Oil and Gas

Federal Income Taxation

2012 Edition

Patrick A. Hennessee
Sean P. Hennessee
Editors

CCH
a Wolters Kluwer business

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EDITORIAL STAFF

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Preface

Oil and Gas—Federal Income Taxation (2012 Edition) is designed to introduce the reader to the federal income tax issues pertaining to the oil and gas industry, and aid tax advisors and others as they deal with tax issues of that industry. Also, we hope to provide the reader with a working vocabulary of the oil and gas business and an understanding of the more important tax aspects of the exploration and production phase of this industry. The book is well documented and footnoted so that the reader is pointed in the right direction for continuing their study of the topic at hand.

The oil and gas industry is extremely risky. Approximately one out of seven exploratory wells in the U.S. discovers commercial quantities of oil. If an oil and gas company is to succeed in this high-risk environment, it needs to take advantage of all legal tax benefits and be advised of the possible tax traps that it might find itself in from time to time. The landscape is littered with dealmakers that clearly did not pay enough attention to the tax ramifications of the proposed deal. By studying some of these tax failures, hopefully, tax advisors will be able to chart a course through this tax mine field that results in legally lowering the tax cost of the transaction.

The oil and gas business is both exciting and frustrating. Rarely do you find bored people in this business—maybe broke, frustrated, and overworked, but not bored. The same is true for the tax advisors to this industry. If asked, most will probably say they tend to be overworked and maybe a bit frustrated at times—but not bored. It is hoped that this book will aid in addressing the burden of their work and their frustration level when addressing some of the complex provisions they face on a daily basis.

We would like to hear from readers regarding other topics of interest that they are encountering that are not covered in this book.

Patrick A. Hennessee

November 2011

About the Editors

Patrick A. Hennessee, Ph.D., CPA, is Professor Emeritus, University of Tulsa. He has been a CPA in both Oklahoma and Colorado. He has taught over 500 oil and gas tax-related seminars to CPAs and attorneys and has had over 10,000 participants in his programs in the last 30 years. He also has a consulting practice in which most of his clients are oil and gas exploration and production firms, or CPAs and attorneys advising on oil and gas issues. He has published numerous articles is both academic and professional journals. He has just recently retired from the University of Tulsa where he taught for over 30 years. While at the University of Tulsa, he served as Director of the School of Accounting; he initiated the University's Master of Taxation and later initiated the on-line Master of Taxation for the University.

Dr. Hennessee was honored with the Oklahoma Society of CPAs' Outstanding Accounting Educator Award for the years 1999 and 2000. He is noted for drawing upon his wealth of practical and technical knowledge of the oil and gas industry to present crisp, insightful classes. Through engaging presentations, problem solving and interactive discussion, students and practitioners effectively learn about property acquisition, geological and geophysical costs, development and depreciation of properties, deal structuring, tax credits, and other complex areas of oil and gas taxation.

Sean P. Hennessee is an attorney with Magellan Midstream Partners, L.P. ("Magellan"), a publicly-traded partnership based in Tulsa, Oklahoma engaged primarily in the transportation, storage and distribution of refined petroleum products as well as crude oil. Prior to becoming in-house counsel for Magellan, he was in private practice in Fort Worth, Texas where he represented and advised clients in transactions encompassing oil and gas, partnership, and corporate tax issues at both the federal and state level.

Mr. Hennessee has served as an adjunct professor on the faculty of the College of Business Administration at the University of Tulsa, and prior to his time with Magellan and in private practice, he work for the Williams Companies, a full-service, Fortune 500 energy company. He earned a Bachelor's of Science in Business Administration, a Masters in Business Administration, a Masters in Taxation, and a Juris Doctor from the University of Tulsa. In addition to working as a Co-Editor on this publication with **CCH**, Mr. Hennessee has also published articles with the Energy Bar Association.

Highlights of Current Developments

The most important changes since the last edition are noted below.

