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April 23, 2013

RE: Comments: Energy Tax Reform Working Group

On behalf of the American Petroleum Institute (API), the only national trade association that represents all aspects of America's oil and natural gas industry, we applaud the efforts of the House Ways & Means Committee and the Energy Tax Reform Working Group to understand the tax issues of concern to our industry.

Currently, America's oil and natural gas industry supports 9.2 million jobs in the United States and 7.7 percent of our nation's Gross Domestic Product. Every day we deliver on average around $86 million to federal coffers in rents, royalties, bonus payments and income tax payments. Our effective tax rate – averaged over the years 2006 through 2011 – is 44.3 percent, well above the 35 percent general corporate tax rate.

Given the size and scope of our industry in the US, we understand that any fundamental changes to the corporate tax code will impact our members, and the millions of American jobs that rely upon a vibrant energy sector.

In an effort to help lawmakers better understand the industry, enclosed are the following documents:

- Data illustrating the industry's contribution to the economy in taxes and in other ways,
- Issue one-pagers pertaining to Section 199, IDC, LIFO, and treatment of dual capacity taxpayers,
- API's general tax reform principles,
- Industry's comments on the Territorial Discussion Draft, and a
- Paper on the legislative history and importance of IDC with executive summary

We hope you find these documents helpful as you work through these important issues. If you have any additional questions, please feel free to contact myself, and Stephen Comstock, Director of Tax & Accounting Policy at comstocks@api.org.

Sincerely,

Brian M Johnson

Oil & Natural Gas: Supporting the Economy While Paying Our Fair Share

The oil and natural gas industry supports America like no other industry. We spur economic growth through hundreds of billions of dollars in investments each year, creating jobs across a wide range of sectors and generating millions of dollars in government revenue.

- Between 2008 and 2010, America's oil and natural gas industry spent $156 billion each year investing in America's infrastructure. In addition, the top 50 exploration and production companies spent another $100 billion on acquiring access to various U.S. properties for future development. The oil and natural gas industry accounts for almost 14 percent of all industries U.S. capital expenditures during that period, more than the utilities and transportation industries combined.

- America's oil and natural gas industry supports 9.2 million jobs in the United States and 7.7 percent of our nation's Gross Domestic Product.

- The oil and natural gas industry directly created 119,500 jobs between 2006 and 2011, while other sectors of the economy lost over 4.5 million jobs.

- In 2011, the industry added up to $545 billion through capital investment, wages and dividends to the U.S. economy – nearly $1.5 billion every day.

- We pay our fair share – and then some. From 2006 to 2011, the oil and natural gas industry paid an effective tax rate of 44.3 percent, higher than any other industry.

- We deliver on average around $86 million per day to federal treasury in rents, royalties, bonus payments and income tax payments.

- Our industry had an average non-gas station salary of almost $93,000 in 2011. That's 93 percent higher than the average private sector salary of almost $48,000 in the U.S.

What's even better? With the right policies, we can do even more. If we adopt a full program of domestic oil and natural gas development – without punitive tax increases – we could create one million new jobs in seven years and increase government revenue by $127 billion by 2020. Smart policies, not tax increases, are the way to create jobs and get much needed revenue for the government.

Repealing the Section 199 Manufacturing Deduction for
Oil and Gas Companies Puts Jobs at Risk

In 2004, Congress enacted the Section 199 deduction which makes deductible a portion of income derived from domestic production, manufacturing and extractive activities to encourage job expansion and creation in the US.

For most U.S. manufacturers, the current deduction is 9% of their net income derived from qualified domestic production activities – this is approximately equal to a three-percentage point reduction (35% to 32%) in the corporate income tax rate for qualified domestic income. However, *recent legislation has already penalized the US oil and gas industry by freezing them at 6%.*

Now, proposals to eliminate Sec. 199 altogether for only the oil and gas industry will have the harmful effect of hurting American energy workers and their contributions to our economic recovery. Congress should support the Section 199 deduction for oil and gas operations because:

- Repeal of the deduction would threaten some of the 9.2 million jobs supported by the US oil and gas industry. The average salary of an extraction and production job (including petroleum geologists, refinery workers, rig builders, accountants, chemical engineers, environmental technicians and many other categories of workers) directly supported by the oil and gas industry is $52,000 *higher* than the average salary in the US.

- The purpose of Sec. 199 was to encourage domestic job creation among US manufacturers and producers. From 2004-2007, the oil and natural gas industry was responsible for nearly 2 million additional domestic jobs.

- According to a Wood Mackenzie study, the repeal of Sec 199 and other proposed tax changes could place as much as 600,000 boe/d at risk in 2011 and by 2017, more than 10% of US oil and gas productive capacity could be compromised. This volume accounts for approximately $10-17 billion in direct upstream investment per year. These proposed tax changes for only the US oil and gas industry could also place thousands of jobs at risk:
    - 58,800 direct, indirect and induced US jobs are at risk in the year implemented
    - 165,000 total direct, indirect and induced US jobs at risk by 2020
    - The Rocky Mountain, on-shore Gulf Coast, and mid-Continent regions of the US have the highest potential jobs at risk

- Further, since the inception of Sec. 199, additional jobs have led to increased US production which strengthens our energy security. Despite declining reserves and access restrictions, according to DOE:
    - Oil production has increased 5.6% between 2005 and May 2010
    - Federal offshore Gulf of Mexico production increased 22%
    - North Dakota production, including the Bakken oil reserve region, has increased 122%, and
    - Domestic natural gas production has increased 16%

- Eliminating the deduction would force the industry to pay more in taxes, creating special challenges for financing high-cost domestic projects. Paying billions more in income taxes would make it harder to find the capital to build costly projects such as a major refinery expansion, and would be harmful to our domestic energy security and continued job creation.

For more information, visit **API.org**

Why Eliminating the IDC Deduction is Bad Tax Policy

The United States has historically allowed immediate deductions for costs associated with the development of technology and resources. These deductions have played a crucial role in advances in technology and spurring transformations in the US economy and America's energy sector. The research and development and the intangible drilling and development cost deductions have identical policy goals: to promote innovation, foster development of new products and resources, and promote economic growth. Proposals to eliminate the IDC deduction would not only jeopardize the advances that are responsible for some of the US's biggest and latest oil and natural gas plays, such as shale oil and natural gas, but also endanger many of the 9.2 million American jobs supported by the industry.

Research & Development Costs	Intangible Drilling Costs
• These costs typically consist of items such as the salary and benefit costs of researchers and their assistants. Examples include the salary of a scientist developing new or improved drugs, or the costs associated with the development of computer software.	• These costs typically consist of the salaries for drillers, as well as fuel and hauling costs. Examples include the wages of workers developing new or improved drilling techniques to get at hard to reach gas or the fuel needed to transport a drilling rig to drill wells in new, unproven locations.
• R&D costs are typically fully deductible in the year they are incurred. Furthermore, an R&D credit is also available.	• IDCs, like R&D, can be fully deducted in the year they are incurred for most taxpayers. Integrated oil companies, though, are limited to only deducting 70 percent of the total costs, with the remainder amortized over 5 years.
• The alternative to immediate expensing of R&D costs would be to capitalize the costs into the particular asset, e.g. a patent or software program, then recover those costs incrementally over the life of the patent or program or 15 years.	• The alternative to immediate expensing of IDCs would be to capitalize the costs into the basis of the property, and recover them incrementally over a long period up to the life of the well.

The bottom line is that both the R&D deduction and the Intangible Drilling & Development cost deduction serve identical policy goals: innovation, development, and growth. Eliminating the IDC deduction would discourage innovation in the energy sector, jeopardizing additional valuable advances in oil and gas exploration, high paying jobs, and America's energy security.

For more information, visit **API.org**

Eliminating the Ability to Expense Intangible Drilling and Development Costs Will Hurt Our Energy Security

Despite great advances in technology, drilling a well is the only means of determining with absolute certainty the presence of hydrocarbons in reservoir rock or sand. When companies drill they incur intangible drilling costs, which are costs that cannot be recovered, such as site preparation, labor, engineering and design. These intangible costs associated with drilling a well usually represent 60 to 80 percent of the cost of the well.

Since 1913, companies have been able to expense these costs. Currently, independent producers can expense 100 percent of their IDC in the year those costs are incurred. Integrated oil companies may expense 70 percent of their IDC in the current year and amortize the remaining 30 percent of those costs over 5 years.

While other businesses are able to expense the costs of creating potential new products and services (such as R&D for the pharmaceutical industry), Congress is considering completely repealing the expensing of IDCs only for the US oil and gas industry. These rules only apply to costs incurred in the US and therefore only impact US oil and gas production – thus making the US less competitive with foreign operations.

- IDC are a necessary and significant cost of oil and gas exploration and production. These costs represent the industry's research and development costs that must be spent in the pursuit of finding new business opportunities.

- According to a Wood Mackenzie study, repealing the deduction would discourage domestic investment and likely result in less revenue to the government and greater dependence on foreign oil. This, along with other proposed tax changes, could result in:
    - A potential loss of 600,000 boe/d of domestic production
    - Estimated $15 billion in capital is at risk in 2011 alone and almost $130 billion over the next ten years
    - In the first year of tax changes, approximately 1% of oil and 5% of natural gas production is expected to be lost
    - An estimated loss of 10-20% of expected total upstream spending in the US each year

- Additionally, the repeal of IDC and other proposed tax changes for only the US oil and gas industry place thousands of jobs at risk:
    - 58,800 direct, indirect and induced US jobs are at risk in the year implemented
    - 165,000 total direct, indirect and induced US jobs at risk by 2020
    - The Rocky Mountains, on-shore Gulf Coast, and the middle of the US have the highest potential jobs at risk

- According to the Department of Energy, US production of oil and gas is already a tough business:
    - U.S. based oil and gas companies spend more than double to produce oil and gas domestically, compared to the cost of production overseas
    - Additionally, nearly half of the US offshore exploration wells drilled are classified as dry holes

- Current tax treatment for domestic exploration will help keep the cost of domestic projects competitive with foreign alternatives – a key component to America's energy security. Eliminating or further restricting the ability to expense IDCs would be punishing oil and gas producers as compared with other similarly situated industries.

For more information, visit **API.org**

Modifying Dual Capacity Taxpayer Rules
Leads to Double Taxation of US Companies

Foreign Tax Credit and the US tax System. Among developed nations, the United States is one of the only countries still using a worldwide tax system. This means, US-based companies are taxed on their income earned here in the US and income earned in other countries when that income is brought back to the US. However, their foreign income is also subject to taxation by the foreign country where it is earned – making it subject to two totally separate income tax regimes.

