Attorney CLE Series

Marcellus Shale

A DISCUSSION OF THE INCOME TAX AND VALUATION ISSUES RELATED TO LANDOWNERS

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Presented by the Business Valuation and Tax Services Groups

GROSSMAN YANAK & FORD LLP
Certified Public Accountants and Consultants

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Bob heads our firm's Tax and Business Valuation Groups. He brings extensive experience in tax and valuation matters that affect businesses, both public and private, as well as the stakeholders and owners of these businesses.

The breadth of his involvement encompasses the development and implementation of innovative business and financial strategies designed to minimize taxation and maximize owner wealth. As his career has progressed, Bob has risen to a level of national prominence in the business valuation arena. His expertise in business valuation is well known, and Bob is a frequent speaker, regionally and nationally, on tax and valuation matters.

After graduating from Saint Vincent College in 1979 with Highest Honors in Accounting, Bob earned a Masters of Science degree in Taxation with Honors from Robert Morris University. He is a CPA in Pennsylvania and Ohio and is accredited in Business Valuation by the American Institute of Certified Public Accountants. Bob also carries the well-recognized credentials of Accredited Senior Appraiser, Certified Valuation Analyst and Certified Business Appraiser.

Bob has written numerous articles for several area business publications and professional trade journals. He is a national instructor for both the American Institute of Certified Public Accountants and the National Association of Certified Valuation Analysts and has served as an adjunct professor for Duquesne University's MBA program.

A member of the American and Pennsylvania Institutes of Certified Public Accountants, Bob previously chaired the Pittsburgh Committee on Taxation. He is also the past chair of the Education Board of the National Association of Certified Valuation Analysts as well as a former member of the organization's Executive Advisory Board, its highest Board.

He is a member of the Allegheny Tax Society, the Estate Planning Council of Pittsburgh and the Pittsburgh Chapter of the American Society of Appraisers. Bob has held numerous offices and directorships in various regional not-for-profit organizations. He received the 2003 Distinguished Public Service Award from the Pennsylvania Institute of Certified Public Accountants and the 2004 Distinguished Alumnus Award from Saint Vincent College.

Bob and his wife, Susie, live in Westmoreland County. They have two children, Matthew and Alyssa.

Melissa A. Bizyak, CPA/ABV/CFF, CVA

Melissa is a partner in the firm's Business Valuation Services Group. She has practiced in public accounting for over 17 years and has significant experience in business valuation and tax-related issues for privately-held concerns and their owners. Melissa's business valuation experience is very diverse, including valuations of professional practices, as well as companies in the manufacturing, oil and gas and technology industries.

These valuations have been performed for a variety of purposes such as Employee Stock Ownership Plans (ESOPs), marital dissolutions, buy/sell transactions, dissenting shareholder disputes, value enhancement and gift and estate tax purposes.

After graduating from the University of Pittsburgh in 1994 with a B.S. in Business/Accounting, Melissa spent more than two years with a local accounting firm in Pittsburgh. She joined Grossman Yanak & Ford LLP in 1997.

Melissa is a certified public accountant. She is accredited in business valuation and certified in financial forensics by the American Institute of Certified Public Accountants (AICPA). She has also earned the AICPA Certificate of Achievement in business valuation. Additionally, Melissa carries the credentials of Certified Valuation Analyst.

Her professional affiliations include membership in the National Association of Certified Valuation Analysts (NACVA) as well as the AICPA and the Pennsylvania Institute of Certified Public Accountants (PICPA). She serves on the Board of Directors of the Estate Planning Council of Pittsburgh as President and is a member of the Robert Morris University Professional Advisor Council.

Melissa has authored articles appearing in professional publications and has written business valuation course-related materials for NACVA and the AICPA. She serves as a national instructor for NACVA.

Melissa is a graduate of the Leadership Development Initiative, a Leadership Pittsburgh, Inc. program. She serves on the Executive Leadership Team for the American Heart Association's "Go Red for Women" initiative.

Melissa resides in the South Hills of Pittsburgh with her husband and their two sons.

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Rebekah has more than seven years of public accounting experience. Her focus is on the provision of tax compliance, planning and research services for individuals and various types of business entities, including corporations, S corporations, partnerships and limited liability companies. She has significant experience with multi-state tax planning and compliance projects.

Rebekah graduated cum laude from Grove City College in 2004, earning her Bachelor of Science degree in Accounting, along with a second major in Spanish. A CPA in Pennsylvania, she is a member of the American and Pennsylvania Institutes of Certified Public Accountants.

Before joining the GYF Tax Services Group in 2006, Rebekah spent two years at an accounting firm where her responsibilities included performing audits and providing tax services for corporate, governmental and not-for-profit businesses.

Rebekah is a graduate of the 2010-2011 Leadership Development Initiative, a Leadership Pittsburgh Inc. program that provides young leaders with the tools necessary to effect positive change in the future of the region. She is active in her church community and a volunteer for various service projects.

She lives in West View with her husband, Steven.

Grossman Yanak & Ford LLP

Headquartered in Pittsburgh, Grossman Yanak & Ford LLP is a regional certified public accounting and consulting firm that provides assurance and advisory, tax planning and compliance, business valuation and technology services. Led by five partners, the 21-year-old firm employs approximately 55 personnel who serve corporate and not-for-profit entities in Pennsylvania, Ohio, West Virginia and New York.

Our firm was founded on the idea that the key to successful, proactive business assistance is a commitment to a high level of service. The partners at Grossman Yanak & Ford LLP believe that quality service is driven by considerable involvement of seasoned professionals on a continuing basis. Today's complex and dynamic business environment requires that each client received the services of a skilled professional with a broad range of experience and knowledge who can be called upon to provide efficient, effective assistance.

Grossman Yanak & Ford LLP combines a diversity of technical skills with extensive "hands-on" experience to address varied and complex issues for clients on a daily basis. We pride ourselves on bringing value-added resolution to these issues in a progressive and innovative manner. Our ability to produce contemporary, creative solutions is rooted in a very basic and ageless business premise – quality service drives quality results. Our focus on the business basics of quality technical service, responsiveness and reasonable pricing has enabled the firm to develop a stable portfolio of corporate clients as well as sophisticated individuals and nonprofit enterprises.

Our professionals understand the importance of quality and commitment. Currently, the majority of the professional staff in our Assurance and Advisory Services and Tax Services Groups hold the Certified Public Accountant designation or have passed the examination and need to complete the time requirements for certification. Each of our peer reviews has resulted in the highest-level report possible, attesting to the very high quality of our firm's quality control function. The collective effort of our professionals has resulted in our firm earning an exemplary reputation in the business community.

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Note: Special thanks to Attorney Carl Staiger of Buchanan Ingersoll & Rooney PC, Pittsburgh, for his review and editorial commentary on Chapter III of these materials.

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Introduction

There can be little argument that the economic opportunities presented by the Marcellus Shale natural gas formation in Pennsylvania and surrounding states are the most profound in a generation or more. Though certain processes within the operational aspects of the industry are not without controversy, it is clear that the industry is here to stay, and that Pennsylvania citizens have and will continue to receive a substantial economic benefit from these activities.

Those receiving such benefits are numerous and varied. Individuals who are so fortunate as to hold land ownership with substantial natural gas reserves are direct beneficiaries of the industry's efforts through garnering a piece of the production income via lease of the natural gas rights. Beyond royalty stream interest holders, there is also the ability to obtain economic benefits through working interests, carried interests and production sharing contracts.

Almost as direct a beneficiary are those Pennsylvanians who have obtained living-wage employment opportunities with companies operating in the industry. Next, and more indirectly, are those ancillary businesses that receive additional revenue by virtue of the increased spending of those involved in the industry.

Finally, the substantial income taxes and payroll taxes paid by these companies and their employees benefit all Pennsylvanians. And with the new Pennsylvania drilling impact fees, with benefits at both the state and county levels, (see pages 37-38 of this book), it is evident that counties with high well counts could see significant windfalls.

In a study released in July 2011, conducted by researchers at Penn State University and commissioned by the Marcellus Shale Coalition entitled, *The Pennsylvania Marcellus Natural Gas Industry: Status, Economic Impact and Future Potential*, it was noted that at current growth rates, the Marcellus Shale formation could become the leading supplier of natural gas in the continental United States within a decade.

As set forth on the Marcellus Shale Coalition website,[1] the study projects that Pennsylvania's Marcellus Shale has the potential to produce 17.5 billion cubic feet of natural gas per day (6.4 trillion cubic feet annually) – representing nearly 600,000 Barrels of Oil Equivalent (BOE) by energy (BTU) equivalence. This amount equates to approximately one-quarter of America's annual natural gas production in 2020, according to U.S. Department of Energy estimates. Based on these projections, by 2020, Marcellus development could support 256,420 jobs and generate $20 billion in added value to Pennsylvania's economy, according to the study.

A full copy of the 60-page study can be accessed through the Grossman Yanak & Ford LLP website at www.gyf.com

[1] www.marcelluscoalition.org

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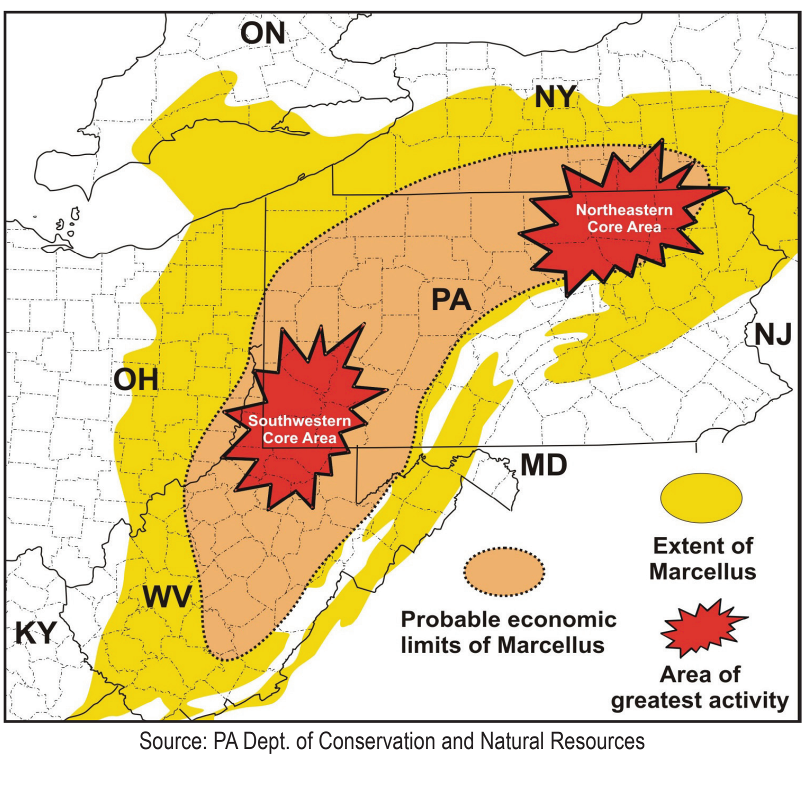
Further key findings in the study include:

- During 2010, the Pennsylvania Marcellus Shale natural gas industry triggered $11.2 billion in economic activity, generated $1.1 billion in state and local taxes, and supported nearly 140,000 jobs.
- The Pennsylvania Marcellus industry is projected to generate more than $12.8 billion in economic activity in 2011, leading to more than $1.2 billion in state and local taxes and supporting more than 156,000 jobs.
- In 2010 natural gas companies paid over $1.6 billion in lease and bonus payments to Pennsylvania landowners.
- As a result of Pennsylvania Marcellus Shale production, residential electricity and natural gas bills across the Commonwealth are $245.1 million lower ($217.4 million from lower natural gas bills and another $27.7 million from lower electricity bills.)
- By 2015, Pennsylvania's Marcellus Shale could produce more than 12 billion cubic feet per day, second only to Texas in natural gas production.
- Marcellus Shale natural gas production could exceed 17 billion cubic feet per day in 2020, potentially allowing the Marcellus to become the single largest producing gas field in the United States, if real natural gas prices do not fall significantly.



Source: PA Dept. of Conservation and Natural Resources

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The obvious impact of all of these economic opportunities to those participating in today's program is that need for legal, tax, consulting and valuation services. Just the mere number of participants in the industry, as well as those receiving ancillary economic benefits, presents a substantial opportunity for all of us to address a broad number of technical and planning issues and complexities. From landowner issues relating to lease negotiation, income tax, estate and gift tax valuation; to ensuring proper accounting and payment of royalties due on production; to developer/driller/operator legal planning and litigation and tax matters; to ancillary businesses and government authority challenges, the industry presents great opportunities for the growth of professional services rendered by those qualified to do so. These opportunities are easily confirmed by the "great migration" of law firms, accountants and other professionals from other oil and natural gas belt states, including Texas.

There is simply no question that many aspects of dealing with the industry are specific and unique. Therein lies the challenge of successfully serving industry participants effectively, efficiently and correctly.

This program is far too brief to cover specific issues in great depth. Rather, it is intended to familiarize participants with the general process of bringing the natural gas contained in the Marcellus Shale formation to market, and, more specifically, explain the role of the landowners in this process, as well as address many of the issues they might encounter in conjunction with their participation in the industry.

Should you have specific questions or inquiries, the panelists will be happy to stay after the program or take calls or emails at a later date.

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Chapter I – *The Oil and Gas Business*

The Oil and Gas Business is generally partitioned into three distinct elements, each representing a separate phase of the oil and gas industry. In combination, these three elements encapsulate the entire oil and gas industrial process, starting with exploration and ending with the refinement of crude oil and the sale and distribution of natural gas, its by-products and those products derived from oil (for example, liquefied petroleum gas, gasoline, jet fuel, diesel oil and asphalt). Most commonly, these three fundamental elements are referred to as *Upstream activities, Midstream activities* and *Downstream activities***.** Midstream activities are often lumped with the downstream category.

Upstream Oil and Gas Activities

The upstream sector commonly includes all of those steps involved in the actual searching for, and the recovery and production of, crude oil and natural gas deposits. It is very often referred to as the exploration and production (E&P) stage or sector. As the name implies, upstream sector activities include the actual search for underground (or underwater) oil and gas fields. The sector generally encompasses the application of all necessary geological and geophysical (G&G) processes and procedures, as well as drilling of exploratory wells to confirm the conclusions and findings identified in the exploration process.

While certain general surface geology can be undertaken by the developer or operator prior to leasing, specific exploration, G&G work and exploratory drilling can only be undertaken after the lease with the landowner is negotiated and executed. Thus, the negotiation of the lease with the landowner is generally the first step in facilitating the upstream sector activities.

Once the exploration phase of the upstream sector activities is complete, the quality of the findings are appraised, and the plan for production of the oil or natural gas field is developed. Included in this process is the design and construction of all necessary surface facilities, including access roads, required surface facilities and waste water collection pools, in addition to the well pads and the well, itself.

Drilling and well design can incorporate historical vertical drilling techniques or alternatively, horizontal drilling. The latter technique has been developed over the last decade to obtain access to once-impenetrable natural gas fields and allow for the extraction of those reserves in a cost-effective and efficient manner. While drilling and extraction techniques are beyond the scope of this program, a brief discussion of the "fracking" process is warranted, given the constant discussion of this matter in the media, as well as the opposing views voiced by the industry and environmentalists.

