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The return of enhanced oil recovery credits, marginal gas well credits and other oil and gas tax considerations in today's pricing environment

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With the continued low commodity pricing environment, many oil and gas companies remain under increased pressure to cut costs and effectively manage cash flow. This often includes an enhanced focus on utilizing available tax-related incentives. The good news is that there are a number of renewed tax considerations to explore during this tumultuous period of low commodity prices, including the enhanced oil recovery (EOR) credit, the marginal well credit (MWC), marginal well benefits as defined by Texas statute and specified liability losses (SLLs).

Enhanced oil recovery credit

The IRS announced the return of the full 15-percent EOR credit for 2016 on July 18, 2016.[1] The EOR credit is a tax credit for qualified EOR costs incurred by a taxpayer in a tax year.[2] The credit is permanent but has been phased out and unavailable for the last 10 years due to commodity prices.[3]

Although the oil and gas industry had speculated about the potential availability of the EOR credit for 2016 earlier in the year based on calculations described below, official confirmation in Notice 2016-44 was welcome guidance for the industry.

Enhanced oil recovery projects

A qualified 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 Code Sec. 193(b)(3).[4] Qualified tertiary methods are provided in the related EOR credit Income Tax Regulations including:

- steam recovery methods (e.g., steam drive injection, cyclic steam injection and in situ combustion);
- gas flood recovery methods (e.g., miscible fluid displacement, CO2 augmented waterflooding, immiscible CO2 displacement and immiscible nonhydrocarbon gas displacement);
- chemical flood recovery methods (e.g., microemulsion flooding and caustic flooding); and
- mobility control recovery method (polymer augmented waterflooding). [5]

Simply accelerating the recovery of minerals does not qualify as an EOR project. Rather, more than an insignificant increase in the amount of crude oil that will ultimately be recovered is required. [6] A qualified EOR project must also meet other specified requirements provided by the statute and regulations including:

- the project must be located within the United States;
- the initial implementation of one or more of the qualified tertiary methods must have commenced after December 31, 1990 [7] ; and
- the project must be certified through procedures described in Reg. §1.43-3. 8

To properly certify the qualified EOR project, in the first year in which the EOR credit is allowable for a project, the operator (or operating mineral interest owner designated by the operator) must submit a petroleum engineer's certification of the project meeting the requirements outlined in the regulations. The same party must also file an annual operator's certification that the project is being operated substantially according to the petroleum engineer's certification, filed not later than the due date, including extensions, of the party's income tax return for the applicable tax year. Once the qualified EOR project is terminated, notice must be filed in the year of termination, due no later than the tax return due date, including extensions, for such year. Reg. §1.43-3 details the content of the petroleum engineer's certification, the operator's continued certification and the notice of termination. As a practical matter, accounting firms will likely have to work closely with the engineering departments of exploration and production (E & P) clients in order to properly certify a qualified EOR project.

Enhanced oil recovery costs

The EOR credit is for 15 percent of the qualified EOR costs. Qualified costs include certain designated expenses associated with an EOR project, including:

- amounts paid for depreciable tangible property;
- intangible drilling and development expenses (IDC);
- tertiary injectant expenses; and
- construction costs for certain Alaskan natural gas treatment facilities. [9]

To the extent the EOR credit is allowed for qualified costs, any income tax deduction otherwise allowed (i.e., IDC, injectant expenses, etc.) must be reduced. [10] In that same respect, the increase in the basis of property that is otherwise allowable for costs for which an EOR credit is claimed (i.e., lease and well capital expenditures) must be reduced by the amount of the credit. [11]

Costs not qualifying include those for waterflooding (though these costs may qualify to the extent such costs are a part of a larger qualified project), cyclic gas injection, horizontal drilling, gravity drainage and costs related to other methods not specifically designated by the regulations. [12] However, the rules do contemplate costs related to the qualification of other recovery methods as technological advances occur and taxpayers may request letter rulings (LTRs) as new circumstances arise. [13]

Taxpayers must consider specific limitations with respect to qualified EOR costs depending upon the type of entity claiming the EOR credit. First, an integrated oil company (i.e., an E & P company that is also considered either a retailer or refiner) [14] may only claim the EOR credit for the amount of IDC allowable as a deduction under Code Sec. 263(c) (no more than 70 percent of total IDC incurred). [15] Second, to the extent a qualified cost is not deductible as a partnership expenditure and does not increase the basis of the property of the partnership, the adjusted bases of the partners' interest in the partnership should be decreased. [16]

Calculating the available credit amount

The EOR credit amount of 15 percent may be reduced or phased out in a given year depending upon the reference price of domestic crude oil. [17] Any reduction to the credit amount is calculated using a ratio, "an amount that bears the same ratio to the amount of the credit as the excess of the reference price for the calendar year before the calendar year in which the tax year begins over $28, inflation adjusted, bears to $6." [18] For any tax year beginning after 1991, the $28 threshold should be multiplied by the inflation adjustment factor for such calendar year.

