# **1 Federal Taxation of Oil and Gas Transactions § 3.03**

***Federal Taxation of Oil and Gas Transactions* > *CHAPTER 3 Percentage Depletion***

**§ 3.03 Limitation on Percentage Depletion Deductions Based on Taxable Income From Property**[[1]](#footnote-2)\*

1. **Generally**

The percentage depletion deduction, with respect to any given property, is limited to 100 percent of the taxable income from the property, computed without allowance for depletion.[[2]](#footnote-3)1

|  |
| --- |
| **Planning Note:**  2IRC § 613A(c)(6)(H).  With respect to marginal production properties, the taxable income limitation was suspended for tax years beginning after December 31, 1997, and before January 1, 2008 and for tax years beginning after December 31, 2008, and before January 1, 2012.[[3]](#footnote-4)2 The reason for the suspension was that Congress wanted to encourage the production of ***oil*** from marginal properties for which it would be uneconomical to continue production without the suspension of the limitation. |

For taxable years beginning before 1991, the limitation was 50 percent. As the 50 percent amount was in effect for many years, it has long been customary to refer to the “50 percent limitation.” In this treatise, we will call it the “taxable income limitation,” but it should not be confused with the “65 percent limitation” of Code Section 613A(d).[[4]](#footnote-5)3 The taxable income limitation (whether at 50 or 100 percent) is applied to the taxable income from the individual property, while the 65 percent limitation applies to the taxpayer’s aggregate taxable income from all sources.

The taxable income limitation applies regardless of whether percentage depletion is allowed under the independent producers and royalty owners exemption[[5]](#footnote-6)4 or under the exemption for certain domestic gas wells,[[6]](#footnote-7)5 and in fact applies to all natural deposits qualifying for percentage depletion.

The regulations define “taxable income from the property” as “gross income from the property as defined in [Code] Section 613(c) and [Regulations Sections] 1.613-1 and 1.613-4, less all allowable deductions (excluding any deduction for depletion) that are attributable to mining processes, including mining transportation, with respect to with depletion is claimed.”[[7]](#footnote-8)6 The Service has ruled that bonus exhaustion, which is excluded from depletable gross income, is also excluded in the computation of taxable income from the property.[[8]](#footnote-9)7 In other words, the depletable gross income used to compute the initial deduction is also used to compute the limitation based on taxable income. This result seems unfair because bonus exhaustion is, in fact, subject to tax, although not to percentage depletion. Moreover, it is not technically supported by the regulations.

1. **Deductions Generally**

In terms of ***oil*** and gas, deductions are required only for production expenses including the expense of selling production, but inherently excluding transportation or processing. The deductions allowed in computing taxable income for the taxable income limitation are the same as those allowed in computing taxable income subject to tax, including operating expenses, selling expenses, administrative and financial overhead, deductible taxes and losses, and intangible drilling and development costs.[[9]](#footnote-10)8 Some of these are directly attributable to a single property, and others must be allocated to each of the taxpayer’s producing properties.

The most important deduction is that for intangible drilling and development costs.[[10]](#footnote-11)9 The sheer size of this deduction will often eliminate any percentage depletion allowance for the taxable year by reducing taxable income from the property to zero. As a result, the timing of the IDC deduction is an important matter, with taxpayers often seeking to deduct these costs in the taxable year prior to initial production from the property. Deducting IDC for the purpose of the taxable income limitation is theoretically questionable because these same costs, if elected to be capitalized, do not reduce the limitation. In fact, the regulations under the Revenue Act of 1921 and the Revenue Act of 1924 computed the taxable income limitation with respect to discovery depletion by deducting only operating expenses, and not development costs, but changed to their current position under the Revenue Act of 1928. This continuing position of the regulations was upheld by the United States Supreme Court.[[11]](#footnote-12)10

