– AMERICAN PETROLEUM INSTITUTE –

TAX REFORM COMMENTS 2013 — 2017

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Table of Contents

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As lawmakers seek changes to our tax code, the American Petroleum Institute, representing all aspects of the US oil and natural gas industry, has spent considerable efforts evaluating how various proposals could impact our industry. Over the years we've provided lawmakers and policy experts with our thoughts on these proposals. Currently Congress has a unique opportunity to seize the momentum and pass stable, pro-growth reforms to our outdated tax code. Lowering the US corporate tax rate, moving to a competitive international tax system, and ensuring that highly capital intensive industries, such as ours, are able to remain competitive in any new system are paramount to get correct. We hope that the comments contained in this package, from 2013 to modern day, are helpful as you seek to understand how certain changes could impact our industry, and ultimately the over 9 million jobs that we support.

Should you have any questions, or wish to discuss these issues further, please contact the API tax team:

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API Comments on Tax Reform
June 2017[1]

Domestic Taxation

Tax Rate

API believes that the U.S. corporate statutory income tax rate should be reduced from the highest in the world to promote domestic investment in the U.S. and to allow U.S. companies to compete internationally. By lowering the corporate statutory rate, U.S. companies will be able to re-invest more earnings into operations, spur domestic growth and provide more jobs.

Integration

Tax reform encompassing a move towards corporate integration must take into account the overall effective tax rate imposed on a corporation's earnings, including foreign tax, corporate tax, withholding tax and personal income tax. Corporate integration should not have a disproportionate impact on certain industries over others. Specifically, corporate integration should take into account the high rate of foreign tax already paid by the oil and gas industry on its foreign operations. Ignoring these foreign taxes in an integration scheme would effectively create a system of double taxation.

Cost Recovery as a Pro-Growth Mechanism

Pro-growth, non-discriminatory capital cost recovery provisions encourage U.S. capital investment which in turn will spur domestic growth. Some proposals have focused on moving to a full-expensing model, which certainly helps a taxpayer's cash flow to be able to invest in new domestic projects. With respect to the oil and gas industry, accelerated cost recovery for tangible items is certainly necessary. In addition to accelerated to cost recovery the oil and gas industry expects to retain the ability to claim cost recovery deductions for intangibles such as mineral interests (e.g. depletion) which will lead to similar domestic growth. In addition to accelerated cost recovery and retention of cost recovery of intangibles, the following items should be retained:

- Intangible drilling and development costs (IDC) represent the labor, supplies, fuel and rent, among other items, associated with the cost of conducting oil and gas exploration and production (60-80% of the cost of the well). Restrictions on the ability of energy companies to expense these costs discourages new domestic oil and gas exploration—particularly with respect to very expensive, but critical, offshore production. Expensing of IDCs promotes investment, creates more jobs and puts U.S. companies on a level playing field with non-U.S. competitors.

[1] This document is considered "evergreen" and is in the process of continuous evaluation and updating by API.

- Companies should be able to include current costs in their cost of goods sold and API supports a general retention of LIFO to value inventory. A forced switch in inventory accounting methods should not be used as a revenue raiser.

Other Issues

- **Derivatives** - The income or loss arising from financial transactions that hedge inventory should be treated as an adjustment to the price paid for the underlying commodity or otherwise fully integrated with the underlying physical sale.

- **Interest Deductibility** – API understands that a move to full expensing of all tangible costs creates policy concerns on whether to retain the current deductibility of net interest expense. However, any policy to eliminate the deductibility of net interest expense should only be considered in a situation where there is a significant rate reduction and the adoption of full cost recovery.

- **Section 199** - Section 199 may not be needed if other pro-growth tax reform positions are implemented; however, if retained, section 199 should be amended to provide equal, non-discriminatory tax treatment to all sectors of the economy. Stable, non-discriminatory tax rules which provide for a level playing field are key factors for long-term economic growth. Section 199 currently reduces the deduction available to oil and gas companies by 3 percentage points whereas other industries are not subject to this reduction.

- **MLPs** – API believes that current MLP status should be retained. The MLP organizational structure lowers the cost of capital for investment in MLP-eligible assets while at the same time offering reliable returns to individual investors. Additional investment in midstream infrastructure may help keep energy costs down, and prices stable for consumers. As a result, MLPs have provided numerous jobs and grown the domestic economy.

Cost Recovery Transitional Issues

API recognizes the need for rules to be implemented which will allow companies to move towards any new tax regime. These rules will allow companies to invest more of their earnings into job producing growth by granting them the benefit of their previous capital outlays.

- **Move to a full expensing approach –** Should policy makers choose to move to a full expensing approach, transition rules should ensure that existing tax basis can be fully recovered. This includes basis in assets such as mineral interests as well as inventory.

- **NOL/Tax Credit Carryforward** - Immediate expensing on a permanent basis must be accompanied by unlimited NOL and tax credit carry forwards. To the extent NOLs and credits are limited, taxpayers must be given flexibility to elect out of expensing.

- **Interest Expense** – Should net interest expense no longer be deductible, API does not have a position on how to address the transition of existing debt. However, the final rules must permit options to accommodate past taxpayer decisions or else historical business decisions would be unfairly compromised.

International Taxation

API supports a move towards a territorial system of international taxation. The current system of taxation on worldwide income harms the ability of U.S. companies to compete internationally and is an unduly complicated tax regime.

API does not support the universal implementation of a minimum tax applied on foreign income. We believe that such a tax would be too complicated, applied too broadly, and lead to potential double taxation situations. However, a minimum tax applied as a safe-harbor could be acceptable. This minimum tax test should be sufficient, but not necessary, for exemption. An exemption should always be granted for income generated by an active trade or business. Additionally, robust foreign tax credit rules need to be retained and some mechanism needs to be developed to 1) allow for pooling of income and taxes to meet the minimum tax threshold and 2) apply an exception for income generated by an active trade or business.

Taxation of Certain Foreign Income Flows – New Regime and Retention of Subpart F

API recognizes that structuring a territorial system may require the designation of certain foreign income streams that are earned by CFCs but, because of the policy need to protect the U.S. tax base, would still be subject to U.S. tax. API believes that active foreign income earned by CFCs should not be subject to U.S. tax. In order to avoid taxation of large shifts in income due to market volatilities, we would support a commodities income exception to any such income designation. Commodities are priced in accordance with global markets creating a very low risk of base erosion related to transfer pricing for commodities transactions. Additionally, oil and gas activities are typically conducted where the relevant oil and gas resources are (and where markets are). Accordingly, commodities income should be excluded from any foreign income subject to immediate U.S. tax.

Branch Taxation – *New Regime*

API believes the current rules governing the taxation of income of foreign branches are sufficient (i.e. no lock-out effect or deferral issues) and that current rules governing the treatment of foreign branches should be retained. A fully-functioning foreign tax credit regime must be maintained to ensure that the income from those foreign branches is not subject to double taxation. API does not object to reasonable branch loss recapture rules.

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Repeal Separate Treatment of Active Oil and Gas Income – *New Regime*

API supports an elimination of tax code provisions which provide separate treatment of active oil and gas income. The current provisions single out the oil and gas industry with discriminatory and outdated measures which put U.S. companies at a distinct disadvantage versus non-U.S. rivals. Under a territorial system, these provisions should be repealed in order to provide a level playing field which will lead to stronger domestic growth and job creation. Specifically, section 907, which limits the use of a foreign tax credit by oil and gas companies as it relates to active income, and section 954(g), related to foreign base company oil related income, should be repealed.

Transitional Issues

- **Retention of Foreign Tax Credit Regime** - It is extremely important that a robust foreign tax credit regime be maintained until any new international tax system is fully implemented. In addition, it is extremely important that a robust foreign tax credit regime be maintained for the income of any foreign branches and for any foreign income that is subject to U.S. tax under subpart F.

- **Repatriation -** API generally does not oppose proposals to tax existing E&P at a significantly reduced rate so long as the following transitional issues are in place:

    - **Use of Foreign Tax Credits** - Foreign tax credits, including FTC carryforwards, should be available to offset U.S. tax (at any potential rate) on proposed repatriation of existing E&P.
    - **Ordering Rules Regarding Repatriated Earnings** – Special ordering rules are required to ease the transition to a territorial system with a deemed repatriation of foreign earnings. In the year prior to the effective date of the tax changes, a multi-step process should be implemented to ensure that the tax due on repatriated earnings can be calculated to allow for the full use of pre-existing NOLs and/or foreign tax credits.
    - **ODL Treatment** – API has promoted rules regarding the use of ODLs. Any proposed tax reform should make clear the 10-year expiration period for FTCs is suspended for any FTCs which would have been used to cover residual U.S. tax liability on foreign income but for the allocation of an ODL to reduce foreign source income. For ODL accounts in existence at the time of tax reform taxpayers may elect to convert the accounts into U.S. NOLs by recapturing any tax benefit the ODLs may have produced. Tax on the recaptured amount should be eligible to be offset by FTCs. For U.S. losses in the years after tax reform taxpayers should have the option to treat the amounts as traditional ODLs, under the ODL rules after tax reform, or as U.S. NOLs under I.R.C. Section 172.

For more information, please visit www.API.org/tax

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April 15, 2015

RE: Comments to the Senate Finance Committee Business & Infrastructure Working Groups (energy)

The American Petroleum Institute (API), on behalf of our members, appreciates the opportunity to provide some input to the working group process as the Senate Finance Committee begins to work through various tax policy issues. Given the size and scope of our industry in the US, changes to the tax code can impact the economics driving the jobs and outlook for our vibrant energy sector. Specifically, due to the capital intensive nature of our operations, the capability of recovering those costs is vitally important.

Of course, 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 over 9.8 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 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]

[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

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 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. This targeted approach has been employed by the Administration budget proposals to repeal provisions such as IDC and LIFO for the oil and natural gas industry.[3] 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. 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.

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.

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.

Infrastructure Funding

[3] More information on the impacts of these targeted tax proposals can be found on the API website at http://www.api.org/policy-and-issues/policy-items/taxes/api-budget-response.

An additional area being considered along with changes to the income tax regime is the funding for our nation's transportation infrastructure. The oil and natural gas industry certainly recognizes the primary role of highways in the U.S. transportation system and our economy. We also understand the need for a continuing federal investment in developing and preserving the nation's highways. The existing federal motor fuels tax applied on fuel products as they enter into the retail marketplace allows for a structured and efficient revenue collection system as well as defines a connection between the highway user and the infrastructure costs.

In considering highway funding mechanisms the industry applies five main principles. First, the imposition of a tax must allow for a high level of transparency between the consumer and the government service the tax is funding. This fosters the commitment by policy makers that the tax's structure, imposition or rate is justified by the level of services needed or expected. Second, the imposition and collection of the tax by the industry must be administrable and efficient. In addition, the tax should be similar to the various state motor fuel taxes to reduce compliance burdens and ensure the incident of taxation is at a point that greatly reduces fraud. Third, the tax must apply in a similar fashion regardless of whether the product is domestically produced or imported and does not apply to exported product. Therefore, it achieves a high level of trade parity. Fourth, the tax should serve as an equitable proxy for transportation usage and fairly apply to a broad spectrum of transportation fuels. Finally, amounts raised should be dedicated to bridge and highway infrastructure programs.

We would expect that any proposal for a new revenue/tax system would adhere to these principles and be structured to generate enough money to meet expected revenue needs. Of course, supplemental revenue raisers may be considered against these principles and used to address shortfalls, but they cannot be derived from permanent changes to industry income tax provisions.

Again, we thank you for the opportunity to comment as part of this process and welcome any questions that you may have. Should you wish to discuss these points further, please do not hesitate to contact me at 202-682-8455.

Sincerely,

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AMERICAN PETROLEUM INSTITUTE

March 28, 2014

Mr. Todd Metcalf & Mr. Mark Prater
Senate Committee on Finance
215 Dirksen Senate Building
Washington, DC 20510

Dear Mr. Metcalf & Mr. Prater:

Re: Baucus Staff Discussion Draft on Cost Recovery and Accounting Reform

On behalf of the American Petroleum Institute (API) we submit these comments on the Staff Discussion Draft for Cost Recovery and Accounting Reform ("Discussion Draft"). API represents more than 580 member companies involved in all aspects of the oil and natural gas industry including exploration, production, transportation, refining, and marketing. The American oil and natural gas industry supports over 9.8 million domestic jobs and represents more than 8 percent of GDP. API supports pro-growth, pro-jobs tax reform that includes competitive and robust capital cost recovery principles to take into account both risk and economic development goals.

For capital intensive industries, such as the oil and natural gas industry, cost recovery is critical for continued growth and stability. According to the U.S. Census Annual Capital Expenditures Survey ("ACES") from 2007-2011 the industry averaged nearly $159 billion in annual capital investment. The industry's capital investment represents 13.7 percent of the investment of all industries. With such high annual investment, robust cost recovery is important for every segment of the oil and natural gas industry – upstream, midstream, and downstream. It also matters to other industries, including manufacturing, that rely on affordable energy to conduct business.