The term "inflation adjustment factor" means, with respect to any calendar year, a fraction the numerator of which is the Gross National Product (GNP) implicit price deflator for the preceding calendar year and the denominator of which is the GNP implicit price deflator for 1990. [19] The inflation adjustment factor for the 2016 tax year is 1.6464. [20] This amount is calculated by dividing the GNP implicit price deflator for the calendar year preceding the tax year of the taxpayer, 109.868, by the GNP implicit price deflator for 1990, 66.732.

The GNP implicit price deflator for 1990 has been rebased eight times since the EOR credit was enacted. For future planning purposes, the St. Louis Federal Reserve Bank's Economic Data department (FRED), accurately reported the 2016 GNP implicit price deflator well in advance of IRS Notice 2016-44. [21] FRED also reports the rebased 1990 GNP implicit price deflator without exception from IRS Notice 2016-44. [22] For purposes of determining the crude oil reference price, the US Energy Information Administration (EIA) typically provides the final reference price figures in April for the preceding calendar year. [23]

Prior to releasing the inflation adjustment factor for the 2016 tax year, the IRS published the crude oil reference price used in determining the amount of the EOR credit, the marginal well production credit and the amount of percentage depletion in the case of oil and natural gas produced from marginal properties. The crude oil reference price for calendar year 2015 applies for the 2016 tax year. The reference price under Code Sec. 45K(d)(2)(C) for calendar year 2015 is $44.39.[24] This reference price for 2015, $44.39, does not exceed $28 multiplied by the inflation adjustment factor for 2016, $46.10 ($28 multiplied by 1.6464).[25] Thus, the full 15-percent credit is available for the 2016 tax year. Note, although the EOR credit has only been either fully phased out (at zero percent) or fully available (at 15 percent) since its enactment, a partial credit scenario is contemplated in the regulations.[26]

Utilization of credits

The EOR credit applies unless a taxpayer makes an election not to apply the credit for a particular year.[27] This election (or revocation thereof) may be filed at any time before the expiration of the three-year period beginning on the due date for the tax return for such year, excluding extensions.[28] For flow-through entities, this election is made at the partnership or S corporation level.[29]

As a general business credit,[30] the amount of the EOR credit is subject to the alternative minimum tax (AMT) and is nonrefundable. Even without a federal tax liability in the current year, the credit may be carried back one year or forward 20 years.[31] Any unused credit remaining after the expiration of the carryforward period is fully deductible at that time.[32]

Marginal well tax credit

The marginal well tax credit is a production-based tax credit that provides a $3-per-barrel credit for the production of crude oil and a $0.50-per-1,000-cubic-feet (Mcf) credit for the production of qualified natural gas from a qualified marginal well.[33]

Similar to the EOR credit, since its enactment in 2004, the MWC has been fully phased out for both marginal oil and natural gas wells due to the relevant commodity prices. No taxpayer has ever claimed the Code Sec. 45I MWC since its enactment, and no IRS form exists to claim the credit since the IRS has never needed to develop one.

Based upon projections of the 2015 reference price for natural gas, it appears that the MWC for natural gas may be available in 2016 for the first time. However, it is clear that the MWC for oil is fully phased out for the 2016 tax year.[34]

Qualified marginal wells

A qualified marginal well generally includes a domestic oil well with (1) production of not more than 15 barrels per day; (2) production of heavy oil; or (3) average production of not more than 25 barrels a day of oil and not less than 95 percent water.[35] Marginal natural gas wells are those producing not more than 90 Mcf a day (one barrel of oil is equal to six Mcf).[36] Finally, only the first 1,095 barrels or barrel-of-oil equivalent per year qualify (6,570 Mcf/year).[37] This limitation is based on the number of barrels or barrel-of-oil equivalents per year, per well. No limitation exists on the number of wells on which a taxpayer can claim the credit.

