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A GUIDE TO FEDERAL OIL AND GAS INCOME TAXATION

By HAROLD S. BLOOMENTHAL*

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INTRODUCTION

This article is written primarily for the reader who has some knowledge of oil and gas law and of the federal income tax laws, but relatively little knowledge of the special impact of the federal income tax laws on oil and gas transactions.[1] The more important tax provisions affecting the exploration and production phases of the oil and gas industry are those relating to (1) income[2]—ordinary, depletable and capital; (2) depletion; (3) intangible drilling and development costs; (4) depreciation and (5) losses—ordinary, capital and net operating. These provisions are in large part interrelated and one of the objectives of this article is to correlate the various provisions and present an integrated account of their overall effect.

Any attempt to encompass within the space limitations of an article the multitude of problems involved in oil and gas taxation must necessarily be oversimplified. Justice Frankfurter has observed 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."[3] The shortcomings of the law in this and other respects have been discussed with considerable skill elsewhere;[4] this article for the most part is concerned with what the law is, to the extent ascertainable, rather than what it should be. The author has attempted to set forth a guide to routine oil and gas tax practice and to indicate the areas in which the law has not clearly crystallized.

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1. The best oil and gas treatise with which the author is familiar is the OIL AND GAS FEDERAL INCOME TAX MANUAL (7th ed. 1953) prepared by the national accounting firm of Arthur Andersen & Co. (Omaha, Nebraska). Unfortunately this manual although fairly widely distributed is not available for sale. The proceedings of the annual institutes on oil and gas law and taxation of the Southwestern Legal Foundation contain a number of excellent oil and gas tax articles and reference to a number of such articles is made in the subsequent notes. MILLER, OIL AND GAS TAXATION (2nd ed. 1951) published by Commerce Clearing House is also a useful treatise. The OIL AND GAS TAX QUARTERLY published four times a year by Mathew Bender & Co., Inc. contains articles and comments by oil and gas tax experts discussing various oil and gas tax problems and is of assistance in keeping informed on current developments in this field.
2. "Ordinary income" is generally referred to as either being subject to the depletion allowance or not subject to the depletion allowance. In this article reference to "ordinary income" is to income not subject to the depletion allowance. Income subject to the depletion allowance will be referred to as depletable income.
3. Concurring in Burton-Sutton Oil Co. v. Comm., 328 U.S. 25, 38; 66 Sup. Ct. 861, 868 (1946).
4. For good discussions of the technical shortcomings see Bergen, *Oil and Taxes—Some Problems and Proposals*, 26 SO. CALIF. L. REV. 396 (1953); JACKSON, *The Need for a Restatement of the Tax Laws Relating to Oil and Gas* in PROCEEDINGS OF THE FIRST ANNUAL INSTITUTE ON OIL AND GAS LAW AND TAXATION 343 (1949). With respect to the pros and cons relating to justification (or lack thereof) of the special tax benefits accorded the oil industry see Baker and Griswold, *Percentage Depletion—A Correspondence*, 64 HARV. L. REV. 361 (1951); Blum, *How to Get All (But All) the Tax Advantages of Dabbling in Oil*, 31 TAXES 343 (1953); Ray, *The Attack on Percentage Depletion* in PROCEEDINGS OF THE SECOND ANNUAL INSTITUTE ON OIL AND GAS LAW AND TAXATION 541 (1951).

Tax advantages[5] resulting from the choice of particular alternatives are considered in connection with the discussion of particular problems. In addition a few general fundamentals will serve as a guide to many of the more common situations:

(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 depletable income. The reason is the obvious one that long term capital gains are taxable at a maximum rate of 26%, whereas ordinary income is taxable at rates as high as 92% for individuals.[6]

(2) As a corollary to the foregoing proposition it is ordinarily desirable to have a transaction regarded as a sale rather than a lease or sublease in that any considertion received by the "vendor" in a lease or sublease transaction must be treated as depletable income.[7]

(3) If income cannot be considered as a capital gain, it is desirable, if possible, for it to fall within the depletable income classification. The reason is that the recipient of depletable income is entitled to take cost depletion or statutory depletion (27½% of gross income), whichever is the larger, within the limitations subsequently noted.[8]

(4) It is desirable for the taxpayer incurring expenditures for the development of oil and gas properties to have as small an amount as possible charged to capital expenditures recoverable through depletion.[9] The reason is that if such charges are capitalized the taxpayer frequently realizes no tax benefit therefrom in that statutory depletion can be taken in any event and does not depend on the cost basis of the property.[10]

(5) It is desirable for the taxpayer financing the drilling of a well to be in a position to deduct the intangible drilling costs as a current expense and to recover through depreciation expenditures on physical equipment.[11] Otherwise, such expenditures must be capitalized by the taxpayer as part of the acquisition costs of the oil and gas interest and recovered through depletion.[12]

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5. For an excellent article stressing such advantages see Jackson, *Tax Planning Before Drilling*, XXVII TULANE L. REV. 21 (1952). See also ANDERSON, *op. cit. supra* note 1, at 191-211.
6. Rates on ordinary income cited in the text apply to calendar years 1952, 1953 and fiscal years beginning after 10-31-51 and before 1-1-54. For calendar year 1954 and fiscal years beginning after 12-31-53 the maximum tax on ordinary income to individuals is 91%. INT. REV. CODE Secs. 11, 12. The maximum rate on a long term capital gain drops to 25% on April 1, 1954 but only with respect to a taxpayer whose fiscal year begins after March 31, 1954. INT. REV. CODE Sec. 117(c).
7. See *infra* 107-108.
8. See *infra* 90-91.
9. The phrase "recoverable through depletion" is a short-hand method of saying that the amount expended is amortized through the depletion allowance. "Recoverable through depreciation" or "depreciable items" is a short-hand method of saying that the amount expended is amortized through the depreciation deduction.
10. This point is expanded on in note 97 and related text.
11. As to the distinction between tangibles and intangibles see *infra* 97; as to the distinction between capital costs recoverable through depreciation and capital costs recoverable through depletion see *infra* 105.
12. See *infra* 99.

(6) It is desirable with respect to each separate property for 50% of the taxpayer's net income (after deductions for all expenses including current intangibles) to be equal to or in excess of 27½% of the taxpayer's gross income from the property. The reason is that the statutory depletion allowance of 27½% of the gross income cannot exceed 50% of the taxpayer's net income from the particular property.[13]

(7) Net operating losses should be avoided by the taxpayer if possible. Inasmuch as the taxpayer must reduce the net operating loss by the amount statutory depletion exceeds cost depletion for the year of the loss and for every year in which the loss is carried back or forward, he is deprived of a large part of the tax benefit that could be derived by offsetting the loss against current income.[14]

(8) It is ordinarily desirable to be taxed as an individual or partnership and not as a corporation. The reason is that if taxed as a corporation the income from the oil property will be subject to double taxation and the taxpayer will be unable to receive the full benefit of the statutory depletion allowance.[15]

(9) It is ordinarily desirable to have a transaction regarded as a tax-exempt exchange or pooling 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.[16]

ORDINARY INCOME

The principal items of ordinary income not subject to the depletion deduction are delay rentals received by the lessor from the lessee[17] and sums received by the owner of the property in return for a grant, unaccompanied by an option to lease, of the privilege to conduct seismograph or other geological surveys on his property.[18] Sums received for an option to lease never exercised are also ordinary income to the recipient not subject to depletion.[19] The taxpayer incurring expenditures for the privilege of conducting geological work or for an option must capitalize such expendi-

13. See *infra* 91.
14. See *infra* 113.
15. See *infra* 127.
16. See *infra* 126.
17. Comm. v. Wilson, 76 F.2d 766 (5th Cir. 1935). "Delay rental is a sum paid under the terms of a lease for the privilege of continuing the lessee's interest without developing the property." G. C. M. 11197, XII-1 CUM. BULL. 238, 240 (1933).
18. Special Ruling, June 18, 1951, CCH 1952 FED. TAX. REP. Par. 6105.
19. No case or specific ruling to the author's knowledge expressly relates to this problem. The only theory on which an option payment could be regarded as depletable income to the recipient is that it constitutes additional "bonus" and as such is an advance royalty. However, if the option is never exercised and no lease ever acquired thereunder the payment obviously cannot be a royalty payment. ANDERSEN, *op. cit. supra* note 1, at p. 3 suggests that an option payment be regarded as additional "bonus" and depletion deducted with respect thereto, but that such deduction be restored to income if at the termination of the option period the option is not exercised or if the option is exercised but the leases acquired thereunder are abandoned or terminated without production. As to "bonus" payments generally and restoration of previous depletion deduction to income see *infra* 86-87.

tures as part of the acquisition costs of the lease (if acquired) and recover same through depletion[20] or write them off as an ordinary loss if no lease is acquired.[21] However, as to expenditures incurred for delay rentals the taxpayer can regard them either as current expenses or capital costs in the nature of carrying charges[22] recoverable through the depletion allowance.[23]

DEPLETION DEDUCTION

There are two principal sources of income which is subject to the depletion allowance: Frist, income received in the form of bonus as consideration for a lease or sub-lease.[24] Second, income received by those having an "economic interest" in oil and gas in place from the proceeds from production.[25] The distinction between a lease or sublease and a sale is discussed in detail below;[26] suffice it to note for the present in this regard that income (generally referred to as a "bonus") received in connection with a leasing or subleasing transaction is regarded as depletable income whereas income from a sale is either capital income or ordinary non-depletable income.[27]

The typical example of bonus income is the money received by the landowner (lessor) from the lessee as consideration for the execution of an oil and/or gas lease. However, income received as consideration for executing a sublease is also bonus income and subject to the same tax consequences.[28] Bonus income is regarded as advance royalty for tax purposes[29] and the recipient is entitled to take the statutory depletion deduction with respect thereto in the year received[30] regardless of whether any production is obtained or whether there is any reasonable assurance of

20. U.S. Treas. Reg. 118, Sec. 39.23 (m) -10 (a); Sunray Oil Co. v. Comm., 147 F.2d 962 (10th Cir .1945). Note with respect to the regulations cited that the new income tax regulations as approved September 23, 1953 are all 118 regulations (previously they were 111 regulations) and all contain the prefix 39, whereas previously they contained the prefix 29. Although some changes have been made, for the most part the new regulations correspond with the previous ones; thus Reg. 118, Sec. 39.23 (m) -10 corresponds with previous Reg. 111, Sec. 29.23 (m) -10.
21. See *infra* 114-116.
22. INT. REV. CODE Sec. 24 (a) (7); U.S. Treas. Reg. 118, Sec. 39.24 (a) -6; G.C.M. 11197, XII-1 CUM. BULL. 238 (1933). In order to capitalize delay rentals the taxpayer must so elect in a statement filed with his return. A new election in this respect may be made each year and the election is available as to each separate property. See discussion in II OIL AND GAS TAX QUARTERLY 206-208 (1953).
23. *Ibid.*
24. U.S. Treas. Reg .118, Sec. 39.23 (m) -10; Burnet v. Harmel, 287 U.S. 103, 53 Sup. Ct. 74 (1932); Sunray Oil Co. v. Comm., 147 F.2d 962 (10th Cir. 1945).
25. U.S. Treas. Reg. 118, Sec. 39.23 (m) -1 (b).
26. See *infra* 108-110.
27. Anderson v. Helvering, 310 U.S. 404, 60 Sup. Ct. 952 (1940); Burnet v. Harmel, 287 U.S. 103, 53 Sup. Ct. 74 (1932).
28. Palmer v. Bender, 287 U.S. 551, 53 Sup. Ct. 225 (1933). An assignment by a lessee of the entire leasehold rights reserving an overriding royalty is a typical subleasing transaction.
29. U.S. Treas. Reg. 118, Sec. 39.23 (m) -10 (a) and (d).
30. Theoretically it is possible to take cost depletion with respect to a bonus payment and the appropriate procedure for computing same is set forth in U.S. Treas. Reg. 118, Sec. 39.23 (m) -10 (a). However, it ordinarily is more feasible to take statutory depletion. U.S. Treas. Reg. 118, Sec. 39.23 (m) -10 (d).

obtaining production.[31] If any production is obtained under the lease or sublease, involved, the recipient of the bouns need make no further adjustment.[32] If, however, the lease 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 terminates, expires or is abandoned.[33]

The lessee paying the bonus must capitalize such expenditure as part of the acquisition cost of the lease and recover same through depletion.[34] He may, however, take such expenditure as an ordinary loss in the year in which he abandons the lease[35] or as a capital or ordinary loss as the case may be in the event he sells the property in the year of sale to the extent that the purchase price is less than his adjusted cost basis.[36] In the event the lease is productive the lessee must exclude a pro-rata part of the bonus from his depletable gross income from production.[37] However, the Tenth Circuit Court of Appeals has held that the taxpayer-lessee deducts an allocated part of the bonus only for the purpose of determining statutory depletion and cannot deduct an allocated part for the purpose of determining his taxable income from the property.[38]

The depletion deduction allowed in connection with bonus income has been referred to by one court as "synthetic depletion."[39] The primary source of income subject to the depletion allowance is not from transactions of this type, but is from the proceeds derived from the sale of oil and gas.[40] Only those who have an "economic interest" in the oil and gas in place can take the depletion allowance with respect to the proceeds derived from

31. Herring v. Comm., 293 U.S. 322, 55 Sup. Ct. 179 (1934); Marrs McLean, 41 B.T.A. 565 (1940).
32. In Dolores Crabb, 41 B.T.A. 686 (1940) acq. 1940-2 CUM. BULL. 2 taxpayer-lessor had taken a depletion deduction on the bonus in the amount of $4,125, but was not required to restore any part of the deduction although at the time of abandonment of the lease the total royalties from production amounted to only $36.98.
33. U.S. Treas. Reg. 118, Sec. 39.23 (m) -10 (c); Sneed v. Comm., 119 F.2d 767 (5th Cir. 1941). The previous depletion deduction taken with respect to the payment of the "bonus" must be restored to income even if the previous deduction did not result in a tax benefit. U.S. Treas. Reg. 118, Sec. 39.22 (b) (12) -1; Douglas v. Comm., 322 U.S. 275, 64 Sup. Ct. 988 (1944). The taxpayer, however, can restore to the capital account (his basis in the property) any amount previously deducted as an adjustment thereto because of depletion taken on the "bonus". U.S. Treas. Reg. 118, Sec. 39.23 (m) -10 (c).
34. U.S. Treas. Reg. 118, Sec. 39.23 (m) -10 (a).
35. See *infra* 114.
36. As to the situations in which the loss will be a capital loss or an ordinary loss see *infra* 110-111.
37. U.S. Treas. Reg. 118, Sec. 39.23 (m) -1 (e) (5) requires that the lessee make this allocation with respect to previous bonus payments by excluding from his gross income from the property for the purposes of computing statutory depletion the amount of the previous bonus payment allocable to the current tax year. Thus if the bonus payment was $100,000 and the estimated reserves are 100,000 bbls., assuming a production during the current tax year of 10,000 bbl., the lessee in computing statutory depletion would have to reduce his gross income by one-tenth of the original bonus payment which would be $10,000.
38. Sunray Oil Co. v. Comm., 147 F.2d 962 (10th Cir. 1945).
39. Driscoll v. Comm., 147 F.2d 493, 495 (5th Cir. 1945).
40. U.S. Treas. Reg. 118, Sec. 39.23 (m) -1 (e) (1).

production.[41] As the result of considerable litigation it is now fairly clear that the owners of the following oil and gas interests have an economic interest for this purpose: landowner's royalty,[42] overriding royalty,[43] oil payment,[44] net profit interest,[45] working interest,[46] and participating interest[47]. The owner of an "economic interest" can take a deduction for depletion without respect to whether his interest entitles him to a share of the production in kind or a share of the proceeds from the sale of production.[48]

The depletion deduction allowed is cost depletion or statutory deple-

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41. U.S. Treas. Reg. 118, Sec. 39.23 (m) -1 (b).
42. Palmer v. Bender, 287 U.S. 551, 53 Sup. Ct. 225 (1933). A landowner's royalty is the royalty reserved by the lessor under an oil and gas lease. Typically the oil and gas lease provides that the lessor shall receive one-eighth of the production as a royalty free of all development and operating costs.
43. Palmer v. Bender, *supra* note 42; Hogan v. Comm., 141 F.2d 92 (5th Cir. 1944); E. F. Simms, 28 B.T.A. 988 (1933) acq. in XV-2 CUM. BULL. 22 (1936). An overriding royalty is generally created by the lessee assigning the lease and reserving a specified cost free royalty.
44. Perkins v. Thomas, 301 U.S. 655, 57 Sup. Ct. 911 (1937); T. W. Lee v. Comm., 126 F.2d 825 (5th Cir. 1942); Comm. v. O'Shaughnessy, Inc., 124 F.2d 33 (10th Cir. 1941). An oil payment is an interest under which the holder receives a specified fraction of the production (or a specified amount per barrel of oil produced) until he has received a specified payment. A typical oil payment provides that the owner is to receive $300,000, or some other specified amount, payable only out of one-tenth or some other specified fraction of production. However, in order to be an economic interest the oil payment must be payable solely out of the proceeds from production from the particular property and there must be no possibility that part of the payment may be from some source other than such proceeds. Anderson v. Helvering, 310 U.S. 404, 60 Sup. Ct. 952 (1940); M-B-K Drilling Co. v. Comm., 194 F.2d 221 (2nd Cir. 1952); T. W. Lee v. Comm., *supra*.
45. Kirby Petroleum Co. v. Comm., 326 U.S. 599, 66 Supt. Ct. 409 (1946); Burton-Sutton Oil Co. v. Comm., 328 U.S. 25, 66 Sup. Ct. 861 (1946). A net profit interest ordinarily is a contractual right to receive a specified percentage of the net proceeds from production. Net proceeds are usually defined so as to permit the operator to deduct the net profit interest holder's proportionate share of the operating costs and in some cases of the costs of development. It differs from a working interest in that the net profit interest owner has no right to develop the property and ordinarily does not own any interest in the lease equipment. There is some confusion in the cases in that the *Kirby* case *supra,* and *Burton-Sutton* case, *supra,* did not expressly overrule Elbe Oil Land Development Co. v. Helvering, 303 U.S. 372, 58 Sup. Ct. 621 (1938) and O'Donnell v. Helvering, 303 U.S. 372, 58 Sup. Ct. 619 (1938) in which the Supreme 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. There is some possibility, therefore, that where the net profit interest is created by a grant carving out such interest from the lease rather than by a reservation by the assignor of the lease that it may not be an economic interest in the oil and gas in place. It has also been suggested that because of the decision in Anderson v. Helvering, 310 U.S. 404, 60 Sup. Ct. 952 (1940) if the net profit agreement provides that the proceeds from the sale of equipment are to be taken into account in determining net profits that the net profit interest may not be an "economic interest". See Bergen, *supra* note 2, at 415-416.
46. Greensboro Gas. Co. v. Comm., 79 F.2d 701 (3rd Cir. 1935). A working interest is generally an interest in an oil and gas lease which gives the interest owner either the exclusive or non-exclusive right to develop the oil and gas property.
47. Kiesau Petroleum Corp., 42 B.T.A. 69 (1940) acq. 1940-2 CUM. BULL. 4. A participating interest is a contractual right to a specified portion of the production. If it is subject to part of the operating costs it is much like a net profit interest created in a stranger to the lease and if it is not subject to any part of the cost it is much like an overriding royalty in a stranger to the lease.
48. Greensboro Gas Co. v. Comm., 30 B.T.A. 1362 (1934) *aff'd* in 79 F.2d 701 (3rd Cir. 1935).

