PRESENT-LAW TAX RULES RELATING TO DOMESTIC OIL AND GAS EXPLORATION AND PRODUCTION AND DESCRIPTION OF H.R. 53 AND H.R. 423

Scheduled for a Hearing
Before the
SUBCOMMITTEE ON OVERSIGHT
of the
HOUSE COMMITTEE ON WAYS AND MEANS
on February 25, 1999

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of the
JOINT COMMITTEE ON TAXATION

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INTRODUCTION

This document,[1] prepared by the staff of the Joint Committee on Taxation, provides an overview of various present-law tax provisions that relate to the exploration for, and the production of, crude oil and natural gas located within the United States (Part I). Part II of the document provides a description of two bills related to the tax treatment of oil and gas: H.R. 53 (Messrs. Watkins, Thomas, McCrery, and others) and H.R. 423 (Messrs. Thomas, Watkins and others). H.R. 53 would provide a tax credit for production of oil and gas from marginal wells, and H.R. 423 would provide five-year carryback for certain oil and gas net operating losses.

The Subcommittee on Oversight of the House Committee on Ways and Means has scheduled a public hearing on tax proposals to increase domestic oil and gas production on February 25, 1999.

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I. PRESENT-LAW TAX RULES APPLICABLE TO DOMESTIC OIL AND GAS OPERATIONS

A. Depletion

General rules

Depletion, like depreciation, is a form of capital cost recovery. In both cases, the taxpayer is allowed a deduction in recognition of the fact that an asset--in the case of depletion for oil or gas interests, the mineral reserve itself--is being expended in order 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 or other interest in the property and geological and geophysical costs (in advance of actual drilling).

Depletion is available to any person having an economic interest in a producing property. Treasury Department regulations state that an economic interest is possessed in every case in which the taxpayer has acquired by investment any interest in minerals in place, and secures, by any form of legal relationship, income derived from the extraction of the mineral, to which it must look for a return of its capital.[2] Thus, for example, both working interests and royalty interests in an oil- or gas-producing property constitute economic interests, thereby qualifying the interest holders for depletion deductions with respect to the property. A taxpayer who has no capital investment in the mineral deposit does not possess an economic interest merely because through a contractual relation it possesses a mere economic or pecuniary advantage derived from production.

Two methods of depletion are currently allowable under the Internal Revenue Code (the "Code"): (1) the cost depletion method, and (2) the percentage depletion method (secs. 611-613). Under the cost depletion method, the taxpayer deducts that portion of the adjusted basis of the depletable property which is equal to the ratio of units sold from that property during the taxable year to the number of units remaining as of the end of taxable year plus the number of units sold during the taxable year. Thus, the amount recovered under cost depletion may never exceed the taxpayer's basis in the property.

Under the percentage depletion method generally, 15 percent of the taxpayer's gross income from an oil- or gas-producing property is allowed as a deduction in each taxable year (sec. 613A(c)). The amount deducted generally may not exceed 100 percent of the net income from that property in any year (the "net-income limitation") (sec. 613(a)).[3] Additionally, the

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[2] Treas. Reg. sec. 1.611-1(b)(1).

[3] By contrast, for any other mineral qualifying for the percentage depletion deduction, such deduction may not exceed 50 percent of the taxpayer's taxable income from the depletable property. A similar 50-percent net-income limitation applied to oil and gas properties for taxable years beginning before 1991. Section 11522(a) of the Omnibus Budget Reconciliation

percentage depletion deduction for all oil and gas properties may not exceed 65 percent of the taxpayer's overall taxable income (determined before such deduction and adjusted for certain loss carrybacks and trust distributions) (sec. 613A(d)(1)).[4] Because percentage depletion, unlike cost depletion, is computed without regard to the taxpayer's basis in the depletable property, cumulative depletion deductions may be greater than the amount expended by the taxpayer to acquire or develop the property.

A taxpayer is required to determine the depletion deduction for each oil or gas property under both the percentage depletion method (if the taxpayer is entitled to use this method) and the cost depletion method. If the cost depletion deduction is larger, the taxpayer must utilize that method for the taxable year in question (sec. 613(a)).

Limitation of oil and gas percentage depletion to independent producers and royalty owners

The Tax Reduction Act of 1975 (the "1975 Act") repealed the deduction for percentage depletion with respect to much oil and gas production. Following the 1975 Act, only independent producers and royalty owners (as contrasted to integrated oil companies) are allowed to claim percentage depletion. Percentage depletion for eligible taxpayers is allowed only with respect to up to 1,000 barrels of average daily production of domestic crude oil or an equivalent amount of domestic natural gas (sec. 613A(c)).[5] For producers of both oil and natural gas, this limitation applies on a combined basis. All production owned by businesses under common control and members of the same family must be aggregated (sec. 613A(c)(8)); each group is then treated as one producer for application of the 1,000-barrel limitation.