"Fracking" is more appropriately described as hydraulic fracturing and is often referred to as *hydro fracking*, *fracking* or *fracing*. It is the process of initiating and subsequently propagating a fracture in a rock layer, by means of a pressurized fluid, in order to release petroleum, natural gas, coal seam gas or other substances for extraction. The fracturing is generally done from a wellbore drilled into reservoir rock formations. The energy from the injection of a highly-pressurized fluid, such as water, creates new channels in the rock, which can increase the extraction rates and enhance the ultimate recovery of fossil fuels.

Hydraulic fractures may be natural or created by human activity, and are extended by internal fluid pressure, which opens the fracture and causes it to extend through the rock. Natural hydraulic fractures include igneous dikes, sills and fracturing by ice, as in frost weathering. Man-made fluid-driven fractures are formed at depth in a borehole and extend into targeted formations. The fracture width is typically maintained after the injection by introducing a *proppant* into the injected fluid. Proppant is a material, such as grains of sand, ceramic or other particulates, that prevents the fractures from closing when the injection is stopped.

The process of fracking is intended to increase the porosity of certain rock formations holding natural gas reserves, thereby easing the extraction process. The fracking process concludes with the collection and proper disposition of waste water and other hazardous materials.

A short video is available at the Marcellus Shale Coalition website (http://marcelluscoalition.org/marcellus-shale/production-processes/drilling/) to better explain the production process of horizontal drilling and fracking.

Once drilled, the final aspect of the upstream sector is the operation of the wells. This includes general operation and maintenance of the well to ensure its ongoing performance. The upstream stage also includes disposition and monitoring of wastewater and other potential contaminants that otherwise could result in environmental issues.

Midstream Oil and Gas Activities

The midstream sector of the oil and gas industry is primarily focused on transportation of the oil and natural gas from the extraction site (i.e., the well area) to refineries and distribution centers. Transporting raw oil and natural gas is a highly-technical process that involves compressing the fluids to necessary pressures in order to be transported through pipelines, like Alaska's Natural Gas Pipeline, or on tankers from the offshore drilling sites.

The midstream sector is also responsible for treating raw materials in order to remove impurities, such as water vapor or hydrogen sulfide. Removing impurities and compressing the fluids helps maximize the amount of oil and natural gas that can be transported. Thus, maximizing efficiency and profits for companies are an important aspect in this sector of the industry.

Some of the heavier hydrocarbons that are extracted cannot be transported easily, and it is generally the midstream sector that converts these chemicals at the production site before they are transported to the refineries for final processing. This is done on midstream platforms that involve converting natural gas to liquid through indirect chemical conversion.

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Downstream Oil and Gas Activities

The downstream sector of the oil and gas industry refers to the refining of crude oil, and the selling and distribution of natural gas and products derived from crude oil. Such products include liquefied petroleum gas (LPG), gasoline or petrol, jet fuel, diesel oil, other fuel oils, asphalt and petroleum coke.

The downstream sector includes oil refineries, petrochemical plants, petroleum product distribution, retail outlets and natural gas distribution companies. The downstream industry reaches consumers through thousands of products, including those listed in the prior paragraph, as well as heating oil, lubricants, synthetic rubber, plastics, fertilizers, antifreeze, pesticides, pharmaceuticals, natural gas and propane.

Distribution is the final step in delivering natural gas to customers. While some large industrial commercial and electric generation customers receive natural gas directly from high-capacity interstate and intrastate pipelines (usually contracted through natural gas marketing companies), most other users receive natural gas from their local gas utility, also called a local distribution company (LDC). LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. There are two basic types of natural gas utilities: those owned by investors, and public gas systems owned by local governments.

Local distribution companies typically transport natural gas from delivery points located on interstate and intrastate pipelines to households and businesses through thousands of miles of small-diameter distribution pipe. The delivery point where the natural gas is transferred from a transmission pipeline to the local gas utility is often termed the *citygate*, and is an important market center for the pricing of natural gas in large urban areas. Typically, utilities take ownership of the natural gas at the citygate and deliver it to each individual customer's meter. This requires an extensive network of small-diameter distribution pipe. The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration reports that there are just over 2 million miles of distribution pipe in the United States, including city mains and service pipelines that connect each meter to the main.

The delivery of natural gas to its point of end-use by a distribution utility is much like the transportation of natural gas discussed in the midstream and transportation section. However, distribution involves moving smaller volumes of gas, at much lower pressures, over shorter distances, to a great number of individual users. Smaller-diameter pipe also is used to transport natural gas from the citygate to individual consumers.

The natural gas is periodically compressed to ensure pipeline flow, although local compressor stations are typically smaller than those used for interstate transportation. The pressure required to move natural gas through the distribution network is much lower than that found in the transmission pipelines because of the smaller volumes of natural gas to be moved, as well as the small-diameter pipe that is used. While natural gas traveling through interstate pipelines may be compressed to as much as 1,500 pounds per square inch (psi), natural gas traveling through the

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distribution network requires as little as 3 psi of pressurization and is as low as ¼ psi at the customer's meter. The natural gas to be distributed is typically depressurized at or near the citygate, as well as scrubbed and filtered (even though it has already been processed prior to distribution through interstate pipelines) to ensure low moisture and particulate content.

Summary

As can be seen, most of the activity relating to the active conduct of a producing well is associated with the upstream activities and encompasses those operational items which are most familiar to those practicing in the region. Transportation (midstream) and distribution (downstream) activities generally require specialized, sophisticated, larger players to meet capital, pipeline access and regulatory requirements. While no natural gas production has value until it is sold, it is inherently the exploration and production phase that most directly affects Pennsylvania's landowners.

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Chapter II – *The Exploration and Production Processes (Upstream Activities)*

The Marcellus Shale Coalition website (www.marcelluscoalition.org) is an extremely useful resource for understanding the Marcellus Shale play in Pennsylvania. On their website, the organization has defined the steps encompassed in the upstream sector of the industry. The following information is taken verbatim, with permission, from that site.

While it is understood that certain portions of this chapter are somewhat duplicative of the information set forth under the "Upstream Oil and Gas Activities" section in Chapter I of these materials, we nevertheless include them here, as well, to provide an industry viewpoint of these processes.

Production Processes

The production of natural gas from the Marcellus Shale formation is important because it produces a clean-burning, Pennsylvania-based energy source in an environmentally-sound manner. It also provides economic benefits to communities across the Commonwealth. Natural gas producers already invested more than $4 billion in Pennsylvania in lease and land acquisition, new well drilling, infrastructure development and community partnerships, with an even greater investment expected in the future.

Leasing

Natural gas producers begin the process of exploring and producing natural gas by obtaining gas and mineral rights from property owners interested in leasing their land for potential drilling activity. Land professionals, or a "landman", conduct due diligence and research in county courthouses for information on property owners and meet with those owners to develop a lease agreement giving the gas producer the right to produce natural gas from their mineral estate.

The lease typically includes a per-acre signing bonus for a specified number of years and an agreed-to royalty payment to the property owner if a well produces natural gas. A number of market-based factors influence the terms included in each agreement. Leases also include provisions to allow for the construction of underground gathering lines to transport natural gas from wells to larger transmission pipelines and processing plants. Landowners are compensated for the use of property needed for these pipelines, as well as other facilities that may be needed.

It is important to note that leases are legal and binding documents. The lease or "contract" represents the official written agreement between two parties, usually the gas company and the mineral/gas owner.

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Exploration

Prior to drilling, gas producers study the specific geologic conditions beneath the ground, and whether it has the potential to produce natural gas. Geophysicists use both two- and three-dimensional seismic testing approaches to learn about underground rock formations such as the Marcellus Shale.

Seismic trucks are used to generate geologic images, sending waves into subsurface rock formations thousands of feet below ground and are reflected back to the surface and received by microphones or geophones that are strategically embedded in the ground and on the earth's surface. Geophones translate the vibrations received from the ground into electrical signals, which are transmitted to a recording truck that logs the acquired data to be processed on a computer.

Three-dimension seismic testing, a more advanced tool, involves the placement of small charges into holes approximately 20 feet in depth on a grid and firing those charges in a timed sequence. Geophone instruments record the data generated by the test, showing three-dimensional images of the rock formations, including the Marcellus formation. By providing data about the location and thickness of the shale in that area, the three-dimensional seismic image helps geologists increase the probability of a more accurate placement of drilling locations. However, these images cannot show whether the rocks contain natural gas. That requires drilling the well.

Drilling

Marcellus gas wells can be drilled using 21st century vertical or horizontal technologies. Vertical wells are sometimes first drilled in an area to obtain information valuable for planning the drilling of more costly and technically demanding horizontal wells. Marcellus Shale natural gas wells in Pennsylvania are drilled horizontally because it offers access to a larger quantity of natural gas, while disturbing a smaller area on the surface. Both vertical and horizontal Marcellus Shale wells produce marketable quantities of natural gas.

The drilling process focuses first on reaching – and protecting – water-bearing zones beneath the ground. Drilling is completed using a small amount of lubricating agents, then the entire length of the well, from the surface to the groundwater strata, is cased and cemented tightly to form a barrier between the wellbore and the earth. As the drill continues to push deeper into the earth, a series of long drilling pipes follow it to establish the well. While drilling through the water barrier there may be short-term cloudiness or turbidity and diminishing of flow.

After drilling vertically to the depth that reaches slightly above the Marcellus Shale formation, the drill bit can then turn to push its way horizontally into the Marcellus Shale, sometimes as much as 5,000 feet, into the formation. This allows for the extraction of larger quantities of natural gas from a single wellhead. Marcellus Shale wells generally take between 15 and 30 days to drill, operating around the clock.

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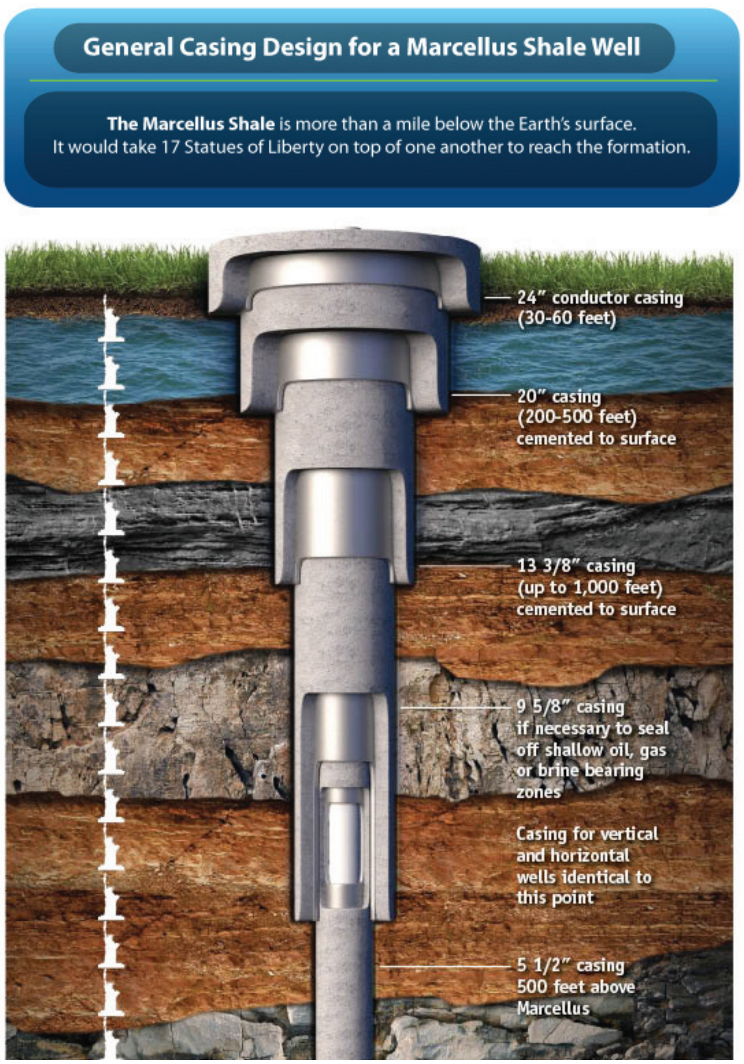
Well Casing

The casing process keeps the well open and protects the earth, similar to the efforts to protect groundwater. The hard metal casing shores up the wellbore and extends through both the vertical (if the well is completed vertically) and the horizontal drilling phases, assuring the long-term integrity of the well from end-to-end.

Cement is then pumped down the well under pressure and forced up the outside of the steel casing until the well column is sealed. The casing process ensures that the producing well is isolated from any fresh water zones. This assures during the producing life of the well that fracture fluids, produced brine water and natural gas are isolated and the freshwater bearing zones are protected.



"Cross-Section of a Typical Marcellus Well," courtesy of Penn State University's Marcellus Center for Outreach and Research (MCOR)

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Hydraulic Fracturing

Extracting natural gas from horizontal Marcellus Shale wells requires the use of more water than traditional shallow vertical wells, ranging between three and five million gallons of water per well. Gas producers must identify and obtain permits from the state regulatory agencies to withdraw water from streams or rivers, with additional oversight on limiting water withdrawals to protect fish and aquatic life. New technologies, however, are allowing producers to recycle much of their water. On average, MSC producers reuse nearly 60 percent of their water, and this figure is expected to grow even larger. In some cases, producers are recycling 100 percent of their water.

Water used in the fracturing process is transported to the site where it is mixed carefully with sand and other lubricating agents, which are all listed publicly on the DEP's website. The first step in the process involves setting a charge, similar to a rifle shot, in a specific area of the Marcellus Shale formation at the end of the well bore. Setting the charge perforates the casing and cement and starts the fracture of the shale formation, opening the interior of the casing to the formation. The fracturing fluids – made up of more than 99.5 percent water and sand – is then injected under controlled high pressure to break open the formation, and expand and hold open the fractures, allowing the natural gas to flow to the well head.

It can take several days to complete the fracture stimulation process, and requires continuous monitoring to ensure the safety of workers and the protection of the environment. Natural gas companies invest millions of dollars to develop a single well. Protecting that investment through a safe operation and successful completion is the first priority for every well drilled.

After a successful fracturing procedure, wells are tested using a controlled flaring process and plugged while equipment is put in place to allow the well to move to the production phase. Some development areas have a pipeline ready to take the gas to market. In these areas, the producer will typically put the gas directly into the pipeline so there is no visual sign of flaring.

Marcellus Shale gas developers recognize that the drilling process is not without short-term inconveniences. The project requires a large fleet of trucks to service the site, including on an average of 400 trucks coming and going during the fracturing process, transporting water to and from the drill pad. Gas developers work with municipalities to post bond to protect and repair roads, post road flagmen when needed, and repair any impacts to the environment that may occur temporarily during the drilling process.

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Site Restoration

Shale gas producers aim to leave behind a small footprint for each well pad through the restoration process. Restoration involves landscaping and contouring the property as closely as possible to pre-drilling conditions. Property owners generally see a small wellhead on a level concrete pad, a small amount of equipment, two to three water storage tanks and a metering system to monitor gas production. All equipment is painted and maintained for safety and appearance by a well tender.