tion, whichever is the greater.[49] The use of the method resulting in the larger depletion allowance is mandatory in determining the taxpayer's adjusted basis in the property.[50] 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.[51] It is important to note with respect to the computation of statutory depletion that separate computations must be made for each separate property.[52]

In computing cost depletion it is necessary to first determine the cost basis of the property in question.[53] This will include all of the acquisition costs of the property[54] such as expenditures for seismograph and other geological data,[55] abstract and attorney fees,[56] bonuses,[57] options,[58] and at the taxpayer's election delayed rentals[59] and intangible drilling and development costs[60] relating to the property in question. The cost basis of the property for depletion purposes is divided by the estimated number of recoverable barrels of oil (or thousand cubic feet of gas) attributable to the interest of the taxpayer in the particular property to obtain the unit (per barrel or per thousand cubic feet) depletion allowance. This per unit depletion figure is then multiplied by the number of such units (barels or thousand cubic feet) produced during the tax year and attributable to the taxpayer's interest and the resulting figure is the deduction permitted as cost depletion.[61]

Statutory depletion is computed by the multiplying the gross income attributable to the taxpayer's interest from the particular oil and gas property by 27½%.[62] The resulting figure must be reduced to the extent that it exceeds 50% of the taxpayer's net income from the particular property.[63] Statutory depletion can never exceed 27½% of the gross income from 100% of production from the property.[64] Accordingly, the operator must exclude from his gross income that part of the proceeds paid to the holders of other economic interests in the oil and gas in place (such as the landowner's

49. INT. REV. CODE Sec. 23 (m); INT. REV. CODE Sec. 114 (b) (3); U.S. Treas. Reg. 118, Sec. 39.23 (m)-4.
50. Producers Oil Corp., 43 B.T.A. 9 (1940) acq. 1941-1 CUM. BULL. 8.
51. *Ibid.*
52. U.S. Treas. Reg. 118, Sec. 39.23 (m)-4.
53. U.S. Treas. Reg. 118, Sec. 39.23 (m)-2 (a).
54. U.S. Treas. Reg. 118, Sec. 39.113 (a).
55. I. T. 4006, 1950-1 CUM BULL. 48.
56. Munger v. Comm., 14 T. C. 1236 (1950).
57. U.S. Treas. Reg. 118, Sec. 39.23 (m)-10 (a).
58. *Ibid.*
59. INT. REV. CODE Sec. 24 (a) (7); U.S. Treas. Reg. 118, Sec. 39.24 (a)-6; G.C.M. 11197, XII-1 CUM. BULL. 238 (1933). See discussion at note 22 and related text.
60. U.S. Treas. Reg. 118, Sec. 39.23 (m)-2 (d); U.S. Treas. Reg. 118, Sec. 39.23 (m)-16. See *infra* 95.
61. U.S. Treas. Reg. 118, Sec. 39.23 (m)-2.
62. INT. REV. CODE Sec. 114 (b) (3); U.S. Treas. Reg. 118, Sec. 39.23 (m)-4.
63. Note 62 *supra.*
64. Helvering v. Twin Bell Oil Syndicate, 293 U.S. 312, 55 Sup. Ct. 174 (1934).

royalty, the overriding royalty, net profit interest, etc.) and the holder of each economic interest computes statutory depletion with respect to his share of the proceeds.[65] 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.[66]

Gross income for depletion purposes is the sales price of oil or gas in the immediate vicinity of the well.[67] Accordingly any amount deducted for the payment of severance or other production taxes should be added back in computing gross income for depletion purposes.[68] On the other hand transportation costs and gathering charges are deducted from the sales price in determining gross income for this purpose.[69] An allocated part of any bonus previously paid by the taxpayer must be deducted from the gross income attributable to the taxpayer's interest in determining the amount of taxpayer's gross income subject to the depletion allowance.[70]

In determining taxpayer's net income for the purposes of the 50% net income limitation, gross income to the taxpayer is the same gross income figure used in computing the 27½% depletion allowance.[71] Net income is

65. *Ibid.* The amount excluded from gross income which represents the share of production of another owner of an economic interest in place is excluded generally not only for purposes of determining statutory depletion but for the purpose of determining the taxpayer's taxable income. Or as stated by the Supreme Court ". . . the same basic issue determines both to whom income derived from the production of oil and gas is taxable and to whom a deduction for depletion is allowable." Anderson v. Helvering, 310 U.S. 404, 407; 60 Sup. Ct. 952, 954 (1940). Accordingly, if part of the gross income is payable to the holder of an economic interest in place it is excluded from the payor's gross income and is income to the recipient who can take depletion with respect thereto; if payable to someone other than an owner of an economic interest in place it is an assignment of income and the payor must include the amount paid in his gross income for the purpose of determining his taxable income and can take statutory depletion with respect thereto. Anderson v. Helvering, *supra.* However, the allocated part of the bonus that must be deducted by the lessee in determining his gross income for statutory depletion purposes (see discussion at note 37 and related text) cannot be deducted by the lessee in determining his taxable income. Sunray Oil Co. v. Comm., 147 F.2d 962 (10th Cir. 1945).
66. Comm. v. Fleix Oil Co., 144 F.2d 276 (9th Cir. 1944).
67. U.S. Treas. Reg. 118, Sec. 39.23 (m) -1 (e) (1); Helvering v. Mountain Producers Corp., 303 U.S. 376, 58 Sup. Ct. 623 (1938).
68. Note 67, *supra.*
69. U.S. Treas .Reg. 118, Sec. 39.23 (m) -1 (e) (1) provides in part: ". . . If the oil and gas are not sold on the property but . . . are transported from the property prior to sale, the gross income from the property shall be assumed to be equivalent to the representative market or field price (as of the date of the sale) of the oil and gas before . . . transportation."
70. U.S. Treas. Reg. 118, Sec. 39.23 (m) -1 (e) (5); Quintana Petroleum Co. v. Comm., 143 F.2d 558 (5th Cir. 1944). See also discussion at note 37.
71. U.S. Treas. Reg. 118, Sec. 39.23 (m) -1 (g). ANDERSON, *op. cit. supra* note 1, at 102 assumes that in computing net income for this purpose the allocated part of the bonus excluded from gross income in determining the 27½% depeltion allowance is added back to the gross income from the property before deducting the various expenses and arriving at the net income. This appears logical particularly if as held in Sunray Oil Co. v. Comm., 147 F.2d 962 (10th Cir. 1945) such amount must be included as part of the taxpayer's gross income in determining his taxable income. However, U.S. Treas. Reg. 118, Sec. 39.23 (m) -1 (g) specifically provides that "net income" for the purpose of determining the limitation on statutory depletion means the "gross income from the property" as defined in paragraph (e) of the same regulation less specified expenses. Paragraph (e) in turn provides that in determining "gross income from the property" an allocated portion of the bonus previously paid must be excluded.

derived by deducting therefrom all operating costs including depreciation (but not depletion), ad valorem and severance taxes, interest on borrowed money,[72] an allocated part of overhead,[73] and intangibles[74] in the event the taxpayer has elected to expense them.[75] Only those overhead costs attributable to exploration and production must be allocated and in this connection an allocation has to be made as between producing and non-producing properties[76] and among the producing properties.[77] The allocation of overhead among the producing properties is made on the basis of their relative production.[78]

If the taxpayer elects to deduct intangibles as a current expense, as he ordinarily will,[79] the 50% net income limitation frequently prevents the taking of statutory depletion in the year in which a well or wells are drilled on the property. The taxpayer can, however, take cost depletion for that particular year without prejudicing his right to take statutory depletion in subsequent years.[80]

The 50% net income limitation on statutory depletion suggests the importance of timing and careful selection of the property to be drilled in planning the drilling program. A taxpayer on the accrual basis who contracts to have the drilling done for him can to a limited extent control the time at which the liability for intangibles will be incurred by variations in the type of drilling contract adopted. Oil and 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 so much per foot of hole drilled. (2) A contract providing that there is no obligation to the drilling contractor until and unless the hole is drilled to completion or to a specified lesser depth.[81] The taxpayer on a cash basis can control the year in which intangibles are incurred to a certain extent by timing his cash expenditures. The taxpayer can whether on an accrual or cash basis determine the year in which intangibles will be incurred as an expense by controlling the beginning and completion dates of the drilling in question.

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) statutory depletion deduction, the taxpayer should attempt to incur as much of the intangible drilling and development costs as possible

72. St. Mary's Oil and Gas Co., 42 B.T.A. 270 (1940).
73. U.S. Treas. Reg. 118, Sec. 39.23 (m) -1 (g).
74. See *infra* 94-97.
75. Wilshire Oil Co. v .Helvering, 308 U.S. 90, 60 Sup. Ct. 18 (1939).
76. U.S. Treas. Reg. 118, Sec. 39.23 (m) -1 (g); G.C.M. 22956, 1941-2 CUM. BULL. 103.
77. U.S. Treas Reg 118, Sec. 39.23 (m) -1 (g).
78. *Ibid.*
79. See *infra* 96.
80. Because of the concluding sentence of INT. REV. CODE Sec. 114 (b) (3) which provides thtat the depletion allowance shall in no event be less than it would be without the provision for statutory depletion.
81. Great Western Petroleum Corp. v. Comm., 1 T.C. 611 (1943).

in the current tax year. Similarly if another well has already been drilled on the property during the current tax year as a result of which the 50% net income limitation is going to prevent the taking of all or a substantial part of the 27½% 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 27½% statutory depletion allowance relating to this property because of the 50% net income limitation, as much of the intangibles as possible should be deferred to the following year when the income from the new well will increase the net income of the particular property.

It is also advisable in this connection, other factors being equal, to carefully select the property to be drilled in the light of the tax consequences. If as between two properties previous drilling on one property during the current tax year has already assured that statutory depletion will not be available because of the 50% net income limitation whereas in the absence of additional drilling the 50% net income limitation will not affect the other property, the drilling should be undertaken on the first property. As between producing properties generally to the extent possible the drilling (other factors being equal) should be concentrated on the properties with substantial net income and limited as to other producing properties so that 50% of the net income from each property will equal or exceed 27½% of the gross income.[82]

A question sometimes arises 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. This problem is raised in connection with so-called "shut-in royalties" which usually result from a provision in an oil and gas lease to the effect that if production is obtained the lessee can retain the lease without producing it (usually because of lack of market) by paying a specified amount to the lessor in lieu of the royalty that would have otherwise been payable. Although there are no cases or ruling the usual practice is to regard a "shut-in royalty" payment as depletable income.[82a]

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82. Asume, *e.g.*, that from property A taxpayer will have net income (before deducting intangibles) of $300,000 whereas from property B he will have net income (before deducting intangibles) of $150,000 and that the intangible drilling and development costs relating to a well drilled on either property will amount to $50,000. Assume further that 27½% of the gross income on property B is $50,000. If the taxpayer drills two wells on property A (thereby reducing his net income with respect to that property to $200,000) and one well on property B (thereby reducing his net income with respect to that property to $100,000) the taxpayer will be able to take the full 27½% on property A and property B. If, on the other hand, two wells had been drilled on property B and one well drilled on property A he would have been able to take the full 27½% with respect to property A, but as to property B his depletion deduction would be limited to $25,000 and he will lose the balance ($25,000) of the 27½% statutory depletion that would have otherwise been available if the drilling program had been planned properly from a tax standpoint.

82a. Seale, *Problems of Depletion in Oil and Gas Leases* in PROCEEDINGS OF THE SECOND ANNUAL INSTITUTE ON OIL AND GAS LAW AND TAXATION 351, 361 (1950).

A similar problem is presented with respect to minimum royalty payments. A minimum royalty provision usually requires the lessee to pay the lessor a specified percentage of the gross production (and in this respect does not differ from the typical royalty) but in no event less than a stated minimum. The excess of the minimum payment over the basic royalty may or may not be recoupable out of subsequent production and may or may not be a fixed obligation on the part of the lessee.

If the obligation to pay the minimum royalty is a fixed obligation—that is, cannot be avoided by forfeiting the lease—, any excess of the minimum royalty over the actual royalty would appear to be additional consideration for the lease if not recoupable or an advance royalty if recoupable.[82b] Accordingly such excess payments should be accorded the same tax treatment for depletion purposes as previously described in connection with bonus payments.[82c] The recipient of such minimum royalty payment should take the depletion deduction with respect thereto and in the event the lease is abandoned without production should restore the depletion deduction previously taken to income in the year of abandonment. If the excess is recoupable, the regulations specifically provide that the leessee may deduct the amount of the excess paid from his gross income either in the year in which such excess is paid or in the year in which the excess is recouped.[82d]

A General Counsel's Memorandum[82e] relating to an agreement by an oil and gas lessee to pay the lessor's ad valorem taxes appears to be inconsistent with the foregoing to a limited extent. The General Counsel's position is that prior to production such payments (at least when they are not recoupable) even though a fixed obligation cannot be regarded as depletable royalty income since there is no production against which to offset them. This opinion overlooks the fact that if the payments are a fixed obligation on the part of the lessee they constitute additional consideration paid for the lease and as such are bonus income. To the extent that this aspect of the General Counsel's opinion is extended to minimum royalty payments it would appear to be inconsistent with the litigated case.[82f].

82b. McFaden v. Comm., 2 T.C. 395 (1943). *Cf.* Alice G. K. Kleberg, 43 B.T.A. 277 (1941).
82c. *Supra* 86-87.
82d. U.S. Treas. Reg. 118, Sec. 39.23 (m) -10 (e). The taxpayer must, however, make his election in this respect in his return for the first taxable year ending on or after December 31, 1939, in which minimum royalties of this type are paid or accrue. A failure to deduct any such items for the year paid or accrued constitutes an election to deduct such items in the year in which recouped. The election made is binding for all subsequent years and the taxpayer must treat all minimum royalties paid of accrued in subsequent years in the same manner. This election expressly applies with respect to determining gross income for statutory depletion purposes (U.S. Treas. Reg. 118, Sec. 39.23 (m) -1 (e). Presumably it also applies to determining gross income for the purpose of computing taxable income inasmuch as it is not expressly limited to determining gross income for statutory depletion purposes and although incorporated by reference in the provision setting forth the procedure for determining gross income for statutory depletion purposes it appears in the regulations as a separate provision.
82e. G.C.M. 26526, 1950-2 CUM. BULL. 40.
82f. See cases cited in note 82b.

If the minimum royalty payments are not fixed obligations but can be avoided by forfeiting the lease, such payments obviously do not constitute additional consideration for the lease. If in this situation they are not recoupable from subsequent production, they are not advance royalties and accordingly such payments prior to production should be regarded as non-depletable income.[82g] If in this situation they are recoupable from production, there is some indication that such payments prior to production will be regarded as non-depletable income[82h] although it could be argued that they are advance royalties and this point has not been clearly resolved. After production whether the excess is recoupable or not such excess is additional royalty and as such depletable income at least to the extent that the total production under the lease is sufficent to pay the minimum royalty.[82i]

The conclusion that minimum royalty payments are additional royalty after production in these circumstances is based on a General Counsel's Memorandum relating to a lessee's agreement to pay the lessor's ad valorem taxes.[82j] This opinion took the postition that after production the lessee's payment of the lessor's ad valorem taxes to the extent that income under the lease is sufficient to pay such taxes represented a readjustment of the division of the proceeds from production as between the lessee and the lessor. The same reasoning would appear applicable to minimum royalty payments. However, presumably to the extent that income from the property is insufficient to pay the minimum royalty after production, the payment of the minimum royalty (if non-recoupable) represents delay rental and as such non-depletable income.