For purposes of the percentage depletion allowance, an independent producer is any producer that is not a "retailer" or "refiner." A retailer is any person that directly, or through a related person, 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 that is obligated to market or distribute such oil or natural gas (or product derived therefrom) under the name of the taxpayer or the related person, or that has the authority to occupy any retail outlet owned by the

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Act of 1990 prospectively changed the net-income limitation threshold to 100 percent only for oil and gas properties, for taxable years beginning after 1990. Moreover, the Taxpayer Relief Act of 1997 suspended the 100-percent net-income limitation for marginal wells for taxable years beginning after December, 31, 1997, and before January 1, 2000.

[4] Amounts disallowed as a result of this rule may be carried forward and deducted in subsequent taxable years, subject to the 65-percent taxable income limitation for those years.

[5] As originally enacted, the depletable oil quantity was 2,000 barrels of average daily production. This was gradually phased down to 1,000 barrels of average daily production for 1980 and thereafter. The 1975 Act also phased down the percentage depletion rate from 22 percent in 1975 to 15 percent in 1984 and thereafter.

taxpayer or a related person (sec. 613A(d)(2)). Bulk sales of crude oil and natural gas to commercial or industrial users, and bulk sales of aviation fuel to the Department of Defense, are not treated as retail sales for this purpose. 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 from the retail sale of oil, natural gas, or any product derived therefrom do not exceed $5 million for the taxable year.

A refiner is any person that directly or through a related person engages in the refining of crude oil, but only if such person or related person has a refinery run in excess of 50,000 barrels per day on any day during the taxable year (sec. 613A(d)(4)).

In addition to the independent producer and royalty owner exception, certain sales of natural gas under a fixed contract in effect on February 1, 1975, and certain natural gas from geopressured brine,[6] are eligible for percentage depletion, at rates of 22 percent and 10 percent, respectively. These exceptions apply without regard to the 1,000-barrel-per-day limitation and regardless of whether the producer is an independent producer or an integrated oil company.

Before enactment of the Omnibus Budget Reconciliation Act of 1990 (the "1990 Act"), if an interest in a proven oil or gas property was transferred (subject to certain exceptions), the production from such interest did not qualify for percentage depletion.[7] The 1990 Act repealed the limitation on claiming percentage depletion on transferred properties effective for property transfers occurring after October 11, 1990.

Percentage depletion on marginal production

The 1990 Act also created special percentage depletion provisions for oil and gas production from so-called marginal properties held by independent producers or royalty owners (sec. 613A(c)(6)). Under this provision, the statutory percentage depletion rate is increased (from the general rate of 15 percent) by one percent for each whole dollar that the average price of crude oil (as determined under the provisions of the nonconventional fuels production credit of section 29) for the immediately preceding calendar year is less than $20 per barrel. In no event may the rate of percentage depletion under this provision exceed 25 percent for any taxable year. The increased rate applies for the taxpayer's taxable year which immediately follows a calendar year for which the average crude oil price falls below the $20 floor. To illustrate the application of this provision, the average price of a barrel of crude oil for calendar year 1997 (the most recent year for which a determination is available) was $17.24.[8] Thus, the

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[6] This exception is limited to wells the drilling of which began between September 30, 1978, and January 1, 1984.

[7] The exceptions to this rule included transfers at death, certain transfers to controlled corporations, and transfers between controlled corporations or other business entities.

[8] IRS Notice 98-42, 1998-33 I.R.B. 12.

percentage depletion rate for production from marginal wells was increased to 17 percent for taxable years beginning in 1998.

The Code defines the term "marginal production" for this purpose as domestic crude oil or domestic natural gas which is produced during any taxable year from a property which (1) is a stripper well property for the calendar year in which the taxable year begins, or (2) is a property substantially all of the production from which during such calendar year is heavy oil (i.e., oil that has a weighted average gravity of 20 degrees API or less corrected to 60 degrees Fahrenheit) (sec. 613A(c)(6)(D)). A stripper well property is any oil or gas property which produces a daily average of 15 or less equivalent barrels of oil and gas per producing oil or gas well on such property in the calendar year during which the taxpayer's taxable year begins (sec. 613A(c)(6)(E)).[9]

The determination of whether a property qualifies as a stripper well property is made separately for each calendar year. The fact that a property is or is not a stripper well property for one year does not affect the determination of the status of that property for a subsequent year. Further, the stripper well property determination is made by a taxpayer for each separate property interest (as defined under section 614) held by the taxpayer during a calendar year. The determination is based on the total amount of production from all producing wells that are treated as part of the same property interest of the taxpayer. A property qualifies as a stripper well property for a calendar year only if the wells on such property were producing during that period at their maximum efficient rate of flow.

