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Issues in the Taxation of Petroleum and Natural Gas Income

Seymour Fiekowsky
U.S. Treasury Department

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Preface

The design of rules for taxing oil and gas income has posed controversial legislative and administrative problems almost from the outset of Federal income taxation in 1916. This is not surprising, for the process by which oil and gas reserves are brought into productive use is more nearly akin to a research and development undertaking, than to a straightforward industrial project. A conceptual distinction may be drawn between investment in the discovery of new information to reduce risk, and investment in well specified items of plant and equipment to produce reasonably well defined products. Income accounting procedures for the latter kind of investment are not without controversy since expected useful lives and residual values are not certain. But the range of difference in possible income accounting rules[1/] is not so great as to excite heated debate. Thus, in the case of measurement of income from petroleum refining, notwithstanding the large investment in plant and equipment,

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1/ Income accounting rules are used to synchronize flows of receipts and expenditures for the purpose of producing periodic estimates of income. The receipts of a particular time period have to be attributed to activities of the current, future, and past periods; and expenditures of the present period have to be similarly attributed. It is the excess of current period receipts (and claims) over current period expenditure of resources (whether "paid" in the current period or not) which is "income" of the current period.

there has been no history of Congressional and administrative controversy over refinery-specific income accounting rules.

But the tax treatment of investment in discovery and development of petroleum has been, and continues to be, the subject of bitter controversy. And, as frequently happens in the course of tax controversies that spill over into popular debate, mythology comes to replace fact, and sloganeering supplants analysis. It is a mark of the deplorable state of public discussion that most of the debate has centered on "percentage depletion", although percentage depletion is scarcely the most significant rule for measuring taxable income from investment in oil and gas reserves. These notes attempt to puncture prevailing myths by identifying the issues of income measurement and by examining the slogans offered by proponents and opponents of percentage depletion.

I. Income measurement issues.

A. A simplified description of the investment process.

For expository purposes, suppose investment in discovery and development of petroleum and natural gas reserves, and a given productive capacity, takes the following form. Someone makes outlays of $20 million over a period of 10 years. These outlays are for geological and geophysical survey work, for drilling test cores and wells, for equipping those wells which are productive, and for installing storage and related facilities. At the completion of this investment program, it is established that the field will produce 10 million barrels of oil. Under these simplified assumptions, and ignoring the mathematics of comparing present and future values, each barrel of oil "costs" the investor $2; this is the capital cost per barrel which should be accounted for in determining the investor's income as the oil is extracted and sold. For example, if in a subsequent year 1,000 barrels are pumped-out at an additional cost of $2,000 and sold for $5,000, the income for that year would be $1,000 ($5,000 less $2,000 production cost and less $2,000 "depletion" of investment cost at $2 per barrel for the 1,000 barrels extracted).

In sum, the rules used for income accounting in this simplified description of the investment process were: (1) Capitalize all costs connected with discovering and developing the reserves of oil; (2) divide this cost by the total quantity of recoverable minerals discovered, the quotient being the capital cost, or depletion charge, per unit of the mineral; (3) subtract this depletion charge, plus any additional costs of extracting the mineral, from gross receipts attributable to extraction to derive net income. Obviously, if it costs $2 per barrel to discover and develop oil and another $1 to lift it, still ignoring the mathematics of discounting, the price of oil will have to be at least $3 per barrel, else investors will not devote their resources to the search. If the price is expected to rise substantially above \$3, more resources will be invested, more oil found, and the price will be driven down to the normal rate of return level, \$3 in the example just described.

B. Complications.

There were two critical elements in this simplified example which gave rise to a correspondingly simple (and fundamentally correct) income measurement rule: (1) The investment process has an easily identifiable beginning and end; (2) after the investment period has ended, the amount of extractable mineral is known with certainty. Unfortunately, the actual conditions of investment and the search for reserves so greatly differ from these simplifying assumptions that the simple income measurement rule is not operational.

(1) The sequential nature of the investment process.

Imagine a geographic region in which there has been no previous discovery of petroleum and gas reservoirs. Suppose that a skilled prospecting company makes preliminary observations and concludes there is a reasonable probability that subsurface petroleum and gas reserves may be found. The would-be prospecting company must then purchase exploratory rights from the landowner, and this purchase of mineral rights usually takes the form of a mineral lease wherein the owner (who becomes the lessor) exacts the highest possible cash payment (called a "bonus") plus a share of future minerals which may be discovered (called a "royalty").

In negotiating a mineral lease, the would-be prospector faces a serious problem: though he suspects the existence of underground reservoirs, he can be sure neither of its exact location nor of its geographic extent. The larger the surface acreage for which he purchases rights, the greater his expense, particularly if, as in the United States, surface rights may be privately held in small plots. On the other hand, if a prospector does not secure rights to a large acreage, the reservoir he may find could extend beyond the boundaries of his lease, and he will fail to capture the full value of the mineral he is principally responsible for discovering. The prospector must, therefore, make a difficult decision, the quality of which will determine his ultimate gain. If, as in the case of auctions of leases on public lands, the total acreage offered for exploration and development is large, individual companies may pool their initial risk (uncertainty about the precise location and extent of underground reservoirs) by jointly bidding on several parcels, and they may engage in similar loss hedging arrangements with neighboring lease holders on private lands.

In any event, from the point of view of potential oil discoverers, the initial outlay for rights to explore is a "capital" expenditure, part of the cost to be cumulated as the ultimate capital cost of a discovery, if any. Under all conventional rules of income accounting, these initial outlays to purchase mineral rights should be capitalized. This is also the case under tax accounting rules by which lease bonuses are capitalized as part of the "depletable basis" of a mineral property, to be recovered by depletion allowances whenever mineral production occurs.

Once mineral rights have been secured, the discovery process entails further expenditures for geological and geophysical surveys and tests to select a likely site for drilling a "new field wildcat," a well to discover a new reservoir. These expenditures are not unlike expenditures made by industrial firms in connection with the design and development of a new product or industrial process: they are generalized expenditures on scientific research intended to produce information of future value. The accounting treatment of this class of expenditures is not universally agreed on, however. Some managements regard research and development as ephemeral outlays, a current cost of doing business deductible from current gross income; others regard them as capital expenditures, to be cumulated as the investment cost of an ongoing project. Although the tax law generally permits current deduction of research and development expenditures, these outlays with respect to oil and gas discovery projects must be capitalized and become a part of the depletable basis of mineral properties.

After one or more drilling sites have been selected, the process next entails drilling of wells. Experience with wildcat well-drilling is highly variable, but overall statistics on domestic drilling indicate that only one of ten or eleven wildcat wells will strike oil or gas and be completed as a productive well; the others will be "dry-holes." It is clear that the cost of drilling all wells, the dry-holes along with the successful discovery well, should be capitalized as part of the investment cost, for even the drilling of a dry-hole yields information of value. In principle, there is no difference between the cost of scrappage inevitably encountered in the manufacture of a machine or other capital asset and the cost of drilling dry-holes; both are a social and private cost of creating productive capital assets and both should be accounted for in that way.

But the completion of a successful new field wildcat does not end the investment process, even if oil and gas begin to flow. It is further necessary to define the size and characteristics of the reservoir, and this requires additional wells. Once the existence of a field has been established, a much higher fraction of the subsequent wells drilled will be successful, perhaps 60 percent. In a real sense, part of the cost of the succeeding wells, which may be called "development" wells, is further investment cost designed to provide additional information about the oil and gas field, little different from prior expenditures with which they should be cumulated. But, in another sense, these additional wells are closely related to current costs of production, for they make possible a higher current rate of production from the reservoir.[1/]

1/ Readers unfamiliar with the nuances of tax accounting may wonder at the need for a distinction between the cost of investment in the "mineral" and investment in "productive capacity." While this distinction has no particular utility from the point of view of investment decisions or mine management, it is critical to tax accounting because property rights in minerals are separable from rights in "movables" under the law, and being separable, they may be exchanged independently. In the event there is an exchange, it becomes necessary to account for gain, or loss, realized by the seller which requires that his "adjusted basis"--original cost of the property right, less allowances for depletion or depreciation--be continuously accounted for. Moreover, the cost of the mineral rights, as distinguished from other property purchased by the new owner, must be established so that tax income accounting for capital consumption may proceed. Since there is no <u>functional</u> economic distinction between the two kinds of rights corresponding to the property law distinctions, an infinite number of strategies may be devised which will outwit the tax collector. A similar need to artificially value "land" and "buildings" bedevils administration of the tax laws with respect to real property.

