

Direct Working Interest vs. Oil and Gas Funds

A Decision Stage Comparison Guide to Tax Treatment, Governance Rights, and Cash Flow Mechanics for Physicians, Dentists, Attorneys, and Financial Professionals

COMPARISON GUIDE | TAX STRATEGY | HIGH EARNERS

Introduction: The Tax Gap High Earners Face

If you are a physician, dentist, attorney, CPA, or financial professional earning $150,000 to $400,000 or more in annual income, you have likely already maximized the standard tax deferral tools available to you: the 401(k), the backdoor Roth, the backdoor IRA. For 2026, the IRS caps the 401(k) elective deferral at $24,500 with a combined plan limit of $72,000, a standard catch-up of $8,000, and a new "super catch-up" of $11,250 for participants aged 60 to 63 (IRS IR-2025-111). IRA contributions are capped at $7,500, and Roth eligibility phases out between $242,000 and $252,000 of modified adjusted gross income for married joint filers, or $153,000 to $168,000 for single filers.

For a surgeon or senior partner sitting at the 37 percent federal bracket, which begins at $640,600 of taxable income for single filers and $768,600 for married filing jointly in 2026 (IRS Rev Proc 2025-32), these vehicles simply do not scale with income. The gap between what qualified retirement plans allow and what high earners actually owe in tax each year is where most professionals begin evaluating direct oil and gas participation.

$72K	37%	$7.5K
401(k) Combined Limit	**Top Federal Bracket**	**IRA Cap**
Maximum combined plan limit for 2026 including employer contributions	Marginal rate beginning at $640,600 for single filers in 2026	Annual IRA contribution ceiling, with Roth eligibility phasing out above $242K MAGI

Two structures dominate this conversation: holding a direct working interest in a specific well or group of wells, or placing capital into a pooled oil and gas fund organized as a limited partnership or limited liability company. Both sit inside the same tax code. Both touch the same underlying asset class, producing oil and gas wells. But the legal form each one takes produces materially different outcomes for how losses offset income, how much governance visibility a participant retains, and how capital moves once it is committed. This guide walks through both structures side by side, using the same evaluation criteria a CPA or tax attorney would apply, so that by the end you understand not which option is universally "better," but which one fits your specific tax position, time availability, and risk tolerance.

⚠ This is not a solicitation and nothing in this guide should be read as a guarantee of any tax or financial outcome. Tax treatment depends on individual facts, basis, at-risk amounts, and professional preparation. Consult a qualified CPA or tax attorney before making any participation decision.

What Is Being Compared

Option A — Direct Working Interest

A participant acquires an undivided fractional working interest directly in a specific oil and gas well or group of wells, typically through a joint operating agreement (JOA) that defines the rights, obligations, and cost-sharing arrangement between the operator and each working interest owner. Treasury Regulation 1.612-4(a) defines an "operator" for IDC election purposes as one who holds a working or operating interest in any operating agreement, under a lease or in fee. The participant's liability for operational costs is tied directly to their percentage share of the well.

Option B — Oil and Gas Funds

A participant contributes capital to a pooled vehicle, structured as a limited partnership (LP) or limited liability company (LLC), which in turn acquires interests across a portfolio of wells or projects. The fund sponsor (general partner or managing member) handles acquisition, operation, and reporting. The participant receives a fund interest or units rather than a direct fractional interest in any single well, and the entity's liability-limiting structure is the defining legal feature that separates this model from Option A.

Seven Evaluation Criteria

Any objective comparison between these two structures should be measured against the same seven criteria a tax advisor or investment committee would use:

1	**Ownership** What legal interest does the participant actually hold — a direct fractional interest in a specific asset or units in a pooled entity?
2	**Participation** How involved is the participant in decisions about drilling, completion, and operations?
3	**Governance & Control** What voting rights, reporting access, or decision authority does the participant retain?
4	**Liquidity** How readily can the participant exit or transfer their position?
5	**Tax Treatment** How are losses, deductions, and depletion allowances characterized, and against what category of income can they be applied?
6	**Exposure & Limitations** What structural or concentration factors limit the position?
7	**Complexity** What is the administrative and reporting burden for the participant and their CPA?

Option A: Direct Working Interest Ownership

The defining tax feature of a direct working interest is **IRC Section 469(c)(3)(A)**, which states that the passive activity definition "shall not include any working interest in any oil or gas property which the taxpayer holds directly or through an entity which does not limit the liability of the taxpayer." In plain terms, a bona fide working interest held directly, or through a structure that does not cap the participant's liability, is statutorily excluded from passive activity treatment.

