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In 1954, Professor Harold S. Bloomenthal published an article in the Wyoming Law Journal entitled "A Guide To Federal Oil and Gas Income Taxation." That article attracted a considerable amount of acclaim from the legal and accounting professions. In the twelve year interim there have been significant changes in Federal income taxation of minerals. In "A Guide To Federal Mineral Income Taxation," Part I of which is reproduced in this Issue, Professor Bloomenthal has accomplished more than simply updating the 1954 article. The materials covered have been considerably expanded in scope and the article includes income taxation of all minerals as well as oil and gas. The Review Editorial Board is confident that this article will become the authoritative work in the field of mineral income taxation.

A GUIDE TO FEDERAL MINERAL INCOME TAXATION -- PART I

Harold S. Bloomenthal*

TABLE OF CONTENTS — PART I

Page

GENERAL PRINCIPLES ......................................................... 80

THE DEDUCTION FOR DEPLETION AND RELATED MATTERS ...... 82

(1) Non-Depletable Income and Capitalized Expenditures ........................................... 83

(2) Distinguishing Between Bonus and Delay Rental .................................................. 84

(3) "Bonus" as Depletable Income ........................................ 86

(4) Tax Treatment of Bonus Payment by Lessee-Payor ........................................... 89

(5) Depletable Income Other Than Bonus ........................................ 91

(6) Shut-in Royalties ..................................................... 94

(7) Minimum Advanced Royalties ........................................ 95

(8) Computation of Cost Depletion ....................................... 101

(9) Computation of Statutory Depletion — In General ............................................. 102

(10) Gross Income for Statutory Depletion — Oil and Gas ....................................... 103

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(11) Gross Income for Statutory Depletion Purposes — Minerals Other Than Oil and Gas ... 104
(12) Computation of Statutory Depletion — Exclusion of Allocated Portion of Bonus from Gross Income .................................................. 106
(13) Computation of Statutory Depletion — The Fifty Per Cent of Taxable Income Limitation .......................................................... 107
(14) Adjustments to Basis Resulting from the Depletion Deduction .......................................................... 111

EXPLORATION AND DEVELOPMENT COSTS ........................................ 113
(1) Exploration Costs ........................................................................ 114
(2) Intangible Drilling and Development Costs — Oil and Gas ............. 116
(3) Deduction for Intangibles — Making the Election ............................ 117
(4) The Election Should Be to Deduct Intangibles Currently .................. 118
(5) What Are Intangible Drilling and Development Costs? .................... 119
(6) Development Costs — Minerals Other Than Oil and Gas .................. 121
(7) Who Can Take Exploration and Development Deductions — In General ........................................ 124
(8) Who Can Take the Deduction — Obligation Work ............................ 126
(9) Who Can Take the Deduction — The Co-Owner Investor .................. 128
(10) Who Can Take the Deduction — The Promoter-Operator ................. 130
(11) Who Can Take the Deduction — Carried Interest and Related Arrangements ........................................ 132
(12) The Partnership Alternative ...................................................... 137

THE DEPRECIATION DEDUCTION AND INVESTMENT CREDIT ... 139
(1) Who Can Take the Depreciation Deduction? ................................. 140
(2) Methods of Computing Depreciation ............................................ 142
(3) The Guidelines ........................................................................... 146
(4) Determining the Appropriate Account for Depreciation ................. 148
(5) The Investment Credit .................................................................. 150
(6) Gain from Disposition of Certain Depreciable Property ......... 151
There are important tax advantages to be gained from investing in mineral operations. The necessity of careful planning in this area is emphasized by the fact that in many instances important tax consequences depend on relatively insignificant variations in the legal machinery employed. The late Justice Frankfurter observed in this regard that the distinctions drawn in some oil and gas tax cases "hardly can be held in the mind longer than it takes to state them." Because of these distinctions and the complex interrelationship of the depletion deduction, the deduction for development expenditures (intangibles in the case of oil and gas exploration and development costs in case of other minerals), the loss deduction for worthlessness, the depreciation deduction and other ramifications of mineral income tax-

The practitioner’s approach to the planning of transactions must be a comprehensive one. This is truly an area in which superficial knowledge can be disastrous in terms of tax consequences. The approach of this article generally has been to go beyond the superficial to a point of understanding that will permit planning for the transactions routinely encountered by practitioners in this general area and to lead practitioners into the regulations and the case law with respect to the problems requiring a more specialized understanding.

The scope of this article is designed to encompass oil and gas and other mineral operations as well. In many areas the controlling principles are identical and considerable duplication can be avoided. In other areas it may be illuminating to contrast the tax treatment of oil and gas with the tax treatment of other minerals. In some areas either the approach or the tax consequences or both are radically different and it behooves the reader to carefully distinguish between oil and gas operations and other mineral operations. Generally, if the article does not expressly distinguish between the two the reader can assume that the tax consequences are the same. To the extent that there is a difference the article expressly refers to oil and gas operations or other mineral operations as may be appropriate. However, the EXAMPLES employed in those instances in which tax consequences are the same employ as a matter of convenience oil and gas transactions.

GENERAL PRINCIPLES

Tax advantages resulting from the choice of particular alternatives are stressed in the subsequent discussion of particular problems. A few general fundamentals that will serve as a guide to many of the more common situations are set forth below:

1. Ordinarily it is desirable to a party receiving income to have it taxed as a long-term capital gain rather than as ordinary or depletible income. The reason is the obvious one that long-term net capital gains involve as a minimum a 50 per cent deduction and the tax in any event cannot
exceed 25 per cent of the gain, whereas ordinary income is taxable at rates as high as 70 per cent for individuals.

2. As a corollary to the foregoing proposition, it is ordinary desirable to the "vendor" to have a transaction regarded as a sale rather than a lease or sublease because any consideration received by the "vendor" in a lease or sublease transaction must be treated as depletable income.

3. If income cannot be considered as capital gain, it is desirable for it to fall within the depletable income classification. The reason is that the recipient of depletable income can take a deduction for cost or statutory depletion (27 1/2 per cent of gross income in the case of oil and gas and a lesser percentage in the case of other minerals), whichever is the greater, within the limitation that the statutory depletion deduction cannot exceed 50 per cent of the taxable (net) income from the property.

4. It is desirable to the taxpayer incurring expenditures for the development of mineral properties to have as small an amount as possible charged to capital expenditures amortizable through the depletion allowance. If such charges are capitalized, the taxpayer frequently realizes no tax benefit therefrom because statutory depletion can be taken in any event and does not depend upon the cost basis of the property.

5. It is desirable for the taxpayer financing the development of mineral properties to be in a position to deduct the development costs (intangibles in the case of oil and gas; exploratory and development costs in the case of other minerals) as current expenses or as expenses pro-rated against production and to recover expenditures on physical equipment through depreciation. Otherwise, such expenditures must be capitalized by the taxpayer as part of the acquisition costs of the mineral interest and amortized through the depletion deduction.

6. It is desirable with respect to each separate property for 50 per cent of the taxpayer’s taxable (net) income (after deductions for all expenses other than depletion but including development expenses) to be equal to or in excess of the amount obtained by multiplying the taxpayer’s gross
income from that property by the appropriate statutory depletion rate. The reason is that the statutory depletion deduction for each property cannot exceed 50 per cent of the taxpayer’s (net) income from that property.

7. It is ordinarily desirable to taxpayers investing in mineral operations to be taxed as an individual (co-owners) or partnership and not as a corporation. If taxed as a corporation, part of the income from the mineral operations will be subject to double taxation and in addition the taxpayer will be deprived of part of the benefit he would otherwise have received from the statutory depletion deduction.

8. It is ordinarily desirable to have a transaction regarded as a tax-exempt exchange or sharing arrangement rather than a sale. The reason is the obvious one that no tax is paid with respect to such transactions whereas a gain from a sale is subject to taxation.

**THE DEDUCTION FOR DEPLETION AND RELATED MATTERS**

The depletion deduction is the most widely publicized and is one of the more important tax advantages to be derived from investing in mineral operations. Assuming the availability of the full statutory depletion deduction the taxpayer, in effect, receives an appropriate percentage of the gross income attributable to his interest in mineral operations tax-free. The statutory depletion rate is 27 1/2 per cent in the case of oil and gas; 23 per cent in the case of uranium, vanadium, zinc, tungsten, beryl, beryllium ores, sulphur and other specified minerals; 15 per cent in the case of oil shale, phosphate rock, potash and all metals as to which the 23 per cent rate is not applicable; 10 per cent in the case of coal, asbestos and other specified non-metallic minerals and 5 per cent in the case of gravel, pumice, peat and other specified non-metallic minerals.² The importance

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². INT. REV. CODE OF 1954, § 613(b); TREAS. REG. § 1.613-2(a) (1960), as amended, T.D. 6841, 1965 INT. REV. BULL. NO. 34, at 27. Oil shale is not specifically referred to in the Code or the regulations. It is generally assumed to be subject to the 15% rate which under the Code is applicable to “all other minerals” for which a specific rate is not set forth. Although both the Code and the regulations set forth a 5% rate for “shale” generally, it is assumed that such reference is to shales other than oil shale. The amendment to the regulations set forth in T.D. 6841 in referring to the
of this deduction, particularly to the taxpayer in the upper tax brackets, is readily apparent.

(1) Non-Depletable Income and Capitalized Expenditures

The principal items of ordinary income not subject to the depletion deduction are gains realized on the sale of mineral properties, delay rentals and consideration received for the granting of a license, unaccompanied by an option to lease, of the privilege to conduct seismic or other geological surveys. The lessor receiving delay rentals must report such income as ordinary income and cannot take the depletion deduction with respect thereto. Consideration received as the result of a sale of oil and gas interests may, of course, be subject to capital gain or loss treatment as discussed in detail in Part II under caption Disposition of Mineral Properties.

The taxpayer incurring expenditures for the privilege of conducting geological surveys on oil and gas properties must capitalize such expenditures as part of the acquisition costs of the oil and gas interest (if acquired) and recover same through depletion or write them off as an ordinary loss if no lease is acquired. Exploratory expenditures relating to other minerals may, on the other hand, under appropriate circumstances and within certain limitations, be expensed. See infra, p. 114. Expenditures incurred for delay rentals may be regarded as either current expenses or capital costs recoverable through the depletion allowance. In order to capitalize delay rentals, the taxpayer must so elect in a statement filed with his return. A new election may be made each year and the election apparently is available as to each separate property.

15% category for other minerals now reads “All other metals” which literally applied would exclude oil shale which is not specifically listed. However, if it was intended by this chance to exclude non-metals not specifically listed under the 15% category this would be inconsistent with Section 613(b)(6) of the Code which specifically refers to “all other minerals.”

3. Commissioner v. Wilson, 76 F.2d 760 (5th Cir. 1935).
7. INT. REV. CODE OF 1954, § 256; Treas. Reg. § 1.266-1(e) (1950); XII-1 CUM. BULL. 238 (1933); Rev. Rul. 55-118, 1955-1 CUM. BULL. 320.
Distinguishing Between Bonus and Delay Rental

As noted in the succeeding subsection, bonus income received by the lessor as distinguished from rental or delay rental is depletable ordinary income. In addition, it is generally assumed and the regulations so provide that bonus payments as contrasted to rental payments cannot be deducted or excluded from income by the payor, but must be capitalized and recovered through the depletion deduction. Further, it has been generally assumed that bonus payments and delay rental payments are readily distinguishable. Bonus is the consideration paid in a leasing or subleasing transaction for the acquisition of the economic interest and, whether paid in a lump sum or in a series of installments, is characterized by the fact that it is a fixed obligation which cannot be avoided by surrender of the economic interest or otherwise. Delay rentals, on the other hand, are defined as "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." Under particular circumstances, however, the distinction may be difficult to make.

The bonus vs. delay rental distinction cases initially involved non-competitive federal oil and gas leases. Oil and gas operators, in the western states, frequently obtain leases on the public domain from the federal government. If the acreage is not within the geologic structure of a known producing oil or gas field, the first qualified applicant is entitled to a lease. The application for a non-competitive lease must be accompanied by a ten dollar filing fee and by the first year's rental of fifty cents an acre. If the acreage is within the geologic structure of a known producing oil or gas field, it can be leased only pursuant to competitive bidding. Internal Revenue Service contended that the filing fee and first year advance rental payment should be capitalized as part of the cost of the lease but, after losing in the Tax Court and two Circuit Courts, acquiesced in the
view that such payments are deductible with respect to federal and comparable state non-competitive leases. However, the Commissioner continues to maintain his position that first-year rental payments are not deductible with respect to private leases.\textsuperscript{12} Although not necessary to its decision, the Fifth Circuit Court of Appeals in the \textit{Jefferson Lake} case (discussed in more detail below) could find no important difference in this regard between non-competitive governmental leases and private non-governmental leases.\textsuperscript{13}

Accordingly, there is some possibility that appropriate drafting can convert "bonus" into "rental" or other payment necessary to the continued use or possession of property. In order to accomplish this, the lease should provide for a first-year rental payable in advance, which, like subsequent rental payments, defers the obligation to commence drilling a well (or developing a mineral property) for a period of twelve months.

\textit{WARNING—}The foregoing cases do not purport to destroy the distinction between rental and bonus in that they acknowledge that both categories exist, but merely make it more difficult to properly characterize a payment as bonus or rental. The Tax Court, for example, clearly intimated that the amount bid by the successful applicant for a competitive federal lease is part of his acquisition costs and must be capitalized.\textsuperscript{14} The Tenth Circuit reaffirmed the view that the cost of acquiring an economic interest must be capitalized,\textsuperscript{15} and the Fifth Circuit in \textit{Jefferson Lake} distinguished between rental and bonus although the tax concepts expressed, with respect to bonus payments, departed radically from those heretofore generally accepted and have since been repudiated.\textsuperscript{16} In the event the agreement recites that the payment made upon execution of the lease is in consideration for the lease or, if as suggested above, the initial payment is

\begin{itemize}
  \item \textsuperscript{11} Commissioner v. Miller, 227 F.2d. 326 (9th Cir. 1955); United States v. Dougan, 214 F.2d. 511 (10th Cir. 1954).
  \item \textsuperscript{12} Rev. Rul. 56-252, 1956-1 \textsc{Cum. Bull.} 210.
  \item \textsuperscript{13} Lambert v. Jefferson Lake Sulphur Co., 236 F.2d 542, 547 (5th Cir. 1956) (dictum).
  \item \textsuperscript{14} Olin F. Featherstone, \textit{supra} note 10.
  \item \textsuperscript{15} United States v. Dougan, \textit{supra} note 11.
\end{itemize}
styled a rental payment but is disproportionate in amount to subsequent payments, some courts undoubtedly will continue to regard such payments as bonus.

—OBSERVATION—Classification as rental will ordinarily be desired by the lessee. However, the lessor ordinarily desires classification as bonus in that he can take depletion, with respect to bonus payments, but not with respect to rental payments. See discussion under (3) below.

(3) “Bonus” As Depletable Income

The consideration received by a mineral owner from the mineral lessee for executing a mineral lease is generally referred to as a “bonus.” While this is the typical arrangement with respect to which a bonus is received, a bonus in the form of cash consideration is sometimes received by the mineral lessee who assigns (or subleases) his lease and reserves an overriding royalty or a net profit interest.\(^\text{17}\) Although there are no decisions or rulings, cash consideration paid a mineral owner for an option to lease is generally regarded for tax purposes as additional bonus.\(^\text{18}\)

Bonus income is regarded as advanced royalty for some tax purposes and the recipient can take the statutory depletion deduction with respect thereto in the year received regardless of whether any production is obtained or whether there is any reasonable assurance of obtaining production.\(^\text{19}\) If commercial production is obtained under the lease or sublease involved, the recipient of the bonus need make no adjustment.\(^\text{20}\) If the lease or sublease expires, terminates or is abandoned without any production under the lease, the recipient of the bonus must restore the depletion deduction, previously taken, to income in the year in which the lease or sublease terminates, expires or is abandoned.\(^\text{21}\) In such a case, the full amount of the depletion deduction previously

\(^{17}\) For the distinction between a lease or sublease on the one hand and a sale on the other see caption Disposition of Mineral Properties in Part II of this Article to be published in the next issue.


\(^{19}\) Treas. Reg. § 1.612-3(a), (d) (1960); Herring v. Commissioner, 293 U.S. 322 (1934).

\(^{20}\) Dolores Crabb, 41 B.T.A. 686 (1940) acq. 1940-2 CUM. BULL. 2.

\(^{21}\) Treas. Reg. § 1.612-3(a) (2) (1960); Sneed v. Commissioner, 119 F.2d 767 (5th Cir. 1941).
taken must be restored to income whether or not the deduction resulted in a tax benefit.\textsuperscript{22} Similarly, if the option to lease expires without being exercised, the depletion deduction previously taken must be restored to income in the year in which the option expires.\textsuperscript{23} In the event the lease terminates after insignificant production, it is clear that no deduction can be taken if this occurs within the same tax year in which the bonus was received.\textsuperscript{24} The Tax Court has recently questioned (without deciding) the propriety of one of its earlier decisions under which the lessor was not required to restore to income the deduction previously taken when some production (but apparently non-commercial) was obtained and the lease abandoned in a subsequent tax year.\textsuperscript{25}

---\textit{SUGGESTION}---Taxpayer-lessee may avoid the necessity of restoring the deduction to income by completely disposing (by sale or gift) his retained mineral interest prior to termination of the lease without production.\textsuperscript{26} However, the disposition must be complete.

The taxpayer may take either cost or statutory depletion, whichever is greater, with respect to bonus income. As a practical matter cost depletion is often unavailable to the lessor, inasmuch as the taxpayer must have a basis for depletion in the minerals in order for cost depletion to be available (part of the land cost cannot be allocated to minerals unless the purchase contemplated minerals), and the property involved probably has to be developed at the time the bonus is received. However, it may in certain special situations be advantageous to a lessor or sublessor with a substantial basis in his mineral interest to take cost depletion.

Cost depletion with respect to bonus income is computed by multiplying the taxpayer's basis for depletion in the mineral property involved by the ratio of the bonus to the sum of the bonus received and the royalties expected to be received.\textsuperscript{27} Statutory depletion is the appropriate depletion

\textsuperscript{22} Douglas v. Commissioner, 322 U.S. 275 (1944). A comparable amount is restored to basis. Treas. Reg. § 1.612-3(a) (2) (1960).
\textsuperscript{23} This is on the assumption that such payments are "bonus." BREEDING & BURTON, op. cit. supra note 18, at ¶ 1.12.
\textsuperscript{24} Seth Campbell, 41 T.C. 91 (1963).
\textsuperscript{25} Id. at 94.
\textsuperscript{26} Rev. Rul. 60-336, 1960-2 CUM. BULL. 195.
\textsuperscript{27} Treas. Reg. § 1-612-3(a) (1) (1960).
rate multiplied by the bonus payment, but in no event can the amount of the statutory depletion deduction exceed fifty per cent of the taxable (net) income of the taxpayer (computed without allowance for depletion) from the property.28

The foregoing tax principles relating to the taking of a depletion deduction with respect to bonus payments are illustrated by the following examples:

EXAMPLE: Adams, the owner in fee of the surface and the mineral rights relating to a tract of land, enters into an oil and gas lease with Baker sometime during tax year 1965, receiving a consideration of $10,000 for entering into the lease. Adams has no cost basis in the minerals as such. The oil and gas lease provides for the usual 121/2 per cent lessor's royalty and is for five years and as long thereafter as oil or gas is produced. The lease contains a delay-rental clause providing for deferment of drilling by payment of a specified per acre annual rental and for automatic termination of the lease in the event Baker fails to drill or to pay the annual rentals. Adams should report $10,000 as income for 1965 and take a statutory depletion allowance of 271/2 per cent ($2,750) as a deduction from income in that year. In the event significant production is obtained under the lease, Adams makes no further adjustments. If, however, in 1969 Baker permits the lease to terminate by failing to pay rentals and there has been no production under the lease, Adams must report the $2,750 depletion deduction taken in 1965 as income in the return he files for 1969.

EXAMPLE: Baker acquired a productive oil and gas lease for which he paid $100,000. He immediately assigned the lease to Carey reserving a five per cent royalty interest. Baker received a bonus of $25,000 for making this assignment. The estimated recoverable reserves from the property are 1,000,000 barrels of oil of which amount 50,000 barrels are attributable to Baker's overriding royalty. On the basis of the current $2.50 per barrel price of crude oil, Baker can expect to receive royalties from the property totaling $125,000. The $25,000 bonus received by Baker is one-sixth

of the sum of the bonus and royalties he can be expected to receive. Accordingly, Baker computes cost depletion by multiplying his cost basis ($100,000) by one-sixth, thereby determining that cost depletion will result in a deduction of $16,666.67. Statutory depletion is computed by multiplying the bonus ($25,000) by 27½ per cent, resulting in a statutory depletion deduction of $6,875. Accordingly, Baker will report the $25,000 bonus as income and will take as a deduction from income cost depletion in the amount of $16,666.67 because it exceeds statutory depletion.

—SUGGESTION—If the bonus is a substantial one, the taxpayer might consider spreading the income received over a period of years by entering into an agreement under which the lessee or sublessee agrees to pay the bonus in a series of annual installments. The fact that the lessee is prepared to pay an initial lump sum bonus does not preclude lessor from entering into an agreement under which the bonus is payable in a series of annual installments. However, if the agreement to pay installments can be valued, there is realized income at the time the lease is executed. It appears further that in the case of many solvent promisors a mere naked promise will be sufficient absent a restriction on assignment to place a valuation on same and result in bunching taxable income. A restriction against assignment of the right to receive the bonus might preclude such valuation; however, absent a business reason for same will probably be attacked on a tax evasion theory. The provisions permitting averaging of income may provide some relief in this situation.