(2) Uncertainty of reservoir content.

The indeterminate shading between investment in additional knowledge of reserves and investment in productive capacity from known reserves poses the problem that, if income from current production is to be measured, the cumulative prior cost of establishing the reserves must be divided by the quantity of reserves to derive an appropriate "depletion" charge. But if the very act of producing from an underground reservoir adds to knowledge of recoverable reserves, it is obviously impossible to distinguish further investment in reserves from mere costs of production. Lacking a definite end of the investment process, when all "reasonable" men, including the tax collector, can agree that a specific quantity of recoverable reserves is in place, the only unambiguous measure of income from the reservoir is the measure that would be derived when production from the reservoir ceases. At that point, the cumulated expenditures of all kinds, from the initial bonus, through geological and geophysical surveys, drilling, pumping, secondary and tertiary recovery, and for labor and materials could be subtracted from cumulative sales to determine aggregate income derived from the field. But a delayed accounting would satisfy neither stockholders and creditors of oil companies, nor the tax collector, all of rules, are equally difficult to make. Nevertheless, some useful conclusions can be drawn from a critical examination of the battery of tax accounting rules that have evolved.

II. Evolution of tax accounting treatment of oil and gas investment and income.

A. Economic policy aspects in the taxation of oil and gas companies.

From an economic policy point of view, tax rules must be evaluated in terms of their impact on investment decisions, for in the long run tax policies determine the relative size of the private capital stock invested in oil and gas capacity and hence the price of these resources. The investment impact evaluation is complicated, because taxes are paid by enterprises which are simultaneously engaged in one or more stages of the investment process: they may be currently producing only from fields discovered and developed long before, or they may be maintaining, or adding to, existing productive capacity by additional exploration and development, or they may be newly entering the oil business, discovering and developing their first field. Depending on their circumstances when the income tax law was first enacted, or now when changes in tax rules may be enacted, different firms will experience different immediate effects in their tax returns, just as these firms have fared differently since 1973 when oil prices have risen sharply. Obviously, a firm producing from existing reserves will immediately benefit more from an oil investment tax reduction or an oil price increase than will a firm heavily engaged in a large investment program; and all firms presently in the oil business will benefit more than those newly attracted to the industry by the tax reduction or price increase.

Rewards from oil and gas discovery are highly variable. Most firms in the oil business, as in any industry, enjoy modest success; their capital earns little more than it might earn if invested in any other industry. Many firms, attracted by the possibility of riches, are probably net losers; their capital would earn more if invested in government bonds. A few firms; either through luck or a "nose" for oil, are exceptionally prosperous even though the industry-wide average return in the oil business is no higher than the average for all industries. Firms at the margin of profitability will be more immediately affected by adverse tax or price movements; and since they are always more numerous than the few highly profitable firms, they will raise loud cries of "unfair destruction of competition" whenever taxes are raised or prices fall. Ironically, the fact that changes do affect numerous marginal firms is proof that the industry is competitive, and that compensatory changes in investment will occur in response to tax and price changes. But not only are company financial records highly variable, the ventures undertaken by a single company are also highly variable. For a cross-section of producing oil properties at some point in time, the implicit rates of return on those properties will be far above average simply because they represent the successful ventures whose returns must offset numerous but uncounted unsucessful ventures. Every industrial firm has produced its share of duds, but only in the minerals industry is the individual "property" an invariant accounting unit; an oil company "consolidates" its properties in its tax returns, but capital accounts, depletion, and abandonment losses are recorded by "property"1/ . Thus as a statistical anomaly, it will appear that the "value"of mineral deposits in use greatly exceeds the "cost" of discovery and developing those properties.

1/ An industrial firm can group its assets in depreciation classes without regard to geographic location, and it need not associate depreciation allowances with any particular kind of business it carries on, or with any administrative division of the enterprise itself. But an oil producer must aggregate its operational data by property so that it can compute the "income from each property" separately. In industrial enterprises, particular investment "mistakes" are typically consolidated with "successes"; in mineral enterprises "mistakes" are segregated from "successes".

B. The tax treatment of expenditures for the discovery and development of oil and gas reserves.

Present income tax rules applicable to oil and gas properties are fundamentally irrational because the rules for classifying investment expenditures evolved separately from the rules governing capital recovery (or depletion). Detailed rules for classifying outlays made in connection with taxing a trade or business are usually developed administratively, and this was the case with oil and gas investment. Meanwhile, Congress independently legislated capital recovery rules with respect to minerals as early as 1916, and specifically with respect to oil and gas in 1926. Normally, the administrative determination of which kinds of expenditure are regarded as "capital" and are classified as "current expenses" would display little if any inconsistency with separately legislated capital recovery rules. But, in the present instance, definitional compromises promulgated by first-generation income tax administrators produced a public policy disaster when they were mixed with the independent legislative decisions regarding cost recovery, or depletion.

Even before Congress invented percentage depletion in 1926, the Treasury and then Bureau of Internal Revenue were settled on a course which ultimately yielded the conclusion that approximately 70 percent of the outlays for discovery and development of oil and natural gas productive capacity are classified as current expense, about 20 percent are capitalized as "depletable basis", and 10 percent are capitalized as "depreciable basis", that is, expenditures for machinery and equipment, largely pumps, pipes and the like, which are replaceable (subject to wear-and-tear and obsolescence) but which are separable from the oil and gas extraction operation itself.[1/]

The 70 percent of total oil and gas investment outlays allowed as a current deduction includes some 40 percent related to dry-holes--outlays for drilling and a pro-rata share of geological and geophysical expenses. Our earlier discussion of the investment process concluded that dry-hole costs should be aggregated by project. In the interests of administrative convenience, however, the view was taken that each well

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1/ These figures are nationwide averages reflecting pre-1970 experience. For some investment projects, such as those undertaken near prior discoveries, the percentage of total investment cost currently expensed may exceed 70 percent. Moreover, because of the multiplicity of mineral interests, it is possible for mineral rights owners to "package" property rights in such a way that more of the "deductible" investment costs accrue to one class of investor than another. Thus, even though the average deductible investment cost may be 70 cents to $1 total investment, some investors may be provided the legal opportunity to deduct as much as 90 cents of each dollar they supply. Of course, they pay for this privilege by accepting less of any future income produced by the property, just as creditors who demand substantial collateral "pay" for this lessening of lenders' risk by accepting a lower rate of interest from the borrower.

constitutes a single project; and since investment in an unsuccessful venture is customarily considered a "loss", that loss should be deductible from gross income when recognized. It is unclear why a lease-aggregation rule was not imposed on each taxpayer, since lease bonuses and other mineral rights acquisition costs have always been capitalized.

Perhaps the reason why dry-hole write-offs continue to be tolerated is that, for reasons that defy rationalization, it was also ruled that "intangible drilling" costs are deductible when incurred.[1/] Since the bulk of the cost of dry-holes was already allowed as current deductions, the write-off of some little geological and geophysical expense seemed not worth contesting. But current deductibility of drilling costs for wells completed as productive now accounts for the remaining 30 of the 70 percent of investment cost currently deductible. This provision must be regarded as an unnecessarily generous compromise with the vicissitudes of oil and gas investment

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1/ The "intangibility" of the drilling costs presumably was inferred from the fact that labor and contractor services were hired to drill the hole, and since the product of all this expenditure was a "hole" nothing "tangible" resulted. Fortunately, income tax accounting has not generally followed this tortured reasoning in other circumstances; apart from the incentive provisions for research and development expenditure, it is seldom held that the cost of "intangible" capital assets can be expensed. Indeed lease acquisition costs, which are "intangible" when purchased must be capitalized, along with geological and geophysical survey expenditures, which are also "intangibles."

accounting. However uncertain may be the result of drilling a particular well, the cost of drilling a productive well cannot, by any standards of income accounting, be considered a current expense of income production. Nor can such expenditures be compared with industrial research and development outlays. A reasonable compromise with the inherent uncertainties would have provided some guidelines formula permitting a pattern of write-offs over the expected life of at least the cost of completing productive wells.

