to continue operating in the area may want to include a non-compete provision which (i) sets forth a non-compete area, and (ii) prohibits the acquisition of any oil and gas leases or mineral interests within the non-compete area by the potential buyer for a specified period of time. Such non-compete areas usually encompass all of the land, and near-by surrounding areas, covered by the seller's oil and gas leases (and/or "proved up" as part of the seller's geological prospects). If the potential buyer is already an active player in such non-compete area, it is reasonable to describe such non-compete area as being limited to the specific lands covered by the seller's oil and gas leases. For obvious reasons, it is very important that a potential buyer which intends to acquire additional interests in such shale play keep very accurate and current track of the non-compete areas to which it is subject.

Standstill. In certain instances, a seller will wish to restrict the acquisition by the potential buyer of the seller's stock for some period of time (generally two to five years), in order to prevent the potential buyer from (i) acquiring a controlling interest in the seller and (ii) trading based on inside information.

Undeveloped Acreage Issues

Purchase Price Calculations. Unlike acquisitions of producing properties, where the purchase price is easily allocated among producing wells based on reserve reports and engineering, the purchase price in an acquisition of undeveloped acreage is most commonly allocated on a net mineral acre basis. Sometimes, hybrid values are used, with a higher value per net mineral acre placed in some areas than in others.

Remaining Primary Term. Buyers of undeveloped acreage will want to be sure that there is enough time left in the primary terms of the leases to accommodate their development plans without the need to obtain lease renewals in the face of competition for new leases. Since a due diligence of the seller's lease files may often not begin until a Purchase and Sale Agreement has been executed, the buyer should try to include insufficient remaining primary terms within the definition of "Title Defects" in the Purchase and Sale Agreement. One way to accomplish this is to include a provision allowing the buyer to elect to exclude leases having remaining primary terms of less than a specified number of months from the transaction, with a corresponding downward adjustment to the purchase price based on the number of net mineral acres covered by each lease so excluded.

Issues Involving Existing Production

Several legal and business issues should be considered by the parties when lands involved in a shale transaction are subject to existing production from other formations.

Definition of Retained Acreage. A threshold issue is whether the seller will be retaining the formation with the existing production. If so, the transaction documents should contain detailed descriptions of the retained and conveyed depths. To ensure certainty regarding the depths retained and conveyed, careful attention should be paid to terminology and precision of the description. If describing a geological formation, it is advisable to refer to the top or base of the formation and use terms like "stratigraphic equivalent" or "correlative equivalent." Certain terms like "total depth" and "perforated interval" are preferable to less certain terms like "productive" and "capable of producing." To provide the most certainty, the drafter should try to use a detailed reference to a stratigraphic interval in a specific well log, identifying details such as the type of log, date, well name, API number, etc.

Tax Implications of Overriding Royalty Reservations. In many cases, leases held by existing production may be decades old. In general, older leases provide for a lower royalty to the mineral owner than modern leases, resulting in a higher net revenue interest to the lessee. Consequently, sellers of high net revenue leases often negotiate to retain an overriding royalty interest, thereby providing additional consideration to the seller while still vesting the buyer with the net revenue interest he might expect under a more modern lease. Although the practice of retaining overriding royalty interests when divesting leases has been prevalent in the industry for ages, lawyers and land and business development professionals should be aware of certain potential adverse tax consequences that can result from this practice. Specifically, when an overriding royalty is retained in connection with the sale of an oil and gas lease, the transaction is treated as a lease, rather than a sale, for federal income tax purposes.[35] Consequences of this tax treatment include the following: (a) the sales proceeds are treated as an advance royalty, taxable as ordinary income, rather than capital gains (resulting in a higher tax rate except for certain corporations),[36] (b) the sales proceeds are offset by cost depletion, rather than the seller's entire basis in the transferred lease,[37] and (c) perhaps most significantly, the seller cannot use the sales proceeds in a tax-advantaged "like-kind exchange."[38] Under certain circumstances, however, there may be creative ways to structure the transaction so as to avoid it being treated as a lease under federal income tax rules.

