DESCRIPTION OF PRESENT LAW AND SELECT PROPOSALS RELATING TO THE OIL AND GAS INDUSTRY

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INTRODUCTION

The Internal Revenue Code includes a number of tax provisions that provide favorable treatment to investment in oil and gas production projects. These incentives include the enhanced oil recovery credit, the marginal wells credit, the expensing of intangible drilling costs, the deduction for using tertiary injectants, the passive loss exemption for working interests in oil and gas properties, percentage depletion, the domestic manufacturing deduction for oil and gas production, and accelerated amortization for geological and geophysical expenses.

Some of these incentives are available to all domestic producers and all domestic production, while others target smaller producers or production that utilizes specific types of extractive technologies. Some of the incentives are not available (or are only partially available) to oil and gas producers whose production activities are integrated with refining and retail sales activities.[1]

In addition to these industry specific incentives, there are several provisions of general application that are particularly important to the oil and gas sector. These include the rules for dual capacity taxpayers and the last-in first-out method of accounting.

The Senate Committee on Finance has scheduled a public hearing on May 12, 2011, on oil and gas tax incentives and rising energy prices. This document,[2] prepared by the staff of the Joint Committee on Taxation, provides a description of various aspects of present law relating to the oil and gas industry along with related proposals to modify certain existing rules and make further proposed changes.

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[1] Integrated oil companies subject to these limitations are oil and gas producers that sell more than $5 million of retail product per year or refine more than 75,000 barrels of oil per year. Major integrated oil companies are a subset of integrated oil companies that (1) have average daily worldwide production exceeding 500,000 barrels per year, (2) had gross receipts in excess of $1 billion in 2005, and (3) own at least a 15 percent interest in a refinery that produces more than 75,000 barrels of oil per year.

[2] This document may be cited as follows: Joint Committee on Taxation, *Description of Present Law and Select Proposals Relating to the Oil and Gas Industry*, (JCX-27-11) May 11, 2011. This document can also be found on our website a www.jct.gov.

I. PRESENT LAW TAX INCENTIVES FOR OIL AND GAS PRODUCTION

A. Credit for Enhanced Oil Recovery Costs (sec. 43)[3]

Taxpayers may claim a credit equal to 15 percent of qualified enhanced oil recovery ("EOR") costs.[4] Qualified EOR costs consist of the following designated expenses associated with an EOR project: (1) amounts paid for depreciable tangible property; (2) intangible drilling and development expenses; (3) tertiary injectant expenses; and (4) construction costs for certain Alaskan natural gas treatment facilities. An EOR project is generally a project that involves increasing the amount of recoverable domestic crude oil through the use of one or more tertiary recovery methods (as defined in section 193(b)(3)), such as injecting steam or carbon dioxide into a well to effect oil displacement.

The EOR credit is ratably reduced over a $6 phase-out range when the reference price for domestic crude oil exceeds $28 per barrel (adjusted for inflation after 1991; $42.57 for 2010). The reference price is determined based on the annual average price of domestic crude oil for the calendar year preceding the calendar year in which the taxable year begins.[5] The EOR credit is currently phased-out.

Taxpayers claiming the EOR credit must reduce by the amount of the credit any otherwise allowable deductions associated with EOR costs. In addition, to the extent a property's basis would otherwise be increased by any EOR costs, such basis is reduced by the amount of the EOR credit.

B. Marginal Well Tax Credit (sec. 45I)

The Code provides a $3-per-barrel credit (adjusted for inflation) for the production of crude oil and a $0.50-per-1,000-cubic-feet credit (also adjusted for inflation) for the production of qualified natural gas. In both cases, the credit is available only for domestic production from a "qualified marginal well."

A qualified marginal well is defined as a domestic well: (1) production from which is treated as marginal production for purposes of the Code percentage depletion rules; or (2) that during the taxable year had average daily production of not more than 25 barrel equivalents and produces water at a rate of not less than 95 percent of total well effluent. The maximum amount of production on which a credit may be claimed is 1,095 barrels or barrel equivalents.

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[3] Except where noted, all section references are to the Internal Revenue Code of 1986, as amended (the "Code").

[4] Sec. 43.

[5] Secs. 43(b) and 45K(d)(2)(C).

The credit is not available if the reference price of oil exceeds $18 ($2.00 for natural gas). The credit is reduced proportionately for reference prices between $15 and $18 ($1.67 and $2.00 for natural gas).[6] Currently the credit is phased out completely.

In the case of production from a qualified marginal well which is eligible for the credit allowed under section 45K for the taxable year, no marginal well credit is allowable unless the taxpayer elects not to claim the credit under section 45K with respect to the well. The section 45K credit is currently expired with respect to qualified natural gas and oil production. The credit is treated as a general business credit. Unused credits can be carried back for up to five years rather than the generally applicable carryback period of one year.

C. Expensing of Intangible Drilling Costs (sec. 263(c))

The Code provides special rules for the treatment of intangible drilling and development costs ("IDCs"). Under these special rules, an operator or working interest owner[7] 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.[8]

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 done by contractors under any form of contract, including a turnkey contract. Such work includes labor, fuel, repairs, hauling, and supplies which are used (1) in the drilling, shooting, and cleaning of wells; (2) in the clearing of ground, draining, road making, surveying, and geological works as necessary in preparation for the drilling of wells; and (3) in the construction of such derricks, tanks, pipelines, and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil and gas. Generally, IDCs do not include expenses for items that have a salvage value (such as pipes and casings) or items that are part of the acquisition price of an interest in the property.[9] They also do not include (1) the cost to operators payable only out of production or gross or net proceeds from production, if the amounts are depletable income to the recipient, and (2) amounts properly allocable to the cost of depreciable property.

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,

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[6] The dollar amounts for purposes of calculating the reduction in credit are adjusted for inflation for tax years beginning in a calendar year after 2005. Sec. 45I(b)(2)(B).