(4) Tax Treatment of Bonus Payment by Lessee-Payor

The regulations provide that a lessee or sublessee paying a bonus must capitalize such expenditures and recover same through depletion. Except in those instances in which the lease is abandoned or sold shortly after acquisition, the lessee seldom derives any substantial tax benefit from capitalizing such expenditures, since statutory depletion, which he ordinarily can take in any event, will usually exceed cost

depletion. The view of the regulations is generally the view of the courts.\textsuperscript{33} However, in the \textit{Jefferson Lake} case, the district court in a direct holding,\textsuperscript{34} and the Fifth Circuit Court of Appeals, by dictum,\textsuperscript{35} adopted the position that bonus payments do not have to be capitalized by the payor, but can be deducted or excluded from income. The court in \textit{Jefferson Lake} based its reasoning primarily on the ground that if such payments are advanced royalties to the recipients, as the Supreme Court has held, they should be regarded as such by the payor as well. The Fifth Circuit has recently\textsuperscript{36} repudiated its prior dictum in the \textit{Jefferson Lake} case and the view of the regulations appears to be too well entrenched to now be changed except by legislation.\textsuperscript{37} Under the regulations in the event of production, the lessee, in computing gross income subject to statutory depletion, must make an adjustment for an allocated portion of the bonus payment\textsuperscript{38} but cannot make a similar exclusion in determining taxable income.\textsuperscript{39} For illustrations of the application of the regulations see infra, p. 107. For the economic significance of this approach see the following example.

\textit{EXAMPLE}: Assume that Adams grants an oil and gas lease to Baker for a cash payment of $50,000 and a reservation of a one-eighth royalty. Assume that total proceeds from production, after royalties, are $350,000. Baker's total percentage depletion deduction over the life of the property is $82,500 (27\frac{1}{2} per cent of $300,000, gross proceeds less bonus). Baker cannot exclude the bonus from taxable income and therefore his gross income from the lease actually subject to tax is $350,000. The percentage depletion allowance of $82,500 absorbs the capitalized bonus, so Baker pays tax on

\begin{itemize}
  \item 33. Shamrock Oil & Gas Corp. v. Commissioner, 346 F.2d 877 (5th Cir. 1965), \textit{cert. denied}, 34 U.S.L. Week 3141 (U.S. Oct. 26, 1965) (No. 433). Murphy Oil Corp. v. United States, 337 F.2d 677 (8th Cir. 1964); Canadian River Gas Co. v. Higgins, 151 F.2d 984 (2d Cir. 1945); Sunray Oil Co. v. Commissioner, 147 F.2d 962 (10th Cir. 1945); Baton Coal Co. v. Commissioner, 51 F.2d 469 (3d Cir. 1931).
  \item 35. Lambert v. \textit{Jefferson Lake Sulphur Co.}, supra note 13.
  \item 36. See the Shamrock Oil & Gas Corp. v. Commissioner, supra note 33.
  \item 37. See Shamrock Oil & Gas Corp. v. Commissioner, 35 T.C. 979, 1059 (1961).
  \item 38. Treas. Reg. § 1.613-2(c) (5) (ii) (1960).
  \item 39. See Example to Treas. Reg. § 1.613-2(c) (5) (ii) (1960). See also Shamrock Oil & Gas Corp. v. Commissioner, supra note 33 and Sunray Oil Co. v. Commissioner, supra note 33.
\end{itemize}
$267,500 ($350,000 minus $82,500). If Baker could have excluded bonus from taxable income, he would pay tax on only $217,500 ($300,000 minus $82,500).

(5) Depletable Income Other Than Bonus

The primary source of income subject to the depletion allowance is not from transactions involving bonus payments, but is the income derived from the sale of minerals. Only those who have an "economic interest" in the minerals in place can take the depletion deduction with respect to the proceeds derived from the sale of production. As the result of considerable litigation it is now fairly clear that the owners of the following mineral interests have an economic interest for this purpose:

1. Landowner's royalty—the royalty reserved by the lessor under a mineral lease. Typically the oil and gas lease provides that the lessor shall receive one-eighth of the gross production (or of the proceeds from the sale of production) as a royalty free of all development and operating costs. In the case of other minerals the percentage royalty retained by the lessor is not as standardized.

2. Overriding royalty—typically a cost-free royalty created by the mineral lessee generally, but not necessarily, as the result of an assignment of the mineral lease in which an overriding royalty is reserved.

3. Production payment—an interest under which the holder is to receive a specified portion of the production (or a specified amount per unit of mineral produced) until he has received a specified payment. The production payment must, to qualify as an economic interest, be payable only out of production.

4. Net profit interest—an interest which gives the

41. Treas. Reg. § 1.611-1(b) (1960).
43. Further, the tax treatment has differed in some instances. See discussion under caption Disposition of Mineral Properties in Part II of this Article to be published in the next issue.
44. Palmer v. Bender, supra note 42; Hogan v. Commissioner, 141 F.2d. 92 (5th Cir. 1944).
45. Perkins v. Thomas, 301 U.S. 655 (1937); United States v. Witte, 306 F.2d. 81 (5th Cir. 1962).
holder no operating rights but entitles him to a specified percentage of the net proceeds from production. Net proceeds are usually defined as a specified percentage of the gross income less the interest owner's proportionate share of the operating costs and in some instances of the costs of development.

—OBSERVATION—There is some confusion in the decisions as to whether a net profit interest is an economic interest in minerals in place. This results from the fact that although the United States Supreme Court in Kirby Petroleum Co. v. Commissioner and in Burton-Sutton Oil Co. v. Commissioner held that a net profit interest is an "economic interest," the Court did not expressly overrule Helvering v. Elbe Oil Land Development Co. or Helvering v. O'Donnell in which the Court had previously held that a net profit interest was not an economic interest with respect to which depletion can be taken. In the Kirby case the Court distinguished the O'Donnell case on the ground that in the O'Donnell case the net profit interest was created in a stranger to the lease. The issue was further confused when the Supreme Court, again without reversing Elbe and O'Donnell, granted the depletion allowance to a net profit interest created in a stranger to the lease. The case arose when Southwest Exploration Co. took a lease from the State of California covering offshore lands on condition that the wells be sunk by slant drilling from upland sites. Huntington Beach Co. owned the only available upland sites and leased them to Southwest in return for a net profit interest. Both parties claimed depletion, which was granted by the Supreme Court to Huntington. The reasoning of the Court was that Huntington's property was essential to the drilling and the grant of the drilling easement was a vital contribution to production.

5. Working interest—a mineral interest giving the owner thereof either the exclusive or non-exclusive right to

48. Id. at 607.
develop the mineral property. This is usually the leasehold interest or an interest in the lease, but could include an interest in the minerals as such.

6. Participating interest—a contractual right to a specified percentage of production. If, as is usually the case, it is subject to part of the operation and/or development costs, it is indistinguishable except in name from a carved out net profit interest. Accordingly, the observation noted with respect to a carved out net profit interest would appear to be pertinent.

7. The extent to which one having a contract right to mine a mineral either by strip-mining or underground mining as an economic interest has given rise to considerable litigation. In Parsons v. Smith the Supreme Court enumerated the following seven factors (since reiterated with approval in Paragon Jewel Coal Co., Inc. v. Commissioner) regarded as significant in finding that the contract miners did not have an economic interest:

   (1) that petitioners' investments were in their equipment, all of which was movable—not in the coal in place; (2) that their investments in equipment were recoverable through depreciation—not depletion; (3) that the contracts were completely terminable without cause on short notice; (4) that the landowners did not agree to surrender and did not actually surrender to petitioners any capital interest in the coal in place; (5) that the coal at all times, even after it was mined, belonged entirely to the landowners, and that petitioners could not sell or keep any of it but were required to deliver all that they mined to the landowners; (6) that petitioners were not to have any part of the proceeds of the sale of the coal, but, on the contrary, they were to be paid a fixed sum for each ton mined and delivered . . .; and (7) that petitioners, thus, agreed to look only to the landowners for all sums to become due them under their contracts.

The particular factors stressed by the Court in the Paragon Jewel case in distinguishing the Southwest case were the fact that the contract miner did not receive a percentage of income (gross or net) from the mining operation and did not look to the sale of the mineral, but rather to the promise of the contracting party for payment. Accordingly, one who mines a mineral under a contract for a fixed price per unit of mineral mined payable by the other contracting party probably does not have an economic interest and cannot take depletion. On the other hand, if the contracting party is compensated by a percentage of the proceeds from the sale of the mineral and is dependent upon the sale of the mineral for his compensation, he probably has an economic interest.

(6) Shut-In Royalties

A question as to whether a particular type of payment is a "royalty" with respect to which the recipient can take depletion or whether it is "delay rental" which is non-depletable income arises in connection with so-called "shut-in royalties." Such royalties usually result from a provision in an oil and gas lease to the effect that, if the property is capable of production but there is no market for the mineral, the lessee can retain the lease without producing it by paying a specified amount to the lessor in lieu of the royalty that would otherwise have been payable. There is commentator support for regarding a "shut-in royalty" payment as depletable income. However, Tax Court and Fifth Circuit decisions cast doubt as to validity of such treatment. The Tax Court case involved an operator who had leased several oil properties. Production from these properties was governed by a state commission which fixed the amount of oil which could be produced from each well. Excessive salt water was produced from one of the leases and the commission permitted

58. But see Lark L. Washburn, 44 T.C. No. 24 (1965) in which the contract miner was denied the right to take depletion although some of the contracts involved provided for compensation based upon a percentage of the selling price of the ore. Cf. Food Machinery & Chemical Corp. v. United States, 382 F.2d 921 (Ct. Cl. 1965).
59. Seale, Problems of Depletion in Oil and Gas Leases, 2 OIL & GAS INST. 351 (SW. LEGAL FDN. 1951).
the operator to discontinue operation of this lease and to produce from other leases substantially the same amount of oil as he would have been allowed to produce from the "shut-in" wells. In order to keep the lease on the shut-in property in force, the operator paid "substitute royalties" based on the amount of the "allowables" transferred. The Tax Court held that the operator's gross income from the operation of the producing leases should not be reduced by the "substitute royalties" for purposes of computing the depletion allowance—the payee did not have an economic interest in the oil produced. The Fifth Circuit decision related to the more typical shut-in royalty situation in which the taxpayer clearly owned an economic interest and is premised on the conclusion that the "payments were made neither in return for the extraction of oil or gas nor in contemplation of that event" and hence are not within the depletion concept which is an allowance for the exhaustion of a wasting asset. Bonus payments were distinguished as they contemplate production.

(7) Minimum Advanced Royalties

The appropriate tax treatment for minimum royalties is relatively clear provided that the particular arrangement in question can be characterized as an advanced or minimum royalty under the appropriate regulations. The difficult problem is classifying the payment in question as a minimum royalty as distinguished from a bonus payment or rental payment. Although the regulations refer to "advanced royalties," it is apparent that the regulations are in fact limited to minimum royalties not based on production and which are recoupable in subsequent years to the extent actual royalties from production exceed the minimum. In the event payments are classified as advanced royalties, the recipient of the payment can take depletion on the entire payment received even to the extent that it exceeds royalties related to actual production. However, in the event the working

64. Id. at 547.
interest against which the advanced royalties are applied expires, terminates, or is abandoned before the advanced royalties have been recouped out of production, the recipient must adjust his capital account by restoring the depletion deduction made in prior years on account of any units paid for in advance but not extracted and a corresponding amount must be returned as income for the year of such expiration, termination or abandonment. The payor of the advanced royalty, on the other hand, may deduct the advanced royalty in the year in which it is paid or may deduct the advanced royalty in the year in which the advanced royalty is recouped. However, the taxpayer must make an election as to the treatment of all such advanced royalties in his return for the first taxable year in which such amounts are paid or accrued and this election is binding on the taxpayer with respect to all properties and for all subsequent years.

It is illuminating to compare the results depending upon classification of a payment as a "bonus," "advanced royalty," or "delay rental:" (1) If the particular payment is characterized as a bonus, the lessor can take depletion which is the same result that will follow if characterized as an advanced royalty, but if, characterized as a delay rental, the lessor cannot take depletion. (2) If the payment is characterized as a bonus, the lessor has to restore the depletion deduction to income in the year of abandonment or termination only in the event there has been no production from the property; if characterized as an advanced royalty and if the property has been productive but the actual royalties over the life of the property have not been sufficient to recover the amount of the minimum royalties, a proportionate part of the depletion deduction previously taken must be restored to income in the year of termination or abandonment. (3) If the payment is characterized as a bonus, the lessee must capitalize the payment and recover same through the depletion deduction; if characterized as an advanced royalty, the lessee can deduct the payment and has an election as to the year in which to deduct same; if characterized as a delay rental, the lessee can deduct the payment in the year of payment or at his election can capitalize same. In
view of the fact that lessee can deduct an advanced royalty whereas a bonus must be capitalized, there are obvious advantages to the lessee to arrange the transaction so that payments are classified as an advanced royalty or delay rental rather than as a bonus. On the other hand, from the lessor’s standpoint, bonus treatment is preferable to advanced royalty treatment and advanced royalty treatment is preferable to delay rental treatment.

**EXAMPLE:** Adams grants a lease to Baker under which there is reserved a royalty of twenty-five cents for each barrel of oil removed and sold. The lease further provides that Adams will at the commencement of each year pay a minimum royalty of $25,000 to be applied on the royalty payable as to the first 100,000 barrels produced during such year and to the extent that production in any year is less than 100,000 barrels the royalty paid not reflecting actual production shall be applied in subsequent years on royalty payments for production in such year exceeding 100,000 barrels. Assume that in the first lease year actual production is 20,000 barrels, in the second lease year production is 30,000 barrels and the lease is then terminated in the third lease year without any further production. In both the first and second lease years Adams will report $25,000 as income and take the statutory depletion deduction ($13,750 for both years combined) on the amount received. In the third year Adams will restore to income the deduction on the 80,000 and 70,000 barrels paid for in advance and not actually produced in the first and second lease year or $9,375 (150,000 bbls × 25¢ = $37,500 × 271/2% = $9,375). If the amounts received by Adams had been in the form of bonus and royalties based upon actual production, there would be no necessity of restoring any part of the depletion deduction. The lessee (Baker) in the foregoing example could by making the proper election deduct the $25,000 in each year in which paid. If the payment had taken the form in part of a bonus, to this extent Baker would have had to capitalize the amount thereof and would also have had to reduce his gross income for depletion purposes by a proportionate part of the bonus.

There are a number of variables and numerous possible
arrangements of the variables that can have impact on classification of a payment as advanced royalty as against bonus or delay rental. The minimum royalty payment may or may not be recoupable in subsequent years, it may or may not be avoidable by termination of the lease, it may be paid before or after production and, in the event of production, total production from the property in a given year may or may not be sufficient to cover the amount of the minimum payment. Further, the minimum payment may relate to a royalty clause that provides for a specified royalty per unit of production or to a royalty clause based on a percentage of proceeds from production. The regulation pertaining to minimum royalties uses language which assumes the existence of a unit type royalty clause, but it is frequently assumed that these advanced royalty provisions apply (and there is no logical reason why they should not apply) to a dollar amount minimum royalty coupled with a percentage type royalty clause. However, the draftsman attempting to obtain the benefit of the regulation should keep this distinction in mind.

The regulations pertaining to minimum royalties appear to be limited to minimum royalties that are payable annually and, hence, do not appear to apply to an advanced royalty paid upon the execution of the lease. Further, such regulations literally apply only to minimum royalties that can be recouped in subsequent years and do not appear to apply to a minimum royalty that cannot be recouped in any year other than the year of payment or to a non-recoupable minimum royalty. The Tax Court, however, has accorded the lessor depletable income treatment with respect to a minimum royalty that can be recouped only in the year of payment.66

Despite the language of the regulations, which do not appear to be so restricted, it is said to be the position of Internal Revenue Service that minimum royalty payments made as a result of an unconditional promise to pay in any event are, irrespective of the right of recoupment, deemed to constitute "bonus" as distinguished from "advanced royal-

ty. In addition, in the somewhat analogous situation of a lessee paying lessor’s share of the ad valorem taxes, it was the published position of Internal Revenue Service (Revenue Ruling 16) that to the extent that same is paid before production that such payment constitutes delay rental whereas such payments subsequent to production are additional royalty and a variation in the sharing arrangement provided total production from the lease is sufficient to cover the amount paid on behalf of the lessor but if insufficient such payment is deemed a rental payment to the extent of the deficiency. Adding all this together one might conclude (but with some reservations as discussed below) that the regulations relating to minimum royalties apply only to (1) minimum royalties payable annually (2) calculated on the basis of a specified number of units of production (3) recoupable out of production in subsequent years (4) avoidable by surrender or termination of the lease (5) on productive properties from which (6) the total production during the particular year is sufficient to cover the minimum royalty. Those seeking advanced royalty characterization should attempt to conform to the foregoing.

Assuming a minimum royalty payment which cannot be avoided and which is recoupable out of production from subsequent years, the Internal Revenue Service’s position in the light of the foregoing seems to be that such payment constitutes a bonus payment rather than an advanced royalty. The recoupment provision is regarded in effect by Internal Revenue Service as merely a variation in the sharing arrangement between the lessor and lessee. The effect of this approach is to deny the lessee the right to deduct such payments whereas the described situation appears to be squarely within the provisions of the regulations which, as noted above, permit deduction of advanced royalty by the payor. Further, as noted above, if such payments are bonus rather than an advanced royalty, the lessor will not have to restore the depletion deduction in the event the property is productive at all.

Although Revenue Ruling 16\textsuperscript{69} involved ad valorem taxes, since it pertained to payments made by a lessee prior to production on behalf of the lessor it is conceivable that this ruling could be extended to the situation in which minimum royalties are paid prior to production or with respect to which total production from the tract is not sufficient to cover the minimum royalties. Revenue Ruling 16 does not appear to distinguish between the situation in which such payments cannot be avoided and with respect to the latter type of payments seems to be inconsistent with the position that an unconditional payment constitutes a bonus. Presumably, Revenue Ruling 16 will be extended to the minimum royalty situation, if at all, only to the extent that the payments can be avoided by surrender in which event a minimum royalty paid before production or with respect to which total production is insufficient may constitute a rental payment. This conclusion appears to be buttressed by the withdrawal by Internal Revenue Service in 1964 of Revenue Ruling 16\textsuperscript{70} for the announced reasons that the issue is primarily one between lessor and lessee and Revenue Ruling 16 was incorrect in reaching the conclusion that whether the payment of lessor's ad valorem taxes is part of the sharing arrangement between lessor and lessee should depend upon whether production income is sufficient to cover the payments. The Revenue Ruling 16 approach would not adversely affect the payor since he can deduct such payments in either event, but would affect the lessor who under the regulations pertaining to minimum royalties can treat such payments as depletable income.

Despite the uncertainty pertaining to appropriate characterization, lessees will undoubtedly want to seriously consider the possible use of minimum royalty payments in lieu of bonus or in return for a smaller bonus in view of the more favorable treatment from the lessees' standpoint afforded payments characterized as "advanced royalties" rather than bonus.

\textsuperscript{69} Ibid.
\textsuperscript{70} Rev. Rul. 64-91, 1964-1 (Part 1) CUM BULL. 219.
(8) Computation of Cost Depletion

The depletion deduction allowed is cost depletion or statutory depletion, whichever is the greater. The use of the method resulting in the greater depletion allowance is mandatory in determining the taxpayer's adjusted basis in the property. The taxpayer does not elect as to the method to be employed in determining depletion (although the data to compute both cost and statutory depletion should be included) and the use of one method in one year does not preclude the use of the other in subsequent years. It is important to note with respect to the computation of depletion that separate computations must be made for each separate mineral property.

In computing cost depletion it is necessary to first determine the cost basis of the property in question. This will consist of all of the acquisition costs of the property including, in the case of oil and gas, expenditures for seismograph and other geological exploration; abstract and attorney fees; bonus paid; option payments; and depending upon the elections made by the taxpayer, delayed rentals, exploration costs in the case of minerals other than oil and gas and intangible drilling and development costs relating to the property in question.

The adjusted cost basis of the property for depletion purposes is divided by the estimated number of remaining recoverable mineral units attributable to the interest of the taxpayer in the particular property to obtain the unit depletion allowance. This per unit depletion figure is then multiplied by the number of such units produced during the tax year and attributable to the taxpayer's interest. The resulting figure is the deduction permitted as cost depletion.

73. Treas. Reg. § 1.611-1(a), (d) (1960); Producers Oil Corp., supra note 72.
76. L. S. Munger, 14 T.C. 1236 (1950).
77. Treas. Reg. § 1.612-3(a) (3) (1960).
78. Ibid.
In subsequent years the cost basis must be adjusted by reducing it by the amount of depletion previously taken and the estimated reserves reduced by the amount of the mineral previously recovered, and, if warranted by additional data, revised upward or downward as the case may be. If the previous estimate was based on the then best available information, no change should be made with respect to cost depletion taken in previous years because the original estimate is now determined to have been in error.\textsuperscript{82}

**EXAMPLE**: Adams acquired an oil and gas lease from Baker for which he paid $15,000. Adams, prior to acquiring the lease, had a seismic survey undertaken at a cost of $5,000 and expended $1,000 in abstract costs and attorneys’ fees. The estimated reserves attributable to Adams’ interest in the property are 3,000,000 barrels of oil. In the first year of production 30,000 barrels were produced which were attributable to Adams’ interest. Adams’ basis for depletion purposes is $21,000 (the sum of $15,000, $5,000, and $1,000).

\[
\text{The depletion unit is } \frac{21,000}{3,000,000} = 0.007
\]

The depletion allowance is $0.007 \times 30,000 = $210.00

(9) Computation of Statutory Depletion—In General

Statutory depletion is computed by multiplying the gross income attributable to the taxpayer’s interest from the particular mineral property by the appropriate depletion rate. The resulting figure must be reduced to the extent that it exceeds fifty per cent of the taxpayer’s taxable (net) income from the particular property. Statutory depletion can never exceed the appropriate percentage of the gross income from one hundred per cent of production from the property. Accordingly, the operator must exclude from his gross income that part of the proceeds paid to the holders of other economic interests in the mineral in place (such as the landowner’s royalty, the overriding royalty, net profit interest, etc.). The holder of each economic interest computes statutory depletion

\textsuperscript{82} McCahill v. Helvering, 75 F.2d 725 (8th Cir. 1935); Treas. Reg. § 1.611-2(c) (1960).
with respect to his share of the proceeds. In this respect the operator excludes only the net amount payable to the holder of a net profit interest and the holder of such interest takes statutory depletion only with respect to the net amount received by him.

