ANALYSIS OF SPECIAL TAX PROVISIONS AFFECTING INDEPENDENT OIL AND GAS PRODUCERS

Special Study

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PART I. DESCRIPTION OF THE INDEPENDENTS

A broad spectrum of firms are engaged in petroleum exploration and production in the United States. The companies range in size from Exxon ($62.9 billion in assets) to Patton Oil ($6.2 million in assets) to the lone stripper operator in Oklahoma. From the standpoint of the actors in the petroleum business, there are two types of firms in the industry--the large integrated producers (the majors) and the independents (all the rest). Whereas the integrated companies are involved in exploration, production, refining, and marketing, the independent firm frequently restricts its operations to the exploration and production phases of the business. In general, the independents are active in onshore areas and leave the high-cost offshore fields to the majors.

Two definitions of "independent" are used in this paper. One is that used by the petroleum industry, which considers all but the the very largest oil and gas corporations--about 25 firms--to be independent producers. Another definition is that of the tax code, which usually defines an independent as a producer with no significant retail or refining operations, thus excluding refiners, gas distribution companies, service station operators, and fuel oil (residential) distributors. For statistical reasons, the standard industry definition will be used in Part I, which provides an overview of independent operators. In Part II (tax provisions), the tax code definition will be used.

The oil and gas industry includes a wide variety of actors--from large multinational corporations to passive investors. A number of parties usually have an economic interest in any given oil property. Partnerships and joint ventures are common, used both to raise capital and to share risks among producers. Although there may be a number of separate economic interests in a given property, there is usually only one firm that does the actual work. This partner or operator is the actor responsible for actually conducting the exploration, production, and distribution operations (though it may also contract with other firms to perform these activities). The distinction between gross and economic (net) interests is important for both statistical and tax reasons. In general, production statistics on a "gross" basis reflect the activities of a firm or subset of firms regardless of ownership interest (that is, gross production is the amount that a company actually produces). On a gross operator basis, a firm will report data for all properties operated, regardless of ownership; this includes working interests, royalty interests, and production payments to the owners. Statistics derived on a "net" basis reflect the economic interests of a firm

or firms. Thus, net company statistics reflect the net ownership of a firm's interests in oil and gas leases. For example, a firm may produce 100 barrels--its gross production--and have an economic (net) interest of only 70 barrels. In addition, firms are generally taxed only on their economic or net interests and not on their gross production.

Structure of the Industry

In 1981, the independents (all oil and gas companies other than the top 24, ranked by value of production) accounted for 25 percent of the oil and 40 percent of the natural gas produced domestically (see Table 1).[1] The "independents" can basically be divided into two groups--the large and medium-sized corporations that are similar to the majors, and a large number of smaller corporations, proprietorships, and partnerships. Firms other than the top 200--that is, firms other than the majors or the large independents--produced about 10 percent of the oil and 11 percent of the natural gas in the United States. Although production is dominated by the larger firms in the industry, there are a number of small firms competing on the fringe. According to 1977 statistics, approximately 6,230 companies were engaged in oil and gas extraction (and another 7,637 were involved in oil and gas field services).[2]

The producing companies generally do not receive 100 percent of the revenue derived from their operations. In 1981, the top 24 companies produced 75 percent of the oil, but had an economic interest of only 62 percent. Similarly, the top 200 firms produced 90 percent of the oil, but had a net interest of 72 percent. The differences between the gross and the net interests reflect the royalty payments to landowners and interests of limited partners and other investors.

On average, firms other than the top 200 produced about 101 barrels per day (net) of oil and 612 MCF (thousand cubic feet) per day of natural gas.[3] In contrast, firms in the top 200 averaged 30,418 barrels per day of oil and 179,862 MCF per day of natural gas production. Stripper production

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1 For statistical reasons, the independents are defined as firms other than the top 24, instead of the top 25.

2 Companies without paid employees are excluded.

3 Clearly, this assumes that the universe of companies has remained the same as in 1977. If more firms have entered the market, which

TABLE 1. OIL AND GAS INDUSTRY STATISTICS, BY CATEGORY OF COMPANIES RANKED ACCORDING TO VALUE OF PRODUCTION, 1981

	Total United States		Top 24 Firms (percent)	Next 176 Firms (percent)	Other Firms (percent)
Gross lease revenues	141,222.1	mil. dol.	69	21	10
Net lease revenues	141,222.1	mil. dol.	56	14	7
Gross oil production	3,111.8	mil. bbl.	75	15	10
Net oil production	3,111.8	mil. bbl.	62	10	7
Net stripper production	438.9	mil.bbl.	40	10	21
Gross natural gas production	20,251.6	BCF	60	29	11
Net natural gas production	20,251.6	BCF	47	18	7
Gross exploration expenditures	16,899.2	mil. dol.	40	32	28
Gross development expenditures	19,001.7	mil. dol.	38	33	29
Gross number of wells drilled	68,622	wells	20	20	60
Employment	215.4	thousand	45	25	30
Gross book asset (net interest, end-of-year)	196,570.0	mil. dol.	67	25	8
Number of firms[a]	6,230		24	176	6,030
Average net oil production (barrels per day per firm)	1,074	bbl/day	219,543	4,028	101
Average net gas production (MCF per day per firm)	6,367	MCF/day	1,078,664	57,298	612

NOTE: BCF is billion cubic feet and MCF is thousand cubic feet.

SOURCE: U.S. Department of Commerce, Bureau of the Census, Annual Survey of Oil and Gas, 1981, Tables 1, 2, 6A, and 6B; and General Report on Industrial Organization: 1977 Enterprise Statistics, Table 16.

a. Number of firms is as reported in 1977 Enterprise Statistics. This excludes companies without a payroll.

(oil from wells that produce less than 10 barrels per day) was about 14 percent of total oil production; the top 200 firms produced 50 percent of this amount. Of the 755,848 producing oil and gas wells in 1981, 409,539 (54 percent) were stripper wells.

In general, most oil is produced by firms organized on a corporate basis. In 1981, corporations produced 95 percent of the oil and gas on a gross operator basis. Sole proprietorships were responsible for about 3 percent and partnerships produced about 2 percent. These shares represent gross amounts produced by the firms, even though they may not be entitled to the full economic interest in the production. On a net basis, the producing corporations have an interest of 75 percent as compared to their 95 percent share of gross oil production. Sole proprietorships and partnerships each have a 1.5 percent net interest in oil production. Nonproducers have net interests in oil of about 22 percent and in natural gas of 29 percent. These interests include parties outside the industry, such as individual royalty holders, limited partners, and landowners (for example, governments and non-oil corporations).

Drilling and Exploration

The independents play a more important part in drilling and exploration than in production. Of the $35.9 billion spent on drilling and equipping exploratory and development wells, 61 percent was spent by firms other than the top 24 companies. Firms other than the top 200 spent 29 percent ($10.3 billion) compared to their 10 percent share of gross lease revenues. Corporations were responsible for 92 percent of drilling expenditures; partnerships and sole proprietorships accounted for a total of 7 percent of expenditures. Corporations also drilled 76 percent of the exploratory and 87 percent of the development wells.

While the large oil and gas corporations spend more for exploration and development wells than the smaller firms, in terms of the number of wells the situation is reversed--firms other than the top 200 drilled 60 percent of the total wells completed during 1981. This indicates that the larger firms drill deeper and more costly wells than the independent firms. The top 200 firms completed wells averaging about 6,700 feet in depth, at $138 per foot; the other firms completed wells averaging about 4,600 feet and costing $54 per foot. In part, this reflects the greater activity of the large companies in offshore areas.

Footnote Continued

is believed to be the case, the average production figures would be lower.

Finance

Oil and gas companies are financed in a variety of ways. The larger companies are often publicly held corporations that can raise cash in the security markets. This is also true of the larger independents, such as Superior Oil or Mesa Petroleum. Larger firms also rely heavily on internally generated funds. It is also common for companies to engage in joint ventures, allowing them to spread the risk (and any consequent rewards). To the extent that these joint ventures are between major corporations, they are financed by the sponsoring firms.

Smaller oil and gas companies are generally privately held corporations, partnerships, or sole proprietorships. These firms rely less on public capital markets and more on private investors and banks as sources of finance. As with the large firms, they are also dependent upon their own internally generated cash for a large part of their capital spending.

