[JOINT COMMITTEE PRINT]

DESCRIPTION OF THE STATUTORY PROVISIONS AFFECTING THE TAX TREATMENT OF DOMESTIC OIL AND GAS PRODUCERS

SCHEDULED FOR HEARINGS

BEFORE THE

SUBCOMMITTEE ON OVERSIGHT
COMMITTEE ON WAYS AND MEANS
U.S. HOUSE OF REPRESENTATIVES

ON MAY 5 AND 6, 1983

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INTRODUCTION

The Subcommittee on Oversight of the Committee on Ways and Means has scheduled public hearings on May 5 and 6, 1983, on the statutory provisions of the Internal Revenue Code affecting the taxation of domestic oil and gas producers.

This pamphlet, prepared in connection with the hearings, contains descriptions of the various provisions of law affecting the Federal taxation of domestic oil and gas producers. The first part of the pamphlet is a summary of present law. This is followed by descriptions of the provisions of present law and the legislative history of those provisions.

I. SUMMARY

The Federal taxation of oil and gas producers differs among independent producers, royalty owners and integrated producers. These differences apply under both the income tax and the crude oil windfall profit tax.

Income Tax Provisions

1. Intangible drilling and development costs (IDCs)

Different rules apply with respect to intangible drilling costs for individuals and corporations and for integrated and nonintegrated producers. Individuals and nonintegrated corporate producers may expense their intangible drilling costs (IDCs) in the year paid or incurred. Integrated corporate producers, however, may expense only 85 percent of their IDCs, with the remainder written off over a 36-month period.

To the extent that intangible drilling costs exceed income from oil and gas production, they are an item of tax preference under the alternative minimum tax for individuals. No similar minimum tax provisions apply to the intangible drilling costs of ordinary corporations. However, individuals may avoid this minimum tax by electing to treat their intangible drilling costs in the same manner as equipment in the 5-year ACRS class.

Furthermore, in the case of individuals and certain closely held corporations, intangible drilling costs deductions are subject to an "at risk" rule under which deductions are limited to the amount with respect to which the taxpayer is at risk.

2. Depletion

In general, percentage depletion is no longer available for oil or gas production, subject to several important exceptions. First, percentage depletion is still available in the case of natural gas sold under a fixed contract and natural gas from geopressured brine. Second, percentage depletion is available for up to 1,000 barrels a day of production by independent producers and royalty owners. Percentage depletion is an item of tax preference under the alternative minimum tax that applies to individuals and the add-on minimum tax that applies to corporations.

Crude Oil Windfall Profit Tax Provisions

There are several differences in the treatment of independent producers, royalty owners and integrated producers under the crude oil windfall profit tax.

a. *Lower tax rates.*—Independent producers are entitled to lower windfall profit tax rates on tier 1 and tier 2 oil.

b. *Exempt stripper well oil.*—Certain stripper well oil production attributable to on independent producer's working interests is exempt from the windfall profit tax.

c. *Exempt royalty oil.*—Certain producers (other than integrated producers) which produce qualified royalty production may exempt up to 2 barrels per day of this production from the windfall profit tax (3 barrels per day after 1984).

d. *Deposit of tax.*—Integrated oil companies must deposit windfall profit taxes more frequently than other producers and first purchasers.

II. DESCRIPTION OF TAX PROVISIONS

A. Income Tax Provisions

1. Intangible Drilling and Development Costs

Present Law

General rules

Cost incurred by an operator to develop an oil or gas property to the point of production are of two types: (1) intangible drilling and development costs, and (2) depreciable costs.

In general, intangible drilling and development costs (IDCs) include all expenditures by the property operator incident to and necessary for the drilling of wells and the preparation of wells for the production of oil or gas (or geothermal energy) which are neither for the purchase of tangible property nor part of the acquisition price of an interest in the property. IDCs include amounts paid for labor, fuel, repairs, hauling, supplies, etc., to clear and drain the well site, make an access road, and do such survey and geological work as is necessary to prepare for actual drilling. Other IDCs are paid or accrued by the property operator for the labor, etc., necessary to construct derricks, tanks, pipelines, and other physical structures necessary to drill the wells and prepare them for production. Finally, IDCs may be paid or accrued to drill, shoot, and clean the wells. IDCs also include amounts paid or accrued by the property operator for drilling or development work done by contractors under any form of contract. Intangible drilling and development costs may be either capitalized and recovered through depletion or depreciation deductions, or currently expensed at the election of the operator.

