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THE IMPACT OF SHALE DEVELOPMENT ON INTERNATIONAL AND DOMESTIC OIL AND GAS CONTRACTS

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I. INTRODUCTION

Shale development has taken off in North America, driven by a combination of technology, new recovery strategies and private mineral rights ownership. Internationally, shale development has to date been slow. There are many reasons for this, ranging from geology, lack of midstream infrastructure, and the lack of access to the sorts of technologies required to develop shale, most notably sophisticated horizontal drilling capabilities. But no impediment has been as big as that set forth by public mineral rights ownership. Sovereign ownership of minerals has drained the political will from the population to support shale development, notwithstanding the benefits that a long-term source of low cost natural gas may provide, in the face of environmental risk associated with hydraulic fracturing. Simply, the environmental risk and inconvenience of development are not borne by the same people who most directly benefit economically from the development of shale.

Shale development is not environmentally benign. It has to be carefully regulated to reduce the likelihood of spills associated with the handling and disposal of toxic chemicals and wastewater. Further, drilling is unsightly and inconvenient. Roads suffer from overuse by heavy trucks, and communities in and around drilling sites struggle with traffic congestion caused by trucks and commuting itinerant workers. In North America, these problems are tolerated because those who suffer

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disproportionately for this inconvenience – the local landowners – are also those with the most to gain from the development, through the licensing of their mineral rights. In jurisdictions where the sovereign owns mineral rights, little value is received back for this inconvenience, and as a result there is no incentive for locals to support shale development.

This is not a new problem to oil and gas. We have seen in the past where, in sovereign-owned mineral jurisdictions, civil unrest has developed among the locals due to insufficient local value derived from oil and gas development. For much of the world where sovereign mineral rights ownership exists, oil and gas has been developed in places where few people live, such as in the Saudi Arabian desert, in Lake Maracaibo, in Siberia or in the North Sea. This has reduced the potential for conflict. But in instances where onshore production has occurred in heavily populated areas, such as in Nigeria, civil unrest has on occasion resulted.

Shale, at least to date, has been a wholly onshore play. What has created the most controversy in America is that, for the first time, we are seeing oil and gas development in regions that are heavily populated, such as Pennsylvania and Ohio. Most of the environmental problems associated with shale development are in fact traditional oil and gas problems, such as the injection of contaminated produced water into salt water disposal wells (believed to set off small earthquakes under certain circumstances) or failed well casing allowing methane to migrate into the ground water. But while Texas, Louisiana and the western states have been dealing with these issues for years, they are new to Pennsylvania and Ohio, and have created controversy as a result. Yet shale development has forged ahead in these states primarily because local landowners have been paid handsomely for leasing their mineral rights. This incentive does not exist in places like Poland, France, England or the Ukraine.²

Eventually, however, shale development will come to these countries, because the value proposition will be too compelling. Ohio and Pennsylvania are beginning to enjoy a manufacturing rebirth due to long term low natural gas prices driven by the Marcellus and Utica shale development. Natural gas is selling for a fraction of what it sells for in Europe, and for an even smaller fraction compared to Asia, providing a major competitive advantage for American manufacturers, with natural gas used both as a fuel and as a chemical feedstock. Eventually European, Asian and other countries will have to respond to this. They will not sit on a source of cheap

² One environmental concern that is unique to shale development deals with the stress put on aquifers. The hydraulic fracturing process consumes a relatively large volume of freshwater, up to 5 or 7 million gallons per well. Since 2011, over half of hydraulic fracturing has occurred in areas listed as suffering draught conditions. See M. Freyman, “*Hydraulic Fracturing & Water Stress: Water Demand by the Numbers*,” Ceres Report at 6 (February 2014), found at: <https://www.ceres.org/resources/reports/hydraulic-fracturing-water-stress-water-demand-by-the-numbers>. In Ohio and Pennsylvania, mostly surface water is used, and groundwater stress has not been a problem. See e.g. A. Mitchell, M. Small, and E. Casman, “Surface Water Withdrawals for Marcellus Shale Gas Development: Performance of Alternative Regulatory Approaches in the Upper Ohio River Basin,” 47 *Environ. Sci. Technol.* 12669, 12670 (2013) (noting that more than 85% of the Marcellus Shale industry’s water comes from surface waters).

energy indefinitely. As fears over environmental problems diminish, shale development will come to the rest of the world.

Ukraine will likely be one of the first European countries to develop shale. Ukraine has a vast organic shale deposit that can be economically developed. Like Ohio and Pennsylvania, Ukraine is heavily populated, and the environmental and logistical problems will be troubling. Unlike Ohio and Pennsylvania, however, Ukraine does not have private mineral rights ownership. As a result, popular local support for shale development may be hard to sustain. But with the threat of Gazprom curtailing natural gas supplies for political reasons, Ukraine's population understands better than most the stakes of developing its own natural gas supply. A nascent oil and gas upstream service industry will also be welcome in Ukraine, as will the promise of sustained low cost natural gas supplies.

As shale is developed in Ukraine and in other jurisdictions, traditional oil and gas contracting will be affected, as it has been already in North America. The oil and gas industry has, through 100 plus years of activity, developed many customs, especially with regard to how it goes about entering into oil and gas transactions. These customs are best reflected in form contracts that are commonly in use, especially those promulgated by trade associations such as the American Association of Petroleum Landmen and the Association of International Petroleum Negotiators.³ But the customs do more than establish protocols for contracting – they often time set the standard for what parties find as “fair” when negotiating a contract.

Negotiations for transactions in unconventional oil and gas development can, as a result, be problematic. Established customs may not fit new circumstances. Is it fair, for instance, for a working interest owner in a shale play to “non-consent” a new well, and then back in after a penalty is paid? Under conventional oil and gas joint operating agreements, this would be allowed. But shale drilling is a relatively high cost, low risk venture – unlike like conventional operations. It might be that non-consenting a well should lead to forfeiture of all valued derived therefrom.

The following discussion surveys some of the traditional contracts used in domestic and international oil and gas development, and considers what we might expect in the way of changes to oil and gas contracting as a result of unconventional oil and gas development.