Whether the Existing Production is Sufficient to Maintain the Leases. An important due diligence consideration for the buyer of leases that are beyond their primary terms, but which have been maintained by production ("HBP leases"), is whether the production has been sufficient to maintain the leases. While some custom lease forms contain specific guidelines for determining what constitutes "paying quantities," in the absence of such lease language, the determination of paying quantities is made under state law, so it is important to know the "paying quantities" analysis of the applicable state. Most traditional oil and gas producing states have well-established law on this issue. Texas, for example, has a two-part test for determining whether the production is in paying quantities. The first part of the test is objective: the production from a well is deemed to be in paying quantities if income from the well exceeds operating and marketing costs. The lessee is not required to show that it will ever recover its capital costs in drilling and completing the well. If the income exceeds the operating and marketing costs, then the analysis ends. Otherwise, the analysis proceeds to the second part of the test. The second part is subjective: the production is deemed to be in paying quantities if "under all the relevant circumstances a reasonable prudent operator would, for the purpose of making a profit and not merely for speculation, continue to operate a well in the manner in which the well in question was operated."[39]

In Louisiana, the "paying quantities" analysis involves a similar but slightly different two-part test: The first part requires a determination of the benefit to the lessor, examining the royalties paid (as compared to the bonus or rentals) and the development of the leased premises. If the

[35] *See* Palmer v. Bender*,* 287 U.S. 551 (1933).

[36] *See* Hogan v. Commissioner, 141 F.2d 92 (5th Cir. 1944); Cullen v. Commissioner, 118 F.2d 651 (5th Cir. 1941).

[37] Treas. Reg. § 1.612-3(a)(1).

[38] *See* Richard Wayne Crooks v. Commissioner*,* 92 T.C. 816 (1989).

[39] *See* Clifton v. Koontz*, 325 S.W.2d 684* (Tex. 1959).

lessor is enjoying adequate benefits (or "serious consideration") in the form of royalties or lease development, then the analysis ends with a finding that the lease has been maintained by production in paying quantities.[40] If it is determined that the lessor has not enjoyed "serious consideration," then it becomes necessary to proceed to the second part of the test. The second part is verbalized in the Louisiana Mineral Code, which provides as follows: "It is considered to be in paying quantities when production allocable to the total original right of the lessee to share in production under the lease is sufficient to induce a reasonably prudent operator to continue production in an effort to secure a return on his investment or to minimize any loss."[41]

In Oklahoma, "production in paying quantities" means oil and gas production sufficient to yield a profit, however small, over the lessee's operating expenses, even though drilling and completion costs may never be recovered.[42] Oklahoma only requires the lessee to discover paying quantities in a well, not to have actually marketed the production.[43] In Arkansas, the focus of the analysis is also on a well's ability to turn even a small profit, excluding the costs of drilling and equipping the well.[44]

As opposed to traditional oil and gas producing states, states that overlie the Marcellus Shale, such as Pennsylvania, New York, Ohio, and West Virginia, do not have well-established precedent covering this issue. Pennsylvania courts appear to use a purely subjective test.[45] After acknowledging that a well that yields a profit produces in "paying quantities," the Pennsylvania Supreme Court stated that "paying quantities" was to be interpreted by referring to the operator's good faith judgment.[46] A Pennsylvania court interpreted this to be a purely subjective test and rejected an argument that the state law also applies an objective test.[47] Ohio also focuses on the subjective determination of the lessee, while still considering the objective ability to yield a profit.[48] Ohio treats a good faith determination by the lessee that the well produces in "paying quantities" to be controlling against the plaintiff because "paying quantities" is to be construed from the lessee's viewpoint.[49]

New York allows lessees the "initial right" to determine if a well produces in "paying quantities," but does not grant lessees absolute authority to determine if "paying quantities" exist, as objective evidence is also considered.[50] Finally, West Virginia, in an early case, appeared to follow a purely subjective test based solely on the lessee's good faith determination of paying quantities.[51] However, more recently, the

