OIL, GAS, AND COAL TAXATION

Jonathan Barry Forman†
Oklahoma Society of CPAs
2017 Tax Institute
November 30, 2017

This background paper discusses Oklahoma’s oil, gas, and coal resources; explains the tax perspectives of owners, investors, and developers; and explains the major tax benefits of oil, gas, and coal investments and operations. In particular, this background paper discusses the different ways of transferring mineral properties and their tax consequences, and it concludes with some comments about the future of the taxation of oil, gas and coal.

I. OIL AND GAS INDUSTRY OVERVIEW
   A. The Oil and Gas Industry
   B. Drilling a Well
   C. The Major Tax Benefits for Oil and Gas Investments
      1. The Pool of Capital Doctrine
      2. Two-Year Amortization for Geological and Geophysical Expenditures (G&G)
      3. The Election to Deduct Intangible Drilling Costs
      4. Percentage Depletion
      5. The Deduction for Qualified Tertiary Injectant Expenses

II. SALES AND LEASES
   A. Cash Bonuses
   B. Delay Rentals
   C. Royalties
   D. Production Payments

III. THE POOL OF CAPITAL DOCTRINE

IV. GEOLOGICAL AND GEOPHYSICAL EXPENSES (G&G)

V. INTANGIBLE DRILLING COSTS

VI. DEPLETION
   A. Overview
   B. The Mechanics of Cost Depletion
   C. The Mechanics of Percentage Depletion
   D. Recapture on the Sale of a Lease after Development

* Copyright © 2017, Jonathan Barry Forman.
† Alfred P. Murrah Professor of Law, University of Oklahoma; B.A. 1973, Northwestern University; M.A. (Psychology) 1975, University of Iowa; J.D. 1978, University of Michigan; M.A. (Economics) 1983, George Washington University; Professor in Residence at the Internal Revenue Service Office of Chief Counsel, Washington, D.C. for the 2009-2010 academic year.
I. OIL AND GAS INDUSTRY OVERVIEW

A. The Oil and Gas Industry

The oil and gas industry has been a major force in the world economy for over 100 years. According to the International Energy Agency, over one-half of the world’s energy needs were served by oil or gas in 2013. The United States is the third largest producer of oil in the world, after Saudi Arabia and Russia. Oil prices have declined from a high of over $100 per barrel in 2008 to a low of less than $50 per barrel in 2014. Prices have modestly increased since then. The United States is the world’s largest producer of natural gas. Oklahoma is in the middle of the Mid-Continent oil region; it has about 4% of the nation’s proven petroleum reserves; and it is one of the top five petroleum-producing states.1 Oklahoma is also one of the top natural gas-producing states, with 7.6% of gross production in 2015.2 The various phases of oil and gas production include geologic and geophysical surveys to identify likely oil sources, exploration of a particular site, development of the site by drilling, and then operation of the producing well. Each of these steps produces tax consequences to the operator and the owner of the sites, which will be addressed in the outline below.

B. Drilling a Well

Landowners and other owners of mineral rights typically do not have the resources or technology to drill an oil well.3 That is where oil and gas companies come in. An oil and gas company typically obtains the rights to explore and drill by entering into a mineral lease with the owner of the mineral rights. The lessor (owner) keeps a royalty interest in the minerals (a/k/a, a “nonoperating interest”), and grants the lessee (driller) a working interest in the land in exchange for the lessee’s promise to explore and drill (a/k/a, an “operating interest”).4

In a typical oil and gas lease, the owner of the mineral interest leases the mineral interest to a company that will drill the well. The owner typically retains a 1/8 royalty interest but bears none of the cost or responsibility for drilling the well. The oil and gas company usually acquires the balance of the mineral rights as a working interest. The working interest entitles the drilling company to share in the production in exchange for its promise and obligation to explore and drill.

All in all, the federal income tax has a large part to play in the exploration, development, and production of crude oil and natural gas. In general, the federal income tax system provides very generous tax treatment for investments in the oil and gas industry.5 Special tax rules permit

---

2 Id. at Overview (noting that “The benchmark price for a blend of U.S. crude oils known as West Texas Intermediate (WTI) is set at Cushing, Oklahoma.”).
4 Treasury Regulation (Treas. Reg.) § 1.614.2(b) defines an operating mineral interest as an interest which bears the costs of production.
5 The IRS has issued a tremendous amount of guidance with respect to the Oil and Gas Industry. For example, Chapter 41 of the Internal Revenue Manual (I.R.M.) includes an Oil and Gas Handbook. I.R.M. Chapter 41 (Oil and Gas Taxation - 1
many investments in oil and gas property to be expensed rather than capitalized and deducted over the income-producing life of the oil or gas property; and percentage depletion reduces the effective tax rate on royalty income.

C. The Major Tax Benefits for Oil and Gas Investments

This subpart summarizes the major tax benefits for investments in oil and gas exploration, development, and production.

1. The Pool of Capital Doctrine

Under the pool of capital doctrine, drillers, equipment suppliers, and investors who contribute materials and services to the development of an oil and gas property in exchange for an economic interest in that property do not have to report any taxable income until the well starts to produce. In general, the contributors are not viewed as performing services for compensation or selling property, but as acquiring capital interests in an ongoing pool of capital. Accordingly, they do not have to pay any tax until the well starts to produce.

In order to have an economic interest the property, the taxpayer must be legally entitled to either a share of the production or share in the proceeds from the sale of production. If the taxpayer is merely conducting mining or drilling operations as a contractor, there is no economic interest in the minerals in place.

2. Two-Year Amortization for Geological and Geophysical Expenditures (G&G)

Geological and geophysical (“G&G”) expenditures are the costs incurred by an oil and gas exploration and production company to obtain, accumulate, and evaluate data that will serve as the basis for the acquisition or retention of oil and gas properties. For most oil and gas companies, G&G costs can be amortized over 24 months.

