

Understanding Oil and Gas Tax Subsidies

How the Tax Code Favors Oil and Gas Production — and What It Costs Taxpayers

Outdated Incentives

Some oil and gas tax preferences—such as expensing of intangible drilling costs—were created well over a century ago to nurture what was a fledgling industry. But now, the U.S. is the world's top producer and net exporter of oil and gas, yet taxpayers are still padding the bottom lines of a mature, highly profitable industry.

Significant Fiscal Impact

These tax preferences have cost taxpayers hundreds of billions of dollars since their inception and are projected to cost up to \$51 billion more in tax expenditure over FY2025-FY2029.

Structural Market Distortion

Oil and gas-specific tax preferences have allowed oil and gas companies to bypass standard income tax rules applied to other industry sectors. Closing these loopholes will level the playing field, saving taxpayers billions of dollars.

What Counts as a Tax Preference

The federal government supports selected activities in two basic ways. It can spend money directly through appropriations and mandatory programs. Or it can reduce or eliminate taxes that would otherwise be owed. The second approach is less visible, but no less real. These provisions are known as tax expenditures.

Under the Congressional Budget and Impoundment Control Act of 1974, tax expenditures are defined as revenue losses resulting from provisions that depart from a “normal” income tax system. Put more plainly, they are deviations from the rules for measuring income and calculating tax liability. The Joint Committee on Taxation (JCT) and the Treasury Department regularly estimate how much revenue those deviations cost.

Tax expenditures generally fall into three categories. Some reduce the amount of income subject to tax through exclusions, exemptions, or deductions. Others apply lower rates to certain types of income. Still others take the form of credits, which reduce your tax liability dollar for dollar.

From a budget standpoint, the difference between direct spending and tax expenditures is mostly procedural. A grant shows up as an outlay. A tax preference shows up as reduced receipts. Either way, the deficit increases unless something else changes. The Congressional Research Service has observed that both mechanisms operate as transfers through the federal budget, even if they move through different legislative channels.¹

Under the statutory baseline used by JCT, the “normal” income tax includes the standard definition of gross income, regular cost recovery rules for capital investment, and the standard rate structures. When Congress allows one sector to deduct costs faster than those rules permit, apply lower rates to certain income, or claim credits not broadly available, that difference is scored as a tax expenditure.

This report follows that framework. The provisions discussed in the sections that follow are those JCT identifies as tax expenditures or that clearly depart from standard income tax treatment, as well as other longstanding preferential tax treatments well recognized by tax experts and researchers. Some were written specifically for fossil fuel producers. Others apply more broadly but, given the structure of the oil and gas industry, deliver disproportionate benefits to that sector.



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The point is to identify where the tax code treats oil and gas producers differently from similarly situated taxpayers, and to measure what those differences cost.

Industry-Specific Oil and Gas Tax Preferences

Some tax provisions apply across the economy. Others were written with a specific industry in mind. This section addresses the latter — rules that apply only, or almost exclusively, to oil and gas producers and that the JCT classifies as tax expenditures.

Overall, these core oil and gas tax preferences were not enacted in response to a recent supply disruption or temporary market shock. The option to expense intangible drilling costs dates to 1916. Percentage depletion was enacted in 1926. Later provisions, including the enhanced oil recovery credit and the marginal well credit, were added during periods of price volatility and concern about domestic supply. Taken together, these rules span nearly a century of federal tax policy.

What these provisions share is straightforward. They depart from standard income tax treatment in ways that reduce taxable income or provide credits beyond what most other industries receive for comparable activities. These industry-specific provisions cost billions of dollars and have done so for generations. They were adopted when the federal income tax was new, domestic production was far smaller, and policymakers viewed oil extraction as a developing industry requiring encouragement. What began as targeted incentives have become permanent features of the tax code.

Percentage Depletion for Oil and Gas Wells (26 U.S.C. §§ 613, 613A)

Percentage depletion was enacted in 1926, when measuring mineral reserves was administratively difficult and lawmakers sought to stimulate domestic extraction. Congress later restricted its use by large integrated producers but retained it for independent oil and gas companies. The basic structure remains largely intact.