[7] An operator or working interest owner is defined as a person that 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 operating or working rights.

[8] Sec. 263(c).

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

but are capitalized, they may be recovered through depletion or depreciation, as appropriate. In the case of a nonproductive well ("dry hole"), IDCs may be deducted at the election of the operator.[10] For 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.[11]

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.[12] This election 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. The election allows a taxpayer to reduce or eliminate the IDC adjustments or preferences under the alternative minimum tax ("AMT").

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]

Pursuant to a special exception, the uniform capitalization rules do not apply to IDCs incurred with respect to oil or gas wells that are otherwise deductible under the Code.[15]

D. Deduction for Qualified Tertiary Injectant Expenses (sec. 193)

Taxpayers engaged in petroleum extraction activities may generally deduct qualified tertiary injectant expenses used while applying a tertiary recovery method, including carbon dioxide augmented waterflooding and immiscible carbon dioxide displacement.[16] The deduction

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

[11] Sec. 291(b)(1)(A). 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. 93-26, 1993-1 C.B. 50.

[12] Sec. 59(e)(1).

[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).

[15] Sec. 263A(c)(3).

[16] Sec. 193. Prior to the enactment of section 193, the income tax treatment of tertiary injectant costs was unclear. In enacting section 193, Congress sought to clarify the tax treatment and encourage the use of qualified

is available even if such costs are otherwise subject to capitalization. The deduction is permitted for the later of--(1) the tax year in which the injectant is injected or (2) the tax year in which the expenses are paid or incurred.[17] No deduction is permitted for expenditures for which a taxpayer has elected to deduct such costs under section 263(c) (intangible drilling costs) or if a deduction is allowed for such amounts under any other income tax provision.[18]

A "qualified tertiary injectant expense" is defined as any cost paid or incurred for any tertiary injectant (other than a recoverable hydrocarbon injectant) which is used as part of a tertiary recovery method.[19] The cost of a recoverable hydrocarbon injectant (which includes natural gas, crude oil and any other injectant with more than an insignificant amount of natural gas or crude oil) is not a qualified tertiary injectant expense unless the amount of the recoverable hydrocarbon injectant in the qualified tertiary injectant is insignificant.[20]

E. Amortization Period for Geological and Geophysical Costs (sec. 167(h))

Geological and geophysical expenditures ("G&G costs") are costs incurred by a taxpayer for the purpose of obtaining and accumulating data that will serve as the basis for the acquisition and retention of mineral properties by taxpayers exploring for minerals.[21] G&G costs incurred by independent producers and smaller integrated oil companies[22] in connection with oil and gas exploration in the United States may generally be amortized over two years.[23]

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tertiary injectants. See, e.g., Joint Committee on Taxation, *General Explanation of the Crude Oil Windfall Profit Tax Act of 1980* (JCS-1-81), January 29, 1981, pp. 114-115.

[17] Treas. Reg. sec. 1.193-1.

[18] Sec. 193(c).

[19] Sec. 193(b). A tertiary recovery method is any of the nine methods described in section 212.78(c)(1) - (9) of the June 1979 energy regulations, as defined in former section 4996(b)(8)(C), or any other method approved by the IRS.

[20] Sec. 193(b)(2). Treas. Reg. sec. 1.193-1(c)(3) provides that an injectant contains more than an insignificant amount of recoverable hydrocarbons if the fair market value of the recoverable hydrocarbon component of the injectant, in the form in which it is recovered, equals or exceeds 25 percent of the cost of the injectant.

[21] Geological and geophysical costs include expenditures for geologists, seismic surveys, gravity meter surveys, and magnetic surveys.

[22] Integrated oil companies are oil and gas producers that sell more than $5 million of retail product per year or refine more than 75,000 barrels of oil per year.

[23] This amortization rule applies to G&G costs incurred in taxable years beginning after August 8, 2005, the date of enactment of the Energy Policy Act of 2005, Pub. L. No. 109-58. Prior to the effective date, G&G costs associated with productive properties were generally deductible over the life of such properties, and G&G costs associated with abandoned properties were generally deductible in the year of abandonment.

Major integrated oil companies[24] are required to amortize all G&G costs over seven years for costs paid or incurred after December 19, 2007 (the date of enactment of the Energy Independence and Security Act of 2007 ("EISA")).[25] A major integrated oil company, as defined in section 167(h)(5)(B), is an integrated oil company[26] which has an average daily worldwide production of crude oil of at least 500,000 barrels for the taxable year, had gross receipts in excess of one billion dollars for its last taxable year ending during the calendar year 2005, and generally has an ownership interest in a crude oil refiner of 15 percent or more.

In the case of abandoned property, remaining basis may not be recovered in the year of abandonment of a property, but instead must continue to be amortized over the remaining applicable amortization period.

F. Percentage Depletion (secs. 613 and 613A)

In general

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 is being expended to produce income.[27] Certain costs incurred prior to drilling an oil or gas property or extracting minerals are recovered through the depletion deduction. These include the cost of acquiring the lease or other interest in the property.

Depletion is available to any person having an economic interest in a producing property. 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. 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, however, does not acquire an economic interest merely by possessing an economic or pecuniary advantage derived from production through a contractual relation.

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[24] Major integrated oil companies are a subset of integrated oil companies that (1) have average daily worldwide production exceeding 500,000 barrels per year, (2) had gross receipts in excess of $1 billion in 2005, and (3) own at least a 15 percent interest in a refinery that produces more than 75,000 barrels of oil per year.

[25] Pub. L. No. 110-140. Prior to the enactment of the Energy Independence and Security Act of 2007, major integrated oil companies were required to amortize G&G costs paid or incurred after May 17, 2006 over five years, as provided in Energy Tax Incentives Act of 2005.

[26] Generally, an integrated oil company is a producer of crude oil that engages in the refining or retail sale of petroleum products in excess of certain threshold amounts.