This matters because losses generated by a non-passive activity can offset active income — meaning W-2 wages, 1099 professional income, and K-1 active business income — with no income-based phase-out of the kind that applies to real estate's $25,000 passive loss allowance, which phases out entirely between $100,000 and $150,000 of modified adjusted gross income (IRS Publication 925). For a surgeon earning $350,000 in W-2 and 1099 income, that real estate allowance has already phased out completely. The 469(c)(3)(A) working interest exception has no such ceiling.

Section 263(c) — IDC Expensing Election

Permits an election to currently expense Intangible Drilling Costs (IDC) rather than capitalize them. IDC includes the non-salvageable costs of drilling, labor, fuel, drilling mud, chemicals, site preparation, and hauling — costs that have no residual value if the well is abandoned. Tangible Drilling Costs (TDC), covering salvageable equipment such as casing, wellhead components, and tanks, are capitalized and depreciated under standard MACRS schedules rather than expensed immediately. For any specific Authorization for Expenditure (AFE), up to 100 percent of eligible intangible drilling costs can qualify for this current-year election, though the actual figure depends on the well's engineering design, the participant's at-risk basis, and their individual tax position.

IRC Section 465 — At-Risk Limitation

The deduction a participant can claim is capped at their actual economic exposure in the well. Nonrecourse debt generally does not count toward basis. This is a critical structural constraint that must be modeled with a CPA before any election is made.

IRC Section 57(a)(2) — AMT Preference Item

"Excess" IDC is treated as an Alternative Minimum Tax preference item, but only above a threshold tied to 65 percent of the participant's net income from oil, gas, and geothermal properties. An independent producer exception under 57(a)(2)(E) generally limits any AMT add-back to no more than 40 percent of alternative minimum taxable income.

IRC Sections 611 & 613A — Percentage Depletion

Once a well reaches production, a 15 percent percentage depletion allowance applies against gross income from that production for independent producers. This continues as an ongoing tax benefit for the life of the well, separate from the initial IDC election.

On governance, a direct working interest owner typically has access to the joint operating agreement, AFE detail for each capital program, and direct reporting on the specific wells in which they hold an interest. This is a meaningfully different governance posture than a fund interest, where the participant's visibility is limited to what the fund sponsor chooses to report across a diversified, commingled portfolio.

Option B: Oil and Gas Funds

A pooled oil and gas fund is, by design, an entity that limits the liability of its investors — whether organized as a limited partnership with a general partner bearing unlimited liability, or as an LLC with members shielded entirely. That liability-limiting feature is precisely the condition that **IRC 469(c)(3)(A)** excludes from its working interest exception.

As a result, losses passed through a fund interest default to passive activity treatment under Section 469 unless the individual participant can separately establish material participation in the fund's operations — which is rare for a time-poor professional who, by definition, is not managing drilling programs personally. Passive losses can only offset passive income, which most high-earning professionals have little or none of, meaning the loss may be suspended and carried forward rather than used to reduce the current year's active income tax liability.

Fund Fee Structure

Fund structures layer in a cost structure distinct from direct ownership. Based on general industry benchmarking across pooled energy vehicles:

Annual Management Fee	Acquisition Fee	Carried Interest
1–2% of committed capital or net asset value	**1–5%** of purchase price when the fund deploys capital into new assets	**~20%** of profits above an 8–10% preferred return hurdle

These layers do not appear in a direct working interest arrangement, where the participant's cost exposure is limited to their proportional share of actual drilling, completion, and operating costs under the JOA.

Liquidity and Accredited Investor Requirements

Liquidity mechanics in fund structures follow a common industry pattern worth understanding before committing capital. Many funds target periodic distributions beginning within approximately six months of fund close, reinvest remaining net income during the early years of the fund's life, then shift toward full income distribution and eventual liquidation as the fund approaches its target life — typically in the 3 to 5 year range, with disclosed hold periods across the industry commonly ranging from 1 to 11 years depending on the specific vehicle and share class.

Fund interests are also typically restricted to investors who meet SEC Rule 501 Regulation D's definition of an accredited investor — generally a net worth exceeding $1 million excluding primary residence, or income exceeding $200,000 for an individual or $300,000 for a married couple in each of the prior two years.

Side-by-Side Comparison

The following table applies all seven evaluation criteria to both structures simultaneously, using the same analytical framework a CPA or tax attorney would apply.