3. The Election to Deduct Intangible Drilling Costs

Working interests can elect to deduct domestic intangible drilling costs (IDCs) as a current business expense, rather than capitalizing them and deducting them over the income-producing life of the oil or gas property.

4. Percentage Depletion

Depletion is a form of capital cost recovery. For example, under the cost depletion method, a taxpayer deducts a ratable share of her adjusted basis in the depletable property as she sells it, but only until she has recovered all of her basis. On the other hand, with percentage depletion,
independent oil and gas producers and royalty owners can generally deduct 15 percent of their gross income each year, and cumulative depletion deductions can exceed the taxpayer’s basis.\(^\text{10}\)

5. The Deduction for Qualified Tertiary Injectant Expenses

Taxpayers can deduct the cost of qualified tertiary injectants used to recover oil and gas.\(^\text{11}\)

II. SALES AND LEASES

A landowner typically owns property as a “fee interest,” which includes ownership of both the surface rights and the right to minerals on and beneath the surface.\(^\text{12}\) The landowner can sell or lease any part of those land or mineral rights. Sometimes, however, the mineral rights are held by someone other than landowner.\(^\text{13}\) In any event, when the owner of the land or mineral rights enters into an oil exploration contract or lease with respect to those mineral rights, the tax consequences of the transaction will turn on the nature of the deed or lease.

The owner of a land interest or mineral rights interest can, of course, sell (deed) that interest to an oil and gas exploration company. In that event, the owner (seller) will recognize a gain,\(^\text{14}\) and the oil and gas company (buyer) will take a cost basis in the interest.\(^\text{15}\)

No gain or loss will be recognized on certain like-kind exchanges of oil and gas properties.\(^\text{16}\) An operating interest in a producing oil lease is real property used in the taxpayer’s trade or business and may be exchanged for other real property.\(^\text{17}\) The IRS ruled that an exchange of a producing oil lease for ranch land qualified as a tax-free exchange.\(^\text{18}\) A royalty interest is a real property interest and may be exchanged for other real property interests.\(^\text{19}\)

More commonly, the owner of a land interest or mineral rights interest will lease the mineral rights to an oil and gas company. The lease agreement will usually provide for an up-front cash bonus and a royalty to be paid to the lessor (owner) of the mineral rights.\(^\text{20}\) Typically, the lessor will get a royalty of 1/8 of production, and the lessee (driller) will take the remaining 7/8.\(^\text{21}\) The lease will also usually obligate the lessee to pay a delay rental for each year that development is not started.\(^\text{22}\)

\(^\text{10}\) I.R.C. § 613.
\(^\text{11}\) I.R.C. § 193.
\(^\text{13}\) I.R.M. 4.41.1.2.1.1, at paragraph 2.
\(^\text{14}\) I.R.C. § 1001. The gain is likely to be a capital gain. I.R.M. 4.41.1.2.1.1, at paragraph 8.
\(^\text{15}\) I.R.C. § 1012.
\(^\text{16}\) I.R.C. § 1031.
\(^\text{18}\) Rev. Rul. 68-331, supra note 17.
\(^\text{19}\) See Crichton v. Comm’r, 42 B.T.A. 490, aff’d, 122 F.2d 181 (5th Cir. 1941) (involving the exchange of a city lot for a royalty interest).
\(^\text{20}\) I.R.M. 4.41.1.2.1.2, at paragraph 1.
\(^\text{21}\) I.R.M. 4.41.1.2.1.4; 4.41.1.2.2, at paragraph 2.
\(^\text{22}\) I.R.M. 4.41.1.2.1.2, at paragraph 1.
The lessee’s interest is typically known as a working or operating interest, while the lessor’s interest is a royalty or nonoperating interest; and these interests can, themselves, be divided, or sold.

A. Cash Bonuses

For income tax purposes, cash bonuses received by the lessor upon the execution of an oil and gas lease are viewed as advance royalties. As such, the lessor may be able to claim cost (but not percentage) depletion. If it turns out that there is no oil and gas production and the lease expires, the lessor may have to restore that previously-allowed depletion to income in the year the lease terminates. The payor of the cash bonus (i.e., lessee) capitalizes the cost into the depletable basis of the lease.

B. Delay Rentals

Oil and gas leases generally require that the lessee begin drilling for oil and gas within one year after the granting of the lease and that if drilling has not begun within that time period, the lease will either expire or the lessee will pay the lessor a sum of money in order for the lessee to retain the lease without developing the property. The lessor will treat these so-called “delay rentals” as ordinary income on which no depletion is allowable. For the lessee, delay rentals generally must be capitalized into the depletable basis of the lease.

C. Royalties

When drilling results in a producing well, royalty payments based on the sales of oil and gas are divided in accordance with the terms of the lease, and those royalties are eligible for percentage depletion. A royalty interest entitles its owner to share in the production from a mineral deposit, free of development and operating costs, and extends undiminished over the productive life of the property. Royalties are included in gross income and can be eligible for percentage depletion. Royalty payments made by the lessee to the lessor are excluded from the lessee’s gross income.

D. Production Payments

A production payment is the right to a specified share of the production from minerals in place (if, as, and when produced) or the proceeds from such production. These are nonoperating interests (i.e., not burdened with the costs of development and production). A
production payment must have an economic life that is of shorter duration than the economic life of the mineral property from which it is created.\(^{33}\) A production payment is generally treated as a mortgage loan on the mineral property burdened thereby and not as an economic interest in minerals in place.\(^{34}\)

III. THE POOL OF CAPITAL DOCTRINE

Under the pool of capital doctrine, drillers, equipment suppliers, and investors can contribute services and materials to the development of an oil and gas property in exchange for an economic interest in that property without triggering a taxable event.\(^{35}\) The contributors are viewed as acquiring capital interests in an ongoing pool of capital, rather than as performing services for compensation or selling property. Accordingly, they do not have to pay any tax until the well starts to produce.