Given the size and scope of our industry in the U.S., any fundamental changes to the corporate tax code will impact our members, as well as millions of American jobs that rely upon a thriving energy and manufacturing sector. The industry recognizes the value of a lower corporate tax rate and supports a move in that direction. However, further measures to extend cost recovery for expenses and investments in order to support a lower tax rate could significantly and negatively impact the cash flow for domestic projects, making them less attractive in a globalized economy.

As such, we are deeply concerned that measures such as those described in the Discussion Draft could result in less domestic energy investment, fewer U.S. jobs and lower domestic energy production. All this could ultimately undermine the goal of pro-growth, pro-jobs tax reform. We would encourage the exploration of proposals that can achieve both of these objectives – lower rates and robust pro-growth capital cost recovery mechanisms. With this submission, we will provide detailed feedback on the following Discussion Draft policy areas:

- Qualified Extraction Expense (application to IDC)
- LIFO repeal
- Depreciation reform
- Repeal of Section 1031 (like-kind exchange)

If you have any additional questions, please feel free to contact Stephen Comstock, Director of Tax & Accounting Policy at comstocks@api.org, Brian Johnson, Director Federal Relations for tax & trade at johnsonb@api.org or me.

Sincerely,

Bryce R. Pressentin, Tax Counsel

CC: Senate Finance Committee Members & Staffs

Proposed Modification to Recovery of Industry Specific Production Expenses Will Hurt Energy Sector Growth -- Reducing Jobs, Investment, and Energy Production

The U.S. oil and natural gas industry has put the U.S. in an unprecedented position of moving toward energy independence in the coming years. This is largely due to technological advancements that have led energy companies to 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 security 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. Tax deductions for ***operating expenses*** associated with drilling a well are consistent with long-standing tax policy, and deviating from this standard treatment risks future investment and innovation required for keeping the goal of energy independence within reach. Furthermore, requiring companies to capitalize the expenses associated with losses – such as ***dry-wells –*** is not consistent with standard tax policy, where losses are recognized when they have economically occurred. The proposed changes in the Discussion Draft for "qualified extraction expenses" will hurt America's energy revolution. By statutorily extending the recovery of ***ordinary and necessary costs*** associated with drilling a well, these proposals would restrict cash-flows leading to a decrease in domestic investment. The reduction in investment would in turn lead to lower levels of domestic production and a loss of American jobs.

IDC background

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.

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.

Economic Impacts of IDC deduction – Cash flow needs for continued investment

The energy industry is capital intensive. Any increase in the cost of drilling or reduction of cash available for drilling can be devastating. Capital intensive businesses 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 laws. 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 U.S. business investment decision. Ignoring the second equation ignores the direct impact that could be felt by Americans across the country.

It is correct to note that the disallowance of IDC as a current deduction results in increased taxes in the first year. However, 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. Lower production will result in lower tax and royalty revenue.

<u>Importance of Discounted Cash flows</u>

Looking at the difference between expensing drilling costs and capitalizing the same costs as a simple timing difference ignores the time value of money. The costs of drilling wells are quite high, so the effects of extending the recovery period of IDC can have an enormous impact on the net present value (NPV) of the deductions. 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 drastically 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. Increasing the costs of producing energy at home is not sound economic or energy policy—it will simply result in less domestic oil and natural gas production and fewer American jobs.

<u>Impact of Extending IDC Deduction</u>

Requiring currently deductible costs to be recovered over an extended time period significantly skews the after-tax cost of drilling labor relative to other labor-intensive activities, and it also discourages U.S.

drilling relative to investment in other countries. According to a Wood Mackenzie study[1], repealing IDC would discourage domestic investment and could generate the following results:

- Potential loss of domestic production that could approach 3.8 million boe/d
- Curtailing an expected $407 billion of capital over the next ten years
- Up to a 5% reduction of natural gas production in the first year of the tax change
- Federal tax increases from the change would be more than offset by the loss in federal, state and private royalties and other state taxes lost in the short term; and federal taxes would be drastically reduced in the long term due to less production and revenues

Additionally, the repeal of IDC and other proposed tax changes for the U.S. oil and natural gas industry places thousands of jobs at risk:

- 190,000 direct, indirect and induced U.S. jobs are at risk in the year implemented
- 265,000 total direct, indirect and induced U.S. jobs at risk by 2023

Current tax treatment for domestic exploration will help keep the cost of domestic projects competitive with foreign alternatives – a key component in spurring the domestic investment needed to reach America's goal of energy independence. Implementing the cost recovery changes associated with the Discussion Draft's proposed "qualified extraction expenses" would increase the costs of domestic energy development. This is not only unsound tax policy, but it is also bad economic and energy policy.

Extending recovery periods on extraction expenses to "pay for" a corporate rate reduction is detrimental to new domestic investment.[2] America's oil and natural gas industry has been one of the few bright spots in America's economic recovery. Now is not the time to implement misguided tax policy that would hurt an industry that supports 9.8 million American jobs. We believe that tax reform should promote pro-growth and pro-job policies.

[1] Impacts of delaying IDC deductibility (2014-2025), released – July, 2013, Wood Mackenzie consulting.

[2] Industry analysis has indicated that the statutory rate would have to be reduced well below any of the rates suggested in congressional tax proposals in order to maintain current and expected investment and production levels.

Proposed Changes to Depreciation Will Lead to Longer Recovery Periods – Reducing Domestic Investment and American Jobs

Background

For Federal income tax purposes, a taxpayer is allowed to use depreciation deductions to recover cost of certain property used in a trade or business or for the production of income. Under the modified accelerated cost recovery system ("MACRS"), adopted in 1986, the amount of the annual depreciation deduction allowed with respect to tangible property for property used in the U.S. is determined for different types of property based on an assigned applicable depreciation method, recovery period, and convention.

In addition to MACRS, the alternative depreciation system ("ADS") is required for property used predominantly outside the United States, tax-exempt bond financed property, and certain tax-exempt use property. An election to use ADS is available to taxpayers for any class of property for any taxable year. Under ADS, all property is depreciated using the straight-line method, over recovery periods which generally are equal to the class life of the property, with certain exceptions.

Currently, all real-property used in a trade or business is depreciable using the straight-line method over a set number of years depending on the type of real property.

Cost recovery through deprecation allows taxpayers to recoup the cost of business assets and redeploy cash for continued investment. In capital intensive industries, like the oil and natural gas industry, extending cost recovery periods and slowing the depreciation recovery convention (e.g., from double declining to declining balance or straight line recovery) will have a significant impact on continued investment in the U.S., and will lead to reduced domestic energy production, jobs and economic activity.

Discussion Draft's Depreciation Proposal

Tangible Property

The Discussion Draft proposes a plan for the simplification of the depreciation system, by repealing the MACRS depreciation system and creating a "pooling system" for tangible assets. The sum of the adjusted basis of the assets in the pool (adjusted basis of assets at the beginning of the year plus additions) equals the "pool balance". [1] The depreciation amount is determined by multiplying the pool balance by a recovery rate associated with a particular pool.[2]

In addition to longer depreciation periods, depreciation is taken on a declining balance method—thus resulting in much lower depreciation than under the current rules. As a result, the taxpayer cannot fully depreciate the cost of pooled assets until the entire pool balance reaches a de minimus balance of

[1] It should be noted that the initial beginning balance includes pre-effective date assets; as such, the Discussion Draft would have retroactive effect to the extent that it applies to the adjusted basis of pre-effective date depreciable assets as of the year of implementation. It should be further noted that the pool balance is not reduced when assets are sold or otherwise become worthless, causing a mismatch between the new tax rules and economic declines in assets. The Discussion Draft would eviscerate two longstanding tax policies: the need to avoid retroactivity and the need to properly reflect economic income.

[2] The applicable recovery rates for the four pools are: Pool 1 - 38 percent; Pool 2 - 18 percent; Pool 3 - 12 percent; and Pool 4 - 5 percent.

$1,000. In addition, the pool concept changes the way taxpayers will recognize gains and losses on disposition of pooled assets. A taxpayer will not recognize gain until the year-end balance of an asset pool is negative. Similarly, a taxpayer will not be permitted to recognize a loss until an asset pool no longer has any assets and the pool still has a positive year-end balance. Special rules apply to foreign assets, assets sold to related parties, and leasebacks.

Real Property

The Discussion Draft creates a new classification for depreciable real-property assets. The new classification, "straight-line property," encompasses residential rental property, non-residential rental property, and a list of assets that previously were allowed to use MACRS.[3] All straight-line property is assigned a recovery period of 43 years.

A transition rule applicable to all straight-line property (including real property) placed in service in a taxable year beginning before January 1, 2015, provides that the adjusted basis of such real property is depreciated over a term of 43 years reduced by the number of taxable years for which the property has already been depreciated.

Impact of the Change

The proposed changes represent a significant increase to the cost recovery period for assets used by the oil and natural gas industry. In the case of a $1 million investment it could take as many as 136 years to fully recover the investment pursuant to the de minimus provision.[4] With the new pooling system, as the investment increases, the recovery period increases, eliminating much of the economic benefits of depreciation.

While the use of asset pools could be a simplification for the purposes of calculating depreciation overall, the system does not take all the complexity out of tracking depreciable assets. Businesses will still need to track assets individually to calculate recomputed basis on asset dispositions. And foreign asset depreciation will need to be calculated in a second set of pools.

The depreciation provisions of the Discussion Draft do not meet the policy goals of pro-growth, pro-jobs tax reform. The depreciation rates that lengthen recovery periods, coupled with the changes to other provisions that extend IDC recovery and the repeal of LIFO, will have dramatic impacts on the oil and natural gas industry. These impacts will lead to significant restrictions on cash-flows and reduced domestic investment, which will result in fewer jobs and less domestic production of oil and natural gas.

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[3] Including natural gas and liquefied natural gas production plants.

[4] For example, a $1,000,000 investment in petroleum production assets (currently treated as 7-year property) would be placed in pool 3. This change would increase the amount of time to fully recover the cost of the investment ***from 8 years to 56 years***. A $1,000,000 investment in refining assets (currently treated as 10-year property) would be placed in pool 3. This change would increase the amount of time to fully recover the cost of the investment from ***11 years to 56 years***. Finally, a $1,000,000 investment in pipeline assets (currently treated as 15-year property) would be placed in Pool 4. This change would increase the amount of time to fully recover the cost of the investment from ***16 years to 136 years.***

Repeal of Section 1031 (Like-Kind Exchange) Will Reduce U.S. Real Property Transactions – Stifling Efficient Movement of Capital and Utilization of Assets

Background

Taxpayers have relied on rules that provide for non-recognition treatment in like-kind exchanges for nearly 100 years. Our tax code has long recognized that when a taxpayer exchanges one property for another of a "like-kind," economically, nothing has changed. This matches the treatment and principle behind capital gains, where a taxpayer does not have to recognize gain until the investment is realized in cash. In that same vein, it is important to note that not all gains are deferred on like-kind exchanges. If a taxpayer receives any boot in the exchange, the lesser of boot or gain is recognized.

Section 1031 has been used for years to provide an efficient flow of capital in transactions involving real property and real property interests. The ability to defer the recognition of gain allows taxpayers to shift resources to more productive property, diversify portfolios, adjust to different business trends, and shift geographic locations. This tax provision provides taxpayers with an efficient method of shedding underutilized or idle assets, and allows other parties to make more productive use of these assets. Like-kind exchanges are used in the oil and natural gas industry for many of these reasons.

Impact of Repeal

The biggest impact of the Discussion Draft's repeal of section 1031 will be in exchanges of real property interests.[1] Tangible depreciable property will effectively retain the benefit of tax deferral through the proposed pooling noted above. Since real property will not be pooled, repeal of section 1031 abandons asset neutrality. As a result, the Discussion Draft creates a distortion in the broader economic utilization of capital. The repeal of like-kind exchange treatment will significantly stifle the efficient flow of capital in real property assets and lead to a "lock-in" effect for real property interests. Lock-in of real property interests will lead to more underutilized and idle assets along with the attendant economic drag. Allowing capital to flow more freely among investments is critical to economic growth and job creation.

[1] The inherent deferral of gain in the Discussion Draft's pooling system removes some of the impact of the repeal of section 1031 for tangible property, as long as the exchanged property is in the same pool.

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April 2, 2013

RE: Comments: Manufacturing 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 Manufacturing 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 and manufacturing sector.

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

- API's general tax reform principles,
- Issue one-pagers pertaining to LIFO and Section 199, and
- 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

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.

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**

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.

<u>Executive Summary - Existing rules are correct tax and energy policy for America</u>

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.

<u>History of IDC - The Beginnings—Administrative conclusions that IDCs are operating costs</u>

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; . . . .*[5]

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*

[5] 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[6].

Courts also recognized the option to expense these costs under these regulations. In the early tax case, *Shaffer v. Commissioner*[7], 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[8].