[40] *See* Wood v. Axis Energy Corp., 04-1464 (La. App. 3 Cir. 04/06/05); 899 So. 2d 138; Vance v. Hurley, 41 So.2d 724 (La. 1949).
[41] LA. REV. STAT. § 31:124. For a thorough discussion of Louisiana law on this issue, see Ottinger, Patrick, S., *Production in "Paying Quantities" – A Fresh Look*, 65 La. L. Rev. 635 (2005).
[42] *See* Stewart v. Amerada Hess Corp., 604 P.2d 854 (Okla. 1980).
[43] *See* Pack v. Santa Fe Minerals, 869 P.2d 323 (Okla. 1994).
[44] *See* Ross Explorations, Inc. v. Freedom Energy, Inc., 8 S.W.3d 511 (Ark. 2000).
[45] *See* Young v. Forest Oil Co., 45 A. 121 (Pa. 1899); T.W. Phillips Gas & Oil Co. v. Jedlicka, 964 A.2d 13 (Pa Super. Ct., 2008). This interpretation of the state's law is being reviewed by the Pennsylvania Supreme Court.
[46] *Id.* at 122-23.
[47] *See* T.W. Phillips Gas & Oil Co., 964 A.2d at 18.
[48] *See* Blausey v. Stein, 1978 Ohio App. LEXIS 9031 (1978).
[49] *Id*.
[50] *See* Peckham v. Dunning, 125 N.Y.S.2d 895, 898-99 (1953).
[51] *See* Barbour, Stedman & Co. v. Tompkins, 81 W.Va. 116, 122 (1917); *but see,* Imperial Colliery Co. v. OXY USA, Inc., 912 F.2d 696, 703 (4th Cir. 1990).

Supreme Court of West Virginia upheld the requirement that a lease must be profitable to be maintained.[52]

Based on a recent Texas case, in some circumstances, a lessee may be able to avoid the termination of a lease that has had marginal production under a "quasi-estoppel" theory, based on the lessor's acceptance of royalties.[53] However, courts in two other gas shale states – Louisiana[54] and Pennsylvania,[55] have held that acceptance of royalties does not prevent a lessor from claiming that a lease has terminated.

Pugh Clauses and Related Provisions. In common usage, the term "Pugh clause" has almost become a generic term for a number of clauses that, over the decades, have been inserted into leases by savvy mineral owners and their counsel, and which may have caused the leases to expire insofar as they cover undeveloped lands or depths. Early Pugh clauses created only a vertical severance.[56] Eventually, many Pugh clauses were broadened to include both horizontal and vertical severances.[57] The buyer should examine such clauses carefully to be certain whether they effect only a vertical severance, or both a horizontal and vertical severance. Often, the answer to this question is not entirely clear, which has led to considerable litigation and the development of a limited body of case law. For example, in *Friedrich v. Amoco Production Company*, the Pugh clause in question provided that unit operations "will not maintain this lease in force as to the land not included in such unit."[58] The lessor argued that because the applicable unit was depth limited, the Pugh clause created both a vertical and horizontal severance. The Corpus Christi Court of Appeals disagreed, finding that the language in the Pugh clause was not specific enough to indicate an intention to create a horizontal severance.[59] The same result has been reached in a case where the Pugh clause provided that the lease would expire except as to "lands covered by this lease which are … included in a pooled unit…."[60]

In Oklahoma, Pugh clause language providing for lease continuation "as to the premises covered hereby and included in" a unit has been interpreted differently by state and federal courts. In *Rist v. Westhoma Oil Company*, the Oklahoma Supreme Court held that such language created only a

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[52] *See* Goodwin v. Wright, 255 S.E.2d 924 (W. Va. 1979).

[53] *See* Cambridge Prod., Inc. v. Geodyne Nominee Corp., 2009 Tex.App. LEXIS 4668 (Tex.App. – Amarillo 2009, no pet.).

[54] *See*, e.g., *Kyle v. Wadley*, 24 F. Supp. 884 (W.D. La. 1938); Louisiana Live Stock & Planting Co. v. Kendall, 98 So. 862 (1923).

[55] *See* Scilly v. Bramer, 85 A.2d 592 (Pa. 1952).

[56] The following is an example of a traditional, vertical Pugh clause: "Operations on or production from any well situated on lands included within a pooled unit embracing a portion of the leased premises and other lands not covered hereby shall serve to maintain this lease only as to that portion of the leased premises embraced in such unit."

[57] The following is an example of a Pugh clause containing both vertical and horizontal severances: "Operations on or production from any well situated on lands included within a pooled unit embracing a portion of the leased premises and other lands not covered hereby shall serve to maintain this lease only as to that portion of the leased premises embraced in such unit, and only from the surface to the base of the deepest producing formation in such unit."

[58] 698 S.W. 2d 748, 750 (Tex. App. – Corpus Christi 1985, writ ref'd n.r.e.).

[59] *Id*. at 754.