If a taxpayer's property consists of a partial interest in one or more oil- or gas-producing wells, the determination of whether the property is a stripper well property or a heavy oil property is made with respect to total production from such wells, including the portion of total production attributable to ownership interests other than the taxpayer's. If the property satisfies the requirements of a stripper well property, then that person receives the benefits of this provision with respect to its allocable share of the production from the property for its taxable year that begins during the calendar year in which the property so qualifies.

The allowance for percentage depletion on production from marginal oil and gas properties is subject to the 1,000-barrel-per-day limitation discussed above. Unless a taxpayer elects otherwise, marginal production is given priority over other production for purposes of utilization of that limitation.

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[9] The amount of equivalent barrels is computed as the sum of (1) the number of barrels of crude oil produced, and (2) the number of cubic feet of natural gas produced divided by 6,000. If a well produced 10 barrels of crude oil and 12,000 cubic feet of natural gas, its equivalent barrels produced would equal 12 (i.e., 10 + (12,000 / 6,000)).

B. Intangible Drilling and Development Costs

In general

In general, costs that benefit future periods must be capitalized and recovered over those periods for income tax purposes, rather than being expensed in the period the costs are incurred. Special rules are provided, however, for the treatment of intangible drilling and development costs ("IDCs"). Under these special rules, an operator or working interest owner (i.e., a person that 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) that pays or incurs IDCs in the development of an oil or gas property located in the United States, may elect either to expense or capitalize those costs (sec. 263(c)).

IDCs include all expenditures made by an operator for wages, fuel, repairs, hauling, supplies, etc., incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas. In addition, IDCs include the cost to operators of any drilling or development work (excluding amounts payable only out of production or gross or net proceeds from production, if the amounts are depletable income to the recipient, and amounts properly allocable to the cost of depreciable property) done by contractors under any form of contract (including a turnkey contract). Such work includes labor, fuel, repairs, hauling, and supplies which are used in the drilling, shooting, and cleaning of wells; in such clearing of ground, draining, road making, surveying, and geological works (as are necessary in preparation for the drilling of wells); and in the construction of such derricks, tanks, pipelines, and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil and gas. Generally, IDCs do not include expenses for items which have a salvage value (such as pipes and casings), or items which are part of the acquisition price of an interest in the property.[10]

If an election to expense IDCs is made, the taxpayer deducts the amount of the IDCs as an expense in the taxable year the cost is paid or incurred. Generally, if IDCs are not expensed, but are capitalized, they may be recovered through depletion or depreciation, as appropriate; or in the case of a nonproductive well ("dry hole"), they may be deducted, at the election of the operator.[11] In the case of an integrated oil company that has elected to expense IDCs, 30 percent of the IDCs on productive wells must be capitalized and amortized over a 60-month period (sec. 291(b)(1)(A)).[12]

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[10] Treas. Reg. sec. 1.612-4(a).

[11] Treas. Reg. sec. 1.612-4(b)(4).

[12] The IRS has ruled that if a company that has capitalized and begun to amortize IDCs over a 60-month period pursuant to section 291 ceases to be an integrated oil company, it may not immediately write off the unamortized portion of the capitalized IDCs, but instead must continue to amortize the IDCs so capitalized over the 60-month amortization period. (Rev. Rul.

Notwithstanding the fact that a taxpayer has made the election to deduct IDCs, the Code provides an additional election under which the taxpayer is allowed to capitalize and amortize certain IDCs over a 60-month period beginning with the month the expenditure was paid or incurred (sec. 59(e)(1)). This rule applies on an expenditure-by-expenditure basis; that is, for any particular taxable year, a taxpayer may deduct some portion of its IDCs and capitalize the rest under this provision. This allows the taxpayer to reduce or eliminate the IDC adjustments or preferences under the alternative minimum tax.

The election to deduct IDCs applies only to those IDCs associated with domestic properties.[13] For this purpose, the United States includes certain wells drilled offshore.[14]

Exemption from uniform capitalization rules

The uniform capitalization rules, which were enacted as part of the Tax Reform Act of 1986, require certain direct and indirect costs allocable to property to be included in inventory or capitalized as part of the basis of such property (sec. 263A). In general, the uniform capitalization rules apply to real and tangible personal property produced by the taxpayer or acquired for resale. Pursuant to a special exception, these rules do not apply to IDCs incurred with respect to oil or gas wells which are otherwise deductible under the Code (sec. 263A(c)(3)).

93-26, 1993-1 C.B.50.)