In order to claim a MWC, the taxpayer must hold an operating interest.[38] If a well is owned by more than one owner, the credit is allocated among the owners in proportion to their share of the revenue interests of all operating interest owners.[39] Further, the MWC is not available if the taxpayer is also claiming the Code Sec. 45K nonconventional sources credit.[40]

Calculating the available credit amount

The MWC, adjusted for a similar inflation adjustment factor used in the computation of the EOR credit, is not available if the reference price exceeds $18 for oil or $2 for natural gas (both then adjusted for inflation). The credit is reduced proportionately by the same percentage that the reference price for either oil or gas exceeds $15 and $1.67 (then adjusted for inflation), compared to $3 and $0.33 (also adjusted for inflation), respectively.[41]

As previously stated, the 2015 reference price for oil is $44.39, much greater than the upper limit of $18, adjusted for inflation. Thus, no MWC for marginal oil production will be available for the 2016 tax year.

The remaining question is whether the MWC for natural gas production will be available for the 2016 tax year. The IRS has yet to publish a reference price for natural gas since the inception of the MWC as a part of the American Jobs Creation Act passed in 2004. The IRS has also never published the inflation adjustment factor to be used in computing the MWC. However, considering publically available information, it appears probable that the MWC for qualified natural gas production in 2016 will be available.

As mentioned above, the inflation adjustment factor is a fraction, the numerator of which is the GNP implicit price deflator for the preceding calendar year and the denominator of which is the GNP implicit price deflator for 1990. The inflation adjustment factor for the MWC is calculated as described, though, substituting "2004" for "1990."[42] The published 2004 GNP implicit price deflator was 108.23.[43] In Notice 2016-44, the GNP price deflator published for 1990 was 112.9. However, considering that the 1990 GNP implicit price deflator has been rebased eight times since 1995 (and four times since 2004),[44] it is safe to assume that the 2004 GNP implicit price deflator should and will be rebased. Per FRED, the average GNP implicit price deflator for 2004 is 89.089.[45]

Assuming the same 2015 GNP implicit price deflator published in Notice 2016-44 would be applicable for the MWC, 109.868, yields an estimated inflation adjustment factor of 1.2332 for the MWC calculation for the 2016 tax year.

Continuing with the above assumption, the MWC would be at least partially available so long as the 2015 reference price for natural gas is less than $2.47 per 1,000 cubic feet ($2.00 × 1.2332). The Natural Gas Supply Association (NGSA) annually publishes the top 40 producers of US natural gas for the

year.[46] The publically available information of 37 of these top 40 producers[47] suggests that the weighted average wellhead sales price of natural gas produced in 2015 by these 37 entities was about $2.19 per 1,000 cubic feet. The total US natural gas production of these 37 entities accounted for just more than 43 percent of the total US natural gas production in 2015.

A reference price of $2.19 per 1,000 cubic feet, using the assumptions detailed above, would yield a MWC of $0.42 per 1,000 cubic feet of natural gas produced from a qualified marginal well in the United States, on an 8/8ths basis.[48] Based on that estimated credit amount of $0.42 per Mcf, a taxpayer's available MWC could be as much as $2,759.40 per well, per year based on the maximum quantity of production allowable for the credit (6,570 Mcf/year). While the credit amount may seem relatively small, consider that the EIA estimates that there were about 380,000 stripper oil wells (one type of a qualified marginal well) in the United States operating at the end of 2015, compared to about 90,000 nonstripper oil wells.[49] The tax benefit of computing the MWC could quickly become significant. For example, MWC estimates of two of the top 40 US natural gas producers, calculated based on wells operated only in the state of Texas, on an 8/8th ownership as reported by the Texas Railroad Commission, both exceeded potential benefits of $4,000,000. Thus, the MWC can be valuable given the current commodity environment in the industry.

IRS response to return of MWC

In early May of 2016 at the American Bar Association Section of Taxation Annual Meeting in Washington, D.C., the MWC was discussed on an Energy & Environmental Taxes panel.[50] An IRS Office of Chief Counsel attorney responded to a question about whether the IRS expected the MWC for natural gas production to return for 2016 and whether the IRS would issue guidance on the reference price or inflation adjustment factor. The IRS attorney indicated that the IRS is aware of the potential for the MWC to return but that the IRS did not "have any formal plan for any kind of guidance."[51] Additionally, the IRS attorney mentioned that the statute does not mandate the IRS to publish an inflation adjustment factor as it does for other tax credits; however, the IRS may be open to issuing some sort of guidance if it becomes necessary.[52] Although the EIA stopped publishing the domestic natural gas reference price several years ago, it was noted that the IRS has had recent conversations with the EIA about publishing a 2015 reference price. However, it remains unclear if or when the EIA will publish a reference price.