Category	Direct Working Interest	Oil and Gas Fund
Ownership	Undivided fractional working interest in a specific, identified well or group of wells, held directly or through a liability-unlimited entity, documented under a joint operating agreement.	Units or partnership interest in a pooled LP or LLC entity that itself holds interests across a portfolio of wells; the participant does not hold a direct interest in any single asset.
Participation	Participant is a named working interest owner on the AFE and JOA, with cost-sharing and election rights tied to their specific percentage interest.	Participant is a passive capital contributor; day-to-day and capital decisions are made by the fund sponsor or general partner on behalf of the pool.
Governance & Control	Access to well-level JOA terms, AFE detail, and operator reporting tied to the specific assets held; working interest owners typically retain consent rights over defined categories of capital decisions under the JOA.	Governance is exercised at the fund level by the general partner or manager; individual participants generally have limited or no vote on specific asset-level decisions.
Liquidity	Transfer generally requires operator consent and JOA-defined procedures; positions are intended to be held for the productive life of the well.	Industry-common hold periods of 1 to 11 years, with distributions often beginning around six months after fund close and full distribution or liquidation occurring near the fund's 3 to 5 year target life; interests are not typically freely tradable.
Tax Treatment	Falls under the IRC 469(c)(3)(A) working interest exception; elected IDC losses can offset active W-2/1099/K-1 income with no income-based phase-out; subject to IRC 465 at-risk limits and IRC 57(a)(2) AMT preference rules; 15% percentage depletion applies under IRC 611/613A.	The entity's liability-limiting structure generally forecloses the 469(c)(3)(A) exception, so losses default to passive activity treatment under Section 469 absent separately established material participation; passive losses can only offset passive income and may be suspended and carried forward.
Exposure & Limitations	Concentrated exposure to the specific wells in which the participant holds an interest; cost exposure is proportional and uncapped beyond the at-risk basis; no diversification across a broader portfolio.	Diversification across multiple wells or projects within the pooled vehicle; return to the participant is reduced by management fees, acquisition fees, and carried interest layered on top of underlying asset performance.
Complexity	Requires direct AFE and JOA review, well-level recordkeeping, and coordination with a CPA familiar with 263(c) elections and depletion calculations for each specific asset.	Administrative burden is largely absorbed by the fund sponsor; participant generally receives a single K-1 reflecting pooled results rather than asset-by-asset detail.

Advantages and Limitations

Direct Working Interest — Advantages

- Preserves the 469(c)(3)(A) active-income offset without an income-based phase-out
- Direct line of sight into the specific wells funded
- No management fee or carried interest layer reducing the participant's share of production economics
- Ongoing 15 percent depletion allowance on production income once wells are online

Direct Working Interest — Limitations

- Concentrated exposure to specific assets rather than a diversified portfolio
- Requires more individualized CPA coordination for elections, basis tracking, and at-risk calculations
- Transfer of the interest is governed by JOA consent provisions rather than open trading

Oil and Gas Funds — Advantages

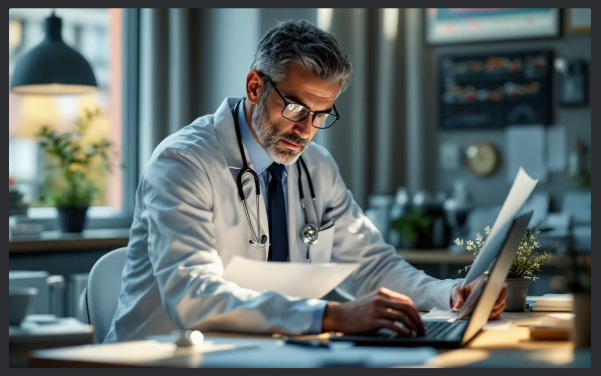
- Diversification across multiple wells or projects within a single commitment
- Day-to-day operational decisions are handled by the fund sponsor
- Reporting is consolidated into a single K-1

Oil and Gas Funds — Limitations

- Liability-limiting entity structure generally forecloses the 469(c)(3)(A) active-income offset, defaulting losses to passive treatment
- Layered management fees, acquisition fees, and carried interest reduce net participant economics
- Limited governance visibility into specific well-level decisions
- Hold periods and distribution timing are set by the fund's lifecycle rather than the individual participant's preference
- Access is generally restricted to accredited investors under SEC Rule 501/506(c)

Best-Fit Scenarios

Neither structure is universally superior. The right fit depends on your income composition, governance preferences, and tolerance for administrative involvement.



Direct Working Interest Is the Better Fit When...

A direct working interest structure tends to fit a high-earning professional who carries a substantial amount of active W-2 or 1099 income each year and wants an election that can offset that specific category of income without a passive-loss phase-out; prefers to review JOA and AFE documentation directly with their CPA rather than relying solely on pooled reporting; and is comfortable with concentrated exposure to a defined set of wells in exchange for direct governance visibility and the absence of a fund-level fee and carry structure.



A Pooled Fund Structure Is the Better Fit When...

A pooled fund structure tends to fit a participant who prioritizes diversification across many assets over concentrated exposure to specific wells; is less concerned with preserving the active-income offset because their income is already substantially passive in nature; and is comfortable ceding governance and reporting detail to a fund sponsor in exchange for reduced administrative involvement.