Election to Expense Qualified Refinery Property. Reg. § 1.179C-1, relating to the election to expense qualified refinery property under Code Sec. 179C has been adopted and Temporary Reg. § 1.179C-1T has been removed by the IRS. The final regulation adopts the temporary regulation with certain modifications to reflect changes made to the law by the Energy Improvement and Extension Act of 2008 (P.L. 110-343). Section 209 of the Energy Improvement and Extension Act of 2008 amended Code Sec. 179C in several respects. It extended the placed-in-service date of Code Sec. 179C(c)(1)(B) to January 1, 2014. Therefore, the final regulation provides that the property must be placed in service after August 8, 2005, and before January 1, 2014. For self-constructed property, the construction, manufacture or production of the property must have begun before January 1, 2010. The final rules also state that a component of self-constructed property must have been acquired or self-constructed before January 1, 2010. The final rules provide that, for property placed in service after August 8, 2005, and on or before October 3, 2008, a "qualified refinery" is any refinery located in the United States that is designed to serve the primary purpose of processing liquid fuel from crude oil or qualified fuels. For property placed in service after October 3, 2008, and before January 1, 2014, a "qualified refinery" is any refinery located in the United States that is designed to serve the primary purpose of processing liquid fuel from crude oil, qualified fuels or directly from shale or tar sands. Under the final rules, refinery property is considered to be qualified refinery property if (a) it enables the existing qualified refinery to increase the total volume output by at least five percent on an average daily basis; (b) in the case of property placed in service after August 8, 2005, and on or before October 3, 2008, it enables the existing qualified refinery to increase the percentage of total throughput attributable to processing qualified fuels to a rate that is at least 25 percent of the total throughput on an average daily basis; or (c) in the case of property placed in service after October 3, 2008, and before January 1, 2014, it enables the existing qualified refinery to increase the percentage of total throughput attributable to processing shale, tar sands or qualified fuels to a rate that is at least 25 percent of total throughput on an average daily basis. The final regulation applies for tax years ending on or after August 22, 2011. For tax years ending before August 22, 2011, taxpayers may apply the rules contained in the temporary regulation (T.D. 9412) or, alternatively, the final regulation. . . . . **¶ 2908.02**

Suspension of Taxable Income Limitation for Marginal Properties. The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (P.L. 111-312) extended the exemption of the net taxable income limit for marginal production for percentage depletion purposes for two years. Code Sec. 613A(c)(6)(H) now provides that marginal production of domestic oil or natural gas is exempt from the net taxable income limit (i) beginning after December 31, 1997, and before January 1, 2008, or (ii) beginning after December 31, 2008, and before January 1, 2012. Thus, for the calendar years of 1998 through 2007 marginal production was exempt from the net income limit for percentage depletion. In addition, for the calendar years of 2009 through 2011 marginal production is exempt from the net taxable income limitation. Note, that for tax year 2008, marginal production was subject to the taxable income limitation for computing percentage depletion for domestic oil and natural gas. . . . . **¶ 1705**

Modified Accelerated Cost Recovery System (MACRS): Bonus Depreciation. The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (P.L. 111-312) permits a taxpayer a 100-percent first-year depreciation deduction for eligible qualifying property acquired after September 8, 2010, and placed in service before January 1, 2012. The "placed in service" deadline is extended to January 1, 2013 in the case of qualifying property having a production period described in Code Sec. 168(k)(2)(B) and for cellulosic biofuel plant property. Additionally, a taxpayer is permitted to expense 50 percent of the cost of qualifying property placed in service after December 31, 2011, and before January 1, 2013. The "placed in service" deadline is extended to include property placed in service after December 31, 2012, and before January 1, 2014 in the case of certain qualifying property having a production period described in Code Sec. 168(k)(2)(B). . . . . **¶ 2904.02**

Election to Expense Certain Depreciable Assets. Prior to the enactment of the Small Business Jobs Act of 2010 (P.L. 111-240), a taxpayer could elect to revoke its election to expense the cost of any Code Sec. 179 property prior to 2010. The Small Business Jobs Act of 2010 extended the period to include tax years beginning before 2012. The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (P.L. 111-312) extended this period (for one year) to include tax years beginning prior to 2013. . . . . **¶ 2908.01**