**EXAMPLE:** Adams acquired an oil and gas lease from Baker who reserved a 2 1/2 per cent overriding royalty. The oil and gas lease provides that Baker or his assigns shall pay Carey, the lessor, 12 1/2 per cent of the gross proceeds from the sale of oil and gas. Adams drills a producing well on the property during the current tax year and the gross income from the sale of the oil and gas produced is $80,000. Adams must pay a royalty of $10,000 to Carey and an overriding royalty of $2,000 to Baker. Accordingly, Adams excludes the total amount of the royalties ($12,000) from his gross income both for the purpose of determining his taxable income and for the purpose of computing the statutory depletion deduction. Carey and Baker report the royalties they receive as income and take a 27 1/2 per cent depletion deduction with respect thereto. Adams computes statutory depletion (assuming the fifty per cent of taxable income limitation is not applicable) in the following manner:

Gross income is $80,000 less $12,000 = $68,000

Statutory depletion before the fifty per cent of taxable income limitation is 27 1/2% × $68,000 = $18,700.

(10) Gross Income for Statutory Depletion Purposes—Oil and Gas

There is a significant difference in the manner of determining gross income with respect to oil and gas from the appropriate method with respect to other minerals. Gross income for statutory depletion purposes in the case of oil and gas is the sales price of oil and gas in the immediate vicinity of the well. Accordingly, any amount deducted for the payment of severance or other production taxes should

83. Helvering v. Twin Bell Oil Syndicate, 293 U.S. 312 (1934).
84. United States v. Thomas, 329 F.2d 119 (9th Cir. 1964); Grandview Mines v. Commissioner, 282 F.2d 700 (9th Cir. 1960); Commissioner v. Felix Oil Co., 144 F.2d 276 (9th Cir. 1944).
be added back in computing gross income for depletion purposes. On the other hand transportation costs and gathering charges are deducted from the sales price in determining gross income for this purpose. If the oil and gas are not sold on the property but are transported from the property prior to sale, the sales price is assumed to be the representative market or field price (as of the date of the sale) prior to transportation. For difficult problems relating to the determination of a representative field price relating to gas processed by the integrated producer see the recent decisions in the Shamrock and Hugoton cases.

EXAMPLE: Adams, an oil and gas lessee, sells to a pipeline company 24,500 barrels of oil attributable to his interest in the property at $2.50 a barrel. The pipeline company deducts five cents per barrel, the amount payable to the state as severance tax and remits $2.45 a barrel. Adams in computing statutory depletion determines his gross income by multiplying 24,500 by $2.50.

EXAMPLE: Adams, an oil and gas lessee, sells oil to a refinery, the sales price being $2.75 per barrel at the refinery. The refinery deducts five cents per barrel, the amount payable to the state as severance tax, and remits $2.70. The posted field price of oil at the field is $2.50 per barrel. Adams uses the posted field price ($2.50 per barrel) in computing his gross income for statutory depletion purposes.

(11) Gross Income for Statutory Depletion Purposes—Minerals Other Than Oil and Gas

Section 613(c) of the Internal Revenue Code provides that gross income for purposes of determining the statutory depletion deduction with respect to mineral properties other than oil and gas wells means "the gross income from mining." However, mining is then defined so as to include not merely the extraction of the ores or minerals, but also certain spe-
cified treatment processes and the cost of transportation for not in excess of fifty miles to the plant or mills at which such treatment processes are applied. As a result, in some instances the gross income from mining includes an added increment substantially in excess of the value of the raw ore at the mine mouth thereby substantially increasing the statutory depletion deduction. As a result of a 1960 amendment to the Code the treatment processes to be included as "mining" and which determine the cut-off point for determining gross income are now specifically set forth in Section 613(c) (4).

In the case of iron ore, bauxite, ball and sagger clay, rock asphalt and ores or minerals which are customarily sold in the crude form, the allowed treatment processes are sorting, concentrating, sintering, and substantially equivalent processes to bring to shipping grade and form. In the case of lead, zinc, copper, gold, silver, uranium, fluor spar, potash, and ores or minerals which are not customarily sold in the form of the crude mineral product, allowed treatment processes include crushing, grinding, beneficication by concentration (including among others gravity and flotation) cyanida tion, leaching and other specified processes used in the separation or extraction of the product from the ore or minerals from other materials. The pulverization of talc, the burning of magnesite, the sintering and nodulizing of phosphate rock and the furnacing of quicksilver ores are also regarded as "mining" for this purpose. In the case of minerals used in making of cement all processes (other than preheating of

88. See United States v. Cannelton Sewer Pipe Co., 364 U.S. 76 (1960) for the case law prior to the amendment. The specific Code provision has not avoided controversies as how to determine the value of the product at the cut-off point. See, e.g., Stone Mountain Grit Co., Inc. v. United States, 16 Am. Fed. Tax R.2d 5959 (D. Ga. 1965); North Carolina Granite Corp., 43 T.C. 149 (1964). Treatment processes relating to oil shale retorting are not specifically set forth and it is understood to be the informal position of the Internal Revenue Service that retorting is not a treatment process included within the term "mining." Presumably, the cut-off point with respect to such shales would include crushing since it is a mineral not ordinarily sold in the crude form. A Bill has been introduced before Congress which would have the effect of specifying retorting as a treatment process included within the term "mining." H.R. 10869, 88th Cong., 2d Sess. (1964). In any event, for some period of time the 50% of net limitation on statutory depletion will probably substantially restrict the amount of such deduction irrespective of the percentage rate or the cut-off point.
the kiln feed) applied prior to the introduction of the kiln feed into the kiln are allowed as "mining" but not any subsequent process. Specifically not allowed as "mining" are electrolytic deposition, roasting, calcining, thermal or electrical smelting, refining, treatment effecting a chemical change and other specified processes. In order for the treatment processes to be regarded as "mining" they must be "applied by the mine owner or operator" which poses an interesting and as yet unresolved question as to whether a non-integrated operator producing uranium, for example, by entering into a tolling arrangement with an integrated operator under which the mine owner retains title to the ores through concentration by leaching could base depletion on the proceeds from the sale of concentrates.

(12) Computation of Statutory Depletion—Exclusion of Allocated Portion of Bonus from Gross Income

If the taxpayer has paid a bonus for his mineral interest, he must exclude from his gross income for statutory depletion purposes the part of such payments which is allocable to the product sold during the current tax year.99 This exclusion is made by determining the percentage of total estimated reserves that have been recovered during the tax year and deducting from gross income that percentage of the bonus payments. If the taxpayer has paid advanced royalties in the form of minimum royalty payments which are recoupable, he may deduct the excess of the minimum over the basic royalty either in the year in which such excess is paid or in the year in which it is recouped.90

Although a bonus is considered an advanced royalty in the hands of the recipient for tax purposes, the payor must regard the bonus as part of his capital cost, recoverable through the depletion allowance. Accordingly, the payor must deduct an allocated part of the bonus for the purpose of determining his gross income subject to statutory depletion but cannot make a similar deduction from gross income in deter-

89. Treas. Reg. § 1.613-2(c) (5) (ii) (1960); Quintana Petroleum Co. v. Commissioner, 143 F.2d 588 (5th Cir. 1944).
90. Treas. Reg. § 1.612-3(b) (3) (1960).
mining his taxable income. The rationale of Jefferson Lake, if adopted, which now appears unlikely, would permit the payor to exclude such proportionate part of the bonus for the purpose of determining taxable income. The taxpayer who is required to pay recoupable advanced royalties in the form of minimum royalty payments, deducts the advanced royalties paid both for the purpose of determining his gross income subject to statutory depletion and his taxable income.

EXAMPLE: Adams, an oil and gas lessee, paid a $100,000 bonus for the lease in question. The estimated recoverable reserves are 1,000,000 barrels of oil and in the current tax year 100,000 barrels of oil are produced. Adams deducts one-tenth of the bonus payment from his gross income in determining statutory depletion but not in determining his taxable income.

EXAMPLE: Adams, an oil and gas lessee, pays during the current tax year a minimum royalty (recoupable) of $100,000. The basic one-eighth royalty amounts to $20,000 and accordingly Adams in subsequent years may recoup $80,000 from the one-eighth royalty to the extent that it exceeds $100,000 in any given year. Adams deducts the $80,000 (as well as actual royalties) from gross income both for the purpose of computing statutory depletion and for the purpose of determining taxable income in either the current tax year or in the year in which actually recouped, depending upon an appropriate election.

(13) Computation of Statutory Depletion—The Fifty Per Cent of Taxable Income Limitation

Statutory depletion cannot exceed fifty per cent of the taxpayer’s taxable (net) income from the particular property. In determining the taxpayer’s taxable income for this purpose gross income to the taxpayer is the same gross income figure used in computing the percentage depletion allowance. Taxable income is derived by deducting therefrom all operating costs including depreciation (but not

91. Treas. Reg. § 1.613-2 (c) (5) (ii)—(iii) (1960). See also discussion at p. 89 supra.
92. See p. 90 supra.
depletion), ad valorem and severance taxes, interest on borrowed money,94 an allocated part of overhead,95 and current exploration and development costs to the extent taxpayer has appropriately elected to expense them.96 In the case of mineral properties other than oil and gas properties, operating cost to be deducted would include costs attributable to processes and transportation which are treated as “mining” for the purpose of determining gross income for statutory depletion purposes.97 Only those overhead costs attributable to exploration and production must be allocated and in this connection an allocation should be made as between producing and non-producing properties and among the producing properties.98 The allocation of overhead among the producing properties is usually made on the basis of their relative production.99

Query: In computing taxable income for this purpose, is the allocated part of the bonus excluded from gross income in determining the percentage allowance added back to the gross income from the property before deducting the various expenses and arriving at the taxable income from the property? In view of the fact that the taxpayer must include such amount in determining his income actually subject to tax the answer would logically seem to be “yes.” However, the present regulations100 determine gross income for this purpose by relating back to the definition of gross income from the property for depletion purposes and hence appear to require that an allocated portion of the bonus be excluded in determining taxable income for the fifty per cent of net limitation.

EXAMPLE: Adams, an oil and gas lessee, has gross income of $68,000 from the property in question. He has elected to deduct intangible drilling and development costs as a current expense. The direct operating costs for the

96. Ibid.
current tax year relating to this property are $15,000. Adams drilled a well on the property during the current tax year and the intangible drilling and development costs incurred in connection with the drilling totaled $49,000. Severance taxes total $1,000. Adams has one other oil and gas lease, the production from which is double the production from the lease in question. Adams’ overhead costs total $6,000.

Adams allocates one-third of the overhead costs or $2,000 to this lease since it produces one-third of the combined production of all his oil and gas properties.

Adams’ taxable income from this property is $1,000 ($68,000 minus the sum of $15,000, $49,000, $1,000 and $2,000).

Adams’ statutory depletion cannot exceed fifty per cent of $1,000 or $500. Accordingly, the statutory depletion deduction which in the absence of the fifty per cent of taxable income limitation would have been $18,700 (27 1/2% × $68,000) must be reduced to $500. Assuming that cost depletion for the current tax year relating to this property would amount to $2,100, Adams will take cost depletion as a deduction since it is greater than statutory depletion.

**EXAMPLE:** Assume the same facts involved in the previous example to be applicable to the following tax year, except Adams has drilled no wells and hence has incurred no intangible drilling and development costs in this tax year. The taxable income from the property in this tax year will be $50,000 and Adams will have to reduce statutory depletion only if it exceeds fifty per cent of this amount, or $25,000. Accordingly, he can take the full 27 1/2 per cent deduction for depletion ($18,700) and will take statutory depletion since it results in the greater deduction.

**SUGGESTION**—An accrual-basis taxpayer, who contracts to have the work done for him, can to a limited extent control the time at which the liability for intangibles or other deductible expenses such as development costs in the case of minerals other than oil and gas will be incurred by variations in the type of contract adopted. Oil or gas wells are generally drilled under two principal types of contracts: (1)
A so-called footage contract under which the party incurring the drilling obligation agrees to pay the driller as the hole is being drilled a specified amount per foot of hole drilled.

(2) A contract providing that the obligation does not accrue until and unless the hole is drilled to completion or to a specified lesser depth.\textsuperscript{101}

The cash-basis taxpayer can control the year in which intangibles are incurred to a certain extent by timing his cash expenditures. However, according to the Service\textsuperscript{102} he may not accomplish this by prepaying expenses, although on the identical facts a district court\textsuperscript{103} has held that prepaid intangibles can be deducted by a cash-basis taxpayer in the year paid when the contract under which paid required prepayment.

Any taxpayer can, regardless of his tax accounting method, determine the year in which intangibles or other deductible expense will be incurred as an expense by controlling the beginning and completion dates of particular activities.

—\textit{FURTHER SUGGESTION}—If the property the taxpayer plans to drill has little or no income during the current tax year so that the taxpayer will be entitled to a very small (if any) depletion deduction, the taxpayer should attempt to incur as many of the intangible drilling and development costs as possible in the current tax year—he can deduct them from other income. Similarly, if another well has already been drilled on the property during the current tax year as a result of which the fifty per cent of taxable income limitation is going to prevent to taking of all or a substantial part of the $27\frac{1}{2}$ per cent statutory depletion deduction with respect to this property, the intangibles incurred in drilling the second well should be concentrated to the extent possible in the current tax year. If, on the other hand, the addition in the current year of intangibles to current expenses will result in a substantial reduction in the $27\frac{1}{2}$ per cent statutory depletion allowance relating to this property, as much of the intangible costs as is possible should be deferred to the

\textsuperscript{101} Cf. Great Western Petroleum Corp., 1 T.C. 624 (1943).
\textsuperscript{102} Rev. Rul. 170, 1953-2 CUM. BULL. 141.
following year when the income from the new well will increase the taxable income of the particular property.

It is also advisable, other factors being equal, carefully to select the property to be drilled in the light of the tax consequence. If, for example, previous drilling on property ABC during the current tax year has already assured that statutory depletion will not be available whereas, in the absence of additional drilling the fifty per cent of taxable income limitation will not affect property XYZ, the drilling (other factors being equal) should be undertaken on property ABC. As between producing properties, to the extent possible, the drilling should be concentrated on the properties with substantial taxable income and limited as to other producing properties, so that fifty per cent of the taxable income from each property will equal or exceed 27½ per cent of the gross income from each property. Similar opportunities are available with respect to minerals other than oil and gas with respect to development costs (stripping, sinking a shaft, etc.) which at the election of the taxpayer can be deducted as a current expense. It is common for informed operators to phase their mining operations so that the deductible development costs are incurred on a specific property in one year (set off against income from other properties) and which is withheld from production until a following year so that the development costs incurred with respect to the property do not affect the statutory depletion deduction.

—OBSERVATION—Under the 1954 Code, taxpayers had considerable latitude in determining the tracts that constitute the "property" both with respect to oil and gas and other minerals which permitted the taxpayer to plan his property aggregations so as to restrict the impact of the fifty per cent of taxable income limitation. However, recent amendments have considerably restricted opportunities for planning in this area with respect to oil and gas properties.

(14) Adjustments to Basis Resulting from the Depletion Deduction

Whenever statutory or cost depletion is allowed or allow-

104. See p. 122 infra.
105. See p. 174 infra.
able the taxpayer must reduce his cost basis in the oil or gas property by the greater of the amount allowed or allowable. If, however, the depletion allowed exceeds depletion allowable, the taxpayer’s basis in the property does not have to be reduced by such excess if the excess previously allowed did not result in a tax benefit. The taxpayer may take the statutory depletion deduction even if he has no cost basis in the property or if previous deductions have eliminated his cost basis entirely. If the taxpayer’s cost basis has been eliminated by previous depletion deductions, subsequent statutory depletion deductions do not reduce the basis to less than zero.

**EXAMPLE:** In 1949 Adams was allowed a depletion deduction of $5,000 although the maximum allowable deduction under the appropriate regulations was $3,000. In 1955 Adams sells the property. In determining his gain or loss in connection with this sale, Adams’ basis should be adjusted by the $5,000 take as a deduction in 1949, if the excess ($2,000) of allowed over allowable depletion resulted in a tax benefit to him in 1949. In the event the excess did not result in a tax benefit to him in 1949, Adams’ basis for gain or loss should be reduced only by the amount of the allowable depletion ($3,000).

**EXAMPLE:** Adams acquired a producing oil and gas lease the acquisition costs of which were $100,000. Of this amount, $50,000 is attributable to capital costs recoverable through the depletion deduction. In the year of acquisition, Adams took a $20,000 depletion deduction and in the following year he took a $30,000 depletion deduction, eliminating his depletable cost basis entirely. Adams can, in subsequent years, take a statutory depletion deduction and no matter how large such deductions are, the depletable cost basis cannot be less than zero.

106. **INT. REV. CODE OF 1954, § 1016(a) (2).**
—OBSERVATION—In order to determine taxpayer’s depletion deduction, it is necessary to know what constitutes a separate mineral property. Inasmuch as a similar determination has to be made with respect to other mineral income tax problems this question is discussed separately at infra, p. 171. In order to derive the full benefit of the statutory depletion deduction, it is often essential that the venture not be taxed as a corporation. How to avoid being regarded as an association taxable as a corporation will be discussed in detail in Part II of this article under the caption “Form of Organization.”

EXPLORATION AND DEVELOPMENT COSTS

Exploration and development for oil and gas and other minerals share some common techniques, but in other respects there are material differences. Exploration for both oil and gas and other minerals utilize general geological principles in an effort to locate potential mineral deposits including geological mapping and reconnaissance surveys. In addition, both use geophysical methods of exploration but those employed in oil and gas particularly in the form of seismic surveys are more highly refined and probably more widely employed. The principal exploration technique with respect to oil and gas is necessarily the drilling of exploratory wells. To a degree this has its counterpart with respect to other metals in the form of exploratory drilling, which, however, is generally confined to much shallower depths than may be the case with respect to oil and gas exploration. Further, the drilling of wells in the case of oil and gas in the event a producing strata is encountered involves at the same time the development of an oil and gas property since the same well will be used to produce the strata. In the case of other minerals, for the most part, after the presence of a mineral deposit is determined, it is necessary to develop the ore body by removing overburden in the case of open pit mining or sinking a shaft and drifting out to the ore body in the case of underground mining. The tax consequences with respect to exploration and development expenditures differ in a number of material respects as between oil and gas operations and the development of other minerals.
(1) Exploration Costs

In the case of oil and gas geological and geophysical exploration costs constitute capital expenditures and not ordinary and necessary business expenses. Hence, expenditures incurred in geologizing an area, seismic surveys, etc., must be capitalized and recovered through the depletion deduction irrespective of whether incurred for the purpose of determining whether to acquire a property or to retain a property previously acquired.108 Geological expenses "necessary in preparation for the drilling" and in the drilling of a well are, however, within the optional deduction for intangible drilling and development costs discussed below.109 Drawing the line between geological surveys relating generally to a property and those which relate to the location of a particular drill site depends upon a number of considerations. The Internal Revenue Service apparently takes the following factors into consideration:110 (1) To relate to the location of a particular drill site and hence be within the option, the property must be one already acquired by the taxpayer. (2) Drill site surveys generally involve a relatively small expenditure and anything in excess of $3,000 to $4,000 is likely to be challenged. (3) Drill site surveys are usually followed shortly thereafter by actual drilling. (4) If the information developed tends to outline the complete structure the geological work probably will not be recognized as being for the purpose of locating a drill site. (5) Drill site surveys are usually geological rather than geophysical.

In the case of minerals other than oil and gas the taxpayer within certain limitations has three alternatives with respect to exploration expenditures:111 (1) Taxpayer may deduct as an expense up to $100,000 as to such expenditures

111. Int. Rev. Code of 1954, § 615(a), (b). H.R. 4665, 89th Cong., 2d Sess., passed by the House of Representatives on February 7, 1966, would remove the annual $100,000 limitation and the $400,000 limitation. However, the Bill also includes recapture provisions designed to preclude a double deduction for exploration and percentage depletion as to properties that become productive and subjects gain from sale to recapture under rules comparable to Section 1245 if the property is disposed of prior to recapture.
provided, however, that all amounts previously or currently being deducted or deferred by taxpayer with respect to this particular property or any other property do not exceed $400,000. (2) Taxpayer may elect to defer such expenditures in any tax year to the extent of the difference between the amount, if any, deducted during such year and $100,000 and subject to the same overall $400,000 limitation referred to in (1). In the event taxpayer defers such expenditures he may then write them off pro-rata against the ore body as it is produced. (3) Taxpayer may elect to (and must to the extent the statutory limitations referred to are exceeded) capitalize such expenditures and recover same through the depletion deduction. There is a tendency in some quarters to confuse deferral and capitalization of such expenditures. If they are deferred, they are subsequently deducted as an expense as the ore body discovered as a result of such expenditures is produced; in such event taxpayer may also take depletion which will ordinarily be statutory depletion as such expenditures do not become part of taxpayer’s basis for depletion purposes. If the costs are deferred, they do become part of taxpayer’s basis in the mineral property for purposes other than determining cost depletion. If the taxpayer capitalizes such expenses, they become part of his basis in the mineral property for all purposes including the determination of cost depletion. Since statutory depletion frequently exceeds cost depletion even with such costs capitalized, often no tax benefit is realized by capitalizing such costs.

In contrast to the deduction for intangibles relating to oil and gas operations discussed below, the elections referred to above can be made for each property, can be made in whole or in part and can differ in each tax year. Taxpayer could, for example, deduct $10,000, defer $50,000 and capitalize $20,000 of such expenditures in one tax year even though incurred with respect to the same property and in the following year could make entirely different elections.