No country wants their global companies to face double taxation. Unlike a territorial/exemption regime which excludes the income outright, the US employs a foreign tax credit system, to prevent double taxation. This system recognizes that foreign income has already been subject to tax in the foreign country where income is earned such that the US tax on foreign income is reduced by legitimate income taxes also paid to the foreign government where the company operates. Without this basic mechanism, US-based companies simply could not pursue or develop foreign opportunities. Companies would otherwise face the prohibitive cost of double taxation on foreign operations, while their non-U.S. based competitors would only be taxed once.

Dual Capacity Taxpayers already face additional rules. Specific tax rules have been in place for decades that apply to dual capacity taxpayers, i.e. taxpayers who make payments to foreign governments in two capacities – once as a taxpayer and again as payment for some specific benefit the taxpayer receives from the government, such as rights to extract oil and gas. These rules require dual capacity taxpayers to prove – in a court of law if so ordered by the IRS – that only *legitimate income tax* is being claimed for foreign tax credit calculations, and royalties or other payments to the foreign government are not inappropriately characterized as income taxes.

The industry supports the policy that royalties are never eligible for a foreign tax credit. However, our industry is often subject to income taxes that are higher than the country's general corporate rate. The IRS can and does challenge the nature of those payments as legitimate income taxes. Taxpayers expect to be able to prove to a court that such payments are indeed income taxes and not some royalty. It is this proven approach that protects the U.S. Treasury from inappropriate foreign tax credit claims and allows US based companies to operate competitively in foreign markets.

Dual Capacity Proposals deny taxpayer's right to be heard in court. Proposals to change the dual capacity rules will take away the taxpayer's right to have their case heard in a court of law. Thus, even in cases where a taxpayer can prove (or has proven in past audits) that their payments were legitimate income taxes, the proposals will deem all or a portion of them to be royalties and automatically disallow a foreign tax credit. The impact can be significant, for example:

> Qatar has two income tax rates: a general rate of 10% and a petroleum rate of 35%. Proposals to modify the dual capacity rules will reclassify a portion of the petroleum tax rate as a royalty. Therefore only US based companies will pay the Qatar petroleum tax PLUS an additional 23% U.S. income tax, for an all-in rate of 58%. Non-U.S. based oil and gas competitors will pay only the 35% Qatar tax.

The current rules work. There has been no real showing of any abuse or issue with the dual capacity rules for the 30 years they have been in place. Changing these rules guarantees double taxation for the industry and undermines the ability for US based companies to compete and operate abroad.

For more information, visit **api.org/tax**

Repealing LIFO accounting will hurt U.S. businesses, stifling job creation and energy production

Background

The tax law requires taxpayers with inventory to value their ending balances in order to determine which costs are included in the cost of goods sold over the course of the year. One of the main methods for valuing ending inventory is the LIFO (last in/first out) accounting method. LIFO accounting is based on the assumption that the last goods brought into inventory are the first goods sold. Therefore the cost of the last goods manufactured or purchased are associated with the goods sold to generate current revenue. This allows for a clear reflection of income as current costs are matched with current income – especially for taxpayers dependent upon commodities as part of their business operations.

LIFO is a well-accepted accounting method used by many American industries and has been approved by the IRS as an appropriate way to value ending inventories since the 1930s. It is not some "gimmick" or "loophole" to inappropriately lower one's taxable income. A taxpayer employing LIFO to value ending inventories for tax purposes must also follow this method to calculate their book income. As a result, there is limited impetus for taxpayers to try and exploit or arbitrage the system - efforts to lower tax income are tied to book income results for shareholders and bondholders.

Impact of Repeal

Repealing LIFO would result in a significant impact on any taxpayer currently employing that method to value their ending inventories. The impact stems from the fact that it deems a reduction in previously reported cost of sales to have occurred and gains to be recognized without any real profit being generated. Therefore, repeal of LIFO accounting would result in a significant up-front tax burden for businesses associated with a *deemed* retroactive reduction of cost of sales. No actual transaction would take place to generate operational cash. As a result, this proposal would place significant cash constraints on taxpayers employing the LIFO methodology. And the expected cash drain would certainly be felt. Taxpayers would need to generate funds to pay the expected tax that would have to come from existing capital reserves that would have otherwise been invested in jobs, new investment or business expansion.

Like taxpayers in other industries, many oil and gas companies with refining operations properly elected to use LIFO many years ago to value and account for their inventory. Since the industry continued to grow and needed to purchase a volatile commodity as a raw material, the LIFO was the best method to allow current costs to offset income for the current year. Congress and the Administration have suggested that LIFO constitutes some type of tax abuse, but no specific tax abuse problem or other policy reason for changing the LIFO rules has been credibly advanced. Again, LIFO is not a gimmick. It is simply an accounting method that clearly reflects taxable income for companies that anticipate inflation or rising prices.

API Tax Reform Principles

Introduction

The goal of any well-structured tax system should be to raise revenue in a way that does the least amount of economic harm, while encouraging domestic investment and job creation, and allowing taxpayers to compete internationally for new opportunities. To achieve these goals, tax rules should be non-discriminatory among industries and should provide a level playing field for taxpayers engaged in similar activities.

Recently, concerns have grown about the current U.S. tax system, (i.e., that the rules limit U.S. competitiveness in an increasingly global economy), leading to calls for tax reform. Any tax reform should be based on sound, transparent policies, and tax rates should be lowered to support a tax structure that promotes investment and is competitive with other major trading partners.

We recognize that tax reform will be a substantial undertaking and will significantly impact how businesses look at the economics of their investments. We also highlight that any new tax rules addressing America's oil and natural gas industry could directly impact the amount of energy that is produced and supplied to the economy. Therefore, in order to help frame the debate on how to approach tax reform with respect to energy, we raise the following considerations.

Domestic Pro-growth/Pro-job Considerations

The U.S. oil and natural gas industry currently supports 9.2 million jobs in the economy, over 2 million of which are supported by the refining and petrochemical segments. The industry as a whole accounts for 7.8 percent of the nation's Gross Domestic Product (GDP). One of the main reasons for this significant impact is the size and scope of the domestic capital investments which are necessary to produce and refine the energy demanded by U.S. consumers. For example, according to the U.S. Census Bureau, oil and natural gas extraction, refining and supporting activities accounted for over 13 percent of all new structure and equipment investment in 2010 – over $100 billion[1]. In addition, the top 50 exploration and production companies spent another $100 billion on acquiring access to various U.S. properties for future development.[2]

Since oil and natural gas reserves are depleting resources, these substantial investments must be made on a recurring and continuous basis for the industry to maintain and continue to grow production and refining in the U.S., and to meet the economy's energy demands. Because investment needs to occur on a continuous basis, a stable and predictable stream of cash flow is critical to the economics supporting domestic projects. Given the risks inherent in the oil and gas business, and the level of the expenditures required, these costs must be recovered quickly in order for the industry to continue to reinvest in the next project or to hire new employees. The industry's oil and natural gas exploration and drilling investment analysis is very similar to the investments made by companies with a heavy concentration of research and development, where the technologies of tomorrow must be funded by the successes of today.

Therefore, any new pro-growth, pro-jobs tax regime must incorporate competitive and robust capital cost recovery provisions that take both risk and economic development goals into account. While a lower statutory rate will likely impact the after tax cash flow of all investments, we have found that in our industry there is not an exact "trade-off" between a lower corporate tax rate and the lengthening of cost recovery periods. We would

[1] 2010 Annual Capital Expenditures Survey, Table 4a, U.S. Census Bureau (released February 8, 2012). http://www.census.gov/econ/aces/xls/2010/full_report.html
[2] US oil and gas E&P benchmark study, 2010. http://www.ey.com/US/en/Industries/Oil---Gas/US-oil-and-gas-E-P-benchmark-study

note that, economy wide, a reduced tax rate can benefit existing investments (such as production from a factory already in place), but that lower rate may not provide for the continued after tax cash flow necessary to drive new investments and projected reinvestments. This is especially true if the capital cost recovery rules are significantly changed in the tax reform process.

Given the size of the oil and natural gas industry, we understand it will be impacted by any tax reform effort. But we believe it is imperative that any new tax system not specifically target any one industry over another for additional tax benefits, burdens, or costs. Using the tax code to pick winners and losers should be avoided. Specifically, within the energy sector we believe that any new tax system should not favor one form of energy at the expense of others or one type of taxpayer at the expense of others, particularly those engaged in the same activities.[3] In a growing economy, all forms of energy production should be encouraged, but efforts to favor one form of energy over others should be avoided.

International Tax Reform – Territorial

We recognize that the taxation of foreign operations by a home country is a very complex area to address in tax reform. However, the industry's main focus in reforming international tax provisions is fairly simple: rules ensuring that foreign source operating income of U.S. based companies is not subject to double taxation are essential for supporting the competitiveness of U.S. companies internationally.

As an extractive industry, we must operate where the resource is located rather than where the tax rate is the lowest. In fact, the industry pays substantial income taxes on its foreign operations, which often causes the industry's effective tax rate to be over 40 percent. The industry is currently able to repatriate a substantial amount of international cash back to the U.S. economy[4] under the foreign tax credit mechanism, which allows U.S. taxes on foreign sourced income to be offset by foreign taxes paid on those operations. This tax system generally alleviates the double taxation concerns.

Therefore, in general, the industry can support a territorial system provided it is competitive with the tax laws of the other major developed countries and allows U.S. based oil and natural gas companies to compete internationally with non U.S. oil and natural gas companies. For example, any move to a territorial system must insure that all active operating and related income would qualify for exemption, and that all industry specific tax restrictions are eliminated. Of course, until such time as a new system is implemented, a fully functioning and competitive foreign tax credit system must remain in place.

Additional Comments & Considerations

The industry recognizes the value of a lower corporate tax rate and supports movement in that direction. However, further base broadening measures used to support a lower tax rate could significantly impact the cash flow for domestic projects. As such, we are concerned that such measures could result in less domestic energy investment and ultimately undermine the goal of pro-growth tax reform. We would encourage the development of proposals that can achieve both of these objectives—lower rates and robust pro-growth capital cost recovery mechanisms.

[3] The U.S. oil and natural gas industry is the only industry in which the tax rules apply differently to significant members of that industry based on size (or involvement in additional business lines such as retail marketing of gasoline or refining). Pro-growth tax reform and an efficient tax system require that tax provisions be nondiscriminatory and evenly applied among taxpayers within an industry.

[4] Over $70 billion was repatriated by the industry in 2009 according to IRS data.

API Tax Reform Principles (cont.)