Intangible drilling and development costs incurred with respect to a property must be charged against taxable income for limitation purposes regardless of whether the result is a dry hole or a producing well. In Revenue Ruling 77-136,[[12]](#footnote-13)11 the Service ruled that dry holes drilled in the development of a known deposit, whether interior development wells, “one location step-outs,” or “exploratory step-outs,” are chargeable to the taxable income of the property of which the deposit is a part. On the other hand, if the facts clearly indicate that the nonproductive well was drilled without the expectation of penetrating a known deposit, the drilling costs need not be deducted in determining the taxable income from any producing property. If a nonproductive well is drilled through a producing deposit in an unsuccessful attempt to reach a deeper separate mineral deposit, and is plugged back and completed as a producer in the producing deposit, only the portion of the IDC allocable to the producing deposit is charged against the taxable income from that deposit. However, if the well cannot be plugged back and completed due to well spacing regulations, no part of the costs is charged to the producing deposit. As discussed elsewhere, the ruling leaves unclear whether a separate property election under Internal Revenue Code Section 613(b)(2) is necessary to isolate the dry hole costs attributable to the search for a new deposit in the same tract.[[13]](#footnote-14)12

The ruling also holds that dry holes drilled prior to the completion of a productive well in the same property in the same taxable year are charged against the income from the productive well. If this is understood to mean that a taxpayer who leases a tract in anticipation of exploring two separate deposits, drills unsuccessfully for one prospective deposit, and then completes a producing well to the other prospective deposit in the same year, must charge the dry hole costs to the producing well, it is on uncertain ground. As discussed elsewhere, the view often asserted by the Service that a taxpayer has only one property in a tract until more than one deposit is proven, regardless of the number of prospective deposits, cannot be accepted as settled.[[14]](#footnote-15)13 However, in absence of evidence that the taxpayer was seeking separate deposits, the costs of dry holes should be charged against income from producing deposits developed later in the same taxable year.

Although not mentioned in the regulations, it would seem that dry hole costs deducted by a taxpayer who has elected to capitalize intangible drilling and development costs[[15]](#footnote-16)14 should be deducted for the purpose of the taxable income limitation in the same manner as IDC that is deducted as incurred. If the taxpayer elects to deduct intangible drilling and development costs over 60 months to avoid treatment as an item of tax preference,[[16]](#footnote-17)15 these deductions should likewise be deducted. Note that this election may be useful where the current deduction of all IDC incurred in the taxable year will eliminate or substantially reduce percentage depletion.

Abandonment losses on equipment have been held chargeable to the property under the authority of the regulations.[[17]](#footnote-18)16 As the regulations speak generally of “losses sustained,”[[18]](#footnote-19)17 casualty losses should likewise be deducted for limitation purposes.

Certain expenses have been held to be inapplicable to the taxable income limitation because they are thought to be unrelated to mineral production. Charitable contributions are not deducted, although payments to charitable organizations that are not contributions (such as payments to hospitals for medical services) are deductible to the extent they are attributable to production.[[19]](#footnote-20)18 Damage payments for breach of a sales contract due to lack of production were held by the Service to be nondeductible as “not attributable to mining.”[[20]](#footnote-21)19 Premiums paid for business interruption insurance were held nondeductible on the theory that they were payments to produce nonmining income and were, therefore, distinguishable from general mining overhead.[[21]](#footnote-22)20 Expenses incurred by a lessor that were arguably related to the operation of the lease were held nondeductible generally (and therefore inherently nondeductible for the taxable income limitation) because they were not the lessor’s obligation under the lease.[[22]](#footnote-23)21 Perhaps most significantly, the Service has ruled that net operating loss carryovers are not deductible for limitation purposes.[[23]](#footnote-24)22 This position is not based on the relationship of the carryover to mineral production, but rather on a determination that expenses should not have an impact beyond the taxable year in which they are paid or incurred.