Exploration expenditures in the case of minerals other than oil and gas are defined as “expenditures paid or incurred during the taxable year for the purpose of ascertaining the existence, location, extent, or quality of any deposit of
ore or other mineral, and paid or incurred before the beginning of the development stage of the mine or deposit." 112 The development stage is reached after the existence of a commercial ore body has been disclosed. 113 Since development costs can be deducted or deferred without limitation as to amount, operators undoubtedly have a tendency to regard this stage as being reached at the earliest possible point.

In the event taxpayer received property in certain types of tax-free transfers (including transfer for stock to a controlled corporation or in connection with a corporate merger or other reorganization subject to the non-recognition of tax provisions of the Code), all exploratory expenditures previously deducted or deferred by the transferor must be included in determining the transferee’s $400,000 limitation. Under Reg. Sec. 1.615-4 such amounts must be included even if expended by the transferor on properties other than those transferred to the taxpayer.

For problems arising generally with respect to allocation of capitalized exploration expenditures to particular properties in the event properties are not acquired or retained and the taking of a loss deduction for abandonment see infra, p. 163.

(2) Intangible Drilling and Development Costs—Oil and Gas

As previously noted the drilling of oil and gas wells from the standpoint of a geologist may involve both exploration and development. However, from a tax standpoint no differentiation is made in this instance between exploratory wells and development wells. The optional deduction for intangibles in the case of oil and gas rather is predicated on the drilling of a well. The regulations permit a taxpayer to elect to capitalize intangible drilling and development costs or to write them off as a current expense. 114 In the event the election is made to capitalize such expenditures they must be recovered through the depletion allowance except for the installation costs of physical (tangible) equipment which

are amortized through the deduction for depreciation. 116 No election with respect to tangible expenditures is provided and all such expenditures must be capitalized and recovered through depreciation.

-OBSERVATION—The intangible drilling and development option is found in the regulations and prior to the adoption of the 1954 Code was not based on any express statutory provision. Congress in 1945 enacted a joint resolution approving the regulation. 117

The 1954 Code expressly requires the Secretary of the Treasury to prescribe regulations corresponding to the regulations which were prescribed under the 1939 Code granting the option to deduct, as expenses, intangible drilling and development costs. 118 The final regulations under the 1954 Code which were not adopted until July of 1965 118 are substantially identical to the regulations under the 1939 Code.

The importance of the intangible deduction in providing capital to a oil and gas operator cannot be overemphasized. 119 If, for example, the operator drills a well on a producing property and the intangible drilling costs incurred in the drilling of the well total $60,000, he can, if he has elected to deduct such costs currently, deduct this amount from the income received from this property or any other property or source in determining his taxable income. Assuming, for example, that his taxable income before deducting intangibles is $300,000, by taking the intangible deduction the taxpayer, in effect, receives $60,000 of this amount free of taxes. Looked at otherwise for a highest bracket (seventy per cent) taxpayer the net cost of his investment to the extent represented by intangibles (and assuming that he does not have other available deductions) is $18,000 ($60,000 less tax (70% × $60,000) = $18,000).

(3) Deduction for Intangibles—
Making the Election

It is important that a taxpayer clearly indicate his elec-

117. INT. REV. CODE OF 1954, § 263(c).
tion to deduct intangibles as current expenses in the first return filed by him after incurring such expenditures. In the event he fails to clearly elect, he will be deemed to have elected to capitalize intangibles.\textsuperscript{120} The election once made is binding for the individual taxpayer in all subsequent tax years and with respect to all properties.\textsuperscript{121} A taxpayer who has elected to capitalize intangibles has an additional election as to whether to write off currently or to capitalize intangibles incurred in drilling a dry hole.\textsuperscript{122} This additional election should be made in the return for the first taxable year in which a nonproductive well is completed. This election is also binding with respect to subsequent tax years and as to all properties of the taxpayer.

A corporation, of course, has an election in this respect distinct from that of its individual stockholders.\textsuperscript{123} A trustee of oil and gas properties also has an election as trustee distinct from his election as an individual.\textsuperscript{124} A partnership constitutes a distinct entity for this purpose and should make a separate election.\textsuperscript{125} Development by tenants in common under an operating agreement may constitute a partnership for this purpose.\textsuperscript{126}

(4) The Election Should Be to Deduct Intangibles Currently

A taxpayer will almost always find it advantageous to deduct intangible drilling and development costs as expenses. In part this is true because it permits the taxpayer to realize the immediate amortization of capital costs. In addition, if intangibles are capitalized, they are (with the exception of installation costs of physical equipment) recoverable only through the depletion allowance. Inasmuch as the statutory depletion allowance of \( 27\frac{1}{2} \) per cent of gross income can be taken regardless of the cost basis of the oil and gas property involved, often nothing is gained by capitalizing the

\begin{itemize}
  \item \textsuperscript{120} Treas. Reg. \$ 1.612-4(d) (1965).
  \item \textsuperscript{121} Treas. Reg. \$ 1.612-4(c) (1965).
  \item \textsuperscript{122} Treas. Reg. \$ 1.612-4(b)(4) (1965).
  \item \textsuperscript{123} I.T. 3763, 1945 CUM. BULL. 113.
  \item \textsuperscript{124} Bessie A. Dye, 1 P-H MEMO DEC. B.T.A., \$ 42,563 (1942).
  \item \textsuperscript{125} INT. REV. CODE OF 1954, \$ 703(b); I.T. 3713, 1945 CUM. BULL. 178; Rev. Rul. 54-42, 1954-1 CUM. BULL. 64.
  \item \textsuperscript{126} Bentex Oil Corp., 20 T.C. 565 (1953). See also discussion under caption Form of Organization in Part II of this Article to appear in the next issue.
\end{itemize}
expenditures recoverable through depletion. Prior to the adoption of the 1954 Code, it was possible to conceive of an unusual situation in which it would be advantageous for a particular taxpayer to capitalize intangibles with respect to a particular property. The 1954 Code (Section 172) permits a net operating loss to be carried back three years and to be carried forward five years whereas previously the carry-back was limited to one year. In addition, the 1954 Code eliminates the adjustment that previously had to be made for the excess of statutory depletion over cost depletion. In view of these changes, it is extremely unlikely that a situation will arise in which it will be advantageous for a taxpayer to capitalize intangibles.127

One possible exception to the foregoing is the situation in which a particular taxpayer has a net operating loss carry forward which will expire if not used in the current tax year. In such event taxpayer is interested in maximizing his taxable income during the particular tax year to the extent of the loss about to expire and if he has incurred intangibles during the current tax year for the first time (or drilled a dry hole for the first time) he could elect to capitalize such intangibles and thereby increase his taxable income. However, such election would be binding with respect to all properties in all future years and if taxpayer intends to continue to drill additional wells in future years capitalizing such expenditures could prove to be extremely short-sighted.

(5) What Are Intangible Drilling
and Development Costs?

In general, intangible drilling and development costs are expenditures incurred in "drilling of wells and the preparation of wells for the production of oil or gas" which have no salvage value.128 Examples of items subject to the option, as specifically set forth in the regulation, are:

all amounts paid for labor, fuel, repairs, hauling, and supplies, or any of them which are used—(1) in the drilling, shooting, and cleaning of wells; (2) in

127. For a series of examples illustrating the reasons why it is generally advantageous to deduct intangibles see Bloomenthal, Tax Advantages of Oil and Gas Operations, P-H Tax Ideas Serv., ¶ 17,011.3(3).

such clearing of ground, draining, road making, surveying, and geological works as are necessary in preparation for the drilling of wells; and (3) in the construction of such derricks, tanks, pipelines, and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil or gas. 129

Geological expenses directly related to the drilling of, and preparing for production, a particular well are, as noted, within the option, but geological expenses resulting from geological activities that led to the acquisition of the particular property must be capitalized as part of the acquisition costs and amortized through the depletion deduction. 130 Expenditures incurred in the construction and installation of derricks, tanks, pipelines and other physical structures necessary for the drilling of the well and the preparation of the well for production are within the option, but the cost of the physical installations themselves must be capitalized and recovered through depreciation. Accordingly, the cost of items having salvage value such as drilling tools, pipe, casing, tubing, tanks, engines, boilers, pumps, etc., must be capitalized and recovered through depreciation. 131

Although the cost of installing physical items, having a salvage value, used in connection with the drilling of wells and their preparation for production is subject to the option, the Internal Revenue Service has taken a narrow view of what is involved in preparing a well for production and regards a well as completed for production when the casing, including the "Christmas tree," 132 has been installed. 133 The ruling provides in this regard that none of the installation costs of the following are within the option:

1. Oil well pumps (upon initial completion of the well), including the necessary housing structures.

2. Oil well pumps (after the well has flowed for a time), including the necessary housing structures.

129. Ibid.
132. "Christmas tree" is a group of valves that control the flow of production from the well and are installed in a producing well after the casing and tubing but prior to the installation of the pump.
3. Oil well separators, including the necessary housing structures.

4. Pipelines from the well head to oil storage tanks on the producing lease.

5. Oil storage tanks on the producing lease.

6. Salt water disposal equipment, including any necessary pipelines.

7. Pipelines from the mouth of a gas well to the first point of control, such as a common carrier pipeline, natural gasoline plant, or carbon black plant.

8. Recycling equipment, including any necessary pipelines.

9. Pipelines from oil storage tanks on the producing leasehold to a common carrier pipeline.

On the other hand, the installation costs of casing, tubing, the Christmas tree, derricks and other physical structures or equipment installed before the Christmas tree are within the option.

Expenditures incurred in operating the wells are not, of course, within the option. However, intangible expenses incurred in deepening the hole or reworking the hole are subject to the option.\(^{134}\) Input wells, drilled for the purpose of stimulating oil production, are treated as if they were part of the oil well to which they relate.\(^{135}\) However, wells drilled to dispose of salt water are not incident to production and are not within the option.\(^{136}\)

(6) Development Costs—Minerals Other Than Oil and Gas

As in the case of exploration expenditures relating to minerals other than oil or gas, expenditures incurred in the development of a mine or other natural deposit (other than an oil or gas well) can be (1) deducted, (2) deferred, or (3) capitalized.\(^{137}\) See discussion at \textit{supra}, p. 114. However, such expenditures are not subject to limitations as to the amount

\(^{134}\) Monrovia Oil Co., 28 B.T.A. 335 (1933); Consolidated Mutual Oil Co. 2 B.T.A. 1067 (1925).

\(^{135}\) Page Oil Co., 41 B.T.A. 952 (1940), \textit{nonacq}. 1940-2 \textsc{cum. bull}. 13.

of such expenditures that can be expensed or deferred as is the case with respect to exploration expenditures. Development expenditures include those incurred in stripping, digging of a shaft and drifting provided they are incurred "after the existence of ores or minerals in commercially marketable quantities has been disclosed." Whether drilling is exploratory or development depends upon the point at which the existence of a commercial ore body is determined and as previously noted it is advantageous to reach the development stage as early as possible. The elections to deduct, defer or capitalize do not control the taxpayer's elections in subsequent years or as to other properties. It is, therefore often possible for the operator to phase his development operations so that such expenditures as to a particular property are expensed in one year and the income from that property realized in the following or subsequent years in order that the expensing of such expenditures will not adversely affect the statutory depletion deduction in terms of the fifty per cent of taxable income limitation. See supra, p. 107. However, deferral of development expenditures is limited by the amount such expenditures as to a particular property exceeds net receipts during the same tax year from the minerals produced from the property. Accordingly, taxpayer with respect to a producing property could not defer the development expenses to some subsequent year unless they exceeded revenues from the same property.

While the deferral of development expenditures to subsequent years permits the writing off of such expenditures against the ore as it is produced and is in addition to the depletion deduction, careful consideration must be given to the extent to which such deferral may in subsequent years reduce the statutory depletion deduction because of the fifty per cent of taxable income limitation. Under some circumstances it may be advisable for the taxpayer to defer such expenditures in the event he will otherwise lose part of a net operating loss carry-over which will otherwise expire since such deferral will increase current taxable income. Further, as in the case of the comparable exploration deduction,

'deferral has radically different consequences from capitalizing such expenditures and care should be taken not to inadvertently elect to capitalize same.

In the event taxpayer elects to defer such expenditures, the amount deferred increases his basis in the mineral property for all purposes other than computing depletion. While capital expenditures recoverable through the depreciation deduction are not included within the elections relating to development or exploration costs, the appropriate depreciation allowance pertaining to such equipment if used in connection with development is a development or exploration expenditure within the elections described.

The foregoing principles are illustrated by the following examples:

**EXAMPLE:** Able owns a mineral property on which the existence of a commercial ore body, *e.g.*, uranium, has been determined by exploratory drilling. During tax year 1964 Able strips the property so as to expose the ore body for mining incurring development costs in the amount of $1,000,000. Able may deduct such amount against other income if he has same or in the absence of other income may deduct such amount and carry forward a $1,000,000 net operating loss. If Able attempted to produce the property during 1964 and realized $500,000 from the property net after deduction of costs other than development costs, the fifty per cent of net limitation on statutory depletion would prevent taking any statutory depletion deduction in the event Able elected to deduct the $1,000,000. If, on the other hand, Able defers producing the property until the following year and realizes $500,000 net in 1965 before allocating development costs, the fifty per cent of net limitation will not come into effect unless statutory depletion exceeds $250,000.

**EXAMPLE:** Able owns a mineral property on which the existence of a commercial ore body has been determined by exploratory drilling. During the tax year 1964 Able strips the property so as to expose the ore body for mining incurring development expenditures in the amount of $1,000,000. Able has a $1,000,000 net operating loss carry forward that
will expire if not used in 1964 and net income from other sources is $1,100,000. Able would like to deduct $100,000 and defer the balance but under the Code must defer the entire amount or he cannot defer at all. Accordingly, Able elects to defer the entire $1,000,000. In 1965 the property is placed into production from which gross revenues of $1,000,000 are realized and net revenues of $500,000 are realized before depletion and before allocating any part of the development costs incurred in prior years. Assume that the ores mined during 1965 amount to one-fourth of the ore body. Able in 1965 will deduct one-fourth of the development costs or $250,000, resulting in taxable income before depletion of $250,000. Tentative statutory depletion for 1965 (assuming uranium) will be twenty-three per cent of $1,000,000 or $230,000 but must be reduced to $125,000 because of the fifty per cent of taxable income limitation. Deferring development expenditures incurred in 1964 has resulted in reducing by $105,000 the amount of the statutory depletion deduction available in 1965.

(7) Who Can Take Exploration and Development Deductions—In General

For the mineral company owning its own properties and incurring exploration and development expenditures for its own account there is generally no problem in determining that to the extent such expenditures are deductible they can be taken by the company. However, particularly with respect to oil and gas operations it is not uncommon for various types of sharing arrangements involving co-participants to be employed in financing the exploration and development of a property. While these arrangements are sometimes also employed with respect to minerals other than oil and gas, they are less commonly employed and generally the regulations and case law pertain to oil and gas development. However, for the most part there appears to be little reason why the same principles should not be applied to the development

189. INT. REV. CODE OF 1954, § 616(b) provides with respect to the election to defer development expenditures that the election if made "must be for the total amount of such expenditures" incurred with respect to the property. By contrast Section 615(b) with respect to the deferral of exploration expenditures permits deferral of "any portion" of such expenditures.
of minerals other than oil and gas to the extent comparable arrangements are involved although in a few instances the regulations are explicit as to oil and gas and silent as to other minerals. The ensuing discussion except to the extent otherwise explicitly noted relates to oil and gas operations and the deduction for intangible drilling and development costs, but is probably also applicable with respect to the deduction (or deferral) of exploration and development deductions in comparable arrangements relating to the development of other minerals.

The regulations provide that the option relating to intangibles can be taken by an operator, defined as "one who holds a working or operating interest in any tract or parcel of land either as a fee owner or under a lease or any other form of contract granting working or operating rights."\(^\text{140}\) It is apparent, therefore, that ordinarily the owner of a royalty, overriding royalty, oil payment, and net profit interest cannot deduct intangibles.\(^\text{141}\) The owner of an operating mineral interest can deduct intangibles, if actually incurred by him, to the extent attributable to his share of the total of all operating mineral interests.

**EXAMPLE**: Adams, a lessee, agrees that if Baker will drill and equip one well on Adams’ lease, free of cost to Adams but with Adams retaining all operating interest Baker will receive an oil payment consisting of ninety per cent of the gross production from the lease or the proceeds thereof until Baker has recovered one hundred per cent of the cost of drilling and equipping the well plus interest. Baker has no part of the operating mineral interest and hence cannot deduct the intangibles. Adams cannot deduct the intangibles although he owns an operating interest as they were no incurred by him. For variations of this arrangement that would permit deduction of intangibles see the discussion at *infra* p. 134.

The taxpayer who drills a well with his own equipment and employees obviously (assuming that he owns the operating rights) has incurred the intangible drilling and develop-

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141. Ibid.
ment costs and can elect to deduct them as current expenses. A taxpayer who has the well drilled for him under a footage contract requiring the payment of so much per foot of hole drilled has always been able to deduct intangibles provided he made the proper election. However, prior to December 31, 1942, if the owner of the operating rights had the well drilled under a turnkey contract providing for the payment of a stated consideration for a completed well, he had to capitalize the contract price and recover same through the depletion allowance. The regulations were amended in 1942 and now specifically provide that intangible drilling and development costs include "the cost to operators of any drilling or development work . . . done for them by contractors under any form of contract, including turnkey contracts."

If the well is drilled for the taxpayer-operator under a turnkey contract, a breakdown should be made in the taxpayer’s return with respect to the portion of the contract price attributable to intangibles and the portion attributable to tangibles. If the taxpayer fails to include such breakdown, the Commissioner may make an allocation on an arbitrary percentage basis. The drilling contract can specify the respective costs of tangibles and intangibles; in lieu thereof, a common method of allocating such costs is to value the cost of the tangible equipment (based ordinarily on what the contractor paid for such equipment) and regard the remainder of the consideration as intangible drilling and development costs. However, in this connection with respect to any equipment beyond the Christmas tree, the value thereof must include not only the cost of the equipment but the cost of installing it as well.

(8) Who Can Take the Deduction—Obligation Work

Prior to a change in the regulations in 1942, the taxpayer drilling a well in return for a fractional interest in the lease had to capitalize the entire cost of the so-called "obligation

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143. J. K. Hughes Oil Co. v. Bass, 62 F.2d 176 (5th Cir. 1932).
well” as part of the acquisition costs recoverable through depletion. Under the current regulations, a taxpayer drilling an obligation well for an interest in a lease must capitalize and recover through depletion only that part of the drilling costs that is in excess of the proportionate share of such costs attributable to the interest acquired or to be acquired in return for the drilling of the well. Since the taxpayer drilling the well owns only part of the operating interest he can deduct only a proportionate part of the intangibles.

EXAMPLE: Adams, the owner of an oil and gas lease, agrees to assign to Baker a fifty per cent undivided interest in the lease in return for Baker’s promise to drill a well at his sole expense. Thereafter, income and expenses are to be shared equally. Baker drills the well at a cost of $100,000 of which amount $60,000 represents intangibles and $40,000 represents depreciables. Baker can deduct $30,000 (50% × $60,000) of the intangibles and can capitalize as recoverable through depreciation $20,000 (50% × $40,000). The balance of Baker’s costs ($50,000) must be capitalized and recovered through the depletion allowance. Inasmuch as Adams has not paid for any part of the intangibles, he cannot take any deduction for intangibles.

—SUGGESTION—If the parties want to enter into an arrangement whereby one of them will drill a well at his sole expense, without reimbursement from production or otherwise, in return for an interest in the property, consideration should be given to the use of a net profit interest. The party drilling the well would under this arrangement be assigned all of the operating rights, the assignor reserving a net profit interest defined in terms of a specified percentage of the gross proceeds less a proportionate share of the operating (but not development) costs. The party drilling the well now owns the entire operating mineral interest and can deduct all the intangibles and capitalize all the depreciables. Not only will the party financing the drilling receive the full benefit of the intangible deduction, but he will avoid the undesirable consequence inherent in the example above of

146. F.H.E. Oil Co. v. Commissioner, 147 F.2d 1002 (5th Cir. 1945).
turning part of depreciable basis into depletable basis. The only disadvantage to the assignor (since he cannot in any event deduct intangibles not incurred by him) is that he can take depletion only on the net proceeds he receives under the net profit interest, whereas if he retained an interest in the lease as such, he could take depletion with respect to the gross income attributable to his fractional interest. See also the partnership alternative discussed below.

—WARNING—The following device is sometimes employed in the drilling of obligation wells: Assignor assigns the entire lease to Operator with provision that one day after completion of the well a one-half interest reverts back to Assignor. The proposed regulations were specifically designed among other things to preclude the deduction of all the intangibles by Operator in this situation. While such regulations have been withdrawn it is likely that Internal Revenue Service will look at substance rather than form in this context.