The pool of capital doctrine applies if:

- The contributor of services receives a share of production, and the share of production is marked by an assignment of an economic interest in return for the contribution of services;
- The services contributed may not in effect be a substitution of capital;
- The contribution must perform a function necessary to bring the property into production or augment the pool of capital already invested in the oil and gas in place;
- The contribution must be specific to the property in which the economic interest is earned;
- The contribution must be definite and determinable; and
- The contributor must look only to the economic interest for the possibility of profit.\(^{36}\)

In recent years, the IRS has sought to limit the scope of the pool of capital doctrine. For example, in Revenue Ruling 77-176, the IRS ruled that to come within the pool of capital doctrine, the economic interest acquired must be in the same property to which the materials and services are contributed.\(^{37}\) Also, in Revenue Ruling 83-46, the IRS ruled that an attorney who contributed legal services to a drill site would have income when he received a royalty interest in the property in exchange for his services.\(^{38}\)

IV. GEOLOGICAL AND GEOPHYSICAL EXPENSES (G&G)

Geological and geophysical (“G&G”) expenditures are the costs incurred by an oil and gas exploration and production company to obtain, accumulate, and evaluate data that it needs to decide about which oil and gas properties it should acquire and retain.\(^{39}\) G&G expenses are usually associated with geologists, seismic surveys, magnetic surveys, or gravity meter surveys.

\(^{33}\) Id.
\(^{34}\) Treas. Reg. § 1.636-1(a).
\(^{35}\) Palmer v. Bender, 287 U.S. 551 (1933); G.C.M. 22730, 1941-1 C.B. 214; Rev. Rul. 77-176, 1977-1 C.B. 77.
\(^{36}\) I.R.M. 4.41.1.2.3.1, at paragraph 8.
\(^{39}\) I.R.M. 4.41.1.2.2.3.2.1.
For most domestic oil and gas companies, G&G expenses are amortized ratably over 24-months. There is a half-year convention so that the G&G expense amortization is treated as occurring at the midpoint of the year in which the expenses were paid or incurred. Accordingly, G&G expense deductions are spread over three tax years. For example, assume that David the Driller spent $10,000 for G&G in Year 1. David would capitalize those G&G expenditures, and he would deduct $2500 (25 percent) in Year 1, $5000 (50 percent) in Year 2, and the last $2500 (25 percent) in Year 3.

This amortization is the exclusive method of recovering G&G expenses. Accordingly, even if the taxpayer abandons the property, remaining basis may not be recovered in the year the property is abandoned, but instead it must continue to be amortized over the remaining applicable amortization period. G&G expenses should be allocated to the leases that are acquired and retained.

For the major integrated oil companies, the amortization period is seven years for G&G expenses incurred after December 19, 2007. G&G expenses incurred with respect to foreign properties are not eligible for favorable amortization treatment. Instead, such costs must be capitalized.

Comment: G&G expenses are generally supposed to be capitalized and amortized over two years, and the IRS auditors will look to see if G&G expenses are instead incorrectly deducted as ordinary and necessary business expenses or as intangible drilling costs (IDC).

40 I.R.C. § 167(h)(1).
41 I.R.C. § 167(h)(2).
42 I.R.C. § 167(h)(3).
43 I.R.C. § 167(h)(4). Under prior law, G&G expenses associated with productive properties were generally deductible over the life of those properties, but the G&G expenses associated with abandoned properties were generally deductible in the year of abandonment. Staff of the Joint Committee on Taxation, Description of Present Law and Select Proposals Relating to the Oil and Gas Industry 5 n.23 (JCX-27-11, May 11, 2011), https://www.jct.gov/publications.html?func=startdown&id=3787 [hereinafter JCT Oil and Gas Industry].
44 I.R.M. 4.41.1.2.2.4.1.
45 An “integrated oil company” is an oil and gas producer that sells more than $5 million of retail product per year or refines more than 75,000 barrels of oil per year. Internal Revenue Service, Oil and Gas Industry 1-3 (Market Segment Specialization Program, 1996), https://www.irs.gov/pub/irs-mssp/oilgas.pdf. Major integrated oil companies produce at least 500,000 barrels a day and have gross receipts in excess of $1 billion. I.R.C. § 167(h)(5)(B).
48 I.R.M. 4.41.1.2.2.3.2.4. Only the small portion of the G&G expenses that relate to a specific well location can qualify as intangible drilling costs. I.R.M. 4.41.1.2.2.3.2.9:

Examiners may find that G&G expenditures are sometimes deducted as Intangible Drilling Costs (IDC). The definition of IDC in Treas. Reg. 1.612-4 does encompass certain “geologic works”. See Exhibit 4.41.1-5 where they are defined as “survey and seismic costs to locate a well site on leased property”. Often, taxpayers will deduct an entire G&G survey as IDC when only a small portion relates to a specific well location. An IRS engineer may have to be consulted if that situation arises. There is no published guidance on whether the amortization rule of IRC 167(h) supersedes the deduction of “well-site G&G” as IDC. The examiner should contact Local IRS Counsel if this is a material issue.

Oil, Gas, and Coal Taxation - 6
V. Intangible Drilling Costs

The holder of an operating or working interest in an oil or gas property can elect to either expense or capitalize its domestic intangible drilling and development costs (IDCs). IDCs are expenditures that a working interest pays to develop oil and gas property. IDCs typically include expenditures made for wages, fuel, repairs, hauling, supplies, and other expenses incident to and necessary for drilling and equipping of wells for the production of oil and gas. In addition, the costs associated with a nonproductive well, or “dry hole,” may also be deducted as incurred. IDCs do not include expenses for items that have a salvage value, such as pipes and casings—these expenditures are instead depreciated.