[13] In the case of IDCs paid or incurred with respect to an oil or gas well located outside of the United States, the costs, at the election of the taxpayer, are either (1) included in adjusted basis for purposes of computing the amount of any deduction allowable for cost depletion or (2) capitalized and amortized ratably over a 10-year period beginning with the taxable year such costs were paid or incurred (sec. 263(i)).

[14] The term "United States" for this purpose includes the seabed and subsoil of those submarine areas that are adjacent to the territorial waters of the United States and over which the United States has exclusive rights, in accordance with international law, with respect to the exploration and exploitation of natural resources (i.e., the Continental Shelf area) (sec. 638).

C. Geological and Geophysical Costs

In general

Under the Code, no current deduction is allowed for any amount paid for new buildings or for permanent improvements or betterments made to increase the value of any property or estate (sec. 263(a)). The regulations define capital amounts to include amounts paid or incurred (1) to add to the value, or substantially prolong the useful life, of property owned by the taxpayer or (2) to adapt property to a new or different use.[15]

The proper income tax treatment of geological and geophysical expenditures ("G&G costs") has been the subject of a number of court decisions and administrative rulings. G&G costs are incurred by the taxpayer for the purpose of obtaining and accumulating data that will serve as a basis for the acquisition and retention of mineral properties by taxpayers exploring for minerals. Courts have ruled that such costs are capital in nature and are not deductible as ordinary and necessary business expenses.[16] Accordingly, the costs attributable to such exploration are allocable to the cost of the property acquired or retained.[17] The term "property" is used in this case in the sense of an interest in a property as defined in the Code (sec. 614), and includes an economic interest in a tract or parcel of land notwithstanding that a mineral deposit has not been established or proven at the time the costs are incurred.

Revenue Ruling 77-188

In Revenue Ruling 77-188[18] (hereinafter referred to as the "1977 ruling"), the Internal Revenue Service ("IRS") provided guidance regarding the proper tax treatment of G&G costs. The ruling describes a typical geological and geophysical exploration program as containing the following elements:

- It is customary in the search for mineral producing properties for a taxpayer to conduct an exploration program in one or more identifiable project areas. Each project area encompasses a territory that the taxpayer determines can be explored advantageously in a single integrated operation. This determination is made after

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[15] Treas. Reg. sec. 1.263(a)-(1)(b).

[16] See, e.g., *Schermerhorn Oil Corporation,* 46 B.T.A. 151 (1942).

[17] By contrast, section 617 of the Code permits a taxpayer to elect to deduct certain expenditures incurred for the purpose of ascertaining the existence, location, extent, or quality of any deposit of ore or other mineral (but not oil and gas). These deductions are subject to recapture if the mine with respect to which the expenditures were incurred reaches the producing stage.

[18] 1977-1 C.B. 76.

analyzing certain variables such as the size and topography of the project area to be explored, the existing information available with respect to the project area and nearby areas, and the quantity of equipment, the number of personnel, and the amount of money available to conduct a reasonable exploration program over the project area.

- The taxpayer selects a specific project area from which geological and geophysical data are desired and conducts a reconnaissance-type survey utilizing various geological and geophysical exploration techniques that are designed to yield data that will afford a basis for identifying specific geological features with sufficient mineral potential to merit further exploration.

- Each separable, noncontiguous portion of the original project area in which such a specific geological feature is identified is a separate "area of interest." The original project area is subdivided into as many small projects as there are areas of interest located and identified within the original project area. If the circumstances permit a detailed exploratory survey to be conducted without an initial reconnaissance-type survey, the project area and the area of interest will be coextensive.

- The taxpayer seeks to further define the geological features identified by the prior reconnaissance-type surveys by additional, more detailed, exploratory surveys conducted with respect to each area of interest. For this purpose, the taxpayer engages in more intensive geological and geophysical exploration employing methods that are designed to yield sufficiently accurate sub-surface data to afford a basis for a decision to acquire or retain properties within or adjacent to a particular area of interest or to abandon the entire area of interest as unworthy of development by mine or well.

The 1977 ruling provides that if, on the basis of data obtained from the preliminary geological and geophysical exploration operations, only one area of interest is located and identified within the original project area, then the entire expenditure for those exploratory operations is to be allocated to that one area of interest and thus capitalized into the depletable basis of that area of interest. On the other hand, if two or more areas of interest are located and identified within the original project area, the entire expenditure for the exploratory operations is to be allocated equally among the various areas of interest.

If, however, from the data obtained by the exploratory operations no areas of interest are located and identified by the taxpayer within the original project area, then the 1977 ruling states that the entire amount of the G&G costs related to the exploration is deductible as a loss under section 165 for the taxable year in which that particular project area is abandoned as a potential source of mineral production.