[27] In the context of mineral extraction, depreciable assets are generally used to recover depletable assets. For example, natural gas gathering lines, used to collect and deliver natural gas, have a class life of 14 years and a depreciation recovery period of seven years.

Two methods of depletion are currently allowable under the Code: (1) the cost depletion method, and (2) the percentage depletion method.[28] 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, a percentage, varying from five percent to 22 percent, of the taxpayer's gross income from a producing property is allowed as a deduction in each taxable year.[29] The Code generally limits the percentage depletion method for oil and gas properties to independent producers and royalty owners.[30] Such producers and royalty owners may generally claim percentage depletion at a rate of 15 percent.[31]

The amount deducted generally may not exceed 50 percent (100 percent in the case of oil and gas properties) of the taxable income from the property in any taxable year.[32] Additionally, the percentage depletion deduction for all oil and gas properties may not exceed 65 percent of the taxpayer's overall taxable income for the year (determined before such deduction and adjusted for certain loss carrybacks and trust distributions).[33] 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 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.[34]

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

As stated above, percentage depletion of oil and gas properties generally is not permitted, except for independent producers and royalty owners, certain fixed-price gas contracts, and

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[28] Secs. 611 - 613.

[29] Sec. 613.

[30] Sec. 613A(c).

[31] Sec. 613A(c)(1).

[32] Sec. 613(a). For marginal production, discussed *infra*, this limitation is suspended for taxable years beginning after December 31, 1997, and before January 1, 2008 and for taxable years beginning after December 31, 2008 and before January 1, 2010.

[33] Sec. 613A(d)(1).

[34] Sec. 613(a).

natural gas from geopressured brine. 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 a derivative thereof): (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 a derivative thereof) under the name of the taxpayer or the related person, or that has the authority to occupy any retail outlet owned by the taxpayer or a related person.[35]

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. Further, if the combined gross receipts of the taxpayer 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, the taxpayer will not be treated as a retailer.

A refiner is any person that directly or through a related person engages in the refining of crude oil in excess of an average daily refinery run of 75,000 barrels during the taxable year.[36]

Percentage depletion for eligible taxpayers is allowed for up to 1,000 barrels of average daily production of domestic crude oil or an equivalent amount of domestic natural gas.[37] 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;[38] each group is then treated as one producer in applying the 1,000-barrel limitation.

In addition to independent producers and royalty owners, certain sales of natural gas under a fixed contract in effect on February 1, 1975, and certain natural gas from geopressured brine, 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.

Prior to the 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.[39] The 1990 Act repealed the limitation on claiming percentage depletion on transferred properties effective for property transfers occurring after October 11, 1990.

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[35] Sec. 613A(d)(2).

[36] Sec. 613A(d)(4).

[37] Sec. 613A(c).

[38] Sec. 613A(c)(8).

[39] Pub. L. No. 101-508.

Percentage depletion on marginal production

The 1990 Act also created a special percentage depletion provision for oil and gas production from so-called marginal properties held by independent producers or royalty owners.[40] 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 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 that 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 1999 was $15.56. Thus, the percentage depletion rate for production from marginal wells was increased to 19 percent for taxable years beginning in 2000. Since the price of oil currently is above the $20 floor, there is no increase in the statutory depletion rate for marginal production.

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).[41] A stripper well property is any oil or gas property that produces a daily average of 15 or fewer 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.[42]

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, a taxpayer makes the stripper well property determination 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 interest. If the property satisfies the requirements of a stripper well property, then the benefits of this provision apply with respect to the taxpayer's allocable share of the production from the property. The deduction

[40] Sec. 613A(c)(6).

[41] Sec. 613A(c)(6)(D).

[42] Sec. 613A(c)(6)(E).

is allowed for the 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.

G. Deduction for Income Attributable to Domestic Production of Oil and Gas (sec. 199)

Section 199 of the Code provides a deduction from taxable income (or, in the case of an individual, adjusted gross income) that is equal to a portion of the lesser of a taxpayer's taxable income or its qualified production activities income.[43] In general, for taxable years beginning after 2009, the deduction is nine percent of such income. With respect to a taxpayer that has oil related qualified production activities income for taxable years beginning after 2009, the deduction is limited to six percent of the least of its oil related production activities income, its qualified production activities income, or its taxable income.[44]

A taxpayer's deduction under section 199 for a taxable year may not exceed 50 percent of the wages properly allocable to domestic production gross receipts paid by the taxpayer during the calendar year that ends in such taxable year.[45]

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[43] In the case of an individual, the deduction is equal to a portion of the lesser of the taxpayer's adjusted gross income or its qualified production activities income. For this purposes, adjusted gross income is determined after application of sections 86, 135, 137, 219, 221, 222, and 469, and without regard to the section 199 deduction.

[44] "Oil related qualified production activities income" means the qualified production activities income attributable to the production, refining, processing, transportation, or distribution of oil, gas or any primary product thereof (as defined in section 927(a)(2)(C) prior to its repeal). Treas. Reg. sec. 1.927(a)-1T(g)(2)(i) defines the term "primary product from oil" to mean crude oil and all products derived from the destructive distillation of crude oil, including volatile products, light oils such as motor fuel and kerosene, distillates such as naphtha, lubricating oils, greases and waxes, and residues such as fuel oil. Additionally, a product or commodity derived from shale oil which would be a primary product from oil if derived from crude oil is considered a primary product from oil. Treas. Reg. sec. 1.927(a)-1T(g)(2)(ii) defines the term "primary product from gas" as all gas and associated hydrocarbon components from gas wells or oil wells, whether recovered at the lease or upon further processing, including natural gas, condensates, liquefied petroleum gases such as ethane, propane, and butane, and liquid products such as natural gasoline. Treas. Reg. sec. 1.927(a)-1T(g)(2)(iii) provides that these primary products and processes are not intended to represent either the only primary products from oil or gas or the only processes from which primary products may be derived under existing and future technologies. Treas. Reg. sec. 1.927(a)-1T(g)(2)(iv) provides as examples of non-primary oil and gas products petrochemicals, medicinal products, insecticides, and alcohols.