When the taxpayer so elects, it will deduct its IDCs in the taxable year in which they are paid or incurred. On the other hand, for purposes of computing the alternative minimum tax (AMT), IDC is a tax preference. In general, IDC is an alternative minimum tax preference to the extent that “excess” IDC exceeds 65 percent of the net income from the properties. In that regard, however, there is a limited exception for independent producers (as opposed to integrated oil companies). Also, a taxpayer that has elected to deduct its IDCs can make a secondary election to capitalize and amortize all or a portion of its IDCs over a 60-month period; and the IDC expenses so amortized are not treated as tax preference items under the AMT.

If the taxpayer instead elects to capitalize its IDCs, those expenses would be recovered through depletion or depreciation deductions, as appropriate.

For an integrated oil company that elects to expense its IDCs, only 70 percent is expensed, and the remaining 30 percent is allowable as a deduction over a 60-month period beginning with the month that the costs are paid or incurred. IDCs incurred outside of the United States must be capitalized.

---

49 I.R.C. § 263(c); Treas. Reg. § 1.611-1(b); Stephen L. McDonald, Federal Tax Treatment of Income from Oil and Gas 15 (1963).
50 Treas. Reg. § 1.612-4(a). See also Appendix Table 1.
52 I.R.C. §§ 167, 168.
53 I.R.C. § 263(c).
54 I.R.M. 4.41.1.5.4.1.
55 I.R.M. 4.41.1.5.4.1.1, at paragraph 1; I.R.C. § 57(a)(2).
56 I.R.M. 4.41.1.5.4.1, at paragraph 2; I.R.C. § 57(a)(2)(E).
57 I.R.C. § 59(e)(1); Treas. Reg. § 1.59-1.
58 I.R.M. 4.41.1.5.4.1.1, at paragraph 2; JCT Oil and Gas Industry, supra note 43, at 4. The election can be made on an item-by-item basis so as to minimize the alternative minimum tax liability.
60 I.R.C. § 291(b); I.R.M. 4.41.1.2.4.3.1.
61 I.R.M. 4.41.1.2.4.3.2.
VI. DEPLETION

A. Overview

In recognition of the wasting nature of the asset, the original depletion allowance for oil and gas development provided for cost recovery of an owner’s mineral investment in a manner similar to depreciation of a tangible asset.62 Typically, the capital costs of mineral investments include the purchase price of the property, discovery costs, and development costs. As with depreciation, the taxpayer is allowed to recover these investment costs as the asset is expended to produce income.

Depletion deductions are allowed only to the owner of an economic interest in mineral deposits (or standing timber).63 An economic interest is an interest: (1) acquired by investment in the minerals in place; (2) that entitles the owner to income derived from the extraction of the minerals; and (3) to which the owner must look for a return of its capital.64 Two methods of depletion are allowable: cost depletion and percentage depletion. A taxpayer using cost depletion recovers the actual costs of the mineral investment over its producing life based on the number of units produced each year.65 The sum of cost depletion deductions may not exceed the original capital investment.

Congress adopted percentage depletion to provide a special incentive for exploration and production activities by allowing the taxpayer to deduct a fixed percentage of the gross value of annual production.66 Percentage depletion allows matching of income and deductions when it is not clear how much of the resource is in the ground, which may have been more important in the early days of oil exploration.67 However, when the value of the mineral deposit exceeds the original cost of the investment, percentage depletion affords the investor a bigger tax deduction and a significantly reduced tax rate, based on successful production.68 Because percentage depletion is computed without regard to the taxpayer’s actual investment in the property, total percentage-depletion deductions can exceed the amount originally invested.

B. The Mechanics of Cost Depletion

To figure cost depletion, a taxpayer must determine: (1) the property’s basis for depletion; (2) the total recoverable units of the mineral in the property’s natural deposit; and (3) the number of units of mineral sold during the tax year.69 There is an elective safe harbor for owners of oil

---

62 GAO REPORT 2000, supra note 59, at 5.
63 Treas. Reg. § 1.611-1(b).
64 Id.; Palmer v. Bender, 287 U.S. 551 (1933).
65 Id.; MacDonald, Federal Tax Treatment of Income from Oil and Gas, supra note 49, at 9. The taxpayer is permitted to deduct a portion of the asset cost, lowering taxable income, over a specified recovery period.
66 Treas. Reg. § 1.612-1.
and gas property that sets total recoverable units equal to 105 percent of a property’s proven reserves.\(^{70}\)

To figure its cost depletion, a taxpayer takes the following steps: (1) divide the property’s basis for depletion by total recoverable units to get the rate per unit; and (2) multiply the rate per unit by the units sold during the tax year to get the cost depletion deduction. For example, if a taxpayer has 100,000 recoverable barrels of oil with a basis of $1,000,000 and this year it sells 5000 of those barrels for $200,000, the taxpayer would report $200,000 in gross income and take a cost depletion allowance of $50,000 ($50,000 = $1,000,000/100,000 \times 5000); and its adjusted basis in the remaining 95,000 recoverable barrels would be $950,000.\(^{71}\)

\(\text{C. The Mechanics of Percentage Depletion}\)

Percentage depletion is available to domestic independent producers and royalty owners, but it is not available for integrated producers who are also large retailers or refiners.\(^{72}\) To figure percentage depletion, the taxpayer multiplies its gross income from its oil and gas property for the year by 15 percent.\(^{73}\) Percentage depletion can result in the recovery of more than the capital investment in the property (i.e., cumulative depletion deductions can exceed the taxpayer’s basis); however, the adjusted basis in the leasehold interest is not reduced below zero.\(^{74}\)

There are a number of limits on how much percentage depletion can be claimed by a taxpayer. For example, percentage depletion cannot exceed 100 percent of the taxable income from the property or 65 percent of the taxpayer’s taxable income for the year.\(^{75}\) There is also a limit on how much oil can be used for percentage depletion; generally, a taxpayer’s depletable oil quantity is an average of 1000 barrels per day;\(^{76}\) and related parties are required to allocate the depletable oil quantity among those parties in proportion to their respective production.\(^{77}\)