Any new tax regime will be difficult for businesses to immediately adopt. Therefore, we support the development and implementation of fair and equitable transition rules. Establishing transition rules that provide adequate time for implementation and that take into account prior reliance on the current tax code as manifested in existing agreements, practices, and other requirements is essential for the success of any new tax system.

Finally, we recognize the difficulty in tackling truly comprehensive tax reform. Subject to addressing the above tax reform principles and considerations, phased corporate or individual tax reform could be a way to facilitate the process for broad tax reform. However, in all cases, targeted, isolated, or piecemeal changes should be avoided.

General Comments on Ways & Means Territorial Discussion Draft

The industry supports movement toward a territorial system that meets the guiding principle of establishing an international taxation regime that is competitive with those of the other major developed countries and thus allows U.S. based oil and natural gas companies to compete internationally with non-U.S. based companies. A participation exemption of no less than 95% would be acceptable (assuming no allocation of indirect expenses such as interest and headquarters costs.) Specific issues we wish to comment are:

1. Exempt Income Principle: Should cover all "active" income. Only passive income in the nature of portfolio type income should be taxable as a general proposition.
    a. All operating and related income other than income that is "passive" under section 904 "basketing" should qualify for exemption as a threshold matter. Look-through and same country rules should be retained.
    b. Foreign base company sales, services and oil related income should be exempt.
    c. Active finance income that is not "passive basket" should also qualify for exemption.

2. Income "Basketing" Principle: Consistent with the exempt income principle, foreign income basketing in future should at most be "active" and "passive."
    a. No other separate 904 baskets need be maintained, and further no "sub-basketing" as under section 907 is required or appropriate.
    b. Any U.S. tax on income that is active but for some other reason is "taxable" (either under a base erosion rule, or branch income (see below), or foreign income earned directly by a U.S. corporation without a foreign branch (e.g., without a foreign permanent establishment)) should be reduced by foreign tax credits on non-exempt income.
    c. Transition rule for FTC carryforwards from pre-effective date years should permit utilization against future non-exempt active foreign income, as all such carryforwards by definition resulted from U.S. taxation of active income.

3. Branches: As a principle, branches should not be "deemed" to be separate corporations "for all purposes of the code." Instead, several options exist for less complex, balanced treatment.
    a. Option 1: Treat branch income as not qualifying for exemption like Germany, Japan, and the initial approach taken by the U.K. to its international tax reform. Branch income would be taxable in the US immediately, but under a worldwide FTC system.
    b. Option 2: Adopt a one-time election to treat branches as not qualifying for exemption (like the current U.K. approach). For taxpayers not making the election, branch income would be treated as exempt to the extent of dividend income (e.g., foreign branch taxable income less foreign income taxes paid would be 95% exempt if that is the participation exemption percentage on dividends, with the remaining 5% being taxable immediately, i.e., not qualifying for deferral).
    c. Option 3. Consider "grandfather" treatment of branches existing at the time of enactment for either Option 1 or 2 treatment, with non-grandfathered branch income treated as exempt to the extent of dividend income (same as taxpayers who do not make the one time election in Option 2 above).
    d. Option 4. Treat branch income as exempt to the extent of taxable income (i.e., same as taxpayers who do not make the one time election under Option 2 above).
4. Anti Base Erosion Options
    a. Options A and C relate mostly to intangible income issues not necessarily as applicable to oil and gas as to certain other industries.
    b. Option B is problematic—at a minimum, it should not apply where country of incorporation is different from country of operation, since many non-tax factors are involved in this business

structure. Also, the “exception” should not be limited to manufacturing in a country for domestic use—export centers need to be recognized.

5. Thin-Capitalization rules
    a. The relative leverage test creates unworkable compliance and administrative burdens.
    b. If a thin cap rule is necessary, suggest conformity with 163(j) rules currently in Code.

Section 907 Special Foreign Tax Credit Rules for Oil and Gas Income

Present Law

In addition to the foreign tax credit limitations found in section 904 that apply to all foreign tax credits, a special limitation is placed on foreign income taxes paid on foreign oil and gas income. Under this special limitation, amounts claimed as taxes paid on (combined) foreign oil and gas income (CFOGI) are creditable in a given taxable year only to the extent they do not exceed the product of the highest marginal U.S. tax rate on corporations multiplied by such combined foreign oil and gas income for such taxable year. Excess foreign taxes may be carried back to the immediately preceding taxable year and carried forward 10 taxable years and credited to the extent that the taxpayer otherwise has excess limitation with regard to combined foreign oil and gas income in a carryover year.

Discussion Draft Proposal

The Discussion Draft does not address section 907.

Recommendation

Section 907 should be repealed and transition rules should be adopted consistent with Section 313(c)(2) of the Discussion Draft.

Discussion

The recommendation is consistent with the goal of simplifying the international tax area. The recommendation is also consistent with Section 313 of the Discussion Draft, which eliminates the separate category limitations contained in Section 904.

Furthermore, the underlying policy rationale for section 907 is no longer relevant in a territorial system of international taxation. The Joint Committee explains that section 907 was "designed to address the perceived problem of "disguised royalties" being improperly treated as creditable foreign taxes… In addition, the section 907 rules have also been described as intended to prevent the crediting of high foreign taxes on FOGEI and FORI against the residual U.S. tax on other types of lower-taxed foreign source income."[5] Under the Discussion Draft, high taxed oil related income should qualify for the dividend exemption, and therefore, no foreign tax credits could be claimed for the foreign taxes attributable to such income. Accordingly, the "disguised royalties" and "high foreign tax" issues no longer exist, and therefore, there is no reason to retain Section 907.

[5] Joint Committee on Taxation, General Explanation of Tax Legislation Enacted in the 110th Congress, p. 359.

Foreign Base Company Oil-Related Income

Present Law

The Technical Explanation of the Discussion Draft sets forth a summary of the Subpart F rules and lists the categories of foreign base company income, including foreign base company sales income, foreign base company services income and foreign base company oil-related income.
Foreign base company oil-related income (FBCORI): FBCORI generally includes all oil-related income (i.e. income from processing, transportation, distribution, and sales and services) derived from foreign sources other than income derived from a source within a foreign country in connection with either (1) oil or gas which was extracted from a well located in that foreign country, or (2) oil, gas, or a primary product of oil or gas which is sold by the foreign corporation or a related person for use or consumption within that foreign country, or is loaded in that country on a vessel or aircraft as fuel for that vessel or aircraft.
The FBCORI rules do not apply to a foreign corporation that, together with related persons, does not constitute a large oil producer (i.e. does not produce greater than 1,000 barrels of oil equivalent per day). Unlike foreign base company sales income, there is no manufacturing exception for FBCORI.

There was little, if any, justification for enactment of these rules back in 1982. These rules have nothing to do with U.S. base erosion or the shifting of mobile income because they are associated with large capital operations such as refineries and pipelines that by necessity must be located near the producing fields and markets that they serve.

Recommendation

The FBCORI category of foreign base company income found in sections 954(a)(5) and (g) should be repealed.

Discussion

The FBCORI rules do not belong in a competitive territorial system. The purpose of the Subpart F rules is to prevent U.S. base erosion by preventing highly mobile income from moving outside of the U.S. taxing jurisdiction. It is hard to image a less mobile form of income than revenue derived from operating a pipeline or a refinery. Yet, the FBCORI rules do not provide an exception for these activities such as the manufacturing exception that exists for other industries under the foreign base company sales income rules. There is no reason why these investments should be treated any differently than those in other industries. Concerns about mobile income in the oil industry are no different than those for other industries, and therefore, no special rules for the oil industry are required

Not only do these rules treat the oil industry differently than other industries, they also treat similarly situated taxpayers within the oil industry differently. Only large producers are subject to FBCORI while their competitors, who only engage in refining or pipeline operations, are not. Under what logic is the income of one refiner who happens to engage in production activity considered mobile while the exact same income of its competitor, who is not a large producer, not considered mobile?

The FBCORI rules should be repealed and the American oil industry treated the same as every other industry.

CFC and Branch Treatment

Background

The income tax rate incurred by the oil and gas industry on overseas earnings generally equals or exceeds the U.S. rate, and thus most US multinational oil and gas companies do not rely on deferral to the extent those in other industries do. Therefore, the industry is able to conduct foreign operations in both CFC and branch form on essentially equivalent economic bases from a U.S. income tax standpoint—i.e., there is generally no significant advantage to "deferral" that a CFC provides, and therefore no tax penalty for investing via a branch . But there are non-tax advantages that operating in branch form provides, most of them related to the host country in which operations are conducted. Many developing countries do not have established corporate legal principles that provide certainty around governance of the local corporate entity. It is typically easier in those cases to avoid the local entity and instead operate as a branch.

Furthermore, branches typically have less burdensome reporting and disclosure requirements than a local entity. In addition, it is sometimes easier to transfer funds into and out of a local branch rather through a local entity. Finally, there can sometimes be local tax benefits to using a branch. For example, some countries have a lower withholding tax on branch remittances than on dividends. At the end of the day, the decision on whether to use a branch or local entity depends on many factors but most of the critical ones will relate to local issues.

Proposal

The proposal treats any first tier "foreign branch" as a CFC for all purposes of the Code[6]. This results in the following consequences:

1. The assets and liabilities of a branch are deemed to be transferred to a foreign corporation, and the reorganization provisions of the code, including section 367, apply to the transfer.
2. The domestic corporation is deemed to be a U.S. shareholder of the deemed CFC.
3. Non-subpart F income generated in a foreign branch would be eligible for deferral.
4. "Payments treated as dividends" between the deemed CFC and the deemed U.S. shareholder are eligible for the new dividends-received deduction.
5. All rules applicable to intercompany transactions, including section 482, apply to transactions between the deemed U.S. shareholder and the deemed CFC.
6. Subpart F income of the foreign branch is immediately taxable and foreign tax credits may be claimed only for the foreign taxes incurred by the foreign branch that are attributable to subpart F income.

The proposal aims to create parity between foreign operations conducted in branch form and foreign operations conducted in a CFC. It is believed that treating all foreign branches as CFCs for all purposes of the Code would achieve this parity and would prevent abusive tax planning through "cherry-picking" of operations to be conducted in branch form versus corporate form. It should be noted that since branches do not qualify for the deferral benefit that CFC treatment affords, there is a logical basis for not otherwise trying to achieve "parity" with CFCs. Thus, some alternative approaches, like that of Senator Enzi—and like those of certain other countries—do not treat branches and CFCs precisely the same, and of course, our own tax laws have historically treated them differently.

[6] The technical explanation provides that "[i]t is intended that the rules and principles applicable in determining whether a foreign corporation is engaged in a U.S. trade or business govern whether foreign business operations constitute a foreign branch."