The 1977 ruling further provides that if, on the basis of data obtained from a detailed survey that does not relate exclusively to any particular property within a particular area of interest, an oil or gas property is acquired or retained within or adjacent to that area of interest, the entire G&G exploration expenditures, including those incurred prior to the identification of the particular area of interest but allocated thereto, are to be allocated to the property as a capital cost under section 263(a). If more than one property is acquired or retained within or adjacent to an area of interest, it is proper to determine the amount of the G&G costs allocable to each such property by allocating the entire amount of the costs among the properties so acquired or retained on the basis of the comparative acreage of the properties.

If, however, no property is acquired or retained within or adjacent to that area of interest, the entire amount of the G&G costs allocable to the area of interest is deductible as a loss under section 165 for the taxable year in which such area of interest is abandoned as a potential source of mineral production.

In 1983, the IRS issued Revenue Ruling 83-105,[19] which elaborates on the positions set forth in the 1977 ruling by setting forth seven factual situations and applying the principles of the 1977 ruling to those situations. In addition, Revenue Ruling 83-105 explains what constitutes an "abandonment as a potential source of mineral production."

[19] 1983-2 C.B. 51.

D. Tax Credits

1. Nonconventional fuels production credit

Taxpayers that produce certain qualifying fuels from nonconventional sources are eligible for a tax credit ("the section 29 credit") equal to $3 per barrel or Btu oil barrel equivalent.[20] Fuels qualifying for the credit must be produced domestically from a well drilled, or a facility treated as placed in service, before January 1, 1993. The section 29 credit generally is available for qualified fuels sold to unrelated persons before January 1, 2003.

A facility that produces gas from biomass or produces liquid, gaseous, or solid synthetic fuels from coal (including lignite) generally is treated as being placed in service before January 1, 1993, if it was placed in service by the taxpayer before July 1, 1998, pursuant to a written binding contract in effect before January 1, 1997. If a facility that qualifies for this binding contract exception is originally placed in service after December 31, 1992, production from the facility may qualify for the credit if sold to an unrelated person before January 1, 2008.

For purposes of the credit, qualified fuels include: (1) oil produced from shale and tar sands; (2) gas produced from geopressured brine, Devonian shale, coal seams, a tight formation, or biomass (i.e., any organic material other than oil, natural gas, or coal (or any product thereof)); and (3) liquid, gaseous, or solid synthetic fuels produced from coal (including lignite), including such fuels when used as feedstocks. Production attributable to a property from which gas from Devonian shale, coal seams, geopressured brine, or a tight formation was produced in marketable quantities before 1980 does not qualify for the credit.

The amount of the section 29 credit generally is adjusted by an inflation adjustment factor for the calendar year in which the sale occurs. The inflation adjustment factor for the 1997 taxable year (the most recent year for which a determination is available) was 2.0331. Therefore, the inflation-adjusted amount of the credit for that year was $6.10 per barrel or barrel equivalent.[21] There is no adjustment for inflation in the case of the credit for sales of natural gas produced from a tight formation. The credit begins to phase out if the annual average unregulated wellhead price per barrel of domestic crude oil exceeds $23.50 multiplied by the inflation adjustment factor.[22] For 1997 (the most recent year for which a determination is available), the inflation adjusted threshold for onset of the phase out was $47.78 ($23.50 x 2.0331) and the average wellhead price for that year was $15.98.

The amount of the section 29 credit allowable with respect to a project is reduced by any

[20] A barrel-of-oil equivalent generally means that amount of the qualifying fuel which has a Btu (British thermal unit) content of 5.8 million.

[21] IRS Notice 98-28, 1998-19 I.R.B. 7.

[22] IRS Notice 98-28, 1998-19 I.R.B. 7.

unrecaptured business energy tax credit (sec. 48) or enhanced oil recovery credit (sec. 43) claimed with respect to such project.

As with most other credits, the section 29 credit may not be used to offset alternative minimum tax liability. Any unused section 29 credit generally may not be carried back or forward to another taxable year; however, a taxpayer, under section 53, receives a credit for prior year minimum tax liability to the extent that a section 29 credit is disallowed as a result of the operation of the alternative minimum tax. The credit is limited to what would have been the regular tax liability but for the alternative minimum tax.

2. Enhanced oil recovery credit

Taxpayers are permitted to claim a general business credit for a taxable year, which consists of several different components (sec. 38(a)). One component of the general business credit is the enhanced oil recovery credit (sec. 43). The general business credit for a taxable year may not exceed the excess (if any) of the taxpayer's net income over the greater of (1) the tentative minimum tax, or (2) 25 percent of so much of the taxpayer's net regular tax liability as exceeds $25,000. Any unused general business credit generally may be carried back three taxable years and carried forward 15 taxable years.