Qualified Tertiary Injectant Expenses. A 2011 Technical Advice Memorandum provided that amounts incurred for constructed and acquired CO2 transportation assets, including pipelines, and CO2 injection field assets, including CO2 injection and recycling facilities, do not qualify as tertiary injectant expenses under Code Sec.193. The IRS reasoned that even though the term "qualified tertiary injectant expenses" is broader than the costs deductible under Code Sec.193, tertiary injectant expenses do not include tangible equipment costs. . . . . **¶ 2803.03**

Nonconventional Source Fuel Credit. The IRS has published the nonconventional source fuel credit, inflation adjustment factor and reference price for calendar year 2010, which is used to determine the allowable tax credit on the sale of fuel from nonconventional sources under Code Sec. 45K. For calendar year 2010, the credit is available only for fuel produced from coke or coke gas (other than from petroleum-based products) and is not subject to phase-out. The reference price that is used to determine the allowable tax credit for coke or coke gas for calendar year 2010 is $74.71 and the inflation adjustment factor is 1.1435. Accordingly, the nonconventional source fuel credit is $3.43 per barrel-of-oil equivalent ($3.00 x 1.1435). . . . . **¶ 2801.06**

Enhanced Oil Recovery Credit. The IRS has issued the inflation adjustment factor for use in determining the enhanced oil recovery credit under Code Sec. 43. The inflation adjustment factor for calendar year 2011 is 1.5326. Because the reference price as determined under Code Sec. 45K(d)(2)(C) for 2010 ($74.71) exceeds $28 multiplied by the inflation adjustment factor for 2010 by $31.80, the enhanced oil recovery credit for qualified costs paid or incurred in 2011 is phased out completely. The GNP implicit price deflator to be used for calendar year 2011 is 110.654. . . . . **¶ 2802**

Intangible Drilling Costs. In a letter ruling, a corporation was granted an extension of time in which to elect to currently expense its intangible drilling and development costs (IDCs). The taxpayer had hired a return preparer who was unaware of the election; the taxpayer made the discovery when it hired an accounting firm to review its oil and gas operations. The taxpayer represented that granting the relief would not result in its having a lower tax liability in the aggregate for the tax years affected by the election than it would have had if the election had been made timely. . . . . ¶ **1005.01**

Environmental Remediation Expenses. Code Sec. 198 permits taxpayers to deduct certain environmental remediation expenditures in the year paid or incurred. The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (P.L. 111-312) extended this provision so that taxpayers are allowed to expense eligible expenditures paid or incurred before January 1, 2012. . . . . ¶ **2902.02**

Oil and Gas Partnerships. The 2012 edition of Oil and Gas—Federal Income Taxation includes expanded and enhanced coverage of oil and gas tax partnerships (Chapter 24), including a new section addressing the contribution of Code Sec. 704(c) property to oil and gas partnerships. . . . . ¶ **2407**

CCH's OIL AND GAS TAXATION LIBRARY IS NOW AVAILABLE. The online Oil and Gas Taxation Library, updated monthly, makes finding answers to your oil and gas taxation questions fast and easy. It includes the Oil and Gas Tax Reporter, the monthly Oil and Gas Tax Reporter Tax Trends Newsletter, State Oil and Gas Tax Severance Summaries, including filing requirements and due dates, Multistate Oil and Gas Smart Charts so you can quickly locate oil and gas severance/production tax, property tax and sales and use tax rates for any jurisdiction, the Internal Revenue Manual—Oil and Gas Handbook, and ISPs/MSSPs, which include the IRS Audit Techniques Guide for the Oil and Gas Industry.