In general, the established oil and gas firms (whether or not they are independent) have a history of profitability and are thereby able to utilize the full range of tax deductions common to the industry: write-offs for intangible drilling costs, percentage depletion or cost depletion, abandonment losses, accelerated depreciation, and investment credits. Smaller and less profitable firms may be less able to take full and immediate advantage of these tax provisions, since savings are limited by the amount of their tax liability. The current tax rules require firms to defer the recognition of losses for tax purposes, thereby reducing the value of deductions. In order for tax deductions or credits to be useful, firms must generate sufficient income and tax liability to absorb them. Thus, it is common for sole proprietors and partnerships (operating) to rely on outside investors with substantial taxable income who can make use of the "extra" write-offs. Those interested in a small oil and gas firm might include other members of the industry--corporations or individuals with positive taxable income--or "passive" investors--such as high-income individuals or non-affiliated corporations that can make use of the write-offs.

Limited Partnerships. Where outside investors are involved in the oil and gas industry, it is commonly involved on a "limited partnership" basis with a general partner (the actual operator). The general partner can be either a corporation or an unincorporated oil and gas firm. The limited partnership arrangement is attractive to outside investors because their liability is limited to their capital contribution, whereas the general partner is liable for the partnership's liabilities in full. The limited partners also generally have little say in how the partnership allocates its drilling and development funds. In this sense, the limited partnership is similar to a corporation--the stockholders have limited liability and do not usually direct the firm's ongoing operations. Unlike a regular corporation,

however, the limited partnership arrangement allows the firm to pass through to the partners their full share of deductions and tax losses.[4]

The tax rules generally allow limited partners to take a proportionately greater share of the start-up deductions in exchange for a lower percentage of the revenues. For example, the limited partners may be allocated 90 to 100 percent of the intangible drilling cost deduction of the operation.[5] One of the advantages of this arrangement is that the limited partners will be able to use the high front-end deductions involved in oil and gas drilling.

The limited partnership financing arrangement has significant advantages over a bank loan. If the operating company borrowed the amount necessary to drill an oil field, it would not be entitled to write off its intangible drilling costs right away unless it had taxable income from other sources. (To the extent that a limited partnership takes out a loan, the partners are restricted from taking a tax loss in excess of the amount they personally are at risk.) Thus, the limited partnership arrangement allows small oil firms to generate capital from outside investors who can use tax deductions that might not otherwise be utilized. In addition, it allows individuals the opportunity to invest in a high-risk operation without becoming active participants in the venture, while the operator is free of the definite repayment obligations associated with a loan.

Limited partnerships provide a significant source of finance for the industry, amounting to several billion dollars over the last few years. In 1980, public partnership "drilling funds" registered with the Securities and Exchange Commission (SEC) raised $1.3 billion.[6] These funds represented about 6 percent of all drilling expenditures in 1980 and 20.6 percent of

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4 Under the Subchapter S revisions of 1982, limited partnerships are now very similar to Subchapter S corporations.

5 "Public Oil and Gas Program Investment Declines in 1982," Investor's Tax Shelter Report, vol. 2, no. 1 (January/February 1983), p. 4.

6 The Tax Reform Act limited special allocations to those circumstances where they have a "substantial economic effect," that is, where the allocation actually affects the dollar amount of the partners' share of the total partnership income or loss, independent of tax consequences.

drilling expenditures by firms other than the top 200. In 1981, capital provided through public drilling funds rose to a record $2.0 billion (6 percent of total drilling expenditures), but fell by 50 percent to $1.1 billion in 1982. Drilling capital is also raised through private placements of limited partnerships that are not registered with the SEC. Although there are no available statistics on the amount supplied through these funds, it has been estimated that the amount provided through privately placed funds may be twice that of SEC-registered funds.

A Limited Partnership In Action. A limited partnership in the oil industry often takes the form of a general partner offering "shares" to investors in the partnership. The sponsoring firm may set up many such partnerships, each as a separate entity. The general partner directs all oil exploration and development operations; the limited partners have no control over the operating methods of the general partner.

The most common form of limited drilling partnership in oil and gas is referred to as a "functional allocation" program. In this type of structure, the sharing of costs turns on their tax treatment. Investors pay all "expensed" costs (those that are written off right away), while the sponsor pays all capital costs. Revenues are shared from the start of production. Although this arrangement maximizes the first-year deductions of the investors, it also maximizes their exposure to risk, since they are fully responsible for the costs of dry holes. Moreover, the sponsor's share of capital costs, although not fully deductible in the first year, benefits from depreciation under the Accelerated Cost Recovery System (ACRS) plus the investment tax credit and percentage depletion. Thus, the sponsor loses little (if anything) by sharing costs in this way, and gains significant insulation against the vagaries of the industry. This is in addition to a revenue-sharing arrangement that disproportionately favors the sponsoring firm.

A typical sharing of the costs and revenues of a functional allocation program is shown below:

	General Partner (percent)	Limited Partner (percent)
Management Fee	0	100
Sales Commissions	100	0
Capital Costs		
Lease bonuses	100	0
Equipment	100	0
Non-capital Costs		
Intangible drilling	0	100
Lifting Costs	50	50
Administrative Overhead	50	50
Revenues	50	50

In this arrangement, the general partner receives 50 percent of the net operating revenue (gross revenue less lifting costs and overhead) in exchange for providing the capital costs, such as lease bonuses and depreciable equipment. As a percentage of the total investment in a producing well, capital costs might be 25 percent. Basically this type of operation calls for the operator to become financially involved when a well is completed and the lease equipment installed. If a lease is abandoned, the limited partners are responsible for the costs involved in nonproducing acreage; the operator is only engaged in acreage that is productive.

Upon formation of a partnership, the proceeds from the sale of "shares" are applied to the development of oil and gas properties. In this case, it is assumed that the limited partners' investment is applied as follows:

	Percent
Management fee	6
Administrative overhead	4
Drilling and equipping wells (Intangible drilling costs)	90

Assume, for example, that the investors put up $555,556, of which 90 percent ($500,000) goes toward drilling an oil well. The 10 percent

($55,556) that goes for overhead and management fees may be amortized over 60 months as reimbursement of the costs of organizing a partnership. (Overhead determined to be in excess of reasonable compensation, or determined to be reimbursement of syndication costs, including sales commissions, would not be deductible.)

The operator leases the rights to 500 acres of land that is unproven. The landowner receives an up-front bonus of $50,000 plus a one-eighth royalty. In the first year, the venture drills and completes its well, expending the full $500,000 in intangible costs. If the well turns out to be dry, the investors are allowed to write off their full investment of $555,556. Assuming they are in the 50 percent tax bracket, their real loss is half of their original investment ($277,778).

If the well strikes oil, the tax implications are much more complex. The limited partners are allowed to write off their full share of intangible drilling costs and overhead in the first year. The management fee is considered a partnership organization cost and is amortized over five years. The income and expense profile of the limited partners is shown in Table 2. The well is assumed to remain productive for nine years, after which time the operating costs exceed revenues. The investors are entitled to 50 percent of the revenues and can deduct 50 percent of the costs. The investors are assumed to be eligible for percentage depletion at a rate of 15 percent. For simplicity, it is assumed that the investors are not subject to the alternative minimum tax, in regard either to intangible drilling costs or to percentage depletion.

In 1984, the gross receipts of the partnership are $400,000 and are reduced by the 12.5 percent royalty to arrive at gross income of $350,000. Both the limited partners and the operator share this amount evenly. The limited partners' share of operating costs is $21,875, yielding a net pretax cash flow of $153,125. This amount is then adjusted to reflect the provisions in the tax code for deriving taxable income. The limited partners are allowed percentage depletion of $26,250 and a deduction of 20 percent of their management fee ($6,667). After these adjustments, taxable income is calculated at $120,208, yielding a tax liability of $60,104. This is subtracted from the investors' pretax cash flow to arrive at their post-tax cash flow of $93,021. This is the amount in which the investor is critically interested when evaluating various investment opportunities.