\(\text{D. Recapture on the Sale of a Lease after Development}\)

When a lease is sold or exchanged, the taxpayer will realize a gain or loss based on the difference between the selling price and the adjusted basis of the property sold.\(^{78}\) In general, the gain will be taxed as ordinary income to the extent that it relates to basis reductions attributable to depletion or IDCs, but the rest can be capital gain.\(^{79}\)

\(\footnotesize{\text{\footnotesize71 I.R.C. § 1016(a)(2).}}\)
\(\footnotesize{\text{\footnotesize72 See generally Internal Revenue Service, Business Expenses, supra note 69, at 34-38; Treas. Reg. § 1.613A-3.}}\)
\(\footnotesize{\text{\footnotesize73 I.R.C. § 613.}}\)
\(\footnotesize{\text{\footnotesize74 I.R.M. 4.41.1.4.1.1, at paragraph 4. While theoretically, the excess of percentage depletion over basis is a tax preference item for purposes of the alternative minimum tax, independent producers and royalty owners are excluded from this provision. I.R.C. § 57(a)(1).}}\)
\(\footnotesize{\text{\footnotesize75 I.R.C. §§ 613(a), 613A(c)(1).}}\)
\(\footnotesize{\text{\footnotesize76 I.R.C. § 613A(c). The taxpayer can elect annually to use all or some of that 1000-barrel amount to determine its depletable natural gas quantity by using a conversion factor of 6000 cubic feet of gas per barrel.}}\)
\(\footnotesize{\text{\footnotesize77 I.R.C. § 613A(c)(8).}}\)
\(\footnotesize{\text{\footnotesize78 I.R.M. 4.41.1.4.1.1, at paragraph 1; I.R.C. § 1001(a).}}\)
\(\footnotesize{\text{\footnotesize79 I.R.M. 4.41.1.4.1; I.R.C. § 1254.}}\)
VII. DEDUCTION FOR QUALIFIED TERTIARY INJECTANT EXPENSES

Taxpayers engaged in drilling for and producing oil may generally deduct the cost of qualified tertiary injectants used to recover that oil.\textsuperscript{80} Tertiary injectants are the fluids, gases, and other chemicals that are pumped into oil and gas reservoirs in order to facilitate the extraction of oil that is too viscous to be extracted by conventional methods.\textsuperscript{81}

Taxpayers take the deduction in the later of the tax year in which the injectant is injected or the tax year in which the expenses are paid or incurred.\textsuperscript{82} All in all, Internal Revenue Code section 193 allows tertiary injectant costs to be expensed rather than capitalized and deducted over the income-producing life of the oil or gas property.

VIII. OTHER TAX BENEFITS FOR OIL AND GAS DEVELOPMENT

A. Credit for Enhanced Oil Recovery Costs

There is also a credit for certain qualified enhanced oil recovery ("EOR") costs.\textsuperscript{83} The credit is equal to 15 percent of the: (1) amounts paid for depreciable tangible property; (2) intangible drilling and development expenses; (3) tertiary injectant expenses; and (4) construction costs for certain Alaskan natural gas treatment facilities. The credit was phased out from 2006 through 2015, but with the low price of oil, the credit was reinstated in 2016.\textsuperscript{84}

B. Marginal Well Credit

Since 2005, there has also a credit for oil and natural gas produced from marginal wells;\textsuperscript{85} however, because of the relatively high price of oil, the credit has been completely phased out for all taxable years since its enactment.\textsuperscript{86}

C. Exception from Passive Loss Limitations for Working Interests in Oil and Gas Property

The passive activity loss rules generally limit deductions and credits from passive trade or business activities,\textsuperscript{87} but these rules do not typically apply to working interests in oil and gas property.\textsuperscript{88}

\textsuperscript{80} I.R.C. § 193.
\textsuperscript{81} I.R.C. § 193(b); GAO REPORT 2000, supra note 59, at 14. Natural gas, crude oil and any other injectant with more than an insignificant amount of natural gas or crude oil generally do not qualify as tertiary injectants. I.R.C. § 193(b)(2); Treas. Reg. § 1.193-1(c).
\textsuperscript{82} Treas. Reg. § 1.193-1.
\textsuperscript{83} I.R.C. § 43.
\textsuperscript{85} I.R.C. § 45I.
\textsuperscript{86} JCT Oil and Gas Industry, supra note 43, at 2-3.
\textsuperscript{87} I.R.C. § 469.
\textsuperscript{88} I.R.C. § 469(c)(3); Treas. Reg. § 1.469-1T(e)(4).
D. Last-In, First-Out Inventory Accounting Method

Oil and gas producers must use inventory accounting, but they can use the last-in, first-out ("LIFO") method. 89 When the costs of production are rising—as they usually are—LIFO results in a lower measure of income than first-in, first-out (FIFO)—and less income tax liability. 90

E. Accelerated Depreciation

Oil and gas producers can also use accelerated depreciation to recover costs that are represented by physical property. 91 For example, many assets used to explore and drill for oil and gas have five-year or seven-year recovery periods, and pipelines generally have a 15-year recovery period. 92

F. Deduction for Income Attributable to Domestic Production of Oil and Gas

Oil and gas producers can deduct 6 percent of their income attributable to domestic production of oil and gas. 93 More specifically, the Internal Revenue Code allows a deduction for 6 percent of the lesser of the taxpayer’s qualified production activity income (QPAI) or its taxable income. 94 QPAI is basically domestic production gross receipts (DPGR) reduced by the cost of goods sold (COGS) and related expenses. 95 Oil-related QPAI includes income from the production, refining, or processing of oil, gas, or any primary product thereof. 96 The deduction is limited to 50 percent of the wages paid and reported in the tax year. 97

IX. Coal Tax Benefits

Many of the same tax benefits that apply to oil and gas production also apply to coal production, including the pool of capital doctrine and percentage depletion. Percentage depletion for coal differs in several ways from percentage depletion for oil and gas, as detailed below. Like oil and gas, coal property may be sold or leased. In addition, coal production enjoys a special capital gains provision. Finally, coal that is mined on an Indian reservation may be eligible for a production tax credit. 98