II. THE EFFECTS OF SHALE DEVELOPMENT ON GRANTING INSTRUMENTS.

“Granting” instruments are defined as those documents that create, by “grant” or “reservation,” a mineral interest.⁴ That is, the landowner may, by an instrument usually described as a mineral deed, create a mineral interest in the name of another person or entity. Alternatively, the landowner may convey the land, but retain for himself a mineral interest. That mineral interest normally includes development and executive rights, i.e., the right to drill for and produce hydrocarbons and the right to execute a hydrocarbon lease.⁵ Oil and gas lawyers have come to use the term

³ Forms can be obtained from their respective websites, <https://www.aipn.org/mcvisitors.aspx> and <http://www.landman.org/industry-resources/forms-contracts>.

⁴ Williams & Meyers, *Oil and Gas Law*, at § 202.2 (LexisNexis 2013).

⁵ *Id.*

“granting instrument” to define broadly contracts between mineral rights owners and operators that enable oil and gas development.

In the international arena, mineral interests in the conventional sense may not be granted. In many jurisdictions one may obtain the right to drill and produce, but not own the hydrocarbons so produced – at least not at the wellhead. As a result, the classification of the different types of agreements between host countries and international oil and gas companies does not easily fall into the same analytical framework normally understood in the U.S. as “granting instruments.” Nonetheless, those contracts providing private rights to explore and produce oil and gas are typically discussed under this heading. Some commentators have disregarded the term altogether, and simply call them “host country contracts.”⁶

There are three basic arrangements for development of hydrocarbons between host countries and multinational oil companies: (1) the concession, (2) the production sharing agreement (“PSA”), and (3) the service agreement.⁷ Each of these types of agreements typically provides for different levels of control granted to the multinational corporation and for different compensation arrangements and different levels of state oil company involvement. Often agreements between a host country and a multinational oil company will be a hybrid of these various types of agreements. The various commentators on international oil and gas contracts seem to be continually redefining the categories of granting instruments, such that some commentators simply call them “host country” contracts.⁸

Multinational oil companies receive exploration and development rights through separate negotiation, competitive bidding, and sometimes a mixture of both. In the United States, the separate negotiation process is used for private lands, while competitive bidding is used for public lands. In other countries, especially those controlled by strong dictatorial leaders, development rights were historically granted to multinational companies through private agreements. Today, most countries use competitive bidding.

Few sovereigns owning mineral rights use either system in pure form. In bidding systems, the winner bidder still has to privately negotiate the details of the contract granting rights to explore. Many countries now use competitive bidding with model contracts and standardized terms to reduce the amount of uncertainty and negotiation after the bidding procedure. Some countries have delegated the power to grant mineral rights to state-owned national oil companies.⁹

⁶ See, e.g. A. Derman, *A Primer on Oil and Gas Host Government Contracts*, Landman Magazine, Sept-Oct. 1997, 15-27.[hereinafter Derman].

⁷ *Id.* There are also joint ventures between host nations and multi-national oil companies, most notably Saudi Aramco. These sorts of agreements have been called “participation agreements.” See e.g. K. Blinn, *et al.*, *International Petroleum Exploration & Exploitation Agreements*, at 99 (Barrows 1986).

⁸ *Id.*

⁹ Although initially many countries created state oil companies to perform the tasks of the development of the country's reserves, relatively few countries have had the financial wherewithal or technical expertise to rely entirely upon self-development. As a result, multinational corporations are sought for purposes of raising capital and providing technology.

A. Concessions and Leases.

Early arrangements to develop mineral reserves were in the form of concessions that tended to be one-sided in favor of the multinational corporation. Characteristics of such agreements were: (1) a grant of rights to mineral development over large amount acreage, (2) for a relatively long period of time, (3) providing to the multinational corporation nearly exclusive control over the schedule and manner in which mineral reserves were developed, and (4) reserving to the mineral rights owner or the sovereign very few rights in the way of control, other than to receive a royalty payment based upon the disposition of the hydrocarbons.¹⁰

In the United States, disputes arose from these one-sided agreements either due to non-development of the lease or to the sales of hydrocarbons at below-market value. The first problem stemmed from oil companies holding large leaseholds with minimal production for long periods of time, allowing other portions of the lease to languish. The second problem developed from oil companies selling hydrocarbons to subsidiaries or by entering into long term, fixed price contracts at below-market prices. Both tended to depress royalties.

Courts in the various American states eventually dealt with these problems by reading into leases covenants that ran in favor of the royalty owners requiring that the producing company prudently administer the property.¹¹ Eventually, lessors became sophisticated enough to insist upon the inclusion of development clauses and market value provisions in their lease language.

The first Middle Eastern concessions were similar to the oil and gas leases granted in the United States in the early part of this century. The leases tended to cover very large areas and were capable of being held indefinitely through small annual rentals or minimal production. Needless to say, egregious imbalances began to occur both in America and in the Middle East. The Middle Eastern sovereigns generally did not follow Mexico's example of 1938 of expropriating all of the development rights from the multinational corporations. Instead, they sought renegotiation as a means of gaining fairness. The concessions remained immensely profitable for Multinational oil companies even with the reduced interest.

Despite this history, many countries continue to use the concession agreement, especially those that do not have national oil companies or well established oil and gas provinces. Modern concession agreements address the traditional problem areas: the long periods of time and vast areas committed, the little control sovereigns have

¹⁰ Most countries also assess a tax of some form on the production of hydrocarbons under mineral leases. In the United States, for instance, producing companies pay a severance tax to the states from which the production is extracted. While taxation will not necessarily appear on any of the granting instruments, they are nonetheless a significant economic consideration for the multinational corporation that obtains a concession. This has led some experts to refer to concessions as "royalty and tax" agreements. However taxes are not unique to concessions agreements; the blurring of the distinction between royalty and taxes doubtless has more to do with the United States foreign income tax credit than with the similarity between taxes and royalties. American oil companies can directly offset foreign royalties from their American taxes by classifying royalties as an income taxes. See e.g. S. Hargreaves, *Fighting Over Big Oil's \$4 Billion a Year Windfall*, CNNMoney, February 11, 2011, available at http://money.cnn.com/2011/02/04/news/economy/oil_subsidies_tax_breaks/index.htm.