Whenever statutory or cost depletion is allowed or allowable 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.[83] 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.[84]

INTANGIBLE DRILLING AND DEVELOPMENT EXPENSES

With respect to expenditures incurred in drilling a well the regulations distinguish between so called "tangible and "intangible" expenditures. "Tangible" expenditures relate in general to physical items having a salvage value, whereas "intangibles" relate generally to items having no salvage

82g. G.C.M. 26526, 1950-2 CUM. BULL. 40; Burnett v. Hutchinson Coal Co., 64 F.2d 275 (4th Cir. 1933) *cert. denied* 290 U.S. 652 (1933).
82h. Burnett v. Hutchison Coal Co., *supra* note 82g.
82i G.C.M. 26526, 1950-2 CUM. BULL. 40.
83. INT. REV. CODE Sec. 113 (b) (1) B so provides with respect to tax years since January 1, 1952 and also with respect to any tax year prior to January 1, 1952 provided an election is made in accordance with the provisions of INT. REV. CODE Sec. 113 (d).
84. Rowan Drilling Co. v. Comm., 130 F.2d 62 (5th Cir. 1942).

value. No election with respect to tangible expenditures is provided and all such expenditures must be capitalized and recovered through depreciation.[85]

With respect to intangible drilling and development expenses the taxpayer can elect to either capitalize them or to write them off as current expenses.[86] In the event the election is made to capitalize such expenditures they must be recovered through the depletion allowance except for installation costs of physical equipment which are recovered through depreciation.[87] The election once made is binding for the individual taxpayer in all subsequent tax years and with respect to all properties.[88] A taxpayer who has elected to capitalize intangibles has an additional election as to whether to write off currently intangibles incurred in drilling a dry hole or whether to capitalize them.[89]

A corporation, of course, has an election in this respect distinct from that of its individual stockholders.[90] A trustee of oil and gas properties also has an election as trustee distinct from his election as an individual.[91] A partnership constitutes a distinct entity for this purpose and should make a separate election.[92] As we note below, development by tenants in common under an operating agreement may constitute a partnership for this purpose.[93]

It is important that a taxpayer clearly indicate his election to deduct current intangibles in the first return *filed* by him after incurring such expenditures.[94] In the event he fails to clearly elect he will probably be deemed to have elected to capitalize intangible expenditures. If the taxpayer elected to capitalize such expenditures after initially drilling a productive well, he must in exercising his additional election with respect to intangibles incurred in the drilling of dry holes clearly make his election in the first return filed after incurring such expenditures.[95] This election is also binding with respect to subsequent tax years and as to all properties of the taxpayer.[96]

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85. U.S. Treas. Reg. 118, Sec. 39.23(m)-16; U.S. Treas. Reg. 118, Sec. 39.23(m)-18. The intangible drilling and development deduction provisions are found in the regulations and are not based on express statutory provisions although the deduction has been recognized for several years. To eliminate any doubt concerning the validity of the regulations relating to intangibles a joint resolution of Congress was adopted in 1945 approving these regulations. House Concurrent Resolution No. 50, 79th Cong., 1st Sess.
86. U.S. Treas .Reg. 118, Sec. 39.23(m)-16(a) (1) and (c) (1).
87. U.S. Treas. Reg. 118, Sec. 39.23(m)-16(b) (1) and (2); United States v. Dakota-Montana Oil Co., 288 U.S. 459, 53 Sup. Ct. 435 (1933).
88. U.S. Treas. Reg. 118, Sec. 39.23(m)-16(d).
89. *U.S. Treas. Reg. 118, Sec. 39.23(m)-16(b) (4).*
90. I. T. 3763, 1945 CUM. BULL. 113.
91. Dye v. Comm., 1942 BTA Memo. Op.
92. I. T. 3713, 1945 CUM. BULL. 178; Bentex Oil Corp. v. Comm., 20 T.C. ...., No. 76 (May 29, 1953).
93. Bentex Oil Corp. v. Comm., 20 T. C. ...., No. 76 (May 29, 1953). See discussion at *infra* 129.
94. U.S. Treas. Reg. 118, Sec. 39.23(m)-16(d).
95. U.S. Treas. Reg. 118, Sec. 39.23(m)-16(b) (4).
96. *Ibid.*

As a practical matter the option to capitalize or deduct currently intangible drilling and development expenses invariably is elected in favor of deducting such expenditures currently. In large part this is due to the fact that 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 27½% of the gross income can be taken regardless of the cost basis of the oil and gas property involved, nothing is gained by capitalizing the expenditures recoverable through depletion unless such costs if depleted on a cost depletion basis exceed the amount recoverable by statutory depletion over the life of the property.[97] If, as is usually the case, statutory depletion will exceed the amount recoverable through cost depletion with the intangibles capitalized, the failure to deduct intangibles as a current expense deprives the taxpayer of a substantial part if not all of the tax benefit he would otherwise derive from such expenditures.[98] A particular taxpayer might find it advantageous to capitalize such expenditures with respect to a particular property, but inasmuch as the election once made is binding with respect to all of the taxpayer's properties, a taxpayer who expects to develop additional properties ordinarily finds it advantageous to deduct such expenditures currently.[99]

97. Assume, for example, that intangibles incurred in drilling a well on a lease amount to $50,000 and that the acquisition cost of the lease was $50,000. Assume an estimated production attributable to the lease interest of 100,000 bbls. and the lessee's annual production as 10,000 bbls. producing a gross income of $250,000 to the lessee. If the intangibles are capitalized, the cost basis of the lease for depletion purposes is $100,000 and the per unit cost depletion allowance is $1.00 per bbl. (Cost basis ($100,000) divided by estimated recoverable reserves (100,000 bbls.). The cost depletion allowance assuming lessee's share of annual production to be 10,000 bbls. is $10,000. Statutory depletion on the other hand is 27½% of $250,000 or $59,750 provided that 50% of the net income from the taxpayer's interest in the property equals or exceeds this amount. The taxpayer obviously is going to take the statutory depletion allowance and each year he does so he must reduce his cost basis in the lease by the amount of the allowance. Accordingly, in two years the cost basis of the lease is going to be eliminated entirely and the taxpayer will have derived no benefit from the $50,000 added to the cost basis by capitalizing intangibles. If, on the other hand, the taxpayer deducted intangibles as a current expense he would have had a $50,000 deduction from ordinary income from other sources (a very substantial tax benefit if he has other income) and he can take the same statutory depletion allowance that he takes if he capitalizes intangibles. The foregoing is an oversimplification but is sufficient to indicate the general advisability of deducting intangibles currently.

98. This statement should be qualified to the extent of noting that if the intangibles are capitalized and if the property is sold prior to the recovery of the entire basis of the property through the depletion allowance, the taxpayer will receive some tax benefit in that to the extent that the cost basis has not been recovered by depletion it will be deducted from the sales price of the property in determining the taxpayer's gain on the transaction.

99. The importance of the intangible deduction in providing capital to an oil and gas operator cannot be overemphasized. If, for example, the operator drills a well on producing property and the intangible drilling expenditures relating to the drilling of the well are $60,000 he can, if he has made the proper election, deduct this amount from the net income received from that property or any other property or source in determining his net taxable income. Assuming, for example, that his net taxable income before deducting intangibles is $100,000 by taking the intangible deduction the taxpayer in effect received $60,000 of this amount free of taxes and can use this "tax-free" income to develop additional properties. Similarly, if the drilling results in a dry-hole the intangibles (and a substantial part of the expenditures involved in drilling a dry hole are intangibles) can be offset against income from other sources. The taxpayer who capitalizes intangibles can deduct such capitalized costs as an

What are intangible drilling and development expenses? In general they are expenses incurred in "drilling of wells and the preparation of wells for production of oil or gas" which have no salvage value.[100] They include all expenditures for "wages, fuel, repairs, hauling, supplies," etc., incident to the drilling of a well and preparing it for production.[101] Geological expenses directly related to the drilling of and preparing for production a particular well are within the option,[101a] 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.[101b] Expenditures incurred in the construction of derricks, tanks, pipe lines and other physical structures necessary for the drilling of the well and the preparation of the well for production are within the option,[102] but the cost of the physical installation themselves must be capitalized and recovered through depreciation.[103] Accordingly, the cost of items having salvage value such as pipe, casing, tubing, tanks, engines, boilers, pumps, etc., must be capitalized and recovered through depreciation.[104]

Although the cost of installing physical items having a salvage value used in connection with the drilling of wells and their preparation for production are subject to the option, the Bureau 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,[105] has been installed.[106] Accordingly, the cost of installing oil well pumps, separators, gathering lines, storage tanks, salt water disposal equipment, recycling equipment, etc., is not within the option and must be capitalized.[107] On the other hand the cost of installing casing, tubing, the Christ-

ordinary loss in the year in which the property is abandoned. However, in order to take the loss deduction the entire property must be abandoned . See *infra* 118-119. Accordingly, the taxpayer cannot deduct such costs as individual dry holes are drilled (in the absence of abandoning the entire property) as he can in effect do by electing to deduct intangibles as current expenses. One informed tax writer has observed that the intangible drilling and development deduction is more important to the oil and gas operator than the more widely publicized statutory depletion allowance. See Jackson, *supra* note 4, at 21-22.

100. U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (a) (1).
101. *Ibid.*
101a. *Ibid.*
101b. I.T. 4006, 1950-1 CUM. BULL. 48.
102. U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (a) (1).
103. U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (c) (1).
104. *Ibid.*
105. As near as the author, who is not versed in the art of petroleum engineering, has been able to determine the "Christmas tree" is a group of valves that control the flow of production from the well and are installed on a producing well after the casing and tubing, but prior to the installation of the pump.
106. Mim. 6754, 1952-1 CUM. BULL. 30.
107. Mim. 6754, *supra* note 106, specifically provides 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. (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 common carrier pipeline, natural gasoline plant, or carbon

mas tree, derricks and other physical equipment installed before the Christmas tree can be deducted as intangibles.[108]

A taxpayer on an accrual basis can deduct intangibles only in the year in which they are incurred which may or may not coincide with the year in which the well is completed.[109] Expenditures incurred in operating the wells are not, of course, within the intangible deduction.[110] However, intangible expenses incurred in deepening the hole or reworking the hole are subject to the option.[111] 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.[112] However, wells drilled to dispose of salt water are not, according to the Internal Revenue Service, incident to production and are not within the option.[113]

A taxpayer who incurs intangible expenses subject to the option can take the deduction regardless of whether he uses his own equipment and employees to drill the well or whether he contracts to have the well drilled.[114] Accordingly, under current regulation a taxpayer who contracts with a drilling contractor for the drilling of a well under a "turnkey" contract[115] or on a footage basis[116] can take the intangible deduction.[117] If a well is drilled under a "turnkey" contract a breakdown should be made by the taxpayer with respect to the portion of the contract price attributable to intangibles and the portion attributable to tangibles otherwise the Commissioner may make an allocation on an arbitrary percentage basis.[118] The contract can specify the respective costs of tangibles and in-

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black plant. (8) Recycling equipment, including any necessary pipelines. (9) Pipelines from oil storage tanks on the producing leasehold to a common carrier pipeline.

108. Mim. 6754, 1952-1 CUM. BULL. 30.
109. Great Western Petroleum Corp. v. Comm., 1 T. C. 624 (1943)
110. U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (c) (2).
111. Consolidated Mutual Oil Co., 2 B.T.A. 1067 (1925); Monrovia Oil Co., 28 B.T.A. 335 (1933).
112. Page Oil Co., 41 B.T.A. 952 (1940) held that the taxpayer could not capitalize and recover through depreciation the cost of water wells drilled for the purpose of stimulating production and that the cost of the drilling of such wells should be considered as development costs recoverable only through the depletion allowance and, therefore, presumably (although the Board did not decide this particular point) subject to the option relating to intangible drilling and development costs. U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 specifically provides that labor, supplies, etc. used in shooting a well are within the option. Since the primary function of an oil pump is to stimulate production it appears to this author that the installation costs of an oil pump are "incident to and necessary for the drilling of wells and the preparation of wells for the production of oil or gas" in the same sense that shooting the well or drilling input wells is. However, as noted in the discussion at note 107 the position of the Internal Revenue Service is otherwise.
113. Mim. 6754, 1952-1 CUM. BULL. 30.
114. This is true with respect to intangibles incurred for tax years subsequent to December 31, 1942. U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (a) (1).
115. A "turnkey" contract is one under which the contractor agrees to drill a well to completion for a specified contract price. Prior to the change in the appropriate regulation in 1942 a taxpayer could not deduct intangibles if the well was drilled prusuant to a turnkey contract. J. K. Hughes Oil Co. v. Bass, 62 F.2d 176 (5th Cir. 1932).
116. A "footage" contract is one under which the contractor agrees to drill the well for a specified price per foot of hole drilled.
117. U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (a) (1).
118. See, e.g., Helvering v. Twin Bell Oil Syndicate, 293 U.S. 312, 55 Sup. Ct. 174 (1934).

tangibles; 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.[119] 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.[120]

Who can take the option? The Regulation provides that the option 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."[121] However, the deduction can be taken by an "operator" only to the extent such expenses are "incurred by" him[122] and only to the extent his fractional part of the operating rights bears to the total operating rights.[123] Thus if the taxpayer owns 50% of the lease but pays only 25% of the drilling costs of a well drilled on the lease he can take only 25% of the intangibles as a deduction and can capitalize only 25% of the depreciable expenditures.[124] If, on the other hand, the taxpayer who owns 50% of the lease (operating rights) pays the entire drilling costs, he can deduct only 50% of such charges with respect to intangibles and capitalize only 50% of the depreciable expenditures.[125] If, as is usuualy the case in this type of situation, the expenditures are made in return for an interest in the lease, all such expenditures in excess of the amount attributable to the fractional share acquired by the taxpayer must be regarded as part of the acquisition costs and recovered through the depletion allowance.[126]

The Tax Court recently held in the *Platt* case[127] that an investor who

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119. ANDERSON, *op. cit. supra* note 1, at 55, 58.
120. U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (c) (1); Mim. 6754, 1952-1 CUM. BULL. 30.
121. U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (a) (1).
122. U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (a) (1), Platt v. Comm., 18 T. C. 1229 (1952).
123. U.S. Treas. Reg 118, Sec. 39.23 (m) -16 (a) (1); Ortiz Oil Co. v. Comm., 102 F.2d 508 (5th Cir. 1939).
124. In the *Ortiz* case, *supra* note 123, the taxpayer was engaged among other things in the business of drilling oil wells and drilled the well in question on a lease in which it had a half-interest under a trunkey agreement with the owners of the other half interest to drill the well for a specified contract sum. Inasmuch as the other interest owners paid more than their proportionate share of the drilling costs the taxpayer was permitted to deduct as intangibles only the amount actually paid by the taxpayer. The excess of the amount the other interest owners paid over their proportionate share of the drilling costs, the court regarded as income to the taxpayer.
125. U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (a) (1), Platt v. Comm., 18 T. C. 1229 (1952).
126. U.S. Treas.2 Reg. 118, Sec. 39.23 (m) -16 (a) (1). Under the current regulation whether the interest is asigned before or after the completion of the drilling is of no consequence.
127. 18 T. C. 1229 (1952). U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (a) (1) as amended in 1942 specifically provides that "... in any case where any drilling or development project is undertaken for the grant or assignment of a fraction of the operating rights, only that part of the costs thereof which is attributable to such fractional interest is within this option." Prior to the amendment of this regulation all such costs had to be capitalized as part of the acquisition costs of the lease. Berkshire Oil Co. v. Comm., 9 T. C. (1947). When a taxpayer acquires an interest in oil and gas acreage in return for drilling a well on the acreage his expenditures in part represent the cost of the lease interest and in part his proportionate share of the well costs. It is

acquires a fractional undivided interest in a lease and a well being drilled thereon could not under the factual situation there involved deduct any part of the investment as intangible drilling and development expenses. The operator-promoter who sold the interests contracted to drill the well to a specific depth but apparently did not represent that the proceeds would be used in their entirety for this purpose. The Tax Court held that even assuming that the promoter-operator contracted to use the proceeds to drill the well and did in fact use the proceeds in the drilling of the well, the taxpayer-investor could not deduct a proportionate part of the intangibles and must capitalize the entire investment as the acquisition cost of his interest in the lease and recover same through the depletion allowance.

Three possible alternatives are suggested by the *Platt* case to avoid the impact of that decision. First, it is clear that if the taxpayer-investor purchases an interest in a lease and is then assessed for his proportionate part of the drilling costs that he can deduct intangibles and capitalize depreciables to the extent of the assessment.[128] Second, if the promoter-operator acts as the taxpayer-investors agent in arranging for the drilling of the well, the taxpayer-investor can deduct intangibles and capitalize depreciables.[129] This suggests using language of agency in the operating agreement and presumably precludes the operator from taking any secret profits in connection with the transaction.[130] Third, the same tax results may possibly be accomplished by segregating in the contract of sale that portion of the contract price that represents the cost of the interest in the lease and that portion which represents the investor's contribution to the drilling cost of the well. Although the *Platt* case did not directly hold that under these circumstances the taxpayer-investor could deduct intangibles with

virtually imposible to accurately allocate such costs between the lease interest and the well interest. The regulation now provides a practical method of making such allocation by permitting the taxpayer to deduct that portion of intangibles paid by him to the extent of his interest in the lease. Essentially the same problem is presented when an investor buys an interest in a lease and the proceeds of his investment are to be used in drilling a well. Part of his investment represents the cost of the lease interest he acquires and part represents his share of the costs of the drilling. Accordingly, he should be permitted to deduct as intangibles that part of such costs attributable to his fractional interest. If, for example, he acquires one/one-hundredth interest in the operating rights and pays $2,000 for such interest asuming that intangibles incurred total $100,000 he should be permitted to deduct $1,000 as his proportionate part of the intangibles and required to capitalize as acquisition costs the balance of his investment. However, the Tax Court in the *Platt* case rejected this argument primarily because the taxpayer did not agree to do the drilling in exchange for an interest in the lease and the drilling was not done by him directly or by contact or through an agent. If the taxpayer had overcome this barrier, the Tax Court makes clear that he would then have to make an adequate showing of the fact that no more than his fractional share of the cost is included in the option deduction.

128. ". . . 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 rights to expense such costs under the option granted in Section 29.23 (m) -16 (b) of Regulations 111." Letter of Chief Counsel of the Bureau of Internal Revenue dated June 24, 1952 quoted in Platt v. Comm., *supra* note 127, at 1231.

129. Platt v. Comm., 18 T.C. 1229 (1952). See also W. D. Ambrose, 42 B.T.A. 1405 (1940), *aff'd* 127 F.2d 47 (5th Cir. 1942).

130. An agent cannot take secret profits. RESTATEMENT OF AGENCY (1933) Secs. 388-389.

respect to that portion of the contract price representing his contribution to the drilling costs, it carefully distinguished this situation from the facts there involved.[131]

Inasmuch as only one who owns an operating interest can deduct intangibles it is apparent that royalty (landowner's and overriding) owners cannot take the deduction nor can the owner of a net profit interest or of an oil payment.[132] A participating interest owner is also precluded from taking the deduction inasmuch as typically such interests merely entitle the owner to a specified percentage of the production after deduction of part of the operating costs without giving him operating rights.[133] Under current regulations a driller who drills a well in exchange for an interest in the operating rights can deduct that part of intangibles and capitalize that part of depreciables that are attributable to the fractional interest he acquires for drilling the well.[134] However, if the taxpayer drills a well in exchange for an oil payment he must capitalize all of the drilling costs as the acquisition cost of the oil payment and receover such costs through depletion inasmuch as he has not acquired operating rights and is not, therefore, an "operator" within the definition of the Regulations.[135]

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 use the money received from investors and did use it in the drilling of the particular well in which they invested.[136] 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".[137] If, on the other

131. 18 T. C. 1229, 1233 (1952). In addition to the three suggestions cited in the text, if the interest owners constitute a joint venture or partnership the joint-venture or partnership could take a deduction for intangibles. It is not clear, however, as to what type of arrangement results in creating a partnership or joint-venture. See Fischer v. Comm., 14 T.C. 792 (1940). Bentex Oil Corp. v. Comm., 20 T.C. ______ No. 76 (May 29, 1953). In the event the interest holders desire to be regarded as a joint-venture or partnership, they should file a partnership return of income pertaining to the lease in question. Bentex Oil Corp. v. Comm., *supra*. However. being regarded as a partnership or joint-venture may have some undesirable non-tax consequences.