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 improving property by an owner of that property. This distinction provides one of the important factual bases

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

[7] 29 BTA 1315 (1934).

[8] 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*

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)[9], 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; . . .*[10]

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 Revenue Act of 1918, of the provisions of section 23 of the Internal Revenue Code and of the*

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

[10] - 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 . . .

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[11]*.*

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[12].

Regulations 118, approved September 23, 1953, retained the option to expense intangible drilling costs incurred by the operator[13]. 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[14]*.*

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. [15]

Economic Impacts of the IDC Deduction—Why changes affect drilling levels

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 breakthrough technology or the additional employee. Capital intensive businesses, therefore, operate under a

[11] H. Con. Res. 50, 79th Cong., 1st Sess., July 21, 1945.
[12] H.R. Rep. No. 761, 79 Cong., 1st Sess., June 19, 1945
[13] Section 39.23 (m)—16
[14] Internal Revenue Code of 1954, 68A Stat. 77 (1954).
[15] 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.

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).[16]

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.

Potential Impact of IDC Repeal on the Industry & the Economy

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[17] 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

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[16] S. Rep. No. 1623 (1954), p 216.
[17] "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.

API Recommendation for Transition to a Territorial Tax System

This document provides API's comments on various issues raised by a move towards a territorial system of international taxation. API would support such a move as a part of comprehensive tax reform, given that the current system of taxation on worldwide income is unduly complicated, harms the ability of U.S. companies to compete internationally, penalizes repatriation of foreign earnings and encourages foreign acquisitions of U.S. companies.

I. Dividend Exemption System

The territorial tax proposals in the Tax Reform Act of 2014 that was introduced by Chairman Dave Camp ("HR 1") and the United States Job Creation and International Tax Reform Act of 2012 introduced by Sen. Enzi (the "Enzi bill") included a new 95% deduction that would generally apply to dividends received from foreign subsidiaries. Under HR 1 and the Enzi bill, 5% of each dividend eligible for the new dividends-received deduction ("DRD") would be subject to U.S. tax.

API and its members are generally supportive of a DRD as a method of implementing a territorial system of taxation. However, a fully territorial system of taxation should not subject the active foreign income of foreign subsidiaries to any U.S. tax (i.e., there should be a 100% DRD). Other countries such as Australia, Canada, the Netherlands and the United Kingdom have fully territorial systems of taxation that exempt 100% of dividends from foreign subsidiaries. [1] API prefers the adoption of a 100% DRD instead of a 95% DRD.

In HR 1 and the Enzi bill, the taxation of 5% of dividends eligible for the new DRD was designed as a "substitute for the disallowance of deductions for expenses incurred to generate exempt foreign income."[2] In other words, a portion of dividends from foreign subsidiaries was proposed to be included in U.S. taxable income as an indirect (or proxy) tax in lieu of requiring the allocation of certain costs (including stewardship, interest expense and general and administrative expenses) against foreign-source income. In this regard, API can support a 95% DRD if the modifications of section 904 that were included in HR 1 are also enacted to ensure that, for purposes of computing the limitation on foreign tax credits, only directly allocable expenses reduce foreign-source income.[3]

II. Mandatory Deemed Repatriation of Foreign Earnings

API's members have paid significant foreign taxes on their foreign earnings. If there is a mandatory deemed repatriation of foreign earnings, taxpayers must be allowed to claim foreign tax credits (FTCs) and FTC carryovers to reduce the U.S. tax on the deemed repatriation. Otherwise, taxpayers will be subject to double tax on their foreign earnings. Accordingly, API and its members would be supportive

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[1] The other OECD member countries with 100% dividend exemption systems are: Austria, Czechia, Denmark, Estonia, Finland, Greece, Hungary, Iceland, Luxembourg, New Zealand, Poland, Portugal, Slovak Republic, Spain, Sweden and Turkey.

[2] Technical Explanation, Estimated Revenue Effects, Distributional Analysis, and Macroeconomic Analysis of the Tax Reform Act of 2014, a Discussion Draft of the Chairman of the House Committee on Ways and Means to Reform the Internal Revenue Code, Joint Committee on Taxation (Sept. 2014) ("**JCT Explanation of HR 1**") at 515. *See also* Technical Explanation of the United States Job Creation and International Tax Reform Act of 2012, Joint Committee on Taxation (Feb. 9, 2012) ("**JCT Explanation of Enzi bill**") at 16.

[3] Section 4102 of HR1. *See also* JCT Explanation of HR 1 at 526.

of a mandatory deemed repatriation of deferred foreign earnings as part of a transition to a competitive territorial system provided that taxpayers are able to fully utilize available FTC and FTC carryovers against the tax imposed on the deemed repatriation, including appropriate ordering rules for the use of net operating losses (NOLs) and FTCs (see below).

Repatriation of Foreign Earnings: Ordering Rules for NOLs and FTCs

First, any repatriated foreign earnings should be "ring-fenced" from the calculation of domestic tax due. Second, taxpayers should be granted the election to convert overall domestic losses (ODLs) into NOLs (see below). Third, taxpayers should be granted the ability to select how much, if any, of existing NOLs to use against the repatriated foreign income. Fourth, tentative tax on the repatriated foreign earnings, net of any NOL offset, should be calculated. Finally, existing FTCs and FTC carryovers should be applied to the tentative tax due on the repatriated foreign earnings. This sequencing of repatriation will permit taxpayers the flexibility and fairness to best use their tax attributes.[4]

III. Treatment of ODLs and Election to Convert to NOLs

Taxpayers having an existing overall domestic loss account (ODL) or an ODL in years after tax reform will be offered the option to either keep the ODL, or to convert the ODL accounts into a U.S. net operating loss (NOL).[5]

IV. Treatment of Branch Income

API believes the current rules governing the taxation of income of foreign branches are working (i.e., no lock-out effect or deferral issues) and that these rules should be retained. API does not object to reasonable branch loss recapture rules.

As discussed below, a fully-functioning foreign tax credit system must be maintained with respect to foreign branches.

V. Retention of the Foreign Tax Credit System

API supports the retention of the foreign tax credit system with respect to foreign income that is not exempt from U.S. taxation by the new DRD. A fully-functioning foreign tax credit system must be maintained to ensure that foreign income is not subject to double taxation. Taxpayers should be able to continue to claim foreign tax credits with respect to income from foreign branches as well as subpart F income.

VI. Anti-Base Erosion Provision

Anti-base erosion provisions should be limited and specifically targeted at stopping U.S. base eroding transactions that artificially shift passive and mobile income. It is imperative that foreign active business

[4] Please see API's document concerning the sequencing of repatriation of foreign earnings for a more detailed explanation.
[5] Please see API's document concerning Overall Domestic Losses – Section 904(g).

income be eligible for a full exemption from U.S. tax consistent with the rules applied by other countries. Anti-base erosion rules that are harsher than other countries' rules would put U.S. companies at a competitive disadvantage and would be counterproductive to the goal of reforming the international tax system to make the U.S. an attractive place for locating headquarters of multinational companies.

We note that both HR1 and the Enzi bill attempt to identify low-taxed intangible income that would not be exempt from U.S. tax. HR1 deems foreign income that is in excess of a normal return (as defined in HR 1) as intangible income that is not eligible for an exemption if it is subject to low foreign tax. In general, API does not support categorizing income as intangible income solely by reference to a deemed rate of return. In the case of HR1, however, income generated with respect to a commodity business is specifically excluded from the definition of intangible income. This is a critical modification to the excess returns approach for identifying intangible income. Commodities, by their very nature, are fungible products with no inherent intangible attributes that distinguishes one product from another. Accordingly, it would not be logical to ascribe an element of intangible income to the sale of a commodity. The commodity business exception in HR 1 prevents the vast majority of the industry's active foreign operations from inadvertently getting caught up in HR1's newly-created intangible income category.

The Enzi bill, on the other hand, takes a different approach for distinguishing intangible income from active income. The Enzi bill applies a facts and circumstances test to determine what income can be considered qualified business income that is excluded from the definition of low-taxed intangible income. API is generally supportive of a facts and circumstances test for identifying qualified business income but believes that the definition of such income should take into account the complex organizational structure of many multinational companies. For example, operations in a given foreign country or region may be structured with multiple operating affiliates but with a single "payroll" company employing the relevant employees in that country or region. As a result, some foreign operating affiliates may have significant property, plant and equipment and conduct a robust trade or business but rely on other affiliates to provide labor and other services. Income of such operating affiliates may not be able to qualify under the definition of qualified business income that was included in the Enzi bill.[6] The definition of qualified business income should be sufficiently flexible to include income generated by foreign entities that have substantial operations even if they do not directly employ operating personnel.[7]

Another significant improvement to a facts and circumstance test that API strongly supports is to follow the approach of HR1 and simply deem all commodity business income as qualified business income.

API does not support the blanket imposition of a minimum tax on foreign income to address base erosion concerns. Such an approach is out of line with the territorial systems of other countries and would lead to significant competitive disadvantages for U.S. headquartered companies, and in the case

[6] JCT Explanation of Enzi bill at 26. *See also* Section 201 of the Enzi bill.
[7] The Renacci-Smith "Option RS" bill of 2016 also described a substantial local business exception for low-taxed foreign income (similar to a qualified business exception). Similar to the Enzi bill, any definition of such an exception must include the flexibility to be inclusive of various corporate structures used for employee hiring.

of the oil and gas industry, would lead to double taxation. We note, however, that both HR1 and the Enzi bill apply a minimum tax threshold as a kick-out of subpart F. API supports using an effective tax rate test as a subpart F kick-out. Any income taxed at a foreign effective tax rate above the threshold would be kicked out. Additionally, income deemed to be qualified business income or commodity income should also be removed from subpart F even if it does not qualify for the kick-out based upon the foreign effective rate. However, API recommends that the test be calculated on a global basis that encompasses all foreign operations, rather than on a CFC-by-CFC or country-by-country basis.

VII. Foreign Base Company Oil-Related Income Should Be Repealed

Section 954(g) creates a category of subpart F income known as foreign base company oil-related income ("FBCORI"). FBCORI captures certain types of refining and transportation income that is clearly generated as part of active foreign operations but is nevertheless treated as subpart F income. There is no justifiable policy reason for treating this income as subpart F income. It is completely inconsistent with the treatment of manufacturing income generated in other industries. Nevertheless, under current law it is merely an anti-deferral rule, so there has been minimal impact on the industry. Under a territorial system, however, FBCORI would act as an anti-exemption rule and its impact could be very severe. Retaining FBCORI in a territorial system is inconsistent with the goal of exempting active foreign operations from U.S. tax. Moreover, retaining FBCORI in a territorial system would be outside of the norm for territorial systems around the world and would put U.S. oil and gas companies at a significant competitive disadvantage.

VIII. Section 907 Should Be Repealed

Section 907 should also be repealed. No particular industry or economic sector should be singled out for separate and unequal treatment. This section subjects the oil and natural gas industry to a special limitation on the use of the foreign tax credit and should be repealed.

IX. Application of the DRD to Certain Sales and Exchanges of Stock of Foreign Subsidiaries

Under current law, gain recognized on the sale of stock of a CFC may be re-characterized under section 1248 as a dividend to the extent of the CFC's earnings and profits. The adoption of a territorial tax system may be structured by adding a new DRD for dividends from foreign subsidiaries (including CFCs and certain other foreign corporations). Gain that is re-characterized as a dividend under section 1248 should be eligible for any such DRD. This approach is generally similar to the territorial proposal in HR 1. API is supportive of preserving section 1248 in the new territorial tax system.

Section 1248 currently applies with respect to the sale of stock of a CFC but not of other foreign subsidiaries. API supports expanding the scope of section 1248 to apply to the sale of stock of CFCs as well as any other foreign subsidiary where the selling corporation would have been eligible to claim the new DRD for dividends from the foreign subsidiary. This could be implemented either (i) by permitting taxpayers to make an election to treat any 10/50 company as a CFC for all purposes of the Code or (ii) by modifying the text of section 1248 so that it would apply with respect to gain recognized on the sale of

CFCs and any other foreign subsidiaries that are eligible for the new DRD (e.g., "specified 10-percent owned foreign corporations" under HR 1).

X. Expansion of Look-Through Rules Regarding the Sale of a Foreign Partnership

Under current law, the sale of a partnership interest by a CFC may be treated for subpart F purposes as the sale of the proportionate share of the partnership's assets related to that partnership interest if the CFC directly, indirectly or constructively owns a 25% or greater interest in the capital or profits interest in the partnership.[8] This rule effectively applies "look through" treatment to the sale of a partnership interest for subpart F purposes if the seller is a CFC with a 25% or greater interest in the partnership. Gain recognized by a CFC on the sale of a partnership interest that qualifies under this look through rule would constitute subpart F income only to the extent that a sale of the underlying assets of the partnership would generate subpart F income.