CFC and Branch Treatment (cont.)

In addition, if the goal of international tax reform is to move towards a competitive territorial system that solves the lock out effect and protects the US tax base, then it is not necessary to move branches to an exemption system to achieve those goals. Thus, while some may view parity as an admirable objective, it should not be an end goal of itself. However, to the extent parity between branches and CFCs is desirable, preferably on an elective basis, it is not necessary to treat branches, especially existing branches, as CFCs for all purposes of the Code in order to achieve such parity. Doing so imposes a harsh toll charge and substantial administrative complexities on branches. This actually introduces a "disparity" in treatment, particularly as it punishes existing foreign operations that happen to be conducted in branch form. The sections below outline the specific concerns with the proposal and propose options for a more equitable approach.

Concerns with the proposal

The technical explanation provides that "[i]t is intended that the rules and principles applicable in determining whether a foreign corporation is engaged in a U.S. trade or business govern whether foreign business operations constitute a foreign branch." The first issue that taxpayers will face is whether their foreign operations rise to the level of a foreign branch. Once that issue is resolved, the next question is what functions, assets and liabilities comprise the foreign branch? It can be challenging to identify the functions, assets and liabilities that belong in a foreign branch. Consider the case of a U.S. corporation with active headquarters and branch operations, some foreign and some domestic. Today's rules handle such a case by directly allocating certain costs, regardless of where incurred, to branch income when such costs are solely for the benefit of the branch. Other costs, such as G&A, R&D and interest are more difficult to identify with a specific operation, and therefore, are apportioned throughout the entire entity. By treating foreign branches as a CFC, branch functions and liabilities that benefit all operations of the taxpayer would need to be allocated in some way into the separate "deemed entities"—something not required under today's rules and arguably undermining the appropriate apportionment of these costs.

Once identified, the assets and liabilities of a foreign branch are deemed to be transferred to a foreign corporation. The deemed transfer of assets and liabilities of a foreign branch to a foreign corporation triggers some of the most complicated provisions of the Code, and could result in an immediate tax liability from any number of them. These tax liabilities can be divided into two categories: (1) immediate recognition of unrealized gains (357(c), 367(a)(3) & (d) and 987)), and (2) immediate recapture of prior branch losses (367(a)(3)(C), 904(f) and 1503(d)). Each of these provisions is briefly discussed in the attached appendix.

Aside from the potential tax liabilities, the deemed outbound of the foreign branch will result in burdensome reporting requirements on the initial transaction and on an ongoing basis. This includes reporting under the general non-recognition provisions of the code, as well as section 367 and the 6038B regulations. In addition, branch operations would now be subject to reporting under Form 5471, which was designed for actual CFCs.

Some branches may require the creation of new accounting systems in order to identify and calculate "payments treated as dividends." In addition, a branch would be required to separately calculate subpart F income in the same manner as though it were a CFC. Furthermore, providing an exemption to branch earnings puts more pressure on the pricing of intra-company transactions and triggers section 482 concerns where none existed before.

CFC and Branch Treatment (cont.)

Recommendations

We present five options, all of which provide an alternative to treating branch as CFCs for all purposes of the Code. Each alternative would avoid the complexities and other detrimental effects noted above that arise from the "deemed CFC" approach.

Option 1: Keep the current rules for all branches

The existing worldwide system of taxation works as intended for the oil and gas industry. The current foreign tax rules prevent double taxation of our foreign earnings and the foreign tax credit limitation, in conjunction with the section 861 allocation and apportionment rules, protect the U.S. tax base. Because the industry does not generally need to rely on deferral, it is not impacted by the lock out effect. Thus, from the industry's perspective there is no policy reason for moving towards a territorial system. We recognize, however, the lock out effect is a problem for many other taxpayers and that continued reliance on deferral is not providing the competitive type of system American companies need to compete in the global economy. Therefore, the industry understands the need to do away with over reliance on deferral and switch to a dividend received deduction for CFCs, even though such a system (under the current 95% exemption proposal) would result in guaranteed double taxation of 5% of our foreign earnings. But the pressure for reform that exists for CFCs does not exist for branches. If the major goals of international tax reform are to solve the lock out effect and move to a competitive territorial system, then there is no reason to change the treatment of branches. The lock out effect only presents itself when there is deferral, but branch income cannot be deferred. The branch rules go back almost one hundred years (and some of our branch operations go back almost as far). They fit within a framework of tax principles that are understood by taxpayers and auditors alike. While we have identified some of the concerns for changing the treatment of branches, there are likely additional as yet unidentified issues that will arise from such a fundamental change. We urge following a conservative principle in tax reform and only changing those provisions that need to be changed in order to achieve the overall objective, and respectfully suggest that the branch rules do not meet those criteria.

We do recognize that continuing the different treatment for branches and CFCs may lead to legitimate concerns about future tax planning and that it is appropriate to address those concerns. We point to the recent international tax reform proposal submitted by Senator Enzi. Senator Enzi's proposal maintains the current tax rules for branches, but then directs the Treasury to issue regulations that would prevent the "inappropriate" planning through the use of branches. We believe that this more limited approach for reforming the tax treatment of branches is the correct one and would avoid many unnecessary and unintended complications. We also point out that other countries, such as Germany and Japan (and the UK on an elective basis), treat branch income as not qualifying for exemption. Surely, these countries share the U.S.' concerns with base erosion, yet they have managed to make their systems work.

Option 2: A one-time election to treat branches as not qualifying for exemption

This follows the approach in the UK. This option would give taxpayers the choice to either change to a new exemption system or elect to stay with the current system (modified as necessary by Treasury regulations) for all of its branches.

Branches not electing to remain with the current system would be subject to an exemption system that does not take them all of the way to CFC status.[7] Treating a foreign branch as a CFC for all purposes of the Code is

[7] The industry also recommends expanding the scope of the exemption system to all non-passive foreign income, including section 863(b) type income.

unnecessary in order to extend the benefits of territorial system to foreign branch operations. The industry believes that the benefits of territoriality can be extended to foreign branches in the following manner:

1. Foreign branches would continue to calculate taxable income and loss as under current law.
2. A [95%] exemption would be applied to net foreign branch taxable income.
3. [95%] of net foreign branch loss would be disallowed.
4. Foreign tax credits would not be available for foreign taxes that are attributable to income eligible for exemption.
5. Each branch's subpart F income will be calculated as if it were a CFC. Such income would not be eligible for the exemption but the taxpayer would be entitled to claim foreign tax credits for taxes attributable to such income.
6. Appropriate rules would be needed to address intra-company (branch to branch) transactions and to ensure the proper allocation and apportionment of more general expenses.

This recommendation avoids unwarranted complexity and costs from a deemed outbound of an existing branch, and would achieve rough parity with a CFC, except no deferral would be afforded to any branch income. In contrast, the current proposal, which would force a foreign branch to immediately recognize certain unrealized gains and to recapture prior losses, is actually contrary to the overall policy goal of treating foreign branches and CFCs similarly. The proposal would not cause the immediate recognition of unrealized gains for CFCs when the switch to an exemption system becomes effective. Why then should foreign branches be required to recognize such gains? To keep parity between CFCs and foreign branches, the answer is that they should not have to. The recommended approach avoids the problem by simply avoiding the deemed outbound of the foreign branch. As a result, provisions such as 357(c), 367 and 987 would not be implicated, and therefore, no resulting tax liability. This solution satisfies the goals of both policy makers and taxpayers. The overriding policy goal of treating foreign branches the same as CFCs is accomplished while at the same time taxpayers avoid undue complexity and potentially severe and non-uniform transition costs.

To the extent it is desirable to maintain the potential for recapturing prior branch losses; the recommendation preserves the ability to do so without immediately triggering the recapture. For example, the exemption amount could be reduced in the appropriate case as a way to recapture prior losses. The industry recommends, however, that the recapture rules be reviewed and modified to ensure that only branch losses that created an actual U.S. tax benefit are subject to recapture.

Under the recommendation, active income earned in both foreign branches and CFCs would be eligible for a 95% exemption; either directly applied to taxable income, in the case of a branch, or in the form of a dividend received deduction, in the case of a CFC. The recommendation does not achieve perfect symmetry between branches and CFCs. Income earned in a foreign branch is not eligible for deferral, while 5% of losses incurred in a foreign branch can be deducted against other income. Taxpayers would likely weigh these factors in making their entity selection but given the modest amounts, i.e. only 5% of net income or loss; it seems unlikely that they would cause significant "cherry picking[8]." Avoiding the establishment of new rules and accounting systems to identify and calculate "payments treated as dividends" justifies this slight loss of perfect symmetry.

The recommendation does not entirely avoid imposing complexities on existing branches. To approach parity between CFCs and branches, a branch would be required to separately calculate subpart F income in the same

[8] Another small benefit for a branch would be to avoid the additional tax burden imposed on the distribution of previously taxed subpart F income from a CFC.

manner as though it were a CFC. In addition, rules would be needed to ensure headquarters-type costs (like G&A and R&D) and other fungible expenses (such as interest expense) are treated appropriately.

Option 3: Continue current rules only for existing branches

Another option is to do away with the election but continue current rules only for existing branches. One way to address the issue of inappropriate tax planning with branches under a new territorial system is to limit the current rules to only existing branches. Because these branches existed prior to the enactment of a territorial system it should be clear that they were not put in place to "game" the new system.

Option 4: A one-time election to treat existing branches as not qualifying for exemption

Same as Option 2 above but only for existing branches and for the same reasons as stated in Option3 above.

Option 5: Exemption applied to all branches

Under this approach, all branches would be forced into the exemption system described in Option 2. above.

Appendix

Section 357(c) – Unrealized gains from liabilities in excess of tax basis

While the deemed transfer should qualify under one or more of the nonrecognition provisions of the Code (i.e. section 351 or 361), that is not the end of the story. Depending on the mix of assets and liabilities that are deemed transferred, taxpayers would be required to recognize gain under section 357(c) if the liabilities transferred to the deemed CFC exceed the tax basis of the assets transferred.

Section 367(a)(3) & (d) Unrealized gains

Section 367(a)(1) turns off the nonrecognition provisions of sections 351 and 361 when property is transferred to a foreign corporation at a gain. Subject to certain modifications, Section 367(a)(3) turns those provisions back on when the transferred property is to be used in the active conduct of a foreign trade or business. Given that only foreign branches would be subject to the deemed transfer and given that the definition of a foreign branch will require the existence of a foreign trade or business, it is likely that the deemed transfer will meet the requirements of section 367(a)(3). As a result, the code's nonrecognition provisions will apply to the deemed transfers, but so will certain toll charges and recapture requirements imposed by section 367.