Under standard tax rules, a business recovers its capital investment through depreciation or cost depletion. Both spread asset costs over time, but depreciation covers equipment and structures, while cost depletion applies to natural resources. Cost depletion allows a taxpayer to deduct the portion of its investment corresponding to the share of the resource extracted in a given year. Once the taxpayer's basis — its remaining unrecovered investment — has been fully recovered, deductions stop. In general, a business may not deduct more than it invested.

Percentage depletion breaks from that structure. Instead of tying deductions to unrecovered investment, qualifying producers may deduct a fixed percentage of gross income from a well — generally 15 percent for oil and gas — regardless of how much they invested or whether they have already recovered their costs. Because the deduction is based on gross income rather than remaining basis, it can exceed total capital invested in the property and continue long after the original investment has been recouped.

No other industry is permitted to claim deductions in excess of basis in this way. That departure from investment-based cost recovery is why JCT classifies percentage depletion as a tax expenditure. JCT estimates that the excess of percentage over cost depletion for oil and gas will reduce revenues by approximately \$3.4 billion over FY2025–FY2029.²

Expensing of Intangible Drilling Costs (26 U.S.C. § 263(c))

The option to expense intangible drilling costs dates to 1916, when the Treasury first permitted immediate deductions for certain non-salvageable drilling expenditures.³ The policy was justified as recognition of the uncertainty and risk associated with early oil exploration.

Under general tax principles, businesses must capitalize costs that create assets and recover those costs over time. A manufacturer constructing a plant, a utility building transmission infrastructure, or a transportation company acquiring durable equipment cannot deduct the full cost in the first year. These investments are depreciated over their useful lives.

Oil and gas producers are permitted to depart from that framework for most intangible drilling costs. Wages, fuel, site preparation, and other non-salvageable expenditures associated with drilling a well may be deducted immediately. Independent producers may expense 100 percent of these costs; integrated producers may expense 70 percent and amortize the remainder over five years.

The distinction is one of timing, but this still has value. Earlier deductions reduce current tax liability and increase the present value of after-tax returns. Unlike small-business expensing provisions that are subject to dollar limits, intangible drilling cost expensing is not capped in the same way.

Oil and gas advocates often compare expensing of intangible drilling costs to the research and experimentation (R&E) deduction available to other industries. Except, the R&E deduction is intended to address genuine technological uncertainty — the development of new products, processes, or methods. Intangible drilling cost expensing applies even when producers deploy well-established drilling techniques in routine development. In that sense, it functions less as a targeted innovation incentive and more as a broad exception to capitalization rules.

JCT classifies this treatment as a tax expenditure and estimates that expensing of intangible drilling costs will reduce federal revenues by approximately \$2.3 billion over FY2025–FY2029.

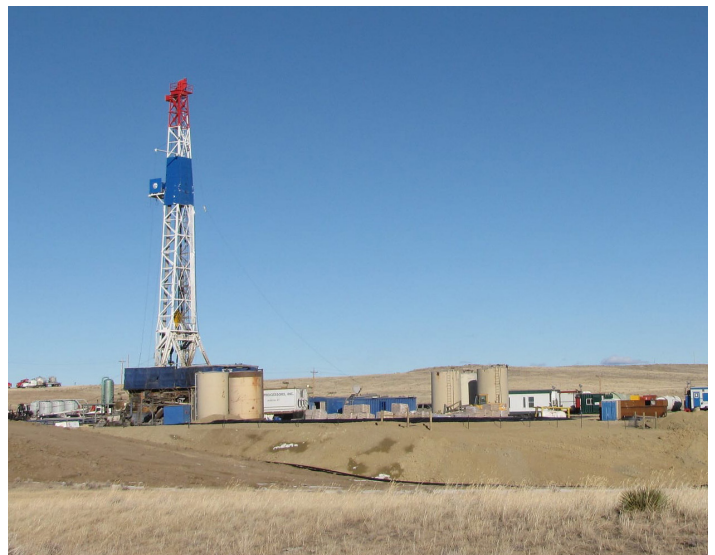


Photo by David Korzilius, Bureau of Land Management

Amortization of Geological and Geophysical Expenditures (26 U.S.C. § 167)

Shortened amortization periods for geological and geophysical (G&G) expenditures were enacted in 2005 and modified in subsequent legislation. G&G expenditures are costs incurred in exploring for and evaluating oil and gas resources. Under general tax principles, costs that generate benefits over multiple years are capitalized and amortized over their useful life. Information used to guide long-term investment decisions is typically treated as a capital asset.