The performance of exploration and/or development work with respect to minerals other than oil and gas in exchange for an interest in a mineral property is one instance in which the regulations provide explicitly for a result comparable to oil and gas. The regulations expressly provide that the provisions relating to deducting or deferring exploration and development expenditures with respect to minerals other than oil and gas are applicable to expenditures "incurred by a taxpayer in connection with the acquisition of a fractional share of the working or operating interest to the extent of the fractional interest so acquired by the taxpayer. The expenditures attributable to the remaining fractional share shall be considered as the cost of his acquired interest and shall be recovered through depletion allowances." 148

(9) Who Can Take the Deduction—

The Co-Owner Investor

Careful planning is necessary in order to enable an investor buying a fractional undivided interest in an oil and gas lease and a well being drilled on the lease to deduct a

proportionate part of the intangibles. If the investor acquires an interest in a lease which at the time of the acquisition already has a well or wells on it, he obviously cannot regard part of his investment as intangible drilling and development costs with respect to the wells that have already been drilled since such costs were not incurred by him. If the investor acquires an interest in a lease on which a well is to be drilled and if the promoter is not obligated to use the investor's capital in the drilling of the well, the investor must capitalize his entire investment as acquisition costs recoverable through depletion. Even if the promoter is obligated to use the proceeds in the drilling of the well, unless the promoter is acting as the investor's agent in the drilling of the well the entire investment may have to be capitalized. If the promoter is acting as the investor's agent in the drilling of the well and if the drilling is undertaken under the same contract providing for the assignment of part of the lease or other operating rights, the investor probably can deduct the intangibles to the extent that such costs are attributable to the fractional interest that he acquires although the Internal Revenue Service can be expected to contend that at least part of the costs are acquisition costs and hence not deductible. The investor can deduct as intangibles his proportionate share of such costs that are assessed to him after his acquisition of the oil and gas interest. See also discussion below relating to "The Promoter-Operator."

—SUGGESTION—The operating agreement supplementing the assignment should, in this situation, specifically provide that the operator is acting as the agent of the investors in incurring drilling and development costs and should use language of agency. Although the operator may be reluctant to do so, it would be advisable to set forth his com-

151. Ibid.
153. "On the accepted ground that the assessment of $2,800 paid by petitioner represented an expenditure for intangible drilling costs, for his account, the respondent concedes his right to expense such costs under the option granted in Section 29. 33(m)-16(b) of Regulation 111."

pensation and for the investors to retain some control over him. It may also be helpful if the contract of sale specifically provides that a specified reasonable part of the investment represents the acquisition costs of the oil and gas interest and that the balance of the investment represents the investor’s proportionate share of the drilling costs. The Tax Court in a case\textsuperscript{154} not acquiesced in by the Service was willing to regard such acquisition costs as nominal when the promoter-operator has actually acquired the lease for nominal costs. Consideration should be given in this context to electing to be treated as a partnership for tax purposes.\textsuperscript{155} See also the partnership alternative discussed below.

In some instances, interest holders agree to contribute to the cost of drilling a well and designate one of the interest holders as “operator” to arrange for the drilling and to supervise collection of monies, the drilling, etc. They may agree to pay more than their proportionate share of the cost of drilling in order to compensate the operator who, in effect, has part or all of his share of the drilling costs paid by the others. If the “operator” is taxable on the excess and the interest holders pay above their proportionate share, a matter discussed below, it would appear that such costs are additional intangibles with respect to which the interest holders can take a deduction.\textsuperscript{156} If such costs are regarded merely as reducing the operator’s development costs, the taxpayer paying in excess of his proportionate share of such costs could deduct only his proportionate share of the intangibles. See also discussion below relating to “The Promoter-Operator.”

(10) Who Can Take the Deduction—The Promoter-Operator

The promoter-operator selling oil and gas interests to finance the drilling of oil and gas wells must be in a position to establish that he was committed to and did use the money received from investors in the drilling of the particular well

\textsuperscript{154} G. F. Hedges Jr., supra note 152.
\textsuperscript{155} Ibid.
\textsuperscript{156} Cf. Ortiz Oil Co. v. Commissioner, 102 F.2d 508 (5th Cir. 1939); G. F. Hedges Jr., supra note 152.
in which they invested. To the extent that the money was not so used and to the extent that the taxpayer is unable to sustain the burden of proof in this respect, monies received by him from the investors must be regarded as "income." 157 If, on the other hand, the operator can establish that the proceeds from the sale of oil payments158 and participating interests159 and probably any other type of oil and gas interests are pledged for use in development and are in fact used for this purpose the proceeds are regarded as a reduction in the development costs of the operator rather than as income. Accordingly, the promoter-operator can take intangibles and can capitalize depreciables only to the extent that the total costs incurred in drilling the well exceed the amount realized from investors.160

—OBSERVATION—Where the promoter-operator sells interest (except possibly oil payments where the consideration received is not pledged) and realizes "income" the gain is capital gain under Code Section 1231 rather than ordinary income.161 If the promoter-operator realizes "income" in the situation in which he does not sell interests but supervises or arranges for the drilling of a well for the interest holders, the income received would obviously be ordinary income. If, however, the operator retains an interest to the extent such income is used to pay his proportionate share of intangibles he will have a deduction.

—FURTHER OBSERVATION—The cases and rulings hold that an operator does not realize "income" if the proceeds pledged for development purposes relate to oil payments and participating interests. The same principle probably applies to situations in which the promoter-operator sells fractional undivided interests in the lease or in other operating

157. Rogan v. Blue Ridge Oil Co., 83 F.2d 420 (9th Cir. 1936).
159. Rogan v. Blue Ridge Oil Co., supra note 157; United States v. Knox-Powell-Stockton Co., 83 F.2d 423 (9th Cir. 1936).
rights.\textsuperscript{162} However, one circuit court has held that where the operator realized from the other interest holders more than their proportionate share of the drilling costs he realized "income" in the amount of the excess despite the fact that such excess apparently was used for the purpose of drilling the well.\textsuperscript{163}

---\textit{SUGGESTION}---A tightly drawn escrow agreement which provides that the funds can be paid to the contractor drilling the well only as specified drilling depths are reached is not only the investor’s best assurance that the proceeds will be used to drill the well, but eliminates the promoter’s problem with respect to the necessity of establishing that such funds were used to drill a well.

---\textit{FURTHER SUGGESTION}---The promoter-operator might agree to drill a well for the interest holders at a fixed cost and at his risk. The promoter-operator then reports the amount received as income from drilling and deducts the actual cost of drilling as an expense of the drilling business. The promoter-operator reports his profit as income but the interest owners and promoter-operator take their proportionate part of the fixed cost of drilling as an intangible. The \textit{Hedges} case\textsuperscript{164} sustained this tax treatment as to the interest owners other than the operator despite the contention of the Service that the intangibles should be based upon the promoter-operator’s actual cost of drilling.

\textbf{(11) Who Can Take the Deduction—Carried Interest and Related Arrangements}

The carried interest arrangement is a common method of financing the drilling and development of oil and gas properties. Although there are a number of variations in terms of the mechanics employed to effectuate the carried interest result, in essence all of these arrangements involve an ar-

\textsuperscript{162} The rationale of G.C.M. 22730, 1941-I \textit{CUM. BULL.} 214 would appear to apply to the sale of working interests as well as oil payments.

\textsuperscript{163} Ortiz Oil Co. v. Commissioner, \textit{supra} note 156. This case may be distinguishable in that the operator did not transfer any interest to the contributors (who already were interest holders); hence, there could be no sharing between the owner of the oil and gas interest and the contributor of capital. Although this appears to be the rationale of G.C.M. 22730, see footnote 162 \textit{supra}, there would appear to be little justification for making a distinction of this nature.

\textsuperscript{164} G. F. Hedges Jr., \textit{supra} note 162.
angement under which O agrees to finance the cost of drilling and equipping a well on a lease owned by L for a specified interest in the mineral lease (usually, but not necessarily, an undivided fifty per cent) with the right to one hundred per cent of the proceeds until he has recovered all of the costs incurred in the drilling of the well. The period of time necessary to recover costs is sometimes referred to as the payout period. There are basically two tax questions involved in these arrangements, both of which must be considered from the standpoint of both of the parties to the transaction. The first such question is to whom during the payout period is the income attributable to the carried interest taxed; and, secondly, who, if anyone, can take the deduction for intangibles. Generally, if the parties were to work out this problem by agreement they would desire a result under which the carrying party doing the financing can take the appropriate deductions and the proceeds, which during payout are being received by the carrying party, are taxed as income of the carrying party. It is believed that if these are the tax consequences desired that such result can be achieved by adopting the appropriate mechanics and by providing contractually that the parties will report income and take deductions in accordance with the foregoing. The reason it is believed that this result can be accomplished is the fact that it represents the tax consequences generally favored by Internal Revenue Service.

**WARNING:** Care must be taken to follow the appropriate mechanics as Internal Revenue Service has not hesitated to advance inconsistent positions in this context when there has been an advantage to be gained by the government. As noted below, it is advisable to obtain a Ruling in connection with each carried interest arrangement.

There are at least three basic types of carried interest arrangements, each of which may in the light of the decisions have different tax consequences although the economic impact of each may be identical. In addition, a net profit interest may be utilized rather than a carried interest arrangement or a partnership arrangement can be utilized to accomplish the same or a similar result to a carried interest
and the economic impact of all of these arrangements is substantially identical. Nonetheless, tax consequences under current tax lore may vary depending upon the particular arrangement employed.

(1) Under one arrangement, usually characterized as a Manahan carried interest,165 L assigns the entire lease to O with a provision to the effect that upon complete payout a one-half interest in the lease is to revert to L. Under this arrangement O reports one hundred per cent of the proceeds as taxable income during payout and takes one hundred per cent of the deductions. These are the tax consequences that Internal Revenue Service appears to favor and hence Internal Revenue Service usually is contending for a Manahan approach. The proposed regulations166 (since withdrawn) relating to the deduction for intangibles expressly adopted an approach that is compatible with this result.

(2) Under the second arrangement, usually referred to as an Abercrombie carried interest, L assigns a one-half interest in the lease to O with a provision to the effect that O is to be entitled to all of the proceeds during the payout period. In the Abercrombie case167 the Fifth Circuit held that in effect O has made a loan to L of the amounts advanced to pay L's proportionate share of the cost and hence the proceeds attributed to L's interest during payout although actually received by O are taxable to L. It follows from this approach that L can deduct his proportionate share of the intangibles and the Fifth Circuit has held in this regard that L can take such deduction at the time of the expenditure even though there is no assurance that production from the well will be sufficient to assure payout.168 A more recent Fifth Circuit decision, however, suggests that it is about to abandon the Abercrombie approach and to adopt Manahan in this situation as well.169 Interestingly enough, although the Commissioner at one time acquiesced in Abercrombie,

169. Weinert v. Commissioner, 294 F.2d 750 (5th Cir. 1961).
he has generally argued for a Manahan result\(^{170}\) although on occasion he has argued without success for Abercrombie.\(^{171}\) The proposed regulations (since withdrawn) dealing with intangibles gave what is in effect an Abercrombie example and applied to this example the Manahan result.\(^{172}\)

(3) Under the third arrangement, commonly referred to as a Herndon carried interest, L assigns to O a one-half interest in the lease and an oil payment payable out of one hundred per cent of L's reserved interest until O has recovered therefrom the amount of L's share of drilling, completion and operating costs. The assumed result under this approach has been to permit O to deduct only one-half of the intangibles since only the operator can deduct same and to deny L the right to deduct intangibles since they are not incurred by him and to tax O on one hundred per cent of the proceeds, half of which O receives from his undivided interest and the balance of which is received from the oil payment.\(^{173}\)

Rather than a carried interest arrangement the parties may provide for the assignment of the entire working interest to O with a reservation to L of fifty per cent of the net profits. The instrument creating the net profit interest defines net profits as fifty per cent of net proceeds after deducting the cost of drilling, completing and operating the well. If the parties intend to create a net profit interest, they must be careful to transfer the exclusive right to develop the lease to O and L must not retain any interest in the equipment located on the property. Although the economic impact again is the same, from a tax standpoint it is reasonably clear that O reports all of the income received from the property as his income during payout and takes all of the deduction.\(^{174}\) This arrangement has an adverse impact from the standpoint of L in that L will have to compute

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170. Id. 756 n. 13. The Service has since withdrawn its acquiescence. 1963-1 CUM. BULL. 5.
171. See Weinert v. Commissioner, supra note 169.
depletion based on the proceeds from fifty per cent of the net rather than from fifty per cent of the gross as would be the case with respect to his share of income after payout under a carried interest arrangement.\textsuperscript{175} It is the position of Internal Revenue Service that all so-called unlimited carried interest arrangements are a net profit interest irrespective of form.\textsuperscript{176} An unlimited carry is one under which the carried arrangement applies after the operator has been reimbursed for drilling and development costs. The net effect is to force parties into the limited carry arrangement under which after payout the carried party's working interest is restored and he receives directly his proportionate share of the proceeds and is billed for his proportionate share of the costs.

Between 1956 and July 15, 1965, the Internal Revenue Service had under consideration proposed regulations which would have eliminated in large part the uncertainty relating to carried interests and other sharing arrangements. The proposed regulations as revised in 1960 made it clear that in a \textit{Manahan} type carry the carrying party could deduct all of the intangibles,\textsuperscript{177} and included an example from which it could be concluded that the same result would follow as to an \textit{Abercrombie} type\textsuperscript{178} which is also consistent with the withdrawal by the Service of its prior acquiescence in \textit{Abercrombie}\textsuperscript{179} and the recent Fifth Circuit repudiation of \textit{Abercrombie} in the \textit{Weinert} case.\textsuperscript{180} However, no sooner had the situation crystallized after 23 years of doubt than Internal Revenue Service restored the prior chaotic situation by withdrawing\textsuperscript{181} the proposed regulations and adopting final regulations which are substantially identical to the 1939 regulations and which are entirely silent as to allocation of the intangible deduction with respect to carried interest arrangements.\textsuperscript{182} The adoption

\textsuperscript{175} Burton-Sutton Oil Co. v. Commissioner, \textit{supra} note 174. Grandview Mines v. Commissioner, 282 F.2d 700 (9th Cir. 1960).
\textsuperscript{176} United States v. Thomas, 329 F.2d 119 (9th Cir. 1964); G.C.M. 22730, 1941-1 CUM. BULL. 214.
\textsuperscript{178} \textit{Supra} note 172.
\textsuperscript{179} 1963-1 CUM. BULL. 5.
\textsuperscript{180} Weinert v. Commissioner, \textit{supra} note 169.
\textsuperscript{181} T.D. 6836, 30 Fed. Reg. 8902 (1965); 1965 INT. REV. BULL. No. 34, at 19.
\textsuperscript{182} Treas. Reg. § 1.612-4 (1965).
of the final regulations was accompanied by an announcement by the Service indicating a willingness to entertain requests for rulings in appropriate cases, stating: "In such rulings, the decision of the Service will depend on the particular facts and circumstances of each individual case."\textsuperscript{183} See also "The Partnership Alternative" discussed below.

(12) The Partnership Alternative

In many sharing arrangements, a partnership may be utilized as an alternative or better method of accomplishing the particular result that may be desired. In the case of an obligation well, for example, L may contribute the lease in question to a partnership and O, on the other hand, may contribute the cash necessary to drill the property. The formation of the partnership in the absence of a transfer of a negative basis property will be without tax consequences\textsuperscript{184} and the partnership if it elects to expense intangibles reports these items not as part of the partnership taxable income or loss but as items to be separately accounted for by the individual members,\textsuperscript{185} each member of the partnership taking his proportionate share of the deduction based on the profit and loss sharing arrangement. Under this arrangement one hundred per cent of the deduction ordinarily will be realized whereas under the obligation arrangement previously discussed only fifty per cent of the deduction will be utilized at best. If L and O both have a basis in the partnership equal to their respective share of the deduction, no problem should arise in this respect. If L, who transfers the property, has little or no basis in the property (and hence the partnership) a portion of the deduction may not be utilized as the Code precludes the deduction by a partner of his distributive share of partnership losses in excess of his basis in the partnership.\textsuperscript{186}

In the carried interest situation L and O instead of entering into a carried interest arrangement can form a partnership with L contributing the lease and O contributing

\textsuperscript{183} Announcement 65-63, 1965 INT. REV. BULL. No. 34, at 53.
\textsuperscript{184} INT. REV. CODE OF 1954, § 721.
\textsuperscript{185} Treas. Reg. § 1.702-1(a) (8) (1956).
\textsuperscript{186} INT. REV. CODE OF 1954, § 704(d). However, the deduction for intangibles is taken outside of the partnership and is not specifically so limited. Treas. Reg. § 1.702-1(a) (8) (1956).
monies in the amount of the drilling and completion costs with a provision in the partnership agreement which permits 0 to recover one hundred per cent of the profits until he has recovered his capital contribution and which further provides that he is to be allocated the entire deduction for the intangibles and depreciables which are to be charged against his capital account. Such allocations are permissible if the principal purpose is not to avoid or evade the federal income tax which generally depends upon whether the allocation has a substantial economic effect upon the partners.\textsuperscript{187} The regulations set forth a somewhat analogous example involving the development of an electronic device which suggests that such allocations have economic effect and will be recognized.\textsuperscript{188}

In the situation in which the promoter-operator would ordinarily sell fractional interests in a lease, the arrangement might instead involve the sale of partnership interests with a transfer of the lease to the partnership by the promoter-operator with a special allocation of the deductions (and a corresponding charge to their capital account) for intangibles and depreciation to the partners contributing cash. Since this allocation has economic effect among the partners it should be recognized.\textsuperscript{189} The promoter-operator could under this arrangement be compensated for services rendered in drilling the well in which event such amounts should be additional intangibles. Under these circumstances the promoter-operator would, of course, have to report his compensation from the partnership as income.\textsuperscript{190} A variation of this arrangement depending upon the objectives of the participants could provide for allocation of the intangibles based upon the profit and loss sharing arrangement in which event the promoter-operator would be taking a portion of the deductions actually paid for by the capital contribution of the investors.\textsuperscript{191}

\textsuperscript{187} Treas. Reg. \textsection 1.704-1(a), (b).
\textsuperscript{188} Treas. Reg. \textsection 1.704-1(b) (2) Example 5 (1956).
\textsuperscript{189} Treas. Reg. \textsection 1.704-1(a), (b) (1956). If the deductions were allocated without a corresponding charge against their capital account query whether same would be recognized.
\textsuperscript{190} Compare G. F. Hedges Jr., \textit{supra} note 152.
\textsuperscript{191} See, however, discussion at note 186 \textit{supra} relating to the extent to which a promoter-operator must have a sufficient basis in the partnership under these circumstances.
The tax consequences under the partnership alternative would be generally the same with respect to minerals other than oil and gas except the appropriate deductions would be the exploration deduction and the development deduction. With respect to both exploration expenditures and development expenditures it is the partnership which makes the appropriate election, but the exploration expenditures are taken into account by the individual partners who each report their distributive share whereas the development expenditures are taken into account by the partnership. For purposes of applying the $100,000 and $400,000 limitations relating to exploration expenditures the limitations are imposed on the members rather than the partnership. The partnership organized could be a general partnership, mining partnership or limited partnership. Care must be taken to avoid an arrangement that would result in the partnership being taxed as a corporation. The non-tax aspects of these arrangements should also be carefully considered as in some instances the non-tax disadvantages may offset tax advantages. Those seeking the best of two possible worlds may attempt to achieve partnership tax results by using a co-ownership arrangement which elects to be taxed as a partnership. The taxpayer accomplished this result in the *Hedges* case under these circumstances, but Internal Revenue Service has refused to acquiesce and taxpayers may be in a better position if a partnership is actually organized.

**The Depreciation Deduction and Investment Credit**

The depreciation deduction, of course, is applicable to all taxpayers not merely mineral operators. Accordingly, the emphasis herein is on depreciation problems peculiar to mineral operations. The previous discussion relating to ex-

196. See discussion under caption Form of Organization in Part II of this Article to appear in the next issue.
197. See discussion under caption Form of Organization in Part II of this Article to appear in the next issue.
199. See discussion under caption Form of Organization in Part II of this Article to appear in the next issue.
exploration and development expenditure has necessarily referred in many instances to the depreciation deduction. As previously noted,200 intangible drilling and development costs cannot be recovered through depreciation, but, if capitalized, must be amortized through the depletion deduction. On the other hand, all expenditures involved in drilling a well representing the cost of tangible physical items must be capitalized and amortized through the depletion deduction. In addition, all installation costs of tangible physical equipment after the installation of the Christmas tree must be capitalized and recovered through depreciation. Installation costs of physical items installed prior to the Christmas tree are within the option relating to intangibles but, unlike other intangibles, if capitalized, such installation costs are amortized through depreciation. Development and exploration expenditures, relating to mineral properties other than oil and gas include depreciation on capital items such as equipment, but not expenditures for the equipment itself.201

(1) Who Can Take the Depreciation Deduction?

A taxpayer having an interest in a lease and the equipment located thereon can take depreciation provided he has an investment (cost basis) in such equipment. Accordingly, the owner of the mineral royalty, overriding royalty, production payment, and a true net profit interest cannot take a deduction for depreciation since he ordinarily does not own an interest in the equipment on the lease.

The taxpayer who drills a well (or performs other work) in return for working interest in a mineral property can capitalize and recover through depreciation only that portion of the expenditures for depreciables that is attributable to the interest he has acquired or will acquire in the lease. The remaining expenditures for depreciables must be capitalized and recovered through depletion.202 Assuming that the taxpayer has a basis in a mineral property and assigns a portion of that property in return for the drilling of a well in a non-taxable sharing arrangement, there is some possibility

201. INT. REV. CODE OF 1954, §§ 615(a), 616(a).
that he might be able to assign part of his basis in the mineral property to the interest he acquires in the well equipment, but this question has not actually been resolved.\(^{203}\) In the event a carried interest arrangement is involved, the taking of the depreciation deduction is necessarily related to the tax consequences imposed with respect to intangibles and the taxing of income during payout. If the Manahan\(^{204}\) approach is followed (carrying party taking all of the intangibles and being taxed as to all of the income during payout), presumably the carrying party would take the entire deduction for depreciation during payout. However, after payout the carrying party would own only a one-half interest in the equipment and presumably can deduct only one-half of the unrecovered basis in the equipment, the other half then becoming part of his basis in his mineral interest. While the carried party would own an interest in the equipment at that point he would have no basis in the equipment unless he is permitted to allocate part of his original basis (if any) in the mineral interest to the equipment.\(^{205}\) If Abercrombie-Prater\(^{206}\) are followed (carried party takes half of intangibles and is taxed as to half of the income during payout), presumably the carrying party and carried party will share the depreciation deduction.