With the adoption of a territorial tax system, subpart F income may be limited to passive income and certain categories of low-taxed income. Very significant active foreign business operations are commonly conducted through partnerships where the relevant owners own between 5% and 25% of the partnership. The sale of a partnership by a CFC where the CFC owns less than 25% of the partnership (but at least 5%) should be taxed on a "look through" basis, like the sale of a 25% or greater interest in a partnership.

XI. Patent Box

API will not have a position on the use of a "patent box" approach until further information can be obtained regarding how a "patent box" regime might be implemented in the U.S. tax system. This provision could be acceptable in comprehensive tax reform as a component of a general anti-base erosion measure.

[8] Section 954(c)(4). *See also* Treas. Reg. Sec. 1.904-5(h).

API Recommendation on Addressing Foreign Tax Credits and Repatriated Earnings

API Principles Concerning Deemed Repatriation and the Use of Foreign Tax Credits:

Under the U.S. worldwide tax system, U.S. companies are subject to U.S. tax on repatriated foreign earnings. To ensure that they are not subject to double taxation, U.S. companies are generally allowed to claim foreign tax credits to reduce the U.S. tax imposed on repatriated foreign earnings.

U.S. oil and gas companies pay significant foreign taxes on foreign earnings.

Under U.S. tax reform, the U.S. worldwide tax system may be transitioned to a territorial tax system. Various tax reform proposals would require a deemed repatriation of deferred foreign earnings. To ensure that they are not subject to double taxation, U.S. companies (including U.S. oil and gas companies) should be allowed to fully claim foreign tax credits against the U.S. tax imposed on the deemed repatriated foreign earnings.

Net Operating Losses:

The past few years have been hard on the U.S. oil and gas industry. The low oil price environment has led to losses on U.S. production activities for many taxpayers. Those losses have resulted in Net Operating Losses (NOLs) for some taxpayers.

If there is a deemed repatriation of foreign earnings under U.S. tax reform, certain taxpayers may claim foreign tax credits to reduce the U.S. tax on the deemed repatriation. If those taxpayers are required to instead use any NOLs to reduce the income that is deemed repatriated, they may be unfairly penalized because they could have used foreign tax credits against the U.S. tax imposed on that repatriated income. Rather, these taxpayers should be offered the election whether to utilize NOLs against the deemed repatriated income prior to the use of the foreign tax credits. The transition to a territorial tax system should not penalize taxpayers that have generated NOLs in or prior to the year when the deemed repatriation may occur.

Need for Ordering Rules:

Ordering rules are required to ensure that the transition to a territorial system: (i) does not result in double taxation and (ii) allows taxpayers to fully realize the benefit of any applicable NOLs.

Taxpayers should be allowed to elect to fully claim foreign tax credits (including deemed-paid credits and foreign tax credit carryforwards) against the U.S. tax imposed on the foreign earnings that are deemed repatriated (before the application of any NOLs if elected by the taxpayer). This elective regime would ensure that U.S. taxpayers are not subject to double taxation and that taxpayers could fully realize the benefit of any applicable NOLs.

Suggested Ordering of Use[1]:

Legislative language should allow taxpayers to elect the following ordering rules:

- Step 1. Begin calculation of US tax on taxpayer transition year income excluding dividend income associated with repatriated foreign earnings. US tax calculation would also exclude any section 902 foreign tax credits directly associated with repatriated dividends.

- Step 2. Elect to convert ODLs into NOLs under API proposed election.

- Step 3. Determine net U.S. taxable income after offsets associated with existing NOLs.

- Step 4. Determine tentative US tax on amount calculated in Step 3 and apply any section 901 or carryforward foreign tax credits as appropriate.

- Step 5. Determine if there are any remaining NOLs and carryforward foreign tax credits available after tentative tax determination in Step 4.

- Step 6. Calculate tax associated with repatriated earnings.

    - A - Allow taxpayers to elect to apply some or all remaining NOLs from Step 5 to reduce income from repatriated dividends. NOLs from Step 5 not elected to be used will be carried forward as otherwise provided for and applied in future tax years.

    - B – Tentative tax determined on repatriated earnings [as reduced by any NOL elected to be used in Step 6 A] can be offset by applicable section 902 foreign tax credits associated with the repatriated dividends to the extent provided for in repatriation legislation. Any residual US tax can be offset by any carryforward foreign tax credits remaining after Step 5.

- Step 7. Combine tax calculated in Step 4 with tax calculated in Step 6.

[1] Section 904(f)(1) imposes a 50% recapture of overall foreign loss in the years subsequent to the loss. This income is recognized as U.S. source income. H.R. 1 provided for the exclusion of Section 904(f)(1) as it related to the repatriation of foreign earnings. A similar provision should be included for all income placed within the "ringfence."

API Comments on Overall Domestic Losses – Section 904(g)

Current Law

A taxpayer has an overall domestic loss when its U.S. source gross income is exceeded by its properly allocated or apportioned deductions, determined without regard to loss carrybacks.[1] When a taxpayer has such a loss and foreign source income in the same taxable year, an Overall Domestic Loss ("ODL") is created. The ODL is allocated to reduce the foreign source income in the tax year by being divided proportionally among General Limitation and Passive income.[2] ODL Accounts are then created to track the U.S. loss used to offset foreign source income.[3]

In a later year, if the taxpayer earns U.S. source taxable income, then a portion of that income will be treated as foreign source in order to recapture the foreign source income offset by the U.S. loss in the earlier tax year.[4] Such recapture is characterized as either General Limitation or Passive income in the same proportion as the existing ODL Accounts.[5] This recapture provision was added to I.R.C. Section 904 with the intent to keep the taxpayer whole with regard to the use of U.S. losses to offset U.S. source income.[6]

The amount of ODL recapture in any given year is equal to the lesser of the remaining ODL Accounts or 50% of the taxpayer's current U.S. source taxable income.[7] As the ODL is recaptured, and the foreign source income is restored, the ODL Accounts are reduced. There is no expiration period for ODLs; recapture continues as long as is necessary to fully recover the ODL Accounts and restore the foreign source income offset in the initial loss year.

If the taxpayer has excess foreign tax credits ("FTC") that are not at risk of expiring, the ultimate result of the current tax treatment of an ODL is that the benefit of the U.S. source loss is deferred until a subsequent year when there is U.S. source income. In the year of ODL allocation, the Overall FTC Limitation in I.R.C. Section 904(a) is reduced because the foreign source income is decreased; in the year of ODL recapture, the Overall FTC Limitation is increased because the foreign source income is increased. However, the existence of an ODL results in no extension of the 10-year expiration periods for excess FTCs, resulting in a loss of the value of expired FTCs that would have been used to offset US tax on foreign source income but for the ODL allocation.

Tax Reform

Tax reform is being considered which would redesign the international tax rules and replace the current worldwide tax system with a territorial system that provides a participation exemption for foreign earnings. For purposes of this paper, it is assumed that such a system would exempt foreign active earnings from taxation in the U.S. until paid as dividend, at which time a participation exemption will exempt or substantially reduce the U.S. tax due on the dividend. It is also assumed for purposes of this

[1] I.R.C. § 904(g)(2).
[2] I.R.C. § 904(f)(5)(D).
[3] Treas. Reg. § 1.904(g)-1(b).
[4] I.R.C. § 904(g).
[5] I.R.C. § 904(g)(3).
[6] See T.D. 9371, 12/21/2007, and H.R. Rep. No. 108-548 at 187 (June 16, 2004). See also S. Rep. No. 108-192, at 19-20 (Nov. 7, 2003).
[7] I.R.C. § 904(g)(3).

discussion that the earnings of foreign branches of US corporations will be included in the U.S. tax return of the U.S. corporation. Additionally, recent tax reform proposals have included provisions requiring a deemed repatriation of deferred non-U.S. earnings. Such proposed tax reform provides an opportunity to redesign the ODL rules to better reflect the intent and purpose of the loss provisions.

As an initial matter, the proposed tax reform should make clear that the 10-year expiration period for FTCs in I.R.C. Section 904(c) is suspended for any FTCs that would have been used to cover residual U.S. tax liability on foreign income but for the allocation of an ODL to reduce foreign source income. [8] The 10-year expiration period could be resumed on those FTCs once the ODL is recaptured in the later taxable year and the foreign income previously offset is restored

This suspension of the 10-year life of FTCs is appropriate since the allocation of ODLs against foreign source income, and later recovery and restoration, were never intended to reduce a taxpayer's ability to cover residual U.S. tax liability on foreign income with FTCs. Rather, the legislative history is clear that the ODL recapture provisions, modeled after the existing Overall Foreign Loss provisions, were adopted in 2004 with the intent to keep the taxpayer whole regarding FTC use.

> The Congress believed that the overall foreign loss rules continue to represent sound tax policy, but that concerns of parity dictate that overall domestic loss rules be provided to address situations in which a domestic loss may restrict a taxpayer's ability to claim foreign tax credits. The Congress believed that it was important to create this parity in order to prevent the double taxation of income. The Congress believed that preventing double taxation of income would make U.S. businesses more competitive and lead to increased export sales.[9]

Under the current rules, a taxpayer is at substantial risk for not being kept whole regarding FTC use when the taxpayer is maintaining ODL Accounts. Today, there is always a risk that ODL recapture, and restoration of foreign source income, will occur after the 10-year life of some or all of its FTCs have expired. Tax reform that suspends the 10-year life of any FTCs that would have been used to offset residual U.S. tax liability on foreign source income but for an ODL allocation is necessary to align the ODL rules and FTC rules with the original intent by Congress.

Consistent with the Congressional intent to allow taxpayers to use U.S. losses to offset U.S. source income while also keeping taxpayers whole with regard to their ability to claim FTCs, the proposed tax reform should further specify that a net U.S. loss in any year after tax reform will be treated, at the election of the taxpayer on its timely filed U.S. Federal income tax return, either as a traditional ODL or as a U.S. net operating loss ("U.S. NOL").

If the taxpayer elects to treat a net U.S. loss as an ODL, then the existing ODL rules, as amended by this tax reform, will apply to the loss. The net U.S. loss will reduce current year foreign source income proportionately among General Limitation and Passive income. ODL Accounts will be created to track the loss into later years. In the future, to the extent that the taxpayer earns net U.S. source income, a portion of that income will recapture the ODL Accounts and foreign source income will be restored.

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[8] I.R.C. Section 907(f) provides additional carryback and carryforward rules for oil and gas FTCs. Current law, however, provides no alignment between the I.R.C. Section 904(g) ODL rules and I.R.C. Section 907. It is API's position that I.R.C. Section 907 should be repealed as part of international tax reform. Given this, we have assumed for this paper that I.R.C. Section 907 is repealed, thus eliminating the potential for distortion upon restoration of the income.

[9] Joint Committee on Taxation's General Explanation of Tax Legislation Enacted in the 108th Congress, JCS-5-05, pg. 269 (May 2005).

If, instead, the taxpayer elects to treat a net U.S. loss as a U.S. NOL, then the loss will be segregated and, consistent with the general NOL rules in I.R.C. Section 172, be eligible to be carried back and rolled forward. In this situation, the U.S. NOLs may only offset U.S. source income and the taxpayer’s ability to claim FTCs is not affected in any year.

With respect to ODL Accounts in existence at the time of the tax reform, an appropriate transition rule would allow taxpayers an election to convert the ODL Accounts into a U.S. NOL by recapturing any tax benefits that the ODL may have produced. Mechanically, the taxpayer would recognize foreign source income up to the amount of the ODL Accounts in the year prior to the effective date of the law change. Tax on the recaptured amount could be offset by FTCs. The net tax liability, if any, would be paid either entirely in the year recognized or, at the taxpayer’s choice, spread evenly over the succeeding ten year period.

In order to ensure a complete identification and capture of foreign earnings, this ODL transition rule should be applied before any proposed repatriation of unremitted foreign earnings or any other similar tax reform transition rule.

Tax reform which provides the taxpayer with an election regarding the treatment of net U.S. losses grants the greatest flexibility to taxpayers attempting to remain competitive while managing business downturns, while also achieving the stated Congressional intent of keeping taxpayers whole for the use of FTCs.

See Appendix for examples of the current I.R.C. Section 904(g) rules and the application of the proposed ODL rules under tax reform.

Appendix

Assume that Z Corporation is a U.S. corporation with operations in Country A which has a 30% local tax rate on all income. Z Corporation has a $100 ODL in 2018, zero U.S. source income in 2019, and $200 in U.S. source income in 2020. In all years, Z Corporation has $600 in foreign source General Limitation income and $400 foreign source Passive income. Z Corporation has $100 in excess General Limitation FTCs that expire in 2019.