The enhanced oil recovery credit for a taxable year is equal to 15 percent of certain costs attributable to qualified enhanced oil recovery ("EOR") projects undertaken by the taxpayer in the United States during the taxable year. To the extent that a credit is allowed for such costs, the taxpayer must reduce the amount otherwise deductible or required to be capitalized and recovered through depreciation, depletion, or amortization, as appropriate, with respect to these costs. A taxpayer may elect not to have the enhanced oil recovery credit apply for a taxable year.

The amount of the enhanced oil recovery credit is reduced in a taxable year following a calendar year during which the annual average unregulated wellhead price per barrel of domestic crude oil exceeds $28 (adjusted for inflation since 1990).[23] For calendar year 1998, this amount was $33.60.[24] If the average unregulated wellhead price exceeds this amount, the credit would be reduced ratably over a $6 phase out range.

For purposes of the credit, qualified enhanced oil recovery costs include the following costs which are paid or incurred with respect to a qualified EOR project: (1) the cost of tangible property which is an integral part of the project and with respect to which depreciation or amortization is allowable; (2) IDCs with respect to which a taxpayer may make an election to

[23] The average per-barrel price of crude oil for this purpose is determined under the same manner as it is for purposes of the section 29 credit.

[24] IRS Notice 98-41, 1998-33 I.R.B. 12.

deduct under section 263(c);[25] and (3) the cost of tertiary injectants with respect to which a deduction is allowable under section 193, whether or not chargeable to capital account.

A qualified EOR project means any project that is located within the United States and involves the application (in accordance with sound engineering principles) of one or more tertiary recovery methods as defined under section 193(b)(3) which can reasonably be expected to result in more than an insignificant increase in the amount of crude oil which ultimately will be recovered. The tertiary recovery methods referred to in section 193(b)(3) generally include the following nine methods which were listed in section 212.78(c) of the June 1979 Department of Energy regulations: miscible fluid displacement, steam-drive injection, microemulsion flooding, in situ combustion, polymer-augmented water flooding, cyclic-steam injection, alkaline flooding, carbonated water flooding, and immiscible non-hydrocarbon gas displacement, or any other method approved by the IRS. In addition, for purposes of the enhanced oil recovery credit, immiscible non-hydrocarbon gas displacement generally is considered a qualifying tertiary recovery method, even if the gas injected is not carbon dioxide.

A project is not considered a qualified EOR project unless the project's operator submits to the IRS a certification from a petroleum engineer that the project meets the requirements set forth in the preceding paragraph.

The enhanced oil recovery credit is effective for taxable years beginning after December 31, 1990, with respect to costs paid or incurred in EOR projects begun or significantly expanded after that date.

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[25] In the case of an integrated oil company, the credit base includes those IDCs which the taxpayer is required to capitalize under section 291(b)(1).

E. Alternative Minimum Tax

In general

A taxpayer is subject to an alternative minimum tax ("AMT") to the extent that its tentative minimum tax exceeds its regular income tax liability (sec. 55(a)). A corporate taxpayer's tentative minimum tax generally equals 20 percent of its alternative minimum taxable income in excess of an exemption amount. (The marginal AMT rate for a noncorporate taxpayer is 26 or 28 percent, depending on the amount of its alternative minimum taxable income above an exemption amount.) Alternative minimum taxable income ("AMTI") is the taxpayer's taxable income increased by certain tax preferences and adjusted by determining the tax treatment of certain items in a manner which negates the deferral of income resulting from the regular tax treatment of those items.

The AMTI of a corporation is increased by an amount equal to 75 percent of the amount by which adjusted current earnings ("ACE") of the corporation exceed AMTI (as determined before this adjustment) (sec. 56(g)). In general, ACE means AMTI with additional adjustments that generally follow the rules presently applicable to corporations in computing their earnings and profits.

AMT treatment of depletion

Since the provisions of the Energy Policy Act of 1992 became fully effective, there has been no AMT preference for oil and gas percentage depletion. Before enactment of that Act, oil and gas percentage depletion deductions in excess of the taxpayer's basis in the property were an AMT preference.

AMT treatment of IDCs

Also as discussed above, in computing its regular tax, a taxpayer who pays or incurs IDCs in the development of domestic oil or gas properties may elect to either expense or capitalize these amounts. The difference between the amount of a taxpayer's IDC deductions and the amount which would have been currently deductible had IDCs been capitalized and recovered over a 10-year period may constitute an item of tax preference for the AMT to the extent that this amount exceeds 65 percent of the taxpayer's net income from oil and gas properties for the taxable year (the "excess IDC preference") (sec. 57(a)(2)).

For taxpayers other than integrated oil companies, the Energy Policy Act of 1992 repealed the excess IDC preference for IDCs related to oil and gas wells for taxable years beginning after 1992 (sec. 57(a)(2)(E)). The repeal of the excess IDC preference, however, may not result in the reduction of the amount of the taxpayer's AMTI by more than 40 percent of the amount that the taxpayer's AMTI would have been had the excess IDC preference not been repealed.