The investor acquiring a fractional interest in a mineral lease and a well located on it does not have the same problem noted in connection with the availability of the deduction for intangibles. Regardless of whether the promoter-operator is acting as his agent, the investor has in any event acquired an interest in the well equipment and has a depreciable basis in such equipment. Such an investor may have a problem in determining his basis in the equipment recoverable through depreciation from his basis in the mineral property (recoverable through depletion). The taxpayer probably can in this connection make an allocation based on the relative fair market values of the equipment and the mineral rights and

\(^{203}\) Cf. E. C. Laster, 43 B.T.A. 159 (1940).

\(^{204}\) Supra p. 134.

\(^{205}\) The possible loss of part of the depreciation deduction in this situation may suggest the use of a partnership (see supra p. 137) or net profit arrangement (see supra p. 135).

\(^{206}\) Supra p. 134.
in lieu of a market with respect to the latter probably can allocate to depreciables the fair market value of his proportionate share of such items and regard the balance of his investment as acquisition costs of the oil and gas rights recoverable through depletion.\(^{207}\)

—\textit{WARNING}—In order to permit the investor to deduct depreciation, the assignment or supplemental operating agreement must give him an interest in the equipment. If the assignment or operating agreement provides that the operator is to have the right to remove and keep the equipment when the property is abandoned, a serious question is presented as to whether the investor acquired an interest in the well equipment. In the event the investor is unable to take the depreciation deduction, the promoter will also be unable to take the deduction inasmuch as he ordinarily will not have a cost basis in the equipment.

The promoter who in a non-taxable transaction\(^{208}\) finances the drilling of the well by the sale of interests to the public and uses the proceeds of such sales to drill a well, cannot take a deduction for depreciation inasmuch as he has no cost basis in the well equipment.\(^{209}\)

(2) Methods of Computing Depreciation

Under Section 167 of the 1954 Code a taxpayer may use any of the following depreciation methods:

1. Straight-line method,

2. Declining-balance method, using a rate not exceeding twice the straight-line rate,

3. Sum-of-the-years-digits method, or

4. Any other consistent method which will not give an aggregate depreciation write-off at the end of any year during the first two-thirds of the useful life of the property any larger than under the declining-balance method, \textit{e.g.}, the unit-of-production method.

\(^{207}\) G.C.M. 22332, 1941-1 CUM. BULL. 228; Herndon Drilling Co., 6 T.C. 628 (1946), \textit{acq.} 1946-2 CUM. BULL. 3 (Acquiesced on this point only); Grain King Mfg. Co., 14 B.T.A. 793 (1928).

\(^{208}\) \textit{Supra} p. 131.

\(^{209}\) Treas. Reg. § 1.167(a)-1 (1956).
While ordinarily a change from one method to another requires the approval of the Commissioner, a taxpayer may normally switch from the declining-balance method to the straight-line method at any time. Such switch may have special implications if the guideline lives have been used which require special study.

Under the straight-line method, the depreciation allowance is determined by dividing the cost basis of the equipment, less estimated salvage value, by its estimated useful life. Under Sec. 167(f) of the Code salvage value may be disregarded up to ten per cent of the basis of the asset. If, however, the economic life of the property is less than the life expectancy of the equipment, the economic life of the mineral deposit may be used as the life expectancy of the equipment.

**EXAMPLE:** The taxpayer has a composite basis of $100,000. The taxpayer computes depreciation by the straight-line method. The life expectancy of the equipment is fourteen years; however, the taxpayer establishes to the satisfaction of the Commissioner that the life expectancy of the resource is only ten years. The salvage value of the equipment is $20,000. The taxpayer's depreciation rate is $9,000 a year computed by deducting the salvage value to the extent it exceeds ten percent from original cost basis and dividing the resulting figure by ten, the life expectancy of the resource.

—**WARNING**—In order to use the life expectancy of the deposit, the taxpayer must establish to the satisfaction of the Commissioner that the life expectancy of the resource is less than the life expectancy of the equipment.

The declining-balance rate is determined by ascertaining the straight-line rate (one hundred per cent divided by original useful life). Under the double declining-balance depreciation, twice the rate so determined is applied to each year's remaining unrecovered cost. Thus, if the useful life is ten years, the straight-line rate is ten per cent and the double declining-balance rate is twenty per cent. If the original cost

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210. Treas. Reg. § 1.167(e)-1(b) (1956).
of the property is $10,000, depreciation the first year is $2,000 ($10,000 times twenty per cent), depreciation the first year is $1,600 (unrecovered cost of $8,000 times twenty per cent), and so on.

—OBSERVATION—Under declining-balance depreciation, not all the cost is written off during the useful life of the property; if the property continues in use, the depreciation deductions will continue, or the unrecovered cost will be recouped when the property is sold or abandoned. However, this "defect" of the declining-balance method may be avoided by switching at an appropriate point to straight-line depreciation.

Under the sum-of-the-digits method, the depreciation rate is a fraction, the numerator of which is the remaining useful life of the property at the beginning of the tax year, and the denominator of which is the sum of the years of useful life at acquisition. For example, for an asset with a useful life of five years, the denominator of the fraction each year will be fifteen \((1 + 2 + 3 + 4 + 5)\). The depreciation allowable for the first year would be \(5/15\)th of cost, for the second year \(4/15\)ths, and so on.

Under the unit-of-production method, the cost basis of the equipment, less salvage value, is divided by the total estimated number of barrels of oil (or other appropriate unit) that can be recovered from the property. The resulting figure is multiplied by the number of barrels (or other appropriate unit) produced during the tax year in order to determine the depreciation deduction. This method is identical to the method employed in computing cost depletion as previously outlined in detail except a different cost basis is used in determining the depletion unit. If the estimated productive life exceeds the general guideline life (fourteen years generally for oil well equipment and ten years for mining equipment), careful consideration should be given to the advisability of using this method.

—OBSERVATION—A taxpayer may use different methods for different assets or classes of assets providing he is consistent. The Commissioner has authorized the use
of the operating-day method, with respect to equipment not ordinarily subject to obsolescence. Under this method the taxpayer estimates the number of useful days of actual use of the equipment over its lifetime, and obtains the depreciation rate by dividing the number of days the equipment is actually used by such estimated total.\textsuperscript{212} A drilling contractor may find this method useful, but must, of course, obtain approval of the Commissioner to change depreciation method.

The 1958 amendments to the Code provide for an additional depreciation allowance regardless of method employed for the first year in which either new or used tangible personal property with a useful life of at least six years is acquired. The additional allowance is twenty per cent of the first $10,000 of cost ($20,000 on a joint return) of such equipment. This allowance is computed and deducted from basis before determining the depreciation otherwise allowed.\textsuperscript{213}

Property eligible for accelerated depreciation methods: The accelerated depreciation methods (declining-balance and sum-of-the-digits) may be used only for tangible property having a useful life of three years or more. In addition, these methods are available only as to: (1) new property acquired after 1953, that is, the property must not have been used before by the taxpayer or anyone else; and (2) property constructed or reconstructed by or for the taxpayer, where the work was finished after 1953, but only as to that part of the property's cost attributable to work done after 1953.

\textit{—OBSERVATION—} No formal election of any of the accelerated methods is necessary. It suffices if taxpayer computes the deduction in accordance with the method selected in his return for the first tax year ending after 1953 in which he acquires property eligible for the accelerated depreciation methods.

Agreements as to useful life: The law authorizes agreements between taxpayers and the Revenue Service as to useful life and rate of depreciation. Once signed, neither

\textsuperscript{212} Rev. Rul. 56-652, 1956-2 CUM. BULL. 125.
\textsuperscript{213} INT. REV. CODE OF 1954, § 179.
party can upset it without showing new facts justifying a change; even then any change will be for the future only.

(3) The Guidelines

In 1962 Internal Revenue Service adopted a new method for determining useful life directly pertinent to methods of depreciation (straight-line, declining-balance and sum-of-digits) based upon useful life, and indirectly pertinent to other methods such as the unit-of-production method since the shorter useful life generally permitted under the guidelines often permit more rapid amortization than under the unit-of-production method. The 1962 Guidelines replaced Bulletin F useful lives which were based on thousands of individual items with four principal groups (1. Assets used by Business in General; 2. Non-manufacturing Activities; 3. Manufacturing; and 4. Transportation, Communications and Public Utilities) which in turn are divided into approximately seventy-five broad classes of assets each of which has a guideline useful life for the entire class. Generally (with the exception of buildings) useful lives under the guidelines are considerably shorter than those provided for in Bulletin F. However, the Guideline system has built in an objective measure of determining whether depreciable assets are being replaced commensurate with depreciation reserves and failure to satisfy these measures may necessitate an adjustment to a longer useful life. For the taxpayer making an initial investment in a single well the ratios are constructed so that such taxpayer can generally use the guideline life for one replacement cycle without adjustment. Guideline lives may not be employed with respect to used property. Since these matters have been considered at length elsewhere and are not peculiar to mineral operations minimal discussion is included in this article.

Some of the guideline lives pertinent to oil and gas operations are the following:

1. Exploration, drilling and production activities of petroleum and natural gas producers—fourteen years. In-

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cludes gathering pipelines and related storage facilities of such producers but not of pipeline companies.

2. Drilling, geophysical and field services by drillers and service outfits working under contract or on a fee or other basis—six years. Does not include petroleum and natural gas producers performing such services for their own account. Includes oil and gas field services, such as chemically treating, plugging and abandoning wells and cementing or perforating well casings.

3. Petroleum refining including the distillation, fractionation, and catalytic cracking of crude petroleum into gasoline and its other components—sixteen years.

4. Marketing of petroleum and petroleum products including related storage facilities and complete service stations—sixteen years. Excludes natural gas distribution facilities.

5. Petrochemical processing equipment and special purpose structures—eleven years.

6. Pipelines including trunk pipelines and related storage facilities of integrated petroleum and natural gas producers—twenty-two years.

The guideline life for mining, (which excludes extracting and refining of petroleum and natural gas) milling, beneficiation and other primary preparation is ten years. Included as mining are sand, gravel, stone and clay extraction. Excluded are the smelting and refining of minerals, the manufacture of cement, stone and clay products. The guideline life for the smelting, reducing, refining and alloying is eighteen years as to ferrous metals and fourteen years as to nonferrous metals. The guideline life for the manufacture of cement is twenty years and for the manufacture of stone and clay products other than cement is fifteen years.

Use of the guidelines is optional and does not preclude the use of longer lives or if justified by taxpayer's replacement policies shorter lives can be utilized. Change to the guidelines is not a change in accounting method requiring the Commissioner's approval, but change from unit-of-pro-
duction method to the straight-line method is such a change requiring approval.215 However, taxpayers may employ one method for determining useful life as to certain assets216 and another method as to other assets and hence could, e.g., use without approval straight-line as to equipment on a newly drilled well even though he previously used (and continues to use) the unit-of-production method as to other assets.

(4) Determining the Appropriate Account for Depreciation

The individual depreciable items utilized in carrying on mineral operations can be capitalized separately and depreciation recovered with respect to each individual item. Very often, however, with respect to mineral properties, taxpayers use a group, classified or composite account in computing depreciation. Under these methods, the cost of all depreciable items classified by use are included in a composite account.217 Inasmuch as depletion must be computed separately for each "property" and inasmuch as the computation of statutory depletion necessitates a determination of the depreciation charges relating to each property, it may be convenient to regard the depreciable equipment on each separate property as one composite account for depreciation purposes. Taxpayers using composite accounts cutting across separate mineral properties must make an appropriate allocation of depreciation to the separate mineral properties for determining the fifty per cent of taxable income limitation on the statutory depletion deduction.218 If the unit-of-production method of computing depreciation is used, grouping by individual properties ordinarily must be employed since this method necessitates a determination of the estimated reserves and generally the estimated reserves can be more appropriately determined on a property-wide basis. Assets having an estimated useful life of less than three years cannot be included in a group, classified or composite account if any

216. Treas. Reg. §§ 1.167(a)-7(c), 1.167(c)-1(c) (1956).
method of depreciation other than the straight-line method is used.\textsuperscript{219}

If the taxpayer uses a group or composite basis, he can take a loss with respect to the unrecovered basis relating to an individual item upon normal retirement of the item only if he based the rate of depreciation on the expected life of the longest lived asset included in the account. Otherwise, the taxpayer takes no deduction as a loss for the unrecovered basis of an individual item because the use of an average rate contemplates a normal retirement of assets both before and after the average life has been reached and there is, therefore, no possibility of ascertaining any loss until all the assets contained in the group have been retired.\textsuperscript{220} If, however, the item in question was not retired normally, but was discarded prematurely because of an unforeseen cause, or, if irrevocably physically abandoned, a loss deduction can be taken with respect to the unrecovered basis of the item.\textsuperscript{221}

\textit{EXAMPLE}: The cost basis of the depreciable items in composite account is $300,000. The tubing is prematurely discarded because of a peculiar characteristic of the oil resulting in an abnormal and unforeseen deterioration of the tubing. The taxpayer can take an ordinary loss with respect to the tubing prematurely discarded and, in computing this loss, uses the life expectancy of the individual item (tubing) rather than the average life expectancy of the composite items. Assume the average life expectancy of the group of items to be twenty years, that the tubing cost $50,000, has a life expectancy of ten years and is discarded after five years. The taxpayer at the time the tubing is discarded has recovered $25,000 in depreciation attributable to the tubing and has an unrecovered basis of $25,000 in the tubing which he can deduct as a loss in the year in which the tubing is prematurely discarded.

To the extent a guideline life is used in connection with composite accounts this would appear to be an average life. However, a guideline life cannot be used with respect to an

\textsuperscript{219} Treas. Reg. \textsection 1.167(e)-1(a)(3) (1956).
\textsuperscript{220} Treas. Reg. \textsection 1.167(a)-8(3)(iii) (1956).
\textsuperscript{221} Treas. Reg. \textsection 1.167(a)-8(3), (4) (1956).
open-ended composite account depreciated on a straight-line or sum-of-the-digits basis although it may be used as to a composite account which includes only acquisitions made during the same year or with respect to composite accounts if the declining-balance method of depreciation is employed.\footnote{222} Accordingly, oil and gas operators could still use in any event composite accounts as to all wells drilled during the same year and if they employ the declining-balance method open-ended composite accounts could be used. In any event composite accounts can be used as before if an average life not based upon the guidelines is employed.

(5) The Investment Credit

The 1962 Revenue Act introduced a new concept into the tax laws relating to depreciable assets, that of the investment credit.\footnote{223} The investment credit is a credit against the tax otherwise payable and hence directly deductible therefrom as distinguished from a tax deduction which merely reduces the net taxable income upon which the tax is computed. The investment credit relates to newly acquired tangible depreciable property (other than a building and its structural components) which is acquired after 1961 and has a minimum life of at least four years.\footnote{224} In the case of used property, the total cost upon which the credit is based is limited to $50,000 per year. If the property has a useful life of less than eight years only part of the cost is included in determining the credit; one-third for a four to five year useful life and two-thirds for a six to seven year useful life.\footnote{225} The investment credit is seven per cent of the qualified investment determined in accordance with the foregoing; the credit is computed annually on each year's qualifying additions.\footnote{226}

The maximum credit that can be taken in one year is limited to the first $25,000 of tax liability plus twenty-five per cent of the tax liability in excess of $25,000.\footnote{227} The unused credit can be carried back three years (but only as to years

\footnote{223}{Int. Rev. Code of 1954, §§ 38, 46-48.}
\footnote{224}{Int. Rev. Code of 1954, § 48.}
\footnote{225}{Int. Rev. Code of 1954, § 46(c).}
\footnote{226}{Int. Rev. Code of 1954, § 46(a)(1).}
\footnote{227}{Int. Rev. Code of 1954, § 46(a)(2).}
subsequent to 1961) and can be carried forward for five years. To the extent, after such carrying back and forward, there remains an unused credit, it is allowed as a deduction (as distinguished from a credit) in the first subsequent tax year.\textsuperscript{228} The tax basis of the qualified property is not reduced by the credit.\textsuperscript{229} If the property is disposed of prior to the end of the useful life appropriate for determining the credit, the tax is increased in the year of disposition by the difference between the credit actually taken and the credit allowed, computed on the basis of the number of years the property is actually held.\textsuperscript{230}

Although not entirely clear, since the investment credit is a credit against taxes rather than a deduction, it does not appear to be necessary to take the investment credit into consideration in determining net income from the property for purposes of the fifty per cent of the net income limitation on the statutory depletion deduction.\textsuperscript{231} However, since the credit does not reduce the taxpayer's basis in the property, the investment credit will not affect the amount of depreciation to be charged against income from the property in determining the fifty per cent of net income limitation.\textsuperscript{232}

(6) Gain From Disposition of Certain Depreciable Property

Prior to the 1962 Revenue Act it was possible to substantially, if not completely, depreciate a depreciable asset by writing off the depreciation deduction against ordinary income and then to sell the asset at its reduced (or zero) basis and realize capital gains on the sale of the asset. The 1962 Revenue Act limits the possibilities in this regard with respect to so-called Section 1245 assets. Section 1245 assets include depreciable personal property (tangible or intangible) and most other depreciable tangible property but not buildings or their structural components. Under the 1962 Revenue Act with respect to dispositions made during tax-

\textsuperscript{228} INT. REV. CODE OF 1954, § 46(b), 181.
\textsuperscript{230} INT. REV. CODE OF 1954, § 47(a)(1).
\textsuperscript{231} Treas. Reg. § 1.613-4 (1960).
\textsuperscript{232} Treas. Reg. § 1.613-4 (1960).
able years beginning after December 31, 1962, gains realized on the sale or disposition of Section 1245 assets will be taxed as ordinary income to the extent of the depreciation or amortization taken subsequent to December 31, 1961.\textsuperscript{33} One impact of these recapture rules is to discourage the use of accelerated depreciation methods if it is likely that the Section 1245 depreciable property will be disposed of. Gifts or "transfers upon death" are not dispositions for this purpose and in normally tax-free transactions gain is recognized to the transferor under Section 1245 only to the extent it would otherwise be recognized.\textsuperscript{34} The Code now expressly provides that to the extent gain is realized upon a disposition under Section 1245, the cost of "mining" for purposes of the fifty per cent net income limitation on statutory depletion is reduced by the amount of the gain thereby increasing the net income from the particular property.\textsuperscript{35} Although it would appear more logical to go back and recompute for each year in which depreciation was taken into consideration, apparently the adjustment is to be made entirely in the year of disposition. Since the reference in this context is to the expenses of "mining" it is not entirely clear as to whether such adjustment is appropriate with respect to oil and gas operations; however, there appears to be no logical reason to distinguish for this purpose between oil and gas and other minerals.

DEDUCTION FOR LOSSES, WORTHLESSNESS AND ABANDONMENT

(1) In General

Losses may be of different types—(1) they may result from carrying on a business at a loss or (2) they may result from a specific event such as the fact that a particular property has become worthless and has been abandoned. The former type of loss, a net operating loss, results from an excess of allowable deductions over gross income and is computed with respect to a taxpayer’s entire operations and not with respect to any particular property. A taxpayer incurring a net operating loss can carry back such loss for three

\textsuperscript{33} INT. REV. CODE OF 1954, § 1245(a).

\textsuperscript{34} INT. REV. CODE OF 1954, § 1245(b).

\textsuperscript{35} INT. REV. CODE OF 1954, § 613(a).
years and can carry forward any remaining loss for five successive years.\textsuperscript{236}

\textit{—OBSERVATION—} The Tax Court has held that an investor in an oil and gas venture was not engaged in a business and could not carry back a loss sustained in the venture.\textsuperscript{237} His interest was very small and was coupled with the acquisition of royalties. However, the decision does emphasize the fact that the net operating loss must be attributable to a business regularly carried on by the taxpayer. Use of a partnership arrangement might alleviate this situation.

Under the 1939 Code in computing the net operating loss it had to be adjusted by reducing it by the amount statutory depletion exceeded cost depletion in the year in which the loss was incurred. Further, in carrying the loss back or forward it had to be adjusted in every year by the amount that the taxpayer's statutory depletion exceeded cost depletion for that particular year. Inasmuch as statutory depletion ordinarily exceeded cost depletion, these adjustments had the effect of depriving the taxpayer of tax benefits from the operating loss to the extent that statutory depletion exceeded cost depletion for the years involved. It was, therefore, ordinarily advisable for a taxpayer engaged in mineral operations to avoid, if possible, incurring a net operating loss. Under the 1954 Code, however, the above maneuvering is no longer necessary. Effective for tax years ending after 1953, a net operating loss is not required to be reduced by the excess of percentage over cost depletion. Nor is the reduction required in any other year to which the loss is carried or for any intervening year.

Section 270 of the Internal Revenue Code limits the losses that can be taken as a deduction by providing that, if in each of five consecutive years the deductions (other than for taxes and interest and specially treated deductions, as noted below) allowable to an individual and attributable to a particular trade or business exceed the gross income from the particular trade or business by more than $50,000, the tax for each of the five years shall be recomputed with such ex-

\textsuperscript{236} \textit{Int. Rev. Code of 1954, § 172.}
\textsuperscript{237} Irving Rothbart, 26 T.C. 880 (1956).
cess eliminated. Further, in making the recomputation, taxpayer's net operating loss for each such year must be eliminated entirely to the extent that it is attributable to such trade or business. Thus, any carry-over or carry-back of a net operating loss, so attributable, either from a year within the period of five consecutive taxable years or from a year outside of such period, is ignored in making the recomputation of net income. The 1954 Code, to a large extent, eliminates mineral operations from this so-called "hobby loss" provision. It achieves this result by excluding from the calculation of the $50,000 loss ceiling deductions for losses resulting from worthlessness or abandonment if incurred in a trade or business, all deductions for intangible drilling and development expenses and the deduction for exploration and development expenditures in the case of other minerals.238 Ordinarily, losses incurred in connection with the operation of mineral properties will result primarily from one or more of these deductions.