The general partner's income statement is shown in Table 3. It is assumed that the general partner is a sole proprietor and is subject to a marginal tax rate of 50 percent. The general partner's income share is the same as the limited partners', except that the operator also receives the 6 percent management fee. The general partner invests $75,000 in depreci-

TABLE 2. OIL EXPLORATION PARTNERSHIP - INVESTORS' ACCOUNTS

		1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
A	Gross Receipts	0	400,000	500,000	450,000	350,000	275,000	200,000	150,000	100,000	50,000
	Less royalty	0	50,000	62,500	56,250	43,750	34,375	25,000	18,750	12,500	6,250
	Gross income	0	350,000	437,500	393,750	306,250	240,625	175,000	131,250	87,500	43,750
B	Income Allocated to Partners (50 percent)	0	175,000	218,750	196,875	153,125	120,313	87,500	65,625	43,750	21,875
C	Expenses Allocated to Partners										
	Intangible drilling costs (100 percent)	500,000	0	0	0	0	0	0	0	0	0
	Administrative and lifting costs (50 percent)	22,222	21,875	21,875	21,875	21,875	21,875	21,875	21,875	21,875	21,875
	Management fee (100 percent)	33,334	0	0	0	0	0	0	0	0	0
D (B-C)	Pre-Tax Cash Flow	-555,556	153,125	196,875	175,000	131,250	98,438	65,625	43,750	21,875	0
E	Tax Adjustments										
	Deduct percentage depletion	0	26,250	32,813	29,531	22,969	18,047	13,125	9,844	6,563	0
	Amortize management fee	-26,667[a]	6,667	6,667	6,667	6,667	0	0	0	0	0
F (D-E)	Taxable Income or Loss (-)	-528,889	120,208	157,395	138,802	101,614	80,391	52,500	33,906	15,312	0
G	Regular Income Tax (50 percent)	-264,445	60,104	78,698	69,401	50,807	40,196	26,250	16,953	7,656	0
H (D-G)	Investor Cash Flow	-291,111	93,021	118,177	105,599	80,443	58,242	39,375	26,797	14,219	0

a. The management fee ($33,334) is not allowed as a deduction; this reduces the tax loss by $33,334. However, the investors are allowed to amortize 20 percent of the fee ($6,667) in the first year. Thus, the net effect is to reduce the tax loss by $26,667 ($33,334 - 6,667).

TABLE 3. OIL EXPLORATION PARTNERSHIP - OPERATOR'S ACCOUNT

		1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
A	Gross Receipts	0	400,000	500,000	450,000	350,000	275,000	200,000	150,000	100,000	50,000
	Less royalty	0	50,000	62,500	56,250	43,750	34,375	25,000	18,750	12,500	6,250
	Gross income	0	350,000	437,500	393,750	306,250	240,625	175,000	131,250	87,500	43,750
B	Income Allocated to Operator (50 percent)	0	175,000	218,750	196,875	153,125	120,313	87,500	65,625	43,750	21,875
C	Other Income and Expenses Allocated to Operator										
	Plus management fee (100 percent)	33,334	0	0	0	0	0	0	0	0	0
	Less administration and lifting costs (50 percent)	22,222	21,875	21,875	21,875	21,875	21,875	21,875	21,875	21,875	21,875
	Less cost of depreciable assets	75,000	0	0	0	0	0	0	0	0	0
	Less lease bonus	50,000	0	0	0	0	0	0	0	0	0
D (B-C)	Pre-Tax Cash Flow	-113,888	153,125	196,875	175,000	131,250	98,438	65,625	43,750	21,875	0
E	Tax Adjustments										
	Deduct percentage depletion	0	26,250	32,813	29,531	22,969	18,047	13,125	9,844	6,563	0
	Depreciation	-64,313[a]	15,675	14,963	14,963	14,963	0	0	0	0	0
	Bonus not deductible	-50,000	0	0	0	0	0	0	0	0	0
F (D-E)	Taxable Income	425	111,200	149,099	130,506	93,318	80,391	52,500	33,906	15,312	0
G	Regular Income Tax (50 percent)	213	55,600	74,550	65,253	46,659	40,196	26,250	16,953	7,656	0
H	Investment Tax Credit (10 percent)	-7,500	0	0	0	0	0	0	0	0	0
J (D-G-H)	Operator Net Cash Flow	-106,601	97,525	122,326	109,747	84,591	58,242	39,375	26,797	14,219	0

a. The cost of depreciable assets ($75,000) is not deductible in the first year; this reduces the tax loss by $75,000. However, the operator is allowed first year depreciation of $10,687, so that the net effect is $64,313 ($75,000 - 10,687).

able assets and $50,000 in the lease bonus in the first year. The bonus is not allowed as a tax deduction--percentage depletion, however, is allowed. The tangible assets are subject to ACRS and the 10 percent investment tax credit. It is assumed that the depreciable property is in the five-year recovery class and is placed in service in the first year.

This type of limited partnership generally favors the sponsoring firm. The general partner has only put up $125,000 to get a 50 percent share of the revenues, while the limited partners have invested $555,556 for the same opportunity. In addition, $75,000 of the operator's investment (depreciable equipment) will be contributed only after the property is known to be productive. The general partner, however, is liable for all debts and obligations that the partnership might generate in excess of the capital contributions of the limited partners.

Although this is only an illustration, it is interesting to note that the internal rate of return for the limited partners (after-tax) is 22.3 percent. In contrast, the internal rate of return on a pretax basis is 16.2 percent. The rate of return is 6.1 percentage points <u>higher</u> after tax than before. This implies that the effective tax rate on the investment is a negative 38 percent. On the general partner's side of the ledger, the post-tax internal rate of return is 94 percent, while the pretax return is 138 percent, yielding a positive tax rate of 32 percent. The reason that these returns are so high is that this is a highly speculative investment that has just happened to pay off. The divergence in returns between the general and limited partners reflects the relative mismatch in revenues and investment between the two parties. Exploratory drilling funds often use the "functional allocation" structure in order to minimize the operator's risk in the venture.

Some limited partnerships engage in a significant amount of borrowing that allows them to leverage their investment. With the adoption of the "at risk" rules in 1976, leveraging can no longer be used to generate a tax loss in excess of the amount for which an investor is personally liable. At present, leveraging a limited partnership increases the amount that the venture stands to lose while simultaneously increasing the potential rate of return on equity. In order for a leveraged investment to pay off, the pretax rate of return must exceed the rate of interest on the loan, otherwise leveraging will lower the rate of return. Because the oil business is risky to begin with, increasing the leverage of the investment magnifies the riskiness of the venture.

For example, suppose the investors in the partnership borrowed 50 percent of their capital contribution. Because they are in the 50 percent tax bracket, the investors are essentially paid back their full capital contribution in the first year. In subsequent years, they would have the

same cash flow as before except that they would be able to deduct interest payments and would have to pay back the loan. Clearly, if the program returns more than the interest rate, the investors are well ahead of the game; conversely, if the project does not succeed, the investors have to pay back the loan out of their other income or assets.

The functional allocation structure is one of four basic partnership arrangements used by oil and gas drilling funds. Briefly, the others are structured as follows:

Promoted Interest. In this structure, the general partner pays 10 percent or more of the exploration and drilling costs. The sponsor shares disproportionately in the revenues (for example, 25 percent). There is a strong identity of interest between the investor and the sponsor because the general partner has a significant stake in the success or failure of the program right from the start.

Carried Interest. The investors pay 99 percent of all costs. Revenues are shared disproportionately (usually 85 percent to limited partners); thus, the investors' "carry" the operator's share of the costs. This type of structure minimizes the risk to the general partner as the investors bear almost all of the downside risk should the project fail.

Reversionary Interest. This is similar to the carried interest structure in that the investors pay for most of the costs. In this case, however, the investors may receive 99 percent of the revenues until "payout" (as defined by the partnership agreement). Once a project is "paid-out," the sponsor's share reverts to a substantial interest, such as 25 percent.

In addition to differing in their structure, drilling partnerships also differ in their drilling philosophy in regard to exploratory versus developmental wells. Exploratory wells are riskier and the rewards potentially greater; developmental wells are generally less uncertain. In 1982, about 58 percent of the funds in drilling partnerships went toward programs that emphasized exploratory wells; 26 percent to programs that emphasized development wells; and the remainder to basically balanced programs.[7]

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7 Arthur King, "Simple Factors Make a Big Difference," Tax Shelter Digest, March 1983, pp. 7-11.