132. U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (a) (1).

133. See, for example, the interests involved in Transcalifornia Oil Co. Ltd., 37 B.T.A. 119 (1938). However, as a practical matter there is little if any difference between such interests and an interest in a lease accompanied by an agreement giving the operator irrevocable agency authority to operate and develop the lease. Accordingly, although Reg. 118, Sec. 39.23 (m) -16 (a) (1) defines operating rights to include "a leasehold interest" it is conceivable that in this situation the Commissioner may contend that the owner of the lease interest is not an "operator" within the meaning of the Regulation.

134. U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (a) (1).

135. Rowan Drilling Co. v. Comm., 130 F.2d 62 (5th Cir. 1942); U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (a) (1).

136. Transcalifornia Oil Co. Ltd. v. Comm., 37 B.T.A. 119 (1938).

137. Rogan v. Blue Ridge Oil Co., 83 F.2d 420 (9th Cir. 1936); U. S. v. Knox-Powell Stockton Co., 83 F.2d 423 (9th Cir. 1936); Thompson v. Comm., 28 F.2d 247 (1928); Rawco Inc., 37 B.T.A. 128 (1938). Although the cases have generally regarded such monies as "income" presumably on the theory that it represents the promoters profit on the drilling operations, conceivably in some situations all or part of the proceeds represent the gain on the sale of an interest in the property in which event the

hand, the operator can establish that the proceeds from the sale of the oil payment[138] or other oil and gas interests are pledged for use in development they are regarded as a reduction in the development costs of the operator rather than as income.[139] Accordingly, the promoter-operator can take intangibles and can capitalize depreciables only to the extent that the total costs incurred in drilling the well exceeds the amount realized from investors.[140] It is readily apparent that an arrangement of this type is undesirable in that no one is permitted to take a deduction for part of the intangibles or recover part of the depreciables through the depreciation allowance–the investor is unable to do so because of the *Platt* case[141] and the promoter-operator is unable to do so because of the foregoing principles.[142]

Regulation 118, Sec. 39.23 (m)-16 provides that intangible drilling and development costs "include the cost to operators of any drilling or development work (excluding amounts payable only out of production . . .) done for them by contractors under any form of contract, including turnkey contracts." The exclusion noted apparently prevents an operator from deducting intangibles when they are paid for by an oil payment and this is the position of the Internal Revenue Service.[143] This exclusion would also appear to apply to a "carried interest"[144] with respect to the carried party's right to deduct intangibles in that they are "payable only out of production. . . ." However, three circuit court decisions,[145] the most recent of which is *Commissioner of Internal Revenue v. J. S. Abercrombie Co.,* 162 F.2d 338 (5th Cir. 1947), have led a number of commentators to believe that the carried party can deduct his proportionate share of the intangibles.[146] In all three cases the court held that the carried party must report as taxable income his proportionate share of the proceeds from production used to reimburse the carrying party in the year which earned despite the fact that the carried party did not actually receive such proceeds. Only the *Harris* case,[147] expressly dealt with the question of deductibility

gain may be a capital gain. *Cf.* Vern W. Bailey, 21 T.C. .... No. 76 (Feb. 9, 1954). As to determination of the holding period with respect to such sales see *infra* 111-112. Note also in connection with this problem the discussion of Ortiz Oil Co. v. Comm., 192 F.2d 508 (5th Cir. 1939) at note 124.

138. G.C.M. 24849, 1946-1 CUM. BULL. 66; I.T. 4003, 1950-1 CUM. BULL. 10.
139. Transcalifornia Oil Co., 37 B.T.A. 119 (1938). *But cf.* Ortiz Oil Co. v. Comm., 102 F.2d 508 (5th Cir. 1939) discussed at note 124.
140. Ortiz Oil Co. v. Comm., 102 F.2d 508 (5th Cir. 1939); Transcalifornia Oil Co. v. Comm., 37 B.T.A. 119 (1938).
141. 18 T.C. 1299 (1952).
142. See *supra* 100-101 as to suggestions for avoiding the impact of the *Platt* case.
143. G.C.M. 22730, 1941-1 CUM. BULL. 214. However, in I Rudman, 36 B.T.A. 803 (1937) intangibles payable out of oil were allowed as a deduction.
144. A "carried interest" situation usually involves an agreement under which one interest holder agrees to finance the drilling of a well and is to recover the other interest holder's proportionate share of the drilling costs out of production. The party finacing the drilling is the "carrying party" and the party whose proportionate share of the costs are to be paid out of production is the "carried party".
145. Comm. v. Abercrombie, 162 F.2d 338 (5th Cir. 1947); Reynolds v. McMurray, 60 F.2d 843 (10th Cir. 1932); T. K. Harris Co. v. Comm., 112 F.2d 76 (6th Cir. 1940).
146. Jackson, *Tax Planning Before Drilling,* XXVII TULANE L. REV. 21, 35-38 (1952).
147. T. K. Harris Co .v. Comm., 112 F.2d 76 (6th Cir. 1940).

of intangibles holding in this regard that the carried party could not deduct intangibles because the contract constituted a turnkey drilling contract. The Regulations have been changed since the decision in the *Harris* case to permit deduction of intangibles incurred under a "turnkey" drilling contract[147a] and accordingly it can be argued that the *Harris* case is authority for the proposition that the carried party can deduct intangibles. This conclusion is supported by the fact that the carried party is taxed on that part of his share of the proceeds used to reimburse the carrying party for the carried party's share of the intangible drilling costs and, therefore, can be said to have incurred such intangible drilling and development costs.[147b] Further the Fifth Circuit Court of Appeals in the *Abercrombie* case[148] regarded "the economic reality of the transaction" as a mortgage by the carried party to the carrying which suggests that the carried party can deduct intangibles in the same manner as one who has financed his share of the drilling costs by borrowing the money and pledging his interest in the production as security. The carrying party, on the other hand, under the rationale of the *Abercrombie* decision can deduct intangibles and capitalize depreciables only to the extent of his interest in the lease since as to the balance he is merely in the position of a secured creditor. Assuming that the carried party can deduct a proportionate share of the intangibles he probably cannot do so until his interest in the lease has earned income used to reimburse the carrying party in that until that time the obligation to pay such costs is merely a contingent one.[149]

To avoid the impact of the *Abercrombie* decision, which results in the party incurring the drilling expenses being limited to only a proportionate part of the intangibles and depreciables and on the other hand results in the imposition of a tax on the carried party for income he never receives, the following alternatives have been suggested:

(1) The assignor can assign the entire lease and reserve an override.

(2) The assignor can assign the entire lease and reserve a net profit interest. The net profit interest can, if the parties so agree, provide that the assignor is to be paid a specified percentage of the net profits after the operator has been reimbursed for drilling and operating costs.

(3) The assignor can assign the entire lease with a provision in the lease to the effect that when sufficient income has been accumulated to reimburse the assignee for one-half of the drilling costs, one-half of the lease is to revert back to the assignor.

As to suggestion (1) it is clear that the assignee owns all the operating rights and hence can take all of the intangibles as a deduction.[150] As to

147a. *Supra* 98.
147b. The weakness of this argument, however, is that under U.S. Treas. Reg. 118, Sec. 39.23(m)-16 the fact that an operator incurred such costs does not entitle him to take the intangible deduction if such costs are payable solely out of production.
148. 162 F.2d 338, at 340 (1947).
149. Sunburst Oil and Refining Co., 23 B.T.A. 829 (1931).
150. Kay Kimball, 41 B.T.A. 940 (1940).

suggestion (2) it is generally assumed[151] that the assignor reserving a net profit interest cannot deduct intangibles and cannot capitalize any part of depreciables and that the entire deduction is taken by the assignee-operator.[152] The cases cited in support of this proposition are not directly in point in that they relate to the question of whether a net profit interest is an economic interest in oil and gas in place and as to whether an assignment of a lease with a reserved net profit interest constitutes a sale or a sublease.[153] However, in concluding that a net profit interest is an "economic interest" the courts held that the owner of the net profit interest could take depletion with respect to and was taxable on only the net amount received.[154] It is, therefore, reasonable to conclude that the assignee-operator who is taxed on that part of the proceeds that represents reimbursement to him for expenses incurred in drilling the well has incurred such expenses and is entitled to take intangibles and to capitalize depreciables with respect thereto. In this regard, however, in drafting the net profit interest, care should be taken to grant all the operating rights to the operator and to reserve only an interest in the net profit as distinguished from an interest in the property; the court in the *Abercrombie* case regarded its decision as "controlled by the fundamental principle that income is taxable to the owner of the property producing the same. . . ."[155]

As to suggestion (3) some tax writers[156] are of the opinion that this arrangement avoids the consequences of the *Abercrombie* decision. This view is based in part on the fact that although the Internal Revenue Service has now acquiesced in the *Abercrombie* decision[157] after initially refusing to do so,[158] the Internal Revenue Service has never withdrawn G.C.M. 22730[159] which is in several respects inconsistent with the *Abercrombie* rationale and implications.[160] The Internal Revenue Service, therefore, can be expected to limit the *Abercrombie* decision to its particular facts and to distinguish situations similar to suggestion (3). However, in some situations it is advantageous to a particular taxpayer to follow *Abercrombie* and accordingly it is not unlikely that the Commissioner will be challenged

151. See, *e.g.*, Jackson, *Tax Planning Before Drilling*, XXVII TULANE L. REV. 21, 39 (1952).
152. G.C.M. 22730, 1941-1 CUM. BULL. 214.
153. Burton-Sutton Oil Co. v. Comm., 328 U.S. 25, 66 Sup. Ct. 861 (1946); Kirby Petroleum Co. v. Comm., 326 U.S. 599, 66 Sup. Ct. 409 (1946).
154. Burton-Sutton Oil Co. v. Comm., *supra* note 153; Kirby Petroluem Co. v. Comm., *supra* note 153; Helvering v. Mt. Producers Corp. 303 U.S. 376, 58 Sup. Ct. 623 (1938); Comm. v. Felix Oil Co., 144 F.2d 276 (9th Cir. 1944).
155. Comm. v. Abercrombie, 162 F.2d 338, 340 (1947). One disadvantage to the holder of the net profit interest as compared to the working interest in this situation is that the working interest owner can take statutory depletion as to the gross income attributable to his interest whereas the net profit interest owner can take depletion only with respect to the net income received by him. Comm. v. Felix Oil Co., 144 F.2d 276 (9th Cir. 1944).
156. See *e.g.*, Jackson, *Tax Planning Before Drilling*, XXVII TULANE L. REV. 21, 37-38 (1952). For a contrasting view see Bergen, *Oil and Taxes—Some Problems and Proposals*, 26 So. CALIF. L. REV. 396. 409 (1953).
157. 1949-1 CUM. BULL. 1.
158. 1946-2 CUM. BULL. 6.
159. 1941-1 CUM. BULL. 214.
160. *Ibid.*

in the courts in this regard as he was in the *Abercrombie* case. Accordingly, the taxpayer who wants to avoid *Abercrombie* would be well advised to rely on either suggestions (1) or (2) rather than suggestion (3) until the matter is clarified.

DEPRECIATION

The previous discussion relating to intangibles and to acquisition costs of oil and gas properties has necessarily referred in many instances to the depreciation allowance.[161] As previously noted intangible drilling and development costs cannot be recovered through depreciation, but if capitalized must be recovered through the depletion allowance.[162] On the other hand all expenditures involved in drilling a well representing the cost of tangible physical items must be capitalized and recovered through the depreciation allowance.[163] In addition all installation costs of tangible physical equipment after the installation of the Christmas tree must be capitalized and recovered through depreciation.[164] If the taxpayer elects to capitalize intangibles, the cost of installing physical items up to and including the Christmas tree, are also recovered through depreciation.[165]

The individual physical items involved in the drilling of a well, the preparation of a well for production and in producing a well can be capitalized separately and depreciation recovered with respect to each individual item.[166] Bulletin "F" sets forth the normal life expectancy of various items used in different phases of drilling and production;[167] however, the taxpayer can if supported be adequate experience of his own or of other operators use different life expectancies.[168] The individual item method as such is seldom used because of the bookkeeping detail involved and because no gain or loss can be taken when the individual items are retired unless the taxpayer has used the maximum expected life rather than the estimated average life in determining depreciation.[169]

Ordinarily with respect to oil and gas properties taxpayers use a group or composite basis in computing depreciation. Under this method the cost of all items in the group are included in a composite account and a single average life expectancy for the items as a group is used in computing

161. *Supra* 97-98.
162. *Supra* 96.
163. *Supra* 94-95.
164. *Supra* 97-98.
165. *Supra* 97.
166. Mim. 4170 (rev.), XV-2 CUM. BULL. 148 (1936).
167. Bulletin "F" provides the following typical life expectancies with respect to oil and gas equipment: Steel Drilling Derricks—10 years; Rotary Drilling Machine—8 years; Casing—20 years; Steel Pumping Derricks—20 years; Shackle Rods—10 years; Sucker Rods—3 years; Pumping Units (Electrical)—20 years; Separators—15 years; Tanks—20 years; Tubing and Packers—10 years.
168. Bulletin "F" (Revised Jan. 9, 1942) p. 3.
169. U.S. Treas. Reg. 118. Sec. 29-23 (e)-3 (discussed at *infra* 120); Bulletin "F", pp. 7-8; McGowen, *The Allowance for Depreciation and the Federal Income Tax Treatment of Depreciable Properties in the Oil and Gas Industry,* in PROCEEDINGS OF THE THIRD ANNUAL INSTITUTE ON OIL AND GAS LAW AND TAXATION 303, 324-325 (1952).

depreciation. Inasmuch as depletion must be computed separately for each "property"[170] and the computation of statutory depletion necessitates a determination of the depreciation charges relating to each property, it is ordinarily convenient to regard the depreciable equipment on each separate property as one composite account for depreciation purposes. If the unit of production method of computing depreciation is used, grouping by individual properties ordinarily must be employed inasmuch as estimated reserves can generally be determined only with respect to the entire property.

Any taxpayer having an investment in depreciable equipment can take a deduction for depreciation.[171] Ordinarily the owner of the landowner's royalty, overriding royalty, oil payment, and a true net profit interest cannot take any deduction for depreciation.[172] However, the 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.[173] In view of the rationale of the *Abercrombie* case[174] it would appear that the owner of a carried working interest is entitled to capitalize and recover through depreciation his proportionate share of the expenditures for depreciable items.[175] The taxpayer who drills a well in return for an interest in the lease can capitalize and recover through depreciation only that portion of expenditures on depreciables that is attributable to the interest he will acquire in the lease.[176]

The taxpayer can use any accepted method of computing depreciation.[178] However, once he adopts a particular method he can change to another only with the approval of the Commissioner.[179] The two commonly used methods of computing depreciation with respect to oil and gas properties are the straight line method and the unit of production method. Under the straight line method the depreciation allowance is determined by dividing the cost basis of the equipment less the estimated salvage value

170. *Supra* 89. If the composite or group method is employed upon the normal retirement of an asset included in the group its cost should be eliminated from the cost basis in determining the depreciation deduction in subsequent years. U. S. Industrial Alcohol Co. v. Helvering, 137 F.2d 511 (2nd Cir. 1943). If, however, an individual item in the group account is discarded prematurely so that a loss deduction can be taken (see *infra* 121-122) the life expectancy of the individual item rather than the group is used in determining the loss. *Ibid.*
171. U.S. Treas. Reg. 118, Sec. 39.23 (m) -18 provides as follows: "Taxpayers operating oil or gas properties will, in addition to and apart from the deduction allowable for depletion as hereinbefore provided, be permitted to deduct a reasonable allowance for depreciation of physical property such as machinery, tools, equipment, pipes, etc., so far as not in conflict with the option exercised by the taxpayer under Sec. 39.23 (m) -16. . . ." G.C.M. 22332, 1941-1 CUM. BULL. 228, Herndon Drilling Co. v. Comm., 6 T. C. 628 (1946).
172. Comm. v. Rowan Drilling Co., 130 F.2d 62 (5th Cir. 1942); Herndon Drilling Co. v. Comm., *supra* note 171; G.C.M. 22332, 1941-1 CUM. BULL. 228.
173. Notes 171 and 172 *supra.*
174. Discussed *supra* 102-103.
175. However, he may not be able to take such deduction until part or all of his share of the cost of the depreciables has been recovered by the carrying party. Sunburst Oil and Refining Co., 23 B.T.A. 829 (1931).
176. U.S. Treas. Reg. 118, Sec. 39.23 (m) -16 (a) (1).
178. U.S. Treas. Reg. 118, Sec. 39.23 (l) -5
179. Bulletin "F" (Revised Jan. 2, 1942) 4, 87.

by its estimated useful life. In this respect Bulletin "F" estimates the useful life of lease and well equipment as a group as twenty years.[180] However, if the economic life of the property is less than the life expectancy of the equipment the economic life of the oil and gas deposit may be used as the life expectancy of the equipment.[181]

Under the unit of production method the cost basis of the equipment less the estimated salvage value is divided by the total estimated number of barrels of oil (or thousand cubic feet of gas) that can be recovered from the property. The resulting figure is multiplied by the number of barrels (or thousand cubic feet of gas) produced during the tax year in order to determine the depreciation deduction.[182] Although the Commissioner has attacked the use of the unit of production method on several occasions, its use has generally been sustained by the courts.[183] The Board of Tax Appeals in one case indicated that it is a proper method only when the useful life of the equipment does not exceed the probable life of the resource.[184] However, the same case found that the unit of production method was a reasonable method of computing depreciation where as there the taxpayer's equipment would upon exhaustion of the field have a salvage value of 10%.[185] On the other hand Bulletin "F" provides that this method is not acceptable if the property has reserves "sufficient to extend operations beyond the physical life of the original plant."[186]

CAPITAL GAINS AND LOSSES

As is well known net long term capital gains result in a taxpayer, whether an individual or corporation, incurring a tax that cannot exceed 26% of the net long term gain.[187] A long term capital gain results from the sale of a capital asset that has been held longer than six months.[188] Long term capital losses and net short term capital losses can be offset against long term capital gains and in the case of an individual against $1,000 of ordinary income.[189] To the extent not so used such losses can be carried over for five subsequent years as short-term losses and offset against subsequent capital gains and in the case of an individual against $1,000 of ordinary income in each of the five years.[190] Because of the 26% tax

180. *Ibid.*
181. U.S. Treas. Rtg. 118 Sec. 39.23(m)-18. However ,in this regard 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.
182. The method is identical to the method used in computing cost depletion except a different cost basis is used. See *supra* 89 for discussion of cost depletion.
183. Golconda Oil Co., 7 B.T.A. 955 (1927); W. T. & M. Co., 11 B.T.A. 722 (1928); Rainbow Gasoline Corp., 31 B.T.A. 1050 (1935); Majestic Oil Corp., 42 B.T.A. 659 (1940). U.S. Treas. Reg. 118, Sec.39.23 (l)-5(a) appears to expressly permit the use of the unit of production method of depreciation generally.
184. Edwin H. Brady, 7 B.T.A. 818 (1927).
185. *Ibid.*
186. Bulletin "F" (Revised 1942).
187. INT. REV. CODE Sec. 117(c). Unless Congress provides otherwise the long-term capital gain tax maximum will be reduced 25% on April 1, 1954. See note 6.
188. INT. REV. CODE Sec. 117(a) (4).
189. INT. REV. CODE Sec. 117(d).
190. INT. REV. CODE Sec. 117(e).

limitation on long term gains and the 50% deduction allowed with respect to the excess of net long term gains over net short term losses,[191] it is always advantageous to taxpayers for a transaction to result in a gain taxed as a long term capital gain rather than as ordinary income. On the other hand because of the limitations noted with respect to deducting capital losses, it is ordinarily desirable for losses to be incurred as ordinary losses.