(2) Losses for Worthlessness—Criteria

A taxpayer may take as a deduction from gross income any loss, other than those resulting from the sale or exchange of capital assets, sustained during the taxable year and not compensated by insurance or otherwise, if incurred in a trade or business or if incurred in any transaction entered into for profit although not connected with a trade or business.239 Such losses since they can be offset against ordinary income have a distinct advantage over a long-term capital loss which must first be set off against long-term capital gains and which cannot be offset at all by a corporation against ordinary income and can only be set off by an individual to a limited extent against ordinary income.240 In order to establish the loss, it must be bona fide and "evidenced by closed and completed transactions, fixed by identifiable events, actually sustained during the taxable period for which allowed."241 The fact that an asset has lost all of its value and has become

238. INT. REV. CODE OF 1954, § 270.
239. INT. REV. CODE OF 1954, § 165(c).
240. See discussion under caption Disposition of Mineral Properties in Part II of this Article to appear in the next issue.
worthless is a closed and completed transaction for this purpose.242

—OBSERVATION—In order to deduct a loss because of worthlessness, it is not necessary for the taxpayer to be engaged in the oil and gas or other mineral business; it is sufficient if the taxpayer has entered into the transaction for profit. Accordingly, the taxpayer who purchases a fractional undivided interest in a mineral property as an investment can take a loss deduction if such interest loses all of its value.

In order to take a loss deduction for worthlessness the property must have no value and should not be sold in the taxable year in which the deduction is claimed. The sale of property for $250 in one instance243 and the fact that the property concededly had some value, but less than $500,244 have been regarded as sufficient to establish that the properties in question were not worthless. Despite the foregoing decisions and the apparent inconsistency of its position, the Revenue Service has successfully argued, in a context in which the Service wanted to establish worthlessness, that the sale of royalties for prices varying from one dollar to twenty-eight dollars tended to establish that the properties were worthless.245

The Revenue Service at one time insisted, in the case of oil and gas interests, that no loss deduction could be taken for worthlessness unless the taxpayer had relinquished all interest therein.246 In the case of the owner of the fee mineral rights, this frequently precluded a loss deduction for worthlessness as such interests in many states cannot be abandoned. However, the Revenue Service subsequently retreated from this position to the view that no such loss deduction can be taken "until it has been demonstrated or proved that all reasonable possibilities of obtaining oil or gas production have been exhausted in the known-producing horizons and all sedi-

243. Aberle v. Commissioner, 121 F.2d 726 (3d Cir. 1941).
244. United States v. Sentinel Oil Co., 109 F.2d 854 (9th Cir. 1940), cert. denied 310 U.S. 646.
245. James Petroleum Corp. v. Commissioner, 238 F.2d 678 (2d Cir. 1956).
mentary beds below even though untested which can be reached under present-day standards of drilling." \(^{247}\) This view was rejected by the Tax Court in the Harmon\(^ {248}\) and Heller\(^ {249}\) cases, the Court stating in the latter that a deduction for worthlessness can be taken "upon proof that dry holes were drilled on or in the immediate vicinity of such royalties during the taxable years, demonstrating the improbability of an oil and gas production in commercial quantities, and that the royalties had thereby lost their sale value in the ordinary channels of trade."

—OBSERVATION—The criteria is loss of sales value in the ordinary channels of trade. As the Court stated in the Harmon case: "We do not think, however, that this mere 'possibility' of future production is in itself sufficient to give value to oil royalties which have been condemned as worthless by those engaged in the trade and familiar with the development in those particular areas." \(^{250}\) In view of the lack of an organized market, and inasmuch as the sales value in the ordinary channels of trade is usually dependent on geological and engineering factors, it is not surprising that most cases involving this question frequently resolve into a battle of opposing geologists.\(^ {251}\)

The criterion of Harmon and Heller is a market criterion—loss of sale value. Yet many cases—particularly cases involving leasehold interests—both before and after the Harmon decision, have emphasized factors other than market factors. The Court of Claims, in holding that a royalty was worthless, has regarded as of particular significance the fact that the lessee surrendered the lease after having paid substantial rentals over a period of years thus evidencing the opinion of an informed oil operator that the acreage had lost all of its value.\(^ {252}\) With respect to leasehold interests the fact that the taxpayer continued to pay delay rentals,\(^ {253}\) drilled a well\(^ {254}\) continued to produce a well capable of producing only

249. Harvey A. Heller, supra note 247, at 224.
250. C. C. Harmon, supra note 242, at 58.
two barrels a day in order to hold the lease255 or otherwise spent monies256 to retain his interest have been regarded as sufficient to indicate continuing value. In all of these instances the Courts appear to be considering something akin to intrinsic value rather than value in the market place.

The decisions regarding the payment of delay rentals as evidence of value may, if consistently followed, require, in effect, the relinquishment of a leasehold interest in order to take a loss deduction. Oil and gas leases invariably provide for the payment of delay rentals and the typical “unless” lease automatically terminates on the failure to pay such rentals.257 No convincing reason has been advanced to justify with respect to the necessity for relinquishment a distinction between leasehold interests and royalty interests. The fact that the latter in many instances cannot be relinquished does not warrant requiring relinquishment in the case of leasehold interests. It is true, as noted, that in the case of leasehold interests it is more difficult to apply the market criterion of salability. In the absence of such applicable criterion it is reasonable to look at the payment of “delay rentals” as a significant but not conclusive factor in determining value. The practice among oil and gas operators is to review a leasehold’s prospects sometime before the annual rental payment is due and determine whether additional rental payments are warranted. The fact that the oil and gas operator continues to make such payments is frequently but not always an indication of continuing value.

Unpatented mining claims located on the unappropriated public domain give the locator the exclusive right to remove locatable minerals. However, in the event the locator fails to perform the annual assessment work required by statute ($100.00 per claim), at the end of the assessment year, which runs from September 1 through August 31 of the following year, an adverse locator may obtain paramount rights by relocating the claim.258 Most mining states provide by statute

258. See Trelease, Bloomenthal & Geraud, Cases & Materials on Natural Resources 567-96 (1965).
that the filing of an affidavit of performance of the assessment work establishes prima facie that the work has been performed. Failure to perform the assessment work does not terminate the locator’s interest in the claim, but merely makes it subject to relocation by others. Further, if a locator fails to perform assessment work in one assessment year he may protect his claim against relocation in subsequent years by resuming in good faith the performance of assessment work prior to an adverse location. In view of the relatively small expenditures frequently involved in the performance of assessment work, it should not necessarily follow that the performance of such work establishes continuing value. On the other hand, in view of the fact that failure to perform the assessment work does not terminate the locator’s rights in the mining claim, it may be advisable for the locator desiring to take a deduction to file a notice of intention to abandon the claim. During World War II Congress provided for a moratorium on assessment work and it was possible for a locator to retain a claim against an adverse location by filing an appropriate notice of intention to retain the claim. It has been held that a locator filing such notice was precluded from taking a loss deduction; however, the case was argued on the issue of whether or not the property had been abandoned rather than whether it had become worthless and there was evidence of value in view of the fact that the locator continued to carry the property as an asset with substantial value on its books.\(^{259}\)

—OBSERVATION—The significance of the rental payment or expenditure for assessment work should be evaluated in the light of its amount, the amount already invested in the lease and other pertinent considerations. The payment of additional delay rentals or performance of assessment work may be an investment in extremis—a desperate attempt to salvage something from the ruins of a former larger investment. The Tax Court has indicated that under such circumstances a deduction for worthlessness may be permitted

\(^{259}\) Talache Mines v. United States, 218 F.2d 491 (9th Cir. 1954).
in a year prior to that in which the final delay rental payment was made.\textsuperscript{260}

---FURTHER OBSERVATION---The decision\textsuperscript{261} holding that taxpayer could not take a loss deduction because he continued to produce a two barrels a day well in order to hold the lease probably would not be followed today. The taxpayer had unsuccessfully attempted to sell the lease and the well undoubtedly was not commercial. The lack of sale value because of the improbability of obtaining production in commercial quantities is the criterion emphasized in the \textit{Heller} decision.

---SUGGESTION---Relinquishment by the taxpayer in the year in which the identifiable event relied upon to establish worthlessness occurs will ordinarily avoid a dispute as to whether the interest is in fact worthless. Technically, however, if the interest is not worthless at the time it is relinquished, the taxpayer has made a gift and cannot take a loss deduction. The year of the relinquishment and the year of the identifiable event should coincide if practicable; otherwise, the Revenue Service may contend that the interest actually became worthless in a year prior to relinquishment.\textsuperscript{262}

The identifiable event usually relied upon to establish worthlessness with respect to oil and gas is the drilling of one or more dry holes on the property in question or on adjacent properties.\textsuperscript{263} Comparable events with respect to other mineral properties would include unsuccessful exploratory drilling or other unfavorable geological or geophysical information. Worthlessness has been established by proof that the land in question was structurally below the water line of the adjacent field.\textsuperscript{264} The foregoing factors continue to be important ones despite the rejection by the Tax Court of the Revenue Service's view that all potential oil or gas bearing horizons within reach of the drill had to be tested. The rejected view represented a geological approach which remains to a certain extent the approach of the Service despite

\textsuperscript{260}L. M. Fischer, \textit{supra} note 254.
\textsuperscript{261}Macon Oil \& Gas Co., \textit{supra} note 255.
\textsuperscript{262}See James Petroleum Corp., \textit{supra} note 256.
\textsuperscript{263}C. C. Harmon, \textit{supra} note 242.
\textsuperscript{264}Chaparral Oil Co., 43 B.T.A. 457 (1941), \textit{acq.} 1941-2 \textit{CUM: BULL.} 16.
the decisions in the *Heller* and *Harmon* cases. The difference is largely one of degree and the fact that in the *Heller* and *Harmon* cases the Tax Court attempted to use the market place to evaluate the impact of geological developments on value.

The Revenue Service has used the criteria of the *Harmon* and *Heller* cases to deny deductions for worthlessness on the grounds that the interest became worthless prior to the taxable year in which the deduction was taken. The Tax Court has agreed with the Service that the loss must be taken in the year of worthlessness even though the taxpayer did not become aware of the geological facts (drilling of dry hole) which condemned the property until a subsequent year. In some instances, at least, this results in a taxpayer losing worthlessness deductions because the taxpayer did not claim the loss for the year in which the Revenue Service now contends the deduction should have been taken. The expiration of the period for filing amended returns may prevent the taxpayer from taking the deduction.

(3) Subsequent Sale of or Income From a "Worthless" Property

The fact that the property in question must be worthless in order to warrant the loss deduction, does not mean that the taxpayer cannot sell the property or otherwise receive income from the property in some subsequent year without destroying the previous deduction. The subsequent sale of or recovery of income from the property does not invalidate the deduction, if when taken it was based on the exercise of a reasonable judgment from the facts then known. However, the sale of the property for a substantial sum within a relatively short period of time from the taxable year in which the deduction was taken, undoubtedly would be some evidence of the fact that the property was not worthless in the year in which the deduction was taken.

If the taxpayer having taken and established a loss for

265. *James Petroleum Corp.*, supra note 256.
268. See *e.g.*, *L. M. Fischer*, supra note 254.
worthlessness recovers part of the loss in subsequent years, it becomes a part of his gross income in the year of receipt.\(^{269}\) Although the Board of Tax Appeals has held that a taxpayer is not precluded from subsequently taking a deduction for statutory depletion with respect to the proceeds from an oil and gas interest previously written off as a loss,\(^{270}\) Form 927 requires completion by the taxpayer of what purports to be a contractual obligation to refrain from taking statutory depletion with respect to subsequent production and/or bonuses to the extent of the loss deducted for worthlessness. The same undertaking requires the taxpayer in the event of a subsequent sale or exchange of the property to treat the gain to the extent of the loss deduction previously taken as ordinary income rather than a capital gain. The recited consideration for the contractual undertaking is the allowance by the Revenue Service of the loss deduction. Query: Is the allowance of a legal right consideration? In the event the Revenue Service does not allow the deduction, but the Court does, is the taxpayer bound by the undertaking?

—**OBSERVATION**—Income received in subsequent years from a property previously written off as worthless has to be included in gross income only to the extent the prior loss deduction resulted in a tax benefit.\(^{271}\)

(4) Partial Worthlessness

The law generally makes no provisions for partial losses (other than by sale) resulting from a reduction in value of an oil and gas or other property interest. The interest in question must become completely worthless and even slight value ordinarily precludes the taking of a loss for worthlessness. Inasmuch as the basis in the oil and gas interest as such must be recovered through the depletion allowance and depletion is computed separately for each property, no deduction for worthlessness can be taken until the entire

\(^{269}\) *Burnet v. Sanford & Brooks Co.*, 282 U.S. 359 (1931). The taxpayer regards the recovery of losses taken in prior tax years as income only to the extent that the previous loss deductions resulted in a tax benefit. *Int. Rev. Code of 1954*, § 111.


property is established to be worthless. In the event a dry hole is drilled on "the property" which does not condemn the entire property, no deduction can at that time be taken for worthlessness.272

Although an oil and gas operator may occasionally purchase both the surface and mineral rights, oil and gas operators and investors usually acquire oil and gas interests completely severed from the surface ownership. However, it is not unusual for the royalty owner to own both the surface rights and the royalty interest created by the oil and gas lease, and mining operators sometimes own both the surface and mineral rights. There is some authority to the effect that the taxpayer who owns both the surface and mineral rights must establish not only that the mineral rights are worthless, but that the surface rights as well have no value.273 This has been held notwithstanding the fact that the property was acquired primarily for its oil and gas potential.274 However, a decision of the Court of Claims has allowed a taxpayer who had a separate basis in the minerals to take a deduction for worthlessness on establishing that his mineral interest had no value despite the fact that the surface continued to have value. The Court stated in this regard that "when . . . the mineral interest in the land had been transferred by lease, reserving a royalty to the owner, we think that the custom in oil-producing areas is to regard the mineral interest as a separate thing from the rest of the ownership of the land."275 Frequently, however, the landowner will have no separate basis in the mineral interest.

A taxpayer can deduct as an ordinary (as distinguished from capital) loss assets discarded permanently from use in the taxpayer's business when because of some unforeseen change in business conditions the usefulness of the asset is suddenly terminated. In order to take this loss, the taxpayer may not have to establish that the property is worthless as even very substantial salvage value may not preclude the taking

272. Frank Lyons, 10 T.C. 634 (1948).
274. Coalinga-Mohawk Oil Co. v. Commissioner, 64 F.2d 262 (9th Cir. 1933).
275. "Rude, W. L. & L. Corp. v. Commissioner" 119 F.2d 293 (5th Cir. 1941).
of this deduction. The few litigated cases have rejected attempts to use this provision as the basis for a loss deduction in situations in which an oil and gas property has declined in value as the result of unsuccessful drilling, but had not become worthless. The Courts have reasoned in this situation that the discarding of the asset did not result from an unforeseen cause.

(5) Allocation of Geological and Geophysical Expenditures' Impact on Loss Deductions

Geological expenditures "necessary in preparation for the drilling of wells" are within the option relating to intangible drilling and development cost. However, geological and geophysical expenditures incurred for the purpose of obtaining and accumulating data which will serve as a basis for the acquisition or retention of a mineral property must be capitalized as part of the cost of such property recoverable through cost depletion. Seismic surveys are a common method of geophysical exploration for oil and gas that fall within the latter category. I.T. 4006 not only requires that such costs be capitalized but further requires their allocation in a manner which defers (and in some instances negates) their deduction as a loss. The I.T. assumes that such geological and/or geophysical expenditures fall into two categories—reconnaissance exploration and intensive exploration. Further, it assumes that such exploration programs are carried out in the form of projects—a single integrated operation—and each project is treated separately for allocation purposes. If a reconnaissance project results in acquiring or retaining any property, all of the expenditures must be allocated to the properties acquired or retained. If more than one area of interest (separable non-contiguous portions of the project area) is acquired or retained such expenditures are allocated equally among such areas of interest. In the

276. S. S. White Dental Mfg. Co. v. United States, 55 F.Supp. 117 (Ct. Cl. 1944). But see discussion at note 296 infra suggesting that the White case may not be followed under the revised regulations.
277. Louisiana Land & Exploration Co. v. Commissioner, supra note 273; Coal- inga-Mohawk Oil Co. v. Commissioner, supra note 274.
279. Louisiana Land & Exploration Co., 7 T.C. 507 (1943), aff'd on other issues, 161 F.2d 842 (5th Cir. 1947); See also p. 114 supra.
event of the more intensive type of exploration, all such expenditures are allocated (on the basis of acreage) to the properties retained or acquired. Only in the event the reconnaissance survey or the intensive exploration, as the case may be, do not result in the retention or acquisition of any property can the expenditures be written off as a loss. Otherwise no part thereof can be allocated to the properties not retained or not acquired as a result of such work. Of course, as the properties to which the costs are allocated subsequently become worthless the amount capitalized can then be written off.

—OBSERVATION—Although I.T. 4006 is expressly applicable to oil and gas presumably the same rationale would be applicable to capitalized exploration and development expenditures relating to other mineral properties. Accordingly, in exercising the various elections it might particularly in the case of exploration expenditures be advisable for taxpayer to elect to capitalize those expenditures which can be allocated to an area that is likely to be abandoned in its entirety.

—SUGGESTION—Keep project areas as small as is reasonable. In such event the possibility that no property will be acquired or retained is increased. Projects can probably be separated both in terms of geography and time. If any property is retained or acquired, it may be advisable to also retain or acquire other properties with some but less potential in the expectation that subsequent events may establish that some of the properties to which a portion of such expenditures have been allocated are worthless.

—FURTHER SUGGESTION—The stout of heart may want to challenge I.T. 4006 which has not been litigated to any extent. To the extent that separate mineral properties are involved\(^\text{281}\) it appears unreasonable not to allocate to each a part of the expenditures which are the basis for the decision to not acquire or retain, as the case may be, the property.

(6) Correlation of Depletion, Depreciation and Deduction for Intangibles With Deduction of Losses Because of Worthlessness

In order for a taxpayer to incur a loss because of worth-

\(^{281}\) See p. 171 infra.
lessness, the property involved must have a basis. With respect to mineral properties taxpayers are ordinarily concerned with two types of bases—the basis in the mineral interest as such which is ordinarily recoverable through depletion, and the basis in the tangible physical equipment which ordinarily is recoverable through depreciation.

A taxpayer's basis in the mineral interest as such will ordinarily have two principal components: (1) The acquisition costs of the interest—consisting generally of the consideration ("bonus") paid for such interest and in the case of oil and gas the geophysical and geological expenditures allocated to its acquisition or retention; (2) Intangible drilling costs in the case of oil and gas and exploration and development expenditures in the case of other minerals to the extent they have been capitalized. In the event the taxpayer can and does elect to deduct intangibles, exploration and development expenses, such expenses are, of course, not part of the basis in the mineral interest.

—OBSERVATION—Taxpayers ordinarily elect to deduct intangibles as expenses. As already noted no loss for worthlessness can be taken until the entire property becomes worthless and a single dry hole does not necessarily establish that the property is worthless. Accordingly, even in the case of a dry hole it is advantageous to deduct intangibles currently rather than to capitalize them in the expectation that they can be written off when the property is established to be worthless. A taxpayer who has elected to capitalize intangibles has a separate election with respect to intangibles incurred in drilling dry holes; for the reason noted this election should usually be made in favor of expensing such expenditures. However, with respect to exploration expenditures relating to minerals other than oil and gas, since the election is not binding with respect to other properties or as to subsequent years and in view of the limitations on the overall amount of such deductions,282 taxpayer should conserve the deduction by capitalizing such expenditures as to properties (and areas) likely to be abandoned.

282. See p. 115 supra.
The taxpayer's basis in the mineral interest is recoverable through cost depletion in the event of production or, in the event of sale, is recovered as a deduction from the selling price in determining the gain on the transaction or as a capital or Section 1231 loss, as the case may be, if the transaction results in a loss. If, however, the interest is never productive and is not sold, tax benefits can be realized only to the extent that a loss can be taken because of worthlessness. The taxpayer's basis in physical equipment is recoverable through the allowance for depreciation and as a reduction of gain (or as a capital or Section 1231 loss) in the event of sale. In the event a lease is non-productive, there ordinarily will be no basis recoverable through the depreciation allowance.

The taxpayer's basis in the mineral interest and in the physical equipment must be adjusted by the greater of allowed or allowable depletion in one instance and depreciation in the other. In the case of productive properties the taxpayer ordinarily must recover such bases through the depletion and depreciation allowances respectively. A taxpayer, for example, could not refrain from taking depreciation annually in the expectation that he could recover the basis in the year the property is abandoned as a loss deduction. If the taxpayer accurately estimates the reserves and the useful life of the resource (and/or the equipment), the depletion and depreciation allowance will result in the recovery of the complete bases. The extent to which the taxpayer can deduct as a loss unrecovered bases in the mineral interest and the equipment at the time the property in question ceases to produce is discussed below.

(7) Loss Deduction of Undepleted Costs

Depletion must be computed for each separate property and on a property-wide basis. No determination can be made as to whether the entire basis in the mineral interest will be recovered through the depletion allowance until production ceases from all portions of the property. Accordingly, the Tax Court has consistently held that no loss deduction can be taken upon the abandonment of a single well if there

283. Kehota Mining Co. v. Lewellyn, 30 F.2d 817 (3d Cir. 1929).
is production on other parts of the same property. The negative inference of these decisions is that undepleted costs remaining at the time production ceases on all of the wells can be taken as a loss deduction.