The implications of this tax treatment of investment outlays may be illustrated by reference to the simplified example presented earlier. Again setting aside the mathematics of discounting, the firm spending an illustrative $20 million to discover and develop an oil field with total recoverable reserves of 10 million barrels would have been allowed to deduct currently $14 million of that amount during the investment period under tax accounting rules. If the firm was then operating other fields, engaged in transportation, refining, or marketing, or <u>any other</u> economic activity producing taxable income during the period of its investment in a new oil field it would have aggregated these deductions (called "net operating losses") relating to the property being developed with the otherwise taxable income, thereby reducing its taxable income by $14 million, and saving $7 million in current tax payments (assuming a 50 percent income tax rate). Of the remaining $6 million of capital outlays, about $4 million would be the "depletable basis", or 40 cents per barrel, while $2 million would be the depreciable basis which might be written-off over 11 years by any allowable depreciation method. Assuming an annual production of about 600,000 barrels in the early years of this hypothetical field, and a price of $5 per barrel produced and sold, the comparative income measures are shown in Table 1.

Table 1

Effect of Investment Cost Accounting on Annual Income

	Income Accounting Methods	
	"Ideal" rules	Tax rules a/
Gross income (600,000 bbls. at $5)	$3,000,000	$3,000,000
Less: Lifting costs, total . . .	600,000	600,000
Capital cost depletion . .	1,000,000 b/	240,000 c/ 360,000 d/
Annual income, early years . . .	1,200,000	1,800,000 e/

a/ This is not taxable income; percentage depletion exceeds cost depletion and would be taken. See the example in the next section.

b/ $2 per barrel.

c/ $0.40 per the barrel.

d/ Assumed depreciation allowance.

e/ In the event the taxpayer had been unable to deduct the $14 million of pre-production "tax losses", these would be carried forward to reduce income during the period until they had been used up.

In this example, income measured under tax rules results in a $600,000 excess comparison with income measured under ideal rules. 1/ The ideal rules start measuring income when oil starts flowing, not when the first dollar is spent on discovering the field. Whereas, the tax method shows "losses" during the investment period, the ideal method produces lower incomes during the productive period. In both cases no more than $20 million will be deducted from gross receipts as capital cost. But the tax accounting rules grossly misallocate income from oil and gas investment over time; they may be said to "defer" recognition of income due to premature deduction (recognition) of cost.

C. Statutory allowances for depletion.

It is difficult at this late date in the history of income taxation to appreciate how difficult it must

1/ The reader will note that under "ideal" rules there is only one figure for capital consumption, $1,200,000, whereas both depletion and depreciation cost are shown under tax rules, a total of $600,000. In this simplified example, the total investment cost of $20,000,000 is attributed to the mineral whose extraction occasioned the investment. When the 10 million barrels have been extracted, the total investment will be worthless, and since we are not here concerned with discounting, the extraction of each barrel represents a "consumption" of $2 of capital. It should also be remembered that lifting costs shown are _total_ costs of operating the field, including repairs to machinery and equipment, assumed to be adequate to carry the whole investment project to its productive end.

have been to manage the introduction of a net income tax applicable to businesses already in existence. Today, virtually all assets held by enterprises have been acquired since March 1, 1913, the starting date for the present income tax. But the Revenue Act of 1913 imposed an income tax on enterprises employing assets which were acquired before tax accounting rules had to be applied. Capital consumption allowances had to be based on March 1, 1913 asset values, or cost if acquired on or after that date. For pre-existing assets, this requirement entailed a massive valuation task. This same requirement was imposed on owners of mineral properties in the Revenue Act of 1916, and if this had been the final word of Congress, much of the controversy that has ensued would not have occurred.

It is important to understand how the 1916 rule applied. Again referring to the simplified example previously described, suppose that the $20 million investment had been completed before March 1, 1913, and the oil field had begun operations January 1, 1913. On March 1, given the facts previously described, and still ignoring the effects of discounting for simplicity, the value of the property would have been $40 million or $4 per barrel for 10 million barrels. As the comparative income statistics in the previous section indicate, the net income per barrel (at a market price of $5) was $2 and in addition there was a capital recovery allowance of $2 per barrel. For such a firm in production before March 1, the depletion allowance under the 1916 rule would have been $4 per barrel, and it would have had a taxable income per barrel of zero. Now suppose the same firm with the same set of facts starts operations with post-1913 investment. In this case the cost of acquiring the 10 million barrels of oil would have been $20 million, (ignoring administrative rules for the treatment of investment expenditures) and the proper depletion allowance would have been $2 per barrel, leaving a taxable income of $2 per barrel. (Of course, had the tax treatment of investment expenditures been used, taxable income would have been $3 per barrel unless the prior deduction of investment costs had resulted in a net loss carry-forward).

At first glance, these disparate results seem unfair. Two identical firms, one which found and developed an oil field before March 1, 1913, the other some time later, are assessed radically different tax bills: the early firm pays no income tax; the later firms pays a tax on $2 per barrel. But recall that the former firm found its oil before there was an income tax: it spent $20 million to find oil worth $40 million in the ground and, on this account earned $20 million, or $2 per barrel, before the income tax was enacted. This firm should not retroactively be assessed an income tax simply because, under the conventional rules of income accounting, the income is not "recognized" until received. In contrast, the other firm engaged in its activity after the income tax was imposed, and if it spent \$20 million to find \$40 million worth of oil, it earned \$20 million, or \$2 per barrel, under the aegis of an income tax and should pay tax accordingly. Salaries earned in 1912 were not taxable; the same salaries earned before March 1, 1913 were.

Thus, whether by chance or by deliberate thought, Congress promugated the correct rule in 1916. Subsequent events suggest that Congress hit on the right rule by chance, for within two years they succumbed to the argument that "discovery value" depletion, namely a depletion allowance based on the value of the deposit discovered, would yield equitable treatment as between post-1913 and pre-1913 oil field production. In effect, Congress agreed in 1918 <u>that the income from investment in oil and gas should be exempt from tax</u>. But, when depletion "discovery value" was coupled with the administrative rules regarding investment outlays then being developed, the result was more than complete exemption of oil and gas income from tax. If adding the \$40 million of total "discovery value" depletion allowances to the \$14 million of expensed exploration and development outlays and the \$2 million of depreciation deductions, net taxable income would be negative over the life of the project. The utter inanity of this state of affairs quickly became apparent in the tax returns of oil producers who were concurrently engaged in any degree of discovery and development investment. The deduction of discovery value depletion invariably produced net operating "losses"; and the first "tax shelter" was born. Offended by this result, Congress moved to "correct the abuse" in a manner which has since become characteristic: rather than repeal the erroneous administrative tax treatment of investment and its own legislative mistake in allowing "discovery value" depletion of the post-1913 properties, Congress instead limited allowable discovery depletion to an amount which reduced taxable income to zero. Allowable discovery depletion could not exceed 100 percent of taxable income computed without regard to depletion. This limitation was later stiffened to a maximum of 50 percent of taxable income computed without regard to depletion.

Since this kind of response to perceived "abuses" has become characteristic, it is worth explaining why such cures are more deadly than the imagined disease. In order to maximize the expected profitability of an investment under this kind of income tax constraint, discoverer-developers are driven to select investment programs conditioned by their momentary tax status--whether they are currently producing oil, how much, and at what lifting costs. As a consequence, investment programs selected are likely to be socially inefficient. For example, investors producing little oil relative to their current investment program are forced by the income limitation to sacrifice tax benefits as compared with investors producing large amounts of oil; thus, the former investors are confronted by effectively higher investment costs for reasons completely unrelated to their judgment or skill. Moreover, income limitations on depletion have the perverse effect of penalizing oil producers who happen to operate properties with physical characteristics that impose higher lifting costs, as commonly happens toward the end of the productive life of a field. If there must be an arbitrary statutory rule for depletion allowances, economic efficiency requires that it be made fully available to all producers, without reference to taxable income.

