JOURNAL OF ENVIRONMENTAL ECONOMICS AND MANAGEMENT 24, 159–187 (1993)

Taxation, Depletion, and Welfare: A Simulation Study of the U.S. Petroleum Resource

ROBERT T. DEACON*

Department of Economics, University of California, Santa Barbara, California 93106

Received September 24, 1991; revised March 7, 1992

Exhaustible resources in the United States are subject to taxes on property value, production, and corporate income. As applied in practice each tax can cause high-grading—the elimination of incentives to explore, develop, and produce marginal resources—and each can tilt the time path of production toward the present or the future. The potential for such tax-induced distortions has been shown in the theoretical literature. Due to the dynamic nature of resource exploitation and the resulting complexity of models developed to study it, however, purely theoretical exercises have been unable to provide detailed results of a sort that could help guide tax policy. The present paper develops a simulation model of the U.S. petroleum resource and uses it to study the effects of taxation on exploration and production. The model is partial equilibrium in scope and views the industry as a present value maximizing representative firm. Given expectations on the future time path of price, and a function that relates reserve additions to exploratory effort, the industry chooses time paths for exploration and production. Parameters of relevant functions are estimated with data for U.S. petroleum operations in the onshore region of the lower 48 states. The simulated outcomes indicate that property and production (severance) taxes cause substantial deadweight losses, a tax on corporate income from extraction imposes a very small deadweight loss, and the property tax significantly biases utilization of the resource away from the future and toward the present. © 1993 Academic Press, Inc.

1. INTRODUCTION

Taxes on property, production, and corporate income are used by local, state, and federal governments to collect tax revenue from exhaustible resource development in the United States. Each of these taxes alters the use of exhaustible resources in two ways. First, a portion of the resource base that would be produced in the absence of taxation, or with a perfectly neutral tax, is rendered subeconomic. This effect can occur at both exploration and production stages: taxation prevents some low grade resources from being produced and renders subeconomic some prospects that otherwise would be profitable to explore and develop. This general phenomenon is termed "high-grading" in what follows. Second, taxation can change the allocation of production across time. In cases where the realloca-

---

*This research was supported by a Gilbert F. White Fellowship at Resources for the Future. Additional research support was provided by the Academic Senate and the SARI Program at the University of California, Santa Barbara. I benefited from comments and suggestions by Doug Bohi, Robert F. Conrad, Jeff Krautkraemer, John Livernois, Drew Lyon, Bill Parke, Jon Sonstelie, Rod Smith, Margaret Walls, and seminar participants at the University of Maryland, the Claremont Graduate School, and the University of Southern California. John Stranlund provided valuable research assistance.

0095-0696/93 $5.00

tion is clearly toward or away from the present, as opposed to unsystematic, this phenomenon is termed "tilting."

The theoretical literature has demonstrated the existence of these effects and has derived useful propositions for the case where the industry exploits a fixed reserve.[1] When one allows for exploration and reserve additions, however, the dynamics of the process become complex and purely analytical models provide few useful results. Simulation is the natural method of study in such circumstances. It is used here to examine the effects of taxes on property, production, and corporate income on petroleum exploration and production in the United States. Rates for all three taxes are chosen to yield the same present value tax revenue, so the excess burdens of alternative taxes and the effects of each tax on incentives to explore and produce can be readily compared.

The model used to study these issues adopts the general structure developed by Pindyck [23] and applied by Yucel [32, 33] for simulation.[2] The industry takes future output prices as given and chooses time paths for exploration and production to maximize the present value of profit. The function of exploration is to add to the industry's reserve and the reserve is valuable because it serves as a form of capital to support production. Despite this general similarity, the model differs from the forerunners mentioned above in several respects. The primary structural difference concerns the specification of the reserve addition process. More importantly, the parameters of relevant functions are chosen to represent a specific resource, the petroleum that exists in the onshore region of the lower 48 states. Further, the following analysis provides quantitative evidence on several issues that have not yet been addressed in the context of a model that incorporates exploration and reserve additions. Among these are the effects of property and corporate income taxes on both exploration and production, and the comparative excess burdens of all three tax instruments.