1. **Administrative and Financial Overhead**

In the regulations issued under the Revenue Act of 1921[[24]](#footnote-25)23 and the Revenue Act of 1924,[[25]](#footnote-26)24 the Treasury required only that “operating expenses” be deducted in measuring the net income limitation for discovery depletion. The Revenue Act of 1926 replaced discovery depletion with percentage depletion but continued the limitation based on 50 percent of net income from the property.[[26]](#footnote-27)25 The regulations under the 1926 Act required the limitation to be computed using deductions for operating expenses, depreciation, and taxes.[[27]](#footnote-28)26 However, the regulations issued under the Revenue Act of 1928 expanded the list of deductions to include intangible drilling and development costs that the taxpayer had elected to deduct and overhead expenses. There was considerable resistance on the part of taxpayers to this expansion because many believed that Congress had intended the net income limitation to be computed only by reference to current direct operating expenses. The Board of Tax Appeals concluded in 1937 that overhead in the form of administrative salaries, interest, and office expenses, to the extent allocable to production activities, could be considered operating expenses in any event.[[28]](#footnote-29)27 However, the question was definitively settled by the 1939 decision of the United States Supreme Court in *Helvering v. Wilshire* ***Oil*** *Co.,*[[29]](#footnote-30)28 in which the Court held that the deduction of intangible drilling and development costs for limitation purposes was within the broad regulatory power granted to the Treasury in the depletion area. This decision inherently provided authority for the deduction of overhead expenses as indicated in the regulations[[30]](#footnote-31)29 and for the deduction of expenses attributable to other than the current year.[[31]](#footnote-32)30

The current regulations refer specifically to “administrative and financial overhead,”[[32]](#footnote-33)31 and the deduction of interest and taxes as an element of financial overhead was recognized before the regulations became this specific. As to interest, it was held that interest paid on debt used to purchase a mineral property is a direct charge to the taxable income from that property.[[33]](#footnote-34)32 Interest on general unsecured debt used for development of mineral properties was held deductible,[[34]](#footnote-35)33 as was interest paid on bonds,[[35]](#footnote-36)34 although neither of these cases considered the necessity of allocating such interest expense between mineral production and other activities. A premium paid pursuant to a repurchase of the taxpayer’s bonds was held to constitute allocable financial overhead.[[36]](#footnote-37)35 Recent cases have clarified that only net interest expense, that is, interest expense offset by interest income, is to be considered in making the deduction.[[37]](#footnote-38)36

Taxes directly attributable to producing properties, such as production, severance, ad valorem, and windfall profits taxes, may be considered direct operating expenses of the respective properties rather than allocable overhead. The regulations have long made specific reference to the deduction of taxes. However, some taxes might properly be considered part of financial overhead. In *Grison* ***Oil*** *Corporation,*[[38]](#footnote-39)37 Oklahoma state income taxes were held deductible in determining the limitation. Allocation of these taxes between different businesses was not required because the taxpayer was engaged only in ***oil*** and gas production. However, the Service has privately ruled that individuals who are partners in an ***oil*** and gas partnership need not deduct any portion of their state individual income taxes in computing the limitation.[[39]](#footnote-40)38 An allocable portion of deductible United Kingdom income taxes was held deductible for limitation purposes by a British corporation operating ***oil*** and gas properties in the United States.[[40]](#footnote-41)39 Note that taxes taken as a credit (such as the foreign tax credit) rather than as a deduction for federal income tax purposes, or capitalized, are not deducted for limitation purposes.[[41]](#footnote-42)40 In one case,[[42]](#footnote-43)41 it was held that state real estate, personal property, income, franchise and miscellaneous taxes, Federal and state social security and unemployment compensation taxes were all deductible for limitation purposes because they are deductible for general taxable income purposes. Of course, some of these should be treated as direct charges to specific properties rather than allocable overhead.

Selling expenses are also listed separately in the regulations, but they will generally constitute allocable overhead rather than the direct expenses of individual properties. Sales expenses listed in the regulations include sales management salaries, rent of sales offices, sales clerical expenses, salaries, sales commissions and bonus, advertising expenses, sales traveling expenses, and an allocable share of the cost of supporting services.[[43]](#footnote-44)42 Selling expenses of taxpayers who sell refined or manufactured, rather than raw, products are subject to a special allocation rule. The portion of such expenses allocable to ***oil*** and gas production (and therefore deducted for limitation purposes) must be equivalent to the typical selling expenses that are incurred by nonintegrated producers in the same mineral industry so as to maintain equality in the tax treatment of nonintegrated producers in comparison with integrated producer-manufacturers. If nonintegrated producers in the same mineral industry do not typically incur any selling expenses, then no portion of the expenses of selling a refined, manufactured, or fabricated product should be deducted for limitation purposes.[[44]](#footnote-45)43 If only insubstantial value is added to ***oil*** and gas by conversion or transportation, the described allocation method is not required.[[45]](#footnote-46)44