Summary

As noted, the information in this chapter is taken directly from the Marcellus Shale Coalition website. While the information is somewhat general and reiterates some of the material previously discussed, the Coalition adds some useful information in refining today's participants' understanding of the upstream sector.

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Chapter III – *Landowner Considerations*

The landowner has what the developer wants, and not too long ago in western Pennsylvania, landowners did not even realize they held assets of such value. As discussed earlier, the most common starting point for natural gas plays in the Pennsylvania Marcellus Shale formation is via a negotiation with the landowner to obtain rights to the desired oil and gas interests on the landowner's property. Most often, the terms of this negotiation will be transacted through an oil and gas lease.

The initial question facing most landowners in Pennsylvania is who holds the rights to the oil and gas reserves below the surface? Generally, if the deed to the landowner's real estate presents the title as "fee simple," it is an indication that the surface owner holds all of the mineral rights.

While this has been the case with the authors' experience, the Pennsylvania Department of Conservation and Natural Resources notes that there is a large population of property owners in the Commonwealth that do not hold the subsurface rights on their properties. As such, it is first incumbent upon landowner's legal representatives to flush out the mineral rights ownership to ensure they belong to the landowner.

In the Commonwealth of Pennsylvania, the grant of "minerals" is generally reviewed as separate and apart from oil and gas. Under the Dunham rule, *Dunham v. Kirkpatrick*, 101 Pa 36 (1882), a grant on reservation of "minerals" does not include oil and gas unless evidence exists to demonstrate that inclusion was the intent of the parties.

A case settled on September 11, 2011, in Pennsylvania's Superior Court, dealt with a dispute regarding a reservation of mineral rights. *Butler v. Charles Powers Estate et al,* Pa. Super. 198 (Pa. Super. Sept 7, 2011), addressed whether Marcellus Shale and the natural gas pool within the shale constitutes a "mineral" under the state's real property law.

Historically, Pennsylvania law has allowed that there is a rebuttable presumption that natural gas is not a mineral for purposes of conveying title to land. The decision in *Butler*, for all intent and purposes, upheld this rebuttable presumption. However, in an "Energy Focus Update" prepared by Buchanan Ingersoll & Rooney PC, it is noted that, "the fact that a Pennsylvania appellate court allowed such a 'settled' question to even be asked has reverberated throughout the Commonwealth's oil and gas industry."

Leasing and Selling Mineral Rights

Once it is determined that the landowner holds the rights to the minerals, including oil and gas, he or she may transfer these rights to one or more parties. Generally, these rights are conveyed in a lease to a developer who then becomes a leaseholder entitled to take those actions necessary to find and extract the natural gas.

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Usually, the consideration for the landowner's rights in the mineral interests is negotiated by a "Landman." A landman is essentially an independent contractor who performs various functions for oil and natural gas exploration companies, for which he receives a commission. One of the functions performed includes negotiating the acquisition of mineral rights.

The starting point for such negotiations is inherently a "standard" lease. In most cases the standard lease contains a number of fundamental considerations that, ultimately, will be critical to usefulness of the document, including:

- Term of the Lease
- Rights Granted/Surface Use
- Pooling
- Warranty Clause
- Ownership Change
- Storage
- Royalty Payout Clause
- Surface Damages
- Other Landowner Considerations

Term of the Lease

Leases are divided into two separate time periods. The first period, or *primary term*, is a set number of years negotiated by the parties during which the lessee must commence drilling operations or pay an annual fee to the lessor. The lease will generally state that if drilling operations are not commenced within a short period of time after the lease is entered, the lease will terminate unless an agreed sum is paid the lessor. This sum is called a *delay rental*. Delay rentals must be paid on each subsequent anniversary date of the lease's primary term if drilling operations have not yet begun by that date.

Failure to receive the delay rental payment by the stipulated time automatically terminates the lease whenever the word "unless" is used in the lease to indicate the necessity of tendering the payment. Some leases contain the word "or" rather than "unless." In the latter case the lease may not terminate.

If production is not established by the end of the primary term, the lease will end. If production has been established, the lease will continue into its secondary term and last so long as substances covered by the lease continue to be produced. Generally the full clause will read, "This lease shall remain in force and effect for a term of __ years (or months) and as long thereafter as substances covered by the lease are produced."

<u>For the best protection, the lessor should consider one or more of the following recommendations</u>:

1. Strive to keep the primary term as short as possible. This should force earlier explorations.
2. If the primary term cannot be shortened, strive to negotiate a higher annual delay rental payment.

3. Make sure the word "unless" is employed in conjunction with delay rentals. Keep a watchful eye on the date by which the delay rental payments must be received. Acceptance of a late payment may be construed as a ratification and the lease will not terminate.

4. Stipulate that the lessee must identify the governing lease and the provisions necessitating any payments made to the lessor. This is an invaluable aid for landowners keeping track of several different leases on their land.

As with any legal agreement, the length of time to which the mineral lease applies can vary. Most often, the authors have observed the initial term of these leases extending three to five years, with five being the norm. Beyond the initial term, many mineral leases contain extension options. The length option period is generally the same as the initial term.

The initial lease execution is often accompanied by a "lease bonus" payment to the landowner. Upon remittance and receipt of the lease bonus, the lease is converted to the status of a "paid up" lease, which does not require payment of the delay rental payment over the primary term. Usually paid within 60-90 days, this payment is predicated upon developer expectations as to the property's potential, and it is based on the number of areas leased. Prior to the Marcellus Shale play identified in western Pennsylvania in 2004 by Range Resources, property owners were leasing these mineral rights for a lease bonus of as little as $25 per acre. With all the hype and services of the play, the authors have recently observed lease bonus payments as high as $6,500 per acre.

Extension of the Primary and Secondary Terms

The primary, and sometimes the secondary, terms of the lease may be extended contractually via *shut-in provisions, dry-hole provisions* or *cessation-of-production provisions*. Most leases will contain all three.

Shut-in provisions allow the lease to remain in effect whenever gas from a producing well is not, for some reason, being sold or used by the lessee. In other words, a well that is shut-in is still classified as a producing well under the lease provisions, and the lease will not terminate. However, a shut-in royalty (or some other stipulated sum generally approximating the value of the delay rental payment) must be paid annually to keep the lease in effect.

Dry-hole provisions, on the other hand, can only extend the primary term of the lease. Basically the lease will provide that if oil or gas has not been discovered when a dry hole is struck, the lease will not terminate, even though the primary term has expired in the interim, if the lessee renews drilling or re-working operations within 60 days (or some other specified period) thereafter. In the event the primary term has not expired and more than 14 months (or some other specified period) still remain, the lessee has two other options available. He can either pay the next delay rental payment, which comes due more than 60 days after the dry hole was discovered, or commence drilling or re-working operations on or before the same date. If less than 14 months remain in the primary term when the dry hole is discovered, the lease will continue in force to the end of the primary term, even though the lessee operations remain idle, and no delay rentals are paid.

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Cessation-of-production provisions correspond quite closely to the dry-hole provisions, but apply only after oil or gas has been discovered. If oil and gas production should cease for any reason, the lease will not terminate if the lessee again follows one of the three options described in the dry-hole provisions. In this instance, though, there are no exceptions accorded under the 14-month rule.

It is quite possible for the primary term to be extended indefinitely via the dry-hole provisions. If the lessee has not discovered oil or gas and is in the process of drilling or re-working operations when the primary term expires, the lease will continue in force for so long as the lessee faithfully renews drilling or re-working operations within 60 days after striking each dry hole. However, if a producing well should subsequently be discovered and its production later ceases, the lessee must strike another producing well stemming from operations commencing within 60 days thereafter or the lease will expire. The discovery of a subsequent dry hole will terminate the lease according to its terms.

Most landowners have little quarrel with dry-hole and cessation-of-production provisions since in both cases oil and gas are being diligently sought. However, landowners may question the shut-in provisions, especially where no apparent reason for the harboring of gas (or possibly oil) exists.

While shut-in provisions may not be used as extensively as in the past, landowners should be aware of the following alternatives that clarify its possible usage.

1. Place a time limit on the shut-in clause – no more than three years or three years beyond the primary term.
2. Escalate the shut-in royalty for each year the gas or oil is shut in.
3. As an alternative, permit the shut-in clause to continue after a stated period but only for a given number of acres immediately surrounding the well. The rest of the leased area will revert back to the lessor-landowner. (This provision may be qualified depending on the reasons for the shut-in).
4. Always phrase the necessity of making the payments under the shut-in provisions in optional terms (*may* or *can*) and not in obligatory terms (*shall* or *will*). In some states a breach of the former terminates the lease, whereas a breach of the latter does not. The only recourse left to the landowner in the latter case is to sue the producer for breach of contract.
5. Specify the circumstances when the shut-in clause may be invoked, i.e., for lack of market, available pipeline or government restrictions, or permit the shut-in only when, in the lessee's good faith judgment, it is economically inadvisable to produce and sell for the time being.
6. Automatically terminate the shut-in provision whenever a well located on adjacent land, situated within a certain number of feet of the leased premises, and completed within the same producing reservoir, begins producing and selling gas in marketable quantities.

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Rights Granted

Perhaps the most critical element of the mineral lease agreement is the rights given to the exploration and production company. These rights carry specific powers to the leaseholder related both to the underlying subsurface mineral rights and the leaseholder's use of the property's surface.

The Granting Clause

The opening paragraph of most leases is the granting clause. It will outline the purpose of the lease and describe the substances that can be explored and produced. Typically, this provision includes exploring, drilling, mining and producing oil and gas and all other associated hydrocarbons in whatsoever nature or kind. The more liberal leases state the agreement covers all other minerals and other gases and their respective vapors.

Landowners should be hesitant about signing the more liberal type lease. Their concern should be with the royalty percentage share that is allocated to the other minerals. For example, landowners should expect a greater royalty from the production of uranium or helium than from carbon dioxide or sulphur. If the lease is silent on this matter, a landowner will receive the same royalty for all minerals that are produced.

As possible alternatives, landowners should enumerate the minerals covered by the lease, to the exclusion of all others, i.e., all petroleum and natural gas and related hydrocarbons and no other minerals or substances in any form. Alternatively, landowners may amend the royalty clause to denote explicitly the percentage share they will receive for the production of any substances likely to be found in commercial quantities. Finally, the lessor may consider inserting an arbitration clause to ascertain the royalty for substances other than oil, gas, and associated hydrocarbons that may be discovered.

Granting Clause and Surface Operations

With few exceptions, the grant of an oil and gas lease carries with it the implied right to use as much of the surface area as is reasonably necessary to explore and produce the oil and gas. Oil companies generally desire a much broader usage of the surface area. Consequently, most leases contain provisions permitting a wide range of surface activities.

Even though the lessee may be liable for surface damages, the inconvenience of unwanted and unwarranted structures and entries upon the surface area by the lessee may be avoided to some degree by the following:

1. Do not grant the unrestricted right to construct permanent facilities such as power stations, storage tanks, or employees' quarters. Also, do not grant an unrestricted right for the surface disposal of salt water if valuable agricultural land is to be preserved. Instead, state that the prior written consent of the lessor is needed for both the construction and location of such structures and sites.

2. Alternatively, attach a map of the proposed lease area specifying where roads, pipelines, telephone lines, salt water disposal sites and even wells may be located. For convenience sake, landowners generally do not permit wells within 200 feet (or other stipulated distance) of a dwelling. Further, provide that all underground transmission devices such as pipelines and telephone lines must be buried below plow depth (or a specified depth) in agricultural areas. If deviations are necessary, permit them only after securing the lessor's written consent.
3. Landowners wishing to cultivate or graze the area immediately above any pipelines should direct the lessee to use the double ditch method for laying pipe. This method requires the top soil be placed on one side of the trench and the subsoil on the other. When backfilling, the subsoil is replaced first followed by the top soil.
4. Specify whether the lessee's structures and equipment must be removed at the expiration of the lease or be forfeited.
5. Identify the parties liable for the construction and maintenance of fences, gates, or similar structures around the premises, pits, drilling sites, and above intersecting pipelines. The precise dimensions and characteristics of these retention devices may need to be included to prevent the erection of inadequate fences and gates.

Pooling

Most leases entered into within the last five years will contain some provision giving the lessee the right to consolidate the leased premises with adjoining leased tracts. The area thus formed is called a "pool" or sometimes a "unit." The rationale for establishing such pools is to unite, under one operator, all the landowners having an interest in a common underground reservoir. By doing so, the lessee avoids unnecessary drilling, protects the rights of the landowners in the common reservoir and prevents waste. Sometimes pooling arrangements are necessary to meet the minimum acreage requirement for a drilling permit under state regulations.

In most states, landowners may be subjected to two types of pooling arrangements. One is voluntary; the other is compulsory or statutory. The voluntary arrangement requires the free consent of the landowner and is generally found in the context of most lease forms. The statutory arrangement, on the other hand, is mandatory whenever the specified requirements under relevant state law have been satisfied. By entering either type of pooling arrangement, the landowner may find the interpretation and application of the lease provisions materially altered.

Obviously, the landowner can do little to avoid compulsory or statutory pooling. The landowner, however, may find it advisable to exercise caution in granting the lessee the unrestricted right to pool the leased premises. The following suggestions may be helpful in this regard.

1. Submit to voluntary pooling in the lease only to the extent necessary to get a drilling permit from the state. Otherwise, the landowner's written consent should be required to pool. Do not consent until the landowner understands the full impact of the pooling arrangement on the lease terms, the full description of the proposed pool area and the details on how the boundaries were determined.

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2. In order to keep a pool from being overly extensive, stipulate in the lease the maximum number of acres a pool may contain. As a rule of thumb, limit the acreage to no more than that specified in a statutory or compulsory pool in your state.
3. Give some thought as to whether the lessee may alter or change the size or shape of the proposed pool after the landowner has consented.
4. Consider whether the pool is limited to certain producing strata or given for any and all producing formations which may be encountered. Also consider which substances may be pooled, i.e., oil and gas but not other gaseous substances, coal or valuable stones.
5. In all cases, try to negotiate the inclusion of a "Pugh" clause in the lease that provides for the severance of the lease into separate tracts whenever less than all of the premises are included in a single pool or unit. A typical Pugh clause will read, "Upon the pooling of less than all of the leased land, this lease shall be severed and considered as separate and distinct leases. The lease term and all the rights and obligations of the lessee under this instrument shall apply separately to the pooled and unpooled acreage." Without a Pugh clause, leases generally have language which extends the "leased premises" to all areas pooled with the original tract. Thereafter, if production, drilling or re-working operations are commenced on any portion of the pool (whether on the original leased tract or not), they will be construed as being undertaken on the leased land. By thus including a small area of a larger lease tract in a pool, the lessee can effectively eliminate the need for tendering delay rentals, reduce the proportionate share of royalties to the respective landowners, and still maintain the full lease by drilling and possibly establishing production on any part of the pooled area.
6. If possible, require all pooling to occur prior to drilling operations and not afterwards.

Warranty Clause

Warranty clauses are inserted into the lease agreement to protect the E&P company, not the landowner. The most common warranty deals with ensuring perfection of the landowner's rights to the minerals.

