Chapter 12

The Tax Treatment of Oil Exploration

I

Some years ago I presented an analysis of the problem of percentage depletion, in which I developed what I believe to be the theoretical structure which is relevant for this problem, at least in those cases where the role of exploration is of primary importance.[1] I do not plan to recapitulate here the overall lines of argument presented in my earlier paper. I do, however, plan to present once again the approach outlined in the mathematical appendix of the earlier paper, for several typographical errors in the published version of that appendix have created unnecessary difficulties for many readers. More important, the numerical examples given in my earlier paper were based on fairly rigid assumptions, some of which have been challenged by other writers.[2] In this paper I take a much more cautious approach, and rather than attempting precise numerical estimates for the key factors involved, I allow for rather broad ranges. These ranges are wide enough to include, I believe, all plausible possibilities. Individual cases which might fall outside these ranges would be so rare as to be truly exceptional, and not representative of the typical pattern of effects.

In order to avoid the complexities entailed in trying, within a single theoretical model, to deal with all the widely different types of activity now covered by

[1] See Arnold C. Harberger, "The Taxation of Mineral Industries," in U.S. Congress, Joint Economic Committee, *Federal Tax Policy for Economic Growth and Stability* (Washington, D.C.: Government Printing Office, November 1955), pp. 439–449. [This volume, Chapter 11.]

[2] See especially Peter O. Steiner, "Percentage Depletion and Resource Allocation," U.S. House of Representatives, Committee on Ways and Means, *Tax Revision Compendium* (Washington, D.C.: Government Printing Office, December 1959), Vol. II, pp. 949–966. Steiner objected to the assumptions which I made about the fraction of exploration costs which were expensed, and about the ratio which depletion allowances typically bore to net income from producing wells. There are a few points in Steiner's treatment which I believe are open to discussion, but the issues are so minor that their introduction here would tend to obscure the main points which this paper attempts to make. The ranges which are given in the present paper for the ratios in question are sufficiently wide that they easily include those used by Steiner.

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percentage depletion provisions, I shall limit the scope of this paper to the case of petroleum. Most of the analysis does have broader applicability, but each separate activity has certain peculiar characteristics of its own which would require at least a special discussion of how the model should be interpreted, if not an alteration of the basic model itself. By focusing on the case of oil, I shall be able to bring explicitly into the treatment certain key features of that particular industry.

One key feature of this industry is the highly competitive nature of exploration for oil. Large numbers of firms, of all different sizes, are engaged in this activity. Given the competitiveness of oil exploration, it has always been a puzzle to me how so many writers, in treating percentage depletion, have assumed that the depletion provisions lead to the firms in the industry making exorbitantly high profits. My contention is that competition in oil exploration is sufficient to keep the rate of return on investment in that activity broadly in line with the rate of return on investment in other sectors of the economy. The rate of return to which I refer is of course net of taxes and tax offsets.

The riskiness of oil exploration does of course lead to wide differences in the experience of individual enterprises. But it cannot be denied that if capital in oil exploration yielded, on the average, 20 percent net of taxes, while in most other activities it yielded only 10 percent, there would be a great rush of capital into oil exploration. This would tend to drive down the rate of return toward 10 percent. Perhaps in the end there would remain some differential (reflecting a risk premium), but the available evidence does not suggest that this premium, if it exists at all, is of substantial magnitude. The rate of return, net of taxes, on capital invested in oil exploration corporations, is not substantially greater than the rate of return on investment in other corporations.

The equalization of the after-tax rate of return between oil exploration and other activities probably applies at the corporate level. There are a great many corporations engaged in oil exploration, and they are all, broadly speaking, subject to the same marginal tax rate. They constitute a sufficiently large mass of capital to be able to bring the rate of return on oil exploration to the point where "corporate" capital would be neither especially advantaged nor especially disadvantaged by either shifting into or out of the oil exploration activity. But if this is the case for corporations (with a 52 percent marginal tax rate), it is likely to be true that individuals in the 70 or 80 or 90 percent tax bracket will find that they really can get a higher after tax rate of return by investing in oil exploration than by investing in other directions. The limits to the amount that they invest in oil exploration will be dictated by considerations of portfolio balance and of risk rather than by purely rate-of-return considerations.

II

In this section and the next I present the mathematical demonstration of the proposition that investment in oil exploration is probably pushed substantially beyond the margin which can be considered as "economic" for the society as a whole.

Consider two capital assets, one a machine and the other an oil well. Let them be equivalent in the sense that the streams of income expected to stem from them, net of other costs but before taxation, are identical. These streams, under competitive conditions, measure the value of the services of these assets to the final users of their products, and hence to the economy. Let the present value of each of these income streams be Y, using as the rate of discount that rate which reflects the typical net-of-tax yield on capital in the economy.