Independent producers may amortize these costs over two years, meaning they are allowed to deduct the expense in equal portions over that short period rather than spreading it out over the much longer time the information may actually be useful. Major integrated producers may do so over seven years. Those shortened recovery periods accelerate deductions relative to the real economic life of the underlying data.

Similar to other tax provisions enjoyed by the industry, front-loading those deductions allows oil and gas companies to reduce their taxable income sooner, improving near-term cash flow. Geological surveys and seismic studies do not suddenly lose their value after two or seven years simply because the tax code says so.

JCT estimates that this preferential amortization reduces revenues by approximately \$300 million over FY2025–FY2029.⁴



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Carbon Oxide Sequestration Credit (26 U.S.C. § 45Q)

The carbon oxide sequestration credit—commonly referred to as 45Q—can be claimed by qualified taxpayers for each metric ton of carbon oxide they capture and sequester that would otherwise have been released into the atmosphere. Congress created the 45Q credit in 2008 to encourage adoption of carbon capture technologies by large industrial emitters, including coal and natural gas power plants.

Since then, the credit has been extended and expanded multiple times. Most recently, the Inflation Reduction Act (IRA) and the One Big Beautiful Bill Act (OBBBA) expanded the credit, raising the maximum value for geological sequestration, enhanced oil recovery, and certain uses of captured carbon to as much as \$180 per ton.

Although often promoted as a mechanism to reduce emissions in hard-to-abate sectors such as steel and cement, fossil fuel companies—particularly oil and gas companies—remain among the largest beneficiaries. The oil and gas sector holds the largest share of current and planned carbon capture capacity.⁵ Lobbying records tell a similar story. Over the past decade, nearly \$1 billion has been spent lobbying Congress and the White House on carbon capture and related technologies, with roughly 90 percent of that spending coming from fossil fuel and adjacent industries.⁶

JCT estimates that the 45Q credit will reduce federal revenues by approximately \$9.2 billion over FY2025–FY2029.⁷

Enhanced Oil Recovery Credit (26 U.S.C. § 43)

The enhanced oil recovery (EOR) credit was enacted in 1990 to encourage the use of tertiary recovery techniques in aging fields—like injecting steam, gas, or chemicals—to squeeze additional oil out of mature or depleted reservoirs, particularly during periods of lower oil prices. It was structured as a targeted production incentive with a statutory phaseout tied to price levels.

The credit provides a tax credit equal to 15 percent of qualified costs associated with certain recovery methods. Unlike a deduction, which reduces taxable income, a credit reduces tax liability dollar for dollar. In general, a 15 percent credit is materially more valuable than a 15 percent deduction.

Although the credit phases out when oil prices exceed statutory thresholds, it remains embedded in the code and automatically reactivates when prices fall. It applies specifically to oil recovery activities and does not have a broad parallel for most other industries seeking to extend the life of aging assets.

The structure reflects industry-specific policy choices rather than neutral cost recovery principles. That is why JCT considers it a tax expenditure. JCT estimates the cost of the enhanced oil recovery credit is de minimis, or less than \$250 million over FY2025–FY2029 under current price conditions.⁸ However, the Department of the Treasury estimates that the enhanced oil recovery credit is \$2.6 billion over the same period.⁹ This gap reflects differences in underlying assumptions and methods. JCT's estimate is based on a CBO baseline and treats provisions with limited expected use as de minimis, while Treasury's estimate reflects the Administration's forecast and assigns a value even if the credit is expected to be used intermittently as prices fluctuate. (See the Appendix for a more detailed explanation of these methodological differences.)