[60] *See* El Paso Production Oil & Gas v. Texas State Bank, 2007 WL 752209 (Tex. App. – San Antonio 2007, Memorandum Opinion).

vertical severance,[61] while in *Rogers v. Westhoma Oil Company*, the Tenth Circuit Court of Appeals held that the identical language created both a vertical and a horizontal severance.[62] The Tenth Circuit reasoned that the intent of the clause was "to prohibit lease continuation as to unproductive portions … whether such portions were the result of horizontal or vertical divisions."[63]

In assessing whether courts in shale states would follow this reasoning by the Tenth Circuit in *Rogers* (or in arguing whether they should), we suggest that one might look to the state law on implied covenants, where some states have, in fact, distinguished between horizontal and vertical development. A vertical Pugh clause will often apply in connection with the development of a known productive horizon, while a horizontal Pugh clause almost always operates in the context of a new formation lying above or below the productive horizon. Whereas an inference of an intent to force the development or release of acreage in a known productive horizon is consistent with the rationale for the implied covenant of reasonable development, an inference of an intent to force the exploration or release of new, unproven formations is more consistent with the rationale for the implied covenant of exploration. The latter covenant is considerably less recognized than the former. Thus, where the language of the Pugh clause is so unclear that the court turns to an interpretation of intent and the application of related oil and gas law principles or policies, we suggest that those courts in states that recognize a separate implied covenant of exploration would be more likely to construe an ambiguous Pugh clause to create both a vertical and horizontal severance than would courts in other states. In this regard, among shale states, only Arkansas[64] and Louisiana[65] clearly enforce an implied obligation to drill exploratory wells without proof that they will probably be profitable.[66] Texas includes the implied duty to explore within the implied covenant of reasonable development, meaning that the lessor must prove the existence of a reasonable expectation of profit from a new well in order to establish a breach – a burden which logic dictates will be heavier in connection with a new formation than with a known productive horizon.[67]

Some Pugh clauses provide that the lease shall continue only as to that "portion" of the leased premises included in the unit. Where the unit is depth limited, would a court find this language to be distinguishable from that in the *Friedrich* case? Certainly the specific language of each Pugh clause will be the key factor in assessing its effect, and must be compared with the specific language in the reported cases to determine whether any such cases are on point. Where it is not abundantly clear from the language of the Pugh clause whether it creates a horizontal severance, the buyer is faced with two issues: First, is it willing to incur the risk of drilling an expensive horizontal shale well with such uncertainty over the validity of its lease? Second, if the answer to the first question is "no," can it assert the uncertainty as a valid title defect under the purchase and sale agreement, in light of cases like *Friedrich*

[61] 385 P.2d 791 (Okl. 1963).
[62] 291 F.2d 726 (10th Cir. 1961).
[63] *Id*. at 731-32.

[64] *See* Skelly Oil Co. v. Scoggins, 231 Ark. 357, 329 S.W.2d 424 (1959); Reynolds v. Smith, 231 Ark. 566, 331 S.W.2d 112 (1960).
[65] *See*, e.g*., Sohio Petroleum Co. v. Miller*, 237 La. 1015, 112 So. 2d 695 (1959) (stating, at 112 So. 2d 699, "it is an implied condition that the lessee will test every part of the lease").
[66] *See* H. Williams and C. Meyers, *Oil and Gas Law*, Lexis Nexis 2008, at § 845.
[67] *See* Clifton v. Koontz, *supra* at note 39; Sun Oil Exploration & Production Co. v. Jackson, 783 S.W.2d 202 (Tex. 1990).

and *Rist*? Even armed with an acquisition title opinion calling for a lease amendment, it may face a fight with the seller over the validity of the asserted title defect.

There are also other, related provisions that are more commonly referred to as "Continuous Development," “Continuous Drilling,” or "Retained Acreage" provisions. These provisions provide for the lease to expire as to undeveloped lands (and sometimes depths) at some point in time. In such a case, the buyer should examine the drilling history to determine if the seller is still within the "continuous development" period and if so, how long before the next well is due to be commenced.

Additional Due Diligence Issues

Regardless of whether the leases being acquired are HBP leases or leases within their primary term, the buyer must watch out for the following issues.