It is settled that overhead items need not be attributable to the current year to be deductible. Interest paid on tax deficiencies attributable to prior years must be deducted.[[46]](#footnote-47)45 Damage claims paid with respect to prior years are deducted as a normal incident of business,[[47]](#footnote-48)46 as are payments in settlement of back pay claims.[[48]](#footnote-49)47 In a 1984 ruling,[[49]](#footnote-50)48 an employer paid a lump sum into a nonqualified deferred compensation plan to provide additional compensation to employees with respect to services rendered in prior years. None of the properties operated in those prior years was still in operation. The Service ruled that the payments must be deducted for limitation purposes. Implicit in the ruling is the notion that the payments are current overhead, apportionable between the taxpayer’s current properties, rather than direct expenses to be charged to the properties in fact benefiting from the services.

Additionally, other indirect items that have been specifically held to be entirely or partially allocable to producing operations for depletion purposes include legal and professional fees,[[50]](#footnote-51)49 receivership fees,[[51]](#footnote-52)50 and payments to a pension plan for services on properties no longer in operation.[[52]](#footnote-53)51 To the extent miscellaneous income is not treated as a separate activity, it should reduce the indirect expenses to be allocated.[[53]](#footnote-54)52

1. **Offsets to Expense**

Trade or cash discounts (or similar allowances) allowed to the taxpayer when purchasing property, supplies, or services reduce the applicable expense for limitation purposes.[[54]](#footnote-55)53 The Service has ruled in favor of excluding state and Federal gasoline tax credits or refunds from the cost of gasoline used by mine operators in computing the limitation.[[55]](#footnote-56)54 This rule can be understood to recognize generally that refunds constitute offsets to the applicable expense.

When an entry representing an offset to expense is more properly treated as a credit to income rather than to expense, the result is less clear. In *Island Creek Coal Co.*,[[56]](#footnote-57)55 the taxpayer sold mine scrap items that had previously been expensed. It credited the receipts to current production expense, thus increasing the taxable income limitation. The Tax Court held that the receipts should have been treated as income from a nonmining activity, rather than as an offset to production expense and, therefore, should have no impact on current taxable income for limitation purposes. The court felt that crediting the scrap income to expense effectively allowed nonmining income to be treated as depletable gross income. It was hardly clear how this was so, as the Fifth Circuit Court of Appeals noted when it later held that interest income could be offset against interest expense for limitation purposes.[[57]](#footnote-58)56 The Tax Court subsequently followed the Fifth Circuit on the interest offset issue, stating that “We reject any implication that a technical income item can never offset an expense item.”[[58]](#footnote-59)57 It distinguished the *Island Creek Coal Co.* decision on the grounds that the scrap sales were a separate business, extraneous to the mining operation. This distinction is not entirely persuasive because interest income is likewise not earned in mineral production activities, yet it is recognized as an offset to interest expense. Note that Code Section 613(a) specifically requires recapture income under Section 1245 from the sale of depreciable property to be used as an offset to mining expenses. This specific reference to “mining” is understood by the regulations to exclude ***oil*** and gas production.[[59]](#footnote-60)58

An expense deducted in a given year will result in a decrease in percentage depletion if it reduces taxable income below the depletion deduction as initially computed. If a taxpayer incurs a substantial deduction in one year and recovers the expense by refund or otherwise in a later year, a decrease in the depletion deduction for the year in which the expense was incurred may not necessarily be offset by an increase in the deduction in the year in which the expense is recovered and used to increase the limitation. The Internal Revenue Service has ruled that the tax benefit rule of Internal Revenue Code Section 111 can be used to resolve this problem.