Without further guidance from the IRS on the reference price for natural gas, whether the MWC is available for 2016, or how to claim the credit, the following actions seem reasonable for taxpayers to undertake:

- Apply a reasonable method to estimate the natural gas reference price such as the method described above or a method based on a variance from Henry Hub Natural Gas Spot Prices or other similar indices.
- Apply a reasonable method to estimate the inflation adjustment factor based on calculations and an expected 2004 GNP implicit price deflator derived from the figures in Notice 2016-44.
- Attach a statement to the 2016 tax return substantiating the basis for claiming the MWC and document the authority, support and reasoning for such position for the taxpayer's records.

The IRS could also issue informal guidance in the form of an Announcement, Generic Legal Advice Memorandum or Chief Counsel Advice to the Industry Director not to challenge a taxpayer's reasonable claim (within certain parameters) where the IRS has not yet issued formal guidance. Such guidance is a possibility later in 2016 or in early 2017 if an inflation adjustment factor notice is not published.

Utilization of credits

The MWC is especially attractive to entities that have paid federal income tax within the last five years. A special carryback provision provides that unused MWCs be carried back for five years rather than the generally applicable carryback period of one year.[53] The credit is also carried forward for 20 years.[54] Utilizing the potential MWC creates the opportunity for refunds and a reduced overall income tax burden.

State marginal well—Texas franchise tax benefits

In addition to the aforementioned federal MWC, there are also other potential tax considerations for marginal oil and gas properties. An example is the Texas franchise tax (also commonly referred to as the "margin tax") revenue exclusion. When companies with upstream operations pay Texas franchise tax, savings potentially exist when two requirements are met for any given month: 1) the applicable commodity price is certified by the Texas Comptroller of Public Account's ("Comptroller") office as meeting the statutory threshold and 2) the well's average production amount over the relevant 90-day period qualifies under the statute.[55] When these two requirements are met for a given month, taxpayers are able to exclude from both the tax base and apportionment percentage revenue earned from the respective qualifying well(s) for that month.[56]

With regard to gas wells, the Comptroller must certify the average closing price of gas for a given month is below $5 per MMBtu.[57] As of June 2016, gas prices have regularly met this price requirement since early 2010.[58] Therefore, effectively only one requirement has existed for gas wells since that time: does the well's production qualify over the relevant 90-day period under the statute? For Texas franchise tax purposes, a gas well's production qualifies in a given month if an average of less than 250 Mcf per day is produced over a period covering that month plus the two preceding calendar months.[59] With respect to terminology, rather than use "marginal well" or other

nomenclature, the Comptroller's office generally refers to such a well simply as a "lowproducing well."

For oil wells, the same concepts apply except the monthly price and monthly production amount differ: the Comptroller must certify the average closing price of West Texas Intermediate crude oil for a given month is below $40 per barrel,[60] and the oil well must average less than 10 barrels of production per day or less over the 90-day period described above.[61] In contrast to gas prices, as of June 2016 the applicable average closing price of crude oil has only met the Comptroller price certification requirement less than a handful of times (e.g., December 2015, January 2016).

Specified liability loss carrybacks

A tax consideration other than tax credits that may be available in the current environment is the use of SLLs. Generally, taxpayers can generally only carry a net operating loss (NOL) back two years. However, to the extent that a portion of the NOL qualifies as a SLL, the applicable carryback period is 10 years.[62] This may open up a pool of previously paid income taxes for refund that might otherwise not be available for recoupment.