In general, these toll charges are designed to deny the benefits of deferral to any built in gain existing in certain types of property transferred to a CFC in a nonrecognition transaction. This is done by recognizing unrealized gain on such property on the date of transfer. The types of property subject to the immediate recognition of unrealized gain are listed in 367(a)(3)(B)(i) through (v) and include such items as inventory-type property and certain installment obligations, account receivables, foreign currency instruments and leased property. In addition, section 367(d) requires that gain be recognized on any intangible property, within the meaning of section 936(h)(3)(B), that is transferred to the CFC.

CFC and Branch Treatment (cont.)

Section 987 – Unrecognized Foreign Currency Exchange Gain/Loss

Another provision that could accelerate the recognition of unrealized gains is section 987. The foreign branch likely constitutes a qualified business unit (QBU) under section 987and if the functional currency of the branch is other than the U.S. dollar, then the translation of the QBU's taxable income or loss into U.S. dollars is govern by section 987. Section 987 also governs how foreign currency exchange gain or loss is calculated with respect to remittances between the QBU/branch and the home office. The deemed incorporation of the branch will likely be treated as a termination of the QBU. The termination of a QBU triggers recognition of all unrecognized foreign currency exchange gain or loss remaining in the QBU/branch.

Section 367(a)(3)(C) – Recapture of branch losses

In addition to the section 367 toll charges described above, section 367(a)(3)(C) requires the recapture of previously deducted branch losses. It is important to note that only branch losses that have reduced foreign source income are subject to this rule. Foreign losses that reduced U.S. source income are subject to the recapture provisions of the overall foreign loss rules of section 904(f), which trump the section 367 recapture rules.

Section 904(f) Overall Foreign Loss Recapture

In the case of a taxpayer that has an overall foreign loss that reduced U.S. tax on U.S. source income, up to 50% of the taxpayer's future foreign source income is subject to characterization as U.S. source income under 904(f)(1). Furthermore, a complete recapture of any remaining overall foreign loss is required when the taxpayer disposes of property that has been used in a foreign trade or business, even if such disposition otherwise qualifies for nonrecognition treatment.

Section 1503(d) Dual Consolidated Loss Recapture

The foreign branch likely constitutes a separate business unit (SBU) under section 1503(d)(3), and therefore, prior branch losses, if any, also would be subject to the dual consolidated loss rules. To the extent that the taxpayer has previously deducted branch losses against consolidated income, the deemed incorporation of the foreign branch would probably trigger the recapture of those loss. This is unlikely to cause a great deal of concern, however, because the recapture provisions of sections 367 and 904, discussed above, both trump section 1503(d). Accordingly, only losses not already recaptured under those provisions would have to be recaptured under 1503(d).

Prevention of Base Erosion: Option B

Discussion of Draft Proposal

Option B of the proposal will treat certain low-taxed income (as defined by Option B) earned by a controlled foreign corporation (CFC), even if active income, as Subpart F income and not subject to the participation exemption. In addition, the proposal notes that a foreign tax credit is allowed for foreign tax "imposed on income included under Subpart F." Includible income under Option B is income that is:

1. Neither derived in an active trade or business within the country of incorporation ("home country exception"); nor
2. Subject to an effective tax rate of at least 10%.

For these purposes, the home country exception is a three-prong test:

1. Income must be derived from the conduct of an active trade or business within the jurisdiction in which the CFC is incorporated;
2. The CFC must maintain an office or fixed place of business (e.g., permanent establishment in the treaty context); and
3. Activities must serve the local market of the home country, either through use of property in the home country or provision of services to people or for property located within the country.

Potential Impact of Proposal

The Technical Explanation of the participation exemption system proposed by the Ways and Means Committee explains that the exemption is intended to apply only to "income from the conduct of an active foreign business," and not to "passive or highly mobile income," which would continue to be subject to the Subpart F rules. This correctly articulates the principles that should be applied to balance the objectives of competitiveness and anti-base erosion. However, Option B does not adhere to these principles, because it potentially would include a broad category of "income from the conduct of an active foreign business" as Subpart F that is neither "passive" nor "highly mobile."

Option B targets cross-border operations that are subject to a low effective rate of foreign tax. The nature of the oil and gas industry requires that its operations span national borders and, as a result, certain active foreign business income could be treated as Subpart F under Option B. The foreign business activities of the industry that could be impacted result from operations with geographically mandated locations, as opposed to those that have shifted from the United States to foreign jurisdictions, because of low foreign tax rates.

Option B's potential impact on cross-border active business operations is inconsistent with improving the competitiveness of the US tax system. Global businesses, both U.S. and foreign-based, structure regional headquarters, service companies, and manufacturing operations (e.g., extraction and refining) to manage their companies effectively and economically, as opposed to investing in infrastructure in every market. Requiring a US company to satisfy a minimum tax test on its cross-border income will subject real, substantial and active foreign business activities of US companies to an additional tax burden that would not be imposed by the home countries of our major competitors.

An effective tax rate test is overly-broad, which can create arbitrary results in determining what is eligible for the exemption. Consider two taxpayers engaged in the same active foreign business each outside the country of incorporation of their respective CFCs. Taxpayer A has an effective tax rate of 9%, and Taxpayer B has an effective tax rate of 11%. Under Option B, Taxpayer B would not have Subpart F income, while Taxpayer A would not qualify for the exception.

For purposes of Option B, the effective tax rate of a CFC is determined under US tax principles, which implies that adjustments to earnings & profits (E&P) would be taken into account. Therefore, the effective tax rate could be impacted in a given year by the significant differences in cost recovery periods for CFCs under US rules compared to local country law or by items that are disregarded solely for US tax purposes. Industries requiring significant capital investments in infrastructure and debt-financing could be particularly sensitive to these adjustments. The result would be a US taxpayer with active foreign business income, even if subject to an effective foreign rate above 10% over the life of a project, being penalized because of a particular snapshot in time.

Under Internal Revenue Code § 954(g), foreign based company oil-related income (FBCORI) includes non-extractive, yet active, oil and gas business activities (e.g., transportation, refining, sales and services), which give rise to Subpart F income if not associated with extraction activities in the same country. This current category of active Subpart F income should be eliminated. However, if replaced by Option B, a broader category of active foreign business income could be treated as Subpart F than under the current foreign based company income rules. Similar to the current FBCORI rules, which differ from the current foreign based company sales and services income rules of §§ 954 (d) and (e), respectively, Subpart F income under Option B is not limited to transactions involving related parties. Unlike the FBCORI rules, Option B does not provide an exception for activities associated with same country extraction. Therefore, under Option B not only would certain FBCORI activities continue to be treated as Subpart F, but foreign oil and gas extraction income (FOGEI) could be included in certain instances. Examples of active foreign business income from oil and gas activities that could result in non-exempt Subpart F income under Option B are included below.

Examples of Active Income Potentially Covered by Option B

1. Extraction

    Fact Pattern: Company undertakes extraction activity in an African country. For non-tax business reasons (e.g., ability to more freely remit cash), Company determines that it will not use a local country entity and incorporates a CFC in an offshore jurisdiction to hold its local country investment. CFC sells the extracted product in Africa for export.

    Result: CFC would have active business income but may not meet any of the prongs of the home country exception and would have to rely on the effective tax rate test. Even if the income is subject to a high statutory rate of tax, price changes or differences in cost recovery periods between the US and the foreign jurisdiction, could result in an effective rate that falls below the 10% threshold in a given year. Natural resources must be developed in the country in which they are found and investment in these countries should not be viewed as an erosion of the US tax base. Taxing it as Subpart F income, as the proposal could, would expand the rules of the current system, achieve an improper result in terms of base erosion and make the US tax system even less competitive than those of other countries.

2. Refining

    Fact Pattern: CFC, incorporated in a country within a geographic market, owns a refinery. CFC sells refined product to multiple jurisdictions. Because of the cost and logistics associated with transportation of both the feedstock (crude) and the end products, it is often most efficient to refine in a country proximate to the market for product. Accordingly, foreign refineries supplying product to multiple jurisdictions is typical in Europe and Asia.

Result: CFC would have active business income and a fixed place of business in its country of incorporation. However, because use of much of the product will be outside of the home country, CFC could not meet the third prong of the home country exception with respect to income on that product and would have to rely on the effective tax rate test. If the foreign jurisdiction has favorable tax provisions (e.g., immediate write-off of capital investment), then the effective rate could fall below the 10% threshold for a number of years and such active income would be taxable. The geographic proximity of major investments in refining assets to the local and regional markets they supply should not be viewed as an erosion of the US tax base. Therefore, to tax it as Subpart F income would achieve an improper result and make the US tax system even less competitive than those of other countries.

3. Pipeline

Fact Pattern: CFC invests in a 50% interest in a transnational pipeline controlled by a National Oil Company (NOC). CFC is required to fund its share of construction costs and to loan the pipeline consortium an amount to cover NOC's costs. The cost recovery period for US E&P adjustments is longer than the local cost recovery period. The accelerated recovery period and debt cost in the consortium drive the effective tax rate below 10% for the CFC. When complete, CFC will earn income from use of the pipeline by third parties and will pay tax in the jurisdiction of incorporation, as well as in each country through which the pipeline runs.

Result: CFC would have active business income in its country of incorporation and would have a fixed place of business via the pipeline in every country in which it earns income. However, not all income would be earned in the country of incorporation. Accordingly, for income earned in other jurisdictions, CFC would have to rely on the effective tax rate test. Even though the income is subject to tax, differences in cost recovery periods between US and foreign country rules could result in an effective rate that consistently falls below the 10% threshold. Natural resources must be developed in the country in which they are found and production must be transported to market in the most economic manner (e.g., via a pipeline). This activity should not be viewed as an erosion of the US tax base. Therefore, taxing this active business income as Subpart F would achieve an improper result and make the US tax system even less competitive than those of other countries.

The examples describing "regional" refining and transportation (pipeline) income are not describing business activities that are unique to the oil and gas industry. Refining is similar to other manufacturing activities and transportation by pipeline of production (from extraction or manufacturing) is the manner in which products get to market. Like manufacturing, the extractive industry requires enormous capital investment and tangible assets. What is unique to the industry is how geography dictates where substantial foreign investment is required. Location of natural resources is what drives capital investment decisions.