---

89 I.R.C. § 471(a); Treas. Reg. § 1.471-1. Under the LIFO method, the assumption is that the last items entered into inventory are the first items sold.
90 See, e.g., JCT Oil and Gas Industry, supra note 43, at 18.
93 I.R.C. § 199.
94 I.R.C. § 199(a)(1), (d)(9)(A). The deduction is only available for working interests (operating interests that bear the costs of production), and it is not available for nonoperating mineral interests (i.e., royalty interests). Treas. Reg. § 1.199-3(i)(9).
95 I.R.C. § 199(c).
97 I.R.C. § 199(b).
98 I.R.C. § 45(c)(9).
A. Percentage Depletion of Coal

To figure percentage depletion, the taxpayer multiplies its gross income from mining for the year by 10 percent.\(^9\) Percentage depletion is limited to 50 percent of the taxable income from the property, in contrast to the 100-percent limitation for oil and gas.\(^10\) As in the case of oil and gas, total percentage-depletion deductions for coal can exceed the amount originally invested. However, for corporations, only 80 percent of depletion in excess of basis is deductible in determining regular tax liability,\(^11\) and 100 percent of depletion in excess of basis is treated as a tax preference item for alternative minimum tax (AMT) purposes.\(^12\) Note that oil and gas depletion in excess of basis is not subject to the AMT.\(^13\)

“Gross income from mining” is specifically defined by statute.\(^14\) Mining includes the extraction of coal from the ground, transportation from the mine to the plant (generally limited to 50 miles), and various treatment processes, including:

- Cleaning,\(^15\)
- Breaking,
- Sizing,
- Dust allaying,
- Treating to prevent freezing, and
- Loading for shipment.\(^16\)

Like recipients of oil and gas royalties, recipients of coal royalties are entitled to percentage depletion. However, recipients of cash bonus payments on oil and gas leases may not take percentage depletion on those payments.\(^17\) Recipients of cash bonus payments on coal leases may take percentage depletion on those payments.\(^18\)

B. Deduction of Mining Exploration Expenditures

The taxpayer may elect to deduct mining exploration expenditures rather than capitalizing such expenditures into the basis of the property (or working interest under a lease).\(^19\) Examples of mining exploration expenditures include collecting published data; aerial and surface

---

\(^9\) I.R.C. § 613(b)(4).
\(^10\) I.R.C. § 613(a).
\(^12\) I.R.C. § 57(a)(1).
\(^13\) Id. “This paragraph shall not apply to any deduction for depletion computed in accordance with section 613A.”
\(^14\) I.R.C. § 613(c).
\(^15\) But see Rev. Rul. 74-568, 1974-2 C.B. 183, in which the IRS held that the costs a coal mine operator incurred to transport and wash coal at a facility operated by the buyer were non-mining costs for purposes of computing the depletion allowance.
\(^16\) I.R.C. § 613(c)(4)(A).
\(^17\) I.R.C. § 613A(d)(5).
\(^19\) I.R.C. § 617.

Oil, Gas, and Coal Taxation - 12
reconnaissance; surface and underground mapping; and sampling costs, reasonably connected to ascertaining the existence, location, extent or quality of mineral deposits.\textsuperscript{110}

Unlike the deduction of intangible drilling costs, the taxpayer must recapture the deduction if the mine begins production.\textsuperscript{111} The recapture of exploration expenditures does not increase gross income from the property for purposes of determining percentage depletion.\textsuperscript{112} Alternatively, the taxpayer could add the exploration expenditures to depreciable basis or elect to capitalize and amortize the expenditures over 10 years.\textsuperscript{113} The treatment of exploration expenditures has an effect on the depletion deduction in several ways. If the costs are capitalized, the basis for cost depletion increases, and the cost depletion deduction also increases. If exploration expenditures are expensed, the expensed amount reduces the taxable income from the mine, which may result in the application of the 50-percent-of-taxable-income limitation on percentage depletion. Foreign exploration expenditures are not deductible, but must be capitalized into the depreciable basis of the property.\textsuperscript{114}

\textbf{C. Deduction of Mining Development Expenditures}

Once the existence of coal in commercial marketable quantities has been established, the taxpayer may elect to deduct the cost of developing the mine.\textsuperscript{115} It may be difficult to distinguish between exploration expenditures and development expenditures. For example, core drilling to fix the existence of a commercially marketable seam of coal would be an exploration expenditure, while core drilling to establish the extent and location of an existing commercially marketable deposit would be a development expenditure.\textsuperscript{116} Unlike exploration expenditures, development expenditures are not required to be recaptured once the mine enters the production phase. However, upon sale of the coal property, both development and exploration deductions must be recaptured as ordinary income.\textsuperscript{117} Furthermore, for corporate AMT purposes, only 70 percent of development and exploration deductions are allowed.\textsuperscript{118}

\textbf{D. Other Deductions: Receding Face Doctrine}

As mining progresses, the mine face may need to be shored up and stabilized to allow continued mining activity. These costs that would otherwise have to be capitalized may be deducted under the “receding face doctrine” if incurred to maintain the normal output of the mine.\textsuperscript{119} Deductible expenses allowed by case law under this doctrine include:

\begin{itemize}
\item \textsuperscript{110} \textit{Levert v. Comm’r}, T.C. Memo 1989-333, aff’d, 959 F.2d 264 (5th Cir. 1992).
\item \textsuperscript{111} I.R.C. § 617(b). The taxpayer may either take the adjusted exploration expenditures into income, or reduce the depletion deduction by the same amount.
\item \textsuperscript{112} Treas. Reg. § 1.617-3(a)(2).
\item \textsuperscript{113} I.R.C. § 59(e).
\item \textsuperscript{114} I.R.C. § 617(h).
\item \textsuperscript{115} I.R.C. § 616.
\item \textsuperscript{116} Rev. Rul. 70-288, 1970-1 C.B. 146.
\item \textsuperscript{117} I.R.C. § 1254.
\item \textsuperscript{118} I.R.C. § 291(b)(1)(B). This provision also cuts back IDC deductions for integrated oil producers, \textit{see supra} note 60.
\item \textsuperscript{119} Treas. Reg. § 1.612-2.
\end{itemize}
• Electric locomotive, mine cars, steel rails, switches, trolley wires, water pipes, conveyer equipment;\textsuperscript{120}
• Electrical substations, power lines, transformers;\textsuperscript{121}
• Car wheels, irons, bolts, and mine pumps;\textsuperscript{122}
• Air shafts, fans, and compressors.\textsuperscript{123}