[45] For purposes of the provision, "wages" include the sum of the amounts of wages as defined in section 3401(a) and elective deferrals that the taxpayer properly reports to the Social Security Administration with respect to the employment of employees of the taxpayer during the calendar year ending during the taxpayer's taxable year. Elective deferrals include elective deferrals as defined in section 402(g)(3), amounts deferred under section 457, and, for taxable years beginning after December 31, 2005, designated Roth contributions (as defined in section 402A).

Qualified production activities income

In general, "qualified production activities income" is equal to domestic production gross receipts (defined by section 199(c)(4)), reduced by the sum of: (1) the costs of goods sold that are allocable to such receipts; and (2) other expenses, losses, or deductions which are properly allocable to such receipts.

Domestic production gross receipts

"Domestic production gross receipts" generally are gross receipts of a taxpayer that are derived from: (1) any sale, exchange or other disposition, or any lease, rental or license, of qualifying production property ("QPP") that was manufactured, produced, grown or extracted ("MPGE") by the taxpayer in whole or in significant part within the United States;[46] (2) any sale, exchange or other disposition, or any lease, rental or license, of qualified film produced by the taxpayer; (3) any sale, exchange or other disposition of electricity, natural gas, or potable water produced by the taxpayer in the United States; (4) construction activities performed in the United States;[47] or (5) engineering or architectural services performed in the United States with respect to the construction of real property in the United States.

Drilling oil or gas wells

The Treasury regulations provide that qualifying construction activities performed in the United States include activities relating to drilling an oil or gas well.[48] Under the regulations, activities the cost of which are intangible drilling and development costs within the meaning of Treas. Reg. sec. 1.612-4 are considered to be activities constituting construction for purposes of determining domestic production gross receipts.[49]

Qualifying in-kind partnerships

In general, an owner of a pass-through entity is not treated as conducting the qualified production activities of the pass-thru entity, and vice versa. However, the Treasury regulations provide a special rule for "qualifying in-kind partnerships," which are defined as partnerships engaged solely in the extraction, refining, or processing of oil, natural gas, petrochemicals, or

[46] Domestic production gross receipts include gross receipts of a taxpayer derived from any sale, exchange or other disposition of agricultural products with respect to which the taxpayer performs storage, handling or other processing activities (other than transportation activities) within the United States, provided such products are consumed in connection with, or incorporated into, the manufacturing, production, growth or extraction of qualifying production property (whether or not by the taxpayer).

[47] For this purpose, construction activities include activities that are directly related to the erection or substantial renovation of residential and commercial buildings and infrastructure. Substantial renovation would include structural improvements, but not mere cosmetic changes, such as painting, that is not performed in connection with activities that otherwise constitute substantial renovation.

[48] Treas. Reg. sec. 1.199-3(m)(1)(i).

[49] Treas. Reg. sec. 1.199-3(m)(2)(iii).

products derived from oil, natural gas, or petrochemicals in whole or in significant part within the United States, or the production or generation of electricity in the United States.[50] In the case of a qualifying in-kind partnership, each partner is treated as having MPGE property to the extent such property is distributed by the partnership to that partner.[51] If a partner of a qualifying in-kind partnership derives gross receipts from the lease, rental, license, sale, exchange, or other disposition of the property that was MPGE by the qualifying in-kind partnership, then, provided such partner is a partner of the qualifying in-kind partnership at the time the partner disposes of the property, the partner is treated as conducting the MPGE activities previously conducted by the qualifying in-kind partnership with respect to that property.[52]

Alternative minimum tax

The deduction for domestic production activities is allowed for purposes of computing AMTI (including adjusted current earnings). The deduction in computing AMTI is determined by reference to the lesser of the qualified production activities income (as determined for the regular tax) or the AMTI (in the case of an individual, adjusted gross income as determined for the regular tax) without regard to this deduction.

H. Exception from Passive Loss Rules for Working Interests in Oil and Gas Property (sec. 469)

The passive loss rules limit deductions and credits from passive trade or business activities.[53] A passive activity for this purpose is a trade or business activity in which the taxpayer owns an interest, but in which the taxpayer does not materially participate. A taxpayer is treated as materially participating in an activity only if the taxpayer is involved in the operation of the activity on a basis that is regular, continuous, and substantial.[54] Deductions attributable to passive activities, to the extent they exceed income from passive activities, generally may not be deducted against other income. Deductions and credits that are suspended under these rules are carried forward and treated as deductions and credits from passive activities in the next year. The suspended losses from a passive activity are allowed in full when a taxpayer disposes of his entire interest in the passive activity to an unrelated person.

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[50] Treas. Reg. sec. 1.199-9(i)(2).

[51] Treas. Reg. sec. 1.199-9(i)(1).

[52] *Ibid.*

[53] Sec. 469. These rules were enacted in 1986 to curtail tax shelters. They apply to individuals, estates and trusts, and closely held corporations.

[54] Regulations provide more detailed standards for material participation. See Treas. Reg. sec. 1.469-5 and -5T.

Losses from certain working interests in oil and gas property are not limited under the passive loss rule.[55] Thus, losses and credits from such interests can be used to offset other income of the taxpayer without limitation under the passive loss rule. Specifically, a passive activity does not include a working interest in any oil or gas property that the taxpayer holds directly or through an entity that does not limit the liability of the taxpayer with respect to the interest. This rule applies without regard to whether the taxpayer materially participates in the activity. If the taxpayer has a loss from a working interest in any oil or gas property that is treated as not from a passive activity, then net income from the property for any succeeding taxable year is treated as income of the taxpayer that is not from a passive activity.