Recommendation

Option B does not effectively differentiate between active foreign business income and passive or highly mobile income and leads to arbitrary results. As such, it does not appropriately address the base erosion issues, which is the stated intent of the proposal. Therefore, we recommend that Option B be eliminated. The home country and minimum foreign tax test that Option B places on cross-border operations ignores the realities of the global economy and how multinational companies operate within it. Capturing such a broad base of active foreign business income will make US companies less competitive.

Under the stated principles of the territorial proposal, all active foreign business income should be afforded the benefits of that regime. However, if there is a concern about highly mobile income qualifying for the exemption, even if active business income, then the exception should focus on the substance of the operations generating such income (e.g., are tangible assets involved in deriving the income). For example, an anti-base erosion rule could be drafted to exclude income earned by a CFC, if: (1) that CFC owns substantial tangible assets (without regard to whether those assets are owned in the country of incorporation); and (2) those assets are a material factor in the realization of such income (whether output is sold within or without the country of incorporation). Maintaining a home country exception and effective tax rate test as safe-harbors could be useful to provide clear guidance and minimize audit disputes, but it should not be used as an irrefutable presumption of Subpart F income.

Other Base Erosion Options

Options A and C address income earned from exploitation of intangibles. Option A addresses transferred intangibles generating excess returns. Option C defines a broader base of intangible income, because neither a transfer from a US person nor excess income is required in order to generate the newly defined Option C category of “foreign base company intangible income”.

Any base erosion proposal involving intangible income should not apply to income from commodity products, since it is unlikely that proprietary intangibles have contributed to the value of such commodities. This is true even if exploitation of technology was involved in the production or manufacture of those products. Thus, if Options A or C are progressed, safe-harbor provisions should be added that exclude commodity products and other manufactured goods where little or no commodity value is attributable to intangibles. These safe-harbor provisions would still allow Options A and C to effectively target the type of income that is of most concern (i.e., income generated primarily from the exploitation of highly-mobile technology).

Summary

Option B could expand the scope of active foreign business income that is treated as Subpart F as compared with the current rules, which is inconsistent with the principles of a territorial system. With respect to the oil & gas industry, the burden created by subjecting any active foreign business income to the Subpart F regime will result in incremental cost and create a significant competitive disadvantage in the international marketplace. US companies, particularly those in the oil & gas industry, face increased competition from NOCs, which are some of the largest oil & gas companies in the world. When US companies compete for access to resources or markets in foreign countries, their competitors look only to the local tax rate when assessing the total cost of investment. Accordingly, any incremental US tax puts US multinationals at a disadvantage with respect to their cost structures. Competitiveness is not achieved by limiting a US multinational’s ability to operate in foreign jurisdictions in a cost-effective manner, especially when substantial investment is required to conduct its business.

Thin Capitalization Comments

Overview

In the context of overall tax reform and the proposed territorial system, the House Ways & Means Committee Summary accompanying the Camp Proposal includes "[t]hin capitalization rules that prevent U.S. companies from borrowing heavily in the United States (generating tax deductions to reduce taxes on their U.S. income) to finance income from overseas operations (which is eligible for the 95% exemption)." While we understand the need to address potential base erosion due to "excess" leverage, we recommend that the Committee adopt existing rules that address the same consideration, rather than introducing a new set of administratively complex rules and calculations.

Camp Proposal

On October 26, 2011, the House Ways and Means Committee released a draft plan (the "Camp Proposal") to move the country to a territorial system of taxation and reduce the corporate tax rate to 25%. The Camp Proposal would limit the deductibility of net interest expense of a U.S. corporation that is a shareholder of a controlled foreign corporation (CFC) if both the CFC and U.S. Corporation are members of a worldwide affiliated group (50% common ownership) that fails each of two tests: (1) the U.S. group is overleveraged relative to the worldwide group; and (2) the U.S. company's net interest expense exceeds a certain (yet to be specified) percentage of adjusted taxable income.

The Technical Explanation to the Camp Proposal states that "net interest for these purposes is defined in section 163(j)(6)(B) as the excess of interest paid or accrued over the interest includible in gross income for the taxable year." The Technical Explanation also states that that the required "computation of adjusted taxable income…is taxable income increased by deductible losses, interest, depreciation and amortization, qualified production expenses and other items prescribed in section 163(j)(6)(A)." Finally, the Technical Explanation provides that "whether interest expenses exceed the prescribed percentage of adjusted taxable income is determined company by company, as is the actual disallowance of deduction."

Section 163(j)

Section 163(j) was enacted in 1989 to limit the US tax impact of certain "earnings stripping" transactions involving excessive interest payments to related parties. Section 163(j) provides both a safe harbor to determine if there is excessive debt, and a comparison of net interest expense as a percentage of adjusted taxable income to limit the amount of deductible interest expense. Under Section 163(j), if a taxpayer's debt to equity ratio is less than 1.5 to 1 (computed using tax asset basis rather than fair market value) it will meet the safe harbor rule and its interest expense will be fully deductible. Further, in making this calculation, section 163(j)(6)(C) provides that all members of the same group will be treated as one taxpayer; therefore, all section 163(j) required computations are made on a U.S. tax consolidated basis, i.e., the separately determined debt and assets of each US member are determined as of the end of the consolidated year and aggregated. This safe harbor ensures that only excessive debt is targeted; in addition, the safe harbor provides a failsafe for those companies in industries that are more highly leveraged but don't have significant depreciable or amortizable assets, and thus could suffer greater disallowances under the 50% "percentage of income" test.

When the taxpayer fails to meet the safe harbor, i.e., where the payor's debt-to-equity ratio exceeds 1.5 to 1, a deduction for "disqualified interest" is disallowed to the extent of the payor's "excess interest expense, defined as the amount in excess of 50% of adjusted taxable income (which is essentially a cash flow/EBITDA amount). Again, the calculation of adjusted taxable income is also done on a US tax consolidated group basis. This calculation is based on taxable income, and adds back certain deductible items (as noted above) to derive a functional cash flow amount to limit excessive interest expense.

Recommendation

Current rules that address "excessive" leverage are well developed, provide appropriate protections, and can easily be utilized in addressing the same issue under the proposed territorial system. This avoids the complexity and uncertainty that would inevitably occur from introducing a new set of thin cap rules, something which has occurred when other countries (such as Germany) addressed these issues. In addition, complicated rules are counter to the simplification goals of tax reform and could actually have a negative impact on U.S. competitiveness. Specifically, a worldwide safe harbor is technically complex, and is likely to provide limited relief given administrative burdens in implementation and audit.

Similarly, applying the rules on a separate company rather than a tax consolidation basis adds enormous complexity and arguably does not provide the correct result to the extent it would differ from a tax consolidation approach. On the other hand, Section 163(j) limits the deduction for interest paid or accrued to foreign payees who are not subject to full U.S. tax on the interest received. If the debtor's debt-to-equity ratio exceeds 1.5 to 1, net interest is deductible only to the extent of 50% of adjusted taxable income (which is essentially a cash flow/EBITDA amount). These are relatively straight forward tests that avoid the administrative complexities noted above.

In summary, given that Section 163(j) provides an existing mechanism to address base erosion with respect to interest payments to foreign related parties – and that the Camp proposal already uses certain parts of section 163(j) to address base erosion – we recommend that existing section 163(j) simply be applied in full in the Camp Proposal, rather than introducing new concepts, e.g., a worldwide safe harbor or separate company calculations.

Summary Hand-Out of Intangible Drilling Cost (IDC) Deduction

- Intangible drilling costs (otherwise known as "IDC") include charges for the wages, fuel, repairs, hauling and other non-salvageable expenses incident to and necessary for the drilling of wells or the preparation of wells for the production of oil or gas.
- These costs usually represent at least 60 to 80 percent of the cost of the well during the initial exploration and development process.
- The election to recover drilling costs quickly allows them to be treated like all other business' operating costs. Drilling wells to meet production demands is necessary for oil and natural gas companies to maintain output volumes on inherently depleting reserves.
- This treatment does not constitute a "subsidy," nor is it a special credit towards the industry, since it does not reduce actual tax liability over the life of any project.
- Further, the current treatment of IDC costs promotes sound domestic energy policy and is necessary to maintain and ensure America's energy security.
- The timing of these deductions has played a crucial role in advances in technology, spurred transformations in the US economy in general and America's energy sector in particular, and is not unique to the energy sector within the tax code.
- The research and experimental cost deduction (Sec 174) and the intangible drilling and development cost deductions (Sec 263(c)) have identical policy goals: to promote innovation, foster development of new products and resources, and promote economic growth.
- All businesses deduct their costs of earning income—IDC cost recovery facilitates reinvestment in the next breakthrough technology or additional employees.
- Investment intensive businesses operate under a regime where cash flow is very important and overly simplified tax assumptions do not account for the complicated connection between business decisions and the tax law.
- Rates of return are directly influenced by the timing of cash outflows and inflows related to the project.
- Significantly delaying the timing of the tax deductibility of drilling costs reduces the discounted cash flow and rate of return values such projects will generate, and thus many projects will no longer meet investment rate criteria.
- Therefore, a lower corporate income tax rate does not offset the negative impact on cash flow should the IDC deduction be eliminated/extended.

Executive Summary - Existing rules are correct tax and energy policy for America

After decades of accepting the energy dependency of the United States, we have come to an amazing position of seeing the U.S move toward energy ***in***dependence in the coming years. This is largely due to enhanced technology that helps energy companies identify meaningful reservoirs, locate and drill wells on the most efficient sites, and develop (and produce from) the wells in a way that is both environmentally responsible and recovers as much of the reservoir as possible. This enhanced technology has been developed through the continuous testing of drilling activities and companies incurring substantial amounts of drilling costs.

Reaching America's goal of energy independence is not guaranteed. It will require continued investment and innovation. With the right policies, the industry will continue to drill the wells and develop the technology needed to keep us on the right path. With the wrong policies, the march to energy independence could be stopped dead in its tracks. This paper discusses tax policy. Specifically, this paper explains why permitting a tax deduction for the operating expenses associated with drilling a well is consistent with standard tax policy, and why deviating from this standard treatment puts at risk the future investment and innovation required for keeping the goal of energy independence within reach.

An onshore well's total cost can be several million dollars—substantially more (e.g., in the hundreds of millions) for offshore wells. Given that companies drill hundreds of wells a year, the amount spent on drilling costs to find new energy sources adds up to billions of dollars. Clearly, the energy industry is a capital intensive business and an increase in the costs of, and reduction of cash available for, drilling can be devastating. This can be seen historically when natural gas and oil prices were so low that energy companies investment returns and available cash were inadequate to fully implement their drilling programs. It also can be seen today, as very low natural gas prices are beginning to impact the pace of drilling in the U.S.