Generally speaking, one would expect that potential purchasers of these two assets would be willing to pay the same price for either of them. However, tax considerations do enter the picture. The machine must be depreciated for tax purposes according to normal procedures, while in the case of the oil well, the special provisions for percentage depletion may be involved. In either case, however, the price which a firm would be willing to pay for an asset should equal the discounted value of the *net* income stream expected to flow from that asset. This consists of the discounted value (Y) of the before-tax income stream, less the discounted value (W) of the tax payments associated with this asset.

In the case of normal depreciation we have

$$W_1 = t(Y - dR_1).$$

Here t is the rate of corporation income tax which is applicable, d is a discount factor, and R_1 is the (as yet unknown) price paid for the asset. The discount factor, d, simply takes account of the fact that the present value of $1,000 spread out over a period of time in the future is less than $1,000. The price paid for the asset is the dollar total which can be written off as depreciation over the life of the asset. But the present value of these writeoffs is only a fraction (d) of the initial price. This fraction will be smaller, the higher is the rate of discount and the longer is the life of the asset.

In the case of percentage depletion, we have

$$W_2 = t(Y - pY) = tY(1 - p).$$

Here p is the fraction which depletion allowances bear to net income before depletion. One should bear clearly in mind that p is *not* the statutory 27 1/2 percent, which applies not to net income before depletion but to the gross value of the output of the asset (the well) at its site. Our statutes do provide that the allowance for percentage depletion may never exceed 50 percent of the net income from the asset at its site; hence p, in the case of oil, must lie somewhere above 27 1/2 percent but may in no case exceed 50 percent.

It is instructive to inquire whether, for the purchaser of an existing producing well, it would normally be preferable to use the option of percentage depletion. I assume here that the prospective flow of output from the well is correctly estimated at the time of its purchase. If cost depletion is to be used, the present value of the after-tax income stream, and hence the price which buyers would be willing to pay for the well, will be

$$R_1 = Y - W_1 = Y - t(Y - dR_1).$$

Solving this, we find:

$$R_1 = \frac{Y(1-t)}{1-td}.$$

If percentage depletion is to be used, the price buyers would be willing to pay for the well is

$$R_2 = Y - W_2 = Y - t(Y - pY) = Y(1 - t + tp).$$

Since p must lie between 27 1/2 and 50 percent, it can be seen that R_2, with a 52 percent tax rate, must lie between $.623Y$ and $.74Y$.

R_1, on the other hand, will be $.48Y/(1 - .52d)$ with a 52 percent tax rate. Plausible assumptions about discount rates, useful life of wells, and patterns of depreciation lead to values of d well within the range of .5 to .75.[3] And this range for d in turn implies a range for R_1 of from $.649Y$ to $.787Y$.

The overlap between the ranges for R_1 and for R_2 signifies that it is not at all surprising that when producing wells are purchased the buying companies very often opt for cost depletion. In fact the ranges indicated suggest that cost depletion may be slightly preferable to percentage depletion when a well is operated by a company which purchased rather than discovered it. The approach presented here is therefore certainly not at variance in this respect with assertions made by industry experts that cost depletion is used in perhaps the majority of cases of wells purchased by operating companies.

Actually, the differences between percentage depletion and cost depletion are probably not great in cases *of purchased wells*. The difference becomes important in those cases where the discoverers of wells retain them in their possession for operation. In the remaining cases, where the discovering company sells the successful wells to producing companies, it is the capital gains provisions of our tax laws rather than the percentage depletion provisions which create artificial incentives for oil exploration.

III

In the cases of both capital gains treatment and percentage depletion treatment of the fruits of exploration, the cost side of the picture is of great importance. In the case of most business assets, their cost of acquisition is clearly and easily defined. In the case of producing oil wells, especially the successful exploratory wells, the cost is not so readily obtained. In an economic sense, the cost of finding successful wells includes the costs of all the unsuccessful searches as well. Yet this is not easily allocable among the successful wells, certainly not for purposes of tax accounting.

Our tax laws take the view that the costs of a successful exploratory well are simply those costs directly incurred in finding it — and in fact the bulk of these costs are allowed to be expensed immediately rather than being capitalized and entering into the "basis" on which a possible capital gain might be computed upon the sale of the well.

[3] The range allowed for d is really very substantial. If we assume a 10-year life and straight-line depreciation, any rate of discount between about 5.5 percent and 15.5 percent would yield a d within the range given. Looking at it another way, if we assume a discount rate of 8 percent and straight-line depreciation over the life of the asset, any asset life between 7 years and 18 years will yield a d within the given range. Taking a 10 percent rate allows us to have any asset life between 5 and 15 years and still remain within the given range. The formula for d is $d = [1 - (1 + i)^{-n}]/ni$, where n is the effective life of the asset and i is the rate of discount.