The simulation results obtained are solutions to an analytical model under differing parameter values. Comparison of these results is the natural counterpart, in dynamic models, to the traditional comparative static exercise. The modeling approach is partial equilibrium. The industry is taken to be competitive and small enough that demand for the industry's output is perfectly elastic; hence, the time path of output price is exogenous. The preceding assumption and the partial equilibrium approach are supported by the following observations; crude oil is traded worldwide, production from the region examined presently accounts for less than 10 percent of worldwide supply, and many of the inputs used, such as exploration crews and equipment, are highly mobile.

To simplify, petroleum is treated as a distinct resource, separable from natural gas, and a single firm is used to represent the entire industry. A final concession to simplicity is that the model abstracts from all uncertainty.[3]

[1] Krautkraemer [17] provides a thorough summary of this literature.

[2] Slade [24] and Gamponia and Mendelsohn [12] have used simulation to study exhaustible resource issues, but their models exclude the possibility of adding to reserves.

[3] Treating oil as separable from gas implicitly assumes that the industry can discriminate perfectly between oil and gas exploration prospects, and that production of "associated gas" in oil fields is sufficiently small to ignore. Empirical evidence on jointness in the exploration process is presented in Livernois [20] using data from Alberta. The potential perils of aggregating production across fields are demonstrated by Livernois [19]. Bohi and Toman [4, Chaps. 3–5] provide a theoretical discussion of aggregation, joint production, and uncertainty issues.

2. STRUCTURE OF THE MODEL

In an untaxed regime the industry's net cash flow in any year is its revenue from production, less production cost, less expense for exploration and development. For year t this is written

$$\Pi_t \equiv p_t y_t - C(y_t, R_t) - D(w_t), \tag{1}$$

where p is price, y is output, w is exploration and development drilling, R is the reserve, $C(\cdot)$ is production cost, and $D(\cdot)$ is drilling cost. Hereafter, upper case variables such as R_t denote stocks measured at the beginning of year t and lowercase variables such as y_t and w_t are flows during year t.

Production cost is assumed to depend positively on current output and negatively on the level of the reserve. This specification follows from a view of crude oil extraction as a process that combines the reserve, a form of capital, with other inputs such as labor to produce extracted crude oil as an output. The implied extraction cost function, which is essentially a cost function for non-reserve (variable) inputs, is increasing in the rate of output and decreasing in the reserve.[4] This specification does not include a measure of cumulative reserve additions, although several authors have argued persuasively for its inclusion. They argue that rational explorers will seek out and find deposits with relatively low extraction costs first, and move on to higher cost deposits—the extensive margin to use the terminology of Livernois and Uhler [21]—only as low-cost sources are depleted. For a given deposit, cost may well rise as its reserve dwindles, but simply adding more reserves does not reverse this because the deposits added tend to be of lower quality. This consideration is excluded from the present model because available data on petroleum extraction costs are insufficient to allow it to be measured. The consequences of this exclusion for the analytical model and the empirical reasons for omitting this consideration are discussed at various places in what follows.

Drilling cost depends on current exploratory and development drilling, w. Exploration and development drilling are represented as a single combined activity to limit the number of control variables in the simulation model. Although exploratory and development drilling are conceptually distinct, it is shown in the next section that the two can be aggregated in the reserve addition process under relatively mild conditions.