¹¹ See Williams & Meyers, *supra* note 4, § 801 et seq. for a detailed discussion of the law of implied covenants.

over operations, and the problems associated royalties. The period and size of concessions are smaller than they used to be, and royalties may be tied to international posted prices. Concessions also may contain relinquishment clauses and express obligations to enter into development programs. The intent is to force the multinational corporations to discover and develop commercially marketable reserves within the period stipulated or, failing this, to release the area back to the government.

In the United States, shale has not yet created significant change in leasing strategies. When landowners have leverage, they use traditional methods of negotiating value: improved bonus and royalty provisions, together with the requirement of a “Pugh clause” – a requirement to either drill or release acreage. But the fundamental form of the lease has been largely unchanged. The biggest nontraditional change seen so far relates to requirements found in some leases that the producers not only return the surface to its original state upon decommissioning, but also that the producer administer pre and post drilling water testing to establish that no contaminants have entered the local aquifer. This requirement stems from the fear that toxic fluids used to fracture shale might migrate into the water table.

But that does not mean more changes will not be forthcoming. One of the more intriguing characteristics of shale development is its relatively low risk of geologic failure. An important reason why countries began to use the PSA in lieu of lease agreements was because the risk of exploration was often relatively low. Sovereigns saw no reason to turn over the majority of production to foreign operators when the reserves were relatively certain to exist. This led to two conditions that are commonly required today in PSA agreements: (1) sharing of production and (2) sharing of data and expertise. The first provision was designed to put the national oil company on equal footing with the operator. The second was designed to develop internal expertise within the national oil company.

Similar conditions exist for shale development in the United States. First, the risk is relatively low: unlike for conventional oil and gas, the principal risk for drilling in shale is mechanical failure, not a dry hole.¹² Second, American landowners often aggregate their holdings to create more leverage with producers, some times creating “land companies.” Inevitably some of these groups will begin to think like the national oil companies – developing strategies for keeping more production, accessing information and skills, and ultimately, to conduct their own operations.

Many small oil companies are also in a position similar to that of national oil companies – they may be holding large leaseholds by production from shallow reservoirs. Some of these companies are subleasing the deep rights to bigger companies with the capital and expertise to drill shale. Commonly, the small company maintains an “overriding royalty interest” (no risk) that is convertible to a “working interest” (risk bearing) after payout. The reason to convert to a royalty interest to a working interest is to thereby access all the information that the operator

¹² See J. Kemp, “Why Shale Plays Really Are Different, *Reuters* (October 16, 2013), <http://www.reuters.com/article/2013/10/16/shale-idUSL6N0I61L120131016>, for an interesting discussion about how shale development more resembles manufacturing than traditional oil and gas exploitation. The new paradigm emphasizes reducing costs and increasing production, rather than improving the discovery success rate of drilling.

has about operations, through a “joint operating agreement.” On the other hand, the reason to avoid having a working interest is to avoid the liability associated with well failure or environmental problems. As the risk of failure goes down, and the need for information goes up, the PSA may be the inevitable result of an improving value proposition associated with shale. Under the PSA, the mineral rights owner is typically carried through drilling operations at no risk, but once payout is reached, a working interest is acquired in the production.

Another reason why we may see shale landowners look to share production rather than royalties: increasingly, the highest value generated from shale development is from the production of natural gas liquids. Shale development has pushed the price of natural gas so low in America, that it has become in some instances a byproduct of natural gas liquid production, just as natural gas once was in America for oil production.¹³ The further production moves from the wellhead, the more vulnerable lessors will be to losing value from their royalty share. This is because the operator typically has exclusive control over all information related to downstream operations, and may or may not be acting in the best interest of the royalty owners, or otherwise sharing all the value derived from processing natural gas. Working interest owners are more likely to have access to operator information on mid and downstream markets.

B. Production Sharing Agreements.

On the international side, PSAs will also see changes as a result of shale development. For instance, shale is drilled more like offshore oil and gas – with a “pad” replacing the platform – where 6 to 8 wells are drilled from one centralized location. The total surface footprint may be 5 acres, but the total reservoir drainage will typically be 1000 acres or more. Even so, this is small by typical PSA standards. PSAs may have to evolve to accommodate the exigencies of shale development, including midstream infrastructure development.

PSAs first appeared in the 1960s in response to the desire producing nations had to develop their own oil and gas resources. Under a PSA, the country grants the operator a contractual right to explore in a specified area in exchange for the operator's opportunity to recover its costs from production, plus a share in production thereafter. In return, the country contributes the acreage and receives a share of production. The operator receives no guaranteed profit in the event the acreage is unproductive. These clauses were initially developed in Indonesia. Indonesian form agreements have since been widely circulated as models for other countries. In the PSA, the operator is not a mineral interest grantee, but rather a contractor. It obtains the exclusive right to conduct exploration and development operations, and to dispose of its share of the production. The operator becomes the

¹³ Natural gas produced as a byproduct of oil production, also known as “casinghead gas” or “associated gas,” was once considered a nuisance in America, when billions of cubic feet of gas was flared. Today natural gas is still flared when no market exists for it. In Nigeria, for instance, flares about 1.9 billion standard cubic feet per day. See D. Howden, “Visible from Space, Deadly on Earth: the Gas Flares of Nigeria,” *The Independent* (November 5, 2013), <http://www.independent.co.uk/news/world/africa/visible-from-space-deadly-on-earth-the-gas-flares-of-nigeria-1955108.html>

owner of the production at the point where it is sold rather than at the point of capture, subject to any duties to supply the local market. In a concession, by contrast, the grantee normally owns the production at the wellhead.

In PSAs the operator will generally have a specific work obligation to explore and develop property, and a financial commitment to expend specific amounts. This may not differ significantly from modern concessions, although the pure concessions, like those used by the Minerals Management Services for the United States, will not have such duties. Control of operations is nominally in the government or national oil company, but in practice the contractor will have considerable discretion to conduct its work program, subject to approval by the state.¹⁴ Some experts consider this control to be troublesome, leading to a frustrating waste of time and resources.¹⁵ In addition, under a PSA, the contractor will own the production facilities until such time they are conveyed to the government after the recovery of costs. In a concession, on the other hand, the grantee will own the assets at least until termination of production, and in the U.S., until such time that the assets are abandoned.

Generally the PSA will have two periods defined for performance: an exploratory/development phase, and a production phase. The length of the exploratory phase will depend upon the difficulty in development and the size of the contract area, as well as the need to attract additional capital. Shale development, however, is likely to require some special considerations for both phases.