Are there any restrictions on assignment? These can include express restrictions in the leases themselves, or, when the seller does not own all of the leasehold, restrictions in Operating Agreements such as preferential rights to purchase and “maintenance of uniform interest” (MUI) provisions. A typical MUI provision prevents a party from selling any interest in the Contract Area under the Operating Agreement unless such sale covers either the entire interest of the party in the Contract Area, or an equal undivided percent of the party’s present interest in the Contract Area. Thus, a conveyance of deep rights only is likely to violate the MUI provision. A seller should consider making such provisions a "Permitted Encumbrance" in the Purchase and Sale Agreement, provided they will not interfere with the sale and could not result in the unwinding of the contemplated transaction.

If the leases are primary term leases, how much time is remaining in the primary term? The buyer will want to ensure that there is enough time to commence sufficient operations to extend the primary term. The buyer may want to negotiate a provision in the Purchase and Sale Agreement giving it the right to exclude from the transaction any leases having a remaining primary term of less than some specified length (with a downward adjustment to the purchase price based on the number of net mineral acres covered by each lease so excluded).

Are there any pooling restrictions that could prevent the buyer from forming units of the size necessary for its development plans? Examples include a pooling provision requiring that all of the leased lands be included in any unit, or one prohibiting pooling except when the well is on other lands, or a clause requiring that the leased lands comprise no less than fifty percent or more of the unit.

Issues in a Typical Shale Farmout

As discussed above, the recent credit crunch has resulted in less outright sales for large cash considerations. To avoid the buyer having to come up with a large cash outlay upfront, many sellers and buyers have turned to farmout agreements.[68] These agreements usually call for a moderate initial consideration – for example, the closing payment may be limited to the farmee’s proportionate share of the farmor’s lease acquisition costs, or some portion thereof. The primary consideration, however, is the farmee’s agreement to “carry” the farmor’s share of the drilling costs in one or more test wells in the shale formation. In the negotiation of such a farmout agreement, the parties should address a number of issues. Examples are as follows:

- What is the upfront consideration?

[68] *See also,* Jeannie Stell*, A&D outlook: JVs, farm-outs and VPPs preferred over sales*, OIL AND GAS INVESTOR, October 2009.

- How long does the farmee have to commence operations on the test well before forfeiting its interest? This decision is often guided by lease expiration dates.
- On how many wells is the farmor to be carried?
- What requirements must be met for a well to satisfy the carry obligation – for example, must it be a horizontal well, and to what depth must it be drilled?
- When does the carry stop and the farmor begin bearing its share of the costs?
- How is the location of each test well determined? The farmor may want the test wells spread over multiple leases or units in order to maintain as much leasehold as possible.
- If the farmee fails to drill and forfeits its interest, does it also forfeit the initial consideration?
- If the farmee drills one or more but not all of the obligation wells, what acreage does it retain?
- Is the farmor entitled to any additional damages if the farmee fails to drill the obligation well (or wells)?
- If there is existing production, is it being reserved by the farmor?
- Is the farmor keeping an override?
- How are the costs of lease renewals and extensions shared?
- Will there by an Area of Mutual Interest (AMI) in which the parties agree to offer each other a proportionate share of any newly acquired leases? If so:
    - How is the AMI defined?
    - Does the AMI description satisfy the Statute of Frauds?[69]
- How are leases lying partially within and partially outside the AMI to be handled?
    - Will the farmor retain shallow depths in the AMI leases?
    - If the farmor is retaining shallow depths in the AMI leases, how are the lease bonus costs to be allocated between the shallow and deep rights?
    - What is the term of the AMI?
    - Does the term of the AMI create any Rule Against Perpetuities issues?
    - If there is an AMI, what if the farmee already owns existing leases within the AMI? Must the farmee offer to the farmor its proportionate share of those leases?
    - Does the AMI create any antitrust concerns?
- What form of operating agreement will govern joint operations? Will there be separate operating agreements for each unit? What are the terms of the operating agreement?
- Is a tax partnership needed to minimize the parties' respective tax liabilities?
- If the farmor is retaining the shallow rights, should it ask for a Logging Agreement? Such an agreement provides for the Operator to use reasonable efforts to run well logs across certain designated shallow intervals in wells drilled upon the lands. It may also provide that any such logging shall be conducted as

[69] *See*, e.g., Westland Oil Dev. Corp. v. Gulf Oil Corp., 637 S.W.2d 903 (Tex. 1982).

a prudent operator using commercially reasonable standards. It may address other specific concerns, such as requiring the Operator to use its best efforts to contain the water loss in those formations that are sensitive to water loss.