Photo by U.S. Geological Survey

Credit for Production from Marginal Wells (26 U.S.C. § 45I)

Congress created the marginal well credit in 2004 to prop up production from low-output oil and gas wells when prices fall. Like the EOR credit, it works like a built-in cushion. When market prices drop below certain thresholds, companies can claim a per-barrel tax credit for qualifying wells. When prices are high, the credit phases out and often costs the Treasury little or nothing.

But when it does kick in, it can be especially valuable. Because it is structured as a general business credit with a five-year carryback and a 20-year carryforward, companies can use it to offset taxes from prior profitable years and, in some cases, receive refunds. In effect, a temporary dip in prices can translate into cash from the Treasury — treatment that is not widely available to most other capital-intensive industries. JCT estimates the cost of the marginal well credit is de minimis, or less than \$250 million over FY2025–FY2029,¹⁰ while Treasury estimates that the credit will cost \$1.6 billion.¹¹ As with the enhanced oil recovery credit, this difference reflects how the two agencies model price-driven provisions. JCT assumes limited activation under its baseline and does not assign a value below its reporting threshold, while Treasury estimates the cost of the credit when it is triggered, even if only in certain years. (See the Appendix for a more detailed explanation of these methodological differences.)



Photo by U.S. Department of Energy, flickr

Expensing of Tertiary Injectants (26 U.S.C. § 193)

Tertiary injectants are gases or fluids used in enhanced oil recovery to increase crude oil production as pressure inside an oil and gas reservoir declines. Oil and gas companies may deduct the cost of these injectants in the year they are incurred, even though the injectants may support production for several years. Congress enacted this provision in 1980. This treatment departs from standard tax principles, which generally require costs associated with multi-year benefits to be capitalized and recovered over time.

JCT estimates that expensing of tertiary injectants reduces federal revenues by less than \$250 million over FY2025–FY2029.¹²

15-year MACRS for Natural Gas Distribution Lines (26 U.S.C. § 168)

Created by the Tax Reform Act of 1986, the Modified Accelerated Cost Recovery System (MACRS) establishes the depreciation schedules businesses use to recover the cost of tangible property for tax purposes. Under MACRS, businesses recover the cost of capital assets by claiming annual depreciation deductions over a specified recovery period.

The Energy Policy Act of 2005 shortened the MACRS recovery period for natural gas distribution lines from 20 to 15 years for general depreciation and established a 35-year period under the Alternative Depreciation System (ADS), which businesses may elect instead. The shorter recovery period allows utility companies to deduct more from their taxable income sooner, even though distribution lines often have usable lives exceeding 20 years.

To qualify for the 15-year recovery period, natural gas distribution lines used by utilities to deliver gas to customers must have been placed in service after April 11, 2005, and before January 1, 2011. In addition, the business must not have entered into a binding contract to construct the distribution lines before April 12, 2005.

JCT estimates that the 15-year MACRS for Natural Gas distribution lines reduces federal revenues by \$300 million over FY2025–FY2029.¹³

Deductions for Foreign Tax – Dual Capacity (26 U.S.C. § 901)

To prevent double taxation, current law allows U.S.-based corporations to claim a foreign tax credit (FTC) against their U.S. tax liability for taxes paid to foreign governments on income earned abroad. Special rules apply to companies known as dual-capacity taxpayers—firms that both pay a levy to a foreign government and receive a specific economic benefit from that government, such as access to publicly owned natural resources.

Under these rules, the portion of the foreign levy that represents payment for the economic benefit—essentially a royalty—should not qualify for the foreign tax credit. The dual-capacity rules were developed in the 1970s and finalized in 1983 to address concerns that some payments made by oil and gas companies to foreign governments were being characterized as income taxes rather than royalties, allowing companies to claim larger FTCs than other industries.

Despite those rules, aspects of the law and certain court decisions have allowed some of these practices to persist. Although this provision is not currently listed as a tax expenditure by JCT or Treasury, several presidential budget proposals have identified it as preferential tax treatment benefiting oil and gas companies. The FY2025 President’s Budget Request estimated that deductions related to foreign tax credits for dual-capacity taxpayers would reduce federal revenues by \$31.4 billion over FY2025-2029.¹⁴

Passive Loss Limitations Exemption (26 U.S.C. § 469)

Passive business activity refers to any activity in which a taxpayer has an economic interest but does not “materially participate.” Normally, taxpayers may deduct passive losses only up to the amount of passive income they earn. Any excess losses may be carried forward to future tax years but remain subject to the same limitation.