There can be no capital gain or loss unless the property involved is a capital asset and unless there is a sale.[192] Whether a particular transaction involves a sale with respect to oil and gas properties has been the subject of considerable litigation. A number of transactions that would appear to involve a sale are for tax purposes deemed to be a sublease or lease rather than a sale. With respect to such transactions any consideration paid in connection with the transaction is considered an advance royalty subject to taxation as ordinary depletable income.[193]

If the "vendor" reserves an economic interest in the oil or gas which interest will continue during the productive life of the property the transaction is a lease or sublease and not a sale.[194] Accordingly, if the fee owner receives a cash consideration for executing an oil and gas lease in which he reserves a royalty[195] or if an oil and gas lessee assigns his lease for a cash consideration reserving an override[196] or a net profit interest[197] no sale is involved and the consideration received by the taxpayer is taxed as ordinary depletable income. If, on the other hand, the taxpayer reserves an oil payment and no other interest, the transaction involves a sale subject to capital gain treatment (other requirements thereof being present) in that the taxpayer has not reserved an economic interest that will continue during the entire life of the lease.[198] However, if the taxpayer reserves an override and an oil payment, he has reserved an economic interest which will continue during the productive life of the property and the entire transaction is considered a sub-leasing transaction and the cash consideration taxed as ordinary depletable income.[199]

The taxpayer must not only retain an economic interest that will continue during the productive life of the property, but it must be in the nature of a "royalty" or comparable interest against which the cash pay-

191. INT. REV. CODE Sec. 117.
192. INT. REV. CODE Sec. 117; Burnet v. Harmel, 287 U.S. 103, 53 Sup. Ct. 74 (1932).
193. Herring v. Comm., 293 U.S. 322, 55 Sup. Ct. 179 (1934).
194. Kirby Petroleum Co. v. Comm., 326 U.S. 599, 66 Sup. Ct. 409 (1946).
195. Herring v. Comm., 293 U.S. 322, 55 Sup. Ct. 179 (1934); Burnet v. Harmel, 287 U.S. 103, 53 Sup. Ct. 74 (1932); Berg v. Comm., 33 F.2d 641 (DC-Cir. 1929) G.C.M. 22730, 1941-1 CUM. BULL. 214.
196. Palmer v. Bender, 287 U.S. 551, 53 Sup. Ct. 225 (1933); G.C.M. 27322, 1952-2 CUM. BULL. 62.
197. Kirby Petroleum Co. v. Comm., 326 U.S. 599, 66 Sup. Ct. 409 (1946).
198. Hammonds v. Comm., 106 F.2d 420 (10th Cir. 1939); Comm. v. Fleming, 82 F.2d 324 (5th Cir. 1936); G.C.M. 22730, 1941-1 CUM. BULL. 214.
199. Palmer v Bender, 287 U.S. 551, 53 Sup. Ct. 225 (1933).

ment may be treated as an advance.[200] If the taxpayer sells all or a part of a royalty,[201] of a lease,[202] of a net profit interest,[203] of an oil pay-payment[204] or of a participating interest,[205] the transaction involves a sale rather than a lease or sublease in that even if the taxpayer retains a part of his original interest any income accruing thereunder results from his ownership of such interest and not from "royalty" or other comparable payments created as a result of the conveyance.[206] A conveyance of an undivided part of the mineral rights would also fall within the foregoing classification and as such involve a sale; however, if the grantee of such rights obligates himself to drill a well or wells the transaction has many of the characteristics of an oil and gas lease and the court may find that the transaction is in substance a lease rather than a sale of the minerals.[207]

An oil payment is frequently created as the result of an assignment of a lease in which the assignor reserves a specified oil payment. However, in some instances the lessee (or royalty owner) creates an oil payment by retaining his original lease (or royalty) and carving out of it for the benefit of his grantee a specified oil payment. The sale of a carved out oil payment as distinguished from a retained oil payment is regarded by the Internal Revenue Service as the assignment of future income and as such the consideration received by the vendor is taxed as ordinary depletable income rather than as a gain (or loss) from the sale of a capital asset.[208] If the

200. Bankers Mortgage Co. v. Comm., 1 T.C. 698 *aff'd* 141 F.2d 357 (4th Cir. 1944) *cert. denied* 323 U.S. 727.
201. R. R. Ratliff, 36 B.T.A. 762 (1937); G.C.M. 12118, XII-2 CUM. BULL. 119 (1933); I. T. 3693, 1944 CUM. BULL. 272.
202. Badger Oil Co. v. Comm., 118 F.2d 791 (5th Cir. 1941); Berry Oil Co. v. U.S., 25 F. Supp. 97 (Ct. Cl. 1939) *cert. denied* 307 U.S. 634 (1939); Roy H. Laird, 35 B.T.A. 75 (1936); Tex-Penn Oil Co., 28 B.T.A. 917 (1933); I.T. 3693, 1944 CUM. BULL. 272. The court in the *Berry* case *supra* said: ". . . The plaintiff has disposed of one-half of the oil below the 2,000 foot level and had no investment therein after the agreement had been executed. It had an interest in the remaining half, but the nature of that interest was simply the right to receive it—not as rent or a payment."
203. This would appear to follow from the fact that a net profit interest is an "economic interest" in oil or gas in place and as such an interest in real property for tax purposes. Kirby Petroleum Co. v. Comm., 326 U.S. 599, 66 Sup. Ct. 409 (1946); I. T. 3693, 1944 CUM. BULL. 272.
204. I. T. 4003, 1950-1 CUM. BULL. 10; G.C.M. 24849, 1946-1 CUM. BULL. 66. However, under current rulings the grantor who carves out an oil payment has made an assignment of future income even though the oil payment is a capital asset in the hands of the grantee. See note 208 and related text.
205. Rawco, Inc., 37 B.T.A. 128 (1938). However, a grantor carving out a participating interest may thereby realize income. See note 137 and related text.
206. Berry Oil Co. v. U. S., 25 F. Supp. 97 (Ct. Cl. 1939) *cert. denied* 307 U.S. 364.
207. See, *e.g.*, West v. Comm., 150 F.2d 723 (5th Cir. 1945); G.C.M. 27322 1952-2 CUM. BULL. 62.
208. I.T. 4003, 1950-1 CUM. BULL. 10 *Cf.* Ortiz Oil Co. v. Comm., 102 F.2d 508 (5th Cir. 1939) in which the court held that the assignment of a carved out oil payment for cash consideration resulted in a sale and presumably the resulting gain if otherwise qualified was subject to capital gain tax treatment. The Internal Revenue Service initially distinguished between carved out short-lived and long-lived oil payments regarding the assignment for cash of the latter as a sale and the assignment of the former for cash as an assignment of future income. I.T. 24849, 1946-1 CUM. BULL. 66. The same distinction was initially made with respect to a gift of a carved out oil payment—a gift of a long-lived oil payment was regarded as complete so that the income received therefrom should be taxed to the donee, whereas a "gift" of a short-lived oil payment was regarded as an incomplete gift and the proceeds from

carved out oil payment is sold for cash and the vendor pledges that he will use the proceeds in drilling and developing the lease to which the oil payment relates, the vendor has not, under current Internal Revenue Service constructions, made a sale and the proceeds are applied to reduce the development cost of the property.[209] The assignment of an oil payment in return for the drilling of a well or for equipment used in the drilling of a well is a non-taxable pooling arrangement rather than a sale.[210]

Inasmuch as an assignment by a lessee who reserves an oil payment is regarded as a sale, whereas an assignment with a reserved override is regarded as a sublease, taxpayers frequently prefer to reserve an oil payment so that the consideration received by them will be regarded for tax purposes as a capital gain rather than ordinary depletable income. If, however, the oil payment is so large that there is little if any likelihood that it will be paid off during the productive life of the property, the Internal Revenue Service may regard the oil payment as the equivalent of a reserved override and tax the consideration received as ordinary depletable income.

Real property and depreciable property used in a taxpayer's trade or business are accorded special tax treatment under Section 117 (j) of the Internal Revenue Code. With respect to short term gains or losses (resulting from the sale of assets held for six months or less) relating to such assets the gain is regarded as an ordinary gain and the loss as an ordinary loss.[211] With respect to long term gains or losses (resulting from the sale of assets held for for more than six months) such gains and losses are set off against each other and if there is a net long term gain it is treated as a capital gain whereas if there is a net long term loss it is treated as an ordinary loss.[212]

Oil and gas interests can be capital assets, stock in trade, or property used in the taxpayer's trade or business. If they constitute capital assets, any sale thereof is subject to capital tax treatment.[213] If they constitute real property or depreciable property used in the taxpayer's trade or busi-

the oil payment taxed to the donor. I.T. 3935, 1949-1 CUM. BULL. 54. *Cf.* R.E. Nail, 27 B.T.A. 33 (1932) holding that a gift of a carved out oil payment of short duration was not an assignment of income and that the proceeds should be taxed to the donee. In 1950 the Internal Revenue Service abandoned the distinction between short-lived and long-lived oil payments and took the position that the sale of all carved out oil payments and all gifts of carved out oil payments, regardless of the probable span of the oil payment, involved the assignment of future income. Accordingly a sale of a carved out oil payment involves an anticipation of future income income and the cash received by the vendor is taxable as ordinary depletable income; a gift of an oil payment according to this view results in the income accruing under the oil payment being taxable to the donor. I.T. 4003, 1950-1 CUM. BULL. 10. For an excellent critique of these rulings see Kuntz, *Assignments of Oil Payments*, 31 TAXES 863 (1953).

209. G.C.M. 22730, 1941-1 CUM. BULL. 214; G.C.M. 24849, 1946-1 CUM. BULL. 66; I.T. 4003, 1950-1, CUM. BULL. 10.
210. G.C.M. 22730, 1941-1 CUM. BULL. 214.
211. INT. REV. CODE. Sec. 117 (j) (1).
212. INT. REV. CODE Sec. 117 (j) (2).
213. INT. REV. CODE Sec. 117.

ness, they are Section 117 (j) assets. If they are held primarily as stock in trade, any sale thereof results in an ordinary gain or loss.[214] It is, therefore, important to determine whether the taxpayer acquires properties primarily for the purpose of development, for investment, or for resale. In the event they are acquired primarily for development they are Section 117 (j) assets; if acquired primarily for investment they are capital assets[215] and if acquired primarily for the purpose of resale they are stock in trade.[216] It is readily apparent that a difficult factual question is involved in each such instance in determining for this purpose the proper classification of the asset sold.[217] An oil and gas company regularly engaged in the business of developing oil and gas properties ordinarily acquires property used in its trade or business when it purchasse a lease or when it purchases minerals for development purposes.[218] If a company or individual acquires a royalty of any type inasmuch as such interests ordinarily are merely held for investment purposes and require no personal services or management duties, they probably constitute capital assets rather than Section 117 (j) assets.[219] However, in the latter situation it is also necessary to determine whether the oil and gas interests are acquired for resale in which event they are stock in trade.[220]

Several problems arise in determining the holding period of oil and gas properties with respect to the sale of capital assets and Section 117 (j) assets none of which have been clearly resolved by the courts. The holding period of a lessor who grants a lease and sells a retained royalty interest probably runs from the date on which he acquired the mineral rights rather than the date of the lease which is also the date on which the royalty as such came into existence.[221] If the rationale of the decisions so holding is that the taxpayer is in effect selling part of his retained oil rights, the same rationale would lead to the conclusion that a taxpayer selling an override, oil payment, net profit interest or any other interest retained by him should regard the holding period as beginning on the date the original mineral interest was acquired rather than the date on which the retained interest is created. If, however, the taxpayer carves out an oil payment from a lease or from any other oil and gas interest the present position of

214. INT. REV. CODE Sec. 117 (a) (1) (A); Greene v. Comm., 141 F.2d 645 (5th Cir. 1944). *cert. denied* 323 U.S. 717.

215. Foran v. Comm., 165 F.2d 705 (5th Cir. 1948). U.S. Treas. Reg. 118, Sec. 39.117 (a) -1 provides in part: ". . . Property held for the production of income, but not used in a trade or business of the taxpayer, is not excluded from the term 'capital assets'. . . ." But see, I.T. 3693, 1944 CUM. BULL. 272.

216. INT. REV. CODE Sec. 117 (a) (1) (A); Greene v. Comm., 141 F.2d 645 (5th Cir. 1944) *cert. denied* 323 U.S. 717; Faring v. Comm., 13 T.C. 8 (1949).

217. Compare, *e.g.*, Greene v. Comm., *supra* note 216 with Foran v. Comm., 165 F.2d 705 (5th Cir. 1948).

218. Fackler v. Comm., 133 F.2d 509 (6th Cir. 1943); Faring v. Comm., 13 T. C. 8 (1949); I. T. 3693, 1944 CUM. BULL. 272.

219. Fackler v. Comm., *supra* note 218.

220. Greene v. Comm., 141 F.2d 645 (5th Cir. 1944) *cert. denied* 323 U.S. 717; Foran v. Comm., 165 F.2d 705 (5th Cir. 1948); Faring v. Comm., 13 T. C. 8 (1949).

221. Alice G. Kleberg, 2 T. C. 1024 (1943).

the Internal Revenue Service is that he has anticipated future income and as such realized ordinary depletable income.[222]

The holding period of an oil and gas lease subject to an escrow agreement does not begin to run until the conditions of the escrow agreement are complied with.[224] The decision so holding indicated that if the escrow condition was the drilling of a well that the holding would begin with the drilling of the well and the acquisition of the lease.[225] However, a recent decision of the Fourth Circuit Court of Appeals held with respect to a productive lease that the holding period did not begin until production was obtained.[226] The rationale of the decision is that the taxpayer acquires a different property when production is obtained and that it is this new property that he sold rather than the original property. This decision has been criticized by several tax writers[227] and may not be followed in subsequent decisions; however, it must be contended with and taxpayers accordingly would be well advised not to sell productive properties until six months after production is obtained.

Assuming that a sale of an oil and gas property including lease equipment involves the sale of a capital asset or a section 117 (j) asset, the taxpayer in determining the gain or loss will have two cost bases to take into consideration: (1) the acquisition cost of the lease and (2) the acquisition cost of the lease equipment. These cost bases will be identical to those used with respect to determining cost depletion and depreciation respectively. The initial cost bases must in each instance be adjusted by reducing it by the amount of allowable depreciation (or depletion) or by allowed depreciation (or depletion) if the latter is greater. If allowed depreciation (or depletion) exceeded allowable depreciation (or depletion), the taxpayer now reduces his basis only to the extent that he derived a tax benefit from the excess of allowed over allowable.[228]

If the taxpayer sells his entire interest in the property, it will probably be regarded as two separate sales—(1) a sale of the well equipment and (2) a sale of the oil and gas interest.[228a] If the taxpayer retains a royalty or other continuing economic interest, he has made a sale of the well equipment and has subleased the oil and gas rights.[228b] If, on the other hand, the taxpayer retains only an oil payment, he has made a sale of the equip-

222. G.C.M. 24849, 1946-1 CUM. BULL. 66; I. T. 4003, 1950-1 CUM. BULL. 10. See discussion at note 208 and related text.
224. Howell v. Comm., 140 F.2d 765 (5th Cir. 1944).
225. *Ibid.*
226. Petroleum Exploration v. Comm., 193 F.2d 59 (4th Cir. 1951) *rev'g* 16 T. C. 277.
227. See, *e.g.*, Bergen, *Oil and Taxes—Some Problems and Proposals,* 26 SO. CALIF. L. REV. 396, 402 n. 30 (1953).
228. INT. REV. CODE Sec. 113 (b) (1) (B) (ii). For tax years prior to 1952 basis must be reduced by greater of allowable or allowed depreciation even if excess of allowed over allowable did not result in a tax benefit unless the taxpayer files an irrevocable election in accordance with subsection (d) of INT. REV. CODE, Sec. 113.
228a. Morris Investment Corp. v. Comm., 5 T. C. 583 (1945) *aff'd* 156 F.2d 748 (3rd Cir. 1946); Krahl v. Comm., 9 T. C. 862 (1947).
228b. *Supra* 108.

ment and a sale of the oil and gas rights.[228c] In all three situations it is necessary to determine what part of the purchase price represents the sales price of the equipment and what part represents the sales price (or bonus, as the case may be) for the oil and gas rights. In all three situations an allocation in the contract of sale will ordinarily be determinative.[228d] If, however, the contract does not make an allocation the taxpayer can in the situation in which he reserves an override recover from the purchase price the amount of his unrecovered basis in the well equipment and regard the balance of the purchase price as a bonus (and as such ordinary depletable income) paid for the subleasing of the oil and gas rights.[229] If the taxpayer reserves an oil payment so that the transaction involves a sale rather than a lease or sublease, he probably can apply the consideration received to the recovery of his entire basis in the depreciable equipment and regard the balance as the sales price of the oil and gas rights.[230] If the taxpayer sells a productive property and retains no interest in the oil and gas rights, the allocation of the sales price should be made on the basis of the relative fair market values of the well equipment and the oil and gas rights.[230a] In determining the gain resulting from a transaction in which the vendor retains an oil payment, the taxpayer should divide his basis in the depletable property between the interest sold and the interest retained on the basis of their relative fair market values at the date of the transaction.[231] The taxpayer does not, however, have to allocate part of his basis in the depreciable equipment to the retained oil payment if the contract of sale clearly provides that the vendor is selling all of his interest in the equipment.[231a] In all three situations the purchaser in the absence of contractual allocation should determine his basis in the property acquired by allocating the sales price to depreciable equipment cost and depletable oil and gas rights cost according to their relative fair market values.[232]