\textbf{E. Capital Gain Treatment on Disposition of Coal Property with a Retained Economic Interest}

Oil and gas royalty payments generally give rise to ordinary income. However, if a taxpayer has held the right to coal for more than one year and disposes of that right with a retained economic interest, it will be treated as the sale of an Internal Revenue Code section 1231 asset.\textsuperscript{124} This, in effect, turns a coal royalty from ordinary income into capital gains. Expenses of entering into and administering a coal disposition contract that qualifies for capital gain treatment are not deductible, but rather are added to the depletable basis of the coal for purposes of determining gain or loss.\textsuperscript{125} Such expenses may include accounting fees, legal expenses, and state severance taxes. Percentage depletion is not allowed if capital gains treatment applies.\textsuperscript{126}

\textbf{F. Credit for Indian Coal}

“Indian coal” is coal produced from coal reserves that on June 14, 2005, were owned by an Indian tribe or held in trust by the United States for the benefit of an Indian tribe.\textsuperscript{127} Interestingly, this provision is contained within section 45, which is entitled “Electricity produced from certain renewable resources.” The applicable Indian coal production tax credit for was $2.387 per ton in 2016 but has since expired.\textsuperscript{128} The Indian coal production credit applies to Indian coal produced from 2006 through 2017.\textsuperscript{129}

\textbf{X. The Future of Oil, Gas, and Coal Tax Benefits}

Many of the special tax rules for oil, gas, and coal development are identified as “tax expenditures” in the tax expenditure budgets prepared annually by the Office of Management

\textsuperscript{120} Marsh Fork Coal Co. v. Lucas, 42 F. 2d 83 (4th Cir. 1930).
\textsuperscript{123} Roundup Coal Mining Co. v. Comm'r, 20 T.C. 388 (1953).
\textsuperscript{124} I.R.C. § 631(c).
\textsuperscript{125} I.R.C. § 272.
\textsuperscript{126} Treas. Reg. § 1.631-3(b)(1).
\textsuperscript{127} I.R.C. § 45(c)(9).
\textsuperscript{129} I.R.C. § 45(e)(10).
and Budget and by the Joint Committee on Taxation.\textsuperscript{130} Policymakers often use these tax expenditure estimates as a rough guide to the cost of these special income tax provisions.\textsuperscript{131} For example, Table 1 reproduces the Office of Management and Budget’s 2017 \textit{Federal Budget} estimates of the revenue losses attributable to some of the special income tax benefits for oil, gas and coal development.\textsuperscript{132}

**Table 1. Estimates of Total Income Tax Expenditures for Fiscal Years 2016–2025**

*(In millions of dollars)*

<table>
<thead>
<tr>
<th>Oil and Gas</th>
<th>2016</th>
<th>2017</th>
<th>2016-25</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expensing of exploration and development costs, fuels</td>
<td>470</td>
<td>460</td>
<td>5,550</td>
</tr>
<tr>
<td>Excess of percentage over cost depletion, fuels</td>
<td>710</td>
<td>860</td>
<td>12,700</td>
</tr>
<tr>
<td>Exception from passive loss limitation for working interests in oil &amp; gas properties</td>
<td>40</td>
<td>40</td>
<td>340</td>
</tr>
<tr>
<td>Amortize geological &amp; geophysical expenditures over 2 years</td>
<td>100</td>
<td>100</td>
<td>960</td>
</tr>
</tbody>
</table>

**Coal**

| Capital gains treatment of royalties on coal                               | 120  | 130  | 1,420   |
| Credit for investment in clean coal facilities                             | 160  | 400  | 1,180   |

*Source: Executive Office of the President and Office of Management and Budget, Analytical Perspectives, Budget of the United States Government, Fiscal Year 2017 228 tbl.14-1 (2016).*

All in all, the special tax rules for oil, gas, and coal development are costly tax expenditures, and Congress may eventually curtail them. In that regard, the Congressional Budget Office often includes repealing the expensing of intangible drilling costs and percentage depletion among its options for reducing the federal deficit.\textsuperscript{133} Similarly, the Obama Administration repeatedly called for repeal of fossil fuel tax preferences.\textsuperscript{134} In 2016, for example, the Obama Administration called for repeal of the following oil and gas tax preferences:


\textsuperscript{131} Admittedly, however, tax expenditure estimates do not necessarily equal the increase in Federal revenues that would result from repealing the special provisions.

\textsuperscript{132} Executive Office of the President and Office of Management and Budget, Analytical Perspectives, Budget of the United States Government, Fiscal Year 2017, supra note 130, at 228 tbl.14-1.