In Revenue Ruling 77-79,[[60]](#footnote-61)59 a corporation was notified that additional state severance tax was due on minerals produced in the state. The corporation protested the tax, but paid $1500x dollars in 1974, claiming the amount as a deduction. The deduction lowered the taxable income limitation such that the percentage depletion deduction was decreased by $500x dollars. In 1976, the state refunded the $1500x dollars. The Service held that the taxpayer could exclude $500x dollars when reporting the refund as gross income. No amount of the refund was to be included in gross or taxable income for percentage depletion purposes. Moreover, the depletable basis of the taxpayer’s property must be reduced by $500x dollars because the exclusion of this amount from gross income was the equivalent to allowing it as a depletion deduction.

1. **Allocation of Overhead and Indirect Costs**

The regulations require that costs not directly attributable to a specific mineral property be properly apportioned between the taxpayer’s several properties. In addition, expenditures that are attributable in part to ***oil*** and gas production and in part to other activities must be properly apportioned between those other activities and the mineral properties.[[61]](#footnote-62)60 Thus, the taxpayer is required to isolate the direct costs attributable to producing properties and to allocate to the producing properties their appropriate shares of indirect costs. The process involves the following elements:

1. The direct costs specifically attributable to individual producing properties are charged to those properties. These include intangible drilling and development costs, operating expenses, depreciation of equipment, deductible taxes specifically attributable to the property (production, severance, ad valorem, windfall profit taxes), and selling expenses directly attributable to the property.
2. Costs that are attributable only to ***oil*** and gas production, but not to specific properties, must be allocated between the specific properties, including nonproducing properties.
3. Costs that are attributable in part to ***oil*** and gas production and in part to other activities (whether ***oil*** and gas refining or marketing, or activities entirely unrelated to ***oil*** and gas) must first be allocated between these two categories, and then those costs allocated to ***oil*** and gas production are allocated between the specific properties.

Of course, the line between direct and indirect costs is not always clear. In one case, a taxpayer engaged in coal mining sought to treat payments to a United Mine Workers fund, made on the basis of 40 cents per ton mined, as overhead to be allocated between its mines on a direct expense basis. The Tax Court held that these payments were a direct expense chargeable to each mining property on a tonnage basis.[[62]](#footnote-63)61

Expenditures that are attributable both to activities relating to mineral property subject to depletion, and to the taxpayer’s other activities, must be properly apportioned between the mineral properties and the other activities.[[63]](#footnote-64)62 Trade association dues paid or incurred by a producer of crude ***oil*** or gas are specifically deductible. In addition, a reasonable portion of trade association dues incurred by a producer of a refined, manufactured or fabricated product is also subtracted from gross income from the property if the activities of the association relate to production, treatment and marketing of the crude ***oil*** or gas. In this instance, the regulations provide that an allocation of such trade association dues, based on the proportion that the direct costs of conversion and the direct costs of transportation bear to each other, is a reasonable allocation.[[64]](#footnote-65)63

Different classes of indirect expenses can be allocated by different methods and under different theories, and the literature of cost accounting can provide assistance. As a practical matter, the allocation of indirect costs between different activities of the taxpayer must be based either on evidence supporting an allocation or on a more arbitrary formula based on some measure of direct costs. Allocation of indirect costs between the taxpayer’s individual properties may also be based on some direct evidence supporting an allocation, or upon relative direct costs or gross production in units or dollars. If the taxpayer has both producing and nonproducing properties between which to allocate indirect costs, the gross production or gross income method is obviously inappropriate, at least in the first instance. Allocation to the nonproducing properties must be made by some other method (for example, direct expense), with the remainder available to be allocated by production.

Some of the items of direct expense, such as intangible drilling and development costs[[65]](#footnote-66)64 and accelerated depreciation, would seemingly distort an allocation of overhead and could justifiably be disregarded. Severance or production taxes as an element of direct expense are more accurately a measure of production. The Service has held in the closely analogous context of the 90 percent of taxable income limitation for the windfall profits tax that the windfall profits tax itself should be disregarded as a direct expense when allocating overhead between individual properties.[[66]](#footnote-67)65 The Service noted that the windfall profits tax (and presumably other taxes based on production) is not a good indication of indirect costs. However, the ruling also rested on other grounds peculiar to the windfall profits tax, so its application to the percentage depletion limitation is unclear.