Ordinarily, the capital gain on an asset sold by a business firm is computed by deducting from the sale price of the asset its actual original cost less depreciation to the date of sale. On the difference a special tax rate of 25 percent applies. In the case of a successful oil well a very different situation emerges. All the costs associated with the dry holes drilled in the course of the search may be written off against ordinary income, as may most of the costs of the successful find. The result is that even when the value of the find is substantially less than the total costs incurred, the company may make a handsome profit.

Suppose that costs are $1,200,000, of which $1,000,000 are allowable as expense. This $1,000,000 of expense carries with it a tax offset of $520,000 for any company with significant net income from other operations. Suppose that the remaining $200,000 are costs associated with the successful well, which are not allowed as expense and which therefore become the "cost basis" of the successful well for the purpose of computing capital gains. Let the successful well be sold for $1,000,000. A capital gains tax of $200,000 (25 percent of $800,000) must be paid upon the sale of the well. From the standpoint of the economy as a whole $1,200,000 worth of resources have been used to find a property worth $1,000,000 — clearly a losing operation. But from the standpoint of the company as a private venture — and because of our tax laws — there is a gain of $120,000 ($1,000,000 receipt from sale plus $520,000 of tax offsets less $1,200,000 costs less $200,000 capital gains tax).

The case is even worse when syndicates of individuals in high income tax brackets do the exploring. Assuming the same cost situation, and individuals in, say, the 80 percent income tax bracket or above, the tax offset would be over $800,000. The individuals could gain even if the successful well sold for as little as $600,000. Their profit would be at least $100,000 ($600,000 receipt from sale plus at least $800,000 in tax offsets less $1,200,000 costs less $100,000 capital gains tax). What for the economy is a disastrous waste of resources (spending $1,200,000 to find something worth only $600,000) is for these individuals a quite acceptable investment. The simple way to avoid this inducement to economic waste is to recognize the special provisions made for expensing on the cost side of the exploration picture, and in the light of these special provisions to disallow capital gains treatment on any sale of oil property.

Most exploration is not done for the purpose of subsequent sale and capital gain, however. It is done rather by producing companies which then operate the successful wells they find, almost invariably under the percentage depletion provisions of the tax law. Cost considerations are important here, too, since once again the costs of dry holes plus a large part of the costs of successful wells can be expensed against ordinary income, and thus obtain tax offsets in addition to whatever offsets accrue through percentage depletion.

Ordinary business investment will tend, in any line of activity, to be pushed to the point where the present value of the net-of-tax stream of income expected to accrue from an asset (R_1) is equal to the cost of the asset (C_1). Hence we have, for an ordinary business investment yielding an income stream whose present value is Y:

$$C_1 = \frac{Y(1-t)}{(1-td)}.$$

In the case of oil exploration by producing companies, we have the same tendency. Exploration will tend to be carried to the point where the present value of net-of-tax receipts is equal to the present value of costs, net-of-tax offsets. The present value of the net-of-tax receipts is given by $R_2 = Y(1 - t + tp)$. This expression incorporates the tax offset involved in percentage depletion itself, but not that involved in the expensing of the bulk of exploration costs. We shall allow for this on the cost side, assuming that these tax offsets apply to some 80 percent of costs. Thus, if actual costs are C_2, costs net of these tax offsets are $C_2(1 - .8t)$. Competitive forces will thus press toward an equilibrium in which

$$C_2(1 - .8t) = Y(1 - t + tp), \quad \text{or in which}$$

$$C_2 = \frac{Y(1 - t + tp)}{(1 - .8t)}.$$

We can now ask the question, how different is the amount of resources which will normally be used to obtain a given income stream in oil exploration from the amount of resources which will typically produce the same income stream via ordinary business investment? To answer this question, we assume Y (the present value of the income stream) to be the same in both cases, and simply take the ratio of C_2 to C_1.

This yields

$$\frac{C_2}{C_1} = \frac{(1 - t + tp)(1 - td)}{(1 - .8t)(1 - t)}.$$

With a 52 percent tax rate, and various values for p and d, this ratio behaves

TABLE 12.1

Values of C_2/C_1 under Alternative Assumptions

p	.275	.35	.5
d			
.5	1.64	1.75	1.95
.65	1.47	1.57	1.75
.75	1.36	1.44	1.61

as shown in Table 12.1. The range of these estimates indicates that in order to obtain an equivalent income stream, between 1.36 and 1.95 times as many resources will typically be used in oil exploration by producing companies as in ordinary business investment.[4]

IV

I cannot believe that it was the intention of our lawmakers to create such strong artificial incentives to oil exploration as appear through percentage depletion and/or the procedure of selling successful wells for capital gains. On the one hand, it is hard to see how this could have been their intention when, at least in the published economic literature, the magnitude of these incentives has not been estimated until recently. On the other hand, even if recently developed analyses had been available to the lawmakers at the time when percentage depletion allowances were first enacted, their choice in adopting percentage depletion would not mean their endorsement of incentives of the present scale. For income tax rates were then much lower than they are today, and the magnitude of the special incentives entailed in percentage depletion depends strongly on the applicable rate of income tax.