But the demise of discovery value depletion did not come about because an enlightened Congress came to understand the error it had committed in 1918. Rather, discovery value depletion was repealed because it proved administratively unworkable. As noted earlier, an inherent characteristic of the oil and gas investment process is great uncertainty concerning the extent of recoverable reserves at virtually every stage before an oil field is abandoned. Not only is the size of recoverable reserves uncertain at the time a well begins to produce, but the value of the reserves in place (the $4 figure in the example) is at least as uncertain. The value of a discovery depends on the expected future price of oil, on the amount of the recoverable reserves, and the characteristics of the field which determine the time pattern of recovery and how much it will cost to lift the oil. Absent a bona fide sale of the total interest in a mineral property, a rare event which almost never occurs immediately after a discovery, there is no easily determinable "discovery value," plus quantity of recoverable oil, on which the taxpayer and revenue agent could agree. Taxpayers, naturally, had an interest in establishing a high "discovery value" and low initial estimates of reserves (which could be revised upward in later years), while revenue agents were eager to establish lower values and higher estimates of reserves to "preserve the revenue." In order to put an end to the growing backlog of unsettled tax disputes, Congress invented percentage depletion in 1926 as a substitute for discovery depletion. The rationale for percentage depletion, if one accepts the reasoning of discovery depletion, was that, on the average, the value of oil in the ground is some fraction of market price; and since market price is more readily determined than the value of oil in the ground, application of the percentage depletion rate to the market price of the oil would provide a "fair" depletion allowance. Of course, the "correct" percentage depletion rate is as variable as oil field productivity and, for any given field, would vary as the market price of oil rose and fell with market demand. Nevertheless, Congress initially determined that 27 1/2 percent of the market price of any oil produced anywhere in the world by an American taxpayer could be taken to represent depletion, provided it did not exceed 50 percent of taxable income computed without respect to depletion. In 1969, the percentage depletion rate for oil and gas was reduced to 22 percent and in 1975, percentage depletion as a general principle was repealed, but an important "small producer" exemption was preserved.[1/]

Neither discovery depletion nor its successor, percentage depletion, is the exclusive allowable method; "cost depletion" is always permissable and is sometimes used. Occassionally, when a field is first brought into production, and the estimate of recoverable reserves is extremely low, the annual production is

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1/ The so-called small producer exemption applies to the first 2,000 barrels of average daily oil production (or 12,000,000 cubic feet of natural gas). This figure is to be phased down until it reaches 1,000 barrels in 1980. The depletion rate is to be phased down from 22 percent to a permanent level of 15 percent in 1984.

a large fraction of estimated reserves, and the fraction of capitalized costs attributed to the well may exceed percentage depletion. Moreover, when a reasonably productive property is sold at a price which represents the present value of recoverable reserves, the buyer will often find cost depreciation preferable to percentage depletion. But in the overwhelming majority of cases, including those instances when cost depletion allowances have exhausted the capitalized depletable basis, percentage depletion is taken.

D. Summary

Table 2 summarizes the effect of tax accounting rules on the amount of income which would be reported for a property described in the simplified reference example and compares these amounts with an ideal income accounting result. Clearly, in this example, percentage depletion yields the taxpayer a lower taxable income than "cost depletion." Indeed, since cost depletion in any year represents a pro-rata deduction of the beginning-of-year depletable basis reduced by <u>all</u> tax depletion allowances taken in prior years, once the taxpayer begins to take percentage depletion, he rapidly exhausts the depletable basis thereby ensuring that percentage depletion will be taken in the future. Unlike conventional capital cost recovery procedures, percentage depletion is not limited to recovery of a fixed base.

Table 2

Effect of Depletion Allowances on Annual Income

	Income accounting methods		
		Tax rules	
	"Ideal" rules	Cost depletion	Percentage depletion
Gross income (600,000 bbls at $5)........	$3,000,000	$3,000,000	$3,000,000
Less: Lifting costs, total............	600,000	600,000	600,000
Capital consumption:			
Depletion.....................	1,200,000	240,000	660,000
Depreciation..................	---	360,000	360,000
Annual income.......................	$1,200,000	$1,800,000 a/	$1,380,000 a/

a/ In the event the taxpayer had been unable to deduct the $14 million of pre-production "tax losses," these "losses" would be carried forward to reduce production period tax income accounting figures until exhausted.

In this example, the 22 percent depletion allowance rate does not equal "discovery value" depletion, for the taxpayer ends up with taxable income of $1,380,000 rather than zero. This is not surprising, for the logic of discovery value depletion was to completely exempt the income from mineral discovery and development from tax. If it could be operationally applied, discovery value, fully reflects the natural differences in quantity and quality of minerals that would be produced by the highly uncertain investment process. The percentage depletion allowance, being a fixed percentage of selling price, does not account for these differences. And since the market price of any _particular_ barrel of oil is independent of the lifting cost of that barrel, the _expected_ percentage depletion allowance per barrel from prolific discoveries is substantially less generous, viewed prospectively, than for run-of-the-mill discoveries.

When this aspect of percentage depletion is combined with the tax treatment of investment expenditures, under which lease bonuses and geological and geophysical expenditures must be capitalized while drilling costs are not, it becomes clear that tax rules discriminate against that kind of investment process which is likely to be most socially productive, namely the search for large and productive reservoirs, and favor the search of accessible reserves and the overdevelopment of existing reserves.

Under our tax laws, the lesser the portion of the investment dollar devoted to extensive geological and geophysical search for good prospects, the greater the potential tax benefit per dollar spent. But the lesser the effort devoted to this fundamental mineral R&D expenditure, the more costly is the oil ultimately found. It is in this sense that percentage depletion must be judged an inefficient tax subsidy.

Finally the observation may be made that because the tax treatment of oil and gas investment so grossly distorts the timing of income for tax purposes, it wastefully distorts utilization of existing reserves. So far as the tax cost of producing an additional barrel of oil productive capacity is concerned, it is "cheaper" to look for a new deposit than to adopt measures (secondary and tertiary recovery techniques) which will extract more oil from existing deposits.

III. Economics of oil and gas investment decisions and the effects of taxation.

Notwithstanding the uncertainties related to investment in oil and gas reserves, the process may be characterized in a manner which permits its analysis by the usual model of rational decision making. Discovery and development is neither an art nor a random process. Although "everybody" cannot expect to achieve average success in finding oil by drilling holes in the ground, neither can "everybody" achieve average success in farming, establishing a manufacturing business, or even a grocery store. Investment decisions require skill in assessing uncertainties and specific knowledge of technology and markets. Not "everybody" is equipped to make the hard decisions called for in investment choice. But those who are equipped do make choices, and this implies the use of a rational procedure. The investor seeks to acquire those assets which promise to yield <u>him</u> a rate of return which is greater than the rate of return <u>he</u> might earn buying other assets--not all other assets, but those of which he has knowledge. He is thus concerned with the outlays he must make to acquire assets and with the stream of receipts and outlays to which the purchase of the assets commits him. He chooses among opportunities known to him, each opportunity consisting of paired outlay and revenue streams.

In the example used in previous sections, the investor who could earn 10 percent in the most profitable of the alternative investments known to him would undertake the discovery and development of that oil field only if his assessment of the expected costs and gains yield him a higher return. The assessment involves reducing each of the streams to a single value at a common date. In the following paragraphs we shall employ the basic methodology used by any investment decision maker, but we shall do so now to demonstrate how the terms of taxation affect the costs and benefits.