Intangible drilling costs (otherwise known as "IDC") include charges for the wages, fuel, repairs, hauling and other non-salvageable expenses incident to and necessary for the drilling of wells or the preparation of wells for the production of oil or gas. These costs usually represent 60 to 80 percent of the cost of the well during the initial exploration and development process.

The correct tax treatment for such costs turns precisely on the fact that, as the government has recognized from the beginning of the income tax code, such costs do not "…necessarily enter into and form a part of the capital invested…", because they do not themselves provide any "salvage value" to the taxpayer with respect to the property. Hence, IDCs are properly treated as all other operating costs are treated, deductible business operating expenses in the year of the expenditure. Far from being "special" tax treatment, current expensing is the correct treatment of IDCs under normalized tax policy.

This tax treatment is also consistent with sound domestic energy policy. Further restrictions on expensing intangible drilling costs would make domestic exploration more expensive, discouraging new domestic oil and natural gas exploration and undermining America's energy security. New investment in domestic energy is critical to meeting future energy demand, boosting U.S. energy security, protecting jobs and creating new ones.

What follows is a history of IDC which supports why the current tax rules provide the correct technical treatment for such costs and why this provision is vitally important to the day-to-day operations of all oil and natural gas extraction.

History of IDC - The Beginnings—Administrative conclusions that IDCs are operating costs

The lore is that IDCs have been allowed since the time of the Tax Act of 1913 based upon the language of the Tax Act of 1913, which provides:

> *That in computing net income for the purpose of the normal tax there shall be allowed as deductions: First, the necessary expenses actually paid in carrying on any business, not including personal, living, or family expenses; . . . .*[9]

However, the first indications of any administrative allowance of the deduction appear to be contained in Regulations 33, "Law and Regulations Relative to the Tax on Income of Individuals, Corporations, Joint Stock Companies, Associations and Insurance Companies Imposed by Section 2, Act of October 3, 1913," issued by the IRS on January 5, 1914. Regulations 33, Article 114 provides under the rubric "General Expenses," which are included in deductible ordinary and necessary expenses, "Expenses of operation and maintenance shall include all expenditures for material, labor, fuel, and other items entering the cost of the cost of goods sold or inventoried at the end of the year, and all other expenses incurred in the operation of the business except such as are required by the act to be segregated in the return."

Questions arose with respect to the proper tax treatment of a number of costs associated with the drilling of oil and gas wells and the production therefrom, and in a February 8, 1917, pronouncement, the Internal Revenue Service and the Treasury Department clarified the proper tax treatment of a number of such costs, including depletion, depreciation, and certain expenses of drilling wells, under the Revenue Act of September 8, 1916. In respect of the latter, the government stated the following:

> *The incidental expenses of drilling wells, that is, such expenses as are paid for wages, fuel, repairs, etc., which do not necessarily enter into and form a part of the capital invested or property account, may, at the option of the individual or corporation owning and operating the property, be charged to property account subject to depreciation or be deducted from gross income as an operating expense…*

Regulations 33 were revised in 1918 to cover the enactment of the Revenue Act of 1916 and the Act of October 3, 1917. Sections 5 and 12 of the Revenue Act of September 8, 1916, amended by the 1917 Act, first authorized a depletion allowance to individuals and corporations operating oil or gas properties. Sections 502 and 503 of the revised Regulations 33 provided an option to either deduct currently or capitalize and recover through depletion the expense of drilling wells:

> *In the case of a lessee, the capital thus to be returned is the amount paid in cash or its equivalent, as a bonus or otherwise by the lessee for the lease, plus also all expenses incurred in developing the property (exclusive of physical property) prior to the receipt of income therefrom sufficient to meet all deductible*

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[9] Tax Act of 1913, Section II (B)

> *expenses, after which time as to both owner and lessee, such incidental expenses as are paid for wages, fuel, repairs, hauling, etc., in connection with the drilling of wells and further development of the property, may, at the option of the operator, be deducted as an operating expense or charged to capital account[10].*

Courts also recognized the option to expense these costs under these regulations. In the early tax case, *Shaffer v. Commissioner*[11], the taxpayer had capitalized drilling costs for the tax years 1913-1915, but elected to expense similar costs for the period 1916-1918. The taxpayer sold the mineral properties in 1919 and sought to increase the basis in the properties by the amount expensed in the later years. In denying the taxpayer's claim, the court held that the regulations had given the taxpayer the option to expense which was validly claimed and that the taxpayer was bound by that election.

Regulations issued in 1919 combined the oil and natural gas expense recovery provisions into a more succinct election:

> *Such incidental expenses as are paid for wages, fuel, repairs, hauling, etc., in connection with the exploration of the property, drilling of wells, building of pipe lines, and development of the property may at the option of the taxpayer be deducted as an operating expense or charged to the capital account returnable through depletion.*

This language was retained in the regulations until in 1933, when the expression "intangible drilling and development costs" was first used in reference to the allowance of the deduction for expenditures 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 or gas. . . ." Furthermore, the regulations gave more detailed examples of the costs the Treasury Department contemplated as being deductible under the regulations and described them as not having a salvage value[12].

Regulations adopted under the 1939 Code in 1943 limited the election for taxable years beginning after December 31, 1942, such that the option to deduct intangible drilling costs was limited to those incurred by the operator, that is, one who holds a working or operating interest in any tract or parcel of land either as a fee owner or under a lease or any other form of contract granting working or operating rights. The concept of costs incurred by an operator, or the "lessee", of an oil and natural gas property, is significant. In most cases, the operator has only a leasehold right to produce the minerals, and all ownership rights in the property revert to the fee owner when production ceases. In addition, the operator generally has the obligation to remove certain production equipment, and to plug and secure any wells drilled. Thus, the total costs of "drilling" a hole, including the restoration obligations, taken on by an operator are distinguishable from the costs of permanently

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[10] Section 502 of the revised Regulations 33, 1918

[11] 29 BTA 1315 (1934).

[12] Regulations 77, Art. 236 Charges to capital and to expense in the case of oil and gas wells. – (a)(1): … *Examples of items to which this option applies are, all amounts paid for labor, fuel, repairs, hauling, and supplies, or any of them, which are used (A) in the drilling, shooting, and cleaning of wells; (B) in such clearing of ground, draining, roadmaking, surveying, and geological work as are necessary in preparation for the drilling of wells; and (C) in the construction of such derricks, tanks, pipe lines, and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil or gas. In general, this option applies only to expenditures for those drilling and developing items which in themselves do not have a salvage value. For the purpose of this option labor, fuel, repairs, hauling, supplies, etc., are not considered as having a salvage value, even though used in connection with the installation of physical property which has a salvage value*

improving property by an owner of that property. This distinction provides one of the important factual bases for treating such costs that do not produce a "salvageable" asset as more akin to operating costs than to permanent improvements to property benefitting the investor.

Additionally, one never knows the volumes of the production that the "asset" will produce when an oil or natural gas well is drilled and completed. The manufacturing plant owner can establish the rated capacity of the plant and its production characteristics with certainty – facing only pricing risk of its goods. Unlike a manufacturing facility, where there is certainty as to the volumes capable of being produced or processed, oil and natural gas producers bear the additional risk of uncertain volume, or production capacity. Again, this additional risk faced by oil and gas producers makes the nature (and hence the tax treatment) of these expenditures different from normal construction costs.

These types of factual differences are often lost on those unfamiliar with the oil and gas business, but they were instrumental in the formulation of the proper tax treatment for costs related to those activities. Such tax treatment should not be changed without a full appreciation of the underlying nature of the business and nature of the expenditures that oil and gas development and production require.

Congressional Action on IDCs—Congressional confirmation of IDCs as operating costs

The phrase "intangible drilling and development costs" eventually showed up in the legislation when, in 1940, Congress sought to impose an excess profits tax to support the war efforts. Section 711 of the Act (Codified in the 1939 Code as Section 711) [13], in defining "Excess Profits Net Income," outlined the adjustments to be made to normal-tax income, including one limiting the use of deducted IDCs:

> *All expenditures for intangible drilling and development costs paid or incurred in the drilling of wells or the preparation of wells for the production of oil or gas, or expenditures for development costs in the case of mines, which the taxpayer has deducted from gross income as an expense, shall not be allowed to the extent that in the light of the taxpayer's business it was abnormal for the taxpayer to incur a liability of such character or, if the taxpayer normally incurred such liability, to the extent that the amount of such liability in the taxable year was grossly disproportionate to the amount of such liability in the four previous taxable years; . . .* [14]

In connection with the Revenue Bill of 1942, Congress rejected a proposal to change the treatment of oil and natural gas drilling and development costs, instead explicitly reaffirming its treatment by adopting House Concurrent Resolution 50:

> *Resolved by the House of Representatives (the Senate concurring). That in the public interest the Congress Hereby declares that by the reenactment, in the various revenue Acts beginning with the*

[13] Pub. L. No. 801, Second Revenue Act of 1940, Sec. 711(b)(1)(H), 54 Stat. 974, 1940.

[14] - Pub. L. No. 10, Excess Profits Tax Amendments of 1941, Sec. 3, 55 Stat. 8, 1941. amended 1939 Code Section 711 to clarify the nebulous "disproportionate" language of the prior act, but also gave a legislative nod to the deduction for intangible drilling and development costs:
Intangible Drilling and Development Costs. – Deductions attributable to intangible drilling and development costs paid or incurred in or for the drilling of wells or the preparation of wells for the production of oil or gas, and for development costs in the case of mines, if abnormal for the taxpayer, shall not be allowed, and if normal for the taxpayer, but in excess of 125 per centum of the average amount of such deductions in the four previous taxable years, shall be disallowed in an amount equal to such excess . . .

Revenue Act of 1918, of the provisions of section 23 of the Internal Revenue Code and of the corresponding sections of prior revenue Acts allowing a deduction for ordinary and necessary business expenses, and by the enactment of the provisions of section711 (b) (1) of the Internal Revenue Code relating to the deduction for intangible drilling and development costs in the case of oil and gas wells, the Congress has recognized and approved the provisions of section 29.23 (m)—16 of Treasury Regulations 111 and the corresponding provisions of prior Treasury Regulations granting the option to deduct as expenses such intangible drilling and development costs[15].

The House Report to the Resolution expressed the intent of Congress was ". . . to remove any doubt as to the validity of Treasury regulations giving to the taxpayer the option to either capitalize or charge to expense intangible drilling and development costs in the case of oil and gas wells." Congress indicated that the "uncertainty occasioned by the raising doubts as to the validity of these regulations is materially interfering with the exploration for and the production of oil," deemed "essential for the maintenance of our military and civilian requirements." Congress further noted that the regulations had been in effect continuously for 28 years and Congress had adopted the same basic statutory provisions since that time from which these regulations are derived[16].