If the taxpayer holds both operating and nonoperating interests, it is arguable that an allocation based solely on gross production or gross income is unreasonable because the administrative expense attributable to each dollar or unit of production from nonoperating interests should be less than that attributable to production from operating interests. Similarly, operating interests burdened by substantial nonoperating interests may involve overhead costs similar to operating interests not so burdened. An allocation of overhead based only on the gross production attributable to the operating interests might therefore be questionable.

Given the inherently arbitrary element in the methods for allocating overhead, it is to be expected that both taxpayers and the Internal Revenue Service will assert allocation methods with an eye to their results in the specific case. One authority addressing the latitude allowed taxpayers in allocating indirect costs is the Tax Court decision in *Occidental Petroleum Corporation.*[[67]](#footnote-68)66 The primary issue before the court was the allocation of indirect expenses between specific properties. Before addressing the specifics of the case, the court ventured some significant observations:

1. The apportionment required by the regulations does not require that the same method or methods be used consistently year after year.
2. The principles of cost accounting with respect to allocation of overhead “are replete with uncertainties and ambiguities.”
3. The Service cannot propose a method of allocation and compel the taxpayer to prove it to be arbitrary. The burden of proof required of the taxpayer is simply to show that the method it proposes “produces a fairer apportionment for its circumstances” than the allocation method asserted by the Service.

The taxpayer argued that indirect expenses should be allocated on the basis of direct expenses, while the Service insisted on an allocation by gross tonnage (of coal) per property. The court made clear that no single method was appropriate for all indirect expenses, but it held the taxpayer had, under the circumstances, carried its burden of proof. It indicated that the direct expense method, while flawed, could be justified in this instance on the ground that a greater share of management attention was required by problem mines, identified by their proportionately greater direct expenses. The court stressed that it could not provide guidance of general applicability, and cautiously confined its function “to finding the proper method of allocation of direct expenses for this petitioner in these years on the facts revealed by this record and within the frame of reference established by the parties.”

The allocation of overhead took on a different aspect during the 1980s, when the Windfall Profit Tax was in effect. The 90 percent of net income limitation under the WPT called for the same allocation of overhead found in the percentage depletion context, but with the opposite results for taxpayers and the Service. Large integrated producers, who did not qualify for percentage depletion anyway, began to argue for increased allocations of overhead to producing properties because such allocations reduced the WPT. As the WPT limitation adopts, by reference, the rules of the percentage depletion regulations,[[68]](#footnote-69)67 decisions in this area will be of continuing significance under Section 613.

In *Shell* ***Oil*** *Company,* the taxpayer argued that abandoned geological and geophysical costs should be treated as indirect costs allocable to producing properties. The Tax Court disagreed, essentially on the theory that such costs were necessarily not incurred with respect to producing properties, but rather only for prospects that were never acquired.[[69]](#footnote-70)68 The Fifth Circuit reversed on this issue, holding that these costs were a necessary part of the business of finding and producing ***oil***.[[70]](#footnote-71)69 On another issue, the Tax Court held that IDC should be included in the allocation base of each property where the direct expense method of allocation is used. The Fifth Circuit understood the *Occidental Petroleum Company* case and the regulations to require only that the taxpayer’s method be reasonable under the specific circumstances, not that it be fairer than the method proposed by the Service. The case was remanded to the Tax Court for a new determination based on this standard. Despite the fact that it claimed to be following *Occidental*, the Fifth Circuit was clearly adopting a standard more favorable to the taxpayer because the *Occidental* case did, in fact, require that the taxpayer demonstrate that its method of allocation produces a fairer apportionment than the Service’s.

Ultimately, the method of allocation chosen should, to the extent possible, match in the fairest and most reasonable way the indirect costs incurred to the activity necessitating the costs. Various items of costs may need to be allocated in different ways, such as square footage, time spent, passage of time, etc. Simplified approaches have been used by taxpayers to approximate proper allocation, but they also hold the burden to prove the reasonability of the allocation.