Fundamental to this analysis is the assumption that entry into the oil business is as free as entry to farming, manufacturing, or any other industry. Objective evidence suggests that this is not an heroic assumption. In the oil business a host of risk-pooling devices have evolved which make it possible for anyone with the requisite skills to enter; there need be no more risk of catastrophic failure in oil than there is in, say, farming, given the infinite divisibility of property rights in minerals. Moreover, available statistics reveal that large numbers of firms enter and leave the oil producing business in response to changes in economic conditions. Finally, there is no evidence whatever that rates of return to investment in oil and gas reserves have been higher than in other industries--although some oil firms, at some times, have earned more than average, as previously noted.

The critical role of this competitive assumption arises from the approach we will take below. If the expected return from oil is above average, given a set of investment cost conditions, more investment will be made, output of oil will increase to drive the price of oil down, or investment costs will rise until the rate of return in oil is no higher than average. And if conditions change to make the expected rate of return below average for a given set of investment cost conditions, investment will be reduced, and output of oil will decline, forcing prices up, or investment costs will decline until the rate of return is no lower than average. Thus, in what follows we adopt the long-run view: rates of return are normal, and, to keep the exposition simple, cost conditions remain unchanged. Therefore, prices of oil will be adjusted to compensate for the rate of return impact of tax rules.

A. The simplified example recast to account for time and rate of return.

Investment decisions are made at some specified time with respect to actions that will occur over a subsequent period. These actions are outlays with respect to an economic activity and corresponding receipts. We have used the example of $20 million expended on the discovery and development of an oil field which contains 10 million barrels of recoverable reserves extractable at some additional cost. But the $20 million will be expended over a span of time, and when the field begins to produce, its flow will also span a future number of years. To analyze this example, then, we must adopt a reference point in time and make additional assumptions necessary to relate events to this reference point.

First, we will continue to use the simplifying assumption that investment is made over some period of time, and that when this period ends, production begins. The point at which production begins will be taken as the reference point.

We assume that investment outlays are made at the rate of $4 million per year for 5 years. At the end of the investment period, using a discount rate of 10 percent, this expenditure has a cumulated value of $24,420,400, which is the real cost to the investor after 5 years. If the investor had made these outlays in alternative projects, his net worth at the end of 5 years would have increased by $4,420,400. However, in accordance with conventional historic accounting rules, the total "basis" of this investment remains $20 million.

We assume that the oil found will be produced by this field over an approximate 15 year period, and the flow will decline at approximately 10 percent per year. This implies the first year production will be about 1.2 million barrels (nearly 3,300 barrels per day), and each succeeding year's output is 90 percent of the prior year's.

For simplicity, we finally assume that the lifting cost per barrel is constant at $1 per barrel. Although this is unrealistic, since the lifting cost per barrel tends to be low early in the productive life of a field and then to rise as natural reservoirs are depleted, it simplifies calculations and does not severely affect the results.

Since, at the point production is to begin, investment cost is $24,420,400 and we know the pattern of output which will result, along with the associated lifting costs, it is a simple algebraic exercise to determine what the selling price per barrel must be so that the present value of the receipts, discounted at 10 percent, will cover lifting costs, also discounted at 10 percent, and be equal to $24,420,400. That price turns out to be $5.026 per barrel. If the future prices of oil are expected to be at least this high, the investment will yield at least 10 percent. As shown in column (1) of Table 3, if all 10 million barrels are sold at $5.026 per barrel, the present value of gross receipts at the time production begins would be $30,485,560, and subtracting from this the present value of future lifting costs equal to $6,065,160 yields net future excess of receipts over outgo of $24,420,400. This is exactly equal to the investment cost evaluated at the same time. Thus, the investor would be assured a rate of return of 10 percent if the oil is sold at $5.026; if the expected future price were higher, the investor would earn more than 10 percent; if the expected future price were less than $5.026, he would earn less than 10 percent.

When the <u>entire</u> span of investment and production is examined, as it must by a prospective investor, no specific allowance need be made for "capital consumption." Capital consumption is inherent in the calculation: the investor has expended $20 million over 5 years, and he recovers his investment,

Table 3

Necessary Price Per Barrel of Oil to Yield 10 Percent,
with Associated Financial Data

Item	Without income tax: "Ideal" rules (1)	With 50% income tax: "Ideal" rules (2)	With 50% income tax: Tax rules: Cost depletion (3)	With 50% income tax: Tax rules: Percentage depletion (4)
Necessary price per bbl..........................	$ 5.026	$ 7.053	$ 5.634	$ 5.110
	Discounted values, when production begins (thousands)			
Gross receipts (10 million bbls)........(a)........	$30,486	$42,776	$34,173	$30,993
Less: Lifting costs....................(b)........	6,065	6,065	6,065	6,065
Net taxes paid..................(c)........	--	12,290	3,687	508
Taxes during production.........(d)........	--	12,290	12,234	9,055
Tax saving during investment....(e)........	--	--	(8,547)	(8,547)
Investment cost = (a)-(b)-(c).....................	$24,420	$24,420	$24,420	$24,420

Note: Individual items may not add to totals due to rounding.

with interest at 10 percent, by selling 10 million barrels of oil over 15 years at $5.026 per barrel, after which his investment is worthless. He has recovered his cost, plus interest.

B. Introducing taxes into the investment decision.

Imposition of an income tax introduces an additional annual outlay which an investor must take into account when determining whether to select an investment. What needs to be added to the above calculations therefore, is a computation of the annual income tax payment which will be demanded if the project is undertaken, and since this involves a set of accounting rules to determine taxable income, we must explicitly set forth the income tax formula. As suggested above, we could apply an "ideal" set of accounting rules and apportion the aggregate investment of $20 million (undiscounted) to the 10 million barrels of oil to calculate an annual depletion allowance as the oil is extracted. Alternatively, we could apply tax accounting rules, which allow the write-off of $14 million of investment cost when incurred, and then determine an annual depletion allowance by either "cost depletion" (combining depreciable basis with depletable basis for ease of calculation) or percentage depletion. We take up each of of these variants in order.

(1) Taxation with "ideal" accounting.

Each year we compute a tax liability, at an income tax rate of 50 percent, that would be generated by selling the quantity of oil produced that year at a price such that, after allowing for the tax and the lifting costs, the after tax net recipts will have a present value of \$24,420,400. Since the income tax formula is specified, we merely deduct from each year's gross receipts the lifting cost plus \$2 per barrel "ideal" cost depletion and multiply by 50 percent to determine taxes paid. And only a slightly more complicated algebraic problem must be solved to determine the necessary selling price of oil, which is found to be \$7.053. Why this is the necessary price to yield the investor a 10 percent rate of return is shown in column (2) of Table 3. Selling 10 million barrels of oil at \$7.053 per barrel will yield a present value of gross receipts of \$42,775,640, and this is sufficient to cover the unchanged lifting costs plus \$12,290,080 in income tax and leave him \$24,420,400 which represents a 10 percent return on investment.

It is worth pausing a moment to compare the before and after tax result. Imposing an income tax in this illustrative case implies that the price of oil must go up by $2.027 per barrel, if the rate of return is not to be reduced. Why would this happen? Unless one is persuaded that investors will undertake investments without regard to rates of return, one must accept the consequence that an income tax imposed on the return from reproducible capital raises before tax rates of return - in other words, causes prices embodying capital costs to rise - in order to ensure the same after tax rate of return. 1/

Consider the probable response of investors to a situation in which the going price for oil has been $5.026 and a tax is imposed. Investors need not drill for oil with the resources at hand; they could retire and convert their capital into an annuity. Suppose that some of them do so. Not only will a reduction of discovery and development activity reduce future flows of oil, but also the signal provided by lesser investment activity will be observed

1/ The assumption that after tax rates of return remain the same implies that the supply of savings for capital formation is highly elastic. While there is no agreement on the likely elasticity of supply of savings, it is difficult to argue it is zero, that the same amount of saving will occur regardless of the return that may be earned. So long as it is not zero, the imposition of an income tax must cause before tax rates of return to be higher than rates of return would be in the absence of tax. That is, some of the "burden" of the income borne by non-capital owners, and the gist of the argument in the text stands.

by those who own producing fields. Anticipating that future prices will be higher, some of the current producers will conclude that oil may be worth more "in the ground" than in a pipeline to the refinery. As they cut-back some of their current output, upward pressure on prices begins, and the process continues until, at a price which assures the necessary rate of return to investors, a sustainable rate of production is achieved. When the adjustment is complete, a length of time roughly proportional to the severity of the initial disturbance, after tax rates of return will have been partially or wholly restored.