Scenario 1 – ODL Under Current Law:

2018 - No Tax Reform	U.S.	General Limitation	Passive	Total
Income	(100.0)	600.0	400.0	900.0
ODL Allocation	100.0	(60.0)	(40.0)	-
Income after ODL	-	540.0	360.0	900.0
U.S. Tax Liability	-	189.0	126.0	315.0
Current Year FTCs		180.0	120.0	300.0
Excess FTCs used		9.0	-	9.0
Remaining U.S. tax due	**-**	**-**	**6.0**	**6.0**
FTCs expiring		-	-	-
Excess FTCs carried over		91.0	-	91.0

The 2018 U.S. source loss offsets Z Corporation's foreign source income on a proportionate basis. Z Corporation creates a $60 General Limitation ODL Account, and a $40 Passive ODL Account. Z Corporation's need for FTCs is reduced in 2018, because the ODL has been allocated to reduce foreign source income. Excess FTCs that are unused in 2018, carry over to 2019. Z Corporation is left with a U.S. tax liability of $6 in 2018 on foreign source Passive income.

2019 - No Tax Reform	U.S.	General Limitation	Passive	Total
Income	-	600.0	400.0	1,000.0
ODL Recapture	-	-	-	-
Income after ODL	-	600.0	400.0	1,000.0
U.S. Tax Liability	-	210.0	140.0	350.0
Current Year FTCs		180.0	120.0	300.0
Excess FTCs used		30.0	-	30.0
Remaining U.S. tax due	**-**	**-**	**20.0**	**20.0**
FTCs expiring		(61.0)	-	(61.0)
Excess FTCs carried over		-	-	-

During 2019, Z Corporation has no U.S. source income, so it maintains its General Limitation ODL Account and Passive ODL Account. The foreign source income offset by the U.S. loss in 2018 is not restored in 2019. Z Corporation's excess FTCs of $61 expire in 2019, even though without the ODL in the earlier year, $21 of those FTCs would have been used.

2020 - No Tax Reform	U.S.	General Limitation	Passive	Total
Income	200.0	600.0	400.0	1,200.0
ODL Recapture	(100.0)	60.0	40.0	-
Income after ODL	100.0	660.0	440.0	1,200.0
U.S. Tax Liability	35.0	231.0	154.0	420.0
Current Year FTCs		180.0	120.0	300.0
Excess FTCs used		-	-	-
Remaining U.S. tax due	**35.0**	**51.0**	**34.0**	**120.0**
FTCs expiring		-	-	-
Excess FTCs carried over		-	-	-

Because there is U.S. taxable income in 2020, a portion of that U.S. income will be treated as foreign source income to recapture the existing ODL Accounts. Recapture will occur to the lesser of the cumulative remaining ODL accounts ($100) or 50% of that year's U.S. taxable income ($100). The recaptured income will be in the same income categories as the previously offset foreign income. Thus, in 2020, Z Corporation's foreign source income, and its need for FTCs, is higher than it otherwise would have been. Z Corporation ultimately pays $21 more in residual U.S. tax liability on General Limitation income than it otherwise would have without the ODL allocation because the credits to cover that additional foreign source income in 2020 have expired in 2019 before ODL recapture.

	U.S.	General Limitation	Passive	Total
2018-2020 Combined U.S. tax liability	**35.0**	**51.0**	**60.0**	**146.0**

During the three year period, Z Corporation will bear 35% U.S. tax on its net U.S. income of $100, or $35. It will have 5% residual U.S. tax on net combined foreign source General Limitation income of $1,800 or $90. Only $39 of that U.S. tax on General Limitation income can be offset by the $100 of excess carried over General Limitation FTCs. The remaining $51 of U.S. tax on General Limitation income must be paid because the excess carried over General Limitation FTCs of $61 have expired before this amount becomes due. Z Corporation will similarly have 5% residual U.S. tax on net combined Passive foreign source income of $1,200 or $60.

Z Corporation's total U.S. tax liability across all tax years is $146. Although Z Corporation is kept whole with respect to the use of the U.S. loss to offset U.S. source income, it has not been kept whole with respect to its use of FTCs. Z Corporation's ability to claim FTCs is restricted because the ODL allocation was recaptured in a year after General Limitation FTCs expired. Z Corporation suffers an increased U.S. tax liability of $21 as a result.

Scenario 2 – ODL after tax reform to suspend FTCs; ODL rules elected

In this instance, assume that tax reform has been enacted, effective beginning January 1, 2018, that suspends the 10-year expiration period of FTCs for credits that the taxpayer would have otherwise used but for the ODL. Further, this tax reform permits the taxpayer to elect to treat its net U.S. loss as either an ODL or a U.S. NOL. Z Corporation elects to treat its U.S. loss as an ODL.

2018 - With Tax Reform	U.S.	General Limitation	Passive	Total
Income	(100.0)	600.0	400.0	900.0
ODL Allocation	100.0	(60.0)	(40.0)	-
Income after ODL	-	540.0	360.0	900.0
U.S. Tax Liability	-	189.0	126.0	315.0
Current Year FTCs		180.0	120.0	300.0
Excess FTCs used		9.0	-	9.0
Remaining U.S. tax due	**-**	**-**	**6.0**	**6.0**
FTCs suspended for ODL		21.0		
FTCs expiring		-	-	-
Excess FTCs carried over		70.0	-	70.0

Because Z Corporation has elected to treat its U.S. losses as ODLs, a General Limitation ODL Account and a Passive ODL Account will be created to track the 2018 U.S. loss allocated to offset foreign source income.

2019 - After Tax Reform	U.S.	General Limitation	Passive	Total
Income	-	600.0	400.0	1,000.0
ODL Recapture	-	-	-	-
Income after ODL	-	600.0	400.0	1,000.0
U.S. Tax Liability	-	210.0	140.0	350.0
Current Year FTCs		180.0	120.0	300.0
Excess FTCs used		30.0	-	30.0
Remaining U.S. tax due	**-**	-	**20.0**	**20.0**
FTCs suspended for ODL		21.0		
FTCs expiring		40.0	-	40.0
Excess FTCs carried over		-	-	-

2020 - After Tax Reform	U.S.	General Limitation	Passive	Total
Income	200.0	600.0	400.0	1,200.0
ODL Recapture	(100.0)	60.0	40.0	-
Income after ODL	100.0	660.0	440.0	1,200.0
U.S. Tax Liability	35.0	231.0	154.0	420.0
Current Year FTCs		180.0	120.0	300.0
Excess FTCs used		**-**	-	-
Suspended FTCs released		21.0		
Remaining U.S. tax due	**35.0**	**30.0**	**34.0**	**99.0**
FTCs expiring		-	-	-
Excess FTCs carried over			-	-

In 2020, when the ODL is recaptured and the foreign source income restored, the previously suspended FTCs are released for use by Z Corporation.

	U.S.	General Limitation	Passive	Total
2018-2020 Combined U.S. tax liability	**35.0**	**30.0**	**60.0**	**125.0**

Z Corporation's total U.S. tax liability across the three year period is $125, which is equivalent to what it would have been had Z Corporation not suffered an ODL. Z Corporation has been kept whole with respect to its use of U.S. losses to offset U.S. source income and with respect to its ability to claim FTCs.

Scenario 3 – ODL after tax reform to suspend FTCs; U.S. NOL rules elected

As above, assume that tax reform has been enacted, effective January 1, 2018, that suspends the 10-year expiration period of FTCs for credits that the taxpayer would have otherwise used but for the ODL. Further, this tax reform permits the taxpayer to elect to treat its net U.S. loss as either an ODL or a U.S. NOL. Z Corporation elects to treat its U.S. loss as a U.S. NOL. Assume further that Z Corporation has no U.S. source income in a prior taxable year against which the U.S. NOL may be carried back.

2018 - With Tax Reform	U.S.	General Limitation	Passive	Total
Income	(100.0)	600.0	400.0	900.0
U.S. NOL Creation	100.0	-	-	
U.S. Tax Liability	-	210.0	140.0	350.0
Current Year FTCs		180.0	120.0	300.0
Excess FTCs used		30.0	-	30.0
Remaining U.S. tax due	**-**	**-**	**20.0**	**20.0**
FTCs expiring		-	-	-
Excess FTCs carried over		70.0	-	70.0

Because Z Corporation has elected to treat its net U.S. loss as a U.S. NOL, that loss is segregated for future use against U.S. source income only. Z Corporation's foreign income, and its ability to claim FTCs, is not affected by the net U.S. loss in any year.

2019 - After Tax Reform	U.S.	General Limitation	Passive	Total
Income	-	600.0	400.0	1,000.0
U.S. NOL	100.0			
U.S. Tax Liability	-	210.0	140.0	350.0
Current Year FTCs		180.0	120.0	300.0
Excess FTCs used		30.0	-	30.0
Remaining U.S. tax due	**-**	**-**	**20.0**	**20.0**
FTCs expiring		40.0	-	40.0
Excess FTCs carried over		-	-	-

2020 - After Tax Reform	U.S.	General Limitation	Passive	Total
Income	200.0	600.0	400.0	1,200.0
U.S. NOL Use	(100.0)			(100.0)
Income after NOL	100.0	600.0	400.0	1,100.0
U.S. Tax Liability	35.0	210.0	140.0	385.0
Current Year FTCs		180.0	120.0	300.0
Excess FTCs used		-	-	-
Remaining U.S. tax due	**35.0**	**30.0**	**20.0**	**85.0**
FTCs expiring			-	-
Excess FTCs carried over			-	-

In 2020, when Z Corporation earns U.S. source income, the U.S NOL can be used to offset that income. Z Corporation's ability to claim FTCs to offset residual U.S. tax liability on foreign source income is not affected in any year.

	U.S.	General Limitation	Passive	Total
2018-2020 Combined U.S. tax liability	**35.0**	**30.0**	**60.0**	**125.0**

Similar to the results in Scenario 2, Z Corporation's total U.S. tax liability across the three year period is $125, which is equivalent to what it would have been had Z Corporation not suffered an ODL. Z Corporation has been kept whole with respect to its use of U.S. losses to offset U.S. source income and with respect to its ability to claim FTCs.

Appendix Summary

Tax reform to suspend the 10-year FTC expiration period for any credits that the taxpayer would have been able to claim but for an ODL, as well as giving the taxpayer an election to treat net U.S. losses as either ODLs or U.S. NOLs, achieves the dual goals of allowing taxpayers the ability to use U.S. losses against U.S. income and keeping taxpayers whole for their ability to claim FTCs.

		Combined U.S. Tax Liability			
	Scenario	**U.S.**	**General Limitation**	**Passive**	**Total**
1	ODL Current law	35.0	51.0	60.0	146.0
2	Tax Reform - ODL Treatment	35.0	30.0	60.0	125.0
3	Tax Reform - U.S. NOL Treatment	35.0	30.0	60.0	125.0

Active Income and International Tax Reform

I. Tax Reform Policy Considerations

The oil and natural gas industry is extremely capital intensive and traditionally subject to high rates of tax on its operations. Companies must access new resources in order to grow, and US companies constantly compete with foreign based and national oil and gas companies for opportunities. In order for US companies to remain competitive with these global firms, it is imperative that foreign earnings not be subject to double taxation upon repatriation. Any incremental US tax creates a cost not faced by competitors in their home jurisdictions. Currently, US multinationals rely on the foreign tax credit system to avoid double taxation on their foreign earnings.

As discussions around tax reform focus on US global competitiveness, we understand that the current tax system may change. We also understand that potential changes may focus on the taxation of income that is highly mobile, intangible or potentially base-eroding. However, the oil and gas industry does not generate such income. Our investments are located where the resource or markets are located, as well as large scale and long term. Further, our products are fungible with pricing set by the global marketplace versus demand for a product based on an inherent intangible. As a result oil and natural gas income is neither low- taxed nor base-eroding.

If a new system were developed, we believe that it should exempt active foreign income associated with significant local country investments or business presence. This approach is consistent with our OECD trading partners and would allow U.S. companies to operate globally on equal footing. However, we recognize that there appears to be growing that certain income (highly mobile, intangible, etc.) should be subject to some level of tax (i.e., global minimum tax, herein referred to as "GMT"). If that is the approach of an international tax reform effort, we believe that income that is not mobile, subject to commodity pricing and associated with substantial tangible investment should be exempt from a minimum tax approach. Further, we believe that it is critical that a GMT or any alternative tax system is carefully designed to not subject such income to incremental U.S. tax, unless the existing foreign tax credit system remains in place.

We understand that there are policy concerns around a full exemption system for certain types of active income. Below we have outlined some industry related concerns in a GMT model and highlighted the potential for double taxation. In addition, we have provided suggestions for approaches to mitigate the double taxation issue.

II. Tax Reform Model - Assumptions

- All passive income will be taxed currently (i.e., no deferral) at US tax rates.
- Active income will be subject to some level of minimum tax based on ETR. (The solutions will address weather that test is on a per country basis or combined foreign income basis.)
- Current Subpart F rules will remain.
- Active income includes income that is not currently defined as passive under Section 954(c)(3) without considering the provisions of Section 956(c)(6).
- The foreign effective tax rate would be computed on an aggregate basis with respect to all active foreign earnings and the associated foreign taxes assigned to those earnings. (Again, determination of per-country or combined foreign income will be addressed in the solutions.)
- Averaged over a period of time {e.g. current year, 60-month, 120-month, etc.} that ends on the date on which the domestic corporation's current taxable year ends, or in the case of CFC earnings, that ends on the date on which the CFC's current taxable year ends.