There will, of course, be no undepleted costs upon abandonment of the entire property if reserves have been estimated properly. It is believed that in the event the taxpayer follows proper procedures in estimating and revising the estimate of recoverable reserves that the problem of undepleted basis can be avoided. The Regulations provide that reserves are to be estimated on the basis of the most accurate and reliable information obtainable. In the event such estimates prove to be in error, neither the taxpayer nor the Commissioner can go back and revise them provided they were based on the most accurate and reliable information available at the time the estimates were made. If they were not based on such information, the Commissioner can (to the extent permitted by the Statute of Limitations) require an adjustment for the year in which an inadequate estimate was made. The taxpayer on the other hand can never go back and correct such estimates on the basis of more accurate or more adequate information. Either party can, however, provided he does so timely, revise the estimate of remaining reserves in either direction provided the most accurate and reliable information indicates the appropriateness of such revision. Accordingly, a taxpayer by reviewing the estimate annually can in the event the original estimate was too high reduce the estimate of remaining recoverable reserve in the first year in which the error becomes apparent and by continuing to do so over the life of the property will recover the entire basis in the property through the depletion allowance. In the event production suddenly and unexpectedly ceases, a loss deduction because of premature abandonment can probably be taken. The considerations in this regard are comparable to those discussed in detail in the next section.

284. Frank Lyons, supra note 272.
in connection with the deduction of a loss for undepreciated costs.

—WARNING—The revising of estimated reserves must be made in the year in which the information indicating the appropriateness of such revision is obtained. The taxpayer is undoubtedly precluded from making the revision in the year of abandonment if available information indicated it should have been made in a prior year.288

—OBSERVATION—The theory adopted to justify the deduction can be of considerable importance. If the basis for the deduction is a revision of the estimated reserves, there is no necessity to establish that the property has no value. If, on the other hand, the taxpayer relies on the loss deduction for worthlessness, he would have to establish that the property has no market value. In some instances a property could continue to have speculative value despite the fact that production has ceased. In those situations in which the taxpayer relies on premature abandonment to justify the loss deduction, he must abandon the property completely and permanently. However, for this purpose it may be possible to contend that each prospective horizon or oil sand is a separate property.289

—FURTHER OBSERVATION—The discussion in this section assumes that cost depletion exceeds statutory depletion. In those frequent instances in which statutory depletion exceeds cost depletion, the entire basis in the oil and gas interest will be recovered before production is exhausted.

(8) Loss Deduction of Undepreciated Costs

Ordinarily a taxpayer recovers his investment in tangible physical equipment through the depreciation deduction. However, recovery of the the entire investment through the depreciation allowance presupposes that a taxpayer is always in a position to accurately determine the life expectancy of the equipment. An accurate determination of such life expectancy is undoubtedly the exception rather than the rule. If the taxpayer under-estimates the life expectancy, the error will result in a more rapid amortization except to the extent

288. See James Petroleum Corp. v. Commissioner, 238 F.2d 678 (2d Cir. 1956).
the Revenue Service uses hindsight to impose deficiencies. If, on the other hand, the taxpayer over-estimates the life expectancy and the particular asset has a lesser life expectancy than the estimated one, the extent to which and when the taxpayer will be able to completely amortize his investment is dependent upon the account and useful life employed.290

Taxpayers using an individual item classification can deduct as a loss the unrecovered basis upon normal retirement.291 Taxpayers using composite or group accounts cannot deduct as a loss unrecovered basis upon the normal retirement of a component item unless the life expectancy used for the composite account was based on the longest lived item in the group.292 In the event taxpayer irrevocably physically abandons with no intention of ever using or selling an item in the group, he can deduct any unrecovered basis as a loss293 provided the retirement is an abnormal one. An abnormal retirement is one caused by factors not readily taken into consideration in determining the depreciation rate.294 In the event the prematurely abandoned item is sold the regulations regard any resulting loss as a capital loss.295 There is some authority which has been questioned by recent cases to the effect that an ordinary loss may be taken despite a sale if the transaction is motivated by factors giving rise to an abnormal abandonment rather than the desire to dispose of the item.296

For impact of guideline lives on too rapid amortization and on utilization of various depreciation methods, see supra, p. 146.

(9) Section 1231 Losses as an Alternative

If no loss can be taken under any of the foregoing theories with respect to mineral interests or equipment, the

290. See p. 149 supra.
291. Treas. Reg. §§ 1.167(a)-8(a) (3) (ii), 1.167(a)-8(d) (1956).
292. Treas. Reg. § 1.167(a)-8(a) (3) (iii) (1956).
293. Treas. Reg. § 1.167(a)-8(a) (3), (4) (1956).
295. Treas. Reg. § 1.167(a)-8(a) (1), (4) (1956).
296. S. S. White Dental Manufacturing Co. v. United States, supra note 276. However, the regulations upon which this decision was based have since been changed in some material respects. See United California Bank, 41 T.C. 437 (1964), relying on the changed regulations to reach a contra result.
taxpayer may be able to obtain substantially similar deductions by selling at a loss the mineral interest and/or the well equipment, if qualified as a Section 1231 asset. Mineral interests can be capital assets, stock in trade, or property used in the taxpayer's trade or business. If they are capital assets, any sale results in capital gain or loss.\textsuperscript{297} If they are real property used in the taxpayer's trade or business, they are Section 1231 assets. Sales of such assets, held for six months or less, result in ordinary gain or loss. If such assets are held for more than six months, gains and losses on sales are first set off against each other; a net gain is treated as a capital gain and a net loss as an ordinary loss.\textsuperscript{298} If properties are acquired primarily for investment, they are ordinarily capital assets; if acquired primarily for resale purposes, they are stock in trade; if acquired primarily for development, they are ordinarily Section 1231 assets. It is readily apparent that a difficult factual question is involved in determining the proper classification of assets sold or exchanged.

A company or individual developing mineral properties ordinarily acquires real property used in a trade or business (and hence Section 1231 assets) when purchasing a lease or minerals for development purposes.\textsuperscript{299} The acquisition of a royalty interest on the other hand ordinarily involves a capital asset rather than a Section 1231 asset inasmuch as such interests ordinarily are merely held for investment purposes and require no personal services or management duties.\textsuperscript{300}

—\textit{OBSERVATION}—It is at least arguable that reserved royalties or overriding royalties, since they are a form of rent, indicate a business of owning and renting properties and therefore are property used in a trade or business.

Whether a fractional interest in a leasehold operated pursuant to an operating agreement constitutes a Section 1231 asset may depend in large part on the extent to which the operating agreement provides for the participation of the interest holder in management of operations and the extent

\textsuperscript{297} INT. REV. CODE OF 1954, §§ 1201, 1202, 1211, 1212.
\textsuperscript{298} INT. REV. CODE OF 1954, § 1231.
\textsuperscript{299} Vern W. Bailey, 21 T.C. 678 (1954), acq. 1954-2 CUM. BULL. 3.
\textsuperscript{300} George S. Engle, 23 P-H TAX CT. MEM. 516 (1954).
to which the interest holder is otherwise engaged in the oil and gas business. However, it seems difficult to deny that anyone so sharing in a joint venture, the object of which is the production of minerals, is engaged in the mineral business.

In the event the mineral interest qualified as a Section 1231 asset, the taxpayer can, to the extent he has no Section 1231 gains against which to offset Section 1231 losses, in many instances avoid any controversy over worthlessness by selling the asset and taking a loss deduction in accordance with the provisions of Section 1231. However, the taxpayer will be unable to use a sale at nominal amounts as a means of taking a loss on a property that became worthless in a prior taxable year.

**Separate Mineral Properties**

(1) Criteria

It is important for a number of tax purposes to determine what constitutes a separate mineral property. As previously noted, the fifty per cent of taxable income limitation on statutory depletion must be determined with respect to each separate mineral property. The taxpayer cannot deduct as a loss his basis in a worthless oil and gas property unless the entire property has become worthless. The recipient of a "bonus" must restore to income any depletion taken with respect to such "bonus" in the year in which the lessee abandons the property without production. Determination of gain or loss on the sale of an oil and gas interest necessitates a determination of what constitutes a separate property.

The 1954 Code defines a "property" for the purpose of computing the depletion allowance in the case of mines, wells and other natural deposits to mean "each separate interest owned by the taxpayer in each mineral deposit in each separate tract or parcel of land." For the purposes of this definition tracts are separated by conveyancing as well as

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301. But see discussion under caption Disposition of Mineral Properties in Part II of this Article to appear in the next issue with respect to the generally unsuccessful attempts of Internal Revenue Service in the event assignor reserves an interest in the mineral property to deny a loss on the sale of equipment and require that such loss be reflected as part of the taxpayer's basis in the retained mineral interest.


Accordingly, it would appear that under this definition the taxpayer has separate properties with respect to each non-contiguous tract even if covered by the same lease and with respect to each separate acquisition even though involving contiguous tracts. The statute is not explicit in this respect but, in view of previous decisions, tracts that meet at only one corner are probably not contiguous.

**EXAMPLE:** Adams enters into an oil and gas lease with Baker covering forty separate tracts which are checkerboarded (meet at only one corner). Adams and Baker both have forty separate mineral properties.

**EXAMPLE:** The XYZ Oil Co. puts together a block of leases acquired in forty separate transactions but all of which taken together completely cover a particular area. The XYZ Oil Co. has forty separate mineral properties.

**OBSERVATION**—The definition of the term “property” treats each separate interest in the same property, e.g., a working interest and a royalty interest, or two working interests acquired at different times, as separate properties. The definition also treats each mineral substance found underlying a tract, e.g., oil and gas, as separate properties and production from separate horizons under the same tract as separate mineral properties.

**FURTHER OBSERVATION**—A taxpayer acquiring interests of the same type in the same property at different times should specify in the sale of any portion thereof, which particular interest he is selling. The Tax Court has refused to apply the first-in—first-out theory and has held, for the purpose of determining the holding period, that in the absence of such specification, taxpayer is deemed to have sold a proportionate part of each interest owned.

The following examples of separate mineral properties are taken from the regulations.

**Example (1).** A taxpayer owns one tract of land under which lie three separate and distinct seams of coal. Therefore, the taxpayer owns three

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separate mineral interests each of which constitutes a separate property.

Example (2). A taxpayer conducts mining operations on eight tracts of land as a single unit. He acquired his interests in each of the eight tracts from separate owners. Even if each tract of land contains part of the same mineral deposit, the taxpayer owns eight separate mineral interests, each of which constitutes a separate property.

Example (3). A taxpayer owns a tract of land under which lies one mineral deposit. The taxpayer operates a well on part of the tract and leases to another operator the mineral rights in the remainder retaining a royalty interest therein. The taxpayer thereafter owns two separate mineral interests each of which constitutes a separate property.

Example (4). In 1954, a taxpayer acquires from a single owner, in a single deed, three non-contiguous tracts of mineral land for a single consideration. Even if each tract contains part of the same mineral deposit, the taxpayer owns three separate mineral interests each of which constitutes a separate property.

Example (5). In 1954, taxpayer A simultaneously acquires in fee two contiguous tracts of mineral land from two separate owners. The same mineral deposit underlies both tracts. Thereafter, taxpayer A owns two separate mineral interests each of which constitutes a separate property.

Example (6). Assume that in 1955, taxpayer A, in example (5), leases the two contiguous tracts of mineral land that he acquired in 1954 to taxpayer B by means of a single lease. Thereafter, taxpayer B owns one mineral interest which constitutes a separate property for such time as the lease continues in existence.

Example (7). Assume that in 1955, taxpayer A, in example (5), sells at the same time all the mineral land he acquired in 1954 to taxpayer B. Thereafter, taxpayer B owns one mineral interest which constitutes a separate property. If taxpayer B acquires the mineral land in a transaction in which the basis of such mineral land in his hands is determined by reference to the basis of such mineral land
in the hands of taxpayer A, then taxpayer B owns two separate mineral interests each of which constitutes a separate property.

Example (8). In 1954, taxpayer A simultaneously acquires two contiguous leasehold interests from two separate owners. The same mineral deposit underlies both tracts. Thereafter, taxpayer A owns two separate mineral interests each of which constitutes a separate property.

Example (9). In 1955, taxpayer A, in example (8), simultaneously assigns the two leases to taxpayer B. Thereafter, taxpayer B owns two separate mineral interests each of which constitutes a separate property.

(2) Aggregations of Operating Interests—Oil and Gas

The 1954 Code permitted taxpayers to aggregate two or more separate operating mineral interests and treat them for all purposes under the income tax laws (including determination of gain or loss upon a sale or exchange) as a single property provided that such interests constitute part or all of an operating unit.\(^{308}\) The term "operating mineral interest" is defined in terms which exclude landowner royalties, overriding royalties, oil payments and presumably net profit interests\(^{309}\) from those interests which can be aggregated under the provisions to be discussed.\(^{310}\) However, a 1964 amendment to the Code\(^{311}\) not only restricts the aggregation of separate oil and gas (but not other mineral) properties, but requires the unscrambling\(^{312}\) of many of the aggregations previously made. Under the 1964 amendment all of the taxpayer's operating interests in all deposits underlying a tract

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309. This would appear to follow from the fact that the owner of a net profit interest takes depletion only on the net amount received. See Commissioner v. Felix Oil Co., 144 F.2d 276 (9th Cir. 1944), and other cases cited at note 84 infra.
310. INT. REV. CODE 1954, § 614(b) (3). See also Lloyd Corp. v. Riddell, 347 F.2d 455 (9th Cir. 1966), and compare G.C.M. 24094, 1944 CUM. BULL. 250. But see discussion at p. 150 infra.
or contiguous tracts covered by the same lease constitute the property unit unless the taxpayer elects to treat whatever individual operating mineral interests (resulting, e.g., from production from more than one producing horizon or from more than one conveyance to him of an operating interest in the same lease) as separate properties. He can, however, have only one combination of interests in a single tract or parcel, and each interest not included in that combination will be a separate mineral property. The acquisition of an additional operating interest in the same tract (as the result of the discovery of another horizon or an additional acquisition in the same lease relating to the same tract) may either be added to an existing combination, treated as a separate property, or, if he had not previously combined operating interests, may be combined with any one other interest in the lease. If there is no combination of interests in the tract at the time of such acquisition, the acquired interest will be treated as a separate property unless the taxpayer elects to combine it with another interest; if there is an existing combination in the tract, it will be treated as part of that combination unless the taxpayer elects to treat it as a separate property.\textsuperscript{313} An election to combine interests must be made in the first year in which the taxpayer incurs development or operating costs relating to such operating interest. The election once made is binding upon the taxpayer for all subsequent tax years.\textsuperscript{314} Except to the extent outlined above separate oil and gas properties which are not committed to a unit plan of operation\textsuperscript{315} cannot be aggregated.

\textit{EXAMPLE}: A holds under a lease a tract which produces oil from two horizons and gas from a third horizon. Absent an election production from all three horizons will be regarded as production from a single mineral property. By making an appropriate election each separate horizon could be regarded as a separate property or two horizons could be combined as a separate property and the third horizon treated as a separate mineral property. If there were

\textsuperscript{315} Int. Rev. Code of 1954, § 614(b)(3). See also discussion under caption Unitization in Part II of this Article to appear in the next issue.
an outstanding leasehold interest in the same tract which A acquired from another party, by an appropriate election A could combine this interest with his existing interest in all three horizons if he has been treating all three horizons as a single property. Or he could under these circumstances treat the acquired interest as three separate properties (one for each horizon) or combine some of them with an existing combination by making the appropriate election. He could not form a combined interest pertaining to his newly acquired interest in the three horizons as he would then have two combinations in the same tract. If he has been treating all three horizons as separate properties, he could elect to combine all or some of the newly acquired interests with any one of the three separate properties or he could treat it as three separate properties each pertaining to one of the producing horizons. If A acquired a lease on an adjoining tract; however, he could not combine it with the tract he already owned as separate tracts cannot be aggregated.

EXAMPLE: Prior to 1964 a taxpayer acquired, and incurred development expenditures with respect to three operating mineral interests in oil, designated Nos. 1, 2, and 3. All three interests are in the same tract or parcel of land. For the taxable year 1964, the taxpayer elects to treat such interests as three separate properties. During the taxable year 1965, the taxpayer discovers and incurs development costs with respect to a fourth operating mineral interest, No. 4, in the same tract of land. During the taxable year 1966, the taxpayer discovers and incurs development costs with respect to a fifth operating mineral interest, No. 5, in the same tract of land. If the taxpayer makes no election relative to No. 4 for 1965, such interest will thereafter be treated as a separate property. Alternatively, the taxpayer may make an election for 1965 to combine No. 4 with any one (and only one) of the three other interests and to treat such combination as one property. If, for example, he elects to combine No. 4 with No. 3, then in 1966, No. 5 will automatically become part of the combination of Nos. 3 and 4 if no election is made to treat it as a separate property. After the combination of Nos. 3 and 4 is formed, Nos. 1 and 2, which
were acquired or discovered prior to the formation of the combination and which were not included in such combination within the time prescribed, may not be included in that or any other combination.

The separate oil and gas mineral property concept determined in accordance with the foregoing is for all income tax purposes under the Code; however, this does not preclude the use of more than one account under a single method of computing depreciation or the use of more than one method of depreciation if otherwise proper.\(^\text{316}\) Depreciation, unlike depletion, is not necessarily determined on a separate property basis.\(^\text{317}\)

(3) Aggregations of Operating Interests—Minerals Other Than Oil and Gas

The taxpayer has considerably more latitude in combining (and as we shall see under certain circumstances separating) what would otherwise be separate mineral properties with respect to operations pertaining to minerals other than oil and gas. If a taxpayer owns two or more separate operating mineral interests which constitute part or all of an operating unit, he may combine them into a single mineral property.\(^\text{318}\) Further, he may have more than one combination as to a particular operating unit provided he includes all of the operating mineral interests which are a part of the same mine in the same combination. In order to combine operating mineral interests it is not necessary that they be contiguous provided they are part of the same operating unit. The term operating unit refers to a producing unit (as distinguished from an administrative or sales organization) and consists of operating mineral interests which are operated together for the purpose of producing minerals. Factors which tend to indicate that mineral interests are operated together include the following:\(^\text{319}\) (a) common field or operating personnel, (b) common supply and maintenance facilities, (c) common processing or treatment plants, and (d) common

\(^\text{317}\) See p. 148 supra.
\(^\text{318}\) INT. REV. CODE OF 1954, § 614(c) (1).
storage facilities. The determination of the taxpayer as to what constitutes an operating unit will be accepted unless there is a clear and convincing basis for changing same.

In addition to combining what would otherwise be separate mineral properties, a taxpayer can to a limited extent divide into more than one mineral property what would otherwise be a single mineral property. If a single tract or parcel of land contains a mineral deposit which is or will be extracted by means of two or more mines, in the event of an appropriate election each separate mine may be treated as a separate mineral property.\(^{320}\)

In order to combine (or separate, as the case may be) the taxpayer must make an appropriate election in the first taxable year in which any expenditure for development or operation in respect of the separate operating mineral interest is made by the taxpayer after the acquisition of such interest.\(^ {321}\) Since no election is necessary at the time the taxpayer incurs exploration expenditures as to a separate mineral interest, a subsequent combination of that mineral interest with other mineral properties requires a recomputation of the tax for the year in which exploration expenditures were deducted.\(^ {322}\) If, for example, in 1964 taxpayer deducts exploration expenditures as to Property 1 and in 1965 when he first incurs development or operation expenditures as to such property he elects to combine it with Property 2 which was producing in both 1964 and 1965, he must go back and recompute the 1964 taxes as if Property 1 and Property 2 had been combined in 1964. The principal effect under these circumstances will be to require, with respect to 1964 taxes, the deduction of exploration expenditures incurred on Property 1 in determining the fifty per cent of taxable (net) income limitation as to Property 2 on the statutory depletion deduction. An election in accordance with the foregoing is binding with respect to the properties involved in subsequent tax years as well. However, such election is not binding with respect to other properties and an election as to other properties even though part of the same operating unit can be...

\(^{320}\) INT. REV. CODE OF 1954, § 614(c)(2).
\(^{321}\) INT. REV. CODE OF 1954, § 614(c)(3).
\(^{322}\) INT. REV. CODE OF 1954, § 614(c)(4).
deferred until the year in which development or operating expenditures are first incurred.

The latitude in determining what constitutes the mineral property with respect to minerals other than oil and gas permits considerable planning with respect, among other things, to the fifty per cent of taxable (net) income limitation on the statutory depletion deduction as is illustrated by the following examples:

EXAMPLE: Taxpayer has been mining from a tract that constitutes a separate mineral property and is realizing substantial income from production. In the tax year under consideration taxpayer incurs his initial development expenditures which are substantial as to another tract which constitutes a separate mineral property but which is part of the same operating unit. During the same tax year taxpayer realizes significant revenues from this second tract, but in the event he treats it as a separate mineral property and deducts development expenditures the statutory depletion deduction will be substantially reduced. By electing to aggregate (combine) the two mineral properties the additional revenues from the first tract may permit the deduction of the development expenditures incurred as to the second tract without affecting the fifty per cent of taxable (net) income limitation on the statutory depletion deduction.

EXAMPLE: Taxpayer owns a tract which constitutes a single mineral property but on which are located Mines A and B. Mine A has been in production for some time and in the tax year under consideration development expenditures which are substantial are incurred for the first time on Mine B. If the development expenditures are deducted, the statutory depletion deduction will be substantially reduced if Mines A and B are regarded as a single property. However, by making an appropriate election Mine B can be regarded as a separate mineral property and the development expenditures relating to Mine B will not adversely affect the statutory depletion deduction with respect to revenues derived from Mine A. By deferring production on Mine B until the

823. See p. 107 supra.
following tax year, deducting such development expenditures will not affect the statutory depletion deduction as to Mine B either.

(4) Aggregations of Non-Operating Mineral Interests

With both respect to oil and gas and other minerals, the taxpayer may be permitted to treat non-operating separate mineral properties in a single tract or parcel or two or more adjacent parcels as a single property. Such treatment is dependent upon convincing Internal Revenue Service that a principal purpose of such aggregation is not the avoidance of tax. If permission is granted for such an aggregation, the taxpayer must continue to regard all such interests as one property for all subsequent tax years unless Internal Revenue Service consents to a different treatment.

PART II WILL APPEAR IN THE NEXT ISSUE.

324.  INT.  REV. CODE OF 1954, § 614(e).