Leases generally will contain a warranty clause binding the landowners to defend their interests in, or title to, the leased premises should a dispute ever arise over ownership. To avoid any possible litigation expenses, landowners should seek to delete such language. Since most oil companies or landmen generally conduct preliminary investigations as to the ownership of the mineral interest prior to any lease negotiations, the warranty clause should not be needed anyway.

If a warranty clause is required by the lessee, the landowner should negotiate to limit the warranty to a "special warranty," and, therein, limit his or her liability under that warranty to only those actions for which the landowner was responsible.

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Ownership Changes

The lease should provide for the lessor's ability to transfer ownership of their respective rights under the agreement. Such a provision adds value to the landowner's rights as it allows greater flexibility in maintaining his position or disposing of it.

The transfer of a royalty interest is a common transaction, oftentimes allowing the landowner the "cash out" by selling that interest to a third party for the "present value" of future cash flows. Such ownership change provisions are often accompanied by notification requirements in the lease that mandate timely notice to the nondeparting party.

To protect the lessor/landowner, restrictions and/or limitations on the transferability or rights of assignment of the lessee should be negotiated in the lease to reduce the chances that the lease will be transferred during the lease term to less-desirable lessees.

Storage

It is not unusual to encounter mineral leases with a standard provision allowing the E&P company the right to "store" natural gas on the property. In such cases, it is essential that the storage fields be identified and that all specifics be set forth in the lease. Obviously, environmental concerns are paramount in natural gas storage, and any agreement between the parties must receive approval from the Federal Energy Regulatory Commission. Generally, rights to storage should be conveyed under a separate storage lease or agreement.

As storage fields are generally located closer to the surface than the natural gas deposits in the Marcellus Shale, the pressure of the field can usually be accomplished without interfering with further exploration and production activities. Additionally, storage accommodations may serve as a separate and distinct revenue source for the landowner, and should be negotiated as such.

The Royalty Payment Clause

Each lease contains a royalty clause that allocates to the landowner a certain portion of the substances produced. Economically, it is probably the most important clause to the landowner. The terms of royalty clauses vary greatly from lease to lease. The authors have observed royalty payments ranging from 12.5 percent to 16 percent, and have been told of royalty rates as high as 22 percent. Consequently, this clause should receive close scrutiny by landowners. Some potential problems to guard against are detailed below.

First, determine which costs, if any, can be deducted from the landowner's royalty payment. The costs encountered throughout the exploration, drilling, production and marketing stages are divided into two categories: those borne solely by the oil company (producer); and those shared by the landowner. Generally all expenses encountered

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up through the production stages are borne solely by the oil company unless the lease states otherwise. Expenses encountered subsequent to production can be either shared or borne solely by the oil company depending on the terms of the lease.

The shared expenses will depend partly upon where the lease fixes the royalty. If the lease is silent on this matter, the royalty is implicitly ascertained "at the well." In such cases, the landowner's royalty payment is free of production costs but bears a proportionate share of certain costs incurred subsequent thereto. If the lease fixes the royalty "in the pipeline," "at the place of sale" or at other delivery points, a different set of costs subsequent to production will be shared but there is no uniformity among the states on this point. These subsequent costs may include such items as compression expenses necessary to make the product deliverable into the purchaser's pipeline, expenses necessary to make the product salable, the expenses used in measuring production, and even transportation costs.

Under Pennsylvania law, and specifically, the *Guaranteed Minimum Royalty Act (GMRA)*, (58 P.S. § 33 et seq), failure to guarantee a royalty at a rate of 12.5% of production (one-eighth) will not be valid. The issue of production costs and whether they are deductible against minimum royalties paid to the lessor/landowner are not specifically addressed in the GMRA.

Note that in a 2010 case, *Kilmer v. Elexco Land Services, Inc.*, 990 A. 2d 1147, 1151 (PA 2010), the court held the GMRA should be read to allow the deduction of post-production costs using an allocation method labelled the "net-back" method.

Another problem that the landowner should consider is determining how the royalty payment is valued or received. Three methods are generally used, based on market price, by way of "proceeds" or by receiving a royalty "in kind."

The first method is based on the market price or value of the mineral, generally at the mouth of the well. In the past, if there was no market at the well, then the market price prevailing in the field was used. And if there was no field market, then the value was determined by sales of marketing outlets. Finally, if there were no comparable sales, the actual or intrinsic value of the substance could be used.

The market price method has been quite popular with landowners because it allows the royalty to follow the recent upward price trend for oil and gas. However, sometimes the prices posted at wells or fields are discriminatively or artificially set and, hence, substantially less than the prices paid for comparable oil and gas at other locations. In such cases, it may be possible to get a higher valuation for the royalty payments but only after a difficult burden of proof has been met by the landowner in a judicial proceeding. To avoid such problems, always try inserting some formula for determining how the market price or value will be established. For example, some leases read, "at the highest price (or percentage thereof) posted for a field within 100 miles by any of the seven major oil companies for like grade and gravity on the day the oil is removed."

The predominant method for calculating operating royalties is as follows:

Amount of cubic feet of natural gas extracted at the wellhead
x
Average monthly price of natural gas
x
Landowner's ownership percentage in the unit
x
Royalty percentage in the lease agreement
Royalty Payment Due

The second method of evaluating royalty payments is by way of "proceeds." This method ties the value of the royalty to the actual revenue (or sales price) received from the sale of the mineral. As such, the resulting returns may or may not equal the mineral's actual market value as discussed earlier. In the past, royalties based on proceeds were very popular. This method gave greater flexibility to the producer in marketing the product, particularly gas. By committing gas to long-term contracts, the producer could insure the landowner of a constant, dependable royalty income over time. The disadvantage was that the resulting proceeds were not immediately sensitive to a rising market price.

The third method of receiving a royalty is "in kind." This method allows the landowner to take actual possession of his share of the mineral's production before it is ever marketed by the producer. It presents an excellent alternative for dealing with a lease based on "proceeds." By inserting an option to take royalties either "in proceeds" or "in kind," the landowner can get the best of both worlds. Whenever the market price rises above any long-term commitment price, the landowner can take his or her share "in kind" and seek a more lucrative market outlet. Whenever the market price falls below any long-term commitment, the lessor's share can be taken in proceeds. As a general rule, lessees are hesitant about granting an in-kind/in-proceeds option unless the lease is in a major producing field. Otherwise, the cost of storage, accounting, delivery and other associated expenses may prove to be economically unfeasible. Such arrangements are exceedingly rare in the Marcellus Shale play.

Without belaboring any one point, the following is a list of factors that also might be considered when negotiating a royalty clause.

1. Detail the time, place and frequency royalty payments are to be tendered. Outline the consequences for royalty payments being missed.

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2. Discuss and resolve whether royalties must be paid for wastes due to leakage, fire, or other reasons that can be attributed to the lessee's negligence.
3. Reserve the option to take "in kind" if feasible.
4. Consider an extra royalty based on a sliding scale with any one of several items as variables. For example, have one royalty based on daily or monthly production of less than (x) barrels per day (or month) and another whenever production exceeds this level. Other variables upon which the scale could be based include whether the substance is free flowing or whether it must be lifted by artificial means, the price of crude oil in the event domestic price controls are eliminated, or the lessee's recouping of all or a certain percentage of the production cost from the well.
5. Determine if and when the landowner should have access to free gas. Many leases allow the lessor the free usage of gas for domestic (and sometimes agricultural) purposes. This access to free gas is nonexistent with respect to the Marcellus Shale play, as free gas issues most often arise in shallow reservoirs.
6. By the same token, decide whether the lessee should have free use of water, oil or gas produced on the leased premises.
7. As mentioned in prior sections, do not forget to include any differing royalty percentages for substances other than oil and gas that might be discovered if the landowner should choose that alternative.
8. Always state the exact costs encountered subsequent to production that may be shared regardless of whether the royalty is fixed "at the well," "in the pipeline," or "at the place of sale." Ideally, negotiate a clause that requires no costs subsequent to production to be borne by the lessor.

Surface Damages

As mentioned earlier, the granting of an oil and gas lease carries with it the implied right to use as much of the surface area as is reasonably necessary for the development of the mineral interest. Only when the lessee goes beyond what is reasonably necessary and negligently injures the surface area will the lessee become liable for damages to the holder of the surface estate. Likewise, the lessee is under no legal obligation to restore the surface area to its condition prior to the commencement of operations.

For better protection, the landowner should insert some provisions in the lease pertaining to surface damages. For instance, a lease clause requiring compensation for all surface damages will render the lessee liable even though the injuries were incurred during the reasonable development of the mineral lease. In most instances, including pooling of interests, only one landowner will be able to recover surface damages. That landowner will be the owner of that area where the drill pad is located.

When compensation is required, it is commonly made "at the site" when drilling or production operations cease. In order to avoid any conflicts in this matter, the landowner should consider the following lease options.

1. Require compensation for all surface damages.
2. If possible, require the lessee to restore the land to its condition prior to any operations.
3. Describe the method or methods to be employed for determining the extent of damages suffered. In the event the parties cannot agree, provide for arbitration or some other means of resolving the dispute.
4. Describe the items for which the lessee will be liable – i.e., injuries to growing crops, pastures, erosion and stagnation of the soil, growing timber, livestock, fences, ditches, canals, buildings and other structures, or the pollution of any waters.
5. Determine if the compensation will be paid annually or in a lump sum. In part, this decision will depend on whether the damages are temporary or permanent in nature.
6. Resolve beforehand how payments will be distributed on the premises.
7. Designate the time period by which all claims or notices must be submitted to the lessee.
8. Possibly require a bond or an advance payment as security for claims against future surface damages.
9. Whenever someone enters into an agricultural lease or purchases surface rights to land void of any mineral interests, he or she should always enter a contract with the owners of the mineral interests stating that a surface damage clause will be included in any mineral lease that is entered. This will insure the lessee or purchaser that any damages to crops, pasture or surface will be compensated.

Lessee's Right to Free Water, Oil and Gas

Landowners should pay close attention to any provisions in a lease providing free water, oil or gas to the producer for operations. Particularly in areas where water is scarce, certain limitations should be placed on these rights. The following suggestions may be helpful.

1. Decide whether free water, oil or gas privileges will be granted to the lessee. If so, stipulate whether the substances may be used for operations conducted both on and off the leased premises. (These provisions may be incorporated into the royalty clause as mentioned earlier.)
2. Do not allow the lessee to take water from wells, tanks, ponds or reservoirs.
3. If recovery measures are undertaken by the lessee involving floodwater operations, deny the use of potable water. State that such water must come from non-fresh sources.
4. If water is to be purchased, state how the market price will be determined.

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Other Factors for the Landowner's Consideration

Without going into detail, the following factors may be considered by landowners when negotiating a lease.

1. If the land contains several producing formations at varying depths, lease each strata independently.
2. Always note in the lease whether the land can be used for underground storage of gas or oil.
3. Always insert provisions allowing free access to books, records, and drilling data accumulated pursuant to operations conducted on the landowner's premises.
4. Provide that if the lessee does not rectify any breach of a covenant contained in the lease within 30 days after lessor gives written notice, the lessee should pay reasonable attorney fees and reasonable investigative costs incurred by lessor in preparing lessor's case for trial.
5. Require lessee to defend, indemnify, save and hold lessor harmless from all claims, demands and causes of action stemming from activities undertaken by lessee or lessee's assignees, their employees, agents, contractors and subcontractors, during operations conducted on the leased premises. As an alternative, require the lessee to post bond and carry comprehensive liability insurance of a specified amount as added security from such claims.

Negotiation

While landmen will present the landowner with a standard-type lease, it is important to note that every provision within the lease is negotiable, within reason. A landowner will require qualified legal assistance to perform this important role. Attorneys finding themselves involved in such negotiations at the front of the transaction can provide a significant benefit to their landowner clients.

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Chapter IV – *Treatment of Income under an Oil or Gas Lease Agreement*

As previously discussed in these materials, landowners entering into an oil or gas lease agreement have much to consider during the negotiating process. After the parties have decided the lease terms and the driller begins its activities on the landowner's property, the landowner often finds himself in receipt of large, even life-changing, sums of income. In addition to conducting due diligence with regards to setting the terms of the lease, the landowner also would be wise to seek counsel with respect to the income tax implications of an oil or gas lease.

Various types of payments commonly negotiated within an oil or gas lease were touched upon earlier in these materials. The specific income tax treatment of these payments to the lessor (landowner) are further discussed herein.

Royalties

Bonus Royalty (Lease Bonus)

The bonus royalty, also referred to as the lease bonus, is a payment received by the landowner (lessor) upon execution of the oil or gas lease. For the oil or gas driller (lessee), the lease bonus payment allows entrance to and exploration of the owner's land. Typically, the bonus royalty is a one-time, lump-sum payment, but may be made via installment payments over an agreed-upon period of time. The negotiated payment generally represents a fixed sum per acre.

For income tax purposes, a lease bonus is taxed to the lessor as ordinary income, not as capital gain income. Pursuant to a decision by the Supreme Court, the bonus royalty is "payment in advance for oil and gas to be extracted," i.e., advance royalty, for federal tax purposes. Practitioners and landowners may desire to report this income as royalty/rental income. However, the Internal Revenue Service (IRS) takes the position that this is classified as other miscellaneous income. Further, income from the bonus royalty may not be used to compute percentage depletion (but is allowed for cost depletion.)

Advance Royalty

An advance royalty is payment to a landowner before extraction of minerals. Like a bonus royalty or a lease bonus, advance royalties may be paid as a lump sum, or may be paid in installments based on predicted production levels, but are paid before a driller has begun production of oil or gas.

If the driller can offset (reduce) future operating royalty payments with advance royalties, the payments are taxed to the lessor as ordinary income and reported on Schedule E as royalty income, and are eligible for percentage or cost depletion allowances. However, if the lessee cannot reduce future royalty payments, the advance royalty is generally treated to the lessor as a lease bonus (miscellaneous other income) or delay rental (Schedule E rental income). Income from the advance royalty, if treated as a delay rental, may not be used to compute depletion.

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Operating Royalty

An operating royalty is paid by the drilling company to the landowner once production has commenced from wells drilled on his or her property. The payment amount is based on a mutually agreed-upon calculation related to the production of the mineral. These payments are generally paid to the landowner on a monthly basis.

This payment is reported on Schedule E, subject to ordinary income tax rates. Operating royalties may be treated as income to calculate allowable depletion (percentage or cost, whichever is greater).

Minimum Royalty

A minimum royalty is a contractual amount below which a royalty payment may not fall for an agreed-upon period of time. Lessors negotiate minimum royalty clauses into their leases to ensure that if production levels fall below a lessee's expectation, the lessor still realizes a set fee. A lessee generally prefers the fees to be recouped when production levels increase above the minimum; however, lessors generally prefer not to allow recoupment.

This income is reported by the lessor as rental/royalty income. The minimum royalty income is allowable for purposes of calculating depletion, to the extent that the minimum royalty payments are recoupable from operating royalty payments. In the event that the minimum royalties are not recoupable, the amount of the payments that exceed the calculated payment based upon production is eligible for cost depletion.

Minimum royalty payments must be separately paid in order to avoid tax treatment as an installment bonus or delay rental.

Income Other than Royalties

Delay Rental

Pursuant to the Internal Revenue Code regulations, "a delay rental is an amount paid for the privilege of deferring development of the property and which could have been avoided by abandonment of the lease, or by commencement of development operations or by obtaining production." In other words, it is a payment received by the lessor for extending the privilege to the lessee of deferring development of the property.