In general, a working interest is an interest with respect to an oil and gas property that is burdened with the cost of development and operation of the property. Rights to overriding royalties, production payments, and the like, do not constitute working interests, because they are not burdened with the responsibility to share expenses of drilling, completing, or operating oil and gas property. Similarly, contract rights to extract or share in oil and gas, or in profits from extraction, without liability to share in the costs of production, do not constitute working interests. Income from such interests generally is considered to be portfolio income.

When the taxpayer's form of ownership limits the liability of the taxpayer, the interest possessed by such taxpayer is not a working interest for purposes of the passive loss provision. Thus, for purposes of the passive loss rules, an interest owned by a limited partnership is not treated as a working interest with regard to any limited partner, and an interest owned by an S corporation is not treated as a working interest with regard to any shareholder. The same result follows with respect to any form of ownership that is substantially equivalent in its effect on liability to a limited partnership interest or interest in an S corporation, even if different in form.

When an interest is not treated as a working interest because the taxpayer's form of ownership limits his liability, the general rules regarding material participation apply to determine whether the interest is treated as a passive activity. Thus, for example, a limited partner's interest generally is treated as in a passive activity. In the case of a shareholder in an S corporation, the general facts and circumstances test for material participation applies and the working interest exception does not apply, because the form of ownership limits the taxpayer's liability.

A special rule applies in any case where, for a prior taxable year, net losses from a working interest in a property were treated by the taxpayer as not from a passive activity. In such a case, any net income realized by the taxpayer from the property (or from any substituted basis property, e.g., property acquired in a sec. 1031 like kind exchange for such property) in a subsequent year also is treated as active. Under this rule, for example, if a taxpayer claims losses for a year with regard to a working interest and then, after the property to which the interest relates begins to generate net income, transfers the interest to an S corporation in which he is a shareholder, or to a partnership in which he has an interest as a limited partner, his interest with regard to the property continues to be treated as not passive.

[55] Sec. 469(c)(3). See also Treas. Reg. sec. 1.469-1T(e)(4).

II. RULES OF GENERAL APPLICATION IMPORTANT TO THE OIL AND GAS INDUSTRY

A. Dual-Capacity Taxpayers

In general

The United States taxes its citizens and residents (including U.S. corporations) on their worldwide income. Because the countries in which income is earned also may assert their jurisdiction to tax the same income on the basis of source, foreign-source income earned by U.S. persons may be subject to double taxation. To mitigate this possibility, the United States generally provides a credit against U.S. tax liability for foreign income taxes paid or accrued.[56]

A foreign tax credit is available only for foreign income, war profits, and excess profits taxes, and for certain taxes imposed in lieu of such taxes. Other foreign levies generally are treated as deductible expenses. Treasury regulations under section 901 provide detailed rules for determining whether a foreign levy is a creditable income tax. In general, a foreign levy is considered a creditable tax if it is substantially equivalent to an income tax under U.S. tax principles. Under the present Treasury regulations, a foreign levy is considered a tax if it is a compulsory payment under the authority of a foreign country to levy taxes and is not compensation for a specific economic benefit provided by a foreign country.[57]

Dual-capacity taxpayers

A taxpayer that is subject to a foreign levy and also receives a specific economic benefit from the foreign country is considered a "dual-capacity taxpayer."[58] A "specific economic benefit" is broadly defined as an economic benefit that is not made available on substantially the same terms to substantially all persons who are subject to the income tax that is generally imposed by the foreign country, or, if there is no such generally imposed income tax, an economic benefit that is not made available on substantially the same terms to the population of the country in general.[59] An example of a specific economic benefit includes a concession to extract government-owned petroleum. Other examples of economic benefits that may be specific if not provided on substantially the same terms to the population in general, include property; a service; a fee or other payment; a right to use, acquire or extract resources, patents, or other property that a foreign country owns or controls (as defined within the regulations); or a reduction or discharge of a contractual obligation.

Treasury regulations addressing payments made by dual-capacity taxpayers were developed in response to the concern that payments which purported to be income taxes imposed

[56] Sec. 901.

[57] Treas. Reg. sec. 1.901-2(a)(2)(i).

[58] Treas. Reg. sec. 1.901-2(a)(ii).

[59] Treas. Reg. sec. 1.901-2(a)(2)(ii)(B).

on U.S. oil companies by mineral-owning foreign governments were at least partially, in substance, royalties or some other business expense.[60] To the extent that a taxpayer meets the definition of a dual-capacity taxpayer, the taxpayer may not claim a foreign tax credit for the portion of the foreign levy that is paid for the specific economic benefit.[61] Treasury regulations require that a dual-capacity taxpayer, similar to other taxpayers, must establish that the foreign levy meets the requirements of section 901 or section 903.[62] However, the regulations require that a dual-capacity taxpayer use either a facts and circumstances method or a safe harbor method in establishing the foreign levy is an income tax.[63]

Under the facts and circumstances method, a separate levy is creditable to the extent that the taxpayer establishes, based on all the relevant facts and circumstances, the amount of the levy that is not paid as compensation for the specific economic benefit.[64] For purposes of applying the facts and circumstances method, the foreign country need not have a generally imposed income tax.

A dual-capacity taxpayer alternatively may choose to apply the safe harbor method on a country-by-country basis to determine whether a levy is a creditable tax.[65] Under the safe harbor method, if the foreign country has a generally imposed income tax, the taxpayer may credit the portion of the levy that application of the generally imposed income tax would yield provided that the levy otherwise constitutes an income tax or an in lieu of tax. The balance of the levy is treated as compensation for the specific economic benefit.[66] If the foreign country does not generally impose an income tax, the portion of the payment that does not exceed the applicable U.S. Federal tax rate, applied to net income, is treated as a creditable tax.[67] In general, a foreign tax is treated as generally imposed for this purpose even if it applies only to persons who are not residents or nationals of that country.[68]

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[60] Testimony of Treasury Secretary Schultz, Hearings on "Windfall" Excess Profits Tax before the House Committee on Ways and Means, 93rd Cong., 2d Sess. 151 (1974).