III. Industry Issues

- Oil and gas income is not mobile and will be subject to statutory rate of tax greater than a likely GMT rate
- Timing differences between local cost recovery and US earnings and profits adjustments will result in a low effective tax rate (ETR) in the early years
- If GMT tested on a per country basis, ETR in certain countries will fall below the GMT rate
- Even if foreign ETR is averaged, long periods of investment can result in low ETR for many years
- Result is <u>double-taxation</u> of active foreign income subject to high statutory rates
- Taxing broad based categories of active income while maintaining existing Subpart F rules will create overlap and could potentially subject active income to a second layer of US tax.

IV. Potential Mitigation Solutions for Double Taxation

To avoid double taxation, provide an exemption for active income that will be subject to tax at higher statutory rates. This can be achieved by excluding income based on: (1) the type (e.g., commodities) of income, the nature of which is associated with local country investments that give rise to timing differences; or (2) a rate on total foreign active income, which avoids double tax on timing differences on income that is subject to high taxes over a project life. These exclusions are described below.

A. Combined Foreign Effective Tax Rate (CFETR) Test

- Provide an exception to GMT for foreign source (FS) active income if the CFETR is greater than GMT rate:

CFETR = Foreign income taxes attributable to FS active income/FS active income E&P

  - Passive income is not included in the CFETR computation
  - Alternative is to use CFETR as a "second-prong" only if a country first fails GMT test.
- Considerations:
  - Is CFETR averaged in same manner as annual GMT test (if foreign ETR is averaged)?
    - Should not matter if CFETR > GMT rate consistently

<u>OR</u>

B. Commodities Exception

- Provide a specific exemption from GMT for "commodities income"
- Policy reasons include market pricing, as well as issues identified above
- The language below is taken from the Tax Reform Act of 2014 (Chairman Camp's Tax Plan):

''(A) ADJUSTED GROSS INCOME.—

''(i) IN GENERAL.—The term 'adjusted gross income' means, with respect to any corporation, the gross income of such corporation <u>reduced by such corporation's commodities gross income.</u>

''(ii) COMMODITIES GROSS INCOME.— The term 'commodities gross income' means, with respect to any corporation, the gross income of such corporation which is derived from commodities which are produced or extracted by such corporation.

. . .

''(C) COMMODITY.—The term 'commodity' means any commodity described in section 475(e)(2).''.

Sec. 475(e)(2) Commodity – For purposes of this subsection and subsection (f), the term "commodity" means—

(A) any commodity which is actively traded (within the meaning of section 1092 (d)(1));

(B) any notional principal contract with respect to any commodity described in subparagraph (A);

(C) any evidence of an interest in, or a derivative instrument in, any commodity described in subparagraph (A) or (B), including any option, forward contract, futures contract, short position, and any similar instrument in such a commodity; and

(D) any position which—

(i) is not a commodity described in subparagraph (A), (B), or (C),

(ii) is a hedge with respect to such a commodity, and

(iii) is clearly identified in the taxpayer's records as being described in this subparagraph before the close of the day on which it was acquired or entered into (or such other time as the Secretary may by regulations prescribe).

Stephen Comstock
Director – Tax and Accounting Policy

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April 15, 2015

To: Senate Finance Committee – International Tax Working Group
RE: Comments to the Senate Finance Committee International Tax Reform Working Group

The American Petroleum Institute (API), on behalf of our members, appreciates the opportunity to provide some input to the working group process as the Senate Finance Committee begins to work through various tax policy issues. Given the size and scope of our industry, changes to the US tax code can impact the economics driving the jobs and outlook for our vibrant energy sector. Of course, 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.

Taxation of Foreign Operations - General

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[1] 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/exemption 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 an exemption system must insure that all active operating and related income would qualify for exemption, and that all

[1] Over $87 billion was repatriated by the industry in 2012 according to IRS data. These amounts only include dividends received from foreign operations – additional foreign income was earned directly by the industry through branch operations and subject to tax.

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.

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.

Specific Issues/Proposals

Over the past few years, API has commented on the US taxation of international operations. We have identified a few specific areas that may be unique to our industry that we believe deserve consideration if international tax reform takes shape. They are as follows:

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

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.

Our recommendation would be to repeal Section 907 and rules for transitioning to Section 904 should be adopted. This recommendation is consistent with the goal of simplifying the international tax area. Furthermore, the underlying policy rationale for section 907 is not relevant even in the current system, let alone a new approach adopting an exemption system or minimum tax structure.

b. Foreign Base Company Oil-Related Income

Foreign base company oil-related income (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.

There was little, if any, justification for enactment of these rules as they have nothing to do with U.S. base erosion or the shifting of mobile income. 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.

We would recommend that the FBCORI category of foreign base company income found in sections 954(a)(5) and (g) should be repealed as it clearly captures only active income where there is no concern about base erosion or profit shifting. If there is a proposal to retain some part of a Subpart F structure, it should be focused on 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. In addition to treating 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. It is not logical that the income of one refiner, who happens to engage in production activity, is treated as mobile while the exact same income of its competitor, who is not a large producer, is not.

c. **Dual Capacity 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.

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. 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.

d. Minimum Tax Ideas

Recent proposals from the Administration as well as Congress have raised the idea that some amount of minimum tax should apply to foreign source income. The determination of whether such a minimum tax should apply to all foreign source income and the minimum tax rate that must be applied are questions that are still being considered and there is no known consensus. The industry is very concerned about the application of a minimum rate test that would be aimed at certain activities but inadvertently impact our operations.

The specific concern is that the application of such a policy could lead to double taxation of capital intensive industries where there are significant timing differences between US tax principles and host country rules. Large capital intensive industries generally recover costs on an accelerated basis for host country tax purposes and reduce taxes in the early years of a project. However, U.S. based companies are required to compute U.S. E&P using the slowest method of cost recovery. In the oil and natural gas industry, it means using ADS straight line for tangible assets and ten-year amortization for foreign intangible drilling costs (IDCs). When accelerated host country cost recovery is coupled with increased foreign E&P from adjustments required under U.S. rules, the result is a low effective tax rate in early years that will reverse of the life of the project. Income could then be treated as “low-taxed” in the early years even if the foreign tax rate is equal to or above the U.S. rate over the life of the project. The resulting incremental U.S. tax, based on a snapshot in time, would be a permanent cost, which penalizes industries requiring heavy capital investment.

A presentation on application of the minimum tax to the industry is attached to this letter for reference.

e. CFC and Branch Treatment

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 status and instead operate as a branch.

Some proposals have struggled with the taxation of branches and whether there should be some type of parity between branches and CFCs. If policy makers are considering this issue we would suggest that it be approached cautiously. 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 as branches are transformed to CFCs as 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. This could result in an immediate recognition of unrealized gains, and immediate recapture of prior branch losses. In considering the branch issue, we have looked at various options to avoid the complexities and other detrimental effects noted above that we would be happy to discuss further with the staff.

f. Thin Capitalization Comments

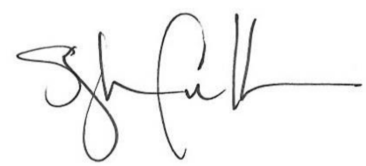
The industry understands the need to address potential base erosion due to “excess” leverage is problematical, but we believe that proposals based on the existing rules will address this consideration adequately and negate a need to introduce a new set of administratively complex rules and calculations, e.g., the worldwide calculation. 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. 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. In addition, we would note that the Camp proposal would reduce the 50% limit to 40%, and not 10% as proposed by the US Treasury. We believe that using 10% to "catch" excess leverage will deviate from the well-developed standards and rules which target base erosion, is not arm's length, and will create double taxation for taxpayers

Again, we thank you for the opportunity to comment as part of this process and welcome any questions that you may have. Should you wish to discuss these points further, please do not hesitate to contact me at 202-682-8455.

Sincerely,



Stephen Comstock

Attachment

ATTACHMENT

Oil & Gas Overseas Operations

American Petroleum Institute

March 25th, 2015

1

Overseas Upstream Operations – Distinctions with Other Industries

- Location of operations driven by resource - not tax planning
  - No U.S. base erosion issue
- Product is fungible
  - No intangible value associated with hydrocarbons
  - Prices established on commodities markets
- Operations subject to high tax rates
  - "Tax haven" entities used for non-tax business purposes
- Large capital costs up front
  - Generates host country/US timing differences
  - Access to resources highly competitive – US, Foreign, and State Owned oil companies
- Double taxation results in costs for US based companies not borne by foreign competitors

2

International Upstream Taxation

		All Taxpayers	Oil and Gas Companies
Foreign Tax Credits	Creditability rules under 1.901-2	Prove creditability of taxes through criteria	Prove creditability of taxes through criteria
	Dual Capacity Taxpayer Rules under 1.901-2A		Prove creditable taxes are not royalties (upstream operations)
FTC Limitation	Section 907		Separate limitation for FOGI qualifying taxes
	Section 904	Overall credit limitation	Overall credit limitation

3

International Refining Operations

- Refining is taxed locally like manufacturing
  - Capital intensive
  - Low margin commodities business
  - Typically located near resources or markets
- US Tax overlay
  - Subpart F treatment (FBCORI) on refinery exports unless derived from oil and gas extracted from same country
  - Applies only to refiners with substantial oil production
  - No "manufacturing exception" like other industries
  - Falls within the 907 FTC limitation

4

Camp Comparison – Facts and Assumptions

- Minimum tax
  - Commodity Exception
  - Retains FBCORI

FACT PATTERN				
Type of Income	Income	Country	Tax Rate	Taxes
Extraction E&P	500,000	A	55%	610,000
Refining & Marketing FBCORI	1,000,000	B	18%	220,000
TOTAL	1,500,000			830,000

Foreign Tax Credit Calculation	Income	Taxes	Income Subject to US Tax
Extraction	500,000	610,000	1,110,000
Refining & Marketing (FBCORI)	1,000,000	220,000	1,220,000
		TOTAL (FOGI)	2,330,000

5

Camp Comparison to Current

	Current Law		Camp	
Statutory Rate	35%		25%	
Tax Treatment	FORI is FBCORI per (954(g)); Income is FOGI and combined with extraction for 907; Full foreign tax credit under 904		FOGEI subject to 95% exemption; FBCORI subject to current year tax at 25%	
Tax Result	US Tax on FOGI FOGI * 35%	815,500	US Tax Extraction Extraction *5%*25%	13,875
			US Tax On Refining FBCORI * 25%	305,000
	Current Year FTC	(815,500)	Current Year FTC	(220,000)
	Residual US Tax	-	Residual US Tax	98,875
	Foreign Tax	830,000	Foreign Tax	830,000
	Total tax Paid	830,000	Total Tax Paid	928,875
	Tax Credit Carry Forward if Foreign tax greater than US tax	14,500	Tax Credit Carry Forward	0
	Effective Tax Rate Total Tax Paid/Total FOGI	36%	Effective Tax Rate	40%

6

President's Minimum Tax Approach

- Minimum Tax
  - All foreign income subject 19% tax
  - ACE Adjustment
  - Reduction equal to 85% of 5 average year host country effective rate.
- For example
  - Host Country statutory rate of 55%
  - 5 Year Average Effective Tax Rate: 15% due to timing differences
  - Overall Project life ETR: roughly 55%

5 year average	Host	US
EBIT	1,000,000	3,666,667
Host tax paid	550,000	550,000
ETR	55%	15%

- Main Reasons for Timing Differences
  - Host Country: IDC current expensing; Tangible costs 25% pool
  - US: IDC amortize over 10; tangible costs ADS @ 14yr

7

Minimum Tax Takeaways

- Double-taxation on income can easily happen even with averaging
  - Local timing differences can result in temporary low effective host country tax rates
  - Income ultimately taxed at high statutory rate over life of project
  - No refund of prior minimum tax available
- Additional elements exacerbate the competitiveness concerns
  - Per Country
  - Dual Capacity
  - FBCORI

8

API comments on Chairman Baucus' Staff Discussion Draft
On International Tax Reform

EXECUTIVE SUMMARY:

API Comments on Chairman Baucus' Staff Discussion Draft for International Tax Reform

The American Petroleum Institute (API) welcomes the opportunity to provide comments on Chairman Baucus' Staff Discussion Draft for international Tax Reform. API is the only trade association that represents all aspects of America's oil and natural gas industry. Our industry is very capital intensive and pays substantial income taxes on foreign operations, which results in an industry wide effective tax rate in excess of 40 percent.

API believes that international tax reform should provide rules to ensure foreign source operating income of U.S. based companies is not subject to double taxation. This is essential to supporting the competitiveness of U.S. companies internationally. With that in mind, the industry can support a move towards a territorial tax system that is competitive with tax laws of other major developed countries, providing U.S. based oil and natural gas companies a level playing ground to compete internationally. In all cases, a fully functioning and competitive foreign tax credit system must remain in place.