NET OPERATING LOSSES

A net operating loss is the loss resulting from an excess of allowable deductions over gross income and is computed with respect to a taxpayer's

228c. *Supra* 108.
228d. Fraser v. Nauts, 8 F.2d 106 (N. D. Ohio 1925).
229. Louisiana Land and Exploration Co. v. Comm., 6 T. C. 172 (1946). The basis of the retained interest is the taxpayer's original basis in the oil and gas right. *Ibid.* *Cf.* Choate v. Comm., 324 U.S. 1, 65 Sup. Ct. 469 (1945).
230. Thomas v. Peckham Oil Co., 115 F.2d 685 (5th Cir. 1940). However, it is not clear as to whether any issue was made in this regard. The principal problem involved the determination of the basis in the retained oil payment. See note 231 (a) and related text.
230a. Krahl v. Comm., 9 T. C. 863 (1947). Ordinarily it will not make any difference in this situation as to how the sales price is allocated as the loss can be offset against the gain. It may, however, make a difference in a situation in which the taxpayer has different holding periods re the equipment and the oil and gas interest and will definitely make a difference in the situation in which the taxpayer is precluded from taking a loss because of INT. REV. CODE Sec. 24 (b) (1) relating to losses disallowed because of the relationship of the vendor and the vendee.
231. Columbia Oil and Gas Co. v. Comm., 118 F.2d 459 (5th Cir. 1941).
231a. Thomas v. Peckham Oil Co., 115 F.2d 685 (5th Cir. 1940).
232. Johnson Lumber Company v. Comm., 12 T. C. 348 (1949); Hazeltine Corp., 32 B.T.A. 4 (1935); Grain King Manufacturing Co., 14 B.T.A. 793 (1928).

entire operations and not with respect to any particular property.[233] A taxpayer incurring a net operating loss can carry back such loss for one year and after carrying it back can carry forward any remaining loss for five successive years.[234] However, in computing the net operating loss it must be adjusted by reducing it by the amount statutory depletion exceeds cost depletion in the year in which the loss in incurred.[235] Further, in carrying the loss back or forward it must be adjusted in every year carried by reducing it by the amount that the taxpayer's statutory depletion exceeds cost depletion for that particular year.[236] Inasmuch as statutory depletion will ordinarily exceed cost depletion, these adjustments have the effect of depriving the taxpayer of tax benefits from the operating loss to the extent that statutory depletion exceeds cost depletion for the years involved since the taxpayer would have been permitted a deduction to this extent even in the absence of the net operating loss deduction. It is, therefore, ordinarily advisable for a taxpayer to avoid if possible incurring a net operating loss. This can be accomplished by timing expenditures (particularly with respect to intangibles), capitalizing delayed rentals and thereby reducing current expenses,[237] or by increasing income through the sale of an oil payment.[238] If, however, it is impossible for the taxpayer to realize other income to offset the net operating loss or to limit his expenditures so as to prevent such loss, he will of course take the net operating loss deduction inasmuch as he will ordinarily derive some tax benefit from the deduction.

LOSSES FROM WORTHLESS OR ABANDONED OIL OR GAS PROPERTIES

The 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 though not connected with a trade or business.[239] In order to establish the loss it must be "evidenced by closed and completed transactions, fixed by indentifiable events, bona fide and actually sustained during the taxable period for which allowed. . . ."[240] There are three common methods of establishing a loss—(1) by sale, (2) by abandonment, (3) by proof of worthlessness. If, however capital assets[241] are involved and the loss results from a sale of the asset the taxpayer is allowed to take the loss

233. INT. REV. CODE Sec. 122(a).
234. INT. REV. CODE Secs. 122(b) (1) (B), 122(b) (2) (B).
235. INT. REV. CODE Sec. 122(d). Magale v. U. S., 93 F. Supp. 1004 (Ct. Cl. 1950); Louisiana Delta Hardwood Lumber Co., Inc. v. Comm., 7 T.C. 994 (1946).
236. INT. REV. CODE Sec. 122(d).
237. *Supra* 92.
238. The sale of a carved out oil payment results in the receipt of ordinary depletable income according to current constructions of the Internal Revenue Service. See discussion at note 208 and related text.
239. INT. REV. CODE Sec. 23(e). INT. REV. CODE Sec. 23(f) is the comparable provision relating to corporate losses. Section 23(e) also provides for certain loss deductions with respect to property not connected with trade or business that are not pertinent to this discussion.
240. U.S. Treas. Reg. 118, Sec. 23(e)-1(b).
241. See *supra* 110-111 as to when an asset is a capital asset.

only as a capital loss[242] and subject to the limitations relating to capital losses heretofore noted.[243] Accordingly, it is invariably desirable from the taxpayer's standpoint to establish the loss by abandonment or worthlessness in which event the taxpayer can take the loss as a deduction from gross income.[244]

The Commissioner at one time took the position that generally with respect to oil and gas interests the loss could be established only by relinquishment of the interest or by a completed transaction in the form of a sale.[245] While as one author has pointed out[246] this ruling would have the effect of permitting the taxpayer to choose the year in which to take the deduction, it would also have the effect in many instances of subjecting the loss to capital loss treatment and limitations. Accordingly, taxpayers had considerable at stake in urging the view that a loss could be taken as a deduction from gross income in the year in which some identifiable event establishes the loss and that in this connection it is not necessary for the taxpayer to relinquish (abandon) or sell his interest in the property provided the identifiable event establishes the worthlessness of the property in question. This view prevailed[247] but even after the Commissioner conceded as much[248] he took the position that in the absence of relinquishment or sale the taxpayer has to establish that there is no possibility of the interest becoming valuable in the future. With respect to oil and gas properties, according to the Commissioner, this would ordinarily require the penetration by drilling of all of the sedimentary beds underlying the property in question.[249] In *Harmon v. Comm.*,[250] the United States Tax Court rejected this view holding that a royalty (and presumably any oil or gas interest) "becomes worthless upon the happening of some event which results in the loss of its sale value in the ordinary channels of trade and would cause a prudent and informed businessman to eliminate it from the asset side of the balance sheet. . . ."

In view of the decision in the *Harmon* case it is clear that a taxpayer can establish his loss with respect to an interest in oil and gas property by establishing that some identifiable event occurring during the tax year (usually the drilling of one or more dry holes on the particular property or on property sufficiently close geologically to condemn the property in question) has destroyed the saleability of the oil and gas interest in question in the ordinary channels of trade. It is not necessary in this regard for

242. INT. REV. CODE Sec. 23 (g); Aberele v. Comm., 121 F.2d 726 (3rd Cir. 1941); Blum v. Comm., 133 F.2d 447 (2nd Cir. 1943); Fischer v. Comm., 14 T. C. 792 (1950).
243. *Supra* 107.
244. INT. REV. CODE Sec. 23 (e), Helvering v. Gordon, 134 F.2d 685 (4th Cir. 1943).
245. S. M. 5700, V-1 CUM. BULL. 241 (1926).
246. Atwood, *Tax Treatment of Worthless Oil or Gas Properties* in PROCEEDINGS OF THE FOURTH ANNUAL INSTITUTE ON OIL AND GAS LAW AND TAXATION 434, 437-38 (1953).
247. Helvering v. Gordon, 134 F.2d 685 (4th Cir. 1943); Rhodes v. Comm., 100 F.2d 966 (6th Cir. 1939).
248. G.C.M. 3890, VII-1 CUM. BULL. (1928).
249. G. C. Harmon v. Comm., 1 T.C. 40 (1942) acq. in 1944 CUM. BULL. 12.
250. *Id.* at 56.

the taxpayer to relinquish his interest and if some identifiable event has in fact made the interest unsaleable the loss must be taken in that year and not in the year of relinquishment.[251] However, relinquishment by the taxpayer in the year in which the identifiable event has taken place will ordinarily avoid any dispute in this regard.[252]

If the taxpayer is relying on some identifiable event which has made the property worthless within the *Harmon* case definition of worthlessness, the taxpayer must refrain from disposing of the property in the year in which the loss is claimed in a manner which will result in the taxpayer directly or indirectly receiving a consideration for the property. The sale of property for $250.00 in one instance[253] and the fact that the property concededly had some value but less than $500.00[254] have been regarded as sufficient to establish that the property in question was not worthless. The law generally makes no provision for a partial loss resulting from a reduction in the value of the oil and gas interest and accordingly if the property has some value the loss cannot be established on the theory that it has become worthless.[255] In this regard the Tax Court has insisted that property will for this purpose be regarded as a single unit so that a taxpayer cannot (even if he has separate bases in the minerals and surface) deduct as a loss his basis in the minerals when the mineral rights are established to be worthless if the property has any value for any other purpose.[256] This decision, of course, has no application to the taxpayer who has only an interest in the minerals.[257]

The fact that the property in question must be worthless in order for the taxpayer to deduct a loss for worthlessness, 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 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.[258] However, the sale of the property for a considerable sum within a relatively short-time of the tax 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.[258a] If the taxpayer recovers part of the

251. G. C. Harmon v. Comm., *supra* note 249.
252. *Ibid.* Even with respect to losses established by abandonment it is necessary to establish worthlessness of the rights relinquished; otherwise the taxpayer has made a gift. Mack v. Comm., 129 F.2d 598 (2nd Cir. 1942).
253. Aberele v. Comm., 121 F.2d 726 (3rd Cir. 1941).
254. U. S. v. Sentinel Oil Co., 109 F.2d 854 (9th Cir. 1940) *cert. denied* 310 U.S. 645.
255. *Ibid.*
256. Louisiana Land and Exploration Co. v. Comm., 7 T. C. 507 (1946) *aff'd* 161 F.2d 842 (5th Cir. 1947); Coalinga-Mohawk Oil Co. v. Comm., 64 F.2d 262 (9th Cir. 1933). *But cf.* Pool v. U.S. 119 F. Supp. 202 (Ct. Cl. 1954).
257. Louisiana Land and Exploration Co. v. Comm., 161 F.2d 842 (5th Cir. 1947).
258. United States v. S. S. White Dental Mfg. Co., 274 U. S. 398, 47 Sup. Ct. 598 (1927); G. C. Harmon v. Comm., 1 T. C. 40 (1942).
258a. In Fischer v. Comm., 14 T. C. 792 (1950), for example, the taxpayer drilled a dry hole in 1943 and had been advised by a geologist that the drilling condemned the

loss in subsequent years, it becomes a part of his gross income in the year of receipt.[259] Although the Board of Tax Appeals has held that the taxpare is not precluded from subsequentlly taking a deduction for depletion with respect to the proceeds from an oil and gas interest previously written off as a loss,[260] Form 927, which must be filed in connection with a claim for a loss deduction resulting from worthlessness of mineral rights, contains an undertaking on the part of the taxpayer to refrain from taking statutory depletion with respect to such subsequent production to the extent of the loss deducted for worthlessness.

A number of pre-*Harmon* case decisions of the Tax Court appear to be outmoded by the decision in the *Harmon* case although they were not specifically overruled. Some tax commentators (and the Commissioner may do likewise) have continued to regard such decisions as controlling with respect to the narrow problem involved in each such case although to some extent at least they appear to be open to question in the light of the rationale of the *Harmon* case. Under these pre-*Harmon* case decisions a lessee ordinarily could take a loss deduction because of worthlessness of the lease only if he permitted the lease to be forfeited or otherwise terminated; in effect requiring the lessee to abandon the lease before taking the loss deduction.[261] Accordingly, under these decisions if the lessee continued to pay the delay rentals[262] or if he continued to produce the lease at a non-commercial rate in order to retain the lease[263] he was not permitted to take a deduction for worthlessness. Another pre-*Harmon* case decision held that the owner of a royalty could not, in effect, ever take a deduction for worthlessness as he was unable to forfeit (abandon) his interest.[263a] The rationale of these cases appears to be that the failure to relinquish (particularly, if the taxpayer has to expend money in order to prevent forfeiture) indicates that the taxpayer believes the property to have some value[264] and further in situations in which the taxpayer does not relinquish the property there is always the possibility that it will become

property in question. In 1944 the taxpayer invested an additional $5,000 and a gas company interested in obtaining the gas production invested an additional $15,000 in drilling another well on the lease which also proved to be dry. The Tax Court acknowledged that with only the 1943 experience before it that they would probably have concluded that the property became worthless in 1943, but that the action of the taxpayer and the gas company in 1944 led the court to conclude that the lease was not in fact worthless in 1943. See also discussion at note 266a.

259. Burnet v. Sanford & Brooks Co., 282 U.S. 359, 51 Sup. Ct. 150 (1931); Rhodes v. Comm., 100 F.2d 966 (6th Cir. 1939); G. C. Harmon v. Comm., 1 T.C. 40 (1942). Under current regulations, however, the taxpayer has to regard the recovery of losses taken in prior tax year as income only to the extent that the previous deductions resulted in a tax benefit. U.S. Treas. Reg. 118, Sec. 39.22(b)-12(1).

260. Louisiana Iron and Supply Co., 44 B.T.A. 1244 (1941).

261. A. T. Jergins Trust, 22 B.T.A. 551 (1931); Macon Oil and Gas Co., 23 B.T.A. 54 (1931); Roy Nichols, 17 B.T.A. 580 (1929).

262. A. T. Jergins Trust, 22 B.T.A. 551 (1931).

263. Macon Oil and Gas Co., 23 B.T.A. 54 (1931).

263a. Roy Nichols, 17 B.T.A. 580 (1929).

264. Macon Oil and Gas Co., 23 B.T.A. 54 (1931); A. T. Jergins Trust, 22 B.T.A. 551 (1931); Roy Nichols, 17 B.T.A. 580 (1929).

valuable in the future. In this latter regard the Tax Court in the royalty case referred to said:[265]

> Interests in royalty rights are interests running with the land, and unless specifically limited as to time or otherwise, are not forfeitable. They may become unsaleable, dormant for a time as it were, but still remain an asset, an asset of questionable value it may be, but nevertheless an asset, that may become valuable any day, and hence may not be deemed such an ascertained loss as to be deductible in determining net profits for taxation purposes.

This rationale is, of course, inconsistent with the decision of the *Harmon* case in which the Tax Court specifically held that the criterion of worthlessness is unsaleability. The Court in the *Harmon* case also rejected the argument that the interest might become valuable at some future date, stating, "We do not think, however, that the 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 of those particular areas."[266] The retention of the royalty by the royalty owner or the lease by the lessee (even in situations in which the lessee will have to expend money in order to retain the lease) would not in view of this rationale preclude the taking of a deduction for worthlessness if the royalty and/or the lease is in fact unsaleable in the ordinary channels of trade. The fact that the interest holder is willing to expend money in order to retain his property and prevent a forfeiture does not necessarily mean that the property is saleable or has any value from a practical standpoint. In many instances the interest holder has already made a substantial investment and is, therefore, willing to invest nominal additional amounts although the property has no market value.[266a]

The deduction as a loss of an investment in oil and gas rights can, of course, be taken with respect to producing properties to the extent that the taxpayer still has a basis in the property in question at the time the loss is established either because of worthlessness or by abandonment. Even in the absence of production inasmuch as a taxpayer cannot take a partial

265. Roy Nichols, 17 B.T.A. 580, 583 (1929).
266. G. C. Harmon v. Comm., 1 T. C. 40, 58 (1942).
266a. In Fischer v. Comm., 14 T. C. 792 (1950) which post-dates the *Harmon* case the Tax Court did regard the fact that the taxpayer spent additional money on the property as significant in establishing that the property was not worthless. However, the taxpayer in that case spent $5,000 (and another party spent $15,000) for the purpose of drilling an additional well after the year in which he claimed the lease became worthless. The court carefully distinguished the situation in which nominal sums are spent in the hope of salvaging a substantial investment stating in this regard—". . . but when we look at 1944 we find petitioner making a further investment of $5,000 in the drilling of the second well. This action did not corroborate, rather it negatives, the petitioner's claim of worthlessness. The record does not convince us that the $5,000 was an investment *in extremis*—a desperate attempt to salvage something from the ruins of a former larger investment. Rather, it speaks more loudly than petitioner's words of protest of a persisting value in the leases as gas and oil property. On the whole record, we conclude that the leases did not become worthless until they were abandoned after the second well proved to be a dry hole. Since this occurred in 1944, it follows that petitioner was not justified in claiming a deduction for worthlessness of his investment in 1943."

loss[267] it is clear that the entire property must become worthless or be abandoned before the loss deduction can be taken.[268] This is particularly true with respect to producing wells since the taxpayer's basis in the oil and gas interest (as distinguished from the physical equipment) must be recovered through the depletion allowance[269] and it is only to the extent that the basis is not recovered through depletion that the taxpayer has suffered a loss.[270] Inasmuch as depletion is computed with respect to each separate property no determination can be made of whether the depletion allowance is going to result in the recovery of the entire basis until the entire property is abandoned or becomes worthless.[271] Accordingly, the Tax Court has consistently held that the abandonment of a well in the absence of an abandonment of the entire prpoerty on which it is located does not permit the taxpayer to deduct as a loss the difference between the basis attributable to the well abandoned and the amount of depletion previously taken and attributable to that well.[272]

Are there any situations in which a taxpayer can deduct as an ordinary loss his investment in oil and/or gas interests or equipment without relinquishing the interest or equipment and without establishing its worthlessness? U.S. Treas. Reg. 118, Sec. 23 (e) -3 (a) suggests some such possibilities in that it provides that a taxpayer can deduct as an ordinary (as distinguished from capital) loss assets discarded permanently from use in the taxpayer's business when through some change in business conditions the usefulness of the asset in the business is suddenly terminated. To establish such loss it is necessary under the provisions of the regulation for the property to be prematurely discarded as the result of some unforseen cause. An ordinary loss for assets so discarded can be taken regardless of the fact that the property is sold as salvage for a fairly substantial sum,[273] and hence it is clear that it is not necessary under this provision to establish the worthlessness of the property. In *Coalinga-Mohwak Oil Co. v. Comm.*[274] a taxpayer who had purchased the fee title to both the surface and minerals, but who purchased the property primarily because of its oil potentialities, attempted to invoke this provision after the mineral rights became worthless to justify a deduction as an ordinary loss of the difference between the purchase price of the property and its "salvage" value for non-mineral purposes. The court refused to permit such deduction because the taxpayer knew that the property might prove nonproductive and therefore the discarding of the asset did not result from

267. U.S. v. Sentinel Oil Co., 109 F.2d 854 (9th Cir. 1940) *cert. denied* 310 U. S. 645.
268. Berkshire Oil Co. v. Comm., 9 T. C. 903 (1947).
269. See *supra* 95.
270. Witherspoon Oil Co., 34 B.T.A. 1130 (1936).
271. *Ibid.*
272. Witherspoon Oil Co., 34 B.T.A. 1130 (1936); Lyons v .Comm., 10 T.C. 634 (1948).
273. S. S. White Dental Manufacturing Co. v. U. S., 55 F. Supp. 117 (Ct. Cl. 1944); Industrial Cotton Mills, 43 B.T.A. 107 (1940). The salvage value can in fact be substantial; in the *White Dental* case the salvage value of the equipment at the time it was discarded from use in the business was estimated to be approximately $75,000 and was actually disposed of for $83,000.
274. 64 F.2d 262 (9th Cir. 1933).

an "unforseen cause". However, the court distinguished the case from a situation in which the taxpayer merely owned the minerals. In view of a subsequent decision limiting the *Coalinga* case to the proposition that a taxpayer who owns both the surface and the minerals must regard the property as a single unit for the purpose of establishing worthlessness,[275] the obvious inapplicability of this doctrine to the situation where the taxpayer owns only a right in the worthless minerals may have been the distinction the court had in mind. From the standpoint of forseeability of non-production there would appear to be no material difference between the situation in which the taxpayer purchases the entire fee and the situation in which he merely purchases mineral rights.