(2) Taxation with tax accounting.

If instead of "ideal" accounting we apply tax rules for the treatment of investment expenditures, we may recompute tax liabilities with "cost depletion," when the depletable costs are 30 percent of the total investment, or $6 million. In this event, as shown in column (3) of Table 3, the necessary price of oil required to yield an unchanged 10 percent return to the investor is only $5.634 per barrel. Under the current tax accounting rules, almost the same amount of taxes are paid during the production period as under "ideal" accounting, but a <u>negative</u> tax, or "tax saving," is incurred during the investment period. Net taxes paid are reduced, and this permits the lower price to prevail. For the same reasons that imposition of a tax may be expected to raise prices, diminution of a tax may be expected to reduce prices.

If percentage depletion is substituted for "cost depletion," a further diminution of tax liability results, in this instance during the production period. The lower tax makes possible a price of $5.110, which is only 7.4 cents higher than the necessary price _without_ taxation. Thus, under the cost assumptions of this example, tax rules have almost succeeded in exempting oil and gas investment income from taxation.

It is instructive to evaluate the relative tax benefits conferred by the tax treatment of expenditures and by percentage depletion. Taking the "ideal" accounting procedures as the norm, [1] expensing of investment expenditures reduces the necessary price per barrel by $1.393, while substituting percentage depletion for "cost depletion" reduces the necessary price by an additional $0.524. Thus, of the entire $1.917 reduction in necessary price per barrel made possible by the package of tax rules, expensing of capital outlays accounts for 73 percent, percentage depletion for only 27 percent.

1/ The reader is reminded that only by virtue of simplifying assumptions is it conceivable that ideal income accounting rules might be employed. In particular, the text ignores the effect of uncertainty and diverse property rights in minerals on the identification of investment outlays, and it assumes that the investment period is discrete and precedes the production period.

As noted in the Preface, although public debate has focused on percentage depletion, percentage depletion is not the most significant element in the tax treatment of oil and gas.

C. Summary

Investment in oil and gas reserves and productive capacity, though it is subject to unique risks, is a rational process. Investors who are qualified by skill, training and experience make choices among known alternatives, each of which may be described as a stream of paired expected outlays and receipts. The investment decision first requires an evaluation of alternatives by converting the time streams of outlays and receipts to values at a common date (normally the decision date), and then selecting that alternative which promises the greatest increment in the investor's expected net worth.

Income taxation affects the investment process by altering the streams of outlays and receipts. But the impact of a tax on income from capital depends upon the rules used for measuring taxable income. As it happens, the rules which have evolved for measuring taxable income from oil and gas investment effectively exempt that income from taxation, largely because so much investment expense is allowed as a current deduction in computing taxable income.

So long as investment in oil and gas reserves and productive capacity is a rational process, and so long as entry into the industry is free, limited only by the willingness of qualified investors to undertake projects, tax burdens are ultimately reflected in the price of oil and gas. The presence of tax is not an "impediment" to investment; it merely requires that prices adjust to provide investors an expectation of normal return. Nor is the absence of tax burden, whether through the expensing of investment outlays or through percentage depletion an aid to financing investment; these devices merely facilitate the existence of a lower price of oil than would otherwise prevail. With or without taxation, the investor must find the financial means to carry out an investment project. When he is at the initial stage of investment evaluation, deciding whether to plunge ahead, the financial resources he may tap consist mainly of his credit worthiness and his liquid assets. If the investor has a substantial net worth which generally signifies a history of successful investment decisions he can readily find coinvestors or borrow needed funds. His access to external financial resources will be enhanced if his current liquidity is high, somewhat diminished if his liquidity is low. But none of these determinants of an investor's access to financial resources is especially dependent on the terms of taxation.

For example, assume that the data in Table 2 represents the condition of an oil producing enterprise before taxes are levied. The pre-tax cash flow is $2,400,000, no matter how "income" is accounted for: in each case, $600,000 of $3,000,000 gross income is paid out for lifting costs. If a 50 percent tax was then levied on each of the three measures of "net income," the net cash flow would be reduced by $600,000 in the case of "ideal" income measurement, by $900,000 in the case of tax accounting with cost depletion, and by $690,000 in the case of tax accounting with percentage depletion. And explained earlier, compensating changes in cash flows resulting from tax and other changes may be expected in the price of oil, and a rational investor is indifferent as to whether his rate of return is generated by gross sales at future higher prices, or by reduced tax payments at future lower prices.1/ In the final analysis, the

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1/ It might be observed, however, that a businessman instinctively prefers a future state of affairs in which the prices at which he has to sell will be lower rather than higher. This is probably due to the widespread understanding by businessmen (in contrast to legislators) that more can be sold at lower prices, and that any single business firm is more secure in a broader market. Even though businessmen know that higher costs, whether for labor, materials, or taxes will ultimately be reflected in higher prices, they resist changes which force this outcome. But the narrow interest of businessmen is not a suitable guide to public policy formation.

terms of taxation have no significant effect on the ability and willingness of qualified investors to undertake projects provided that evaluations of <u>future</u> prices and outlays result in favorable profit expectations.

IV. Slogans

The foregoing sections have set forth the proposition that taxing the investment income from oil and gas production is not a simple exercise of taxing "oilmen." Notwithstanding the popular and fallacious notion that "income taxes" are "direct" and hence cannot be shifted, a tax on income from capital imposes a cost like any other which must eventually be reflected in prices. Capital is mobile--it can be shifted to a wide variety of applications--and it is ultimately variable in quantity; more or less capital will be accumulated depending on the reward capital owners are provided.

Without inquiring into the broader question whether a <u>general</u> income tax on capital is more or less absorbed by <u>all</u> capital owners, or partially by capital owners and partially by sellers of personal services (wages and differential returns to human capital), we may take it as incontrovertible that discriminatory income taxation of a particular form of capital <u>will</u> <u>not</u> be borne by those who own that particular form of capital. If, as in the case of oil and gas, the burden of tax has been made preferentially <u>low</u>, this does not "enrich" oil and gas property owners. The preferential taxation will have served only to attract more investment, to a point where after tax rates of return are no different from rates of return in other nonpreferred investments.

This state of affairs is a serious cause for concern, not because "oilmen" escape taxation, which generally speaking they do not, but because the tax system is overtly used to misallocate capital from the more fully taxed sectors of the economy to the least taxed. For example, in the figures shown in Table 3, net taxes paid represent 29 percent of total payments by purchasers for oil if "ideal" income accounting methods are applied, only about 11 percent under tax accounting with cost depletion, and only 1.65 percent under tax accounting with percentage depletion.[1/] What all this means is that consumers are misled by the tax laws to believe that oil costs less

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1/ Using the "ideal" data as a norm, it is apparent from Table 3 that $42,776,000 must be equal to the present value of lifting costs plus capital consumption plus income on investment plus income taxes, all pertaining to the 15 year production period. It may be deduced that the "proper" present value of future capital consumption allowances is $12,131,000, and we may therefore compute "before tax income" under the three tax regimes of Table 3 as follows:

	Income Accounting Methods		
	"Ideal rules"	Tax Rules	
Gross income		Cost depletion	Percentage depletion
Gross income................	$42,776	$34,173	$30,993
less: Lifting cost........	6,065	6,065	6,065
Capital consumption.......	12,131	12,131	12,131
Before tax income.........	$24,580	15,977	$12,797
Net tax paid...........	12,290	3,687	508
After tax income	$12,290	12,290	$12,290

while other products, produced by capital which is more fully taxed, cost more. Accordingly, too much oil is produced and consumed, and too little of the other goods. Everyone would be better off if this state of affairs had been avoided by better tax policy-making; "oilmen," other owners of capital,

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1/ continued from page 46

Note: It might assist readers unfamiliar with the mathematics of discounting to consider the analogy of an installment sale, or mortgage loan. The present value of compensation to the owner of the property, to equal his cost of $24,420 (from Table 3) and yield him a 10 percent return on investment, has to be a series of payments whose present value is $24,420, "interest plus return of capital." In this example, $12,131 is the present value of the return of capital portion, $12,290 the "interest," or income, portion. He must "net" this regardless of the tax rules, and he may do so under different terms of relaxation if his gross receipts compensate him.