Based upon these principles, we have analyzed the Discussion Draft as follows:

- Option Y provides a limited exemption system while also limiting the ability to use foreign tax credits. This will lead to double taxation of the industry's active foreign income and will impede the ability of U.S. firms to compete for reserves in foreign markets.
- Option Z retains the current worldwide system while ending deferral. The segregation of like active foreign income into new categories for foreign tax credit purposes impacts the efficacy of the current foreign tax credit rules. This will lead to double taxation of the industry's active foreign income and will impede the ability of U.S. firms to compete for reserves in foreign markets.
- U.S. Related Income/U.S. Import Property rules will result in incremental U.S. tax under both Options by penalizing one type of active foreign income. There are policy concerns regarding such a broad exclusion of active foreign income from active income treatment.
- Any review of the taxation of international operations should address the continued relevance of section 907.[1] There is not a need for this provision to be in the existing foreign tax credit rules, and it is made more redundant in the proposals under both Options.
- The Discussion Draft's provisions common to both Options give rise to many policy concerns:
    - Limiting the check-the-box rules will increase costs of deploying capital in foreign markets.
    - Not providing look-through rules for payments by controlled foreign corporations will recharacterize income sourced from active receipts as passive.
    - Repealing Fair Market Value method removes a fair and equitable method of apportioning interest expense.
    - Eliminating section 902 will result in double taxation on income of 10/50 companies.
    - Creating a broad base erosion provision for related party payments represents a policy shift on the arm's length standard.

[1] All references are to Internal Revenue Code of 1986.

I. Introduction

API represents more than 580 member companies involved in all aspects of the oil and natural gas industry including exploration, production, transportation, refining, and marketing. The American oil and natural gas industry supports over 9.8 million domestic jobs and represents more than 8 percent of GDP. As an extractive industry, we operate where the resources are 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. Given this high effective tax rate, the existing foreign tax credit rules allow U.S. based companies to compete in today's global energy market on a relatively equal footing with competitors based in countries with territorial systems.

Recently, concerns have grown about the current U.S. tax system (e.g., that the rules limit U.S. competitiveness in an increasingly global economy), leading to call for tax reform. Any tax reform should be based on sound and transparent policies. Tax rates should be lowered in manner that promotes investment and provides a system that is competitive with 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 understand that the taxation of foreign operations by a home country is very complex area to address in tax reform. However, our industry's main focus in reforming international tax provisions is fairly simple: rules must be maintained to prevent the double taxation of foreign source operating income of U.S. based companies to ensure the competitiveness of U.S. companies internationally.

Any move to a territorial or exemption based system must ensure that all active operating and related income would qualify for a competitive exemption,[2] 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. We recognize that the current system has created what is referred to as the "lock-out" effect for certain industries. Our industry does not contribute to this lock-out effect and continually repatriates substantial cash back into the U.S. economy.[3] The current foreign tax credit mechanism allows U.S. taxes on foreign source income to be offset by foreign taxes paid on that income, which generally eliminates double taxation.

Within this framework, our comments on Senator Baucus' Staff Discussion Draft for International Tax reform ("Discussion Draft") address Option Y, Option Z, and the Provisions common to both Options from an industry perspective. API recognizes the significant technical work involved in drafting these reform proposals and appreciates the opportunity to provide comments.

[2] Less than a full exemption will result in incremental U.S. tax for an industry in an excess credit position. However, we recognize that simplification may require a minimal income inclusion.
[3] Over $125 Billion was repatriated by the industry in 2010 according to IRS data.

II. Technical Comments on Option Y and Option Z

A. Option Y

1. Relevant Provisions

Option Y provides a limited exemption from U.S. tax for some active foreign income, ends deferral for other types of foreign income and restricts foreign tax credit usage for all other active foreign income. Option Y's exemption mechanism applies to certain active foreign income by providing a 100 percent deduction for the qualified portion of dividends received (DRD) by qualified shareholders from a Controlled Foreign Corporation (CFC). The DRD is limited to dividends attributable to foreign earnings that have not already been included in the taxpayer's income by reason of subpart F, which is significantly expanded under Option Y to include a broader base of active foreign income of a CFC.

With respect to the concept of deferral (currently found in subpart F of the Code), Option Y repeals the current foreign base company sales, service and oil related income categories, but includes a modified category of foreign personal holding company income and adds two new categories of subpart F income: United States related income (USRI) and low-taxed income.

Option Y also makes substantial changes to the foreign tax credit rules. Most importantly, foreign taxes on exempt income (i.e., high-taxed income) are disallowed as credits. For non-exempt income (i.e., subpart F income and foreign branch income) only taxes attributable to that item of income can be claimed as a foreign tax credit. In addition, Option Y creates six new categories of income for purposes of section 904: (1) passive income; (2) USRI; (3) low-taxed income; (4) foreign branch income; (5) insurance income; and (6) all other income. Foreign tax credit carryforwards (non-passive) will be included in the all other income category.

Option Y causes significant concern to the industry for a number of reasons. First, from a policy perspective, it has a much broader base than other tax regimes and, therefore, would undermine the competitiveness of U.S. based companies. No other country imposes an effective tax rate on active foreign income in order to qualify for an exemption.

Second, the structure of Option Y targets discrete parts of our globally integrated business for additional U.S. tax notwithstanding the high overall foreign effective tax rate that we incur. The industry incurs effective tax rates on foreign operations that are significantly above the U.S. statutory rate. However, disallowing foreign tax credits for taxes associated with high-taxed income and creating separate credit limitation categories to go along with the expansion of subpart F income will result in double taxation on foreign operations. This imposes a significant disadvantage on U.S. firms in the competition for access to foreign reserves and markets.

Below is an analysis of the potential impact of Option Y on the industry. USRI is separately discussed in section II.C.

2. Potential Impact

The new low-taxed income category of subpart F includes items of income that have a foreign effective rate that is less than 80 percent[4] of the maximum U.S. corporate tax rate. The effective foreign tax rate on any item of income is computed using U.S. tax principles and taking into account only taxes and other deductions related to the tested item of income. A taxpayer is allowed a deduction of 20 percent of low taxed income from the amount included in gross income.

Because the low effective tax rate test applies on an item by item basis, it would lead to double taxation for U.S. oil and natural gas companies in many cases. Extraction, transportation, refining and marketing are all part of the industry's integrated supply chain. In addition, all are active businesses that require significant infrastructure investments in countries in which the industry operates. However, extraction is generally taxed at a higher rate than transportation or refining and marketing activities. Overall, the effective foreign rate on the total supply chain is in excess of the U.S. rate.

Under Option Y, the taxes attributable to high-taxed activities conducted in a CFC would be disallowed, because the income would qualify for a DRD. In addition, income from CFC activities with an effective tax rate at or below the requisite threshold rate, as described above, would be treated as low-taxed subpart F income and isolated in a separate foreign tax credit category. The result is incremental U.S. tax even though the taxpayer is left with overall effective tax rate on active foreign income in excess of not only the U.S. rate but also the foreign effective tax rate on such income (i.e., double taxation).

We also take issue with the use of an effective tax rate to measure low-taxed income for capital intensive industries, such as oil and natural gas production, and refining. Determining the foreign effective tax rate under U.S. tax principles implies that U.S. adjustments to foreign earnings & profits (E&P) would be taken into account. Large capital intensive industries generally recover costs on an accelerated basis for host country tax purposes and reduce taxes in the early years of a project. However, U.S. based companies are required to compute U.S. E&P using the slowest method of cost recovery. In the oil and natural gas industry, it means using ADS straight line for tangible assets and ten-year amortization for foreign intangible drilling costs (IDCs). When accelerated host country cost recovery is coupled with increased foreign E&P from adjustments required under U.S. rules, the result is a low effective tax rate in early years that will reverse of the life of the project. Income could then be treated as "low-taxed" in the early years even if the foreign tax rate is equal to or above the U.S. rate over the life of the project. The resulting incremental U.S. tax, based on a snapshot in time, would be a permanent cost, which penalizes industries requiring heavy capital investment.

Finally, an international tax system that currently taxes income based upon an effective tax rate test imposes a great deal of uncertainty on U.S. companies when evaluating long-term investments in foreign countries. U.S. multinationals may make investments in a country with an understanding of effective tax rates, realizing that they may be equal to or higher than the U.S. rate at the time the investment is made. Under Option Y, the income would be exempt. However, host countries can

[4] In our analysis we used the rates stated in the Discussion Draft. We note that rates in the Discussion Draft were bracketed to indicate the fact that they were not intended to be concrete.

change their tax rules for a number of reasons. In a case where the host country later lowers its statutory tax rate, the result could be an effective tax rate below 80% of the U.S. rate. Previously exempt income could now be subject to incremental U.S. tax that was not expected at the time of investment. Even when there is no overall increase in tax cost to the U.S. company, there is still a disadvantage with respect to non-U.S. competitors, who will benefit from the lower tax rate without incremental home country tax.

Example 1:

A U.S. multinational operates integrated extraction, transportation and refining businesses outside the U.S. through several CFCs. It earns $1,000 of extraction income and $1,000 of refining and transportation income, which is subject to statutory rates of 55% and 20%, respectively. The combined effective rate on its income is 37.5%. Under current law, the company's effective rate on its foreign income is the foreign effective rate, which exceeds the U.S. tax rate.

Assume that the U.S. statutory rate is lowered to 28%. Under Option Y, each item of income would be analyzed separately. The extraction income would qualify for a DRD and its taxes would be disallowed as foreign tax credits. The refining and transportation income would be treated as low-tax income and subject to a U.S. tax rate of 22.4% (80% x 28% U.S. rate = 22.4%).

Tax on Extraction Income:	$550
Tax on Transportation & Refining Income:	$200
	$24 Incremental U.S. Tax
	$774/ $2000 (Foreign Income) = 38.7%

This example illustrates two important points. The first is how Option Y results in double taxation for the industry. The resulting 38.6% effective tax rate is above both the U.S. (28%) and the foreign (37.5%) effective tax rates. The second point is how Option Y creates a competitive disadvantage for the U.S. firm with respect to the transportation and refining sector of its business. Under this example, the U.S. company would pay an effective tax rate on those operations that is over 11% higher than the effective tax rate paid on the same activities by non-U.S. companies (22.4% vs. 20%).

Example 2:

Assume that a U.S. multinational makes a $3,000 investment in a new, foreign extraction project. Net income, before cost recovery is $1,000 per year for the next 10 years, and the statutory rate is 55%. Under local tax laws, the investment is completely recovered over the first three years, but under U.S. rules the investment is recovered over ten years. The results under Option Y with a 28% U.S. tax rate are shown below.

Local Tax		
	Taxable Income	Tax
Years 1 – 3	$0	$0
Years 4 – 10	$7,000	$3,850
Total	$7,000	$3,850

U.S. Tax				
	Taxable Income	Tentative Tax	FTC	US Tax
Years 1 – 3	$2,100	$470	$0	$470
Years 4 – 10	$4,900	$1,097	$3,850	$0
Total	$7,000			$470

Total Tax	
Local Tax	$3,750
U.S. Tax	$470
Total	$4,220
Effective Tax Rate: $4,220 / $7,000 = **60.2%**	

This example illustrates how income on a high-taxed project would be treated as low-taxed income, resulting in double taxation and an effective tax rate in excess of the rate of non-U.S. competitors.

In summary, Option Y does not provide a competitive exemption system and weakens the existing foreign tax credit rules. As a result, it would increase the effective tax rate on active foreign income generated in the oil and natural gas industry. As an industry subject to high taxes, our foreign source income neither creates the "lock-out" effect nor generates the "nowhere" income that is the focus of international reform.

B. Option Z

1. Relevant Provisions

Option Z attempts an activity-based approach to international reform of CFC taxation. Instead of categorizing income based on local country rates, it generally treats all income of a CFC as either active or passive. Specifically, Option Z eliminates deferral and repeals all categories of subpart F, including

FBCORI. These former categories are replaced with two new categories: Active Foreign Market Income (AFMI) and Non Active Foreign Market Income (NAFMI). AFMI is subject to a 40% exemption from U.S. tax, while NAFMI is subject to the full rate.

Generally, in order to qualify as AFMI, the income must be generated through economically significant activities of a qualified trade or business derived in connection with services performed and property sold or exchanged for use outside the United States. Economically significant activities are defined as those performed outside the United States by officers or employees of the CFC, which make a substantial contribution to the production of income. Manufacturing and extraction are included in the definition of a qualified trade or business. While not explicitly listed as a separate category of subpart F income, the definition of AFMI basically excludes U.S. import property (USIP) from qualifying as AFMI.

Option Z maintains foreign tax credits for all income. However, to the extent AFMI is exempt from tax, a pro-rata amount of foreign tax credits are disallowed. With respect to foreign tax credits, there are three 904 limitation categories; AMFI, passive and "all other income" (which includes foreign branch income and USIP). Similar to Option Y, pre-law change foreign tax credit carryforwards (non-passive) would be included in the all other income category.