As previously discussed in detail a taxpayer can take as a deduction from gross income a reasonable allowance for depreciation of tangible physical equipment.[276] A taxpayer who depreciates the individual items (pumps, casing, tubing, etc.) and who uses the maximum life expectancy of the item in question, can upon its retirement, normal or otherwise, deduct as a loss any unrecovered basis in the item.[276a] If the taxpayer groups various items for depreciation purposes and if the depreciation rate is based on the life expectancy of the longest lived item in the group, the taxpayer can deduct as a loss the unrecovered basis of any item retired whether the retirement is normal or otherwise.[276b] If, however, the taxpayer groups various items into a single account for depreciation purposes and uses an average life expectancy he cannot in the case of normal retirement of the individual items deduct as an ordinary loss his unrecovered basis until the entire group of items has been retired.[276c] The extent to which the taxpayer can deduct such items as a loss prior to the retirement of the entire group will usually depend upon the extent to which U.S. Treas. Reg. 118, Sec. 39.23 (e) -3 (a) is applicable.

In the event the taxpayer for depreciation purposes groups all of the physical items relating to a single well into one account and uses the straightline method of depreciation, he can, if he forsees that the life of the

275. Louisiana Land & Exploration Co. v. Comm., 161 F.2d 842 (5th Cir. 1947).
276. *Supra* 105-107.
276a. U.S. Treas. Reg. 118, Sec. 39.23 (e) -3 (d). This entire discussion assumes that the taxpayer has adjusted his basis by the higher of allowed or allowable depreciation. If the taxpayer has not taken the full amount of the allowable depreciation in previous years he cannot deduct as a loss upon retirement any unrecovered basis attributable to his failure to take the full depreciation allowance in previous years. Kittredge v. Comm., 88 F.2d 632 (2nd Cir. 1937). Mim. 4170 (rev.), XV-2 CUM. BULL. 148 states in this regard: "A taxpayer is not permitted under the law to take advantage in later years of his prior failure to take any depreciation allowance or his action in taking an allowance plainly inadequate under the known facts in prior years." This is an area in which the Commissioner may attempt to rely on hindsight rather than an objective appraisal of the facts as they existed at the time the depreciation rate was set. See, *e.g.*, Illinois Pipe Line Co., 37 B.T.A. 1070 (1938). The ensuing discussion assumes that it is not necessary to establish worthlessness under U.S. Treas. Reg. 118, Sec. 23 (e) -3 (a) for it is clear that this regulation assumes the property will have salvage value at the time it is discarded. U.S. Treas. Reg. 118, Sec. 39.23 (e) -3.
276.b. U.S. Treas. Reg. 118, Sec. 39.23 (e) -3 (d).
276c. U.S. Treas. Reg. 118, Sec. 39.23 (e) -3 (b).

resource is going to be less than the life of the equipment, use the life of the resource as the life expectancy of the well equipment in determining the depreciation rate.[277] Accordingly, the taxpayer will recover his entire cost basis in the equipment through the depreciation allowance by accurately estimating the life expectancy of the resource as applied to the individual well. If the taxpayer has estimated the life of the resource incorrectly and it is exhausted before he has recovered his entire basis in the well equipment, this would appear to be normal retirement of all of the items in the group and he could take as a loss at that time any unrecovered basis in the well equipment.[278]

If the taxpayer groups all wells on a particular property into a single composite account for depreciation purposes using the straight-line method based on the average life expectancy of the well equipment, the taxpayer could not deduct any unrecovered basis relating to the abandonment of equipment on a single well upon normal retirement.[279] If, however, the well is not retired normally but because the particular well is no longer capable of producing, the taxpayer probably can take as a loss his unrecovered basis in the well equipment relating to the particular well. The principal problem in this respect is whether the equipment has been discarded from use in the taxpayer's business because of an unforseen cause.[280] The examples cited in the regulation make apparent that foreseeability is related to probability and if the event that has occurred is the type that is not probable, and therefore difficult if not impossible to account for in setting the depreciation rate, the event is not foreseeable.[281] In view of this fact the discarding of well equipment because of premature exhaustion of the resource would appear to justify a loss deduction.[282]

If, however, the taxpayer uses a property-wide composite account and determines the life expectancy of the equipment by the life expectancy of the resource, he probably cannot take a loss deduction for the unrecovered basis in a well abandoned because of non-production until the entire prop-

277. U.S. Treas. Reg. 118, Sec. 39.23 (m) -18 However, the taxpayer must in this regard establish to the satisfaction of the Commissioner that the reasonable life of the resource is shorter than the normal useful life of the physical equipment.
278. U.S. Treas. Reg. 118, Sec. 39.23 (e) -3 (b).
279. U.S. Treas. Reg. 118, Sec. 39.23 (e) -3 (b); Witherspoon Oil Co., 34 B.T.A. 1130 (1936).
279a. *Ibid.* U.S. Industrial Alcohol Co. v. Helvering, 137 F.2d 511 (2nd Cir. 1943); Aetna-Standard Engineering Co. v. Comm., 15 T. C. 284 (1950).
280. U.S. Treas. Reg. 118, Sec. 39.23 (e) -3.
281. U.S. Treas. Reg. 118, Sec. 39.23 (e) -3 (a) provides in part, ". . . in order to establish a loss requires proof of some unforseen cause by reason of which the property has been prematurely discarrded, as, for example, where an increase in the cost or change in the manufacture of any product makes it necessary to abandon such manufacture. . . ." This type of cause obviously is not unforseeable but since it is unlikely to happen it is difficult to take care of it through the usual deductions for depreciation or obolescence.
282. *Ibid.* However, the taxpayer probably has to establish that the equipment cannot be used for similar purposes on other properties either by him or by someone else. U.S. Treas. Reg. 118, Sec. 39.23 (e) -3 (a) specifically requires that "its use as such is permanently abandoned." See Mohawk Petroleum Co. v. Comm., 148 F.2d 957 (9th Cir. 1945) (concurring opinion) and compare Industrial Cotton Mills, 43 B.T.A. 107 (1940) with Wilson Line, Inc. v. Comm., 8 T. C. 394 (1947).

erty has been abandoned.[283] In this situation it would appear that since the depreciation rate is based on the average life of the resource, which takes into account the varying lives of the different wells on the same property, that the retirement of an individual well is normal retirement of one item in the composite account. If, however, the taxpayer can establish that the life expectancy of the resource used in determining the depreciation rate will equal or exceed the life of any asset in the composite account (that is, no well will produce longer than the life expectancy used), the taxpayer has used the life of the longest lived asset and accordingly can take the unrecovered basis of individual wells as a loss as they are individually retired.[284]

If the taxpayer uses a composite property-wide account and the unit of production method of computing depreciation, he cannot deduct as a loss his unrecovered basis in the equipment upon abandonment of individual wells. Inasmuch as in this situation the depreciation rate assumes a recovery of the cost basis in the equipment over the productive life of the entire property and the estimated reserves are computed for the entire property, "no retirement loss is allowable so long as the lease continues to produce and other equipment on the same lease is in use."[284a] The problem in this respect is very similar to the situation with respect to recovery upon abandonment of a single well of those costs normally recoverable through the depletion allowance.[284b]

If no loss can be taken under any of the foregoing theories with respect to oil and gas interests or equipment, the taxpayer may be able to obtain substantially similar deductions by selling the equipment if it has been held for six months and is a Section 117 (j) asset, as it frequently will be in the case of equipment and in the case of oil and gas interests other than royalty interests.[284c] The main advantage of taking a loss as an ordinary loss rather than a loss on the sale of Section 117 (j) assets is that with respect to the latter type loss, although it is regarded as an ordinary loss and hence is deductible from ordinary income, before it can be deducted it must (if it is a long term loss) be offset against long term gains resulting from the sale of other Section 117 (j) assets.[284d] In some instances this will result in reducing the loss or eliminating it entirely; while it is true that losses so applied reduce the amount of taxable gain the loss is being used to offset a gain taxable at capital gain rates.

The basis for determining the amount of the deduction for losses sustained when property is abandoned or becomes worthless is the adjusted

283 . U.S. Treas. Reg. 118, Sec. 39.23 (e) -3 (b).
284. U.S. Treas. Reg. 118, Sec. 39.23 (e) -3 (d); Illinois Pipe Line Co., 37 B.T.A. 1070 (1938); U. S. Industrial Alcohol Co. v. Helvering, 137 F.2d 511 (2nd Cir. 1943).
284a. Mohawk Petroleum Co. v. Comm., 47 B.T.A. 952, 958 (1942) *aff'd* 148 F.2d 957 (9th Cir. 1945).
284b. See *supra* 118-119.
284c. See *supra* 110-111 as to when property is a Section 117 (j) asset.
284d. See *supra* 110.

basis (Section 113 (b) of the Internal Revenue Code) used in determining the loss from the sale or other disposition of the property.[285] With respect to losses established on the theory of worthlessness or abandonment, no adjustment need be made for salvage value for presumably there is none. However, with respect to a loss based on the premature discarding of an asset because no longer useful in the taxpayer's business the loss allowed is the difference between the adjusted basis and the estimated salvage value of the asset in question.[286]

Section 130 of the Internal Revenue Code limits the losses that can be sustained by providing that if in each of five consecutive years the deductions (other than taxes and interest) 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. In making the required recomputation the taxpayer can deduct otherwise allowable deductions from gross income only to the extent that they do not exceed the gross income from the particular trade or business by $50,000 for that particular year. Accordingly, the net loss for each of the years involved relating to a particular business cannot exceed $50,000 upon recomputation. Further, in making the recomputation the net operating loss[287] for each such year must be eliminated entirely to the extent that it is attributable to such trade or business. The Internal Revenue Service has recently ruled that in computing the loss for Section 130 purposes, that in the case of partnerships the loss attributed to the taxpayer-partner is to be limited to the taxpayer's distributive share of the partnership loss.[288]

SEPARATE PROPRIETIES

As previously noted several tax determinations depend upon what constitutes a separate property. In this respect the 50% net income limitation on statutory depletion must be determined with respect to each separate property.[289] Before the taxpayer can deduct as a loss his basis in a worthless oil and gas interest the entire interest must be condemned or abandoned.[290] The recipient of a "bonus" must restore to income any depletion allowance taken with respect to such "bonus" in the year in which the lessee abandons the property in question.[291] Questions also arise as to what constitutes a "property" in computing a gain or loss on the sale of an oil and gas interest.[292] The Tax Court although conceding that the "argument is not with force" rejected the contention of the Commissioner that

285. G. C. Harmon v. Comm., 1 T. C. 40 (1942); U.S. Treas. Reg. 118, Ses. 39.23 (e)-2.
286. U.S. Treas. Reg. 118, Sec. 39.23 (3)-3 (a).
287. See *supra* 113-114 as to circumstances under which the net operating loss can be taken.
288. Rev. Rul. 155, I.R.B., August 17, 1953, p. 6.
289. *Supra* 90-92.
290. Berkshire Oil Co., 9 T. C. 903 (1947).
291. Driscoll v. Comm., 147 F.2d 493 (5th Cir. 1945).
292. *Supra* 107-113.

the "property" unit is the same for all tax purposes.[293] However, the determination of what constitutes a separate property for depletion purposes, for restoration of depletion to income, and for purposes of the loss deduction for worthlessness are necessarily interrelated and presumably a decision in one context is some authority in resolving the similar problem in another context.[294]

If a landowner owning an extensive tract of land enters into several leases with different individuals, each lease constitutes a separate property at least for restoration of depletion purposes.[295] A lease covering more than one tract is a single property if the tracts are contiguous along one side.[296] The Tax Court has held that noncontiguous tracts (including tracts contiguous only at one corner) covered by the same lease, each constitute separate properties for the purpose of determining whether the lessee can deduct a loss for worthlessness.[297] However, the Fifth Circuit Court of Appeals has held that non-contiguous tracts covered by the same lease constitute one property for the purpose of determining whether the lessor has to restore depletion on bonus to income.[298]

Internal Revenue Service rulings take the position that if a taxpayer acquires two adjacent tracts from two separate owners in the same year they are two separate properties at least for depletion purposes.[299] If, however, the taxpayer then sells the two adjoining tracts by the means of a single instrument his vendee acquires one property.[300] However, according to the rulings of the Internal Revenue Service, three separate properties result where a taxpayer acquires three non-contiguous tracts from one per-

293. Black Mt. Corp., 5 T. C. 1117, 1120 (1945). U.S. Treas. 118, Sec. 39.23 (m) -1 defines "property" with respect to the use of that term in connection with percentage depletion as follows: "The property, as used in Section 114 (b) (2) (3) and (4) and Sections 39.23 (m) -1 to 39.23 (m) -19, inclusive, means the interest owned by the taxpayer in any mineral property. The taxpayer's interest in each separate mineral property is a separate 'property'; but, where two or more mineral properties are included in a single tract or parcel of land, the taxpayer's interest in such mineral properties may be considered to be a single 'property' provided such treatment is consistently followed."

294. For an outspoken view to the contrary see Borden, *A Survey of "The Property" As Referred to in Section 114(b)(3) of the Internal Revenue Code*, OIL AND GAS TAX QUARTERLY 15 (1953). Mr. Borden's view is that the "mineral deposit" as such is the property for purposes of determining statutary depletion and that the boundaries of the tract or parcel determine the property for other tax purposes (gain and loss loss on sale, abandonment, loss, etc.). See in this connection discussion at note 304. It is clear from the decisions that the Tax Court regards "the property" for depletion purposes as closely related to the property for purposes of abandonment. Witherspoon Oil Co., 34 B.T.A. 1130 (1936); Berkshire Oil Co., 9 T. C. 903 (1947).

295. Sneed v. Comm., 119 F.2d 767 (5th Cir. 1941).

296. Berkshire Oil Co., 9 T. C. 903 (1947). Each separate well ordinarily is not a separate property. Lyon v. Comm., 10 T. C. 634 (1948).

297. Berkshire Oil Co., 9 T. C. 903 (1947).

298. Houston Farm Development Co. v. Comm., 194 F.2d 521 (5th Cir. 1952). See also Driscoll v. Comm., 147 F.2d 493 (5th Cir. 1945). G.C.M. 22106, 1941-1 CUM. BULL. 245 is contra and takes the position that separate tracts are separate properties and that separate tracts exist when they are divided geographically.