A delay rental may be negotiated as a fixed fee per acre and is generally paid to the lessor at the end of the year during the primary lease term. If the payments by the lessee are recoupable from future production payments (i.e., once production begins, royalty payments due are reduced by delay rental payments already made), delay rentals may be characterized as advanced royalty payments.

The lessor reports true delay rental fees on Schedule E as rental income, which is subject to passive activity rules. Income from the delay rental may not be used to figure a depletion deduction.

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Production Payments

Production payments represent a negotiated and allocated portion of production revenue payable to the holder of the rights to that production payment. From a tax perspective, Internal Revenue Code (IRC) § 636, enacted in 1969, controls. Production payments were typically treated as economic interests subject to depletion prior to the enactment of § 636. However, § 636 and the regulations provide that in order for a production payment to be classified as an economic interest subject to the depletion allowance (rather than a loan payment, as discussed below), it must be qualified as an economic interest according to the types of income previously discussed.

Pursuant to IRC § 636, production payments are treated in several different ways, as follows:

- ***Carved-out Production Payments (§ 636(a))*** – A production payment carved out of mineral property shall be treated as if it were a mortgage loan on the property, and shall not qualify as an economic interest in the mineral property. In the case of a production payment carved out for exploration or development of a mineral property, the preceding sentence shall apply only if and to the extent gross income from the property (for purposes of § 613) would be realized, in the absence of the application of such sentence, by the person creating the production payment.
- ***Retained Production Payment on Sale of Mineral Property (§ 636(b))*** – A production payment retained on the sale of a mineral property shall be treated as if it were a purchase money mortgage loan and shall not qualify as an economic interest in the mineral property.
- ***Retained Production Payment on Lease of Mineral Property (§ 636(c))*** – A production payment retained in a mineral property by the lessor in a leasing transaction shall be treated, in the hands of the lessor, as a bonus payment received in installments from the lessee, and will be treated as ordinary income taxable to the lessor.

Further, Treasury Regulation § 1.636-3 includes the following elements in the definition of a production payment:

- A right to a specified share of production or the proceeds from such production.
- It must be an economic interest.
- The property upon which it is a burden need not be an operating mineral interest.
- If it can be satisfied by other than production, it is not an economic interest.
- It can be measured by dollars, quantum of mineral, or time.
- It includes "in-oil payments," "gas payments," and "mineral payments."
- It must have an expected economic life (at the time of its creation) of shorter duration than the economic life of the mineral property upon which it is a burden. This test is further qualified by "may not reasonably be expected to extend in substantial amounts over the entire productive life of such mineral property."

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Damage Payments

Specific payments by the lessee to the lessor for damages sustained on the lessor's land during exploration or while a lease is in place may be treated by the lessor as a non-taxable return of capital (with a reduction to the basis of the property). If the payment exceeds the basis of the property, the excess income is reported on Form 4797 and is treated as Section 1231 gain if the property was held for more than a year. However, the burden of proof is on the taxpayer-lessor to show that payments are separate and are not of the nature of rental income for the lessee's use of the land.

Types of payments by the driller to the landowner treated as damages are compensation for the destruction of standing timber and disturbance of land in order to build access roads, drilling pads and fracturing ("frac") ponds.

It is important to stress here that the treatment of damage payments as non-taxable return of capital are more likely the exception than the rule. Case history has resulted in favorable tax treatments to the lessor when the lessor can show that damage payments are, in fact, not rental compensation. The IRS burden of proof, however, is likely onerous. When the burden of proof cannot be met, the IRS will consider the payments to be ordinary income not subject to depletion.

Shut-in Fee

Payments during the period that a producing well is temporarily closed or is not connected to a pipeline for extraction are shut-in fees. These are usually classified for tax purposes as a royalty payment or rental income. If the lease will terminate as a result of non-payment, the shut-in fees are considered to be delay rentals (still ordinary income for landowners). Shut-in fees treated as delay rentals are not allowable income for depletion deduction calculations.

Right of Way Income

Right of way income is generally in the form of a one-time payment for an easement for well, tank battery, flow line and road locations. These payments by the lessee are for rights to access and use a landowner's property.

Right of way income is generally considered to be miscellaneous income and taxed at ordinary tax rates. However, in some cases, these payments could be considered compensation for damages. If for damages, the lessor recognizes no income, and the payments are considered to be non-taxable and a return of capital (with a reduction to the basis of the property). If the payment exceeds the basis of the property, the excess income is reported on Form 4797 and is treated as Section 1231 gain if the property was held for more than a year. Of course, this favorable tax treatment may be challenged, with the burden of proof being on the taxpayer-lessor.

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Seismic Income

Seismograph payments are made by the drilling company to the landowner for the privilege of accessing the landowner's property and conducting exploration on his land. The income is taxable to the landowner as ordinary income, and is not subject to depletion.

Miscellaneous Fees

Other types of income that are generally not included in a standard lease agreement are fees for maintaining a staging area on a landowner's property and fees for building a facility reception point and compressor station. The lessor and lessee negotiate the terms of these payments separately. Income under these separate agreements are typically one-time payments and are treated to the lessor as ordinary, other miscellaneous income.

Example of a Lease Agreement

(from Chapter 3 of CCH's *Oil and Gas Tax Reporter*)

A, the owner of a ranch, grants B an oil and gas lease on 640 acres for a cash bonus of $3,200 per acre and a one-eighth royalty. The lease grants B the right to enter upon the land and conduct seismograph operations for a separate consideration of $640, provides for delay rental in the sum of $5 per acre per year, and provides that, in the event at the end of the primary term there are wells capable of production on the property, but which are shut in due to lack of a satisfactory market, the lease may be extended by the payment of $5 per acre per year shut-in royalty.

- The bonus payment received by the lessor must be treated as ordinary income, subject to cost depletion.
- The lessor must report the sum of $640 received for the seismograph operations as rental income unless damages were caused to his property by reason of these operations. In that event, basis in the minerals damaged would be charged against this receipt to determine gain or loss. If basis in the mineral interests is not severable from basis in surface rights, presumably the payment received would be treated as recovery of a portion of total basis.
- The sums received as delay rental and shut-in royalty will be taxed as rental income. If the shut-in royalty had been advance minimum royalty to be recovered by the lessee out of future production, it seems reasonable to treat them as minimum royalty income which may be subject to cost depletion.

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Other Income Tax Considerations and Deductions from Income

It is prudent to briefly touch on several other foundational concepts of taxation relevant to the oil and gas industry. The nature of a taxpayer's (whether an individual or a business entity) interest in an oil or gas operation is of key importance to determining the recognition of income and allowable deductions. These determinations are dependent upon whether a taxpayer owns an economic interest in the oil or gas activity. Only an owner of an economic interest is entitled to a depletion deduction (discussed further below).

An economic, or ownership, interest includes: fee simple interest, mineral interest, operating or working interest, royalty interest, overriding royalty interest, net profits interest, production payments interest, farmout interest and carried interest. The definition of each follows, extracted nearly verbatim from Chapter 1 of CCH's *Oil and Gas Tax Reporter* as a convenience to participants. Some of these economic interests were discussed earlier in these materials.

Fee Simple

All ownership interests in a mineral property are, in some way, derived from the basic fee simple interest. This interest includes ownership of the surface and subsurface (or mineral) rights and, to an extent, a limited amount of airspace over the land.

Typically, a landowner with a fee simple interest will dispose of his mineral rights rather than developing them himself. He may sell all or a portion of this mineral interest or lease the operating rights. In the case of an outright sale, the purchaser acquires a fee interest in the minerals. If the operating rights are leased, the lessee only acquires a term interest in the minerals. The lessee's interest will then revert to the landowner upon the termination, expiration or abandonment of the lease.

Mineral Interest

The term "mineral" has different meanings, which vary according to state law and local usage. Oil and gas may or may not be considered minerals, for example, depending upon where the term is used. For federal tax purposes, the term is primarily used to delineate natural deposits that are eligible for percentage depletion. However, depletion is not available for minerals derived from sea water, air or similar inexhaustible sources.

The term "mineral interest" generally refers to rights to the minerals in place. The owner of the basic mineral interest has the right to extract the minerals, sell all or a portion of his interest, or lease the operating rights. If owned by someone other than the landowner, the mineral interest may also include limited surface rights. Specifically, the owner or his lessee may be entitled to use so much of the surface as is reasonable to extract the minerals. Although the entire mineral interest may be in the form of an unleased mineral fee, it is generally divided into various types of ownership interests.

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Operating or Working Interest

An operating or working interest is charged with the costs and responsibilities of developing and operating the property. The owner usually has the right to conduct exploration activities, control drilling operations and share in production. Since this interest bears the costs of developing and operating the property, its owners are usually entitled to receive most of the production or production income. For federal income tax purposes, an operating or working interest owner is required to account for the costs of production in determining his percentage depletion limitations.

An operating or working interest may be owned in fee or acquired under a lease, sublease or sharing arrangement. An operating or working interest owned by someone other than the fee owner is usually considered a term interest. Generally, such an interest will continue as long as minerals are produced in paying quantities or for a specified term.

Royalty Interest

A royalty interest is the right to receive a specified amount of the gross income or production from a mineral property. The amount may be expressed as a fraction or percentage of total production. In some cases, it may be expressed as a specific amount per unit. A royalty owner is ordinarily liable for his share of production or severance taxes, but not for the costs of exploration, development or operation. A royalty interest is therefore a nonoperating interest for federal income tax purposes.

A royalty interest is usually retained by the landowner when he leases the operating rights to his property. The landowner's royalty is considered a perpetual interest since the landowner's rights will continue even if the lease is terminated or abandoned. It is not uncommon, however, for a landowner to carve out and sell a portion of his royalty.

Overriding Royalty Interest

An overriding royalty operates in much the same way as a regular royalty. It is the right to receive a specified share of the gross income or production from a mineral property. Again, the amount may be expressed as a fraction or percentage of total production or as a specific amount per unit. The owner is usually liable for his share of production or severance taxes, but not for the costs of exploration, development, or operation. It is therefore a nonoperating interest for federal income tax purposes.

An overriding royalty is generally created in one of two ways. It is either retained in a transfer of the operating interest or it is carved out of that interest. The duration of an overriding royalty is therefore limited to the life of the operating interest. Upon the termination or abandonment of the operating interest, any overriding royalties created out of it will cease to exist. This is the major difference between an overriding royalty and a landowner's royalty.

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This distinction between a regular royalty and an overriding royalty is usually not significant for federal income tax purposes. As a practical matter, it is not uncommon to hear these terms used loosely, and perhaps incorrectly, to describe almost any royalty interest.

Net Profits Interest

A net profits interest entitles its owner to share in the gross production from a mineral property. The owner's share of gross production is measured as a fraction of the net profits from the operation. If there is a loss from operations, the net profits interest owner ordinarily receives no production or production income in that year, and perhaps will receive none until all of the cumulative losses have been recovered. This depends upon the actual terms of the instrument or agreement creating the net profits interest. Although a net profits interest owner's share of production is reduced by the costs of developing and operating the property, he will have no liability for such costs to the extent they exceed his share of production income.

The amount of "net profits" due to the net profits interest owner is determined by the terms of the instrument creating the interest. For example, one instrument may provide that "net profits" are determined separately for each tax year. Another instrument may provide that operating losses in one year may be carried forward and recovered as an offset against "net profits" in future years.

Another consideration is the handling of expenses. One instrument may provide that exploratory or development expenses are deducted in arriving at "net profits." Another instrument may provide that only operating expenses are deducted in arriving at "net profits."

A net profits interest is treated as a nonoperating interest for federal income tax purposes. The owner is ordinarily required to pay his share of production or severance taxes, however.

A net profits interest is usually retained when an operating interest is transferred or is carved out of that interest. The duration of a net profits interest is, therefore, ordinarily limited to the life of the operating interest. It is not uncommon, however, for a net profits interest to be retained by the original owner of the fee interest in the minerals. In this situation, the net profits interest may be perpetual.

Production Payment

A production payment is a right to a specified share of the gross production from minerals in place or to the proceeds from such production. It may be imposed on an operating or nonoperating interest in a mineral property. For example, a production payment may be payable out of a royalty interest, an overriding royalty interest, a net profits interest or an even larger production payment. The duration of a production payment, however, must be shorter than the duration of the property it burdens. Generally, a production payment is limited by a specific dollar amount, a quantity of minerals or a period of time. A production payment ordinarily bears none of the costs of exploration, development or operation of the property. It is therefore a nonoperating interest for federal income tax purposes.

A production payment must, by the terms of the conveying instrument, be satisfied solely out of proceeds from the sale of production from the property burdened by the payment in order to be classified as an economic interest. Hence, if the payment is collateralized by a mortgage on lease and well equipment or by a guarantee by the owner of the property, it would not represent an economic interest.

The status of production payments as economic interests was significantly changed by the *Tax Reform Act of 1969*. Prior to August 7, 1969, production payments were considered to be economic interests. After August 6, 1969, however, the economic interest status of most production payments was revoked. Generally, a production payment is now considered to be a mortgage loan on the burdened property. There are exceptions to this general rule for certain carved-out production payments, the proceeds of which are pledged for exploration or development. Also, production payments retained on a lease of mineral property may be subject to treatment as a lease bonus.

A production payment may be retained from a transfer of a larger mineral property or carved out of such an interest. As previously noted, the duration of a production payment must be shorter than that of the interest it burdens. It is the duration of a production payment that distinguishes it from other types of nonoperating interests.

Farmout

A farmout is an arrangement under which the owner of an operating interest assigns this interest to another operator as a means of financing the costs of developing and operating the property. For example, the owner of the operating interest may transfer his entire operating interest and keep a nonoperating interest in the property. The transferee then assumes the entire burden of developing and operating the property. There are, however, many different ways in which a farmout may be structured.

The operating interest acquired in a farmout generally continues for as long as the conveying instrument (usually an assignment of a lease) maintains it in effect. In some arrangements, however, the extent of the interest may be reduced after the person receiving the operating interest (the "farmee") recoups his costs of developing and operating the property. See the following discussion of "carried interest."

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Carried Interest

A carried interest is created when the owner of an operating interest enters into an agreement with another party for the development of the property, and the agreement provides that the other party will "carry" the owner by paying a disproportionate share of the development expenses. The arrangement may be between two co-owners or between one who owns the entire operating interest and an operator who acquires his interest by developing the property.

In the usual transaction, the owner of an operating interest (the "carried party") will assign his interest to an operator (the "carrying party"). The carrying party is required to pay all the development costs and to look to future production for reimbursement. When the operator has been fully reimbursed, a fraction of the operating interest will revert to the carried party. The carried and carrying parties then share all future income and expense in accordance with their agreed shares of the operating interest.

Specific Oil and Gas Industry Deductions Allowed

Depending upon the type of ownership interest that a taxpayer holds in an oil or gas activity, certain industry-specific deductions from income are allowed to be recognized. Generally, an owner of an operating, or working, interest is entitled to the deductions of exploration and production. The owner of an interest other than a working interest is generally not permitted to deduct operating expenses, but may be allowed to reduce his income by way of a depletion deduction.