A primary goal of the PSA is to attract a multinational corporation that is willing to risk capital and to use its technological expertise to develop a country's reserves for operation by the sovereign. Importantly, unlike for operations under a joint operating agreement, the operator bears all the risk of a commercial failure. Typically in a PSA, the sovereign has a state oil company that is expected to learn from the multinational so that reserves can eventually be turned over to that company for operation. The critical provisions of the PSA will be found in the areas of (a) management, (b) investment and work commitments, and (c) clauses defining the government and operator take.¹⁶

For host nations seeking to exploit shale using production sharing agreements, a key issue will be the size of the contract area. Shale resources, unlike traditional oil

¹⁴ See, e.g., E. Smith, et al., *International Petroleum Transactions* (Rocky Mountain Mineral Law Foundation 1993) at 337-38; Blinn, et al., *International Petroleum Exploration & Exploitation Agreements* (Barrows 1986) at 78.

¹⁵ See Derman, *supra*, at 16-17.

¹⁶ Of particular importance in the government take clause is the formula setting forth how quickly the multinational corporation recovers its investment capital. In the 1977 Model Production Sharing Contract between Pertamina and private companies, the foreign company could recover as much as 40% of the annual output of hydrocarbons to meet preproduction and production costs. After production costs were met, the balance of production was a split of 65% to the state and 35% to the foreign corporation. Under this formula, foreign companies were able to recover their invested capital costs in Indonesia during the 1970's in 3-5 years. See E. Smith, et al., *International Petroleum Transactions*, at 342 (Rocky Mountain Mineral Law Foundation 1993).

and gas development, are not confined to local fields. They cover an entire basin, wherever the shale exists with sufficient organic material, thermal maturity and pressure to produce. Accordingly, the contract area can be very small (as small as 600 acres), or very large (as large as the entire basin). For early agreements, to attract investment, the contract areas may need to be large, similar to what might be traditionally found in a concession. In this case, it will be important for the host nation to ensure that drilling is continuous, in part to offset the aggressive decline rates commonly associated with shale, but primarily to ensure that development does not languish whenever the operator finds other priorities for its capital investments.

Contract areas may, however, be small once a basin is demonstrated as profitable, and there is an infrastructure in place to handle the production. In America, shale units are typically in the 1000-acre range. With improving technologies, companies are drilling further horizontally, and completing more of the well bore. Accordingly, we can expect to see larger units. Smaller contract areas should have a relatively short exploration period. In this regard, PSAs may resemble farm out agreements granted by producing companies to their competitors in the United States. In these agreements there is usually a one-well obligation ("drill to earn" provision) and a one or two year drilling requirement. Under such an agreement, the working interest is earned only upon payout of the operation.

The host nation will also want to have the ability to dispose of its own interest in the production from shale development. This is normal for oil in PSAs, but not necessarily for natural gas. Indeed, most PSAs also provide operators with considerably more time and control for natural gas development than for oil, since building infrastructure and developing natural gas markets are tricky businesses. But the host nation may have an interest in developing commercially marginal natural gas reserves when the operator does not. Such would be the case if, for instance, the host government sought to kick start a petrochemical industry. If the host nation does market its natural gas separately, a gas balancing agreement will be necessary.

For shale development, complications will arise not only from natural gas sales, but also from transporting gas and processing natural gas liquids. This is an area where national oil companies may have little expertise, and will likely have a strong interest in changing this. The PSAs used for shale operations may need to allow for the national oil company to be involved in the management of all midstream operations. This would be important not only for ensuring that the host nation receives full value for processing, but also for understanding the value proposition for processing in general. One of the more important aspects of the shale boom in America has been the development of the midstream and downstream businesses associated with natural gas liquids.

For shale development, complications will arise not only from natural gas sales, but also from the processing of natural gas liquids. This is an area where national oil companies may have little expertise, and will likely have a strong interest in changing this. The production sharing agreement used for shale operations should allow for the national oil company to be involved in the management of all midstream operations. This will be important not only for ensuring that the host nation receives full value for processing, but also to understanding the value proposition for processing in general. One of the more important aspects of the shale boom in America has been the development of the midstream and downstream businesses associated with natural gas liquids.

C. Risk-Service Contracts.

Some countries choose to develop their resources entirely through a national oil company or their state ministries. Even in these instances, foreign involvement in mineral development is frequently found to be desirable. In countries where the concessions or production sharing agreements are impossible or undesirable, those countries may rely on agreements such as service contracts or technical assistance agreements in order to obtain assistance from foreign corporations.

The basic concept of the service agreement is that the multinational oil company, acting as a contractor, will advance capital for the purpose of exploration and conducts those exploration activities on behalf of the host country or its national oil company. In return the contractor is reimbursed for its expenditures and is paid a fee based upon the amount of hydrocarbons produced, or is allowed to recover its operating production costs plus a specified rate of return. The service agreement will take one of two forms, depending upon the amount of risk assumed by the contractor. In a true service relationship, the contractor does not assume risk in the event that the project or venture is unsuccessful. This is called the "no-risk" service agreement. In these types of agreements, the National Oil Company may directly contract with service companies to undertake a scope of work in a fashion similar to how Shell Oil Company might contract with Halliburton. This tends to be how the more sophisticated national oil companies, such as the Kuwaiti Oil Company, contract. These sorts of agreements, and how shale development may affect them, are discussed in section 4 below.

More commonly, there is the "risk-service" agreement, pursuant to which the contractor agrees to assume varying degrees of risk by funding exploration without benefit of reimbursement should such activities prove unsuccessful. The company who enters into the risk-service contract receives no ownership rights in the service area or its production, yet bears the entire financial risk of the venture.¹⁷ Similar arrangements have been found in the United States where oil and gas lending companies offer non-recourse, high interest loans to small producers where the loan is repaid through production. In this sense, we once again see small domestic producers in a role very similar to those of foreign host nations: owning valuable oil and gas properties, with drilling expertise, but with little capital to develop those properties. The difference of course is that these lending institutions do not also act as a contractor.