Depreciable costs are amounts paid or accrued during the development of a property to acquire tangible property ordinarily considered to have a salvage value. For example, the cost of drilling tools, pipe, cases, tubing, engines, boilers, machines, etc, fall into this category. This class of expenditures also includes amounts paid or accrued for wages, fuel, repairs, etc., in connection with equipment or facilities not incidental or necessary for the drilling of wells, such as structures to store or treat oil or natural gas. These expenditures must be capitalized and depreciated in the same manner as ordinary items of equipment, and they are treated the same for both independent producers and integrated producers.

The "operator" of an oil or gas property is one who holds an operating or working 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. In general, the operating interest in an oil or gas property must bear the cost of developing and operating the property. Only persons holding an operating interest in a property may deduct IDCs. The term operating interest does not include royalty interests or similar interests such as production payment rights or net profits interests.

Generally, if IDCs are not expensed, but are capitalized, they can be recovered through depletion or depreciation, as appropriate. However, if IDCs are capitalized and are paid or incurred with respect to a nonproductive well ("dry hole"), they may be deducted, at the election of the operator, as an ordinary loss in the taxable year in which the dry hole is completed.

Fifteen percent reduction for integrated corporations

In the case of a corporation which is not an independent producer (i.e., which is an "integrated" producer), the allowable deduction with respect to certain corporate tax preferences, including IDCs, is reduced by 15 percent. The disallowed amount must be added to the basis of the property and amortized over a 36-month period starting with the month the costs are paid or accrued. Capitalized IDCs are not, however, taken into account for purposes of determining cost depletion. Amounts paid or accured with respect to nonproductive wells (dry hole costs) are still deductible when the non-productive well is completed.

At risk

Losses attributable to exploring for, or exploiting, oil and gas resources, including expensed IDCs, are disallowed in the case of individuals and certain small corporations, except to the extent that such taxpayers are at risk with respect to such activity at the close of the taxable year. A taxpayer is considered at risk with respect to (1), the amount of money or the adjusted basis of property contributed by the taxpayer to an activity, and (2), amounts borrowed with respect to the activity for which the borrower is personally liable for repayment or has pledged property other than property used in the activity as security for the borrowing. Because the at risk rules do not apply to large publicly held corporations, most large integrated oil or gas companies are not subject to the at risk rules.

Recapture

If an operator elects to expense IDCs paid or accrued after 1975 and then disposes of the oil, gas, or geothermal property, a portion of the expensed IDCs must be treated as ordinary income (instead of capital gain). This portion is equal to the lower of (1) the amount of IDCs deducted since January 1, 1976 (which, but for being deducted, would have been reflected in the adjusted basis of the property), reduced by the amount (if any) by which the depletion deduction with respect to such property would have been increased if such amounts had been capitalized, or (2) the gain on the sale, exchange, or involuntary conversion of the property.

Minimum taxes

While IDCs are currently deductible at the election of the operator, the economic value of this current deduction election is reduced by the effect of the alternative minimum tax with respect to noncorporate operators.

In the case of a trust, estate, or individual (noncorporate taxpayer), if the alternative minimum tax for that person for any taxable year exceeds the regular tax imposed on such person, the excess is an additional tax due for the taxable year. The taxpayer's alternative minimum tax is equal to 20 percent of that taxpayer's alternative minimum taxable income over the exemption amount.[1]

Alternative minimum taxable income is adjusted gross income, less certain deductions, plus the amount of the taxpayer's tax preference items. A noncorporate taxpayer's regular tax for the taxable year is the income tax imposed on that taxpayer for the taxable year, reduced by any credits allowable against such tax (excluding the credit for wages, interest, dividends, and patronage dividends withheld at source, the earned income credit, and the credit for certain uses of gasoline and special fuels).