Working interests in oil or gas wells, however, are exempt from this passive loss limitation. This exemption allows oil and gas investors to deduct excess passive losses against active income generated from other business activities in which they materially participate.

Although not listed as a tax expenditure by JCT, the Treasury Department recognizes this exemption as preferential treatment.¹⁵ The FY2025 President’s Budget Request estimated that the exemption reduces federal revenues by approximately \$38 million over FY2025-2029.¹⁶



USDA Forest Service photo by Treva Slaughter

Master Limited Partnerships / Publicly Traded Partnerships (26 U.S.C. § 7704)

As a general rule, companies whose shares trade on public markets are taxed as corporations. The corporation pays income tax on its profits. Shareholders then pay tax again on dividends or capital gains. That two-level structure is the default for publicly traded firms.

Publicly traded partnerships are an exception. If at least 90 percent of their income comes from specified “qualifying” activities — including oil, gas, and other natural resource operations — they may be taxed as partnerships rather than corporations. The entity itself pays no corporate income tax. Income passes through and is taxed once at the investor level.

The result is a structure that combines the liquidity and access to capital of public markets with single-level taxation typically reserved for private partnerships. While the partnership structure is technically available to other qualifying activities, it has been used predominantly in the energy and natural resource sectors, particularly for pipelines and midstream operations. Energy firms that meet the qualifying income test can avoid a layer of corporate tax that most other publicly traded companies cannot.

JCT classifies this treatment as a tax expenditure and estimates that the publicly traded partnership preference will reduce federal revenues by approximately \$0.3 billion over FY2025–FY2029.¹⁷

Taken together, these industry-specific provisions bend standard cost recovery rules or provide targeted credits that are not generally available to similarly situated taxpayers in other sectors. Enacted at different points over the past century, often in response to supply concerns or price swings, they remain embedded in the code as structural advantages layered on top of one another. The result is measurable revenue loss for taxpayers and an ongoing subsidy for the oil and gas industry.

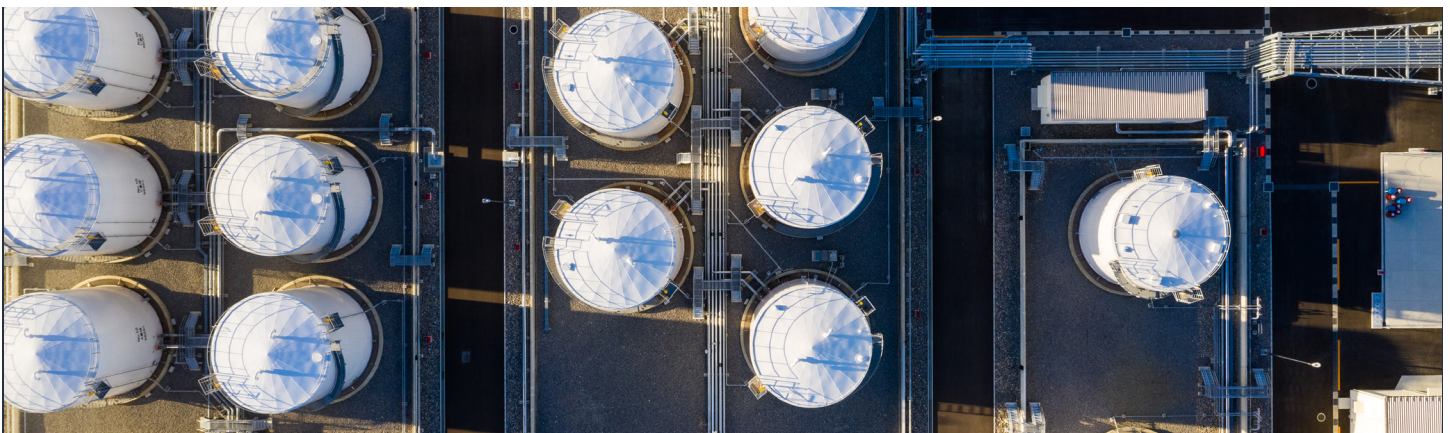


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Broader Tax Provisions That Deliver Significant Benefits to Oil and Gas

Not every tax rule that benefits oil and gas producers was written with that industry in mind. Some provisions apply across the economy. But the structure of oil and gas businesses — capital-intensive, inventory-heavy, highly leveraged, and often organized through partnership structures — means those rules carry particular weight for that industry.