Service and Risk/Service Agreements are also potentially applicable to shale development, both in the United States and internationally. The elements that have driven the creation of service agreements exist for shale development: a relatively low risk of failure leading to a desire by mineral rights owners to develop the property themselves. Currently the costs of drilling and completing one unit of around 1000 acres (assuming six wells from one pad at around \$6 million per well)¹⁸

¹⁷ *Id.* at 371-384 (Discussion on the differences between "service" and "risk-service" contracts).

¹⁸ Andrew R. Thomas, Iryna Lendel, Edward W. Hill, Douglas Southgate, and Robert Chase, *An Analysis of the Economic Potential for Shale Formations in Ohio*, Urban Publications, February 1 2012, Paper 453 at 31, available at http://engagedscholarship.csuohio.edu/urban_facpub/453. The costs will vary depending upon depth to the shale, pressures, the length of the horizontal lateral and how many zones are

is about \$36 mm, possibly too much for nonrecourse loans in this early stage of shale development. But as expertise develops among both small producers and small service companies alike, and as we see small land companies in America develop from landowner associations, we may see the use of service or risk-service contracts to exploit shale.

Internationally, the same principal holds. The sovereign may find it easier and safer to offer a risk-service contract covering a small contract area rather than to offer traditional large contract areas under concessions or PSAs. This may also enable the sovereign to better control for environmental permitting. What will control the choice of granting instrument, in the end, will be what level of control the sovereign wishes to keep, and how much risk it is willing to take.

III. ISSUES IN JOINT OPERATIONS AND ASSET PURCHASE AGREEMENTS IN SHALE PROVINCES

Joint operations have become the rule rather than the exception in the oil and gas business. Even in the United States where investments in the onshore oil and gas business are relatively modest, most companies are skittish about incurring a substantial amount of risk on one exploration project. As a result, the industry has developed industry custom for "Joint Operating Agreements," known as "JOAs," the structure for which is set forth in industry trade association form agreements. The most popular agreement forms are those promulgated by the American Association of Petroleum Landmen and by the Association of International Petroleum Negotiators.¹⁹

In the international market, oil and gas investments tend to be even larger than they are in the American domestic market, and as a result, most multinational corporations prefer to enter into joint ventures before bidding. Normally parties do not enter into a JOA until the mineral rights are acquired, so for purposes of bidding, the parties will typically enter into a joint bidding agreement. Forms of these agreements are also available from the trade associations. These agreements must, however, comply with the public law of the jurisdiction of the host country, in particular the anti-trust and bid-rigging laws. Further, the host countries will normally require that one party be primarily responsible for the project, usually designated as the operator.

Under a JOA an operator is appointed, usually the party with the largest interest in the concession. Many countries require that the operator appointed by the participants must be approved by the agency overseeing operations. The operator has a general responsibility to manage and conduct the joint operations under the supervision of a management committee composed of representatives from each participant. In the United States, there is normally no operating committee (except in some offshore JOA's), and the only redress that non-operators generally have is removal of the operator.

Generally the operator's duties include specific functions necessary to the decision-making processes. These will include preparing program proposals, budgets and cost estimates; disseminating reports and data on the progress of operations; contracting for materials and services needed for operations; managing accounting

completed, among other issues. Other costs will include leasehold acquisition, site preparation, and post production facilities.

¹⁹ Websites containing these forms are listed in footnote 2.

procedures; and furnishing legal, technical and advisory services, including the securing of permits and other regulatory approvals required for operations. The operators are required to conduct these operations in a prudent, safe manner in accordance with good oilfield practices and conservation principles generally followed by the petroleum industry under similar circumstances. However, the operator's liability to the non-operators under this standard of performance is usually limited to gross negligence or willful misconduct. Joint operating agreements may also limit the liability further by excluding the operator from liability for consequential damages.²⁰

Notwithstanding all the exculpatory language that exists in joint operating agreements, the operator's standard of performance and the extent of its exposure to damages are not entirely clear. In the United States, most jurisdictions have held that there is no fiduciary duty on the part of the operator towards the non-operators. On the other hand, many courts and jurisdictions have held that there is something more than a mere indebtedness on the part of the operating company paying the other owners their shares of profits from well production. The operator has full control over the operations and distribution of income. As a result, courts have held that the joint operating agreement creates a "trustee-type" relationship imposing a duty of "fair dealing" between the operator and the non-operators.²¹

The joint operating agreement typically requires each party to pay its proportionate share of costs of required activities (with the exception of, in some cases, the national oil company). Acceptance of any project is conditioned upon prior approval through the issuance of an Authority for Expenditure (AFE) that is prepared and circulated by the operator. The AFE sets out the planned operations to be conducted and the estimated cost of performance. One problem that frequently arises is that the AFE estimate turns out to be low. It is generally understood in the industry that consent to an estimated cost contained in an AFE is consent to the total operation, regardless of cost, unless specifically set forth differently in the JOA. It is also not uncommon for the operator to require non-operators to advance money towards its share of costs of a work program or other operations. Parties that opt out of operations usually can back in after a penalty period, typically between 200 and 500% of the cost of operations.²²

Shale operations will present some special challenges to the JOA. For instance, parties might want to rethink the penalty provision in shale operations. Shale development is a high cost but relatively low risk operation, and opting out of basic operations – such as drilling a well – might not be acceptable. Further, setting pads for shale development is similar to setting a platform offshore – usually that is not an operation parties can opt out of yet stay in the operating agreement.

²⁰ For an overview of the operator's rights and responsibilities under the AIPN form operating agreement, see 23 A. DERMAN, MODEL FORM INTERNATIONAL OPERATING AGREEMENT: AN ANALYSIS AND INTERPRETATION OF THE 1995 FORM, at 18-32 (Section of the Natural Resources, Energy, and Environmental Law, American Bar Association 1997).[hereinafter DERMAN OPERATING AGREEMENT].

²¹ D. Pierce, *Transactional Evolution of Operating Agreements in the Oil and Gas Industry*, Special Institute on Oil and Gas Agreements: Joint Operations, Sante Fe, New Mexico, (May 17, 2007), available at http://washburnlaw.edu/profiles/faculty/activity/_fulltext/pierce-david-2007-1rockymountainminerallawfdn.pdf

²² DERMAN OPERATING AGREEMENT, *supra* note 18, at 56-86.