2. Potential Impact

The focus of Option Z on activities versus local effective tax rate should generally limit treatment of active foreign income as passive. In addition, all AFMI is treated consistently for exemption and foreign tax credit purposes. However, there are distinct limitations in Option Z when viewed in terms of global competitiveness. First, the segregation of USIP from AFMI (see Section II. C., infra.) represents a significant departure from the overall activities based approach. Second, segregating AFMI from USIP and branch income impedes the efficacy of the existing foreign tax credit rules for active foreign income. Third, the partial-exemption system versus the full-exemption system leaves U.S. multinationals with the burden of incremental U.S. tax not borne by foreign competitors.

As an example, a U.S. taxpayer has extraction activities in two different jurisdictions (Country A&B), each generating $1,000 of pre-tax income. Activities in Country A are conducted through a branch and those in Country B in a CFC. The tax rates are 35% and 25%, respectively. The blended effective tax rate of those earnings is 30%, which is above the speculated rate under a Baucus tax plan. Under the current rules, the income would be treated consistently for foreign tax credit purposes resulting in no incremental U.S. tax. However, under Option Z, the same foreign business activities are separated into different baskets, resulting in incremental U.S. tax on income earned from Country B. In balancing competitiveness and base erosion, there is not a policy reason for incremental U.S. tax on foreign active income of a like kind that has been subject to a combined effective rate above the U.S. rate.

C. U.S. Related Income/U.S. Import Property

Both Options, though semantics differ, introduce a new category of income that is subject to full and immediate U.S. taxation. In Option Y, the mechanism is treating USRI as Subpart F income. In Option Z, USIP would be excluded from the definition of AFMI. Accordingly, it would NOT be subject to the 40%

exemption rule (making it 100% taxable), and it would be in a separate section 904 category (e.g., all other).

Income could be treated as USIP even if sold to a third-party outside the United States. The specific standard provided is whether it is "reasonable for the controlled foreign corporation (or a related person) to expect that…" the property would be used in the United States. The exclusion for USIP is likely to impact income earned from refined products. Because that income is generally subject to lower taxes, excluding it from AFMI and including it in other income will increase the overall effective tax rate on that income. It would be similar to the examples in Option Y (Section II. A.2., supra.). However, instead of being subject to tax at 80% of the U.S. rate, it would be subject to tax at the full U.S. rate under both Options.

The U.S. import property rule could also impact extraction income. If there were a lower effective tax rate on extracted product in a given year (based on the effective tax rate issues discussed above, see Example 2) and that product were ultimately imported into the U.S., it would be subject to incremental tax under either option as follows:

- Option Y: If foreign effective tax rate in a given year was greater than 80% of the U.S. rate but less than 100%, and it is treated as USRI, it will be subject to incremental U.S. tax. This would be the case even if, over the life of the project, the income will be subject to a rate in excess of the U.S. rate. If it were not USRI, then it would be treated as exempt income.
- Option Z: Without regard to the rate, the income will not qualify for AFMI. Therefore, it will be segregated in the all other income category and subject to full U.S. tax. If the effective rate is low on that particular item of income in a given year, that extraction income will be subject to incremental U.S. tax.

There is a specific concern with respect to extraction income earned in Canada. If the effective tax rate is below a reduced U.S. rate, as it is expected to be, then the export of Canadian oil to the U.S. will result in incremental U.S. tax. Oil and natural gas is a significant industry in Canada that provides needed feedstock to meet U.S. demands. Based on Canada's trading partner status, the policy issues that may arise from these provisions must be considered.

Finally, there are issues unique to the oil and natural gas industry, because resources must be produced in the jurisdiction where they reside. With respect to refined product, the capacity is limited in the United States and cannot always meet the necessary demand. These industry related policy issues have been contemplated in former base-erosion proposals. The Senate Finance paper on international competitiveness discussed the provisions of a bill introduced by former Senator Dorgan.[5] The purpose of the bill was to eliminate the benefits of "round-tripping" products, by exploiting U.S. developed intangibles and/or manufacturing products offshore while generating revenue from U.S. markets. The bill specifically exempted what is now foreign oil and gas income (FOGI). Options Y and Z do not specifically address income attributable to intangibles, as the Camp discussion draft does, but instead,

[5] S.260 (111th Congress), A bill to mend the Internal Revenue Code of 1986 to provide for the taxation of income of controlled foreign corporations attributable to imported property (Sponsored by Sen. Dorgan).

broadly targets base-erosion and lockout concerns through these provisions. Because foreign income from industry activities do not give rise to either of these policy concerns, an similar exception for FOGI would be imperative in keeping U.S. multinationals internationally competitive.

D. Section 907

We noted that the Discussion Draft does not address section 907. In addition to the foreign tax credit limitations found in section 904 that apply to all foreign tax credits, section 907 places a special limitation on foreign income taxes paid on FOGI. Under this special limitation, amounts claimed as taxes paid on FOGI 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 FOGI in the given 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.

We believe that any proposed changes to the taxation of international operations should consider the need for section 907. Section 907 has limited relevance today when foreign tax credit baskets have been reduced down to general and passive categories, and the related regulations are well-defined. Going forward, proposals focusing on territorial or exemption regimes would further erode the need for a separate oil and gas limitation. Specific to the Discussion Draft, the structural framework of both Option Y and Option Z certainly negate the need for section 907. Under Option Y, the credits on high-tax income are disallowed, because the income is exempt from U.S. tax. In addition, the limitation on available credits for subpart F income essentially separates foreign tax credits by both country and activity. Under Option Z, the activity based nature of defining foreign source income treats all qualifying AFMI consistently. Because the framework of Option Z is limiting taxation on AFMI while fully taxing NAFMI income, without regard to the foreign effective rate on that income, there is not a need to separate one form of active business income from another. Under either option, section 907 should be eliminated, which would also be consistent with the goals of fairness and simplification.

III. Provisions Common to Both Options

A. Check-the-Box

1. Overview

The Discussion Draft modifies the rules of section 7701 and provides that any business entity (foreign or domestic) which is not otherwise required to be treated as a corporation shall be treated as a corporation if: (1) it is wholly-owned by a single CFC; or, (2) all of its ownership interests are held directly by two or more members of an expanded affiliated group, at least one of which is a CFC. As such, disregarded entities of a CFC and certain partnerships (both foreign and domestic) that are owned by at least one CFC will now become corporations for U.S. tax purposes.

Additionally, the Discussion Draft provides that existing disregarded entities and partnerships would be deemed to have made an election to change their entity classification to a corporation and would face the full collateral tax consequences. Under Treas. Reg. §301.7701-3(g), the election results in a deemed contribution of all of the entity's assets and liabilities into a corporation, followed by the liquidation of the entity (in the case of a partnership).

2. Impact of Changes

The current entity classification rules allow U.S. multinational companies to make efficient financing decisions outside the U.S., because the transactions are often disregarded for U.S. tax purposes. To compete internationally, it is important for U.S. multinational companies to efficiently redeploy excess foreign capital to foreign operations. The changes outlined in the Discussion Draft will add undue complications and potential costs that will make U.S. based companies less competitive in foreign markets.

By removing U.S. multinationals' ability to use disregarded entities to finance foreign operations, the changes in the Discussion Draft will result in intercompany interest payments being classified a subpart F income and subject to current taxation. Because non-U.S. based companies are not subject to similar rules, this change will place U.S. companies at a significant competitive disadvantage when operating in foreign markets.

3. Transition Issues

The deemed election to change entity classification from a disregarded entity to a corporation under the Discussion Draft's changes to the check-the-box rules could also present entities with adverse tax consequences. Entities that were established under previous rules and never intended to be treated as corporations should not be burdened by adverse tax effects from a deemed entity classification change.

Additionally, the changes to the check-the-box rules will result in some partnerships becoming 10/50 companies. If an existing partnership does not have the requisite U.S. shareholder ownership after the deemed classification change to become CFC it will become a 10/50 company. The Discussion Draft contains additional provisions that will adversely impact tax treatment of 10/50 companies. (See Section III.D., infra.)

B. CFC Look-Through Rules

The Discussion Draft does not adopt the current CFC look-through rules. Look-through rules allow payments within related party structures to carry the designation of the underlying income that generated the payment rather than be recast as a separate type of income. The stated legislative purpose for the current CFC look-though rules was to enable CFCs to deploy capital where needed around the globe without incurring additional U.S. tax burdens, thereby enhancing competitiveness of U.S multinational companies. One of the goals of the Discussion Draft is to increase the ability of U.S. multinational companies to compete against foreign companies in foreign markets and mitigate the lock-out effect.

The policy behind the CFC look-through rule is important in any international tax reform. Though a move to exemption and territorial based systems still require base erosion rules to capture passive income, some allowance needs to be made to avoid reclassifying income inappropriately. By not extending the look-though rule, active income of a lower tier CFC could be reclassified as passive income when the income flows to higher tier CFC in the form of interest or royalties. In doing so, the Discussion Draft would appear to be in conflict with its goal of increasing U.S. multinational companies' ability to compete internationally. The original policy behind the implementation of the look-through rules is still sound, and no alternative policy position has been presented to justify not making these rules permanent.

C. Fair Market Value Apportionment Method

The Discussion Draft prohibits taxpayers from using the fair market value (FMV) of assets for purposes of allocating interest under section 864(e) and requires the use of adjusted tax basis of assets. There is no analysis accompanying the Discussion Draft, so it is difficult to understand the rationale behind the change. The relative FMV of assets is an appropriate way of equitably allocating interest expense, and in many cases, a much more representative measure of interest allocation than adjusted tax basis.

D. Treatment of 10/50 Companies

The repeal of section 902 in the Discussion Draft will cause double taxation on dividends from 10/50 companies. Under section 902 of current law, U.S. corporate taxpayers that own 10% or more of the voting stock of a foreign corporation are generally allowed to claim "deemed-paid" foreign tax credits on dividends received. This rule applies to foreign corporations that are classified as a CFCs and to non-controlled 10/50 companies. As a result of this change, dividends paid out of foreign source earnings from a 10/50 company will not benefit from a deemed paid credit or a dividends received deduction. This directly results in double taxation of foreign source earnings. Neither Option Y nor Option Z provides relief from this double taxation.

While 10/50 companies are not the most common vehicle for foreign investments, the use of 10/50 companies may sometimes be necessary due to local factors such as a requirement of local majority ownership. The Discussion Draft's changes to the check-the-box rules (as discussed above) will create more 10/50 companies and increase the instance of double taxation on 10/50 income. These changes would be a major impediment for investments where the use of a 10/50 company is required by law or is the most attractive ownership vehicle for other economic considerations. Additionally, the repeal of section 902 would also penalize historic 10/50 structures that were established for non-tax reasons.

E. Related Party Payments in Base Erosion Arrangements

The Discussion Draft introduces a provision that denies deductions for any "related party payment" arising in connection with a "base erosion arrangement." This broadly drafted language represents an unprecedented approach on base erosion. One of the stated goals of the Discussion Draft is creating a U.S. tax environment that encourages companies to remain in the U.S., and/or to invest in the U.S. However, the unilateral and anti-competitive nature of this provision does not achieve either of these objectives.

Under current rules, U.S. companies are allowed to deduct a variety of payments to foreign related parties, based on both long-standing U.S. tax principles on ordinary and necessary business expenses, as well as internationally recognized principles such as the arm's length standard. Deductibility of ordinary and necessary business expenses represents globally competitive tax policy and provides fiscal stability for both taxpayers and governments. The Discussion Draft proposes to change sound policy by denying certain U.S. taxpayers the ability to deduct ordinary and necessary business expenses, when deemed a "base erosion arrangement." This is concerning, because it represents a unilateral move away from the arm's length standard and a challenge to a foreign jurisdiction's sovereign right to establish its own fiscal regime. This proposal would result in the double taxation of foreign based multinational companies in the U.S. In addition, it violates U.S. treaties, and would have negative impact on U.S. investment, jobs and economic activity. Finally, the rule would involve increased administrative complexity for both taxpayers and the U.S. government.

International Tax Reform Comments

2013

Enclosed are documents which reflect the US oil and natural gas industry's comments on international tax reform – primarily focused on the House Ways & Means Majority "Discussion Draft."

Material for Congressional Staff – Not for Broad Distribution

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).

General Comments on Ways & Means Territorial Discussion Draft (cont.)

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."[1] 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.

[1] 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[2]. 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

[2] 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."

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.

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.

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.

CFC and Branch Treatment (cont.)

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.[3] Treating a foreign branch as a CFC for all purposes of the Code is 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.

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

CFC and Branch Treatment (cont.)

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[4].” 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 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.

[4] 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.

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.

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.

CFC and Branch Treatment (cont.)

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.

Prevention of Base Erosion: Option B (cont.)

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.

Prevention of Base Erosion: Option B (cont.)

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).

Prevention of Base Erosion: Option B (cont.)

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.

Thin Capitalization Comments (cont.)

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.

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