In general, IDC deductions are a tax preference item for purposes of the alternative minimum tax to the extent they exceed the amount which would have been deductible had they been capitalized and recovered over a 10-year amortization period, but only to the extent of the excess of such deductions over the taxpayer's income for the taxable year from the oil or gas (or geothermal) property. The 10-year amortization period applies on a well by well basis, starting with the month in which production for such well begins. At the election of the operator, the capitalized IDCs may be recovered as if subject to cost depletion rather than over the 10-year period.

However, IDCs paid or accrued by an individual are not treated as tax preference items if the individual elects to capitalize them and deduct the IDCs over a 10-year period. In addition, in the case of any IDC expenditure by an individual which is not allocable to a limited partnership interest or certain subchapter S corporation shareholdings of such individual (i.e., in general, individuals with operating interests, general partners, and sole proprietors), such IDCs are not treated as items of tax preference if the individual elects to deduct the IDCs over a 5-year period. If the 5-year amortization schedule (which is the same as the accelerated cost recovery 5-year recovery schedule) is chosen, then the amount of the IDC is a qualified investment for purposes of the investment tax credit.

Legislative History

IDC election

The election to currently deduct IDCs has been permitted by regulations since the Revenue Act of 1918.[2] Although the validity of the regulations allowing for the election to expense IDCs was questioned prior to 1945, no court held the regulations invalid until the decision of the Fifth Circuit in *F.H.E. Oil* v. *Commissioner.*[3] In that case, the Fifth Circuit viewed the expenditures represented by IDCs to be capital expenditures intimately related to and insepara-

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[1] The exemption amount is equal to $30,000 for single persons and $40,000 for married couples.

[2] Reg. No. 45, Art. 223 (1919).

[3] *F.H.E. Oil* v. *Commissioner,* 147 F.2d 1002 (5th Cir. 1945), reh. den., 149 F.2d 238 (5th Cir. 1945), second motion for reh. den., 150 F.2d 857 (5th Cir. 1945), aff'g 3 T.C. 13 (1944), nonacq. 1944 C.B. 37, nonacq. withdrawn and acq. 1960-1 C.B. 4.

ble from the investment in the well, recoverable (in the case of a producing property) by way of depletion or depreciation. To allow the operator to both deplete his investment in the well and also currently deduct his IDC expenditures would result, said the Fifth Circuit, in a double deduction not permitted by Congress.

In 1945, the same year as the *F.H.E. Oil Company* v. *Commissioner, supra,* decision, and in response to that case, the Congress passed House Concurrent Resolution 50 (79th Cong., 1st Sess.) which recognized and approved the provisions of Treasury Regulation 111 and the corresponding provisions of prior Treasury Regulations granting the option to deduct as expenses such intangible drilling and development costs.

No court after the Fifth Circuit decision adopted the *F.H.E. Company* v. *Commissioner, supra,* rule, and the Internal Revenue Service continued to allow the current deduction of IDCs if properly claimed. In 1951, the Congress enacted the precursor of present section 616 providing for the current deduction of development costs incurred in the development of natural deposits other than oil or gas. The Committee Reports accompanying this legislation indicated that no similar provision was required for oil and gas wells because IDCs were already currently deductible.

In enacting the 1954 Code, the Congress provided specific direction to the Secretary of the Treasury to promulgate regulations allowing for the option to expense or capitalize IDCs. In 1978, this Code provision was amended to direct the Secretary of the Treasury to expand his regulations to include IDCs paid or accrued in connection with the development of geothermal deposits.

In 1982, this provision was again amended to conform to the Tax Equity and Fiscal Responsibility Act (TEFRA) provisions dealing with IDCs. Under these provisions, individuals could elect to amortize IDCs over a 10- or 5-year period and avoid tax preference treatment. In the case of corporations which are integrated producers, TEFRA provides for the 15 percent reduction of expensable IDCs and amortization of the disallowed amount over 36 months.