A 1982 study of drilling funds indicates the risks and rewards to the investor of such ventures.[8] The average post-tax expected internal rate of return was 9.9 percent, and 21.2 percent of the funds were expected to return in excess of 20 percent. In contrast, about 25 percent were not expected to break even on an after-tax basis.

Drilling funds are the most speculative in the oil and gas area. Other partnerships, called "income" funds, buy proven reserves in the ground, and thereby eliminate the largest risk in the oil industry. The big uncertainty with these programs is future oil and gas prices and not whether a well will be a "duster." In general, these partnerships purchase working interests in producing properties, with the limited partners bearing the costs of exploiting those interests. An income fund is basically an investment in the future price of oil, with a more stable return than an exploratory drilling program. In 1982, income funds registered with the SEC attracted $1.3 billion in capital.[9]

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8 Ibid.

9 "Public Oil and Gas Program Investment Declines in 1982," p. 5.

PART II. SPECIAL TAX PROVISIONS AFFECTING INDEPENDENT OIL AND GAS PRODUCERS

Federal tax law sometimes differentiates between the integrated oil companies and the independents. This part examines several tax code items that impose differing burdens on particular groups of producers in the oil industry. All of the distinctions that have been made between independent and integrated companies have been enacted since 1975 and exempt independents in whole or in part from oil industry tax increases. Although differences in tax treatment existed before 1975 for corporations, partnerships, and sole proprietorships, only recently have oil producers been distinguished by the type of operations they perform. For tax purposes, an "independent" producer is classified as one engaged almost exclusively in the exploration and extraction phases of the oil business. An independent cannot refine more than 50,000 barrels in any single day during the year nor have annual retail sales in excess of $5 million. This basically excludes all producers with significant downstream operations. Unless otherwise noted, this definition applies to all provisions concerning independent producers in the tax code.

DEPLETION

Oil and gas firms, as well as firms in other extractive industries, are allowed a deduction to reflect the exhaustion of reserves as they are produced. Depletion allowances are analogous to depreciation provisions for capital assets--both are intended to compensate the taxpayer for the decline in value of assets over time.

Basically, two forms of depletion are available to taxpayers for computing annual depletion allowances--percentage depletion and cost depletion. Percentage depletion allows a firm to deduct a fixed percentage of the gross income from the property, regardless of its actual initial cost or current basis. In contrast, cost depletion allows the firm to deduct a percentage of the historical cost equal to the percentage of recoverable reserves produced in a given year. The cost basis of a property is its historical acquisition cost, which includes lease bonus payments, exploratory costs, and any capital expenditures that are not expensed (such as intangible drilling costs) or that are not subject to depreciation (such as lease equipment). Cost depletion is limited to the original cost basis of the property, while percentage depletion is computed without regard to the basis.

Until 1975, all oil and gas producers were allowed to use either cost or percentage depletion, whichever was greater, for tax purposes. The percentage of gross income allowed as a deduction was 22 percent, although before 1970 it had been 27.5 percent. The 1975 Tax Reduction Act severely restricted the allowance for percentage depletion. It limited the deduction to independent producers (excluding integrated companies) and allowed percentage depletion on only the first 2,000 barrels per day of production (phasing down to 1,000 barrels per day by 1980).[1] In addition, it lowered the depletion rate from 22 to 20 percent in 1981, and phased the rate down to 15 percent in 1984 and thereafter. For the purposes of the act, royalty holders and holders of nonoperating interests were also allowed percentage depletion under the same restrictions as independent producers. In 1983, about 29 percent of the value of oil and gas is estimated to be subject to percentage depletion--independent producers accounting for about 13 percent and royalty holders for 16 percent. The act also disallowed percentage depletion on proven properties that were sold after 1974, except in certain special circumstances. Table 4 presents the percentage depletion rates and relevant restrictions since 1926.

Although percentage depletion allows a company to recover more than the cost basis of the property over its useful life, this does not mean that it is preferable to cost depletion in every year. In any cost recovery system, whether it is depreciation for equipment or depletion for oil and gas properties, the primary element in determining the benefits of certain tax provisions is their timing over an investment's life. In the early years of a well's life cost depletion allowances often exceed percentage depletion. Because independent producers have the choice between percentage and cost depletion, they will commonly choose to use cost depletion in the early years of a well and switch over to percentage depletion in later years when the cost basis has declined sufficiently.

Percentage depletion has an advantage over cost depletion in the out-years of a property because by then the cost basis has been reduced. Moreover, during periods of oil price increases, percentage depletion is highly preferable because the size of the allowance increases with inflation, whereas cost depletion is linked to the historical cost of the property.

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1 Natural gas produced by independents is also allowed percentage depletion based on a conversion factor of 6,000 cubic feet per barrel of oil. Gas producers are allowed to deduct percentage depletion (22 percent) if it is sold under a fixed contract, in effect on February 1, 1975, that prevents price increases from reflecting the increased income taxes resulting from the repeal of percentage depletion.

TABLE 4. PERCENTAGE DEPLETION RATES ALLOWED FOR INDEPENDENT PRODUCERS

Year	Percentage of Gross Income (percent)	Quantity Limitation (bbl/day[a])
1926 - 1969[b]	27.5	None
1970 - 1974	22.0	None
1975	22.0	2,000
1976	22.0	1,800
1977	22.0	1,600
1978	22.0	1,400
1979	22.0	1,200
1980	22.0	1,000
1981	20.0	1,000
1982	18.0	1,000
1983	16.0	1,000
1984	15.0	1,000
1985+	15.0	1,000

SOURCE: Walter J. Mead, Dennis D. Muraoka, and Philip Sorensen, "The Effect of Taxes on the Profitability of U.S. Oil and Gas Production: A Case Study of the OCS Record," National Tax Journal, vol. 35, no. 1 (March 1982), p. 23.

a. The quantity limitation imposes a limit on the amount of percentage depletion that can be claimed by each eligible company (or taxpayer). Alternatively, percentage depletion can be taken on a limited amount of natural gas production. The depletable gas quantity in cubic feet is the depletable oil quantity multiplied by 6,000.

b. Integrated companies were also allowed percentage depletion before 1975. An integrated company is defined as one that has more than $5 million in retail sales (on an annual basis) or refines more than 50,000 barrels on any day during the tax year.

Since independents are allowed their choice of depletion methods, they obviously have an advantage over the integrated firms.

Percentage depletion may be more or less generous than expensing (writing off the full cost in the first year).[2] In order to mimic expensing, either the full lease acquisition costs would have to be allowed as a deduction in the first year or firms would have to be allowed an annual depletion deduction equal to the net income related to the depletable assets.[3] Because the ratio of net to gross income varies by property (and age of well), no single percentage depletion rate will yield the same result as expensing for all properties. (The ratio of depletable to total assets involved in production also varies considerably by property.) If the policy goal is to provide expensing, it would be easier and more accurate to allow firms to write off all of their oil and gas investments in the first year rather than to allow percentage depletion. This approach would cause problems only for taxpayers unable to use the full deduction in the first year.

Minimum Tax Considerations. Percentage depletion that exceeds the adjusted cost basis of a property is subject to the add-on minimum tax for corporations and the alternative minimum tax for individuals. The current minimum tax rates are 15 percent for corporations and 20 percent for individuals. Cost depletion is not subject to the minimum tax.

When the adjusted cost basis of a property goes to zero, the full percentage depletion deduction is subject to the alternative minimum tax for individuals (assuming the taxpayer's other tax preferences exceed the exemption amount for the minimum tax). The alternative minimum tax is truly an alternative tax because taxpayers pay the greater of their regular tax or their minimum tax. For a taxpayer subject to the alternative

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2 Expensing provides a good comparison because it implies a zero effective marginal tax rate on the asset. In addition, intangible drilling costs, as well as ACRS three- and five-year property, are essentially subject to expensing. Other building and structure investments are accorded less generous capital recovery than expensing, however.

3 For example, if 50 percent of an investment in an oil property was capitalized (that is, subject to depletion), a firm would be allowed to deduct 50 percent of the net income from the property (for present purposes, "net income" refers to gross income less production costs and excise taxes, but not depletion). Thus, if net income was 75 percent of gross income, the appropriate percentage depletion rate would be 37.5 percent (50 percent of 75 percent) of gross income.

minimum tax, marginal percentage depletion deductions are worthless--in fact, extra deductions would raise the taxpayer's total liability. Thus, the alternative tax changes a $50 tax saving to a $20 liability. Only taxpayers with very large amounts of tax-preferred income will be subject to the alternative tax.