Operating income from oil or gas activities is calculated by taking gross revenue less these particular deductions and general/administrative expenses. Following is a brief overview of operating deductions that may be allowed, including geological and geophysical costs, intangible drilling costs and depletion. Additional discussion of these items is beyond the scope of these materials and presentation.

Geological and Geophysical Costs

Exploration costs, known as geological and geophysical costs ("G&G costs"), are incurred by the oil or gas driller in connection with surveying land for feasibility of drilling a well. Examples of G&G costs are professional fees paid to geologists and various geographical surveys. These costs are not permitted to be deducted as current expenses and must be capitalized and amortized over 24 months, using a half-year convention.

Intangible Drilling Costs

Expenses incurred by the operator/driller of an oil or gas well that are not ultimately part of the tangible well and well equipment are classified as intangible drilling and completion costs. Examples of these costs include ground clearing, wages, supplies, fuel, repairs, rig transportation costs, damage payments to the landowner and fees for professional (geologists, surveyors, engineers) services. There are many other drilling cots that are included in this category.

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Depending on the operator's income tax situation and various other considerations, intangible drilling costs may be expensed for federal income tax purposes as a current deduction from income or may be capitalized and amortized over a certain period of time, or a combination of the two methods. Note that for Pennsylvania income tax purposes, however, intangible drilling costs are not allowed to be currently deducted and must be capitalized and amortized.

Depletion

The concept of a depletion allowance is similar to the deduction for cost of goods sold in a manufacturing operation. Depletion is an annual allowance of return of capital used in the production of mineral income. Where depreciation is a deduction allowed for the cost of tangible, personal property, depletion is allowed on the intangible costs (i.e., leasehold costs) incurred in connection with the mineral production. Note that the cost base for the depletion deduction does not include intangible drilling costs, which are treated separately as discussed above.

Two methods of depletion are allowed – cost depletion and percentage depletion. Both are allowed to be taken only when actual mineral production begins, not simply when the underlying capital costs are incurred.

Cost depletion is calculated by dividing the adjusted tax basis of the property by the total mineral units expected to be recovered (referred to as "reserves"), resulting in a per-unit cost. The per-unit cost is then multiplied by the total units produced for the year. Cost depletion may not exceed the total tax basis of the property. If cost depletion exceeds percentage depletion, cost depletion represents the depletion deduction for that year.

Percentage depletion is calculated at a rate of 15% of gross income from the property, and is limited to 100% of taxable income from the property and 65% of the taxpayer's net income for the year. The calculation of taxable income from the property involves multiple factors. Unlike cost depletion, percentage depletion may exceed the tax basis of the underlying property and may be taken for as long as production and income from the property continues. If percentage depletion exceeds cost depletion, percentage depletion represents the depletion deduction for that year.

There are numerous federal and state income tax rules and regulations surrounding these specific deductions. Further discussion is beyond the scope of this presentation.

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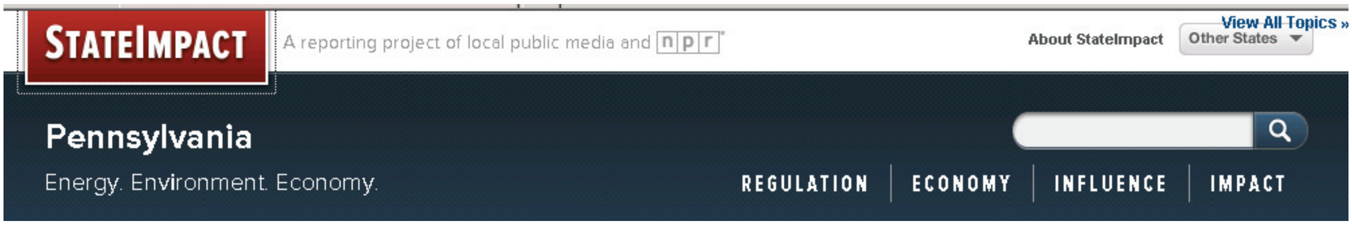
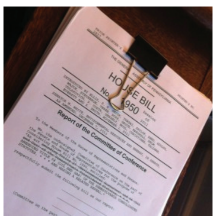




What the New Impact Fee Law Means for Pennsylvania

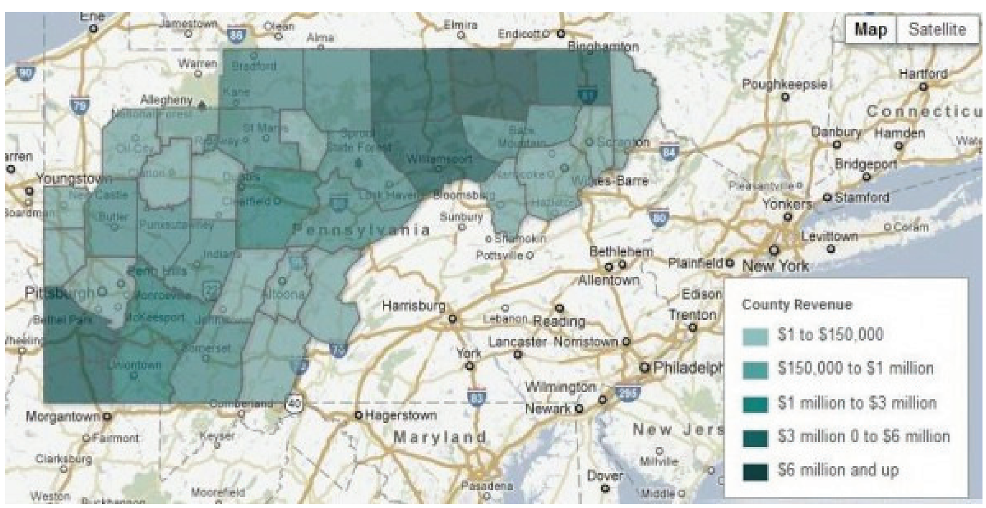
BACKGROUND

After years of deliberation on the issue, Pennsylvania legislators passed a bill overhauling the state's natural gas drilling laws on February 8, 2012.

THE FEE

The legislation places an impact fee on every well drilling for gas in the Marcellus Shale formation. The levy will change from year to year based on natural gas prices and the Consumer Price Index, but in 2012, drillers will pay $50,000 per-well. (Smaller, vertical wells will pay $10,000 this year.)

The bill's authors estimate the fee will generate around $180 million, when payments are turned in on September 1. 60 percent of the revenue will stay at the local level, going to counties and municipalities hosting wells. The rest will go to various state agencies.



While the fee is administered and collected on the state level, counties will decide whether or not to enact it. County commissioners have until mid-April to enact a fee. If any county chooses *not* to collect the money, its municipalities will have a 60-day window to override the decision. When more than half of the county's townships and boroughs pass a resolution calling for a fee, the levy will automatically be adopted.

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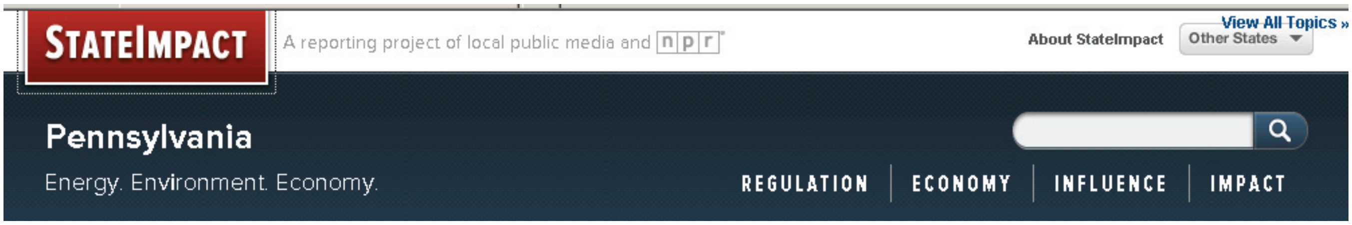

RESTRICTING LOCAL POWER

In addition to setting a fee, the legislation restricts municipal zoning of drilling operations. Townships and municipalities are required to allow drill rigs in all types of zones, except for densely-populated residential areas. It sets state standards for the minimum distance between wells and streams, schools, buildings and water sources. If a local government passes ordinances and regulations that go beyond the new state standards, the Public Utility Commission will have the power to bar the municipality from receiving any impact fee money.

OTHER NOTABLE ASPECTS OF THE LEGISLATION

- The bill authorizes the annual transfer of millions of dollars from the Oil and Gas Lease Fund to the Environmental Stewardship Fund and Hazardous Sites Cleanup Fund.
- Drillers' zone of presumed liability will expand from 1,000 to 2,500 feet. That means if a water source within this area is contaminated, the assumption will be that drilling messed it up.
- The Department of Environmental Protection can "enter into contracts" with private well control teams, who would be given limited immunity from civil lawsuits.
- Companies would be required to submit reports to DEP detailing chemicals used during the hydraulic fracturing process. This information would be published on FracFocus.org, which is becoming a national clearinghouse for fracking disclosure information.
- Civil penalties against drillers who violate regulations would be increased to $75,000.
- The bill sets new bond levels for drillers, based on the length of well bores and the amount of wells each company operates.

This article, along with helpful links, can be found at http://stateimpact.npr.org/pennsylvania/tag/impact-fee/

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Chapter V – *Royalty Valuation Considerations*

There is absolutely no question that issues related to valuation of properties in Pennsylvania, Ohio and West Virginia is a hot topic. Mineral (including oil and gas) rights have value because they have the possibility of generating cash. As noted earlier in this material, landowners can generate cash by selling their land (fee interest) or leasing the property for a bonus payment and the potential for royalty income based upon production when/if a well(s) is drilled on the property. Valuations are being performed for properties in various stages ranging from producing property, properties recently leased and those not yet leased.

This chapter will introduce concepts and methods unique to valuation in this area, as well as address certain issues that the legal community should be aware of when assisting your clients. Please note that the terms "valuation" and "appraisal" are used interchangeably.

Types of Mineral Rights

The key to any valuation in this area is to define up front "what does the client own" and "exactly what is being valued." This is typically called the holder's "bundle of rights." The following are types of mineral rights:

- ***Fee interest*** – outright ownership of land
- ***Royalty interest*** – right to receive a fraction of production without paying any cost
- ***Working interest*** – responsibility to pay some or all costs, in return for some or all production (after royalty payment)
- ***Carried interest*** – right to receive a share of production, without paying any up-front costs (non-operating)
- ***Production sharing contract*** – license and right to develop minerals

The focus of this material is the landowner, and therefore, the oil and gas rights as they relate to a fee interest and royalty interest will be addressed.

Common Transactions

The most common transaction (as described earlier in these materials) is one that involves the owner leasing acreage and in return receiving a bonus, annual rental fees and royalty payment out of any future production. Royalty owners may also sell their royalty streams. Other transactions include the lease holder selling a partial interest in the lease to another working interest owner and a working interest owner selling its working interest.

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Standard of Value

The most common standard of value used in the determination of the value in connection with these transactions is fair market value. The characteristics of fair market value include:

- Contemplation of a hypothetical market transaction;
- Remuneration is in cash or cash-equivalent;
- Neither party (buyer or seller) is forced to enter into the transaction;
- Both parties are knowledgeable about the property and the market; and
- It is an arm's-length transaction.

An "arm's-length transaction" is defined in Black's Law Dictionary as follows:

Said of a transaction negotiated by unrelated parties, each acting in his or her own self-interest; the basis for a fair market value determination. A transaction in good faith in the ordinary course of business by parties with independent interests... The standard under which unrelated parties, each acting in his or her own best interest, would carry out a particular transaction.[2]

In addition to the fair market value concept another consideration when valuing property in this area is *highest and best use*, which is defined as the highest and most profitable use for which the property is adaptable and needed, or likely to be needed, in the reasonably near future. Highest and best use is that use, which sequentially determined is:

- Legally permissible,
- Physically possible,
- Financially feasible, and
- Maximally productive.

The economic concepts of utility and substitution drive the highest and best use analysis. The highest and best use of a property determines its utility to a potential purchaser. The purchaser of such a property would pay no more than a competing property with the same utility while a seller would accept no less than a seller of a comparable property.

There is market evidence in this area that the highest or hypothetical use can be equivalent to the real use for the subject property as most oil and gas transactions are based on potential future use. Further, there is an active market for oil and gas leases in the geographic area.

[2] Pratt, Shannon P. *The Market Approach to Valuing Businesses*, Second Edition. Copyright 2005.

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Valuation Methods

There are three approaches to valuation including *cost, market* and *income.* The cost approach is used in connection with fixed assets (i.e. pipelines and refineries) and at times for exploration stage properties (not for development properties). As such, the cost approach will not be addressed herein.

Market Approach

The market (or comparable sales) approach includes both prior sales of the property and comparable sales transactions. The theory of the market approach to valuation of any asset is the economic principle of substitution. An investor would not pay more than one would have to pay for an equally desirable alternative. As such, it is broadly accepted within the valuation community that the market approach is a valid approach because it uses observable, factual evidence of actual sales of other properties to derive indications of value.

Comparable sales can be used as a check of reasonableness for landowners. The shortcomings of this approach are that information is highly-proprietary, as it is difficult to obtain information from other landowners; there is a lack of sufficient detail in the public domain; and there is a wade range of unit values. However, information can be obtained in the public market relative to transactions involving working interests.

For example, in February 2010, Houston-based Anadarko Petroleum and Mitsui E&P USA LLC, an affiliate of Tokyo's Mitsui & Co. Ltd. entered into a transaction whereby Mitsui paid $1.4 billion for approximately 100,000 acres in a joint venture with Anadarko, primarily in north-central Pennsylvania. This price equates to $14,000 an acre. In April 2010, Reliance Industries, India's largest energy company, entered a joint venture with Atlas Energy, wherein Reliance obtained 40 percent (120,000 acres) of Atlas' Marcellus Shale leases for $1.7 billion ($340 million in cash and $1.36 billion in drilling), which computes to a price of approximately $14,200 per acre.

Income Approach

The income approach is a very common approach when valuing royalty interests in oil and gas leases, as the oil and gas estate is owned and exploited to generate an income stream. The royalties generated from the exploitation of the oil and gas reserves is income benefitting the owner of the mineral estate.

The income approach is based upon the economic principle of anticipation (sometimes called the principle of expectation). The basic concept of the income approach is to project the future economic income associated with the oil and gas lease and to discount the projected income stream to a present value at a discount rate appropriate for the expected risk of the prospective economic income stream.

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The fundamental concept underlying the cash flow derived by a landowner from an oil and gas lease is as follows:

Cash flow = Production (quantity) x Price x Royalty Rate

The factors that must be considered in the valuation of royalty income include the royalty rate, unit sales price of the mineral, the projected annual amount of mineral unit production, the projected number of years of production and the year production will commence. Finally, the discount or risk rate attendant to realizing the future royalty stream at the times they are being projected is applied.