CCH's OIL AND GAS TAX REPORTER (in print) is updated quarterly. The OIL AND GAS TAX REPORTER covers the latest developments impacting oil and gas taxation, including federal energy legislation, IRS rules and regulations, court decisions and state tax severance changes. To subscribe to the OIL AND GAS TAXATION LIBRARY or the OIL AND GAS TAX REPORTER by phone, call 800-248-3248, or write to CCH, 4025 West Peterson Avenue, Chicago, IL 60646-6085.

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Introduction to Oil and Gas Taxation

¶ 101 Oil and Gas Taxation: Introduction

The taxation of natural resources is one of the more complicated areas of the U.S. federal income tax system. From the acquisition of the mineral rights, to the exploration and development of the property, to the ultimate production of the mineral, there are unusual and challenging tax aspects along every step of the way. The natural resource industry is unique in the requirement for large capital investments as well as an equally high degree of risk. This section discusses some of the basic theories of oil and gas taxation and provides a basic explanation of descriptive terms unique to the industry. Each of these terms is examined in greater depth later in the text.

This text begins with a discussion of the nature of oil and gas reserves in order to gain a better understanding of the oil and gas industry. The material which follows is organized in a logical sequence of events which traces the normal industry pattern for developing oil and gas reserves.

The subsequent chapters are structured as follows:

Acquisition of Interests	Chapters 2-8
The Exploration Period	Chapters 9-10
The Production Period	Chapters 11-18
Dispositions	Chapters 19-21
Oil and Gas Taxation: Other Areas	Chapters 22-31

¶ 102 Oil and Gas Taxation: Basic Theories

The federal income tax rules for natural resources are based on certain concepts not found in other areas of taxation. Among these are the concepts of "economic interest" and the "pool of capital" doctrine. The "economic interest" concept is used to determine whether ownership interests will be recognized as such for tax purposes. The "pool of capital" doctrine makes nontaxable transfers of ownership interests possible in certain circumstances. These concepts are discussed more fully in Chapter 2.

.01 Economic Interest

A critical factor in any transaction involving mineral properties is determining who owns the economic interest. This will determine who is taxable on the mineral income from the property. In addition, only the owner of an economic interest is entitled to claim a depletion deduction. The characterization of any transfer of mineral rights as a sale, lease, sublease, or sharing arrangement is also governed by this concept.

The origin of economic interest as a concept is generally traced back to the Supreme Court's opinion in *Palmer v. Bender.*[1] In that case, the Supreme Court held that the right to depletion does not depend solely upon the form of the taxpayer's legal interest in the minerals. It also turns upon the substantive issue of whether the taxpayer has an economic interest in the minerals that are depleted by production. The Court described an economic interest in the following language:

> The language of the statute (allowing depletion) is broad enough to provide, at least, for every case in which the taxpayer has acquired, by investment, any interest in the oil in place, and secures, by any form of legal relationship, income derived from the extraction of the oil, to which he must look for a return of his capital.[2]

In practical terms, an economic interest can be thought of as a clear and direct interest in a mineral property and the income from its production, which has enough substance to be treated as an ownership interest for income tax purposes (that is, the awarding of taxable income and related deductions). The economic interest concept has been continually defined, misinterpreted, and redefined by the courts.

.02 Pool of Capital Doctrine

An exchange of property or services for cash, services, or other property ordinarily results in taxable gain or loss. The pool of capital investment doctrine can change these results, however.

An economic interest may be acquired in exchange for a contribution of cash, property, or services to be used towards the development of the property. Under the pool of capital doctrine, these amounts may be treated as a nontaxable contribution to the reservoir of capital necessary to the development of the property, rather than as a taxable exchange.

The pool of capital doctrine appears to have had its origin in certain lease and sublease transactions. In these transactions the grantee acquired the right to develop and operate the property for a prescribed period of time. This right was considered to have no economic value at the time of transfer. Minerals might or might not be present under the property, and might or might not be found. If found, the minerals acquired value only as a result of the grantee's development activities. Since the grantee arguably received nothing of value in such transfers, the cash, property, or services which he provided simply represented his contribution to the overall "pool of capital" required for development of the property.[3]

In GCM 22730,[4] the Service applied this pool of capital doctrine not only to lease and sublease transactions but also to sharing arrangements, which are discussed at ¶ 206.