The industry's reserve at the start of year t equals cumulative reserve additions up to that date less cumulative production. Cumulative reserve additions are taken to be a concave function of cumulative drilling; hence, the reserve available in year t is

$$R_t = F(W_t) - Y_t, \qquad F' > 0,\ F'' < 0, \tag{2}$$

---

[4] The notion that reserves serve as a capital input to production is adopted by Livernois [19] and is implicit in the discussions of Devarajan and Fisher [10, p. 1281]. The implied extraction cost function is prominent in the theoretical model developed by Pindyck [23] and further examined by Yucel [32, 33] and others. A cost function with these same general attributes, cost dependent on the rate of output and the level of reserve, emerges from a pressure decline model of the petroleum reservoir. It also has been developed from a model with a fixed total reserve in which the quality of deposits declines as extraction proceeds; see Solow and Wan [27]. Livernois [19, pp. 72–73] provides an efficient summary of cost functions found in the theoretical literature.

where W is cumulative drilling, Y is cumulative output, and $F(\cdot)$ is cumulative gross reserve additions. The state variables W and Y evolve according to the transition equations

$$W_t + w_t = W_{t+1}, \tag{3}$$

$$Y_t + y_t = Y_{t+1}, \tag{4}$$

for $t = 0, \ldots, T$.

The formulation for reserve additions differs from that found in Pindyck [23] and in the work of those who have applied his model. In the notation of the present paper Pindyck's model specifies that $R_{t+1} - R_t = G(Z_t, w_t) - y_t$, where Z_t is cumulative gross reserve additions at the start of year t. Equation (2) can be rearranged to yield a specification equivalent to this, but there are two advantages to leaving it as is.[5] First, the specification in (2) leads to a Lagrange equation and first-order conditions that are simple to derive and straightforward to interpret. Second, it results in a second-order sufficient condition for the maximization problem that has a natural interpretation and is easy to impose in simulation.

Given a time path for price, $p_0, \ldots, p_T$, an interest rate, r, and a terminal date, T, the behavior of the industry is characterized as the solution to the following problem. Choose $(w_0, \ldots, w_T), (y_0, \ldots, y_T), (W_1, \ldots, W_{T+1})$, and $(Y_1, \ldots, Y_{T+1})$ to

$$\max \sum_{t=0}^{T} \Pi_t (1+r)^{-t}$$

subject to (2), (3), (4), $w_t \geqslant 0$, and $y_t \geqslant 0$, where W_0 and Y_0 are given.[6]

After substituting (2) into (1), the Lagrange equation for this problem is written

$$L = \sum_{t=0}^{T} \left\{ \Pi_t (1+r)^{-t} + \phi_t (W_t + w_t - W_{t+1}) + \lambda_t (Y_t + y_t - Y_{t+1}) \right\}. \tag{5}$$

It is customary to interpret a dual variable as the payoff to relaxing its associated constraint. If (3) were relaxed in a way that increased W_{t+1}, given W_t and w_t, the result would be a larger reserve in $t + 1$ and hence greater future profit. The value of W_{t+1} is therefore positive and the shadow price ϕ_t is positive as well. On the other hand, if (4) were relaxed in a way that increased Y_{t+1}, given Y_t and y_t, the result would be a smaller reserve in $t + 1$ and hence lower future profit, so λ_t is negative.[7]

---

[5] To derive Pindyck's [23] reserve addition model from the one used here, note that Eqs. (2) and (3) imply $R_{t+1} - R_t = F(W_t + w_t) - F(W_t) - y_t$, or $R_{t+1} - R_t = H(W_t, w_t) - y_t$. Letting Z_t stand for gross reserve additions, so $Z_t = F(W_t)$, the change in the reserve can be written $R_{t+1} - R_t = H(F^{-1}(Z_t), w_t) - y_t$, or $R_{t+1} - R_t = G(Z_t, w_t) - y_t$, which is Pindyck's formulation.

[6] Initial stocks, W_0, Y_0, are assumed to be non-negative. The non-negativity conditions for w and y, together with (3) and (4), imply that non-negativity conditions for W and Y can be ignored. The reason for fixing the terminal date exogenously is explained later.

[7] The constraints (3) and (4) are equalities, so the signs of their dual variables could be changed by multiplying either constraint by minus one. Pindyck's [23] model also has two shadow price variables, λ_1 and λ_2, which are of opposite sign.