Regulations 118, approved September 23, 1953, retained the option to expense intangible drilling costs incurred by the operator[17]. With the re-codification of the tax laws in 1954, the IDC deduction was finally given clear imprimatur of the law in the Internal Revenue Code of 1954 with the adoption of Section 263 (c):

Intangible Drilling and Development Costs in the Case of Oil and Gas Wells. — Notwithstanding subsection (a), regulations shall be prescribed by the Secretary or his delegate under this subtitle corresponding to the regulations which granted the option to deduct as expenses intangible drilling and development costs in the case of oil and gas wells and which were recognized and approved by the Congress in House Concurrent Resolution 50, Seventy-ninth Congress[18].

Congress has subsequently imposed some limitations on the ability to expense IDCs over time, but the underlying principle and the treatment of such costs as more in the nature of operating costs than permanent improvements to property benefitting the investor has been largely unchanged. [19]

<u>Economic Impacts of the IDC Deduction—Why changes affect drilling levels</u>

Reasonable cost recovery is not unique to the oil and natural gas industry. It is available and essential to all business operations. American companies spend millions - sometimes billions - of dollars building infrastructure and investing in their industries here at home. These costs must be recovered in order to reinvest in the next

[15] H. Con. Res. 50, 79th Cong., 1st Sess., July 21, 1945.
[16] H.R. Rep. No. 761, 79 Cong., 1st Sess., June 19, 1945
[17] Section 39.23 (m)—16
[18] Internal Revenue Code of 1954, 68A Stat. 77 (1954).
[19] As a result of several tax changes in the 1980's, integrated companies can currently expense 70% of domestically incurred IDCs, with the remaining 30% recovered over 60 months. Independent oil and gas producers (i.e., those with little or no refining or retail marketing operations) continue to be able to fully expense their domestic IDCs as incurred, although all domestic IDCs in excess of a 5 year amortization period are treated as an alternative minimum tax preference item under Section 59(e). Foreign IDCs are amortized over 10 years.

breakthrough technology or the additional employee. Capital intensive businesses, therefore, operate under a regime where cash flow is very important and a simple tax approach does not illustrate the very complicated connection between business decisions and the tax world.

That connection, for the oil and natural gas industry at least, focuses on two equations:

First Equation:
Revenue – Drilling Costs – All Other Deductions = Taxable Income X 35% = Tax

Second Equation:
Cash Revenue – Cash Outlays – Taxes = Cash Available for Additional Drilling

Many are able to grasp the first equation; that is, increasing oil and natural gas companies' taxable income (by disallowing deductions) will produce more tax. However, many also ignore the second equation; that is: greater taxes reduce the amount of cash available for continued drilling or – said differently – less exploration and production of available U.S. energy resources. Both equations play into a US business investment decision and ignoring the second equation is to ignore the direct impact that could be felt by Americans across the country, whether in oil and natural gas regions or not.

The economic policy basis behind the IDC deduction acknowledges the second equation and the benefit of putting energy capital to work in drilling programs and the production of oil and natural gas to meet the demands of the U.S. economy. The very moment a well is completed and starts producing, it becomes a wasting asset that will eventually be used up. Accordingly, to maintain supply, additional drilling for new production must be immediately started to fill in as the first well depletes. Increasing taxes on oil and gas companies in any significant way has a dramatic, negative effect on the U.S. oil and natural gas investment, thereby reducing production and supplies.

It is correct to note that the disallowance of IDC as a current deduction results in increased government taxes in the first year. But it should also be noted that businesses that are looking to grow and manage shareholder money must look further out on the timeline. In the first year (and every year thereafter), energy companies will have less cash available for additional drilling, which will directly lead to less production. This lower production results in lower government tax and royalty revenue, as well as other potential impacts on consumers. This is a dynamic impact that compounds year after year into bad news for consumers and energy companies. Here is a simplified example:

	Current Tax/Cash Flow Impact:	Tax/Cash Flow Impact (10 yr Amortization)
Tax Calculations		
Revenue	$1,000	$1,000
Drilling costs	($400)	($40)
All Other Deductions	($100)	($100)
Taxable Income	$500	$860
Tax Rate	35%	35%

Tax	$175	$301
Cash flow		
Revenue	$1,000	$1,000
Cash outlays	($500)	($500)
Taxes	($175)	($301)
Cash Available for Drilling	$325	$199

Based on the above example, government will realize an increase in tax revenue in the year of enactment of $126 ($301 - $175=$126). But equally true is that drilling will go down by almost 40 percent ($325 for drilling reduced to $199), the implications of which include: 1) a material number of wells will not be drilled, 2) a material number of employees and contractors would be impacted, 3) wells drilled in prior years will continue to deplete without enough new wells to replace them, 4) there will be less supply of domestic oil and natural gas and thus imports will increase, and 5) government revenue will decrease in future years due to lower production.

Discounted Cash Flow Analysis—Why timing items affect drilling levels

It is also correct to note that the difference between expensing drilling costs and capitalizing the same costs is a *timing* difference. But once again, that answer is too simple and ignores the time value of money. The dollars at stake are so large that the difference in the years of deduction is enormous. The timing difference argument (i.e., there is no tax increase to energy companies over time) is a simplistic view that would not be used by any competent finance or treasury department. Companies in the oil and natural gas industry evaluate whether to invest in new projects and drill new wells based on the returns they can expect from such investments. Rates of return are directly influenced by the timing of cash outflows and inflows related to the project. Significantly delaying the timing of the tax deductibility of drilling costs significantly reduces the discounted cash flow and rate of return values such projects will generate, and thus many projects will no longer meet investment rate criteria. Thus, dismissing the significance of the proposed change by describing it as merely a timing difference, once again, ignores the impact of drilling and tax costs on the sustainability, much less growth, of U.S. energy supplies. Increasing the costs of producing energy at home—which amounts to increasing the costs of hiring American workers—is not sound economic or energy policy—it will simply result in less oil and natural gas production and supplies and fewer American jobs

IDCs Are Not Unique in the Tax Code—Comparisons to costs in other industries

The United States has historically allowed immediate deductions for costs associated with the development of technology and resources. These deductions have played a crucial role in advances in technology and have spurred transformations in the US economy in general and America's energy sector in particular. The research and experimental cost deduction (Sec 174) and the intangible drilling and development cost deductions (Sec 263(c)) have identical policy goals: to promote innovation, foster development of new products and resources, and promote economic growth. The legislative history of the codification of IDC in the 1954 Internal Revenue Code supports the potential overlap of these two sections. Section 174 also came into the code in 1954, but excluded from its coverage (by Section 174(d)) oil and natural gas exploration expenditures, specifically noting in the legislative history that coverage of such costs under Section 174 was not necessary because they had been covered separately under Sec. 263(c).[20]

The largest costs deducted under Sec. 174 by companies such as high-tech or pharmaceuticals typically consist of items such as the salary and benefit costs of researchers and their co-workers. Examples include the salary of a scientist developing new or improved drugs, or the costs associated with the development of computer software. When compared to the costs deducted under Sec. 263(c) for the oil and natural gas industry, they are virtually the same. IDCs typically consist of the salaries for drillers, as well as fuel and hauling costs. Examples include the wages of workers involved in finding and developing new oil or natural gas prospects, as well as workers involved in developing improved drilling techniques to get at hard to reach gas or to drill wells in new, unproven locations.

When one compares these extremely similar deductions, it is interesting to note that the oil and natural gas industry, through the same type of cost recovery, is actually disadvantaged compared with other industries. Under Sec. 174, high-tech and pharmaceutical costs are typically fully deductible in the year they are incurred. Furthermore, a research tax credit is available in addition to the one year deduction. However, IDC costs under Sec. 263(c) can only be fully deducted in the year they are incurred by independent oil and natural gas companies; integrated oil companies are limited to deducting 70 percent of the total costs in the year incurred, with the remainder amortized over five years, and neither generally qualifies for the additional research credit. While the economic policy rationale is the exact same for both of these provisions, in practical application, the oil and natural gas industry is at a disadvantage from an overall tax standpoint.

The bottom line is that both the R&E deduction and the IDC deduction serve identical economic policy goals: innovation, development, and growth. Eliminating the IDC deduction would discourage innovation in the energy sector, jeopardizing additional valuable advances in oil and natural gas exploration, high paying jobs, and America's energy security.

<u>Potential Impact of IDC Repeal on the Industry & the Economy</u>

Repealing the IDC deduction would require currently deductible costs to be recovered over an extended time period. As discussed, this significantly skews the after-tax cost of drilling labor relative to other labor activities and US drilling relative to investment in other countries. According to a Wood Mackenzie[21] study, repealing IDC would discourage domestic investment and could generate following results:

- Potential loss of domestic production that could approach 600,000 boe/d
- Curtailing an expected $130 billion of capital over the next ten years
- A more focused impact on natural gas with as around 5% of natural gas production is expected to be lost in the first year of the tax change

[20] S. Rep. No. 1623 (1954), p 216.

[21] "Evaluation of Proposed Tax Changes on the US Oil & Gas Industry." Wood Mackenzie. August 2010. http://www.api.org/~/media/Files/Policy/Taxes/Evaluation_Proposed_Tax_Changes_on_US_Oil_and_Gas_852010.pdf

Additionally, the repeal of IDC and other proposed tax changes for only the US oil and gas industry place thousands of jobs at risk:

- 58,800 direct, indirect and induced US jobs are at risk in the year implemented
- 165,000 total direct, indirect and induced US jobs at risk by 2020
- The Rocky Mountains, on-shore Gulf Coast, and the middle of the US have the highest potential jobs at risk

Any proposals to eliminate the IDC deduction would not only jeopardize the advances that are responsible for some of the US's biggest and latest oil and natural gas plays, such as shale oil and natural gas, but also endanger many of the 9.2 million American jobs supported by the industry.

Conclusion

Treating the labor costs and other operating expenses associated with drilling a well as deductible expenses is consistent with standard tax policy. Deviating from this standard treatment puts at risk the investment and innovation required for keeping the goal of energy independence within reach.
The US corporate tax system should be one that promotes domestic investment and international competitiveness without picking winners and losers.

Current tax treatment for the costs of drilling wells in the U.S. keeps the cost of domestic production competitive with foreign alternatives – a key component in spurring the domestic investment needed to reach America's goal of energy independence. Eliminating or further restricting the ability to expense IDCs (mostly labor costs), thereby increasing the cost of energy development in the U.S., is not only incorrect tax policy, but also bad economic, jobs, and energy policy.