[61] Treas. Reg. sec. 1.901-2A(a)(1). The payment may be deductible, however, as an ordinary and necessary business expense.

[62] Treas. Reg. sec. 1.901-2A(b)(1).

[63] Treas. Reg. sec. 1.901-2A(c).

[64] Treas. Reg. sec. 1.901-2A(c)(2).

[65] A taxpayer may make an election to use the safe harbor method with respect to one or more foreign states. The election applies to the year of the election and to all subsequent taxable years unless revoked. The election is made by the common parent and applies to all members of the affiliated group. See Treas. Reg. sec. 1.902-2A(d).

[66] Treas. Reg. sec. 1.901-2A(d) and (e). Detailed rules are provided for determining the amount that imposition of the generally applicable tax to the dual-capacity taxpayer would yield, based on the taxpayer's gross receipts, costs and expenses, and other factors.

[67] Treas. Reg. sec. 1.901-2A(e)(5).

[68] See Treas. Reg. sec. 1.903-1(b)(3), Ex. 4.

After the promulgation of the regulations, many dual-capacity taxpayers elected the safe harbor method for determining what portion, if any, of the separate foreign levy they paid would be treated as a creditable income tax. However, in 1999, the Tax Court in *Exxon Corp. v. Commissioner* determined that the entire amount of the petroleum revenue tax paid by Exxon to the U.K. government did not constitute compensation for a specific economic benefit and would thus qualify as tax for purposes of the foreign tax credit.[69] The Court considered that Exxon entered into an arm's length licensing agreement with the U.K. government to gain access to the North Sea oil fields prior to the enactment of the petroleum revenue tax, and determined that Exxon's right to explore, develop and exploit petroleum resources was dependent on the licensing agreement and payment of license fees under that agreement and not in exchange for payment of the tax. Subsequent to the decision in *Exxon*, anecdotal evidence suggests that a significant number of dual-capacity taxpayers revoked their safe harbor elections and adopted the facts and circumstances method to argue for tax treatment for the entire amount of the qualifying levy.

Limitation on the use of foreign tax credits

The foreign tax credit generally is limited to a taxpayer's U.S. tax liability on its foreign-source taxable income (as determined under U.S. tax accounting principles). This limit is intended to ensure that the credit serves its purpose of mitigating double taxation of foreign-source income without offsetting U.S. tax on U.S.-source income.[70] The limit is computed by multiplying a taxpayer's total U.S. tax liability for the year by the ratio of the taxpayer's foreign-source taxable income for the year to the taxpayer's total taxable income for the year. If the total amount of foreign income taxes paid and deemed paid for the year exceeds the taxpayer's foreign tax credit limitation for the year, the taxpayer may carry back the excess foreign taxes to the immediately preceding taxable year or carry forward the excess taxes forward 10 years.[71]

In addition, this limitation is calculated separately for various categories of income, generally referred to as "separate limitation categories." The total amount of foreign taxes attributable to income in a separate limitation category that may be claimed as credits may not exceed the proportion of the taxpayer's total U.S. tax liability which the taxpayer's foreign-source taxable income in that separate limitation category bears to the taxpayer's worldwide taxable income. The separate limitation rules are intended to reduce the extent to which excess foreign taxes paid in a high-tax foreign jurisdiction can be "cross-credited" against the residual U.S. tax on low-taxed foreign-source income.[72]

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[69] *Exxon v. Commissioner*, 113 T.C. 338 (1999) (hereinafter "*Exxon v. Commissioner*"). See also *Philips Petroleum Co. v. Commissioner*, 104 T.C. 256 (1995).

[70] Secs. 901 and 904.

[71] Sec. 904(c).

[72] Sec. 904(d). For taxable years beginning prior to January 1, 2007, section 904(d) generally provides eight separate limitation categories (or "baskets") and effectively many more in situations in which various special rules apply. The American Jobs Creation Act of 2004 reduced the number of baskets from nine to eight for taxable

Special rule for foreign oil and gas income

A special limitation applies with respect to taxes on combined foreign oil and gas income applied prior to the foreign tax credit limitation discussed above.[73] This limitation was adopted prior to the issuance of the regulations providing the rules discussed above for dual-capacity taxpayers and was intended to address the concern that payments made by oil companies to many oil-producing nations were royalties disguised as tax payments.[74] Additionally, the limitation sought to prevent the crediting of high foreign taxes on foreign oil and gas income against the residual U.S. tax on other types of lower-taxed foreign source income.[75]

Under this special limitation, amounts claimed as taxes paid on combined foreign oil and gas income are creditable in a given taxable year (if they otherwise qualify as creditable taxes) only to the extent they do not exceed the applicable U.S. tax on that income. The applicable U.S. tax is determined for a corporation as the product of the amount of such combined foreign oil and gas income for the taxable year and the highest marginal tax rate for corporations.[76] Any excess foreign taxes may be carried back to the immediately preceding taxable year and carried forward 10 taxable years and credited (not deducted) to the extent that the taxpayer otherwise has excess limitation with regard to combined foreign oil and gas income in a carryover year.[77] Amounts that are not limited under section 907 (relating to combined foreign oil and gas income discussed above) are included in the general basket or passive basket (as applicable) for purposes of applying the section 904 limitation.

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years beginning after December 31, 2002, and further reduced the number of baskets to two (i.e., "general" and "passive") for taxable years beginning after December 31, 2006. Pub. L. No. 108-357, sec. 404 (2004).