The first-order conditions for a maximum are

$$\partial L/\partial w_t = \partial \Pi_t/\partial w_t(1+r)^{-t} + \phi_t \leqslant 0, \qquad w_t \geqslant 0,\ w_t\,\partial L/\partial w_t = 0, \tag{6a}$$

$$\partial L/\partial y_t = \partial \Pi_t/\partial y_t(1+r)^{-t} + \lambda_t \leqslant 0, \qquad y_t \geqslant 0,\ y_t\,\partial L/\partial y_t = 0, \tag{6b}$$

for $t = 0, \ldots, T$; and

$$\partial L/\partial W_t = \partial \Pi_t/\partial W_t(1+r)^{-t} + \phi_t - \phi_{t-1} = 0, \tag{6c}$$

$$\partial L/\partial Y_t = \partial \Pi_t/\partial Y_t(1+r)^{-t} + \lambda_t - \lambda_{t-1} = 0, \tag{6d}$$

for $t = 1, \ldots, T$, plus the transition equations (3) and (4) and the initial stocks W_0 and Y_0. Because no value has been assigned to terminal stocks we also have

$$\partial L/\partial W_{T+1} = -\phi_T = 0 \tag{6e}$$

and

$$\partial L/\partial Y_{T+1} = -\lambda_T = 0. \tag{6f}$$

Interpretation of the first-order conditions is simplified by focusing on cases where (6a) and (6b) hold with equality. When written out in detail condition (6b) requires that $(p_t - C_y(y_t, R_t))(1+r)^{-t} = -\lambda_t$, where $C_y = \partial C/\partial y$. The left-hand side of this equation is the marginal *current* profit, price minus marginal extraction cost, of producing a barrel of oil in year t, expressed in present value. Producing a marginal barrel in t lowers the reserve in $t+1$, however, and the unit of reserve used is worth $-\lambda_t$, as the following argument shows. A unit of the reserve is valuable because it lowers production cost by $-\partial C/\partial R_{t+j}$ in all future periods. To relate this to $-\lambda_t$, write out (6d) in detail as $\lambda_\tau - \lambda_{\tau-1} = -C_R(y_\tau, R_\tau)(1+r)^{-\tau} > 0$, where $C_R = \partial C/\partial R$, and sum such expressions for $\tau = t+1, \ldots, T$. Recalling that $\lambda_T = 0$, one obtains $\sum_{\tau=t+1}^{T}(\lambda_\tau - \lambda_{\tau-1}) = -\lambda_t = -\sum_{\tau=t+1}^{T} C_R(y_\tau, R_\tau)(1+r)^{-\tau} > 0$. Thus $-\lambda_t$ is the present value cost decrease that results from a marginal addition to the reserve in period t. Accordingly, condition (6b) equates the marginal current profit of producing a barrel of output to the marginal cost of using a unit of the reserve.

Condition (6a) can be interpreted in a similar fashion. When written out in detail it requires $D'(w_t)(1+r)^{-t} = \phi_t$, where $D' = dD/dw$. The left-hand side of this equation is the present value marginal cost of drilling, and ϕ_t is the marginal benefit as the following argument demonstrates. When (6c) is written out in detail and summed for periods $t+1, \ldots, T$, it implies

$$\phi_t = -\sum_{\tau=t+1}^{T} C_R(y_\tau, R_\tau)F'(W_\tau)(1+r)^{-\tau}.$$

The sum on the right-hand side equals the present value of future production cost savings caused by drilling a marginal well in period t. Drilling a marginal well in t raises W_{t+j} in all future periods and this, in turn, increases future reserves by $F'(W_{t+j})$. With higher reserves, future production costs are lower and the present value of these cost reductions equals the summed expression above. Thus ϕ_t is the benefit of a marginal well, and condition (6a) requires that the marginal cost and marginal benefit of drilling be equal.