SLLs include any amount allowable as a deduction under Code Sec.162 or 165 that is attributable to product liability or expenses incurred in the investigation or settlement of, or opposition to, claims against the taxpayer on account of product liability.[63] SLLs also include any amount allowable as a deduction which is in satisfaction under a federal or state law requiring the reclamation of land, the decommissioning of a nuclear power plant (or any unit thereof), the dismantlement of a drilling platform, the remediation of environmental contamination or a payment under any workers compensation act. An SLL applies only if the act (or failure to act) giving rise to the liability occurs at least three years before the beginning of the tax year and the taxpayer used an accrual method of accounting throughout the period(s) during which the act (or failure to act) occurred.[64]

Pertinent to E & P entities, expenses related to the reclamation of land include dismantling surface facilities, contouring and grading land, placement of subsoil and topsoil or an approved substitute in graded area, reseeding native vegetation, crops or trees and future monitoring to ensure successful reclamation.[65]

Qualifying expenses related to the dismantlement of a drilling platforms include costs to permanently plug and abandon wells drilled from said platform, costs to remove decks and booms from the platform, costs to clear the sea floor of all other obstructions and costs to remove decommissioned pipelines. Further, the legal liability for the dismantlement of a drilling platform occurs the sooner of when drilling the well commences, a platform, pipeline or other facility is installed, an obstruction to other users of the area has been created, taxpayer becomes a lessee where a leased well had not been permanently plugged or a taxpayer becomes the holder of a pipeline right-of-way.[66]

Costs incurred to prevent and remedy environmental contamination include costs for site investigations including reports and action plans, site preparation, reimbursement of federal or state environmental agencies for investigation or remediation costs, actual cleanup of contamination, containment or encapsulation costs, excavating, stockpiling or transplanting contaminated soil to a waste facility, treatment of soil, costs to prevent pollutants from entering the environment in the first place[67] and any of the aforementioned costs allocated to inventory.[68]

Many of these types of costs can be identified through a detailed review of financial statements. The taxpayer my elect to forego the 10-year carryback period for SLLs in any given tax year.[69] In the absence of such an election, the taxpayer must carry these costs back separate from the regular federal NOL. As such, it is important to track these costs separately. Interviews with the engineering department may be necessary to obtain a firm understanding as to what costs should be characterized as SLLs. SLLs are limited to the amount of the NOL for that year.[70] For example, a taxpayer may not carryback or carryforward an SLL that would not cause the taxpayer a NOL in the year in question. Also, SLLs do not apply if costs have been deducted under Code Sec. 468.[71]

Many oil and gas companies, particularly those with upstream operations, will routinely have significant costs that qualify as SLLs. Moreover, special procedures to request and expedite a refund of these overpayments are often available. To the extent a tentative refund is in excess of $2 million or $5 million in the case of a C corporation after December 19, 2014, generally no refund or credit will be made unless the IRS submits a report to the Congressional Joint Committee on Taxation.[72]

Other considerations

These are just a few examples of the many potential considerations for enhancing cash flow during the current economic environment. In addition to other federal and state income tax considerations, there are often important considerations in the sales and use, excise and severance tax areas. Although some considerations may not rise to a priority level during more vibrant times, in the present pricing environment the cumulative impact may be significant and often merits a fresh focus and review.