Minimum taxes

The minimum and alternative minimum taxes of present law originated with the minimum tax on tax preference items (sometimes referred to as the "add-on" minimum tax) added to the Code by the Tax Reform Act of 1969.[4]

As originally enacted, individuals and corporations were required to pay a minimum tax at the rate of 10 percent of the total of their tax preference items in excess of $30,000, to the extent that such tax exceeded the regular tax. The list of tax preferences under the 1969 Act included many special deductions. For example, accelerated depreciation to the extent it exceeds straight-line depreciation was included as an item of tax preference, as was the untaxed portion of long-term capital gains. With respect to oil and gas, the original minimum tax included percentage depletion in excess of basis as a tax preference item.

As part of the Tax Reform Act of 1976, the minimum tax rate was increased from 10 to 15 percent and the $30,000 exemption was

[4] Code sections 56–58 (1954 IRC); Tax Reform Act of 1969.

replaced with an exemption equal to the greater of $10,000 or the regular tax deduction. Also, the list of tax exemptions was expanded. A tax preference for intangible drilling costs, to the extent such costs exceeded the amount allowable under a 10-year amortization method (or, at the election of the taxpayer under a cost depletion method), was added. Because the 1976 Act focused on tax shelters whereby high income individuals avoided tax, IDCs were made a tax preference only for individuals and subchapter S corporations, not for ordinary corporations. In 1977, Congress limited the tax preference to the amount by which ICDs exceeded oil-related income, largely in response to criticism by individual producers that they were being treated unfairly in comparison with corporate producers, particularly the large integrated oil companies. In 1978, when Congress provided expensing for IDCs on geothermal wells, these IDCs were included in the minimum tax as well.

The minimum tax provisions were substantially amended, once again, under the Tax Equity and Fiscal Responsibility Act (TEFRA).[5] Under TEFRA, the add-on minimum tax with respect to noncorporate taxpayers was repealed effective for taxable years beginning after 1982. Therefore, the add-on minimum tax now applies only to corporations.

In 1978, the Congress enacted the alternative minimum tax. As originally enacted, the alternative minimum tax was imposed on noncorporate taxpayers and was payable to the extent it exceeded the taxpayer's regular tax, including any add-on minimum tax imposed for the taxable year. The alternative minimum tax was imposed on alternative taxable income, which was the taxpayer's taxable income increased by (1) the deduction for long-term capital gains, and (2) the amount of the taxpayer's adjusted itemized deductions. The tax rate was 10 percent of the alternative minimum taxable income from $20,000 to $60,000, 20 percent of the amount from $60,000 to $100,000, and 25 percent of the alternative minimum taxable income in excess of $100,000. No tax was owing with respect to alternative minimum taxable income from zero to $20,000. The 25-percent bracket was repealed by the Economic Recovery Tax Act of 1981 (ERTA).

Tax credits, other than the foreign tax credit, generally were allowable against this tax only if attributable to an active trade or business and only to the extent the tax was not attributable to net capital gains or to adjusted itemized deductions. Any credit disallowed by this rule increased the amount allowed as a credit carryover.

In connection with the repeal of the add-on minimum tax in 1982, Congress added the items of tax preference previously subject to that tax, including IDCs, to the base of the alternative minimum tax.

2. Depletion

Present Law

General rules

In general, ordinary and necessary expenses paid or incurred in operating a well are currently deductible. Depletion and depreciation are a species of ordinary and necessary business expense. In both cases, the taxpayer is allowed a deduction in recognition of the fact that an asset is being expended to produce income. Certain costs incurred prior to drilling an oil or gas property are recovered through the depletion deduction. These include costs of acquiring the lease and geological and geophysical costs.

Two methods of depletion are currently allowable under the Internal Revenue Code: the cost depletion method, and the percentage depletion method. Under the cost depletion method, the taxpayer is allowed to deduct that portion of the adjusted basis of the property equal to the ratio of units sold from that property during the taxable year over the number of units remaining "as of the taxable year" (i.e., in general, the number of units remaining in the property at the end of the taxable year to be recovered, plus the number of units sold during the taxable year).