- Who is responsible for payment for seismic data? Will the data be jointly owned? If the data will be proprietary, the party who is not responsible for payment may wish to have the right to acquire a license to the data from the party who pays. The parties may wish to attach the form of license as an exhibit to the Farmout Agreement. If the data is spec data, the acquiring party should provide the other party with access to the data to the extent permitted by the seismic license. It should also cooperate in the acquisition of an additional license by the non-acquiring party.

PIPELINE ISSUES

Pipeline issues are important in the shale plays – particularly as to capacity. In addition, certain natural gas pipelines, even if they are intrastate lines such as may be found in many of the shale plays, are required to make certain filings with the Federal Energy Regulatory Commission (FERC) each year.

Capacity Constraints. The enormous promise of large amounts of natural gas production from the shale plays can only be realized if there is adequate pipeline capacity to transport such production to consumers. This is a problem today in the major shale plays including the Barnett and particularly the Marcellus shale. Unlike established production areas, there may be no or a limited number of pipeline facilities serving those areas. The impact on producers, marketers, and royalty owners are the alternatives of paying premium prices for limited transportation capacity, or shutting in production. Lawyers who specialize in this area can craft solutions, such as organizing greenfield pipelines, or can negotiate commercially acceptable transportation agreements based on their knowledge of tariffs, regulatory requirements, and industry practices.

Form 552. By Order issued on December 26, 2007,[70] the FERC modified its regulations applicable to market participants that engage in wholesale (buy and sell) physical transactions of natural gas in excess of 2,200,000 MMBtus annually to provide summary information to the FERC on or before May 1 for the preceding calendar year (the deadline for 2008 was extended to July 1) on Form 552.[71] Market participants include non-jurisdictional entities such as intrastate pipelines, marketers, end-users, and independent power producers. The purpose of Form 552 is to implement the transparency provisions of a new section of the Natural Gas Act.[72] The Form also requires reporting of volumes associated with transactions that utilize, contribute to, or could contribute to price indices. The FERC has the authority to impose, *inter alia,* fines of $1 million/day per transaction for failure to comply with its regulations. Obviously, any pipeline, including those in the shale plays, should be aware of and comply with this regulation.

OTHER, MISCELLANEOUS ISSUES

Pooling. Subdivision of land has made it necessary to pool tracts to create pooled units. Many states that contain shale plays,

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[70] 121 F.E.R.C. ¶ 61,295 (1997), *available at* http://www.ferc.gov/whats-new/comm-meet/2007/122007/G-1.pdf.

[71] F.E.R.C. Form No. 552, *available at* http://www.ferc.gov/docs-filing/forms/form-552/form-552.pdf.

[72] *See*, 121 F.E.R.C. ¶ 61,295 (1997), *available at* http://www.ferc.gov/whats-new/comm-meet/2007/122007/G-1.pdf.

such as Louisiana,[73] Colorado,[74] and Pennsylvania,[75] allow the state to pool tracts into compulsory spacing units even if opposed by one or more mineral owners. In Texas, the Railroad Commission, under the Texas Mineral Interest Pooling Act,[76] can force pool separately owned interests overlying a common reservoir to create a pooled unit if a mineral interest owner makes a fair and reasonable offer to pool and the lessor rejects the offer. The Texas Mineral Interest Pooling Act was recently used to force pool lands in Fort Worth overlying the Barnett Shale.[77] Most pooled units in Texas, however, are formed voluntarily under the pooling clause found in most oil and gas leases.

Surface Damages. Surface damages litigation differs greatly in Texas and Louisiana. Texas precedent requires surface restoration awards to be reasonably related to a property's value.[78] In Louisiana, a 2003 state Supreme Court decision established that damages for breach of a contractual standard of restoration do not have to be related to, and in fact can grossly exceed, the property's market value, and moreover, the plaintiff does not even have to use the awarded damages to actually restore the surface.[79]

Hydraulic Fracturing. The hydraulic fracturing required to effectively and efficiently produce oil and gas from shale formations may lead to claims of subsurface trespass. The Supreme Court of Texas held in 2008 that a neighboring unleased mineral owner does not have a cause of action for subsurface trespass caused by hydraulic fracturing because of the rule of capture, which provides that there is no liability for draining a neighbor's oil and gas.[80] The court did not directly address whether fractures that cross lease boundaries constitute a trespass. Thus, Texas has eliminated or severely restricted a cause of action for subsurface trespass from hydraulic fracturing. Other emerging resource states considering this issue may look to this Texas decision for guidance.