Footnotes

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1. IRS Notice 2016-44, IRB 2016-29.
2. Code Sec. 43(a).
3. IRS Notice 2015-64, IRB 2015-40.
4. Code Sec. 43(c)(2)(A)(i).
5. Reg. §1.43-2(e)(2).
6. Reg. §1.43-2(b).
7. Note, Reg. §1.43-2(d) allows an exception for a "significant expansion" of project begun before January 1, 1991.
8. Reg. §1.43-2(a).
9. Code Sec. 43(c)(1).
10. Code Sec. 43(d)(1).
11. Code Sec. 43(d)(2).
12. Reg. §1.43-2(e)(3).
13. Reg. §1.43-2(e)(3)(v).
14. Code Secs. 613A(d)(4) and (2).
15. Reg. §1.43-1(d)(2).
16. Reg. §1.43-1(f).
17. Code Sec. 43(b).
18. Code Sec. 43(b)(1).
19. Code Sec. 43(b)(3).
20. *See* Table 2 of Notice 2016-44.
21. *See* FRED website, *https://fred.stlouisfed.org/data/GNPDEF.txt*.
22. *Id.*
23. *See* EIA website, *www.eia.gov/petroleum/marketing/monthly/pdf/pmmtab18.pdf*.
24. IRS Notice 2016-43, IRB 2016-29.
25. IRS Notice 2016-44, IRB 2016-29. Please *also see* Ann. 2016-29, IRB 2016-34, 272 (Aug. 22, 2016) correcting a typo in Notice 2016-44. The notice had said that the phaseout price was $46.01 but should have said $46.10.
26. Reg. §1.43-1(c)(3).
27. Code Sec. 43(e).
28. Code Sec. 43(e)(2).
29. Reg. §1.43-6.
30. Code Sec. 38(b)(6).
31. Reg. §1.43-1(a)(1).
32. Code Sec. 196.
33. Code Sec. 45I(b)(1). Note, these credit amounts are then adjusted for inflation as specified by the statutory language and legislative history.
34. As described below based upon the 2015 reference price for crude oil provided in Notice 2016-43.
35. Code Sec. 45I(c)(3)(A).
36. Code Sec. 613A(c)(6)(E).
37. Code Sec. 45I(c)(2)(A).
38. Code Sec. 45I(d)(2).
39. Code Sec. 45I(d)(1).
40. Code Sec. 45I(d).
41. Code Sec. 45I(b)(2)(A).
42. Code Sec. 45I(b)(2)(B).
43. *See* Table 1 of Notice 2016-44.
44. *Id.*
45. *See* FRED website, *https://fred.stlouisfed.org/data/GNPDEF.txt*; (88.083 + 88.850 + 89.398 + 90.026)/4 = 89.089.
46. "Top 40 Natural Gas Producers in US 2015 4th Quarter." April 2016. *www.ngsa.org/analyses-studies/*.
47. Of the top 40 producers, one did not have public financial statements and two had fiscal year-ends.
48. The $0.42 MWC per Mcf is determined based upon an inflation adjusted credit amount of $0.62 (1.2332 x $0.50 per Mcf) reduced by the ratio described above and in Code Sec. 45I(b)(2). The term "8/8ths basis" refers to the gross operated or total operated basis— the total reserves or production associated with the well operated by an individual operator.
49. J. Perrin, *Stripper wells accounted for 10% of US oil production in 2015*, June 29, 2016. *See www.eia.gov/todayinenergy/detail.cfm?id=26872*.
50. The panel was on May 6, 2016, and was titled *Emerging Issues in Oil and Gas*.
51. *See* Bloomberg BNA Daily Tax Report, Natter, Ari, *New Tax Credits Expected for Oil, Gas Producers*, May 6, 2016.
52. Code Sec. 43(b)(3)(B) requires that the Secretary "shall publish" the inflation adjustment factor by 1 April for the preceding calendar year. No similar language is provided in Code Sec. 45I, however, Code Sec. 45I(b)(2)(C) provides that the reference price is "in the case of qualified natural gas production, the Secretary's estimate of the annual average wellhead price per 1,000 cubic feet for all domestic natural gas." Although not a directive, this language infers that the IRS provide the necessary data to determine the credit.
53. Code Sec. 39(a)(3).
54. *Id.*
55. Tex. Tax Code §171.1011(r)-(s).
56. Tex. Tax Code §171.1011(r).
57. Tex. Tax Code §171.1011(s).
58. After 2010, such certification by the Comptroller is published on a monthly basis in the *Texas Register* available through the Texas Secretary of State.
59. Tex. Tax Code §171.1011(r)(2); Texas Comptroller of Public Accounts, Franchise Tax Total Revenue Frequently Asked Questions No. 24 (Sept. 9, 2011), *http://comptroller.texas.gov/taxinfo/franchise/faq_revenue.html#rev24*.
60. Tex. Tax Code §171.1011(s).
61. Tex. Tax Code §171.1011(r)(1); Texas Comptroller of Public Accounts, Franchise Tax Total Revenue Frequently Asked Questions No. 24 (Sept. 9, 2011), *http://comptroller.texas.gov/taxinfo/franchise/faq_revenue.html#rev24*.
62. Code Sec. 172(b)(1)(C).
63. Code Sec. 172(f)(1)(A).
64. Code Sec. 172(f)(1)(B).
65. Industry Director's Directive #2 on Specified Liability Losses IRC 172(f), LMSB-4-0309-011 (June 19, 2009).
66. *Id.*
67. *See* IRS Letter Ruling LTR 201105009 (Oct. 19, 2010) (concluding amounts incurred to seal pipeline to prevent hydrocarbon residues from escaping into the environment qualify as well as clean-up costs to remove hydrocarbons that have escaped into the ocean).
68. Industry Director's Directive #2 on Specified Liability Losses IRC 172(f), LMSB-4-0309-011 (June 19, 2009).
69. Code Sec. 172(f)(6).
70. Code Sec. 172(f)(2).
71. Code Sec. 172(f)(1)(B)(i).
72. Code Sec. 6405(b).

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