The corporate add-on minimum tax imposes a 15 percent levy on the excess of percentage depletion over the basis of the property. When the basis has been reduced to zero, the minimum tax imposes an additional tax of $21.90 (per $100 of depletion), thereby reducing the tax benefit of depletion from $46.00 to $24.10, a reduction of 48 percent.[4]

REDUCED WINDFALL PROFIT TAX RATES FOR INDEPENDENT PRODUCERS

The Crude Oil Windfall Profit Tax Act of 1980 established a federal excise tax on oil production based on an estimate of the windfall profit received by producers as a result of oil price decontrol. The act basically established three categories of oil and set different tax rates for each class. The three oil "tiers" are defined as follows:

Tier One. All oil except that oil classified as Tier Two or Tier Three.

Tier Two. Stripper oil (that is, oil produced from wells with less than 10 barrels per day of production) and oil produced from the Naval Petroleum Reserve.

Tier Three. Newly discovered oil (production from properties developed after 1978), heavy oil, and incremental tertiary oil.

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4 The reduction in the tax benefit from depletion resulting from the add-on minimum tax is greater than simply the rate (15 percent) times the preference amount (for example, $100). This effect is a result of the fact that a firm's regular tax liability is deducted from the minimum taxable income. For example, the $100 preference gives rise to a tax saving of $46 in regular tax and a direct minimum tax of $15, for a net saving of $31 ($46 - $15). In addition, the preference has reduced the firm's regular tax by $46, thereby reducing the deduction from minimum taxable income--that is, minimum taxable income goes up by $46 because of the preference. This increment is also taxed at 15 percent, so that the total additional tax is $21.90 ($15.00 + $6.90). Thus, the resulting value of the tax preference is $24.10 ($46.00 - $21.90), and the effective minimum tax rate is 21.9 percent.

The standard tax rates specified by the law are 70 percent (of the windfall profit)[5] on tier one oil, 50 percent on tier two oil, and 30 percent on tier three oil.[6] For oil in either tier one or tier two, the act specified reduced rates for independent oil producers on their first 1,000 barrels of production per day.[7] The reduced rate on tier one oil is 50 percent and on tier two 30 percent; there is no reduced rate on tier three oil. Royalty holders are not eligible for the reduced tax rates. Table 5 sets out the tax rates and production shares for 1981 in each category of oil.

In 1981, 6.5 percent of tier one oil (4.5 percent of all taxable oil) was subject to the lower 50 percent rate for independents. This advantage was equivalent to about $3 per barrel of production. On 1,000 barrels per day of production, this amounted to about $1.1 million per producer on an annual basis. This benefit, however, should decline as long as oil prices remain steady (or increase less than the rate of inflation). Because the windfall profit declines if oil prices rise less than the GNP deflator, the tax differential is smaller when real oil prices are lower. In 1981, tier one oil was approximately 70 percent of domestic production. The total tax advantage for reduced rates (on tier one oil) in that year was roughly $494 million. Because the tax is deductible against the corporate income tax, however, the net benefit is only about $266 million since the lower rate reduces the amount allowable as a deduction, thereby increasing income taxes.[8]

Stripper Exemption. Tier two oil (about 14 percent of domestic production) was also subject to reduced rates for independent producers

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5 The windfall profit is defined as the difference between the market wellhead price and the 1979 controlled price. For example, the tax on tier one oil equals 70 percent of the market price less the base price; that is, tax = 0.7 (market price - base price). The controlled (or base) price is indexed to reflect changes in the GNP deflator.

6 The tax rate on newly discovered oil was reduced by the Economic Recovery Tax Act of 1981 to 15 percent over a six-year period. The current rate is 25 percent and will be 15 percent starting in 1986.

7 As defined by the Windfall Profits Tax Act of 1980, an independent's status is determined on a quarterly basis instead of on an annual basis. Thus, in any quarter an independent cannot refine more than 50,000 barrels on any day nor have retail sales in excess of $1.25 million.

8 This assumes a marginal tax rate of 46 percent for both individuals and corporations.

TABLE 5 SHARES OF TAXABLE PRODUCTION AND WINDFALL PROFIT TAX LIABILITY BY OIL TIER (1981)[a]

Oil Tier	Percent of Taxable Oil Production	Percent of Windfall Profits Tax Liability
Tier One	70.3	82.0
Taxed at 70%	65.8	77.3
Taxed at 50%	4.5	4.6
Tier Two	13.1	11.2
Taxed at 60%	8.3	8.6
Taxed at 30%[b]	4.8	2.6
Tier Three (Taxed at 30%)	16.6	6.8
Newly discovered[c]	11.3	5.2
Incremental tertiary	0.6	0.3
Heavy oil	4.6	1.3
Total	100.0	100.0

SOURCE: U.S. Department of the Treasury, Internal Revenue Service, Statistics of Income Bulletin, vol. 2, no. 2 (Fall 1982), p. 44.

a. Taxable production excludes production that is exempt, such as state and local government interests, Indian oil, or charitable interests.

b. Production in this class is basically stripper production, which has been made exempt from tax as of January 1, 1983.

c. The newly discovered tax rate is now 25 percent and will decline to 15 percent in 1986 and thereafter.

under the 1980 act. This advantage has been superseded, however, because the Economic Recovery Tax Act of 1981 (ERTA) basically exempted all stripper production by independent companies. In the first quarter of 1982, the average tax per barrel of tier two oil (produced by an integrated company) was $7.80.[9] Because the independent tax rate was half the normal rate, the tax benefit was about $3.90. With the adoption of the stripper exemption, this advantage is now equivalent to the full $7.80. Because the tax is deductible against the income tax the net advantage is about 54 percent of this amount. In addition, the decline in oil prices has also eroded this tax advantage. It is estimated that the current tax differential for independents on stripper oil is now about $6.10 (gross) per barrel (assuming a $30 barrel of oil).

The exemption for stripper oil does not count against a firm's 1,000 barrel limit on oil eligible for reduced rates in either tier one or tier two. (Independents could have some tier two production resulting from the Naval Petroleum Reserve.) A firm could, for example, exempt 700 barrels per day of stripper oil and still receive favorable tax treatment on 1,000 barrels per day of tier one and/or tier two oil.

The exemption of stripper oil was justified in order to prevent "premature abandonment of such properties as the costs of production rise relative to the income available from the property."[10] This exemption will have the effect of extending the economic life (and increasing the ultimate total production) of oil wells that are marginally profitable. That this exemption was only allowed independent producers seems inconsistent with the general intent of the law, however. In 1981, about 40 percent of the output from stripper leases was produced by the top 24 companies (on a net company basis). This indicates that stripper oil production is not solely a province of the independent firm. From the policy standpoint of increasing oil production, there does not appear to be any rationale for eliminating an incentive for independents to cap wells while retaining it for integrated firms.

WINDFALL TAX EXEMPTION FOR ROYALTY HOLDERS

Current law allows royalty holders an exemption from the windfall profit tax of two barrels of production per day in 1982 through 1984; in

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9 U.S. Department of the Treasury, Internal Revenue Service, Statistics of Income Bulletin, vol. 2, no. 3 (Winter 1982-83), p. 42.

10 Joint Committee on Taxation, General Explanation of the Economic Recovery Tax Act of 1981, p. 321.

1985 and thereafter, the exemption will be three barrels per day. When originally passed, the Windfall Profit Tax Act did not include any tax exemption or credit for royalty holders. However, the Omnibus Reconciliation Act of 1980 established a $1,000 tax credit for royalty holders on oil removed in 1980; no provision was made for subsequent years. In ERTA, the Congress extended this credit to $2,500 for 1981 and provided the exemptions that exist under current law for 1982 and thereafter. The rationale for this credit was that the "windfall profit tax on small amounts of royalty income imposed a hardship on many low- and middle-income taxpayers."[11] In 1983, the average tax per barrel is estimated to be about $4.50 (gross) and $2.25 (net), assuming a price of $30.[12] Thus, the two-barrel-per-day exemption currently in effect is equivalent to about a $1,640 credit for the taxpayer facing a 50 percent marginal tax rate, which is less than the $2,500 credit allowed in 1981. (For the taxpayer in the 30 percent tax bracket, the equivalent credit is $2,300.) If the three-barrel-per-day exemption were effective in 1983, it would result in an equivalent credit of about $2,460 for the taxpayer in the 50 percent bracket, and $3,450 for the taxpayer in the 30 percent bracket.