In addition, for purposes of computing the an integrated oil company's ACE adjustment to the AMT, IDCs are capitalized and amortized over the 60-month period beginning with the month in which they are paid or incurred (sec. 56(g)(4)(D)(i)). The ACE preference does not apply to independent oil and gas producers since enactment of the Energy Policy Act of 1992.

F. Passive Activity Loss and Credit Rules

A taxpayer's deductions from passive trade or business activities, to the extent they exceed income from all such passive activities of the taxpayer (exclusive of portfolio income), generally may not be deducted against other income (sec. 469).[26] Thus, for example, an individual taxpayer generally may not deduct losses from a passive activity against income from wages. Losses suspended under this "passive activity loss" limitation are carried forward and treated as deductions from passive activities in the following year, and thus may offset any income from passive activities generated in that later year. Suspended losses from a passive activity may be deducted in full when the taxpayer disposes of its entire interest in that activity to an unrelated party in a transaction in which all realized gain or loss is recognized. An activity generally is treated as passive i f the taxpayer does not materially participate in it. A taxpayer is treated as materially participating in an activity only if the taxpayer is involved in the operations of the activity on a basis which is regular, continuous, and substantial.

A working interest in an oil or gas property generally is not treated as a passive activity, whether or not the taxpayer materially participates in the activities related to that property (sec. 469(c)(3) and (4)). This exception from the passive activity rules does not apply if the taxpayer holds the working interest through an entity which limits the liability of the taxpayer with respect to the interest. In addition, if a taxpayer has any loss for any taxable year from a working interest in an oil or gas property which is treated pursuant to this working interest exception as a loss which is not from a passive activity, then any net income from such property (or any property the basis of which is determined in whole or in part by reference to the basis of such property) for any succeeding taxable year is treated as income of the taxpayer which is not from a passive activity.

Similar limitations apply to the utilization of tax credits attributable to passive activities (sec. 469(a)(1)(B)). Thus, for example, the passive activity rules (and, consequently, the oil and gas working interest exception to those rules) apply to the nonconventional fuels production credit and the enhanced oil recovery credit. However, if a taxpayer has net income from a working interest in an oil and gas property which is treated as not arising from a passive activity, then any tax credits attributable to the interest in that property are treated as credits not from a passive activity (and, thus, not subject to the passive activity credit limitation) to the extent that the amount of such credits does not exceed the regular tax liability of the taxpayer for the taxable year which is allocable to such net income.

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[26] This provision applies to individuals, estates, trusts, personal service corporations, and certain closely held corporations.

G. Sales and Exchanges of Property Interests

Under present law, individual taxpayers are subject to a maximum statutory income tax rate of 39.6 percent. If an individual recognizes capital gains, however, the gains generally are subject to a maximum tax rate of 20 percent. There currently is no differential between the rates of taxation of capital gains and ordinary income in the case of corporate taxpayers.

Gain recognized from the disposition of an interest in an oil or gas property generally is characterized as capital gain. The Code contains a special recapture provision, however, which mandates that in certain cases a portion of any gain is to be treated as ordinary income and not as capital gain (sec. 1254). Specifically, the Code provides that if a taxpayer disposes of "section 1254 property" that was placed in service after 1986, then the lesser of (1) the gain recognized on the disposition or (2) the aggregate amount of (a) depletion deductions which resulted in a reduction in the basis of the property disposed of and (b) IDCs deducted pursuant to an election under section 263(c) and which, but for the deduction, would have been included in the adjusted basis of the property, is characterized as ordinary income.[27] For this purpose, the term "section 1254 property" means any property (within the meaning of sec. 614) if any IDCs are properly chargeable to such property or the adjusted basis of such property includes adjustments for depletion deductions.

[27] For dispositions of property placed in service before 1987, taxpayers are not required to recapture depletion deductions and are required to recapture IDC deductions only in excess of the amounts which would have been deductible as depletion if the IDCs had been capitalized.

H. Net Operating Losses

A net operating loss ("NOL") is generally the amount by which business deductions of a taxpayer exceed business gross income. In general, an NOL may be carried back two years and carried forward 20 years to offset taxable income in such years.[28] A carryback of an NOL results in the refund of Federal income tax for the carryback year. A carryforward of an NOL reduces Federal income tax for the carryforward year. Special NOL carryback rules apply to (1) casualty and theft losses of individual taxpayers, (2) Presidentially declared disasters for taxpayers engaged in a farming business or a small business, (3) real estate investment trusts, (4) specified liability losses, (5) excess interest losses, and (6) farm losses.