[73] Sec. 907. For taxable years beginning before January 1, 2009, the components of what is now defined as combined foreign oil and gas income included foreign oil and gas extraction income ("FOGEI") and foreign oil related income ("FORI"). Under the prior rules, FOGEI and FORI were subject to separate limitations under section 907. Pub. L. No 110-343, Sec. 402(a). Amounts claimed as taxes paid on FOGEI of a U.S. corporation qualified as creditable taxes (if they otherwise so qualified), if they did not exceed the product of FOGEI multiplied by the highest marginal U.S. tax rate on corporations. A separate limitation was deemed to apply to FORI which theoretically applied in certain cases where the foreign law imposing such amount of tax is structured, or in fact operated, so that the amount of tax imposed with respect to FORI generally was "materially greater," over a "reasonable period of time," than the amount generally imposed on income that was neither FORI nor FOGEI. Joint Committee on Taxation, *General Explanation of Tax Legislation Enacted in the 110th Congress*, (JCS-1-09), March 2009, at 358.

[74] Joint Committee on Taxation, *General Explanation of the Revenue Provisions of the Tax Equity and Fiscal Responsibility Act of 1982*, (JCS-38-82), December 31, 1982, sec. IV.A.7.a, fn 63.

[75] H.R. Conf. Rept. No. 103-213, at 646 (1993).

[76] Sec. 907(a). For an individual, the limitation is the product of the amount of such combined foreign oil and gas income for the taxable year and a fraction, the numerator of which is the tax against which the credit under section 901(a) is taken and the denominator of which is the taxpayer's entire taxable income.

[77] Sec. 907(f).

B. Last-In, First-Out Inventory Accounting Method

In general

In general, for Federal income tax purposes, taxpayers must account for inventories if the production, purchase, or sale of merchandise is a material income-producing factor to the taxpayer.[78]

Under the last-in, first-out ("LIFO") method, it is assumed that the last items entered into the inventory are the first items sold. Because the most recently acquired or produced units are deemed to be sold first, cost of goods sold is valued at the most recent costs; the effect of cost fluctuations is reflected in the ending inventory, which is valued at the historical costs rather than the most recent costs.[79] Compared to first-in, first-out ("FIFO"), LIFO produces net income which more closely reflects the difference between sale proceeds and current market cost of inventory. When costs are rising, the LIFO method results in a higher measure of cost of goods sold and, consequently, a lower measure of income when compared to the FIFO method. The inflationary gain experienced by the business in its inventory is generally not reflected in income, but rather, remains in ending inventory as a deferred gain until a future period in which sales exceed purchases.[80]

Dollar-value LIFO

Under a variation of the LIFO method, known as dollar-value LIFO, inventory is measured not in terms of number of units but rather in terms of a dollar-value relative to a base cost. Dollar-value LIFO allows the "pooling" of dissimilar items into a single inventory calculation. Thus, depending upon the taxpayer's method for defining an item, LIFO can be applied to a taxpayer's entire inventory in a single calculation even if the inventory is made up of different physical items. For example, a single dollar-value LIFO calculation can be performed for an inventory that includes both yards of fabric and sewing needles. This effectively permits the deferral of inflationary gain to continue even as the inventory mix changes or certain goods previously included in inventory are discontinued by the business.

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[78] Sec. 471(a) and Treas. Reg. sec. 1.471-1.

[79] Thus, in periods during which a taxpayer produces or purchases more goods than the taxpayer sells (an inventory increment), a LIFO method taxpayer generally records the inventory cost of such excess (and separately tracks such amount as the "LIFO layer" for such period), adds it to the cost of inventory at the beginning of the period, and carries the total inventory cost forward to the beginning inventory of the following year. Sec. 472(b).

[80] Accordingly, in periods during which the taxpayer sells more goods than the taxpayer produces or purchases (and inventory decrement), a LIFO method taxpayer generally determines the cost of goods sold of the amount of the decrement by treating such sales as occurring out of the most recent LIFO layer (or most recent LIFO layers, if the amount of the decrement exceeds the amount of inventory in the most recent LIFO layer) in reverse chronological order.

Simplified rules for certain small businesses

In 1986, Congress enacted a simplified dollar-value LIFO method for certain small businesses.[81] In doing so, the Congress acknowledged that the LIFO method is generally considered to be an advantageous method of accounting, and that the complexity and greater cost of compliance associated with LIFO, including dollar-value LIFO, discouraged smaller taxpayers from using LIFO.[82]

To qualify for the simplified method, a taxpayer must have average annual gross receipts of $5 million or less for the three preceding taxable years.[83] Under the simplified method, taxpayers are permitted to calculate inventory values by reference to changes in published price indexes rather than comparing actual costs to base period costs.

Special rules for qualified liquidations of LIFO inventories

In certain circumstances, reductions in inventory levels may be beyond the control of the taxpayer. Section 473 of the Code mitigates the adverse effects in certain specified cases by allowing a taxpayer to claim a refund of taxes paid on LIFO inventory profits resulting from the liquidation of LIFO inventories if the taxpayer purchases replacement inventory within a defined replacement period. The provision generally applies when a decrease in inventory is caused by reduced supply due to government regulation or supply interruptions due to the interruption of foreign trade.

[81] Sec. 474(a).

[82] Joint Committee on Taxation, *General Explanation of the Tax Reform Act of 1986 (H.R. 3838, 99th Congress; Public Law 99-514)*, (JCS-10-87), May 4, 1987, p. 482.

[83] Sec. 474(c).

III. SELECTED PROPOSALS TO LIMIT OIL AND GAS TAX INCENTIVES

A. Description of the President's Proposal for Fiscal Year 2012

The proposal repeals (1) the enhanced oil recovery credit, (2) the marginal wells credit, (3) the expensing and 60-month amortization of IDCs, (4) the deduction for tertiary injectants,[84] (5) percentage depletion for oil and gas, (6) the domestic manufacturing deduction for income derived from the domestic production of oil and gas, (7) the exception for passive losses from working interests in oil and gas properties, and (8) the LIFO method of accounting. With respect to IDCs, the proposal requires that such costs be capitalized and recovered through depletion or depreciation, as applicable.

The proposal also increases the amortization period for G&G costs of independent and non-integrated producers from two to seven years. The seven-year amortization period would apply even if the property is abandoned such that any remaining unrecovered basis of the abandoned property would continue to be recovered over the remainder of the seven-year period.