> For the physicians, dentists, attorneys, and financial professionals this guide is written for — people whose income is overwhelmingly active (W-2 compensation, 1099 professional fees, or active K-1 income from a practice or firm) — the 469(c)(3)(A) distinction is usually the deciding factor, since it is the structural feature that determines whether an elected IDC deduction can actually reach the income being taxed at the 37 percent marginal rate in the first place.

Decision Guidance & Questions for Your Advisor

Work Through This Sequence With Your CPA or Tax Attorney

1 Confirm Active vs. Passive Income

Confirm how much of your annual income is active versus passive under IRC 469, since this determines whether the 469(c)(3)(A) exception is even relevant to your situation.

2 Review At-Risk Basis

Review your at-risk basis under IRC 465 for any specific well or fund commitment you are evaluating, since the deduction cannot exceed your actual economic exposure.

3 Model the AMT Impact

Model the AMT impact under IRC 57(a)(2) against your specific income profile, since the independent producer exception caps the add-back at 40 percent of AMTI.

4 Request the Full Fee Schedule

If comparing a specific fund offering, request the fee schedule in writing — management fee, acquisition fee, and carried interest terms — so you can calculate net participant economics rather than evaluating headline production or reserve figures alone.

5 Review Governing Legal Documents

Review the governing legal documents directly — the JOA and AFE for a direct interest, or the LP/LLC operating agreement and private placement memorandum for a fund — before committing capital.

This decision should never be made in isolation from your existing CPA and financial planning relationship. The goal of either structure is to fit cleanly into the tax strategy your advisors already manage, not to replace it.

Questions to Bring to Your Professional Advisor

- Does my current mix of active versus passive income make the IRC 469(c)(3)(A) working interest exception meaningful for my tax position this year?
- What is my at-risk basis for the specific interest I am evaluating, and how does IRC 465 limit my potential current-year deduction?
- How would IRC 57(a)(2) treat any excess IDC generated by this election relative to my alternative minimum taxable income?
- If I am evaluating a pooled fund, what is the combined effect of the management fee, acquisition fee, and carried interest on my net economics over the fund's full life cycle?
- What governance rights, reporting access, and consent provisions apply to the specific JOA or LP/LLC agreement I am reviewing?
- What is the expected hold period and distribution timeline for this specific structure, and how does that align with my broader liquidity needs?
- Does this structure require me to meet SEC accredited investor standards under Rule 501/506(c), and have I confirmed my eligibility?
- How should the depletion allowance under IRC 611/613A be incorporated into my multi-year tax projections once production begins?

Next Steps: Participate With Confidence

Understanding the legal distinction between these two structures — a direct fractional interest preserved under 469(c)(3)(A) versus a pooled entity that limits liability and defaults to passive treatment — is the single most consequential decision point for a high-earning professional evaluating oil and gas participation for tax purposes. Neither structure is categorically superior; each follows a different statutory path with different governance, liquidity, and reporting consequences attached to it.

The right next step is to bring the specific AFE, JOA, or fund offering documents you are considering to your CPA or tax attorney, model the at-risk and AMT mechanics against your own return, and confirm the structure aligns with both your tax position and your appetite for direct operational involvement before any capital contribution is made. Continued education on these statutory mechanics — rather than a rushed decision — is what allows a working interest owner to participate with confidence.

Explore Your Options at Summit Ventures

Sources and References

[1] 26 CFR 1.612-4(a), Treasury Regulation defining "operator" for Intangible Drilling Cost election purposes.
[2] IRC Section 263(c), statutory authority for the current-year IDC expensing election.
[3] IRC Section 469(c)(3)(A), exact statutory text excluding certain working interests from the passive activity definition.
[4] IRC Section 465, at-risk limitation on allowable deductions.
[5] IRC Section 57(a)(2), Alternative Minimum Tax treatment of excess Intangible Drilling Costs and the independent producer exception.
[6] IRC Sections 611 and 613A, percentage depletion allowance for independent producers.
[7] IRS Publication 925, Passive Activity and At-Risk Rules, including the $25,000 real estate passive loss allowance and its $100,000 to $150,000 MAGI phase-out.
[8] IRS Revenue Procedure 2025-32, 2026 federal income tax bracket thresholds.
[9] IRS IR-2025-111, 2026 retirement plan contribution limits.
[10] SEC Rule 501, Regulation D, definition of accredited investor.
[11] Industry benchmarking on pooled oil and gas fund fee structures (management fee, acquisition fee, carried interest) and fund lifecycle/distribution patterns, based on aggregated industry disclosure practices.
[12] U.S. Energy Information Administration, Short-Term Energy Outlook, September 2026, record U.S. crude oil production forecast.
[13] American Petroleum Institute, "Industry Explained," 2023 economic contribution figures for the oil and natural gas industry.