Because "before tax" incomes are not independent of the terms of taxation, this example serves to illustrate why the popular diversion engaged in by economists and legislators alike, when they appeal to published financial statements to compute "effective tax rates," is so useless as a guide to policy formulation. Not only are financial statement incomes produced by rules that already reflect major adjustments to the effects of taxation, but also the results they report for a particular year show "income" and "tax" figures which are not synchronized. For example, an oil company currently investing heavily in new properties will report "low taxes" that year, an irrelevant fact for any long term analytical purpose in view of the time span required to assess the outcome of this year's decisions.

and all wage earners would have benefited. They would also benefit in the future if corrective action were taken now.

Although this paper is now complete as a review of the issues which must be dealt with in the future evolution of tax policy in this controversial area, it may be useful to critically review slogans most commonly repeated both by those who regard efforts to correct tax policy mistakes as suicidal and by those who evangelically preach the gospel that everyone should "pay his fair share of income tax."

A. "Repeal of percentage depletion would deprive the oil (hard minerals, sand, gravel, etc.) industry of capital needed to increase domestic capacity."

Those who wave the banner emblazoned with this slogan take great pains to show that annually their firms spend at least as much on exploration and development as the tax saving from percentage depletion. If they could not take these deductions and thus had to "pay" higher taxes, they would have to cut their investment.

(1) The kernel of truth and its triviality.

After a set of tax rules has been in effect for a long period, prices of products and therefore gross receipts become adjusted to the tax regime and rates of return are normalized. Then, if the tax rules are stiffened, as by elimination of percentage depletion, firms currently engaged in producing the preferred product will immediately suffer a reduction in net cash flows. The same result would occur if wage rates, money market rates, severance and property tax rates, or any other cost rose. Whether any of these changes in the economic environment will impede investment is determined less by their impact on current year's cash flows than by their anticipated effect on the long-term profitability of investment.

Presently, when the current and near term market price of oil is well above expected future levels, the impact of a tax or other cost increase on current cash flows of oil companies can have little consequence for investment decisions.

Even with a substantial tax increase, their net cash flows after the price changes would still be far above their net cash flows before the price changes. Additionally, the increased value of existing assets provides the companies with a windfall increase in net worth that further enhances their access to capital markets. Moreover, firms not presently producing oil cannot be affected by a repeal of percentage depletion; they must weigh investment prospects for a future without percentage depletion in the same way present producers do. And if they agree with present producers that the future price of oil will be adequate, they will invest with no more difficulty than they might if there were percentage depletion.

But addressing the problem more generally, elimination of percentage depletion _should_ retard investment if all qualified investors believe that less oil will be demanded in the future at higher prices. If consumers will reduce their demand for oil with an end of subsidized prices, it would be a waste of scarce social capital to invest now to produce the unwanted quantities. On the other hand, if the market will pay an unsubsidized price with no reduction in quantity purchased, investors will proceed, just as they would in the face of other rising costs of production.

In sum, the *sine qua non* of capitalism is that the capitalist risks *his* capital for which *he* earns a rate of return *in the future*. He will undertake this risk of his capital, when justified, whether his future return is supplied by tax subsidy, cash subsidy, or simply market price. There is no magic in percentage depletion (or in any other tax preference).

B. "Repeal of percentage depletion falls hardest on "independent" oilmen who do the most drilling and who maintain competition in the industry."

Technically, an "independent" oil producer is one who *sells all* his output to others, *i.e.*, is not engaged in either transporting, refining, or marketing of oil products. But, in practice, an "independent" is considered to be a firm producing less oil per day than the smallest of the oil companies whose names are household words because they sell branded oil products. As a consequence, many "independents" are large businesses, whether measured by assets, sales, or income, while others are operators of stripper wells producing a few barrels of oil a day, but otherwise not engaged in reserve discovery and development. "Independent" is the oil business euphemism for "small business," which often seems to mean an enterprise smaller than the 500th in the *Fortune* list of the largest U.S. corporations.

It is argued by spokesmen for this interest group that they drill upwards of 80 percent of "exploratory" wells, and that they depend heavily on capital raised from investors to whom the deductibility of percentage depletion, and drilling costs, is extremely important. Denied these preferences, the argument goes, the independents would be driven from the field, and oil production would be monopolized by a few giant oil companies.

(1) Separating truth from fiction: "Independents drill more than 80 percent of all exploratory wells."

Just as "independent" is a treacherous descriptive term, so is "exploratory well." In the discussion of Section I, the term "wildcat" was used to identify an exploratory well drilled to find a <u>new reservoir.</u> Technically, such other wells as "outpost" wells--wells drilled subsequent to completion of a successful wildcat to establish limits of the field discovered--and wells drilled in <u>existing</u> fields to discover deeper or shallower pools of oil are also "exploratory" wells. But it is the successful new field wildcat that makes significant additions to reserves and productive capacity.

One reason why "independents" are touted as drillers of more than 80 percent of all exploratory wells is that many of the wells they drill are not wildcats but rather "farm-outs" from companies engaged in wildcatting, or they are wells drilled in established oil-bearing regions. New reserves discovered with such wells are, more likely than not, piddling fields, barely worth commercial production.

On the basis of studies concerning genuine wildcatting, it was concluded that "independents" and "minor" oil companies ("small" producers which also engage in other stages of the oil business) have accounted for no more than 75 percent of wildcat drilling. But, what is more significant, these "independents" and "minors" account for only about 20 percent of geophysical and geological survey work done. As a consequence, their success rate is lower than that of the so-called "majors," and the fields they discover are less prolific. The "majors," though they account for relatively less drilling, have succeeded in _finding_ more than 60 percent of the recoverable reserves. 1/ As noted earlier, most firms in

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1/ McKie, J.W., "Petroleum Conservation in Theory and Practice," _Quarterly Journal of Economics_, Vol. LXXVI (February, 1962). Erickson, E.W., _Economic Incentives, Industrial Structure and the Supply of Crude Oil in the United States, 1946-58/59_, unpublished Ph. D. dissertation, Vanderbilt University, 1968.

the oil business enjoy modest success, a few attain outstanding successes. It is not surprising that the successful grow to "major" status. Nor is it necessary that numerous moderately successful firms stay in business to assure wholesome competition. All that is necessary for competitive vigor is that entry be open to all who would venture the expense of a careful search for oil. For this, neither tax preferences nor other subsidies are necessary.

(2) A kernel of inconsequential truth: "Independents" rely on investors to whom oil tax deductions are important.

In recent years, a remarkable "growth" industry has been the marketing of shares in limited partnerships in "oil ventures." Frequently, the general partner responsible for organizing these "ventures" is a small, "independent," oil company which utilizes the legal arrangement as a convenient device for selling to the limited partners the right to deduct immediately drilling expenses. In the event production ensues, the limited partners will have a share in production (and production expense) entitling them to percentage depletion deductions. By aiming the distribution of such limited partnership interests to individuals with otherwise highly taxable incomes--from professional or other personal services or other investments--the general partner ("independent") is able to highly advertise the resultant deductions--"you get back 70-90 cents for each dollar you invest and tax-sheltered income if we strike oil!"

If the sponsoring general partner really lets all these passive investors who are utter strangers to him fully share the potential rewards for successful discovery, he obviously can gather capital more cheaply than if he appealed to investors for whom the value of tax deductions would be lower. But, as recent experience with certain oil funds amply demonstrates, general partners are content to market the deductions and retain for themselves the lion's share of the rewards, a mode of behavior which sooner or later becomes apparent to would-be "investors." As statistics on actual subscriptions to "funds" registered with the SEC indicate, a quick peak to such marketings was reached some years ago; hardly enough is currently marketed each year to maintain the capital stock already subscribed.