Allowing for heterogeneity in reserves would alter the structure and interpretation of the maximization problem somewhat. Rational agents would exploit reserves with low extraction costs first, so unit extraction costs would rise over time. The spirit of this phenomenon could be captured by including cumulative discoveries as a positive argument in the cost function, so extraction cost becomes $C(y_t, R_t, F(W_t))$.[8] In this case the first-order condition for W_t becomes $-(C_R + C_F)F'(W_t)(1 + r)^{-t} = \phi_t - \phi_{t-1}$. The costate variable ϕ_t represents the shadow value of drilling and can be shown to equal $\phi_t = -\{\Sigma_{\tau=t+1}^{T} C_R(y_\tau, R_\tau, F(W_\tau))F'(W_\tau)(1 + r)^{-\tau} + \Sigma_{\tau=t+1}^{T} C_F(y_\tau, R_\tau, F(W_\tau))F'(W_\tau)(1 + r)^{-\tau}\}$. The first sum increases ϕ (since $C_R < 0$), and represents the present value of cost reductions that occurs with a discovery because the producer has more reserve capital to work with. The second sum reduces ϕ (since $C_F > 0$), and thus detracts from the value of exploration because new discoveries occur on the extensive margin and lower the average quality of reserves used in all future periods. The reasons for not including this possibility in the actual simulation are noted in the following section.

Each of the three tax instruments examined alters Π_t, and hence alters the profit maximizing exploration and production strategy, in a different way. Before proceeding to examine these effects, however, parametric forms for the functions that comprise the model must be chosen and parameter estimates obtained.

3. ESTIMATION

The model requires estimates of three functions: reserve additions, $F(\cdot)$, drilling cost, $D(\cdot)$, and production cost, $C(\cdot)$. Two general considerations guided the approach to estimation. First, because the model relies on present value maximization to obtain solutions, and because it is used to simulate behavior far outside the range of data used in estimation, the specific functional forms adopted must yield an objective function that is globally concave in the choice variables. This requires that $C(\cdot)$ and $D(\cdot)$ be convex and that $F(\cdot)$ be concave. Second, care was taken to ensure that the cost data used in estimation incorporate all categories of cost incurred by U.S. oil producers. This led to some adjustment of regularly published drilling cost data to include the cost of pre-drilling exploration activities and expenditures for lease equipment installed after wells are completed. Data sources and empirical methods are explained in the Appendix.

Reserve Additions

The function $F(W)$ is assumed to be strictly increasing, concave, and bounded. Concavity implies that the amount of reserve added by a marginal foot of drilling declines as cumulative drilling increases. This agrees with the notion that the industry finds and develops the easiest deposits first, and moves to less accessible

---

[8] Livernois and Uhler [21] point out that one generally cannot aggregate extraction costs across deposits when they are of heterogeneous quality. Swierzbinski and Mendelsohn [29] provide a simple model in which aggregation is possible, however, even though the industry adds to the reserve through exploration. In their model extraction costs depend negatively on the level of the reserve and positively on cumulative discoveries.

sites only as the stock of attractive prospects is depleted.[9] Boundedness is a geologic fact of life, although the bound might never be reached by an economically rational exploration strategy.

The function adopted is

$$F(W_t) = \Gamma(1 - \exp(-\beta W_t)), \tag{7}$$

a form often used to model the petroleum discovery process in a given size class of fields. Cumulative reserve additions approach Γ asymptotically as cumulative drilling grows. The parameter β is positive and is related to the efficiency of exploration.

Equation (7) was estimated with annual time series on cumulative footage drilled and cumulative production for the period 1946–1987. Footage drilled seemed a more appropriate measure of activity than number of wells, since the average depth of wells changes over time. The starting date for forming the cumulative variables W and $F(W)$ is 1859, the year the first successful oil well was drilled in the United states. The variable W was measured as the sum of footage drilled for exploratory and development wells. Since exploration and development each typically account for about 30% of total industry expenditure, it is clear that any model intended to represent the industry must incorporate both activities.