The operator is also given authority to award contracts to the best-qualified contractor as determined by cost and ability, but the parties will also place some restrictions on the operator's contract practices. Generally, contracts with affiliates will be subject to careful scrutiny by the operating committee. In shale plays, where some operators have expertise not generally available, it is not uncommon for the operator to have a subsidiary that performs an assortment of well services, ranging from drilling to recycling water.

Joint operating agreements generally provide for some type of a "take-in-kind" position for the non-operators who choose to market their share of hydrocarbons separately from the operator. This is much easier where there is significant infrastructure that allows this sort of marketing arrangement, especially for natural gas. In the United States, parties enter into a separate agreement called a "gas balancing agreement" that deals with the problems associated with shares of production and the separate marketing thereof. In the event that a party has not taken its proportionate share of gas production from a well (i.e., under-produced), that gas is credited to future production under the gas balancing arrangement. These provisions will be commonplace in shale provinces, which tend to be principally gas plays. Gas balancing agreements will be especially important in places where operators cannot get contracts that take all gas output (called take or pay contracts).

Shale joint ventures may also trigger issues relating to the competency of the operator. With costs being so high, and the work being so specialized, non-operators will insist upon a highly competent operator. Under many operating agreements, it is difficult to remove the operator absent the insolvency of the operator, unless the operator's interest in the property drops below some specified threshold, typically around 20%. JOAs in high cost provinces, such as for shale development, will likely need to outline a different, less onerous standard for removal of the operator.

Farm outs frequently lead to joint operations, wherein the party farming out or selling assets maintains a carried interest that can be converted to a working interest. Such arrangements will require a JOA to be agreed to in form for execution upon the assignment of the working interest in the operations. These types of arrangements will be commonplace in North American shale provinces, as small companies with leaseholds are farming out deep or shale rights to bigger companies. International farm outs, where assignments require more scrutiny, are less common.

An oil and gas asset purchase and sale agreement will also be affected by shale development strategies. Normally purchase and sale agreements require a period of due diligence²³ prior to acquisition. The first issue in a shale development due diligence review will be that of ensuring good title. Many shale provinces are in areas where there has been little or no production for the last 50 years. In Ohio and Pennsylvania many leases have been kept alive with marginal production. This will

²³ The term "Due Diligence" is used to refer to the buyer's examination of the seller's records and properties in an effort to verify title and confirm that the assumptions on which the purchase price is based are accurate. The term comes from the provisions of the typical purchase and sale agreement that generally provides that the buyer will have both the access and the right to examine the pertinent files, books, records and properties of the seller. The buyer is charged with knowledge of all defects or deficiencies which could have been discovered through the exercise of due diligence in the examination of the official title records and the files, books, records and properties of the seller. Contrary to what many in the oil and gas industry think, there is no duty of due diligence, absent specific language in the purchase and sale agreement requiring it.

trigger careful scrutiny of the title. Those who are not getting bonuses due to the lease being held by production are predictably challenging title in some instances.²⁴

Shale joint ventures may also trigger issues relating to the competency of the operator. With costs being so high for the specialized work being done, non-operators will insist upon an operator who has such specialized knowledge. If they do not, the non-operators may seek to remove the operator. Under most operating agreements, it is difficult to remove the operator absent the insolvency of the operator, unless the operator's interest in the property drops below some specified threshold, typically around 20%.

If third party financing is involved, the due diligence investigation will include some sort of third party reservoir engineering analysis. Here again companies involved in shale development can expect different models than that they have traditionally seen. Conventional petroleum engineering accounting strategies, such as those applied by the Society of Petroleum Engineering, do not easily apply to projecting shale production. With the high rate of commercial success for shale properties (often greater than 90%), lenders are likely to be more forgiving in projecting production from shale development than they would be for conventional exploration.

IV. SERVICE CONTRACTS IN SHALE BASINS

Two types of contracts commonly used in the oil and gas service industry are drilling and well services agreements. Often oil and gas operators use master service agreements when they anticipate an ongoing relationship with a service company. These tend to be form agreements that the operators prepare for all their service agreements, and tend to be written favorably in favor of the operator, especially if that operator is big, and has considerable leverage. The reverse may be true, however, for national oil companies that conduct their own operations, who may be offered form master service agreements that favor the service company.

As with most contracts, the principal negotiation will be around costs. In the case of drilling contracts, it will be about day rates, standby rates, and commissioning/decommissioning rates, if applicable. Costs for well service contracts may be set by day rates, or they may be based upon a set price for the service provided. Frequently, well service contracts include elements of both services and equipment. These costs will be critical for the operator since they will be reflected in the operator's AFE. Of course it will also be critical to the service company, since it determines the profitability of the services rendered.

The next major point of negotiation is usually allocation of risk. When problems arise during drilling and other oil field operations, consequences can be substantial, both in property damage and in personal injuries. What's more, because problems may arise thousands of feet down hole where direct observation is difficult, it is not always obvious what the problem is, or how it came to pass. In short, allocating fault may not be difficult. As a result, companies who contract for high risk, high stake services like to eliminate uncertainty. A primary goal for companies entering

²⁴ The need to review title records is still necessary for state owned properties, although title investigation will be considerably less complex. There may be encumbrances from service providers, such as workman liens, on the wells. Moreover, properties may be leased from government agency and then assigned multiple times before it is sold years later.

into oil and gas contracts is to ensure that it is clear who is responsible for damages, and to make sure that there are neither gaps in insurance coverage, nor double coverage. A secondary goal is to reduce the likelihood of protracted litigation resulting from disputes over fault.

The most common strategy used by producers and service companies to constrain costs associated with mechanical failure is the so-called “knock for knock” indemnification provision.²⁵ Under this provision, each party assumes the risk associated with its own equipment and personal, regardless of fault, and agrees to indemnify the other party for claims arising out of injuries suffered to their own persons and property. For this reason, those with gallows humor sometimes call this a “bury your own dead” provision. The thinking behind this provision is that parties who control their own equipment and personal are in the best position to reduce the risk of failure. But more importantly, by taking the element of fault out of risk allocation, it reduces the likelihood of protracted and costly disputes.