Federal Taxation of ***Oil*** and Gas Transactions

Copyright 2024, Matthew Bender & Company, Inc., a member of the LexisNexis Group.

**End of Document**

1. \*Jeff Wright (Leader, ***Oil*** & Gas Practice, Deloitte Tax LLP) and James Toups (Managing Director, ***Oil*** & Gas Practice, Deloitte Tax LLP) would like to thank and acknowledge the many Deloitte Tax LLP professionals that contributed to the development of this chapter. [↑](#footnote-ref-2)
2. 1IRC § 613(a); Treas Reg § 1.613-1(a). [↑](#footnote-ref-3)
3. [↑](#footnote-ref-4)
4. 3*See* § 3.05. [↑](#footnote-ref-5)
5. 4IRC § 613A(c). [↑](#footnote-ref-6)
6. 5IRC § 613A(b). [↑](#footnote-ref-7)
7. 6Treas Reg § 1.613-5(a). [↑](#footnote-ref-8)
8. 7Rev Rul 79-73, 1979-1 CB 218, *amplified by* Rev Rul 81-266, 1981-2 CB 139. [↑](#footnote-ref-9)
9. 8Treas Reg § 1.613-5(a). [↑](#footnote-ref-10)
10. 9*See* IRC § 263(c). [↑](#footnote-ref-11)
11. 10Helvering v Wilshire ***Oil*** Co, 308 US 90 (1939). [↑](#footnote-ref-12)
12. 11Rev Rul 77-136, 1977-1 CB 167. [↑](#footnote-ref-13)
13. 12*See* Ch 4. [↑](#footnote-ref-14)
14. 13*See* Ch 4. [↑](#footnote-ref-15)
15. 14Treas Reg § 1.612-4(b)(4). [↑](#footnote-ref-16)
16. 15IRC § 59(e). [↑](#footnote-ref-17)
17. 16Elk Lick Coal Co v CIR, 23 TC 585 (1954). [↑](#footnote-ref-18)
18. 17Treas Reg § 1.613-5(a). [↑](#footnote-ref-19)
19. 18Rev Rul 60-74, 1960-1 CB 253; United States Potash Co v Commissioner, 29 TC 1071 (1958). [↑](#footnote-ref-20)
20. 19Rev Rul 80-317, 1980-2 CB 202. [↑](#footnote-ref-21)
21. 20Island Creek Coal Co v CIR, 382 F2d 35 (4th Cir 1967). [↑](#footnote-ref-22)
22. 21Westbrook v Commissioner, TC Memo 1993-634. [↑](#footnote-ref-23)
23. 22Rev Rul 60-164, 1960-1 CB 254. [↑](#footnote-ref-24)
24. 23Regulations 62, Art 201(h). [↑](#footnote-ref-25)
25. 24Regulations 65, Art 201(h). [↑](#footnote-ref-26)
26. 25*See* Ch 1. [↑](#footnote-ref-27)
27. 26Regulations 69, Art 201(h). [↑](#footnote-ref-28)
28. 27Rocky Mountain ***Oil*** Co v CIR, 36 BTA 365 (1937). [↑](#footnote-ref-29)
29. 28Helvering v Wilshire ***Oil*** Co, 308 US 90 (1939). [↑](#footnote-ref-30)
30. 29Sheridan-Wyoming Coal Co v Helvering, 125 F2d 42 (DC Cir 1941); Mirabel Quicksilver Co v CIR, 41 BTA 401 (1941). [↑](#footnote-ref-31)
31. 30Montreal Mining Co v CIR, 41 BTA 399 (1940). [↑](#footnote-ref-32)
32. 31Treas Reg § 1.613-5(a). [↑](#footnote-ref-33)
33. 32St Mary’s ***Oil*** & Gas Co v Commissioner, 42 BTA 270 (1940). [↑](#footnote-ref-34)
34. 33Mirabel Quicksilver Co v CIR, 41 BTA 401 (1941). [↑](#footnote-ref-35)
35. 34Sheridan-Wyoming Coal Co v Helvering, 125 F2d 42 (DC Cir 1941). [↑](#footnote-ref-36)