Under the percentage depletion method, a fixed statutory percentage of the taxpayer's gross income from the property (but not in excess of 50 percent of the taxpayer's taxable income from the property and 65 percent of the taxpayer's overall taxable income) is allowed as a deduction. The percentage is currently 16 percent for oil and gas production (15 percent in 1984 and thereafter). Secondary and tertiary production is entitled to the 22-percent depletion allowance until 1984. After 1984, secondary and tertiary production by independent producers and royalty owners should be subject to 15 percent percentage depletion. This result may, however, require a statutory amendment.

Under present law, a holder of an economic interest in an oil or gas property (or other natural deposits and timber) may deduct an allowance for depletion in computing taxable income. For most natural resources other than timber (including oil and gas), taxpayers must determine their depletion deduction under both the percentage depletion method (if the taxpayer is entitled to use this method) and cost depletion method. If the cost depletion deduction is larger, the taxpayer must utilize that method for the taxable year.

The allowance for cost depletion may not result in recovery of more than the taxpayer's basis in the property. The percentage depletion allowance is computed without regard to the taxpayer's basis in the property and may, therefore, exceed the taxpayer's cost basis in the property. The excess is a tax preference under the minimum taxes.

In general, percentage depletion with respect to most oil and gas production was repealed in 1975. The exemptions from the repeal of percentage depletion included in the Tax Reduction Act of 1975 depend upon the type of production, and the producer.

Under the Tax Reduction Act of 1975 and present law, certain types of natural gas production are entitled to percentage depletion, regardless of whether or not the producer is an integrated or independent producer. Sales of natural gas sold under a fixed contract and natural gas from geopressured brine fall into this category. Natural gas sold under a fixed contract may be depleted at a 22-percent rate, gas from geopressured brine is entitled to a 10-percent rate.

In general, "natural gas sold under a fixed contract" is domestic natural gas sold by the producer under a contract in effect on February 1, 1975, and at all times thereafter before such sale. The contract price for such gas cannot, however, have been adjusted to reflect any increase in income tax liability of the seller by reason of the repeal of percentage depletion.[6]

"Qualified natural gas from geopressured brine" is natural gas determined to be produced from geopressured brine under the National Gas Policy Act of 1978, which is produced from a well the drilling of which began after September 30, 1978, and before January 1, 1984.

Other exemptions to the repeal of percentage depletion added to the Code by the Tax Reduction Act of 1975 and contained in present law depend upon the identity of the producer. Under these exemptions, independent producers and royalty owners (as contrasted to integrated oil companies) are allowed to take percentage depletion with respect to up to 1,000 barrels of average daily production of domestic crude oil or up to 6 million cubic feet of average daily production of domestic natural gas.[7] The 1,000-barrel amount is reduced proportionately to the extent the producer elects percentage depletion for natural gas.

An independent producer is any producer who is not a "retailer" or "refiner." A retailer is any person who directly, or through a related person,[8] sells oil or natural gas or any product derived therefrom. (1) through any retail outlet operated by the taxpayer or related person or, (2) to any person obligated to market or distribute such oil or natural gas (or product derived therefrom) under the name of the taxpayer or the related person. In determining whether or not a person is a retailer, sales of oil or natural gas do not include bulk sales to commercial or industrial users, and the sales of oil or natural gas products do not include bulk sales of aviation fuel to the Department of Defense. Further, a person is not a retailer within the meaning of this provision if the combined gross receipts of that person and all related persons are from the retail sale of oil, natural gas, or any product derived therefrom, do not exceed $5 million in the taxable year.

A refiner is any person who directly or through a related person engages in the refining of crude oil, but only if such taxpayer or

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[6] Price increases after February 1, 1975, are presumed to take such tax increases into account, unless the taxpayer demonstrates to the contrary by clear and convincing evidence.