The present value (or worth) of the of the future benefit streams is defined as follows:

$$PV = \sum_t \frac{Q_t \times P_t \times R_t}{(1+D)^t}$$

Where:

Q = Quantity or production

P = Price

R = Royalty rate

D = Discount or risk rate

t = Years to wait for the anticipated cash flow

In order to calculate the anticipated royalty to the landowner, well production must be forecasted into the future. The production forecast is closely related to the reserve estimate typically prepared by a petroleum engineer ("PE"). Production will be forecasted out until costs begin to exceed revenue, which is when the economic limit is reached

It is the understanding of the authors of this material that gas production is a matter of diminishing returns – a well's output begins with a rush, then declines into a long tail so that nearly half of total production occurs within the first two years. Thus, approximately half of a landowner's payments will come within the first two years.

Note that all of this assumes that a single landowner receives all of the royalties from a particular well. In reality, a company must often negotiate leases with several landowners to assemble enough land for a "drilling unit," which is 640 acres, or one square mile.

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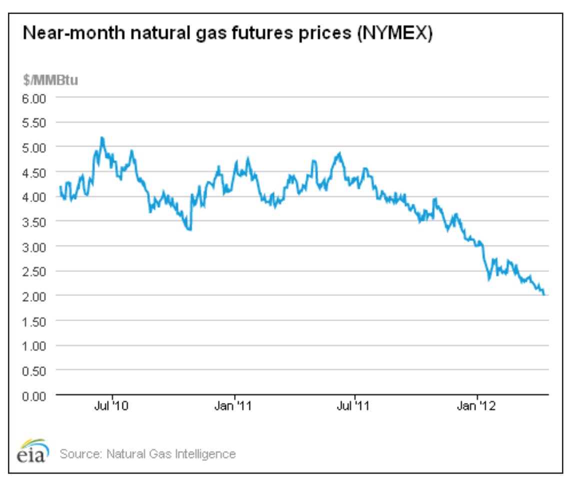
Production is forecasted typically using decline curves. The general purpose of a decline curve is to fit an estimated curve to the future production rate of a well. Ideally, the forecasted curves will begin with historical performance rates and project future rates from this data. Decline curves can be exponential or hyperbolic, or based upon historical performance of wells on the property, if available. In instances where a well is fairly new and historical performances are relatively limited, multiple projection techniques can be weighed to conservatively forecast a decline curve.

Average annual production and decline trends are typically reported by the drilling company. Companies operating Marcellus Shale gas wells have shown a hyperbolic decline reflecting a steep first-year decline. It should be noted, however, that unlike other geological zones that have produced for many decades, the Marcellus Shale play has produced for only approximately five years. For this reason, many reserve estimators are basing mid- and long-term future Marcellus Shale production forecasts on longer-producing wells including the Barnett Shale of Fort Worth, Texas. However, very critical is the geologic research and understanding of the similarities and differences of Marcellus shale compared with other plays (including Barnett).

Once future production is estimated, the price of the gas is also forecasted. Spot price, which is the price for oil and gas for short-term delivery or purchase, can be used. Wellhead spot gas prices can be volatile, which we have experienced. Futures price is the price for future delivery or purchase of oil and gas. At any time there are many futures prices including one month out, two months out and six months out.

Pricing will depend on the product and location. For example Henry Hub, a point on the natural gas pipeline system in Louisiana, is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). In addition to the NYMEX futures market, other sources of price forecasts include (but are not limited to) consensus surveys from the Society of Petroleum Evaluation Engineers, energy bank forecasts and Energy Information Administration of the United States Department of Energy.

Over the long term, natural gas prices have generally been below oil prices measured in heat equivalent units, known as British Thermal Units (BTUs). Natural gas prices have been low due to several factors including, large discoveries in resource plays adding to the resource base; the state of the economy reducing industrial demand; and the emergence of renewable electricity generation (particularly wind energy). However an offsetting factor is that natural gas is favored for power generation since it produces lower carbon emissions than coal. The trend (as of the date of this material) of NYMEX natural gas prices is presented in the chart shown to the right.



Marcellus Shale: Tax & Valuation Issues Related to Landowners

The royalty rate applied in the calculation is stated in the oil and gas lease. Note that leases may provide for the royalty to be calculated after deductions for transportation, dehydration and compression, if any. For property in which there is no lease in place, a royalty rate will be estimated.

A reasonable royalty rate can be derived from comparable lease transactions. In order to determine that a lease is comparable certain elements of comparability should exist including size of the property, location, basic term of the lease, number and term of the options to renew and extent services are provided by the lesser and/or lessee. Comparability is important, as it is unreasonable to apply rates from some larger deals which are reported to the public to a small 100-acre farm.

Some landowners have found it advantageous to form larger groups, both to share knowledge and to negotiate as a unit with gas companies. For example, one such unit known as The Friendsville Group brought together some 900 landowners holding a total of 35,000 acres in Susquehanna and Bradford counties in northeastern Pennsylvania and neighboring Broome County in New York. In September 2010, the group struck a deal with Fortuna Energy (now Talisman Energy USA Inc.), in which the company agreed to bonus payments of $5,500 per acre and royalty payments of 20 percent. A day later, Chesapeake Energy countered with an offer of $5,750 per acre and the same royalty.

The rate used to discount the expected future cash flows to present value is the estimated rate of return currently available in the market on alternative investments with comparable risk. A discount rate, as used interchangeably with cost of capital, reflects both the time value of money as well as risk.

Capital market theory divides risk into two components: *systematic risk* and *unsystematic risk*. Systematic risk is the uncertainty of future returns owing to the sensitivity of the return on the subject investment to movements in the returns for a composite measure of marketable investments. Unsystematic risk is a function of the characteristics of the industry and the type of investment interest. Obviously the discount rate for properties with no lease in place or a lease with no drilling will be higher than the rate applied to producing properties. With respect to royalty interests in oil and gas leases, discounting is typically done before income tax.

The table on the following page is a sample calculation based upon a 150-acre property in Washington County with the following fact pattern:

- Developed mid-2011
- Gas Price: $2.00
- Hyperbolic decline
- 30-year life
- Inflation: 2.5%
- Royalty: 14%
- Discount rate: 16%

PRESENT VALUE OF WELL ROYALTY CASH FLOW					
YEAR	PRODUCTION MCF	PRICE	GROSS	ROYALTY	PV ROYALTY
2011	850,000	$ 2.00	$ 1,700,000	$ 238,000	$ 220,997
2012	367,200	2.05	752,760	105,386	84,352
2013	277,970	2.10	584,085	81,772	56,423
2014	232,105	2.15	499,904	69,987	41,631
2015	202,628	2.21	427,327	62,626	32,114
2016	182,162	2.26	412,200	57,708	25,510
2017	167,407	2.32	388,282	54,360	20,716
2018	155,187	2.38	368,936	51,651	16,969
2019	145,410	2.44	354,366	49,607	14,049
2020	136,394	2.50	340,676	47,695	11,644
2021	128,211	2.56	328,241	45,954	9,672
2022	120,518	2.62	316,260	44,276	8,034
2023	113,287	2.69	304,717	42,660	6,673
2024	106,490	2.76	293,595	41,103	5,542
2025	100,100	2.83	282,879	39,603	4,603
2026	94,094	2.90	272,553	38,157	3,824
2027	88,449	2.97	262,605	36,765	3,176
2028	83,142	3.04	253,020	35,423	2,638
2029	78,153	3.12	243,785	34,130	2,191
2030	73,464	3.20	234,887	32,884	1,820
2031	69,056	3.28	226,313	31,684	1,512
2032	64,913	3.36	218,053	30,527	1,256
2033	61,018	3.44	210,094	29,413	1,043
2034	57,357	3.53	202,426	28,340	866
2035	53,916	3.62	195,037	27,305	719
2036	50,681	3.71	187,918	26,309	598
2037	47,640	3.80	181,059	25,348	496
2038	44,781	3.90	174,451	24,423	412
2039	42,095	3.99	168,083	23,532	342
2040	39,569	4.09	161,948	22,673	284
Residual					1,393
					$ 581,481

Marcellus Shale: Tax & Valuation Issues Related to Landowners

Other Considerations

As previously noted valuations are being performed for properties in various stages ranging from producing property, properties recently leased and those not yet leased. Upon valuing an oil and gas lease where no drilling is taking place or a lease has not be executed, a valuation should include consideration of many factors including:

- The number of permits outstanding versus the number of wells drilled. Drilling rigs bore the holes and set pipes, but all wells do not go into production immediately. The number of gas drilling rigs is declining in Pennsylvania and nationwide, due to a combination of low natural gas prices and renewed interest in oil. There were 882 new permits issued in Pennsylvania in the first 3½ months of 2012. According to Baker Hughes, a company that monitors national counts, there were 98 drilling rigs in Pennsylvania during the week of March 23, 2012. That number is down from a peak of 116 reached during the summer of 2011.
- The number of wells drilled in the subject geographic area and their performance history. Productivity of rigs can differ depending on the operator.
- The lack of adequate processing and transportation infrastructure.
- The county in which the property is located, as there are certain areas in which Marcellus Shale reserves are preferred over others. Susquehanna County is considered to be the most prolific in the Marcellus Shale play drilled between 2006 and June 2010. Washington and Greene counties in the southwest, and Bradford and Tioga (in addition to Susquehanna) counties in the northeast, are so-called "sweet spots."
- What the price of natural gas will be when it is produced. Natural gas is selling at one quarter of the 2008 average price. The more players and the more gas produced makes it difficult for drilling companies to make money.
- The estimated failure rate. The existence of wells that failed to produce.
- The Marcellus Shale play encompasses approximately 60 million acres with 80-acre wells. As of March 2012, there were 98 working drill rigs in Pennsylvania. As of April 6, 2012, there were 647 active natural gas rigs in the United States, according to the U.S. Energy Information Administration. There are seven wells drilled per year, per drill rig. This means that drilling companies will be selective in where and how they drill.
- Adjust the discount rate for risk attendant to anticipated timing and probability of future drilling, prepare a probability weighted model or rely on reserve adjustment factors (RAF).
- The qualifications of the PE estimating the production decline curves.

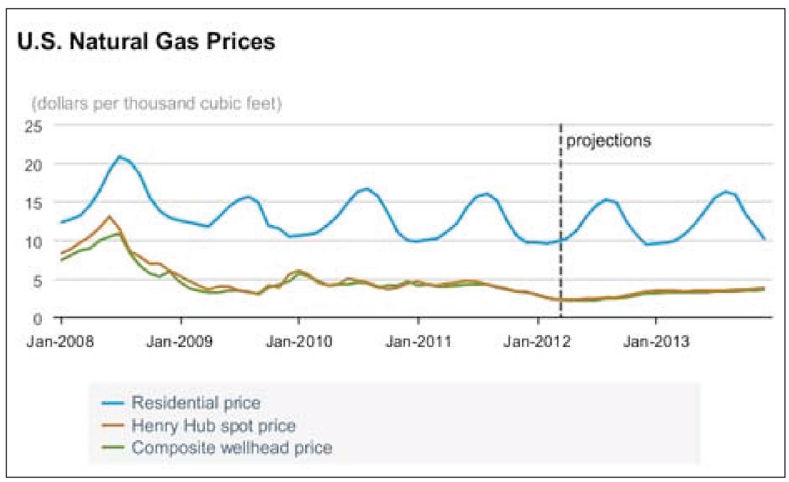
In conclusion, the industry has many nuances and issues specific to it and many factors should be considered by a qualified appraiser in conjunction with the valuation of a royalty interest in oil and gas leases.

Marcellus Shale: Tax & Valuation Issues Related to Landowners

Current Environment

In contrast to price movements in the global market for crude oil, price changes for natural gas in many regional markets are more closely aligned with supply-and-demand conditions in those markets. During 2011, benchmark prices at Henry Hub averaged about $4.00 per thousand cubic feet (Mcf), compared with about $4.50 per Mcf in 2010. On March 31, 2012, the end of what is considered winter for the natural gas market, spot natural gas prices at the Henry Hub approached $2 per Mcf. On April 18, 2012, the natural gas spot price at Henry Hub was $1.87 per Mcf. The winter of 2011-2012 was warmer than normal across most of the country – national population-weighted heating degree days (HDDs) were down between 13-36% relative to monthly historical normals from November through March (see chart below). By region, every part of the country was warmer than normal for the winter except the Pacific region, which was just slightly (2%) cooler than normal. This relative lack of cold weather reduced natural gas demand and the need to pull natural gas from underground storage.

Fluctuations in the price for natural gas in the United States are closely associated with customer demand relative to the volumes produced in North America. The U.S. Energy Administration has released projections of natural gas prices through 2013, as illustrated in the chart to the right.



After a long period of steady growth, U.S. daily dry gas production growth leveled off during the first three months of 2012, averaging 63.8 Bcfd through March 31, a level almost 9% above the same period in 2011. Production from the Marcellus play accounted for much of the year-over-year growth in dry natural gas production.

The availability of a secure supply of low-cost natural gas in the United States is restoring a global competitive advantage for many domestic gas-intensive industries: chemicals, aluminium, steel, glass, cement and other manufacturing industries. Some of these industries are beginning to invest in the expansion of their U.S. operations based on the availability of low cost gas. Lower gas costs are also helping to hold down electricity prices as the share of natural gas in power generation increases. Additionally, residential and commercial consumers of natural gas are enjoying lower heating costs.

Marcellus Shale: Tax & Valuation Issues Related to Landowners

Industry players are sharing their outlook and plans for 2012 in light of gas prices. An article from Platts (a leading provider of energy, petrochemicals and metals information), *Marcellus Gas Producers See Opportunities Despite Current Low Prices*, summarizes a presentation given at an industry gathering in New Orleans. The article states that natural gas producers remain proactive in the face of low prices.

Marcellus pioneer, Range Resources, plans to spend 85% of its $1.6 billion capital budget for 2012 in the Marcellus play – mostly in the wet gas southwestern Pennsylvania part of the play, but 23% will go to the dry northeastern part of the state. The Houston-based company has 75% of its 2012 gas production hedged at $4.45/Mcf. Range's costs in the Marcellus were 89¢/Mcf in 2011, and they are projecting cost will be 80¢/Mcf in 2012, resulting in a 58% profit margin at $3/Mcf gas prices.

CEO of EQT, David Porges, stated EQT's response to low prices was to stop drilling in West Virginia's and Kentucky's Huron Shale, and to slightly scale back its Marcellus efforts to stay within the company's cash flow. Still, in 2012, EQT plans to drill 132 Marcellus wells, focusing on Greene County in southwest Pennsylvania and Tioga County in the northeast for dry gas, and Doddridge and Wetzel counties in West Virginia for gas and liquids. In 2011, while natural gas liquids only comprised 20% of EQT's production mix, they accounted for 80% of its revenue. Mr. Porges noted that low prices "are a great opportunity for EQT and our competitors to figure out a better way to operate."

Consol Energy CEO, J. Brett Harvey, stated that even a coal company is bullish on the Marcellus. With 361,000 acres of leasehold, much of it contiguous with its coal holdings, Consol should produce approximately 1 Bcf/d from the Marcellus and has 50% of its volumes hedged at $5.25/Mcf. Consol plans to move 50% of its production to liquids in 2012, but its gas production is still profitable because its low cost and close-to-high-priced markets. Additionally, in 2012, Consol will drill 99 wells in the Marcellus and 22 wells in the adjacent Utica Shale. Consol has 50% joint ventures in both plays with Noble and Hess, respectively.