\textsuperscript{134} See, e.g., Executive Office of the President and Office of Management and Budget, Analytical Perspectives, Budget of the United States Government, Fiscal Year 2017, supra note 130, at 177, 201 tbl.12-2; U.S. Department of the Treasury, General Explanations of the Administration’s Fiscal Year 2017 Revenue
(1) The enhanced oil recovery credit for eligible costs attributable to a qualified enhanced oil recovery project;
(2) The credit for oil and natural gas produced from marginal wells;
(3) The expensing of intangible drilling costs;
(4) The deduction for costs paid or incurred for any tertiary injectant used as part of a tertiary recovery method;
(5) The exception to passive loss limitations provided to working interests in oil and natural gas properties;
(6) The use of percentage depletion with respect to oil and natural gas wells;
(7) The ability to claim the domestic manufacturing deduction against income derived from the production of oil and natural gas; and
(8) Two-year amortization of independent producers’ geological and geophysical expenditures, instead allowing amortization over the same seven-year period as for integrated oil and natural gas producers.  

Similarly, the Obama Administration called for repeal of the following tax preferences for coal activities:

(1) Expensing of exploration and development costs;
(2) Percentage depletion for hard mineral fossil fuels;
(3) Capital gains treatment for royalties; and
(4) The ability to claim the domestic manufacturing deduction against income derived from the production of coal and other hard mineral fossil fuels.

In May 2016, leaders of the so-called G7 nations pledged to end most subsidies for fossil fuels by 2025. The G7 nations include the UK, the US, Canada, France, Germany, Italy, and Japan. Of course, the Trump Administration sees things quite differently.

---

135 EXECUTIVE OFFICE OF THE PRESIDENT AND OFFICE OF MANAGEMENT AND BUDGET, ANALYTICAL PERSPECTIVES, BUDGET OF THE UNITED STATES GOVERNMENT, FISCAL YEAR 2017, supra note 130, at 177.

136 Id.

APPENDIX

Appendix Table 1. Classification of Expenditures in Acquisition, Development, and Operation of Oil and Gas Leases

A. Leasehold Cost (Capital Expenditure)
1. Research of lease location by engineer, geologist, etc., for purposes other than locating a well site.
2. Geological and geophysical expenditure leading to acquisition or retention of an oil and gas property (limited to expenditures after August 8, 2005 for foreign properties; see I.R.M. 4.41.1.2.2.3.1).
3. Expenses in connection with leasing the property from a landowner.
4. Legal costs of securing lease and clearing title.
5. Legal fees incurred to obtain access to the property and to obtain easements, etc.
6. Lease bonus paid to the landowner or other owner.
7. Purchase price of an existing lease.
8. Core-hole wells drilled to obtain geological data (limited to expenditures after August 8, 2005 for foreign properties; see I.R.M. 4.41.1.2.2.3.1).
9. Cost of seismic work incurred by an oil and gas company to determine the size of the reservoir or reserves (limited to expenditures after August 8, 2005 for foreign properties; see I.R.M. 4.41.1.2.2.3.1).
10. Legal fees incurred in drafting contracts.
11. Travel expenses incurred in acquiring leases.
12. Salaries of land department personnel in acquiring leases.
13. Equalization payments paid in furtherance of a unitization when paid in connection with prior IDC.
14. Bottom-hole contribution when paid to obtain information which enhances the value of the property (limited to expenditures after August 8, 2005 for foreign properties; see I.R.M. 4.41.1.2.2.3.1).
15. IDC if no election to expense has been made under IRC 263(c) or if "foreign IDC."
16. Delay rentals unless the taxpayer can establish that it was not reasonably likely for the lease to be developed.
17. Remaining basis in equipment which is transferred to another person under any type of reversionary agreement.

B. Intangible Drilling Costs (current deductions or capital cost depending on election)
1. Administrative costs in connection with drilling contracts.
2. Survey and seismic costs to locate a well site on leased property.
3. Costs of drilling.
4. Grading, digging mud pits, and other dirt work to prepare drill site.
5. Cost of constructing roads or canals to drill site.
6. Surface damage payments to landowner.
7. Crop damage payments.

8. Costs of setting rig on drill site.
9. Transportation costs of moving rig.
10. Technical services of geologist, engineer, and others engaged in drilling the well.
11. Drilling mud, fluids, and other supplies consumed in drilling the well.
12. Transportation of drill pipe and casing.
13. Cementing of casing (but not the casing itself).
14. Rent of special equipment and tanks to be used in drilling a well.
15. Perforating the well casing.
16. Logging costs, but not velocity surveys.
17. Costs of removing the rig from the location.
18. Dirt work in cleaning up the drill site.
19. Cost of acidizing, fracturing the formation, and other completion costs.
20. Swabbing costs to complete the well.
21. Cost of obtaining an operating agreement for drilling operations.
22. Cost of plugging the well if it is dry.
23. Cost of drill stem tests.

C. Lease and Well Equipment (Capital Expenditures)
1. Surface casing.
2. Equalization payments of a unitization when paid in connection with equipment.
3. Cost of well casing.
4. Salt water disposal equipment and well.
5. Transportation of tubing to supply yard but not from supply yard to well site.
6. Cost of production tubing.
7. Cost of well head and "Christmas Tree."
8. Cost of pumps and motors including transportation.
9. Cost of tanks, flow lines, treaters, separators, etc., including transportation.
10. Dirt work for tanks and production equipment.
11. Roads constructed for operation of the production phase.
12. Laying pipelines, including dirt work and easements.
13. Installation costs of tanks and production equipment.
14. Construction costs of trucks turnaround pad and overflow pits at new tank battery.

D. Lease Operating Expense (current deduction)
1. Cost of switcher or pumper to operate the wells.
2. Cost of minor repair of pumps, tanks, etc.
3. Grading existing roads.
4. Treat-o-lite and other materials and supplies consumed in operating the lease.
5. Pulling sucker rods, pump, and cleaning the well.
6. Utilities.
7. Taxes other than Federal income taxes.
8. Depreciation of equipment used on the lease.
9. Rental of lease equipment.
10. Salaries for painting and cleaning the lease.
11. Lease signs.
12. Salaries of other operating personnel—farm boss, superintendent, engineer, etc.
13. IDC when elected to expense under IRC 263(c).
14. Salt water disposal costs (other than those under C.4. above).
15. Allocable portion of overhead costs.