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[28] A taxpayer could elect to forgo the carryback of an NOL.

II. DESCRIPTION OF H.R. 53 AND H.R. 423

A. Description of H.R. 53 (Mr. Watkins, Mr. Thomas, Mr. McCrery, and Others): Tax Credit for Production of Oil and Gas From Marginal Wells

Description of the Bill

H.R. 53 would create a new income tax credit for the production of crude oil and natural gas from marginal wells. The credit would be a component of the general business credit (sec. 38). The marginal well production credit for any taxable year would equal the product of (1) the credit amount, and (2) the qualified crude oil production and the qualified natural gas production which is attributable to the taxpayer. The "credit amount" would be $3 per barrel of qualified crude oil production and 50 cents per 1,000 cubic feet of qualified natural gas production. "Qualified crude oil production" and "qualified natural gas production" would be defined as crude oil or natural gas which was produced from a marginal well.

The term "marginal well" would be defined as a domestic well which during the taxable year has marginal production. Marginal production would be defined as domestic crude oil or domestic natural gas which is produced during any taxable year from a property which (1) was a stripper well property for the calendar year in which the taxable year begins, or (2) was a property substantially all of the production of which during the calendar year was heavy oil (i.e., oil that has a weighted average gravity of 20 degrees API or less corrected to 60 degrees Fahrenheit). A stripper well property would be defined as an oil or gas property which produces a daily average of 15 or less equivalent barrels of oil and gas per producing well on the property in the calendar year during which the taxpayer's taxable year begins.

Under the bill, the credit amount would be phased out as oil and gas prices increased. This would phase out the credit for barrels of qualified crude oil with reference price between $14 and $17 and qualified natural gas with reference price between $1.56 and $1.89.[29] In taxable years beginning in a calendar year after 1999, these dollar amounts would be indexed for inflation. The reference price for the calendar year for qualified crude oil would be the Treasury Department's estimate of the annual average wellhead price per barrel for all domestic crude oil, or in the area of natural gas, the Treasury's estimate of the annual average wellhead price per 1,000 cubic feet for all domestic natural gas.

Crude oil or natural gas produced during any taxable year from any well would not be treated as qualified crude oil production or qualified natural gas production to the extent production from the well during the taxable year exceeds 1,095 barrels or barrel equivalents.[30]

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[29] The reference price for a taxable year would be the reference price for the calendar year preceding the calendar year in which the taxable year begins.

[30] "Barrel equivalent" means, with respect to natural gas, a conversion ratio of 6,000 cubic feet of natural gas to one barrel of crude oil. The annual barrel limitation would be reduced

The credit could be claimed only on production which was attributable to the holder of an operating interest. In the case of a marginal well in which there is more than one owner of operating interests in the well, and the crude oil or natural gas production exceeds the limitations, then crude oil or natural gas production would be determined on the basis of the ratio which the taxpayer's revenue interest in the production bears to the aggregate revenue interests of all operating interest owners in the production.

The proposed credit would not be allowed for production from any well if the production also qualified for the nonconventional fuels production credit unless the taxpayer elected not to claim the nonconventional fuels credit (sec. 29) with respect to the well. The marginal well production credit also would be permitted to offset, in full, the regular tax and the alternative minimum tax. Any unused credits generally could be carried back 10 years and carried forward 20 years.

Effective Date

The provisions of the bill would apply to production after the date of enactment.

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proportionately to reflect a taxpayer's short taxable year and also to reflect wells not in production the entire taxable year.

B. Description of H.R. 423 (Mr. Thomas, Mr. Watkins, and Others): Net Operating Loss Carryback for Certain Oil and Gas Losses

Description of the Bill

H.R. 423 would provide a special five-year carryback for certain eligible oil and gas losses. The carryforward period would remain 20 years. An "eligible oil and gas loss" would be defined as the lesser of (1) the amount which would be the taxpayer's NOL for the taxable year if only income and deductions attributable to operating mineral interests in oil and gas wells were taken into account, or (2) the amount of such net operating loss for such taxable year. In calculating the amount of a taxpayer's NOL carrybacks, the portion of the NOL that would be attributable to an eligible oil and gas loss would be treated as a separate NOL and taken into account after the remaining portion of the NOL for the taxable year.

A taxpayer could elect to forgo the five-year carryback period for an eligible oil and gas loss. The election to forgo the five-year carryback period would be made in the manner prescribed by the Treasury Department and would have to be made by the due date of the return (including extensions) for the year of the loss. The election would be irrevocable. If a taxpayer elected to forgo the five-year carryback period, then the eligible oil and gas losses would be subject to the rules that otherwise have applied under section 172 absent the five-year rule under the bill.

Effective Date

The provisions of the bill would apply to NOLs arising in taxable years beginning after December 31, 1997.