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Enhanced Oil Recovery Credit Reinstated for 2016

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The enhanced oil recovery ("EOR") credit under section 43 of the Internal Revenue Code will be applicable for 2016 without any phase-out.[1] Previously, the EOR credit had been applicable without phase-out during calendar years 1991 through 2005 and completely phased-out during calendar years 2006 through 2015. Following this 10-year hiatus, many oil industry professionals may have little or no experience with the EOR credit; those professionals as well as individuals with prior experience may benefit from the summary refresher presented in this article.

"EOR" is a term that describes various techniques to increase the amount of oil that can be produced from an oil reservoir. Primary and secondary (e.g., waterflood, gas cycling) recovery techniques generally can extract 20 to 40 percent of the original oil in place. By using an EOR project approximately 30 to 60 percent or more of the reservoir's original oil in place can be extracted,

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[1] Notice 2016-44, I.R.B. 2016-29 (July 18, 2016) ("Because the reference price for the 2015 calendar year ($44.39) does not exceed $28 multiplied by the inflation adjustment factor for the 2015 calendar year ($28 multiplied by 1.6464 $46.01), the enhanced oil recovery credit for qualified costs paid or incurred in 2016 is determined without regard to the phase-out for crude oil price increases."). Unless otherwise indicated, section references are to the Internal Revenue Code of 1986, as amended (the "Code") or the applicable regulations promulgated pursuant to the Code (the "regulations").

prolonging the life of the reservoir by up to 30 years.[2] Thermal EOR projects generally use high pressure steam injection or in situ combustion in heavy oil reservoirs. Chemical EOR projects generally involve the injection of surfactants, polymers, and/or alkalis to increase oil production by lowering surface tension between the oil and the reservoir rock. Gas injection EOR projects generally use carbon dioxide (CO_2), nitrogen, or hydrocarbon gas to create miscibility and decrease oil viscosity.

For tax years beginning after December 31, 1990, section 43 provides an EOR tax credit as a component of the general business credit; therefore, any portion of the EOR credit that cannot be used during the current tax year may be carried back one year and carried forward 20 years.[3] The credit is equal to 15 percent of qualified domestic EOR costs paid or incurred during the tax year. To the extent a credit is allowed for these costs, the taxpayer must reduce the amount otherwise deductible or required to be capitalized and recovered through depreciation, depletion, or amortization, as appropriate for these costs.[4]

A taxpayer can elect whether or not to apply the credit for a particular tax year at any time before expiration of the three-year statute of limitations for that year by attaching a statement to an original or amended tax return.[5] This election can be made on a project-by-project basis, and the election can be revoked by attaching a statement to that effect on a subsequently filed amended return for the same tax year. An election to forgo the EOR credit may be desirable for taxpayers subject to the alternative minimum tax because the EOR credit can only reduce the regular tax liability.

The credit is phased out as crude oil prices increase. The reduction is equal to an amount that bears the same ratio to the amount of the credit as the excess of the reference price for the preceding calendar year over $28 bears to $6.[6] The reference price used for this purpose is the same reference price used in computing the section 45K credit for producing fuel from a nonconventional source. For calendar years beginning after 1991, the $28 base price will be adjusted for inflation, using an inflation adjustment factor published annually by the IRS.[7]

Computation of the EOR credit requires the identification of two components: (1) the costs that are within the definition of qualified EOR costs, and (2) projects that may be characterized as qualified EOR projects. Each of these two components is considered separately.

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[2] See http://energy.gov/fe/science-innovation/oil-gas-research/enhanced-oil-recovery.

[3] Section 39(a)(1).

[4] Section 43(d).

[5] Section 1.43-6.

[6] Section 43(b).

[7] Section 43(b)(3)(B).

Qualified Costs[8]

Qualified EOR costs are those amounts paid or incurred for:

- Tangible property that is an integral part of a qualified EOR project, i.e., used directly in a tertiary recovery method and is essential to the completeness of the method;[9]
- Intangible drilling and development[10] of a well to be used in a qualified EOR project; and
- Tertiary injectant.