Last-In, First-Out (LIFO) Inventory Accounting (26 U.S.C. § 472)

Under LIFO, a company is treated as selling its newest inventory first. When prices are rising, that means it deducts the higher, more recent costs against current sales. The result is lower reported income — and lower taxes — than under first-in, first-out (FIFO) accounting.

LIFO was originally justified as a response to inflation. If prices rise, FIFO can make it appear that a company has large profits simply because it is selling older, cheaper inventory at today's higher prices. LIFO matches current sales with current costs. That rationale makes sense in industries where inventory turns over quickly and becomes outdated, such as automobiles or electronics.

Crude oil and refined petroleum products are different. They are globally traded commodities. A barrel of oil in storage does not become obsolete with the model year. Its value moves with market prices, not design cycles. In that context, LIFO functions less as a shield against inflationary distortion and more as a mechanism for deferring taxes when prices rise.

Oil companies hold large inventories of crude and refined products. During periods of price volatility, LIFO can materially reduce taxable income and defer tax liability for extended periods. JCT classifies LIFO as a tax expenditure because it departs from its definition of a normal income tax base and estimates that LIFO will reduce federal revenues by approximately \$9.9 billion over FY2025–FY2029.¹⁸

Accelerated and Bonus Depreciation (26 U.S.C. § 168)

Under standard tax principles, a business recovers the cost of buildings, equipment, and other long-lived assets over time. A factory is typically depreciated over decades. Many types of equipment are depreciated over five to seven years.

MACRS allows many assets to be written off more quickly than their economic life would suggest. The 15-year MACRS for natural gas distribution lines mentioned above is an example of this. Additionally, bonus depreciation has, at times, allowed businesses to deduct a large share — and in some years up to 100 percent — of certain capital investments immediately rather than over time.

These provisions apply across industries, but they matter most where upfront capital costs are large. Oil and gas development requires substantial spending on drilling rigs, well equipment, pipelines, processing facilities, and related infrastructure. The faster those investments can be deducted, the sooner tax liability falls. Earlier deductions are more valuable than later ones because they reduce taxes today rather than years from now.

For oil and gas producers, accelerated depreciation operates alongside — not instead of — industry-specific expensing of intangible drilling costs. Drilling-related development costs may already be deducted immediately under §263(c). Accelerated and bonus depreciation then apply to much of the remaining tangible infrastructure investment. The result is layered, front-loaded cost recovery that compounds the timing advantage available to capital-intensive projects in this sector.

JCT estimates that bonus depreciation alone will reduce federal revenues by approximately \$296.4 billion over FY2025–FY2029 across the economy.¹⁹ While not limited to energy, the capital intensity of oil and gas production — combined with its industry-specific expensing rules — means the sector captures a meaningful share of this benefit.



Oil Pipeline in Alaska
U.S. Geological Survey Photo, Public Domain

Federal Oil and Gas Subsidies	FY25-29 Cost (\$-billions)	Source/Notes
Excess of Percentage Over Cost Depletion, Oil and Gas	3.4	Joint Committee on Taxation
Expensing of Exploration and Development Costs, Oil and Gas	2.3	Joint Committee on Taxation
Enhanced Oil Recovery Credit	2.6	Department of the Treasury
Marginal Well Credit	1.6	Department of the Treasury
Amortization of Geological and Geophysical Expenditures	0.3	Joint Committee on Taxation
Carbon Oxide Sequestration Credit	9.2	Joint Committee on Taxation
15-year MACRS for Natural Gas Distribution Lines	0.3	Joint Committee on Taxation
Expensing of Tertiary Injectants	-	
Deductions For Foreign Tax - Dual Capacity	31.4	FY2025 President's Budget
Passive Loss Limitations Exemption	0.04	FY2025 President's Budget
Master Limited Partnerships for Oil and Gas Companies	0.3	Joint Committee on Taxation
Total	51	