But knock for knock provisions may run afoul of the local public law. In Louisiana, for instance, knock for knock provisions are unenforceable to the extent they apply to personal injuries that happen within the state.²⁶ Arguably “no fault” provisions can encourage carelessness, and that may be against public policy at least when it comes to personal injury. Maritime jurisdictions, on the other hand, have no such anti-indemnity statute. As a result, accidents that occur in offshore Louisiana have often resulted in jurisdiction jockeying by parties and their insurers to obtain favorable application of law.

In addition to anti-indemnity statutes, most jurisdictions also have public laws that require that parties not enter into no-fault contracts that seek to exculpate them from liability stemming from their grossly negligent or intentional acts. For the same reason, waivers of consequential damage provisions are often not applicable against grossly negligent acts. Of course the distinction between gross and normal negligence is in the eye of the beholder. Fact finders often blur the distinction when damages are egregious, even if the negligence is not. As a result, in instances where the stakes are sufficiently high, one might expect to have to litigate fault.

Shale provinces may be such a place. To date, operations have been onshore, mitigating some of the risk. On the other hand, shale provinces tend to be located in areas of heavy population, such as in Ohio, Pennsylvania or Eastern Europe. Injury risk to third parties (especially for pollution) will be considerable. And damages in such cases are likely to be large (triggering gross negligence claims). As a result, we can expect that knock for knock provisions may not be applicable in those circumstances where it might be most needed: complex litigation with high stake outcomes.

Subcontracting is another consideration for service contracts in shale development. Subcontracting is becoming more and more common in the oil and gas industry, today comprising as much as 70% of services performed on a typical

²⁵ For a good overview of indemnity provisions and how they work in the oil and gas business, see K. Bullock, *A Brief Overview of Indemnity Provisions and Allocation of Risk In Energy Agreements*, Texas Lawyer’s In-House Counsel Summit, (May 17, 2012) <http://www.chamberlainlaw.com/assets/attachments/Indemnity%20Provisions%20in%20Energy%20Agreements.pdf>.

²⁶ *Id.*, at 12-13 (citing La. R.S. 9:2780; *Transcontinental Gas v. Transp. Ins. Co.*, 953 F.2d 985, 991 (5th Cir. 1992)).

well.²⁷ Meanwhile, oil and gas drilling operations are becoming increasingly high-risk endeavors undertaken in difficult circumstances, such as in deep water, in high-pressure zones, or, as is the case for shale, for horizontal drilling. The result is that increasingly small contractors may be asked to take on disproportionate risk, given the size of their contracts, via “pass through” provisions requiring that subcontractors indemnify producers for injuries to subcontractor personnel or property. This could be a significant barrier to small local companies looking to break into the oil and gas industry in shale provinces.

In shale operations, drilling and completion costs are high, but predictable (except for cases involving pollution). The principal risk is mechanical failure, not a dry hole. As a result, one likely change we might expect is that small operators will negotiate for the drilling company to take on the risk of mechanical failure. In such a case, the operator might opt for a “turnkey” rather than a “day work” contract. In a turnkey drilling contract, the drilling contractor, for a set price, guarantees the delivery of a working well, and in so doing, takes on some or all the mechanical risk. This form of contract is more popular with small operators who are willing to pay a premium to ensure that they won’t face huge cost overruns associated with delays or mechanical failures. The driller, on the other hand, will want to be sure that the costs are predictable before agreeing to a turnkey contract.

Shale drilling will have that sort of predictability, especially as the basin becomes familiar to the drilling company. As we begin to see landowner groups develop their own properties, turnkey drilling contracts may become popular. For the operator, the biggest issue to consider in entering into a turnkey contract, next to the price, will be the track record of the driller. Ambitious drilling engineers sometimes set up shop as a turnkey company with limited resources. These start-up companies can underbid other contractors because, notwithstanding what the contract says, they really intend to take no risk. They rent their equipment and subcontract the work, all of which works fine if everything goes smoothly. But if there are delays or mechanical problems, the under-financed start-up will seek to renegotiate the deal, and failing this, will walk off the job, leaving the producer with environmental problems and a pack of unpaid and unhappy subcontractors – many of whom may have access to self-help remedies that can attach to production from the well.

Today most high stakes drilling is undertaken through a day-work drilling contract. In this instance, the operator pays the drilling company a “day rate” for being on the job. Accordingly, should there be delays due to weather, mechanical problems, failed equipment and so forth, the drilling company continues to rack up significant charges. It is customary for a drilling company to charge lower “standby” rates during delay periods, such as may occur during a “fishing” expedition when equipment gets stuck down hole. Long fishing expeditions are times of considerable angst for producers --- they face fees not only from the fishing tool company who tries to retrieve the stuck equipment, but they also incur standby fees from the driller. As each day passes, and costs increase, the stakes grow larger for the producer as it decides whether to abandon the well.

Day-work drilling contracts usually contain knock for knock provisions, however as we have seen, the chances are high that the parties will still end up disputing fault.

²⁷ E. Wilson and J. Kuszewski, *Shared Value, Shared Responsibility: A New Approach to Managing Contracting Chains in the Oil and Gas Sector*, at 8, (International Institute for Environment and Development London 2011) (<http://pubs.iied.org/16026IIED.html>).

If this happens, both the driller and operator will seek to distance themselves from control of operations. By industry custom, producers usually have a “company man” on location during drilling – an experienced oil and gas drilling hand who has worked his way up the non-professional ranks, but who is not a drilling engineer. The driller will contend that this person is ultimately responsible for all decisions on location. Producers, on the other hand, will argue that this person has limited knowledge, and that the driller not only provides the equipment and expertise, but also knows best how to resolve problems that arise during drilling. Under the terms of the International Association of Drilling Contracts (IADC) forms, the contract makes clear the producer is in charge of all decisions. Yet the IADC contract also requires that the driller’s equipment be used in the manner it was designed for, something that the driller has the most knowledge to ensure happens.

In North America, as small producers get into shale drilling, and as drilling companies acquire expertise in each shale basin, we can expect turnkey contracts to become more popular. On the international side, as National Oil Companies begin to conduct their own operations, reliance will be even greater on drilling company expertise. Under those circumstances, we might also expect that National Oil Companies will increasingly use turnkey drilling contracts whenever possible.