Thus, this source of "capital" for the independents, which never was very large in terms of annual investments made in the oil industry, is back to its former negligible level. For "independents," as for others who undertake oil ventures, reliance for additional capital will remain where it belongs, among those insiders who have demonstrated a capacity for undertaking such ventures and among outsiders able to carefully judge the qualifications of those with whom they invest. If neither depletion nor other oil tax preferences accounted for significant infusions of oil capital during the past 30 years, when rates of return from oil investment were merely normal, their absence will not impair the flow of capital to this industry in the future, and particularly not in the immediate future when rates of return are spectacularly high.

C. "Repeal of percentage depletion will initiate tax-minimizing sales of properties by independent oilmen, and the majors will monopolize the production of oil."

Although this slogan is less widely disseminated, it is taken seriously by many because the warning comes from persons well-versed in the intricacies of tax law. In essence, this contention is based on the following chain of reasoning: Repeal of percentage depletion leaves "cost depletion" as the only allowable tax accounting procedure; since the discoverer-developer-producer of oil from existing fields has little depletable basis to recover via cost depletion from future production, he will sell to another party because the other party, being able to "deplete" the purchase price over the remaining life of the well, can offer a price higher than the value of the property in the original owner's hands.

(1) Analysis of the problem.

Suppose that the information about a property is equally well-known to both the present owner and a potential buyer. The present owner will sell the property if, and only if, the price the buyer would be willing to pay, less the capital gains tax which the original owner would have to pay if he sells, exceeds the value to the original owner if he does not sell. The price of oil and the expected production pattern are data known to both the present owner and potential buyer. For simplicity, let us assume that both parties to the potential transaction are equally efficient operators, are in the same tax bracket, and let us ignore depreciation and assume that all capital recovery takes place through percentage depletion. What price would induce the present owner to sell when percentage depletion is abolished?

If the present owner were to retain the property, its present value to him would be comprised of two parts: (a) the present value of the after tax stream of gross income receipts (in the absence of any capital recovery allowance) minus lifting costs, plus (b) the present value of the "cost depletion" tax savings he might accrue over the remaining life of the property. This present value equals the original owner's reservation price.

If the same property were purchased by another, its present value to the new owner would be comprised of two parts: (a) the present value of the after tax stream of gross income receipts (in the absence of any capital recovery allowance) minus lifting costs, which is the same for the new owner as the original owner, plus (b) the present value of the purchaser's tax savings due to "cost depletion" of the price he would be willing to pay. Then, in order for a sale to occur, the purchaser's offer price less capital gains tax must exceed the present owner's reservation price.

It can be demonstrated that the critical determinants for the occurrence of a sale are: (a) the adjusted basis of the property in the hands of the seller at the time in question; (b) the capital gains tax rate to which the present owner would be subject in the event of sale; and most critically, (c) the producing characteristics of the property, which we may simply call the "decline rate," which will determine the present value of cost depletion deductions.1/

1/ In general, the slower the production decline from an oil property, the more productive the well. Imagine that there is an oil well presently producing 3 barrels a day and which has been producing at that rate for the last 20 years. Since its production obviously depends on natural seepage from surrounding formations, there is no basis for expecting the output to decline below 3 barrels for the foreseeable future. The "cost depletion rate" for such a property ought to be zero: neither the present owner, nor a prospective purchaser could claim cost depletion on the basis of a decline in productive capacity. Given its output characteristics, this is a "highly productive" well, provided it costs less to pump up the seepage than the oil is worth above ground. Similarly, a large reservoir with highly propulsive "natural drive", if properly managed, holds

The fears expressed that elimination of percentage depletion would result in the wholesale exchange of oil properties which would then end up in the hands of a few large oil companies are grossly exaggerated because:

(a) The mathematics of the exchange strongly imply that the only properties likely to be sold are those which have two characteristics: they are in a sharp state of decline, and the owner has no depletable basis remaining.

1/ continued from page 58

forth the prospect of a large yield (per day and aggregated over tens of thousands of days) which will decline only slowly over many years before reaching a stage of rapid decline. In its early years, cost depletion of such a property will be minimal, only a tiny fraction of recoverable reserves will be extracted each year, and only much later will annual output begin to markedly exhaust remaining reserves. The present value of this stream of depletion deductions will be extremely low, if evaluated at the beginning of the field's productive life, and almost as low as the slow producer just described. In neither of these cases would the prospect of cost depletion be worth much to an owner and rightly so, for each, in its own way, is a veritable perpetual fountain of wealth.

Ironically, only in the case of fields subject to rapid decline, no matter what the initial flow rate, is the present value of tax savings related to cost depletion of calculable significance. Obviously, such a field cannot be a prolific producer, and each of the first years' output represents a considerable fraction of its lifetime output. For example, a field with a 10 percent per year decline rate and a life of about 15-20 years would have produced half of its total output in a little more than 5 years. Even with a 25-30 year life, a field with a 10 percent decline rate would have produced half its output within 6.5 years; but a field with a similar life but a decline rate of only 5 percent would not have produced half its output before 9 years.

(b) In the case of newly developed properties, only those are likely to be sold to minimize taxes which have little depletable basis (because little more was spent than for drilling) and which have a short expected life (and thus a high decline rate). There may be large numbers of properties possessing these characteristics, but the total annual capacity they represent is trivial and in no event are they the kind of properties a large oil company would seek, since they are costly to manage. Indeed, one of the results of eliminating percentage depletion will be a more rapid divestment by large oil companies of many of their currently marginal properties.

D. "Repeal of percentage depletion will make the tax system fairer and make oil companies pay their fair share of taxes."

Just as the sloganeers who insist that percentage depletion is vital to finance investment are deluded, so are those who argue that "oilmen" somehow evade their fair share of taxes. It is incontrovertible that depletion deductions and other artificialities of the tax rules governing investment are worth more to high income investors that to low, and it is equally incontrovertible that the after tax rates of return in oil, like those elsewhere, are determined by the behavior of the marginal investor, not the wealthiest. It therefore follows that the net benefit conferred on the wealthy is the difference between <u>their</u> tax benefit and that of the marginal investor, not the full benefit of "nontaxability." For example, suppose that the marginal investor is someone with a tax rate of about 40 percent, and suppose his after tax rate of return is 10 percent. Prices of products are adjusted so that, with the battery of tax deductions, whatever they might be, the 40 percent taxpayer nets the 10 percent norm. A 50, 60 or 70 percent bracket taxpayer will receive the same price as the 40 percenter, experience the same actual outlays, but his tax bill will be reduced more, for the artificial tax deductions lower his taxable income by the same amount but "save" him more. Instead of paying the higher tax appropriate to his income status, he pays no more than the 40 percenter. He is not relieved of all tax, but only the extra tax that would otherwise by imposed on him by the progressive income tax.

From one point of view, this degradation of the progressivity of income tax is deplorable. It seems schizophrenic on the part of Congress to enact steeply progressive income taxes and then to proceed to enact tax subsidies which blunt the progressivity. The only way to avoid this result is to make all tax subsidies, whatever their intent, not exemptions of income from tax, but, rather, taxable subsidies.

From another point of view, this result of percentage depletion and other artificial accounting rules is desirable. Saving and capital accumulation is the supply of a socially beneficial resource, no different from the supply of personal services. In both cases the supplier should be paid the same price for rendering a specified service regardless of his personal circumstances; but a progressive income tax precludes this result. In the absence of tax preferences, under a progressive income tax, the supplier of an additional dollar of capital nets less if he is wealthy than if he is not, just as his sale of an additional dollars' worth of personal service nets him less. A purely proportional income tax, coupled with a system of transfer payments not conditioned on economic services supplied, would avoid this inherent inefficiency of progressive income taxation and achieve the equity goals espoused by proponents of progressive income taxes.