[7] As originally enacted, the depletable oil quantity was 2,000 barrels of average daily production. This was gradually reduced to 1,000 barrels for 1980 and thereafter. With respect to domestic natural gas, the natural gas quantity is 6,000 cubic feet multiplied by the number of barrels of depletable oil quantity (6,000 x 1,000=6 million). Production of natural gas sold under a fixed contract and natural gas from geopressured brine is excluded in determining the 1,000 barrel amount.

[8] A related person is, in general, any person with respect to which the taxpayer has a significant ownership interest (generally defined to be a 5 percent or more interest).

related person has a refiner run in excess of 50,000 barrels per day on any day during the taxable year.

Special rules apply with respect to oil and natural gas produced from secondary or tertiary processes. Prior to 1984, the taxpayer's 1,000-barrel amount is first allocated to the taxpayer's secondary or tertiary production, which is entitled to a 22-percent depletion rate. To the extent any portion of the 1,000-barrel amount remains after its allocation to secondary or tertiary production, the excess may be allocated to other production of the taxpayer. If the taxpayer's secondary or tertiary production exceeds the 1,000-barrel amount, the 1,000-barrel amount must be allocated among all the taxpayer's secondary or tertiary production. For this purpose, secondary or tertiary production is the increased production of crude oil or natural gas from a domestic well after the application of a secondary process. Such increased production is the excess of actual production (either in rate or duration) over the maximum production from primary methods which would have resulted during the taxable year if such process had not been applied.

To prevent proliferation of the independent producer and royalty owner percentage depletion allowances, all production owned by businesses under common control and members of the same family must be aggregated. Each group is then treated as one producer for application of the 1,000-barrel amount. Further, if an interest in a proven oil or gas property is transferred after 1974 (subject to certain important exceptions), the production from such interest does not qualify for percentage depletion. The exceptions include transfers at death, certain transfers to controlled corporations, and transfers between controlled corporations or other business entities.

At risk

Losses attributable to exploring for, or exploiting, oil and gas resources, including depletion deductions are disallowed in the case of individuals and certain small corporations, except to the extent that such taxpayers are at risk with respect to such activity at the close of the taxable year.

Minimum taxes

Included as an item of tax preference for both the minimum tax (with respect to corporations) and the alternative minimum tax (with respect to individuals), is the excess of the percentage depletion deduction allowable for the taxable year (on a property-by-property basis), over the taxpayer's adjusted basis in the property at the end of the taxable year (determined without regard to that year's depletion deduction).[9]

Legislative History

Under the Revenue Act of 1913, oil and gas producers were permitted to deduct a reasonable allowance for depletion. This deduction was computed using a cost depletion method. However, to pre-

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[9] In general, the term "property" means each separate interest owned by the taxpayer in each mineral deposit in each separate tract or parcel of land.

vent the taxation of income accruing prior to 1913, the law permitted taxpayers to base their cost depletion deductions on the value of the property as of March 1, 1913, rather than actual cost incurred. As a result, the depletion deductions permitted on new oil wells using cost depletion were substantially below those allowed on pre-1913 wells. To create greater parity between pre- and post-1913 oil wells and to encourage development of oil production during World War I, Congress enacted a system of discovery value depletion in the Revenue Act of 1918, enacted in early 1919. Under the discovery value method of computing depletion, the taxpayers were permitted to deduct the fair market value of the mineral property, determined at the time its commercial value was established, over the life of the property in proportion to the units of production.

In the 1920s, the oil, gas and mineral industries experienced a recession, one of the results of which was that depletion computated using discovery values from 1918 to 1920 period exceeded the gross income from the property. As a result, the Congress limited the discovery value depletion deduction to 50 percent of the taxpayer's net income from the property.