36. 35St Louis, Rocky Mountain & Pacific Co v CIR, 28 TC 28 (1957). [↑](#footnote-ref-37)
37. 36Ideal Basic Industries Inc v CIR, 82 TC 352 (1984); General Portland Cement v CIR, 628 F2d 321 (5th Cir 1980), *cert denied,* 450 US 983 (1981). [↑](#footnote-ref-38)
38. 37Grison ***Oil*** Corp v CIR, 42 BTA 1117 (1940). [↑](#footnote-ref-39)
39. 38Ltr Rul 7808003. [↑](#footnote-ref-40)
40. 39***Kern*** ***Oil*** Co v CIR, 9 TC 1204 (1947). [↑](#footnote-ref-41)
41. 40Treas Reg § 1.613-5(c)(1). [↑](#footnote-ref-42)
42. 41Montreal Mining Co v CIR, 2 TC 688 (1943). [↑](#footnote-ref-43)
43. 42Treas Reg § 1.613-5(c)(4)(iv). [↑](#footnote-ref-44)
44. 43Treas Reg § 1.613-5(c)(4)(ii). [↑](#footnote-ref-45)
45. 44Treas Reg § 1.613-5(c)(4)(iii). [↑](#footnote-ref-46)
46. 45Holly Development Co, 44 BTA 51 (1941). [↑](#footnote-ref-47)
47. 46Montreal Mining Co v CIR, 41 BTA 399 (1940). [↑](#footnote-ref-48)
48. 47Rialto Mining Corp v CIR, 25 BTA 980 (1932). [↑](#footnote-ref-49)
49. 48Rev Rul 84-46, 1984-1 CB 146. [↑](#footnote-ref-50)
50. 49Lumaghi Coal Co v Helvering 124 F2d 645 (8th Cir 1942). [↑](#footnote-ref-51)
51. 50CA Hughes & Co 14 TCM 172 (1955). [↑](#footnote-ref-52)
52. 51Rev Rul 84-46, 1984-1 CB 146. [↑](#footnote-ref-53)
53. 52Rev Rul 84-46, 1984-1 CB 146. [↑](#footnote-ref-54)
54. 53Treas Reg § 1.613-5(c)(1); Rev Rul 68-214, 1968-1 CB 299. [↑](#footnote-ref-55)
55. 54Rev Rul 66-226, 1966-2 CB 239. [↑](#footnote-ref-56)
56. 55Island Creek Coal Co v CIR, 30 TC 370 (1958). [↑](#footnote-ref-57)
57. 56General Portland Cement v CIR, 628 F2d 321 (5th Cir 1980), *cert denied*, 450 US 983 (1981). [↑](#footnote-ref-58)
58. 57Ideal Basic Industries Inc v CIR, 82 TC 352 (1984). [↑](#footnote-ref-59)
59. 58Treas Reg § 1.613-5(b)(1). [↑](#footnote-ref-60)
60. 59Rev Rul 77-79, 1977-1 CB 34. [↑](#footnote-ref-61)
61. 60Treas Reg § 1.613-5(a). [↑](#footnote-ref-62)
62. 61Occidental Petroleum Corp v CIR, 55 TC 115 (1970). [↑](#footnote-ref-63)
63. 62Treas Reg § 1.613-5(a). [↑](#footnote-ref-64)
64. 63Treas Reg § 1.613-5(c)(6). [↑](#footnote-ref-65)
65. 64*See* Shell ***Oil*** Co v CIR, 952 F2d 885 (5th Cir 1992), concerning the potential for distortion when IDC is used for allocation. [↑](#footnote-ref-66)
66. 65Rev Rul 85-79, 1985-1 CB 337. [↑](#footnote-ref-67)
67. 66Occidental Petroleum Corp v CIR, 55 TC 115 (1970). [↑](#footnote-ref-68)
68. 67*See* Ch 16. [↑](#footnote-ref-69)
69. 68Shell ***Oil*** Co v CIR, 89 TC 371 (1987). [↑](#footnote-ref-70)
70. 69Shell ***Oil*** Co v CIR, 952 F2d 885 (5th Cir 1992). [↑](#footnote-ref-71)