The following table reveals this dependency very clearly. In it, values of C_2/C_1 are calculated for different tax rates, assuming $d = .65$ and $p = .35$ (as in the central cell of Table 12.1).

TABLE 12.2
Values of C_2/C_1 under Alternative Tax Rates
(percentage depletion, assuming $d = .65$, $p = .35$)

Tax rate	C_2/C_1
.1	1.056
.2	1.126
.3	1.218
.4	1.342
.5	1.519
.6	1.789
.7	2.250
.8	3.200

Whereas with a 50 percent tax rate, percentage depletion gives incentives to use roughly 1 1/2 times as many resources as need be used in other investments to obtain the same income stream, the figure is only 1.056 times when the tax rate is 10 percent and 1.126 times when the tax rate is 20 percent. Thus, until the middle 1930s (when corporation taxes began to approach their current levels), the special incentives stemming from percentage depletion were of a comparatively small magnitude. With the subsequent successive increases in the corporation tax rate, petroleum exploration has been automatically placed in a much more favored position relative to other kinds of investment activity. I would contend strongly that it was not the design of our legislators to bring about this increasing favoritism toward petroleum exploration. Tax rates were raised because of pressing needs for additional revenue, and the basic structure of provisions for depletion was simply left untouched as rates were altered. But this had the effect of greatly enhancing the relative advantage enjoyed by petroleum exploration as an outlet for investment.

Exactly the same sort of dependency of the relative advantage for petroleum exploration on the level of tax rates appears when the effects of capital gains taxation are analyzed. Assume that buyers of already discovered wells uniformly choose to use cost depletion rather than percentage depletion, and as a consequence are willing to pay the same price for a well producing a given income stream as purchasers would pay for other kinds of capital equipment yielding the same income stream. Differences in the amounts of resources used to produce the income streams thus emerge only on the cost side. In the case of ordinary capital equipment the costs (C_1) incurred to produce a stream whose present value is R_1 will tend to be equal to R_1. When petroleum exploration is undertaken for purposes of capital gain it is the present value of costs net of taxes and tax offsets which will tend to be equal to R_1. If costs in this case are equal to C_3, and 80 percent of these costs can be written off against ordinary income, while the remaining 20 percent provide the "cost basis" for computation of capital gain, we have, in equilibrium:

$$C_3 - t(.8C_3) + t'(R_1 - .2C_3) = R_1,$$

where t is the tax rate on ordinary income and t' is the special tax rate applying to capital gains.

TABLE 12.3
Values of C_3/C_1 under Alternative Tax Rates
(capital gains, assuming $t' = 1/2t$, or $t' = .25$, whichever is less)

Income tax rate (t)	C_3/C_1
.1	1.044
.2	1.097
.3	1.164
.4	1.250
.5	1.364
.6	1.596
.7	1.923
.8	2.419

[4] Altering the assumption that 80 percent of the total costs of exploration obtain tax offsets independently of percentage depletion does not change the general conclusions derived from Table 12.1. Changing this percentage to 90 would alter the ratios in Table 12.1 upward by about 10 percent; changing the percentage to 70 would alter them downward by about 8 percent. Steiner's data (*op. cit.*, p. 960, Table 3, especially rows a_1 and a_2) suggest that any alteration should probably be upward toward 90 percent rather than downward toward 70 percent.

Using the fact that for ordinary investments yielding income streams of present value R_1, C_1 tends to be equal to R_1, we may write:

$$C_3(1 - .8t - .2t') = C_1(1 - t'),$$

or

$$\frac{C_3}{C_1} = \frac{(1 - t')}{(1 - .8t - .2t')}.$$

It can be seen from a comparison of Table 12.3 with Table 12.2 that the incentive given to petroleum exploration by the capital gains provisions of our tax laws is almost as great, for any given tax rate, as that given by the percentage depletion provisions. Moreover, the differential incentive given by the capital gains provisions is like that given by percentage depletion in that it increases with the tax rate, from small values when the tax rate is in the neighborhood of 10 or 20 percent to high values when it is 50 percent and more. The conclusion appears inescapable that strong incentives for excessive investment in petroleum exploration really came into being in the last few decades, as income tax rates were raised toward their present high levels. To bring the relative incentives for petroleum exploration back to the level at which they were when percentage depletion was first enacted would entail, at present corporation tax rates, a very substantial reduction in the current 27 1/2 percent depletion rate, and a very substantial increase in the tax rate applicable to capital gains on oil properties.