Although the exemption helps low- to moderate-income royalty holders, it also provides a tax break for the high-income taxpayer. In 1980, 57 percent of the net royalty income (from all sources, not only from oil and gas) was reported on returns filed by taxpayers with an adjusted gross income (AGI) in excess of $50,000.[13] Twenty percent of the returns reporting any royalty income had adjusted gross incomes in excess of $50,000. The two-barrel-per-day exemption implies that the royalty holder may be receiving (gross) royalty income of $21,900 annually (at a $30.00 price per barrel) free from the windfall profit tax. The three-barrel-per-day exemption results in $32,850 tax-free royalty income. (Although these royalties are exempt from the windfall profit tax, they remain subject to the regular personal income tax.) For reference, the average AGI on tax returns in 1980 was about $16,200; the average royalty income (from all sources) for royalty recipients with AGI under $50,000 was $3,184; and for royalty recipients with AGI over $50,000 it was $17,293.

In 1982, about 4 to 5 percent of domestic oil production was subject to the royalty exemption. For the calendar year, the tax saving was

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11 Ibid.,

12 The net is lower than the gross because the windfall profits tax is deductible against the personal income tax.

13 Net royalty income is gross royalties <u>less</u> depletion and other related costs.

approximately \$856 million (gross); on a net basis the saving was about \$498 million. The net saving is less than the gross because lower windfall profit taxes results in a lower deduction (for taxes) and higher personal income taxes.

INTANGIBLE DRILLING COSTS

Until the Tax Equity and Fiscal Responsibility Act of 1981 (TEFRA), both independent and integrated oil producers were allowed to expense their expenditures for intangible drilling costs. These are capital expenditures with no salvage value, such as amounts paid for fuel, labor, materials, and supplies used in the preparation and drilling of oil or gas wells. They exclude expenditures for lease equipment, such as storage tanks or pumping machinery, which would be handled as five-year recovery property under ACRS. Although lease equipment is eligible for the investment tax credit, intangible drilling costs (IDCs) that are expensed do not qualify for the credit. The combination of accelerated depreciation and the investment tax credit is about equivalent to expensing at a 10 percent discount rate; thus, lease equipment and expensed IDCs currently receive similar effective tax treatment.

In TEFRA, the Congress reduced (to 85 percent) the percentage of IDCs that integrated oil corporations could expense; the independent companies may still deduct 100 percent of their IDCs. The remaining 15 percent of an integrated firm's IDCs are amortized on a straight-line basis over three years. In present value terms, this provision reduced the value of deduction for IDCs from 100 percent to about 97 percent (using a discount rate of 10 percent). This provision only applies to producing properties--intangible costs associated with dry holes will continue to receive full expensing treatment.

Minimum Tax Considerations. While the TEFRA provisions directly scaled back the deductions for IDCs for integrated firms, the minimum tax on individuals reduces the value of these deductions for limited partnerships and Subchapter S corporations. Before TEFRA, the individual minimum tax (and the corporate minimum tax for Subchapter S firms) required individuals to include intangible drilling costs in their minimum tax base.[14] The minimum tax rate was 15 percent, and 10 percent of the

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14 Intangible drilling costs are included in a taxpayer's minimum tax base to the extent that (1) they exceed the amount that would have been deducted had they been amortized over ten years; and (2) that the amount in (1) is greater than a taxpayer's net income from oil and gas properties.

IDC was deductible in the first year. Thus, the minimum tax imposed an effective tax rate of 13.5 percent on the preference, assuming the taxpayer was subject to the tax.[15] For a taxpayer in the 50 percent tax bracket, this provision was equivalent to reducing the preference by 34 percent, to 66 percent of its original value.[16]

Under TEFRA, individuals in partnerships, sole proprietorships, or Subchapter S corporations are subject to a new alternative minimum tax which replaces the minimum tax under prior law. The new minimum tax includes IDCs as a tax preference and the deduction is taxed at a marginal rate of 20 percent (instead of 15 percent as under previous law). The amount of IDCs included in the alternative minimum tax base equals the amount in excess of straight-line amortization over ten years. This is the same definition as under pre-TEFRA law. The alternative minimum tax on IDCs has the same kind of effect as it does on percentage depletion. The marginal IDC deduction ($100) changes from a $50 tax saving under the regular tax (for the taxpayer in the 50 percent bracket) to an $18 liability under the alternative tax. Thus, extra IDC deductions for persons subject to the alternative minimum tax are worthless.[17]

Individuals with limited partnership interests have the option of amortizing their IDCs over ten years (straight-line), and thereby excluding them from the minimum tax base. Taxpayers will find it to their advantage to use the option to capitalize their IDCs if they are subject to the alternative minimum tax. For example, the taxpayer in the 50 percent bracket would reduce the present value of the tax deduction from $50 to

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15 Under pre-TEFRA law 50 percent of a taxpayer's regular tax was deductible against the taxpayer's minimum taxable income. Thus, the direct minimum tax on IDCs would be $13.50 (per $100 of deduction) and the indirect tax would be $3.75 for a total of $17.25. The indirect tax equals 15 percent of one-half of the reduced liability resulting from the preference. In the case of the taxpayer in the 50 percent bracket, $\$3.75 = (0.15)(0.5)(0.5)(\$100)$.

16 The taxpayer could have capitalized intangible drilling costs and recovered them through cost depletion, thereby avoiding the minimum tax. However, this was probably not a profitable strategy since future deductions are worth considerably less than current deductions (on a present value basis).

17 This assumes that the full amount of the "excess" IDCs are included in the minimum tax base. To the extent that income from other oil and gas properties is used to reduce the excess IDCs, the reduction in the value of the preference will be less.

$32.25 by amortizing it over ten years (assuming a 10 percent discount rate). This reduction, however, is clearly preferable to the alternative of an $18 liability to the IRS.

TEFRA also included a second option for taxpayers who are operators (for example, general partners or sole proprietors) of oil and gas properties. These individuals are permitted to treat IDCs as five-year recovery property under ACRS, and thereby exclude IDCs from their minimum tax base. Under ACRS, the taxpayer is entitled to accelerated depreciation plus the 10 percent investment credit (subject to the 50 percent basis adjustment). At a 10 percent discount rate, this option for IDCs is about equivalent to expensing; at a lower discount rate, it is more generous than expensing. Thus, the alternative minimum tax can be completely escaped (at no cost) by taxpayers who are operators of oil and gas properties. Because the ACRS option was not available under prior law, TEFRA actually reduced the minimum tax burden on taxpayers with an active interest in oil and/or gas production.

The current treatment of IDCs for different types of taxpayers is summarized in Table 6.

AT-RISK RULES

The Tax Reform Act of 1976 placed a limitation on the tax loss associated with an oil and/or gas investment that a taxpayer could deduct; the tax loss cannot exceed the amount the partner is personally liable for. This provision was necessitated by the prevalence of limited partnerships where the partners' personal liabilities are limited to their capital contributions. For example, a partnership may incur a debt for which the partners are not personally liable if the loan cannot be repaid. To the extent that loans were used to drill wells, the intangible drilling costs allocated to the partners could thus have exceeded their capital investment. Limited partners were thereby able to leverage their investment, without facing the concommitant personal liability should the project fail. Under the 1976 tax rules partnerships can still borrow, but the tax losses allowed cannot exceed the capital interest of the partners, unless they are personally liable for these loans. Corporations that invest in limited partnerships are subject to the same at-risk rules as individuals.