In the Revenue Act of 1926, Congress concluded that discovery value depletion for oil and gas, which created considerable uncertainty and litigation (about discovery values, etc.), should be replaced with a simpler method or computation. Thus, the 1926 Act provided for percentage depletion with respect to oil and gas properties. The 5 percent of net income limitation of prior law and the option to claim cost depletion were retained. The 27½ percent depletion rate set in the 1926 Act reflected the size of discovery value deductions taken under prior law relative to gross incomes. The depletion rules for oil and gas established in the 1926 Act remained essentially unchanged until the Tax Reform Act of 1969, when the statutory 27½ percent rate was reduced to 22 percent.

The provisions of present law limiting percentage depletion on oil and gas to independent producers and royalty owners were enacted as part of the Tax Reduction Act of 1975. That Act also reduced the 22 percent rate to 15 percent over a period of years. Since the 1975 Act, there have been a number of minor changes to oil and gas depletion provision including (1) a 1976 amendment relating to the treatment of partnerships; (2) a 1978 amendment providing for a percentage depletion on natural gas from geopressured brine at a 10-percent rate; (3) a 1980 amendment to the anti-transfer rules permitting transfers to closely-held corporations in limited circumstances; and (4) a 1982 amendment with respect to the computation of the depletion allowance for shareholders of a subchapter S corporation.

B. Crude Oil Windfall Profit Tax Provisions

Present Law

General rules

The crude oil windfall profit tax is a temporary excise tax imposed on the windfall profit element of the price of domestically produced crude oil when it is removed from the premises on which it was produced. In general, the windfall profit element with respect to any barrel of taxable crude oil is the excess of the sale (removal) price of the barrel over the sum of the adjusted base price and the applicable State severance tax adjustment. The windfall profit on any barrel of crude oil cannot, however, exceed 90 percent of the net income attributable to such barrel.

The adjusted base price and the tax rate applicable to a particular barrel of crude oil removed from the premises depends on its classification into one of three tax tiers and on the identity of the producer. The first tier, which is the most heavily taxed, is comprised of all oil that does not fall into some other tier. The base price for tier 1 oil is the energy regulation ceiling price which would have applied to such crude oil had it been produced and sold in May of 1979 as upper tier oil, reduced by 21 cents, and adjusted for inflation. The average base price for tier 1 oil is $16.65 for the second quarter of 1983.

Tier 2 oil is oil from a stripper well property within the meaning of the June 1979 energy regulations and oil from an economic interest of the United States in a Naval Petroleum Reserve. The base price for tier 2 oil was set at $15.20 per barrel, adjusted for grade, quality, and field, and further adjusted for inflation. The average tier 2 base price for the second quarter of 1983 is $19.76.

Tier 3 oil is newly discovered oil, heavy oil, and incremental tertiary oil. The base price for tier 3 oil was set at $16.55 per barrel, adjusted for grade, quality, and field, and further adjusted for inflation. The average tier 3 base price for the second quarter of 1983 is $23.72. Tier 3 base prices are adjusted for inflation plus 2 percent per year.

The tax rates applicable to taxable crude oil are set forth below:

Tier one oil	70 percent; 50 percent for independent producers.
Tier two oil (stripper oil,[1] Petroleum Reserve oil).	60 percent; 30 percent for independent producers.
Tier three oil:	
Newly discovered oil	25 percent for 1983, 22.5 percent for 1984, 20 percent for 1985, and 15 percent for 1986 and thereafter.
Heavy oil and incremental tertiary oil.	30 percent.

[1] Qualified independent stripper oil is exempt beginning in 1983.

All domestically produced crude oil is taxable unless specifically exempted from the tax. The categories of exempt oil include any crude oil from a qualified governmental interest or a qualified charitable interest, exempt front-end oil, exempt royalty oil, and exempt stripper well oil.

The windfall profit tax is scheduled to phase out over a 33-month period, beginning after December 31, 1987, if the cumulative revenue raised by the tax reach $227.3 billion, but in any event, no later than January 1991.