Finally, the proposal modifies the dual-capacity taxpayer rules. In the case of a dual-capacity taxpayer, the proposal allows a taxpayer to treat as a creditable tax the portion of a foreign levy that does not exceed the foreign levy that the taxpayer would pay if it were not a dual-capacity taxpayer. The proposal replaces the current regulatory provisions, including the safe harbor, that apply to determine the amount of a foreign levy paid by a dual-capacity taxpayer that qualifies as a creditable tax. The proposal also converts the special foreign tax credit limitation rules of section 907 into a separate category within section 904 for foreign oil and gas income. The proposal yields to United States treaty obligations to the extent that they allow a credit for taxes paid or accrued on certain oil or gas income.

These proposal is generally effective for taxable years beginning after 2011 (amounts paid or incurred after 2011 for G&G costs).

B. Description of the Revenue Provisions in S. 940

The revenue provisions in S. 940 repeal for major integrated oil companies (1) the expensing and 60-month amortization of IDCs, (2) the deduction for tertiary injectants,[85] (3) percentage depletion for oil and gas, and (4) the domestic manufacturing deduction for income derived from the domestic production of oil and gas.

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[84] If section 193 were repealed, the treatment of tertiary injectant expenses would revert to prior law and might include capitalization and recovery through depreciation, capitalization and recovery as consumed (e.g., as a supply), or deduction as loss in the year of abandonment or the year production benefits ceased. Amounts expensed as depreciation, depletion, or supplies may be subject to capitalization under section 263A. See, e.g., Treas. Reg. sec. 1.263A-1(e)(3).

[85] If section 193 were repealed, the treatment of tertiary injectant expenses would revert to prior law and might include capitalization and recovery through depreciation, capitalization and recovery as consumed (e.g., as a supply), or deduction as loss in the year of abandonment or the year production benefits ceased. Amounts expensed as depreciation, depletion, or supplies may be subject to capitalization under section 263A. See, e.g., Treas. Reg. sec. 1.263A-1(e)(3).

The proposal also modifies the dual capacity taxpayer rules. The modification proposed in S. 940 is the same as the President's budget proposal except that it applies only to major integrated oil companies and does not convert the special foreign tax credit limitation rules of section 907 into a separate category within section 904 for foreign oil and gas income.

C. Proposed Tax on Severance of Crude Oil and Natural Gas from the Outer Continental Shelf in the Gulf of Mexico

On June 19, 2007, the Senate Committee on Finance approved as part of its mark up of the "Energy Advancement and Investment Act of 2007," a proposal to add an excise tax on crude oil and natural gas produced from the outer continental shelf in the Gulf of Mexico.[86] Under current law, there is no Federal severance tax on oil and gas produced on the outer Continental Shelf (OCS). The United States leases Federal lands potentially containing oil and gas deposits from offshore or submerged lands under the Outer Continental Shelf Lands Act of 1953, as amended.[87] Many offshore oil and gas lessees are required to pay the United States a royalty of not less than 12.5 percent pursuant to the terms of their lease, which is sometimes paid in kind.[88] The royalty rate for most newly-issued OCS leases is 18 ¾ percent.[89]

The proposal establishes an excise tax equal to 13 percent of the removal price of any crude oil or natural gas produced from Federal submerged lands on the outer continental shelf in the Gulf of Mexico pursuant to a lease entered into with the United States that authorizes the production ("taxable crude oil or natural gas") during the taxable period. The tax is to be paid by the producer of the taxable crude oil or natural gas. For this purpose, crude oil includes condensates and natural gasoline. Under the proposal, each calendar year is a taxable period. The Secretary is to provide for the filing, and time for filing of the return of tax imposed under the proposal.

The removal price is defined as the amount for which the barrel of taxable crude oil (or dollars per thousand cubic feet in the case of natural gas) is sold by the taxpayer. In the case of sales between related parties, and crude oil or natural gas removed from the property before it is sold, the removal price is the constructive sales price. If the manufacture or conversion of crude oil into refined products begins before such oil is removed from the property, such oil is treated as removed on the day such manufacture or conversion begins, and the removal price is the

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[86] See Joint Committee on Taxation, *Description of the Chairman's Modification to the Provisions of the "Energy Advancement and Investment Act of 2007,"* (JCX-33-07), June 18, 2007 at 34. The bill, including the severance tax provision, was approved by the Senate Committee on Finance by a vote of 15-5 and offered as Baucus Amendment No. 1704 to H.R. 6 (the "Energy Independence and Security Act of 2007") of the 110th Congress. However, the cloture vote in the Senate was not successful. The proposal can be found at section 885 of the amendment.

[87] 43 U.S.C. secs. 1335 and 1337.

[88] 43 U.S.C. secs. 1335, 1337 and 1353(a)(1).

[89] See, MMS Gulf of Mexico Lease Terms and Royalty Relief <http://www.boemre.gov/econ/PDFs/GOMLeaseTermsRRSummary.pdf>

constructive sales price. In determining the removal price of oil or natural gas from a property in the case of any transaction, the Secretary may adjust the removal price to reflect clearly the fair market value of oil or natural gas removed.

The proposal allows as a credit against the excise tax imposed by the proposal an amount equal to the aggregate amount of royalties paid under Federal law with respect to the production of taxable crude oil or natural gas produced from Federal submerged lands on the outer continental shelf in the Gulf of Mexico. In no event may the aggregate amount of the credit exceed the aggregate amount of tax imposed by the proposal in any calendar year.

The Secretary is authorized to prescribe such regulations and guidance as is necessary for the withholding and quarterly deposit of the tax imposed by the proposal, as well as other guidance as is necessary to carry out the proposal.

The proposal provides that the amount of the excise tax imposed, net of the credit for royalty payments, is deductible as a tax under section 164 of the Code.