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[1] *Palmer v. Bender,* SCt, 3 USTC ¶ 1026, 287 US 551 (1933). See also *Lynch v. Alworth-Stephens Co.,* SCt, 1 USTC ¶ 117, 267 US 364 (1925), and *Burnet v. Harmel,* 3 USTC ¶ 990, 287 US 103 (1932).

[2] *Palmer v. Bender, supra* note 1.

[3] *Palmer v. Bender, Burnet v. Harmel, supra* note 1. See also Rev. Rul. 69-352, 1969-1 CB 34.

[4] GCM 22730, 1941-1 CB 214.

Certain requirements must be met in order for the pool of capital investment doctrine to apply. The interest received must be in the property to which the cash, property, or services are contributed. If the cash, property, or services are contributed to one property, and an interest is received in another, there is no "pooling" and the doctrine does not apply. The contribution must also be made before the related development costs have been incurred, and before the property has been fully developed.[5]

¶ 103 Acquisitions

A direct ownership interest in a mineral property may be acquired by various means, including gift or inheritance. Normally, however, such interests are acquired by purchase, by lease, or by entering into a sharing arrangement. Each of these transactions has its own separate tax effects.

.01 Purchase, Sale or Exchange

An interest in a mineral property is generally considered to have been purchased, sold, or exchanged where the owner retains no continuing interest in the severed portion.

Whether the transfer is treated as a sale or exchange may also be governed by what happens to the consideration received. The transfer may clearly be a sale or exchange if all the consideration received is kept by the transferor. On the other hand, the transfer may be a nontaxable pooling transaction to the extent that any part of the consideration is pledged directly to the development of the property.

.02 Lease or Sublease

A mineral owner usually arranges for the development of his mineral property by means of a lease. Under the lease, the owner (lessor) transfers the operating rights to the operator (lessee). The owner usually retains the surface rights and the right to receive a royalty. The lessee may be required to pay a lease bonus to the owner.

The lease grants the lessee the right to enter the property and extract the minerals. Generally, the lease is for a specified term of years (the primary term), during which the lessee has the right to begin development to obtain production. During each year of the primary term, the lessee may either begin development activities, or pay a delay rental in order to put off development until the next year. The lease may terminate if the property is not in the production stage by the end of the primary term. If production is obtained by the end of the primary term, however, the lease may continue for as long as minerals are produced in paying quantities.

The original lessee may decide to enter into a sublease and have another party develop the property. A sublease occurs when a lessee assigns his operating rights to a third party. The original lessee may retain an interest in the transferred property such as an overriding royalty interest, a net profits interest, or production payment as his consideration for granting the sublease. He may also receive a bonus from the sublessee. The sublessee is usually subject to the same development responsibilities as the original lessee.

A lease or sublease could be a partly nontaxable pooling transaction, to the extent the consideration received is pledged to development of the property. Lease bonuses and delay rentals are usually paid directly to the grantor, however, and do not represent

[5] *Rawco, Inc., Ltd.*, 37 BTA 128, CCH Dec. 9920 (1938).

contributions to the development of the property. For this reason, such payments normally represent taxable income to the person receiving them.

.03 Sharing Arrangements

Under a sharing arrangement, the owner of an operating interest transfers all or part of his interest to another party in exchange for that party's contribution of cash, property, or services to the development of the property. In order to create a sharing arrangement, the person transferring the interest must own the operating interest. The cash, property, or services received must also be pledged directly to the development activity. However, the interest transferred to the contributing party may be either an operating or nonoperating interest.

Where a nonoperating interest is transferred, this may take the form of an overriding royalty, a net profits interest, or in some instances, a production payment. A typical example would be the transfer of an overriding royalty interest to an independent geologist who performs services necessary for the development of the property.