Proprietary Technology. One characteristic of shale plays is the continued development of more sophisticated horizontal drilling, hydraulic fracturing, and completion techniques. Where the operator has technology which is patented, patentable, proprietary, or subject to restrictions as to disclosure under agreements with third parties, the operator may need to restrict the disclosure of such technology to other parties to the operating agreement. In that case, it should be specified in the operating agreement that certain technology is confidential and proprietary to the operator and will not be revealed to the other parties to the operating agreement.

Claims of Unconscionability. Initial leases granted by inexperienced lessors are sometimes granted on terms that overwhelmingly favor the oil and gas operator.[81] Lessors may seek renegotiation or

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[73] LA. REV. STAT. ANN. § 30-10.
[74] COLO. REV. STAT. § 34-6-116.
[75] 58 PA. STAT. ANN. § 408.
[76] TEX. NAT. RES. CODE ANN. § 102.001 *et seq*.
[77] Tex. R.R. Comm'n, *Application of Finley Resources, Inc. for the Formation of a Unit Pursuant to the Mineral Interest Pooling Act (Barnett Shale) Field, Tarrant County, Texas*, Docket No. 09-0252373 (Aug. 25, 2008) (final order granting application).
[78] *See* Aaron G. Carlson, *A Comparison of Select Subjects of Louisiana & Texas Oil and Gas Law*, 35 Annual Ernest E. Smith Oil, Gas & Mineral Law Inst. 9, at 10 (Univ. of Tex. Sch. Of Law Continuing Legal Educ. 2008).
[79] *See* Corbello v. Iowa Prod. *Co*., 850 So.2d 686 (La. 2003).
[80] *See* Coastal Oil & Gas Corp. v. Garza Energy Trust, 268 S.W.3d 1 (Tex. 2008).
[81] See, J. Zach Burt, *Playing the "Wild Card" in the High-Stakes Game of Urban Drilling: Unconscionability in the Early Barnett Shale Gas Leases*, 15 TEX. WESLEYAN L. REV. 1 (2008).

termination of such leases alleging unconscionability, which allows courts to refuse to enforce such contracts because they unreasonably favor one side or preclude meaningful choice by the other party.[82] However, the doctrine of unconscionability is not intended to protect against bad deals. Courts will consider the leases at the time they were created, not in hindsight,[83] and the contracts must shock the court before courts will invalidate them.[84] Although it is unclear if such claims would be successful, operators should be aware of the possibility of a claim of unconscionability.

Naturally Occurring Radioactive Material (NORM). Some shale formations contain NORM that can be brought to the surface through oil or gas well operations. The Barnett Shale and the Marcellus Shale contain NORM.[85] In some homes underlain by the Marcellus Shale, the level of radioactive substances was double the EPA's threshold level to take action.[86] Twenty-five oil and gas sites overlying the Barnett Shale were decontaminated between 2005 and 2007.[87] Operators in these areas need to be aware of and comply with applicable environmental laws in disposing of NORM.

CONCLUSION

This article highlights many transactional, operational, and regulatory issues surrounding operations in the various shale plays currently active in the United States. By identifying and planning for these issues in advance, they can be more easily, efficiently, and successfully managed.

[82] See BLACK'S LAW DICTIONARY 642 (New Pocket ed. 1996).
[83] *See* El Paso Natural Gas Co. v. Minco Oil & Gas Co., 964 S.W.2d 54, 61 (Tex. App.-Amarillo 1997) rev'd on other grounds, 8 S.W.3d 309 (Tex. 1999).
[84] *See* Ski River Dev., Inc. v. McCalla, 167 S.W.3d 121, 136 (Tex. App.-Waco 2005, no pet.).
[85] *See* Lisa Sumi, *Shale Gas: Focus on the Marcellus Shale*, 14 (2008), *available at* http://www.earthworksaction.org/pubs/OGAPMarcellusShaleReport-6-12-08.pdf.
[86] *Id*. at 15.
[87] *See* Peggy Heinkel-Wolfe, *Poisoning Property*, DENTON RECORD-CHRONICLE, November 11, 2007, *available at* http://www.dentonrc.com/sharedcontent/dws/drc/localnews/stories/DRC_11-12_NORM2.200398aa0.html.