In general, sole proprietorships and general partnerships are liable for the full amount of debt they incur, and are allowed to write off the full amount of any tax loss related to their investments. Corporations (both regular and Subchapter S) allow stockholders to limit their personal liability to their capital investment. Corporate stockholders in regular (non-Subchapter S) corporations cannot deduct any more than their capital

TABLE 6. TAX TREATMENT OF INTANGIBLE DRILLING COSTS

Type of Taxpayer	Tax Treatment	Present Value of $100 Deduction[a] (dollars)	Present Value of Tax Saving (dollars)
Corporation - Integrated (46 percent tax rate)	First-year expensing of 85 percent of IDCs; the remainder amortized over 3 years (straight-line)	97.40	44.80
Corporation - Independent (46 percent tax rate)	First-year expensing	100.00	46.00
Sole proprietor or general partnership (50 percent tax bracket and subject to alternative minimum tax)	Either (A) First-year expensing subject to minimum tax rules **or**	-90.00[b]	-18.00
	(B) Treat IDCs as five-year recovery property; no minimum tax	98.50	49.25
Limited partner (50 percent tax bracket and subject to alternative minimum tax)	Either (A) First-year expensing subject to minimum tax rules **or**	-90.00[b]	-18.00
	(B) Amortize IDCs over 10 years; no minimum tax	64.50	32.25
Individual (50 percent tax bracket and <u>not</u> subject to alternative minimum tax)	First-year expensing	100.00	50.00

a. Assumes a 10 percent discount rate and $100 IDC.

b. Assumes taxpayers have no net income from oil and gas properties; the excess IDCs equal the difference between expensing and ten-year amortization. The negative sign implies that there is <u>no</u> tax saving, but an actual tax liability.

investment as a tax loss--this would happen if the corporation's stock price dropped to zero. The corporation structure, even though it provides limited liability to its shareholders, does not allow any tax losses to flow through to stockholders that are in excess of their investment. In contrast, Subchapter S firms both provide limited liability to their shareholders and allow tax losses to "flow through" to the owners, much as under a limited partnership. (The Subchapter S Revision Act of 1982 eliminated the limitations on the extent to which shareholders could utilize percentage depletion deductions.) The Subchapter S rules, however, limit the tax loss that can be claimed by the taxpayers to their capital basis plus any indebtedness of the corporation to the stockholder. Thus, for purposes of the at-risk rules, Subchapter S firms are treated analogously to limited partnerships.

In general, the tax law prevents all individuals from generating tax losses in excess of their capital investment, unless they are personally liable for the debts incurred to generate those losses.

ACCELERATED WINDFALL PROFITS TAX PAYMENTS

In general, the first purchaser of domestic crude is required to withhold the windfall profit tax amounts payable to the producer and deposit those amounts with the Treasury. The purchaser is liable to the Internal Revenue Service (IRS) for the payment of the amount withheld, as determined by the certification provided by the operator. (This includes any certification of any part of the production eligible for reduced independent tax rates or exemption.) The purchaser files a quarterly return showing the tax withheld and provides each producer with an information statement indicating the amounts of oil purchased and the tax withheld.

The first purchaser must deposit the withheld payments to the IRS within a certain length of time. Major refiners or retailers are required to make semi-monthly estimated deposits of withholding tax. All other purchasers are required to make deposits within 45 days after the end of the month in which the oil was removed from the premises.[18]

The interval between when a tax is withheld and when it is deposited allows a firm to earn interest on the withheld amounts for that interval. On average, the majors are allowed a very brief period (7.5 days) between the time when a tax is withheld and it is due the Treasury. (This assumes

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18 These provisions are described in Joint Committee on Taxation, General Explanation of the Crude Oil Windfall Profit Tax Act of 1980, pp. 57-58.

that tax is withheld at a constant daily rate over the month.) In contrast the independent purchaser is allowed 60 days (on average) before the withheld tax must be deposited. Thus, on average, the independent purchaser may be able to earn eight times more interest on the withheld tax collections than a major company could. To the extent that the independent operator takes on the deposit obligations of an independent first purchaser, the operator can take advantage of the delayed timing of the liability (the operator and the first purchaser may elect to have the operator assume the purchaser's responsibilities under the tax, Code § 4995(a)(7)(A).) However, if the first purchaser is a major company, the independent operator's payment obligation is the same as for a major company.

REVENUE PROJECTIONS

Significant revenues could be raised over the 1984-1988 period by making the tax provisions consistent for all firms. Table 7 sets forth CBO's revenue projections from various changes in the tax law that would move toward uniformity of treatment for different producers.

Two options are presented for intangible drilling costs. The first option--capitalization of all intangible drilling costs associated with producing wells--would apply to both independents and integrated companies. This would require firms to amortize their drilling costs over the productive life of the well, rather than expensing them all (or 85 percent) in the first year. These costs would be added to the depletable basis of the property and recovered through cost depletion. Currently, this is the generally accepted practice that firms use for financial (as opposed to tax) reporting. The second intangible drilling cost option would only affect independent companies--it would require them to amortize 15 percent of their IDCs over three years as is currently required of integrated companies.

There are also two options for the windfall profit tax. The first would eliminate the current independent exemption for stripper oil, but would leave intact the reduced rate of 30 percent. The second alternative is more sweeping in that both the stripper exemption and the reduced rates on both tier one and tier two oil would be abolished. Under this option, all tier one oil would be taxed at a 70 percent rate and all tier two oil would be taxed at 60 percent. (Interests currently exempt, such as state and local governments, Indian oil, or charitable oil would remain untaxed.) Both these options would only affect production by the independent companies.

The option to repeal percentage depletion would also only affect the independent firms. Under this alternative, firms would be required to use

TABLE 7. ESTIMATED REVENUE EFFECTS OF CHANGING TAX PROVISIONS FOR OIL AND GAS PRODUCERS (By fiscal year, in billions of dollars)

Option	1984	1985	1986	1987	1988	Cumulative Five-Year Increase
Capitalize All IDCs	2.1	3.6	3.3	3.2	3.1	15.3
Amortize 15 Percent of IDCs over 3 Years	0.1	0.1	0.1	*	*	0.4
Eliminate Stripper Exemption for Windfall Profits Tax (Retain Reduced Tax Rate)	0.2	0.2	0.2	0.2	0.2	1.1
Eliminate All Reduced Windfall Profit Tax Rates for Independents (No Stripper Exemption)	0.5	0.6	0.5	0.5	0.5	2.6
Repeal Percentage Depletion	0.9	1.7	1.9	2.0	2.2	8.7
Repeal Exemption for Royalty Holders	0.4	0.5	0.4	0.4	0.4	2.0
Expense All IDCs	-0.2	-0.2	-0.1	-0.1	-0.1	-0.6
Extend Stripper Exemption to Include All Producers	-0.7	-0.9	-0.9	-0.9	-0.9	-4.3

SOURCES: Joint Committee on Taxation and Congressional Budget Office.

* Less than $50 million.

the cost depletion methods that the integrated companies are currently required to use. In general, the independent companies already use cost depletion for financial reporting purposes so that they can report higher earnings to their shareholders.

Repeal of the two-barrel-per-day exemption from the windfall profit tax for royalty holders would not directly affect either the independent or the integrated producers, as the exemption does not distinguish oil by type of producer. Instead, it would make the tax treatment of holders of nonoperating royalty interests the same as that of operating interests, who are not currently allowed the exemption. Elimination of the exemption would primarily affect those individuals who are currently royalty recipients.

Lastly, two options are included that would increase consistency, but would reduce revenues. The first option would repeal the 15 percent reduction of the first-year write-off for drilling costs adopted in TEFRA. All firms would be allowed full expensing. The second alternative would extend the stripper exemption to integrated as well as independent firms. Thus, the windfall profit tax would not impose an incentive for any firm to abandon wells that might still be economically productive.

PART III. METHODOLOGY FOR ESTIMATING PRODUCER TAX BURDENS

One approach to measuring the overall burden of taxation on oil and gas production is to estimate the total taxes a producer is liable to pay over the life of a given property. By discounting the tax payments back to the present, the total "present value" of tax payments can be calculated. This method allows all tax provisions and their timing differences to be taken into account.

The basic framework for this approach involves a "discounted cash-flow" (DCF) model that forecasts the revenues and costs from an oil investment over its life. The investor (producer) discounts the investment's income stream over time in order to calculate the total present value of future income from the project. The investor will purchase the property as long as the owner's asking price is less than or equal to the estimated value of the future net income stream. In the DCF model used here, it is assumed that the investor is willing to pay the landowner an amount (the lease bonus) that is exactly equal to the present value of the future net cash flow.

The discount factor used in the model is 12.5 percent and reflects the minimum anticipated return that the investor will accept after all taxes. If the after-tax return is less than 12.5 percent, the investor will forgo the investment opportunity. Thus, the investor will offer the landowner a bonus that assumes a 12.5 percent post-tax return over the life of the investment.