*This chart does not include cost estimates for broader tax preferences such as LIFO and bonus depreciation, which adds up to \$306.3 billion in tax expenditure. Most cost estimates come from JCT's Estimates of Federal Tax Expenditures for Fiscal Years 2025-2029. However, JCT counts any tax expenditure with estimated revenue effects below \$250 million over a five-year period as de minimis, and does not provide a cost estimate, and in those cases Department of the Treasury's Tax Expenditures Fiscal Year 2027 cost estimates are used. When neither JCT nor the Treasury provides a cost estimate, TCS used estimates from the President's budget.

What This Means

Many of the tax provisions described in this report were enacted when the oil and gas industry looked fundamentally different from today. Expensing of intangible drilling costs dates to 1916. Percentage depletion was enacted in 1926. Later credits were layered on during periods of price instability and concern about domestic supply. At the time, policymakers described these measures as tools to encourage exploration, reduce investment risk, and help build a domestic industry.

A century later, the industry no longer resembles some fragile or capital-starved enterprise. The United States is producing oil and natural gas at or near record levels. Monthly U.S. crude oil production averaged roughly 13.6 million barrels per day in 2025, in many months, surpassing its 2019 peak.²⁰ Natural gas production is projected to set new records as well, with marketed output expected to average more than 120 billion cubic feet per day in 2026 and rise further in 2027.²¹

The United States is not only producing at historic levels; it is exporting at historic levels. The country has been a net exporter of total petroleum products for several years and ships roughly 6.3 million barrels per day of refined products. Liquefied natural gas exports have grown from essentially zero in 2016 to roughly 15 billion cubic feet per day by 2025, with projections exceeding 18 billion cubic feet per day by 2027. The United States is now one of the largest — and at times the largest — LNG exporters in the world.

These are not the metrics of a fledgling industry. They reflect a dominant global producer operating at scale.

At the same time, the tax code continues to provide industry-specific preferences originally justified as temporary or strategic supports. JCT estimates that the principal oil- and gas-specific tax expenditures will reduce federal revenues by billions over the coming years. Broader structural provisions — including LIFO, publicly traded partnership treatment, accelerated depreciation — cost tens of billions more across the economy, with oil and gas among the significant beneficiaries.

Provisions adopted in the early twentieth century to nurture domestic production now apply to an industry setting production and export records. Preferences designed to offset exploration risk remain in place for companies reporting strong cash flow, expanding capital expenditures, and returning substantial sums to shareholders.

The question is not whether oil and gas is an important industry. It is whether an industry that has achieved sustained, record-scale production and global dominance should continue to receive tax treatment that departs from baseline rules applied to other taxpayers — nearly a century after those preferences were first enacted.



Photo by Jan Zakelj, Pexels

Appendix

Why JCT and Treasury Estimates Don't Always Match

Some of the provisions in this report have very different cost estimates depending on the source. That is not a mistake. It reflects differences in how the Joint Committee on Taxation (JCT) and the Department of the Treasury build their estimates.

The most basic difference is that they are working from different economic assumptions. JCT uses a Congressional Budget Office baseline, while Treasury uses the Administration's forecast. For provisions tied to market conditions—like the enhanced oil recovery and marginal well credits—those assumptions can determine whether a credit is active at all.

They also model taxpayer behavior differently. JCT generally assumes that if a tax preference were removed, taxpayers would shift to the next best option in the tax code. Treasury tends to evaluate provisions more in isolation, which can make the estimated cost appear larger.

JCT also applies a reporting threshold. Provisions expected to reduce revenue by less than \$250 million over five years are treated as “de minimis” and do not receive a specific estimate. Treasury still assigns a value even if a provision is expected to be used only occasionally or in small amounts, which can add up over time.

These differences show up most clearly in provisions that are triggered by changing market conditions. In those cases, the same policy can appear to cost little or nothing in one report and billions in another.



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