Where the transferred interest is an operating interest, the arrangement is commonly referred to as a "farmout." A farmout can be structured in an almost unlimited variety of ways. In a simple farmout, the transferee is obligated to pay all the development costs as consideration for the transfer. In a carried interest farmout, the transferee has the same obligation, but is entitled to recoup all of his development costs from future production income. These arrangements are discussed in more detail later.

A sharing arrangement may be partly taxable and partly nontaxable. The transaction may be taxable to the extent that the cash, property, or services received are not used exclusively for the development of the property in which an interest is received. Depending upon the form of the transaction, the taxable amount may be treated as a bonus to the grantor or as income to the grantee of the interest.

¶ 104 Oil and Gas Taxation: Descriptive Terms

There are many different types of ownership interests. As a result, it is helpful to be familiar with some of the descriptions used to differentiate these economic interests.

.01 Operating or Nonoperating Interests

The terms "operating" and "nonoperating" indicate whether the mineral interest is charged with the costs and responsibilities of operating the property.

An operating interest bears such costs, and is usually entitled to receive most of the production. For federal tax purposes, an operating interest is generally defined as any interest which would be required to take the costs of production into account in determining the percentage depletion limitations.[6] The operating interest may be held by the owner of the basic mineral fee, or by a lessee or sublessee.

A nonoperating interest bears none of the costs or responsibilities of operating the property. The owner of a nonoperating interest simply receives a specified part of the gross production or income. For federal tax purposes, a nonoperating interest is generally defined as any interest other than an operating interest.[7] Some examples of nonoperating interests would include royalty interests, overriding royalty interests, net profits interests and production payments.

.02 Retained or Carved-Out Interests

The terms "retained" and "carved-out" indicate the manner in which the interest being described was separated from the basic operating interest.

[6] Code Sec. 614(d) and Reg. § 1.614-2(b).

[7] Code Sec. 614(e)(2) and Reg. § 1.614-5(g).

A retained interest is usually a nonoperating interest which was retained when the basic operating interest was transferred. An example would be the royalty interest retained by a landowner when he leases the operating rights.

A carved-out interest is generally a nonoperating interest which was "carved out" and transferred to another by the owner of the operating interest who, following the conveyance, continues to hold the operating interest. For example, if the owner of an operating interest transfers an overriding royalty interest to a geologist in exchange for his services, this is a "carved-out" interest.

.03 Term or Perpetual Interests

The terms "perpetual" and "term" refer to the life of the ownership interest. A perpetual interest is generally one which does not terminate on the expiration or abandonment of the lease. As an example, the royalty interest retained by a landowner may be considered a perpetual interest.

A term interest is one which is limited to a specific period of time, or the duration of the lease. The expiration or abandonment of the lease usually terminates such an interest. Most interests other than the landowner's fee simple or royalty interest are term interests.

¶ 105 Ownership Interests

Various types of ownership interests are commonly encountered in the extractive industries. Each of these interests has its own individual characteristics in terms of creation, rights, responsibilities, and duration. The following discussion deals with these interests in terms of their federal income tax attributes.

.01 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.

.02 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 from similar inexhaustible sources.[8]

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

[8] Code Sec. 613(b)(7).

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.

.03 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.[9]

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.

.04 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.

.05 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.[10]

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.

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.

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[9] Reg. § 1.614-2(b).

[10] Reg. § 1.614-2(b) and Reg. § 1.614-5(g).

.06 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.[11] 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.

.07 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.[12] It is therefore a nonoperating interest for federal income tax purposes.[13]

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.

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[11] Reg. § 1.614-2(b) and Reg. § 1.614-5(g).

[12] Reg. § 1.636-3(a).

[13] Reg. § 1.614-2(b) and Reg. § 1.614-5(g).

The status of production payments as economic interests was significantly changed by the Tax Reform Act of 1969.[14] 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.[15] 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.

.08 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."

.09 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.

¶ 106 Types of Payments

The holder of an ownership interest may specify the manner in which his share of production is to be paid. He may also be entitled to receive certain additional payments which do not represent a division of production.

[14] P.L. 91-172.

[15] Code Sec. 636.