The DCF model is used to estimate the taxes of three different organizations as follows:

1. Major Integrated Corporation. The investor in a major corporation pays the corporate income tax, the personal tax on dividends, and the capital gains tax on retained earnings. It is assumed that the firm distributes 40 percent of its cash flow and retains 60 percent. The major firm must pay full windfall profits tax rates and must use cost depletion. (The cost depletion basis equals the upfront bonus payment for the property.) Eighty-five percent of intangible drilling costs are written off in the first year, the remainder are amortized over three years.

2. Independent Corporation. Like the investor in the integrated firm, the individual who invests in an independent firm pays the corporate income tax, the personal income tax, and the tax on capital gains. It is assumed that the firm distributes 40 percent of its cash flow and retains 60 percent. The independent corporation pays lower windfall profits rates and is allowed percentage depletion on 1,000 barrels per day of oil production. Because the firm is allowed percentage depletion, it must also pay the add-on minimum tax equal to 15 percent of the excess of percentage depletion over the adjusted cost basis of the property. The firm is allowed to expense all intangible drilling costs.

3. Sole Proprietorship or Partnership. This firm is composed of an individual operator or group of operators (who are not corporations) that all have working interests in the property. This type of organization is advantageous because it avoids the corporate income tax altogether; the individual(s) are subject only to the personal income tax. The firm is allowed reduced windfall profits tax rates, and percentage depletion on the first 1,000 barrels per day of oil production. It is assumed that the owners are not subject to the alternative minimum tax on either percentage depletion or intangible drilling.

In order to provide consistency, it is assumed that the investors in all three firms are in the same tax bracket (50 percent). In addition, it is assumed that all individuals and firms have sufficient taxable income to absorb all the deductions that might arise from an oil investment property. For capital gains purposes, it is assumed that the shareholders hold their stock for four years and then realize their gains. The effective capital gains tax rate under this assumption is 15 percent (instead of the statutory 20 percent), and the overall effective personal tax rate (as a percentage of current cash flow) is 29 percent. In other words, the personal income tax rate is 29 percent for investors in a corporation and 50 percent for investors in a noncorporate enterprise. It is assumed that none of the properties are sold during their productive lives.

The three hypothetical properties differ in their production profiles and investment characteristics. Table 8 presents the variables for each property. For simplicity, it is assumed that the future price of oil increases at the same annual rate as inflation (5 percent). The wells were chosen so that the production from each well would be treated differently for purposes of the windfall profits tax. Well No. 1 is assumed to produce "new" oil, Well No. 2 is basically a stripper well, and Well No. 3 produces "old" oil.

TABLE 8. ASSUMED VARIABLES FOR DCF MODEL

	Well No. 1	Well No. 2	Well No. 3
Required Post-Tax Rate of Return (Hurdle Rate)	12.5 percent	12.5 percent	12.5 percent
Time of Investment	1983:1	1983:1	1983:1
Time of Initial Production	1983:2	1983:2	1983:2
Time of Peak Production	1984:2	1984:1	1984:2
Time Production Starts to Decline	1985:1	1985:1	1986:1
Peak Production Rate (barrels per day)	200	15	50
Initial Reserves	487,539	50,622	121,262
Production Decline Rate	15 percent	10 percent	17.5 percent
Annual Operating Cost	a/	a/	a/
Drilling Investment (producing well)	$ 750,000	$ 250,000	$ 400,000
Drilling Investment (dry wells)	$ 2,100,000	0	$ 300,000
Lease Equipment Investment	$ 160,000	$ 40,000	$ 60,000
Oil Tier	Tier 3	Tier 1-2	Tier 1
Windfall Profits Base Price	$ 23.45	$ 19.84	$ 16.11
Oil Price Inflation	5 percent	5 percent	5 percent
GNP Price Inflation	5 percent	5 percent	5 percent
Royalty Rate -- to Landowner	12.5 percent	12.5 percent	12.5 percent
State Severance Tax Rate	4.6 percent	4.6 percent	4.6 percent

a. Annual operating cost equals $8,000 plus $60 per barrel of daily production. This amount is adjusted by the GNP price index over time.

The way the DCF model is structured allows the bonus payment to vary to reflect differences in tax treatment. The full amounts of any differences in taxation are assumed to be 100 percent capitalized into the lease bonus. This implies that taxation does not affect oil prices, but that it is manifested in lower payments to the landowners. Thus, higher taxes would mean that the landowners would be paid less, and vice versa.

The DCF model measures only the returns from prospective investments; it does not indicate the returns to past investments. Once the investment becomes a sunk cost, the actual taxes paid over its life will be a function of actual events, not of forecasts or assumptions. In terms of affecting investment behavior on the margin, it is the prospective post-tax returns that determine a firm's investment decisions. The oil production profile used in the DCF model is the expected profile prior to the investment. Ex post evaluations may significantly differ as more information is gained. However, ex post evaluations do not determine initial investment decisions, although they do affect subsequent marginal decisions concerning recovery techniques.

The results from the DCF model are summarized in Table 9. The taxes and tax rates are higher for the corporations than for noncorporate firms because of the corporate income tax. The rates shown here are higher than might be expected, but this analysis is limited to investors in the 50 percent personal tax bracket.

The first well provides an interesting contrast between the integrated and independent corporations. Because it is classified as new oil (tier three), both firms pay the same amount in windfall profit taxes. The integrated firm pays about 20 percent more in corporate taxes because of the requirement for cost depletion and the amortization of 15 percent of its IDCs. This is partially offset because the independent must pay the add-on minimum tax for percentage depletion. In addition, the investors in the independent must pay higher personal taxes because the firm's after-tax cash flow is higher. As a result of these offsetting effects, the overall taxation of the independent is about 5 percent (three percentage points) less than for the integrated company.

The difference in tax rates between the independent corporation and the general partnership indicates the advantage of organizing a firm on a partnership (or Subchapter S) basis. Both firms pay the same windfall profits taxes, but the partnership pays no corporate income tax. As a result, the partnership tax rate is about 20 percentage points lower for all three wells.

The DCF model can be applied to other properties under alternative assumptions. It is not likely, however, that these changes would alter the

TABLE 9. ESTIMATED PRESENT VALUE OF TAXES FOR THREE OIL WELLS (In thousands of dollars, except as noted)

Producer	Well No. 1	Well No. 2	Well No. 3
Integrated Corporation			
Corporate income tax	2,125.3	127.8	335.5
Add-on minimum tax	0	0	0
Windfall profits tax	200.9	140.7	602.5
Personal income tax	1,695.0	122.2	323.9
Total taxes	4,021.3	390.7	1,251.8
Tax per barrel (dollars)	8.25	7.71	10.40
Tax rate[a]	56 percent	61 percent	67 percent
Present value of tax depletion	534.2	3.8	16.3
Original depletion basis (lease bonus)	1,139.9	9.2	32.9
Independent Corporation			
Corporate income tax	1,760.4	98.1	261.9
Add-on minimum tax	64.1	11.3	30.2
Windfall profits tax	200.9	79.9	430.3
Personal income tax	1,782.3	145.2	386.4
Total taxes	3,808.7	334.4	1,108.8
Tax per barrel (dollars)	7.81	6.61	9.14
Tax rate[a]	53 percent	53 percent	61 percent
Present value of tax depletion	1,313.1	124.5	340.7
Original depletion basis (lease bonus)	1,353.5	65.4	185.9
Sole Proprietorship or Partnership			
Corporate income tax	0	0	0
Add-on minimum tax	0	0	0
Windfall profits tax	200.9	79.9	430.3
Personal income tax	1,802.6	106.9	285.1
Total taxes	2,003.5	186.8	715.4
Tax per barrel (dollars)	4.10	3.69	5.90
Tax rate[a]	31 percent	33 percent	44 percent
Present value of tax depletion	1,537.5	124.5	340.7
Original depletion basis (lease bonus)	3,157.7	213.1	579.3

a. The tax rate is the comprehensive marginal tax rate based on a corporate rate of 46 percent and a personal rate of 50 percent. The tax rate is the percentage difference between the pretax and post-tax rate of return on the total investment.

conclusion that the combination of preferential tax provisions significantly reduces the burden placed on independent oil companies--especially those that are organized on a noncorporate basis.