V. MARKETING HYDROCARBONS IN SHALE PROVINCES

The marketing of natural gas and natural gas liquids will be a critical issue in determining the viability of shale development, especially outside of North America. In North America, companies typically do not undertake marketing efforts until after the discovery of proven reserves. This is because in America there is an extensive natural gas infrastructure providing pipelines that provide markets in and around most oil and gas fields.

Shale development is changing this model. The reason: oil companies can accurately anticipate both discoveries and reserves before they drill. What’s more, with the high cost of drilling and completing wells, operators are loath to shut in wells, awaiting midstream infrastructure. As a result, companies in the United States now are planning the marketing of natural gas well in advance of drilling. This includes engaging the midstream companies in long term planning. In Ohio, for instance, a number of gathering, processing and fractionation projects have been announced in 2013 and 2014 as the midstream oil and gas industry positions itself for anticipated Utica Shale natural gas production in 2014 and beyond.²⁸

In international markets operators have had to plan marketing of natural gas in advance of exploration discoveries for some time. This will not change for shale development. But as with the early markets in America, there will be issues relating to balancing natural gas supply with demand. However the problem of matching supply and demand in shale provinces is far more manageable than that found in the early days of American gas markets, when most natural gas was produced as a byproduct of oil production. Most shale gas is non-associated gas, and as such, can be more easily shut in or reduced. In the United States, when markets were

²⁸ See, e.g. SCIO, *Utica East Ohio Midstream LLC Begins Production*, The Daily Jeffersonian (September 15, 2013) available at <http://www.daily-jeff.com/business/2013/09/15/utica-east-ohio-midstream-llc-begins-production>.

developing in the 1950s, nearly all gas was associated with oil production, and if no market existed, "take or pay" contracts were required to avoid flaring.²⁹

But to attract the market to Louisiana, the oil companies marketed their gas under long-term warranty commitments, sometimes from 20-30 years. Frequently these contracts had minimal price escalations, and they warranted delivery of daily amounts of natural gas, regardless of how much gas the companies actually produced from their fields. When prices escalated in the 1970s producers found themselves selling gas under long-term contracts for a fraction of the market value of the gas. They also found themselves embroiled in litigation with royalty owners that sought market value for their share of the production. Worse, production shortages developed as producers could not justify drilling or work-overs with the low prices received under the long-term contracts.

By the late 1980s, after oil and gas prices crashed, the problem was reversed: pipeline companies that had entered into long term "take-or-pay" contracts were required to take all the producers' gas, regardless of need, at very high prices. That in turn led to protracted take-or-pay litigation that plagued the industry until the mid 1990s.

New shale provinces will now find themselves in the same position that Louisiana and Texas were in the 1950s – they are just developing gas markets and infrastructure. However, with most shale be non-associated, producers are better able to provide flexibility to producers under take or pay obligations. This will encourage midstream industries to take more risk in developing infrastructure in advance of shale development. However the problem Louisiana had in balancing outputs and requirements has not gone away; today, natural gas liquid production is creating in some locations the exact same problem that associated gas created. In Ohio for instance, where early development has been in the liquid rich portion of the Utica, problems with lack of a market for both methane and ethane associated with natural gas liquid production may yet evolve.

There are certain elements common to gas sales that will find their way into any gas marketing agreement. These will include: a supply commitment (providing identification of specific reservoirs and fields); term (in the international arena generally 20-30 years); sale price and price adjustments (specifying, usually, a fixed price and currency in which payment is to be made); quantity (specifying daily and yearly quantities to be made available); quality (specifying the minimum acceptable specifications for the gas to be delivered); delivery point (specifying the point at which gas is to be transferred from the producer to the purchase); take obligations (requirements of the purchaser to take certain volumes offered); transportation and other facilities (specifying which party is responsible for the infrastructure); and dispute resolution. Typically such contracts are "dedication" in nature; that is, they dedicate certain reservoirs or wells to a contract. These specific provisions may not be greatly affected by shale development. The most likely issue for negotiation in shale provinces will relate to the daily take. Midstream users want as much flexibility as they can get to match their supply to their demand on a day-to-day

²⁹ Eventually, by the 1960s, in response to plentiful cheap gas, a petrochemical business developed in South Louisiana and East Texas. In addition, by the 1970s utility companies began using natural gas as a fuel to produce heat and electricity for businesses and homes.

basis. Accordingly operators are required to develop back up gas sales contracts and gas balancing agreements to mitigate the problem associated with the midstream company failing to take production.

In new international shale provinces, it will be interesting to see if oil companies, eager to develop a market for natural gas and ethane in countries where a minimal markets now exist, will once again enter into "warranty" contracts. As history has shown, these contracts may be fraught with danger for a producing company should they experience a shortage of production. But producers also can exert much more control over the supply in dry gas shale regions. Further they can mitigate their risk by hedging their supply obligations with third party gas supplies. Producers may find warranty contracts difficult to resist under the circumstances. To the extent that natural gas liquids drive production to the point that natural gas is byproduct, however, producers could face many of the problems faced by producers in Louisiana fifty years ago.

VI. CONCLUSIONS

Contracting in the oil and gas business is affected greatly by both "industry custom" and by the advent of form contracts. These contracts and customs serve both as a framework for contract negotiations and as a standard for "fairness." If a producer or contractor is accustomed to certain ways of conducting business, it will develop a sense that these customs are fair, and any deviation therefrom is not tolerable. Often times such changes will be strongly resisted, even if the proposed changes make economic sense. For this reason, it took nearly 20 years for operating companies to accept PSAs, after the industry had grown accustomed to using lease agreements to acquire mineral rights for some 70 years.

Shale development will test many industry customs. Transactions will necessarily involve a number of new concepts that have not been previously encountered in traditional settings. It has the potential to upset deeply rooted concepts, such as how granting instruments, joint operating agreements or service contracts should look. It also has the potential to affect how oil and gas accounting will be done for financing purchase and sales agreements.

In new oil and gas provinces, such as Ohio, Pennsylvania or Ukraine, learning oil and gas customs can be a hard lesson for those trying to break into the industry as service providers. They need to get up to speed quickly on customs, form agreements, and applicable laws. But unconventional oil and gas recovery will also lead eventually to unconventional agreements. In this regard, the nascent upstream service industry in new shale provinces are not so far behind - there is reason to be to be optimistic that oil and gas companies will be rethinking how they transact business as a result of the shale boom.