EOR costs must also be paid or incurred with respect to an asset that is used for the primary purpose of implementing a qualified EOR project.[11] Similarly, the costs of acquiring, constructing, transporting, erecting, or installing an offshore drilling platform do not qualify for the credit unless the primary purpose of the platform is the implementation of a qualified EOR project.[12] Treasury requires an allocation of costs when property has both qualifying and nonqualifying uses, but this requirement does not apply unless the primary purpose of the property is the implementation of an EOR project.[13]

Tangible property costs are included in the credit base in the year the property is placed in service for depreciation, while the other creditable costs are included in the credit base in the year they are deductible for federal income tax purposes. Taxpayers must reduce the basis of EOR property by 100 percent of the credit allowed.[14] Integrated oil companies should note that section 291 is applied after the determination of the EOR credit.[15]

Costs incurred before the first injection of liquids and gases can qualify for the credit, but the credit cannot be claimed until after the first injection occurs. Thus, if the first injection occurs after year's end, but before the date on which the taxpayer files a tax return, the taxpayer may claim the EOR credit for the qualifying costs incurred prior to the first injection on that return. If the first injection occurs later, the taxpayer must amend the return to claim the credit for costs incurred prior to the first injection. If the first injection is expected to occur more than 36 months after the first qualifying expenditures are incurred, taxpayers should request a private letter ruling ("PLR") from the IRS asking for permission to claim the credit on tax returns filed before the first injection date.[16]

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[8] Section 1.43-4.

[9] Sections 1.43-4(b)(3) and (c)(4).

[10] IDCs incurred for a well to be used for primary production do not qualify for the credit, even if the taxpayer anticipates using the well in a tertiary recovery method in the future. Sections 1.43-4(b)(2) and (c)(5).

[11] Section 1.43-3(c)(1).

[12] Section 1.43-4(c)(3).

[13] Section 1.43-4(a)(2).

[14] Section 43(d)(2).

[15] Section 1.43-4(b)(2).

[16] Section 1.43-4(d)(1). Written determinations such as private letter rulings represent the IRS's analysis of the law as applied to a taxpayer's specific facts, and these type of written determinations are not intended to be relied on by third parties and may not be cited as precedent. Section 6110(k). They do, however, provide an indication of the IRS's position on the issues addressed.

The purchaser of an existing qualified EOR project may claim the credit for any qualifying costs exceeding the acquisition costs. The acquisition costs themselves are not eligible for the credit, however. Furthermore, the IRS will disregard any costs paid or incurred for an asset that is acquired, used, or transferred in a manner designed to duplicate or otherwise unreasonably increase the EOR credit.[17]

Section 43(c)(1)(C) was amended in 2000[18] to ensure that normal operating costs incurred to "self-produce" tertiary injectants would qualify for the credit in the same manner as the cost of purchased injectants. Revenue Ruling 2003-82[19] provided some detailed guidance on qualified tertiary injectant costs. It established a definition of tertiary injectant costs as costs related to the use of a tertiary injectant—such as costs for acquisition or production, injection, recovery, and reinjection. However, the ruling also finds that "qualified tertiary injectant expenses" do not include costs a taxpayer would have paid or incurred in the development or operation of a mineral property if an EOR project had not been implemented with respect to the property. Costs related to the use of a tertiary injectant and that also are related to other activities (for example, primary or secondary recovery) must be reasonably allocated among the tertiary injectant and other activities to determine the amount of tertiary injectant expenses paid or incurred by the taxpayer for the taxable year.

The IRS in EOR Directive #1[20] provided additional guidance on qualified expenses.[21]

"Qualifying Activities" were determined to include:

- Operating source wells, pumps, compressors, meters, lines, etc. to transport tertiary injectant from point of acquisition to the EOR project and eventual injection into the reservoir
- Operating equipment used to produce, recover, recycle, and reinject tertiary injectant into the reservoir
- Repairing equipment used to produce, recover, recycle, and reinject tertiary injectant into the reservoir
- Performing workovers on injection wells

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[17] Section 1.43-4(e).

[18] The amendment was retroactive to the original enactment of the credit in 1991.

[19] Rev. Rul. 2003-82, 2003-2 C.B. 125.

[20] Industry Director Directive #1 – Enhanced Oil Recovery (May 2, 2007), *available at* 2007 TNT 102-7. EOR was previously a Tier II audit issue; a memorandum dated August 17, 2012 from the LB&I Commissioner announced, in part, the end of the Tiered Issue process, "All prior Industry Director Directives ("IDDs") relevant to these issues are withdrawn and should no longer be consulted or followed." https://www.irs.gov/businesses/corporations/tiered-issues. We include a discussion of the IDDs because they provided at least some limited guidance in this complex area.

[21] *Id.* Attachment 3 – Audit Evaluation for EOR Tax Credit.