299. G.C.M. 22106, 1941-1, CUM BULL. 245 as modified in G.C.M. 24094, 1944 CUM. BULL. 250.

300. *Ibid.*

son in a single deed.[301] The Tax Court has rejected the government's contention that each separate acquisition necessarily constitutes a separate property and accordingly it is not clear as to the extent that the taxpayer can combine as a single property tracts acquired as the result of separate acquisitions.[302] This situation frequently presents itself when an oil operator puts together a lease block consisting of a number of individual leases acquired from several lessors. The Tax Court in permitting the taxpayer to combine as one property separate acquisitions, regarded the "economic and practical unit" from the standpoint of operations as the "property" for depletion purposes.[303] Conceivably as applied to oil and gas development this view might permit a taxpayer to combine as a single property his interest in a single oil or gas pool, as from the operator's standpoint the pool is in many respects the economic or practical unit for operations.[304] However, on the other hand, inasmuch as each lease has its own drilling requirements, royalty provisions, etc., it could be argued that the individual lease constitutes the "economic" or "practical" unit for operation.[305]

Although the Commissioner has refused to acquiesce therein, the Tax Court has held that where the taxpayer received part of the working interest and an oil payment in one transaction, the taxpayer has two separate properties for the purpose of computing depletion.[306] The Commissioner had

301. *Ibid.* This appears to be contra to the holding of Houston Farm Development Co. v. Comm., 194 F.2d 521 (5th Cir. 1952).
302. Black Mt. Corp., 5 T.C. 1117 (1945). In this case the Tax Court held that the taxpayer could regard two contiguous coal mines separately acquired but involving the same seam of coal as one property disregarding in this regard G.C.M. 22106, 1941-1 CUM. BULL. 245. The court stated (at pp. 1121-22): "We are unable to see the necessity for the Commissioner's contention that every separate acquisition of coal lands must be treated as a separate property for the purpose of computing percentage depletion. Separate acquisitions can, under proper circumstances, be combined to form one property and, likewise, under proper circumstances, one acquisition may become a part of two different properties for this purpose."
303. Black Mt. Corp., 5 T.C. 1117, 1120 (1945).
304. Mr. Borden, *supra* note 294, argues that despite any Internal Revenue Service rulings or judicial decisions to the contrary that there can be no other conclusion with respect to "the property" for statutory depletion purposes. He argues that the appropriate regulations relating to a definition of "the property" for this purpose now have the force of law because of repeated statutory re-enactments since the adoption of the regulations. U.S. Treas. Reg. 118, 39.23 (m)-1, the argument continues, defines "the property" to mean "the interest owned by the taxpayer in any mineral property." U.S. Treas. Reg. 118, Sec. 39.23 (m)-1 (b) defines a "mineral property" as the "mineral deposit, the devlopment and plant necessary for its extraction, and so much of the surface of the land only as is necessary for purposes of mineral extraction. . . ." Accoringly, he concludes (at p. 19) that the property for statutory depletion purposes is "the three dimensions of the mineral deposit (namely, each separate productive structure or pool), the development and plant necessary for its extraction, and the two dimensions of such much of the surface only as is necessary for the purpose of mineral extraction. . . ." Although Mr. Borden does not cite the *Black Mt. Corp.* case, *supra* note 303, the reasoning of this case parallels his in many respects, the court relying in large part (at p. 1120) on the definition of a "mineral property" as found in U.S. Treas. Reg. 118, Sec. 39.23 (m)-1 (b).
305. The *Black Mt.* case, *supra* note 303, involved contiguous tracts. However, if the criterion for determining boundaries of separate properties for percentage depletion purpose is the oil and gas structure or pool the fact that the tracts are not contiguous should not make any difference in this respect.
306. Herndon Drilling Co. v. Comm., 6 T.C. 628 (1946) non-acq 1946-2 CUM. BULL. 6. *Cf.* Mascot Oil Co. v. Comm., 29 B.T.A. 652 (1933) (Petition for review dismissed) 75 F.2d 1009 (9th Cir. 1935).

previously established a precedent for this holding by successfully contending that a taxpayer who had a working interest with respect to one portion of a mine and a royalty interest with respect to another portion thereof, had two separate properties.[307] Two separate interests in the same property if separately acquired (*e.g.*, taxpayer acquires one-eighth working interest and subsequently acqures one-fourth working interest in the same tract) constitute two separate properties for tax purposes.[308] Although not entirely clear of doubt, a taxpayer may be able to regard two different minerals (*e.g.*, oil and gas) produced from the same horizon under the same tract as each constituting a separate property.[309] The taxpayer may at his election, provided he does so consistently, regard two or more mineral deposits (ordinarily production from two horizons) from the same tract as one property, if they were acquired as part of one transaction and would otherwise have been considered as a separate property if there had been only one mineral deposit.[310]

NON-TAXABLE EXCHANGES

Exchanges of property held for productive use in trade or business or for investment for property of a like kind are non-taxable.[311] The Fifth Circuit Court of Appeals has recently held that the exchange of a fee interest in the minerals for an oil payment is a tax-free exchange of real property interests of a like kind.[312] In reaching this conclusion the court rejected the contention that the interests were not of a like kind in that the mineral interest was for an indefinite period whereas the oil payment was for a definite period.[313] The court emphasized the fact that both were interests in the minerals and both were interests in real property.[314] Accordingly, it would appear that any type of oil and gas right can be exchanged for another oil and gas interest without incurring a tax.[315]

If the promoters of a corporation transfer oil and gas properties to a corporation which they control in exchange for stock the exchange is not taxable.[316] However, "control" for this purpose requires that the trans-

307. Helvering v. Jewell Mining Co., 126 F.2d 1011 (8th Cir. 1942). This case is, however, distinguishable from the *Herndon* case, *supra* note 306 in that the two interests were acquired at different times and related to different parts of the tract in question.
308. G.C.M. 24094, 1944 CUM. BULL. 250; ANDERSON, *op. cit. supra* note 1, at 80.
309. Gray v. Comm., 183 F.2d 329 (5th Cir. 1950) holding that for purposes of determining whether a transaction involves a sale or sublease that the oil rights and the gas rights relating to the same tract may be considered two separate properties.
310. U.S. Treas. Reg. 118, Sec. 39.23(m)-1(i); G.C.M. 22106, 1941-1 CUM. BULL. 245; G.C.M. 24094, 1944 CUM. BULL. 250.
311. INT. REV. CODE Sec. 112(b)(1). This tax-exemption, however, is not available to exchanges involving stock in trade or securities. *Ibid.*
312. Fleming v. Campbell, 205 F.2d 549 (5th Cir. 1943).
313. *Ibid.*
314. *Ibid.*
315. It has, for example, been held that an exchange of productive acreage for non-productive is an exchange of property of like kind. (E. C. Laster, 43 B.T.A. 159 (1940) as in an exchange of oil and gas rights for a fee interest in improved urban realty (Comm. v. Crichton, 122 F.2d 181 (5th Cir. 1941).) See also I. T. 4093, 1952-2 CUM. BULL. 130.
316. INT. REV. CODE Sec. 112(b)(5).

ferors own 80% of the voting stock and 80% of all other classes of stock of the corporation after the completion of the transaction.[317] If more than one individual is involved in the transfer, they must own after the transfer the same relative proportionate interest in the corporation as they owned in the property prior to its transfer to the corporation.[318]

The assignment of an oil and gas interest in exchange for equipment to be used in drilling a well on the same property or in return for an agreement on the part of the assignee to drill a well is not taxable. The transaction is view as a pooling or sharing arrangement rather than a taxable exchange of property of an unlike kind.[319] In connection with such transactions the assignor should allocate part of his basis in the oil and gas rights to the depreciable equipment in which he acquires an interest.[320] He cannot, however, as previously noted, deduct any part of the intangible drilling and development costs as they are not incurred by him.[321] If the assignor also receives cash in connection with the transaction he must treat the cash as income in determining the gain or loss on the sale of the interest.[322]

ASSOCIATIONS TAXED AS CORPORATIONS

It is generally desirable in order to avoid double taxation on income and in order to permit the taxpayer to obtain the full benefit of the statutory depletion allowance[324] to have the proceeds from production taxed to the individual interest holders rather than to an association taxable as a corporation.[325] Co-lessees under current rulings are not taxed as a cor-

317. INT. REV. CODE Sec. 112(h).
318. INT. REV. CODE Sec. 112(b) (5).
319. U.S. Treas. Reg. 118, Sec. 39.23(m)-16(a) (1); S. M. 3322, IV-1 CUM. BULL. 112 (1925); G.C.M. 22730, 1941-1 CUM. BULL. 214. See also Burton-Sutton Oil Co. v. Comm., 328 U.S. 25, 66 Sup. Ct. 861 (1946); Rawco Inc., 37 B.T.A. 128 (1938); E. C. Laster, 43 B.T.A. 159 (1940).
320. INT. REV. CODE Secs. 113(a) (6), 113(b) (2), 114(a), 114(b) (1). E. C. Laster, 43 B.T.A. 159 (1940). The allocation should be made on the basis of the relative fair market values of the depreciable and depletable properties. *Ibid.*
321. *Supra* 109.
322. G.C.M. 22730, 1941-1 CUM. BULL. 214. Whether regarded as ordinary income or a capital gain depends upon the usual factors discussed *supra* 107-113. The taxpayer determines his basis in the part sold by allocating the original basis between the part sold and the part retained on the basis of their relative fair market values. Columbia Oil and Gas Co. v. Comm., 118 F.2d 459 (5th Cir. 1941).
323. As is well known, corporate earnings are taxed to the corporation and when distributed to the stockholders are also taxable income to the stockholder. INT. REV. CODE Secs. 13 and 22a.
324. In determining a corporation's income for the purpose of determining the taxability of a corporate distribution to stockholders the excess of statutory depletion over cost depletion has to be added back to the net income of the corporation. U.S. Treas. Reg. 118, Sec. 39.115(a)-2(c) (1). Accordingly, to the extent that the corporate distribution represents the increment of net income resulting from the statutory depletion allowance the stockholder is taxed on income that would have been tax free if he (rather than the corporation) could have taken the statutory depletion allowance. A corporate stockholder cannot take the statutory depletion allowance with respect to corporate distributions based on earnings from oil and gas interests and this is true with respect to a closed corporation. Tressler v. Comm., 206 F.2d 538 (4th Cir. 1953).
325. The position of the Internal Revenue Service in regard to the taxation of oil and gas ventures as corporations is set forth in I. T. 3930, 1948-2 CUM. BULL. 126 and I. T. 3948, 1949-1 CUM. BULL. 161.

poration if the operating agreement reserves the right to the co-owners to take their share of the production in kind or if the co-owners reserve the right to direct the sale of the minerals produced.[326] The co-owners can reserve the right to direct the sale by individually entering into a purchase agreement or granting an option to purchase of an indefinite duration and in this respect it is immaterial that other co-owners enter into similar contracts provided they each enter into the contract as an individual and not through a common agent.[327] The co-owner may also in this respect grant irrevocable agency powers to dispose of his share of production provided his agent is not another co-owner or an agent with like powers of agency from another co-owner.[328] Nor, under present rulings, is the co-owner deemed to have lost the right to direct the sale of his share of production if he grants revocable at will authority to an agent representing two or more co-owners to enter into a purchase agreement or grant an option to purchase for such reasonable periods of time as are consistent with the minimum needs of the industry under the circumstances, but not to exceed one year.[329]

Co-lessees developing a property under an operating agreement constitute an association taxable as a corporation, according to current Internal Revenue Service rulings, if they irrevocably authorize another co-owner or agent with like powers of agency from another co-owner to act as their agent in selling their share of production or in granting options to purchase their share of production.[330] Co-owners who grant revocable at will authority to another co-owner or his agent, constitute an association taxable as a corporation if the agent has authority to conclude contracts of sale or to grant options for a period longer than reasonably required by the minimum needs of the industry under the circumstances.[331] In this regard the contract entered into or the option granted cannot be for a period of time exceeding one year.[332]

The foregoing summarizes the position of the Internal Revenue Service as to the manner in which co-lessees developing an oil and gas property are to be taxed. However, the position of the Service in this respect is not entirely consistent with some of the litigated cases. In *Stantex Petroleum Co. v. Comm.*[333] the operator was granted the right to contract for the sale of all the oil and gas produced including the share of various holders of fractional undivided interests in the lease. The operating agreement which was part of the assignment to interest holders did not limit the period for which such contracts could be granted and did not reserve in the interest holder the right to revoke the operator's authority to execute

326. I.T. 3930, 1948-2 CUM. BULL. 126; I.T. 3948, 1949-1 CUM. BULL. 161.
327. I. T. 3930, 1948-2 CUM. BULL. 126.
328. I. T. 3948, 1949-1 CUM. BULL. 161.
329. *Ibid.*
330. *Ibid.*
331. *Ibid.*
332. *Ibid.*
333. 38 B.T.A. 269 (1938) non-acq. 1938-2 CUM. BULL. 59.

contracts of sale relating to the production of oil and gas from the property in question. The Board of Tax Appeals held that the co-lessees were tenants in common and that the operator acted as their agent in developing the properties and marketing the output. They were, therefore, liable for any acts committed by the agent within the limitations of his authority and as such distinguishable from stockholders of a corporation. Accordingly, the Board held, there was not an association taxable as a corporation. In *Comm. v. Horeshoe Lease Syndicate,* 110 F.2d 748 (5th Cir. 1940) the Fifth Circuit Court of Appeals sustained a finding of the Board of Tax Appeals that co-owners who granted the authority to develop and market to an operator by a power of attorney constituted a partnership rather than a corporation. The majority of the court regarded the question as one of fact with respect to which the finding of the Board of Tax Appeals had to be sustained if supported by substantial evidence. In finding that it was supported by substantial evidence the court relied on the fact that the co-lessees had not achieved limited liability, management was not elected, no meetings were held, no by-laws enacted, and the co-owners had no voice in management.[334]

If the co-lessees do not constitute a corporation, are they taxable as individuals or as a partnership? Inasmuch as partners are taxed on their proportionate share of partnership net income as individuals[335] for many purposes, it does not make any difference whether they constitute a partnership or not. However, inasmuch as a partnership has a separate election with respect to the deduction of intangible drilling and development costs[336] it is important for this purpose and possibly for others to determine whether co-lessees constitute a partnership.[337] Internal Revenue Service regards such arrangements (assuming that they are not an association taxable as a corporation) as creating a "qualified partnership"[338] and one commentator[339] has suggested that the ruling of the Internal Revenue Service permits the co-lessees to determine whether they are to be considered a partnership or not although the language of the ruling itself is not clear in this respect. The Tax Court recently held that co-lessees did not constitute an association relying in large part on the fact that each co-lessee disposed of his own share of production and found that they constituted a partnership with a separate election as to the deduction of intangibles where they had consistently filed a partnership return of income.[340]

Assuming that co-lessees constitute an association taxable as a corporation, the owners of royalties (landowner's and overriding), oil pay-

334. Comm. v. Horseshoe Lease Syndicate, 110 F.2d 748 (5th Cir. 1940).
335. INT. REV. CODE Sec. 181 provides as follows: "Individuals carrying on business in partnership shall be liable for income tax only in their individual capacity."
336. Bentex Oil Corp. v. Comm., 20 T. C. ....No. 76 (May 29, 1953).
337. *E.g.,* whether investors who acquire an interest in an oil and gas well can deduct intangibles. See note 131 and related text.
338. I. T. 3930, 1948-2 CUM. BULL. 126.
339. Comment, II OIL AND GAS TAX QUARTERLY 253 (1953).
340. Bentex Oil Corp. v. Comm., 20 T.C. ....No. 76 (May 29, 1953).

ments, net profit interests, etc., are not members of the association and are taxed as individuals.[341] A corporation as a co-lessee can become a member of an association taxable as a corporation and in this regard the considerations heretofore noted are appropriate in determining whether an association of this type exists.[342] If a corporation enters into an operating agreement that is improperly drawn in this respect, the proceeds will be taxed as that of a separate corporation and the corporate stockholders in effect will be subject to double-plus taxation.[343]

UNITIZATION

The typical unit agreement results in effect in exchanging an oil and gas interest in specifically described acreage for a lesser interest of the same type in a larger tract.[344] This is apparent when unitization is accomplished by the actual exchange of cross-assignments. It is substantially true where unitization is accomplished by committing a particular oil and gas interest to the unit agreement without actually transferring title. In either event the transaction essentially involves the exchange of property of a like kind and as such is a non-taxable exchange.[345] The participant in the unit has in effect a fractional undivided interest in the unit with respect to which he can take depletion and deduct intangibles to the same extent as a fractional interest holder in any other type of oil and gas right.[346] Whether the unit participants constitute an association taxable as a corporation depends upon the same considerations previously noted with respect to the development of oil and gas properties by co-owners.[347]

FORMS

Regulation 118, Sec. 39.23 (m)-11 requires every taxpayer claiming a deduction for depletion and depreciation of mineral property to keep accurate accounts recording the cost of other basis of the mineral deposit and the plant and equipment together with subsequent allowable capital additions and all other required adjustments. The regulations also require that the taxpayer taking depletion or depreciation with respect to mineral

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341. Among other things there would not with respect to such interest appear to be ". . . centralized control of group affairs," which is one of the prerequisites to taxation as an association. I. T. 3930, 1948-2 CUM. BULL. 126, 128.
342. Bentex Oil Corp. v. Comm., *supra* note 340.
343. That is the association would pay the initial corporate tax, the corporation would have to regard 15% of the income received as part of their gross income for tax purposes (INT. REV. CODE Secs. 13 and 26(b)) and if the corporation distributed its earnings the stockholders would be taxed on their proportionate share of such earnings.
344. There are very few decisions, rulings, etc., specifically dealing with tax problems resulting from unitization agreements. Accordingly, considerable reliance has to be placed on rulings and decisions rendered in analgous situations.
345. Comm. v. Crichton, 122 F.2d 181 (5th Cir .1941); E. C. Laster, 43 B.T.A. 159 (1940); I. T. 4093, 1952-2 CUM. BULL. 130; *Unitizations Involving Cash Adjustments Upon Formation,* III OIL AND GAS TAX QUARTERLY 1 (1953).
346. *Supra* 86-107. Hill, *Tax Problems Arising Out of Unitization Agreements* in PROCEEDINGS OF THIRD ANNUAL INSTITUTE ON OIL AND GAS LAW AND TAXATION 427 (1942).
347. *Supra* 127-130.

properties submit the detailed data specified by the regulations.[348] The information required with respect to depletion data relating to oil and gas properties, can be furnished on Form O which can be obtained by request from the office of any director of internal revenue. If a taxpayer takes a deduction for worthless mineral rights, he should submit Form 927, Proof of Worthlesness of Mineral Rights.

The usual income tax forms are used by a taxpayer reporting income from oil and gas properties and the form used in this respect depends upon whether the taxpayer is an individual, partnership, trust or corporation. Oil and gas taxpayers operating properties as co-lessees under a form of co-ownership not resulting in an association taxable as a corporation[349] do not have to complete Form 1065, partnership return of income, but may simply "attach thereto a schedule showing the total working interest, names and addresses of the co-owners, the percentage of each co-owners' interest in the co-ownership, total costs and expenses billed each co-owner with respect to drilling for and producing the oil and gas and the total revenue credited in those cases where the operating co-owners distributed revenues to the other co-owner (by way of cash or credit) from the sale or other disposition of the co-owner's oil and gas."[350] If the co-lessees desire to be taxed as a partnership, it is probably advisable for them to submit a completed Form 1065 and an accompanying schedule. However, one tax commentator has suggested that the current Service ruling[351] permits the co-lessees to regard themselves as individuals not comprising a partnership and that if this is their intent they should not have the operator file Form 1065 and the accompanying schedule, but should submit the same information by schedules attached to their individual returns.[352]

CONCLUSION

We conclude as we began with a note of caution. The law relating to oil and gas income taxation is technical, complex, and in a constant state of flux. An attempt has been made in this article to set forth the law as found in the appropriate statutes, regulations, rulings and judicial decisions to the extent that it has crystallized. In the area in which the law is not clear an effort has been made to set forth the position of the Internal Revenue Service and to indicate the extent to which the courts have in the past and may in the future disagree with the Commissioner. In this latter area in particular the practitioner will want to consult the original sources and more specialized discussions when such problems arise.

348. U.S. Treas. Reg. 118, Sec. 39.23(m)-12 and 13.
349. See *supra* 127-130.
350. I. T. 2785, XIII-1 CUM. BULL. 96 (1934).
351. I. T. 3930, 1948-2 CUM. BULL. 126.
352. Comment, OIL AND GAS TAX QUARTERLY 235 (1953).