In conclusion, the ratio between the spot prices of crude oil and natural gas has been generally increasing since January 2009, but it has climbed rapidly in recent months. In terms of production implications, a higher crude-oil-to-natural-gas ratio encourages drilling for oil in preference to natural gas and makes natural gas liquids developments relatively more attractive than the development of dry natural gas resources. On the consumption side, the higher ratio also encourages end users to choose natural gas over products derived from crude oil, such as distillate and residual fuel oil, wherever substitution is feasible.

Marcellus Shale: Tax & Valuation Issues Related to Landowners

Chapter VI – *Estate and Gift Tax Planning*

This chapter is intended to briefly address the types of interests and an estate planning vehicle commonly used to transfer such interests – the family limited partnership (FLP). Other estate planning mechanisms, including intentionally defective grantor trusts and charitable lead annuity trusts, are beyond the scope of this presentation.

In the context of gift and estate tax purpose valuations, valuators will consult many sources for guidance including the Internal Revenue Code (the Code), Treasury regulations, revenue rulings, revenue procedures and case law, to name a few.

For federal gift and estate tax purposes, the standard of value is "fair market value" which is defined as under Treasury Regulations 25.2512-1 (gift tax) and 20.2031-1(b) (estate tax), for these purposes as:

> *"the price at which the property would change hands between a willing buyer and a willing seller when the former is not under any compulsion to buy and the latter is not under any compulsion to sell, both parties having reasonable knowledge of relevant facts."*

Regardless of the standard by which the gas company is paying for the gas (for example, market value), valuing the royalty for gift and estate purposes is performed under the fair market value standard.

Define Property Transferred

For purposes of federal gift and estate taxation, it is of the utmost importance to properly identify the property interest being transferred. This will obviously have an impact on how the subject asset is valued.

There are three separate estates of land recognized by Pennsylvania law: the surface, the right of support and the minerals contained thereunder.[3] The right of property in oil and natural gas belongs to the owner of the land while they are in place. The right can be severed from the ownership of the surface by grant or exception as separate corporeal right.[4]

There should be a diligent search performed for previous fee transfers or lease arrangements going back well before drilling in the Marcellus Shale play came into existence. As noted in Chapter III, there have been instances in which the landowner sold his/her land with no mention or severance of the oil and gas interest.

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[3] *Smith v. Glen Alden Coal Co.*, 347 Pa. 290, 32 A.2d 227 (1943).

[4] *Duquesne Natural Gas Company v. Feflolt*, 203 Pa. Superior Ct. 102, 198 A.2d 608 (1964)

Marcellus Shale: Tax & Valuation Issues Related to Landowners

It is important to understand the distinction between a lease and a fee simple. When property is leased for oil and gas drilling as we typically see, the owner of the land who granted the lease (lessor) must include the value of the land in his/her estate upon death. Note that under Pennsylvania law, a lease of real property for a term of more than three years must be made in writing and signed by the parties creating the lease.[5]

The significance of holding a fee simple interest is that one may own the entire bundle of rights in what is called a "fee simple absolute" or "fee simple determinable," which is a situation where the land and interest revert back to the landowner after the interim use expires. Upon the conclusion of oil and gas production, the land reverts back without any action on any parties' part under a fee simple determinable. This is critical to understand, as the value of the reversionary interest is included in the owner's estate.

Old leases in existence on the land of owners who are entering into Marcellus Shale gas leases should be reviewed closely to determine whether language contained in the old lease has, in fact, passed title to the land, oil and gas to the *lessee*.

For properties in which there is no gas being produced, these properties are treated differently for federal estate and gift tax and Pennsylvania inheritance tax. For federal estate and gift tax purposes, prior to production, gas interests can be difficult to value, as noted in the previous chapter, however, they are valued. In accordance with a 2003 ruling from the Pennsylvania Inheritance Tax Office, "where no oil or gas existed on the property at the Taxpayer's date of death, the interests have no ascertainable value for inheritance tax purposes". [6]

In Revenue Ruling 67-172 the IRS indicated that royalties from producing gas wells are present interests and, therefore, annual exclusions are applicable to gifts of such royalties. In the Tax Court case, *Jardell v. Commissioner*, 24 T.C. 652 (1955) the court held that the annual exclusion is not applicable to a gift of royalties derived from production the following year as it did not vest a "substantial present economic benefit."

In all situations, the IRS will look to the concept of "retained control" or "retained enjoyment" to determine whether a property interest is transferred or there is an assignment of income. It should be clear that a transfer of a property interest was, in fact, made. If the owner of the minerals retains an economic interest in the oil and gas in place and has the right to negotiate and enter into future leases affecting the property, an argument can be put forth by the IRS that a property interest was not transferred. Retained enjoyment will be discussed later in this chapter.

[5] 68 Pa. Stat. Ann. Sec. 250.202

[6] Pennsylvania Inheritance Tax No. INH-03-008, Oil and Gas Lease, August 7, 2003

Marcellus Shale: Tax & Valuation Issues Related to Landowners

Family Limited Partnerships

One of the most common estate planning vehicles is the family limited partnership (FLP). The typical FLP structure is as follows:

- Senior generation property owner contributes property to a partnership in exchange for 99-percent limited partner partnership interests
- Senior generation property owner/spouse contribute cash to a general partner entity
  - S corporation
  - Limited liability company
- General partner contributes cash to partnership for one-percent general partner interest
- Limited partner partnership interests are valued using fractional interest discounts
- Limited partner partnership interests are gifted from senior generation property owners to junior generation heirs
- Transfer tax avoided by virtue of lifetime exclusions/annual gift tax exclusions

Timing of organizing the FLP and making transfers are key to an effective estate plan. Transfers of property to the FLP can be made at inception of the lease prior to the drilling, which will allow movement of more interests based upon a lower value. Once drilling is underway, values should be higher.

Case law regarding FLPs has developed for many years. Issues have been identified surrounding the proper establishment of the FLP and observing certain formalities. See *Shepherd v. Commissioner*, 115 T.C. 376 (2000) and *Senda v. Commissioner*, No. 05-1118, 433 F3d. 1044, 97 AFTR 2d 2006-419 (8th Circuit 2006), aff'g T.C. Memo 2004-160.

As previously noted in this chapter, issues also surround the circumstance in which the senior generation (property owner) retains enjoyment of the assets contributed to an FLP. Section 2036 – application of "Transfers with Retained Life Estate," may cause the inclusion of assets previously contributed to a FLP or LLC in a decedent's taxable estate.

An estate includes the value of any assets transferred during lifetime in the decedent's estate if the decedent retained for his or her life either:

- The possession or enjoyment of or the right to the income from the property transferred, or
- The right, either alone or in conjunction with any person, to designate the person who shall possess or enjoy the property or the income there from.

Marcellus Shale: Tax & Valuation Issues Related to Landowners

The value of the gross estate will include the value of all property, to the extent of any interest therein of which decedent has at any time made a transfer (except in the case of a bona-fide sale for an adequate and full consideration in money or money's worth), by trust or otherwise, under which he or she has retained for his/her life or any period not ascertainable without reference to his/her death or any period which does not in fact end before his/her death.

Section 2038 – "Revocable Transfers" states that the value of the gross estate must include the value of all property, to the extent of any interest therein of which the decedent has at any time made a transfer (except in case of a bona fide sale for an adequate and full consideration), by trust or otherwise, where the enjoyment thereof was subject at the date of death to any change through the exercise of a power (in whatever capacity exercisable), by the decedent alone or by the decedent in conjunction with any other person (without regard to when or from what source the decedent acquired such power), to alter, amend, revoke or terminate, or where any such power is relinquished during the three-year period ending on the date of the decedent's death.

After more than 10 years of judicial decisions construing the valuation and estate planning benefits of family limited partnerships, Internal Revenue Code section 2036 has become a formidable weapon for the Internal Revenue Service. In the event section 2036 is applicable, valuations of FLP or limited liability company (LLC) interests become irrelevant.

In conclusion, proper estate planning involving interests in Marcellus Shale must begin with a clear determination of the interest to be transferred. This will enable the landowner's advisors to devise the most effective means to transfer and value such assets.

Chapter VII – Conclusion and Final Thoughts

The western Pennsylvania and tri-state Marcellus Shale play presents an almost-limitless opportunity for economic development for our state and the region. However, the speed at which this industry has grown, and is expected to grow in the coming decade, as well as the sheer volume of transactions, business entities and exploration, production, transmission and distribution activities, is certain to bring a like-number of economic issues and legal challenges to bear. Combined with the specific oil and gas industry expertise required to address many of the upcoming professional opportunities, it is easy to see participation in serving this new and exciting industry is not as much a matter of choice, as it is a matter of necessity.

It is not difficult to observe that the natural gas opportunities afforded by this discovery and new technology could replace a substantial portion of the region's displaced blue-collar positions. The need to service these opportunities from a legal, tax, accounting and valuation perspective falls to all of us in attendance today. Enhanced understanding of these transactions and activities will be a natural evolution for all of us, but those that are able to more-quickly embrace the technical aspects of the many legal and economic issues involved, will move to the front of the pack.

Grossman Yanak & Ford LLP has taken a lead position in providing services related to the oil and gas industry, and we are confident the we have the expertise necessary to assist legal counsel in any number of economic, tax, valuation and accounting undertakings related to representation of clients in the industry.

This program has been presented to focus primarily on the landowner involved in moving rights to natural gas through leasing and other devices. A focus on operating or "working interest" holders will be the focus of a future program, which will allow participants to better understand the exploration and production side of the business.

Obviously, this program was designed and intended to serve as an introduction to these concepts. No program of this length could possibly address in-depth, the many nuances of issues facing landowners contemplating entering into a mineral lease. However, as always, we hope our session today has provided some useful information that you can take with you to enhance your practices.

Should you have a specific fact pattern that may require follow-up, please feel free to contact Bob Grossman, Melissa Bizyak or Rebekah Flanders. All would be happy to speak with you concerning your questions.

Online Resources: Marcellus Shale and the Oil & Gas Industry

Marcellus Shale Coalition

www.marcelluscoalition.org

Organization/Website Description: Founded in 2008, the Marcellus Shale Coalition (MSC) is an organization committed to the responsible development of natural gas from the Marcellus Shale geological formation and the enhancement of the region's economy that can be realized by this clean-burning energy source.

Pennsylvania Independent Oil & Gas Association

www.pioga.org

Organization/Website Description: The Pennsylvania Independent Oil and Gas Association of Pennsylvania (PIOGA) is the principal nonprofit trade association representing Pennsylvania's independent oil and natural gas producers, marketers, service companies and related businesses. PIOGA member companies drill and operate the majority of the state's crude oil and natural gas, including the Marcellus Shale.

Pennsylvania Department of Environmental Protection, Oil & Gas Programs

http://www.portal.state.pa.us/portal/server.pt/community/oil_and_gas/6003

Organization/Website Description: The DEP's Office of Oil and Gas Management is responsible for the statewide oil and gas conservation and environmental programs to facilitate the safe exploration, development, recovery of Pennsylvania's oil and gas reservoirs in a manner that will protect the commonwealth's natural resources and the environment. The office develops policy and programs for the regulation of oil and gas development and production pursuant to the *Oil and Gas Act*, the *Coal and Gas Resource Coordination Act*, and the *Oil and Gas Conservation Law*; oversees the oil and gas permitting and inspection programs; develops statewide regulation and standards; conducts training programs for industry; and works with the Interstate Oil and Gas Compact Commission and the Technical Advisory Board.

Penn State University – College of Agricultural Sciences, Natural Gas Extension

http://extension.psu.edu/naturalgas

Organization/Website Description: Penn State Cooperative Extension's Marcellus Education Team is a group of more than 40 county-based educators and faculty who are teaching about and researching the wide range of issues arising from Marcellus Shale natural gas drilling.

Penn State Marcellus Center for Outreach & Research

www.marcellus.psu.edu

Organization/Website Description: The Marcellus Center for Outreach and Research (MCOR) is Penn State's education and research initiative on unconventional gas plays. We serve state agencies, elected and appointed officials, communities, landowners, industry, environmental groups and other stakeholders. We are committed to expanding research capabilities on technical aspects of developing this resource and to providing science-based programming while protecting the Commonwealth's water resources, forests and transportation infrastructure.

Online Resources: Marcellus Shale and the Oil & Gas Industry

America's Natural Gas Alliance

www.anga.us

Organization/Website Description: America's Natural Gas Alliance exists to promote the economic, environmental and national security benefits of greater use of clean, abundant, domestic natural gas. We represent 31 of North America's largest independent natural gas exploration and production companies and the leading developers of the shale plays.

American Petroleum Institute

www.api.org

Organization/Website Description: The American Petroleum Institute (API) is the only national trade association that represents all aspects of America's oil and natural gas industry. Our more than 400 corporate members come from all segments of the industry. They are producers, refiners, suppliers, pipeline operators and marine transporters, as well as service and supply companies that support all segments of the industry.

U.S. Energy Information Administration

www.eia.gov

Organization/Website Description: The U.S. Energy Information Administration (EIA) collects, analyzes, and disseminates independent and impartial energy information to promote sound policy making, efficient markets, and public understanding of energy and its interaction with the economy and the environment.

Keystone Energy Forum

www.keystoneenergyforum.com

Organization/Website Description: The Keystone Energy Forum is a group of concerned citizens and partners committed to improving the public's understanding of, and support for, the many opportunities presented by the Marcellus Shale natural gas reserves here in Pennsylvania. Our goal is to educate fellow Pennsylvanians to ensure our elected officials are creating sound policies which promote a strong economy and energy security.

Oil & Gas Journal – International News and Technology

www.ogj.com

Organization/Website Description: The Oil & Gas Journal is the world's most widely-read petroleum industry publication, designed to meet the needs of engineers, oil management and executives throughout the oil and gas industry.

Oil and Gas Investor

www.oilandgasinvestor.com

Organization/Website Description: This interactive, searchable version of Hart Energy Publishing's *Oil and Gas Investor Magazine* is a complete source for information about the financial world of oil and gas.

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The following courses have been presented by our professionals:

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The Market Approach to Business Valuation: *Understanding the Methods and Their Basic Application* .... (October 7, 2009)

The Cost/Asset Approach to Business Valuation: *Understanding the Approach and Reviewing Expert Reports* .... (February 4, 2010)

Quantification and Application of Valuation Discounts: *Understanding the Uses and Misuses of Discounts for Lack of Control and Lack of Marketability* .... (October 1, 2008)

S Corporations vs. C Corporations: *Understanding Valuation Differences* .... (March 6, 2008)

Special Purpose Valuations: *Understanding the Nuances of Valuation in the Context of ESOPs and Buy-Sell Agreements* .... (June 3, 2010)

Special Purpose Valuations: *Business Valuations for Estate & Gift Tax Planning* .... (October 7, 2010)

Economic Damages: *Lost Profits Determinations* .... (February 10, 2011)

An Attorney's Guide to Financial Statements: *A Primer for Understanding, Interpreting and Analyzing Financial Statements* .... (June 15, 2011)

Marcellus Shale: *A Discussion of Income Tax & Valuation Issues Related to Landowners* ...(October 11, 2011)

Family Limited Partnerships: *The Realities of Estate Planning with FLPs* .... (February 8, 2012)

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