"Non-Qualifying Activities" were determined to include:

- Performing workovers on wells that do not produce any fluids used for injection or to fuel equipment used to handle tertiary injectants
- Performing workovers on wells that produce fluids used for injection or to fuel equipment used to handle tertiary injectants, when the sole purpose of the workover is to improve the efficiency of recovering saleable hydrocarbons
- Disposing of tertiary injectant (as opposed to recovery for reinjection)
- Conducting environmental studies
- Operating any wells or equipment located outside of the bounds of the project unless it is specifically described in the petroleum engineer's certification

"Qualifying Costs" were determined to include:

- Wages and fringe benefits of field personnel, to the extent they are engaged in qualifying activities (i.e., the operation of equipment to produce or acquire or use tertiary injectant), assumes these costs are of the nature that non-operators would reimburse the operator
- Payments to third parties for consumables such as raw materials, fuel, and utilities used for qualifying activities
- Expenditures to third parties to perform qualifying activities
- Overhead and administrative costs to the extent they support qualifying activities and are of the magnitude that non-operators would reimburse the operator

"Non-Qualifying Costs" were determined to include:

- Royalties and severance taxes paid on value of hydrocarbon sales
- Ad valorem taxes based on appraised value of mineral
- Ad valorem taxes based on appraised value of equipment
- Amounts paid for non-qualifying activities
- Overhead above field level that would not be reimbursed by non-operators

Further guidance was provided by the IRS in EOR Directive #2.[22]

- The qualified cost of the self-produced natural gas used as a fuel in an EOR process is its day-to-day cost of production and any other costs that directly relate to its production and use within the project (e.g., royalties or severance taxes). The cost of production attributable to this natural gas would be a subset of the day-to-day cost to operate the entire EOR project and must be determined by a reasonable method.
- Royalties and severance taxes are not routinely due on produced hydrocarbons that are consumed within a lease or unit as part of production operations.
- The cost of water disposal equipment that is located "downstream" of the equipment used to complete the separation of water from the produced crude oil is not a qualified tangible property cost.
- The cost to dispose of produced water is not a qualified tertiary injectant expense.
- The de minimis exception contained in section 1.43-4(a)(2)[23] does not apply to situations in which the same type of injectant is used in more than one EOR project and an allocation of its cost must generally be made between the projects.
- Generally, if one of the reasons a well workover is being performed is to correct or improve the injection of steam into the well, then some portion of the workover cost will qualify as a tertiary injectant expense.

The EOR credit Tier II status was changed to monitoring in 2010.[24]

Qualified Projects[25]

A qualified EOR project must (1) employ an approved tertiary recovery method, (2) be reasonably expected to result in more than an insignificant increase in the ultimate recovery of crude oil, and (3) be certified.

Approved Tertiary Recovery Method

The project must employ one of 10 approved tertiary recovery methods described in the regulations. Specifically, waterflooding, cyclic gas injection, horizontal drilling, and gravity drainage are not qualified

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[22] Industry Director Directive #2 – Enhanced Oil Recovery Credit (May 14, 2009), *available at* 2009 WL 1456729.

[23] The de minimis exception provides that any cost paid or incurred for an asset that is used to implement a qualified EOR project and that is also used for other activities is not required to be allocated, if the use of the property for nonqualifying activities is not greater than 10 percent.

[24] Industry Director Directive #3 – Enhanced Oil Recovery Credit (Mar. 18, 2010), 2010 WL 1231040.

[25] Section 1.43-2.

tertiary recovery methods. Congress empowered the Treasury to expand the list of qualified tertiary recovery methods, and in PLR 200511002[26] the IRS approved the injection of low salinity water as a qualified EOR method.

More Than an Insignificant Increase

The project must be reasonably expected to result in more than an insignificant increase in the amount of crude oil that will ultimately be recovered. There is no precise definition for this standard. Rather, the regulations indicate that all the facts and circumstances should be considered in making this determination.

Certification

The regulations impose three certification requirements:[27] (1) initial certification of the project by a petroleum engineer; (2) annual certification by the operator or designated owner; and (3) notice of project termination. The petroleum engineer's certification must be submitted in a project's first year to the IRS Center in Austin, Texas,[28] by the extended due date for the operator's federal income tax return for that tax year. In this certification, the petroleum engineer must describe in detail the method used and the expected results and attest that the project qualifies for the EOR credit. The annual operator certification must be filed in Austin by the extended due date for the operator's federal income tax return for all later tax years during the life of the project, indicating that the project has been implemented