Provisions affecting the treatment of independent producers

Lower rates for independent producers

Up to 1,000 barrels of average daily production, determined on a quarterly basis, of tier 1 or tier 2 oil by independent producers is entitled to lower windfall profit tax rates. Although the regular windfall profit tax rate for tier 1 oil is 70 percent and tier 2 oil is 60 percent, independent producers are entitled to a 50 percent rate for tier 1 and a 30 percent rate for tier 2 oil. An independent producers for this purpose is any person who is not a retailer or refiner for the calendar year (within the meaning of the percentage depletion provision). In general, a retailer is anyone who directly, or through a related person, sells more than $5 million per taxable year in oil or natural gas, subject to certain exclusions, at retail. A refiner is any person who directly, or through a related person, engages in refining crude oil, and who has a refinery run on any day during the taxable year in excess of 50,000 barrels. Subject to certain exceptions, independent producer oil does not include production attributable to an interest transferred on or after Janaury 1, 1980. In general, these exceptions include a transfer at death, transfers within a related group, etc.

Exempt stripper well oil

Exempt stripper well oil is oil which is produced by an independent producer from a stripper well property after 1982 and which is attributable to the independent producer's working interest in the stripper well property. This oil is exempt from the windfall profit tax. For this purpose a stripper well property is a property, which during any consecutive 12-month period beginning after December 31, 1972, had an average daily production of crude oil (excluding condensate recovered in nonassociated production) but not in excess of 10 barrels per day per well. Since the exemption applies only to oil from working interests, royalty owners do not benefit from this provision. There is no overall barrel limitation on the amount of oil that may be exempt with respect to any producer.

The benefit of the stripper well exemption is claimed by way of the operator filing an exemption certificate with the person obligated to withhold the windfall profit tax with respect to that person's production (generally the first purchaser).

Exempt royalty oil

Up to two barrels per day (three barrels per day in 1985 and thereafter) of qualified royalty production of a qualified royalty owner is exempt from the windfall profit tax. Qualified royalty production is taxable crude oil which is attributable to an economic interest (other than an operating interest) held by a qualified royalty owner. A qualified royalty owner is any producer who is an individual, estate, or qualified farm corporation. Thus, this exemption is not available to incorporated producers or to producers holding operating interests. The benefit of the qualified royalty owner exemption is claimed by the operator filing a Qualified Royalty Owner's Exemption Certificate (Form 6783), with the person who withholds windfall profit tax on behalf of the qualified royalty owner (generally, the first purchaser).

The qualified royalty oil exemption is also allowed to trust beneficiaries who are individuals or estates if the trust produces qualified royalty oil. Rules are provided to limit the aggregate benefit available to any individual to two or three barrels a day as appropriate. In general, the benefit of the exemption is obtained by the qualified beneficiary filing for a refund of overwithheld tax.

Deposits of tax

The windfall profit tax is collected through withholding by the first purchaser for taxable crude oil if the oil is sold before removal from the premises. In other cases, the producer must pay the tax directly. Although the first purchaser of the taxable crude oil is required to withhold and deposit the amount of the tax from the amount due the producer of such oil, the tax is itself imposed on the producer.

Amounts withheld or owed by integrated oil companies must be deposited with the United States twice monthly. Amounts withheld or owed by persons other than integrated producers, such as independent producers and royalty owners, must be deposited 45 days after the close of the month in which the oil is removed. In the case of oil purchased under a contract by an independent refiner under which no payment is required to be made before the 46th day after the close of the month in which the oil is purchased (as opposed to removed) deposit must be made before the first day of the third month beginning after the close of the month in which the oil is removed.

Legislative History

The Crude Oil Windfall Profit Tax Act was enacted in 1980 (effective March 1, 1980) to accompany the phased decontrol of domestic crude oil prices under a program announced by President Carter on April 5, 1979. The 1980 Act was amended by the Omnibus Reconciliation Act of 1980, which provided for a $1,000 royalty owner credit and by the Economic Recovery Tax Act of 1981 which provided for the independent stripper oil exemption, the royalty owner exemptions, and the phase down of the tax rate on newly discovered oil from 30 percent to 15 percent. Other amendments were made by TEFRA (repeal of the TAPS adjustment), and the Technical Corrections Act of 1982 (partial exemption for certain qualified royalty oil held in trusts).

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