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[26] PLR 200511002 (Nov. 23, 2004) (The low salinity water caused changes in the properties of the fluids in the reservoir which do not occur with conventional waterflooding.). *See also* PLR 200634008 (May 22, 2006) (Approved method used a combination of native and non-native enriched gases to facilitate a multiple contact vaporization process, which modifies the fluid properties of the oil causing it to be displaced from the rock.); PLR 200627009 (Apr. 6, 2006) (Approved method involved the simultaneous permanent removal of water from watered-out portions of the reservoir and the injection of immiscible natural gas from an extraneous source into the upstructure portion of the reservoir.); PLR 200610009 (Sept. 30, 2005) (Approved method used injection wells to alternate injection of enriched hydrocarbon gas and water into the reservoir.); PLR 200546011 (Aug. 5, 2005) (Approved method used the injection of an unidentified injectant will affect the reservoir fluid by increasing the pH of the reservoir fluids, and by reducing the interfacial tension between the oil, reservoir rock, and water.); PLR 200543008 (July 20, 2005) (Approved method used water alternating gas (WAG) technique with lean gas produced in the unit having a significant concentration of CO2 and enriched with intermediate hydrocarbons, principally ethane and propane.); PLR 200427012 (Mar. 19, 2004) (Approved method used injection of lean gas alternating with water into the reservoir.); PLR 200027007 (Mar. 30, 2000) (Approved method used the injection of rented dry non-native hydrocarbon gas into nearly depleted oil reservoirs.); TAM 200227002 (July 23, 2001) (Approved method used the injection of lean hydrocarbon or nonhydrocarbon gas into the reservoir to vaporize oil.); PLR 9550012 (Sept. 13, 1995) (Approved method used the simultaneous permanent removal of water from the watered-out portions of the reservoir and injection of an immiscible nonhydrocarbon gas.).

[27] Section 1.43-3.

[28] Our present understanding is that it would be prudent to also mail a copy of all engineer certifications to:

Internal Revenue Service
LB&I Central Compliance Practice Area
Attention: Director's Office
1919 Smith Street
Mail Stop 1000-HOU
Houston, TX 77002

according to the petroleum engineer's certification. Finally, the operator must notify the IRS on the termination of a project no later than the extended due date for filing the operator's federal income tax return for the tax year in which the last injection of liquids and gases occurs. While failure to file the certification statements in the time and manner prescribed in the regulations will not disqualify the project, the credit will not be allowed until after the certification requirements have been satisfied.

Pre-1991 EOR Projects

Generally the EOR credit is effective for costs paid or incurred in tax years beginning after December 31, 1990, for projects beginning after that date. A special rule provides that any significant expansion after December 31, 1990, of a project begun before January 1, 1991, is treated as a qualifying EOR project.[29]

Treasury has identified three circumstances in which a project will be considered a significant expansion:[30]

> (1) A project affects acreage that was substantially unaffected by the project's previously implemented tertiary activities;
>
> (2) A project is expanded to a reservoir previously unaffected by a tertiary method; and
>
> (3) The prior method has been terminated for at least 36 months. However, neither a change in tertiary recovery methods nor a more intensive application of a method constitutes a significant expansion.

In a PLR,[31] the IRS additionally provided that the restart of an EOR project less than 36 months after its termination was nevertheless a significant expansion and treated as a separate project. The IRS noted that the original EOR project was terminated for financial reasons unrelated to the credit, the original project owner was not related to the new owner, the resuscitation of the project will not benefit the original owner and the original project was not terminated in order to make an otherwise nonqualifying project eligible for the credit. However, in another PLR,[32] the IRS concluded that in the absence of new drilling or new perforations a more intensive application of the same tertiary recovery method to the same reservoir volume could not constitute a significant expansion project.

When cyclic steam wells that commenced steam injection before January 1, 1991, are continuously cycled after that date, each cycle does not constitute a qualifying "significant expansion project."[33]

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[29] Omnibus Budget Reconciliation Act of 1990, P.L. 101-508, § 11511(d); section 1.43-2(d).

[30] Section 1.43-2(d).

[31] PLR 9434019 (May 26, 1994). *See also* TAM 200227002 (July 23, 2001) (additional reservoir volumes swept that had not been swept by a pre-1991 EOR project).

[32] TAM 200535028 (May 5, 2005). *See also* Industry Director Directive #1 – Enhanced Oil Recovery, *supra* note 20.

[33] Industry Director Directive #2 – Enhanced Oil Recovery Credit, *supra* note 22.

Conclusion

The oil industry's total EOR credits allowed for 2016 is expected to be significant and will likely be significant for a number of individual oil companies. The EOR credit rules are stringent, require highly factual determinations, and are based both on engineering judgment and reasonable accounting allocation methods. Further, financial statement disclosures will need to be considered. After a 10-year hiatus, significant efforts will be needed to harvest the benefits of the EOR credit.

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