There are several reasons for combining exploratory and development drilling in a single variable. The simplest reason is pragmatic, since treating them separately would add another control variable to the simulation model and greatly increase the computational burden. Further, although exploration and development are conceptual distinct, the two often are not accurately distinguished in published data on drilling. Finally, the conditions under which one is theoretically justified in combining both activities are not terribly restrictive. Sufficient conditions for aggregation are: (i) the relative marginal costs of exploration and development drilling remain constant over time, and (ii) cumulative gross reserve additions are a homothetic function of cumulative development drilling and cumulative exploration drilling. This result, a variant of the Samuelson substitution theorem, implies that even though substitution between exploration and development drilling is possible, firms always find it profitable to undertake the two activities in fixed proportions. In this case one may safely use exploratory drilling, development drilling, or any linear combination of the two as an argument in the cumulative reserve addition function.[10]

The variables W and $F(W)$ in (7) are cumulative, so the error term in the corresponding regression equation is specified as cumulative as well, i.e., a random walk. The reserve addition equation was therefore estimated in first-difference

---

[9] For empirical evidence on exploration in Canada see Livernois [20].

[10] The sufficient conditions can be stated as follows: (i) drilling cost is $D = D(w_t^e + \eta w_t^d)$, where η is a positive constant and w_t^e and w_t^d are current exploratory and development drilling; and (ii) reserve additions are given by $f = f(W_t^e, W_t^d)$, where $f(\cdot)$ is homothetic and W_t^e and W_t^d are cumulative exploratory and development drilling. Details are available from the author. The implied fixity of proportions was not grossly violated during the period studied here. Development drilling footage averaged 72% of total drilling footage during 1946–1987, and the coefficient of variation of this share in annual data was only 5%.

form.[11] Because W is a choice variable for the industry a two-stage non-linear least-squares estimator was used. The resulting parameter estimates are

	Γ	β
Estimate	224,998.5	0.0001388
t statistic	(11.86)	(4.75)

where W is measured in millions of feet and $F(W)$ is measured in millions of barrels.[12]

Drilling Cost

The drilling cost function is assumed to be quadratic:

$$D(w_t) = \gamma w_t + \delta w_t^2. \tag{8}$$

This equation includes no intercept because no compelling reason could be found for attributing a fixed cost to the drilling activity. The quadratic form was chosen in part because it implies a positive intercept for marginal cost, i.e., a positive cost for the first foot of drilling undertaken in a given year. Current drilling is a choice variable for the industry and hence is endogenous. Estimation by two-stage non-linear least squares yielded

	γ	δ
Estimates	29.3276	0.1281
t statistics	(1.33)	(1.90)

where w is in millions of feet, cost is in millions of 1982 dollars, and the sample period is 1959–1987. The equation fits the data well ($F = 277.05$) but the t statistics are low due to obvious collinearity between drilling and drilling squared.[13]

---

[11] When estimated in levels, with a first-order autoregressive error term, the autocorrelation coefficient was not significantly different from one.

[12] The instruments used in the two-stage estimation procedure are current and lagged crude oil price and one and two period lags of cumulative drilling. The estimated equation makes no provision for technological change. As Livernois [20] points out it would be futile to include a simple time trend because cumulative drilling is itself a trend. The cumulative drilling variable may, as a consequence, pick up technological change that is of the learning-by-doing variety. The stability of the function was examined by re-estimating it for two 20-year subsamples of the data set; none of the estimates for these subsamples differed by more than one standard error from the values reported in the text. Finally, because it seemed desirable to start the simulations off at actual 1987 values for the state variables, equation (7) was re-estimated and forced through the 1987 data point. This yielded estimates of 230,600 and 0.0001165 for Γ and β, and these values were used in the simulations.

[13] The error term was assumed to follow a first-order autoregressive process; the estimated $\rho = 0.92$. Current and lagged oil price and lagged drilling, together with the squares of these variables, were used as instruments. The reported equation makes no provision for either technical change in drilling or for a sort of depletion effect that might be reflected in higher costs per foot as cumulative drilling proceeds. These two possibilities were examined by incorporating, in separate runs, a linear trend and cumulative drilling as independent variables. The t statistics for these variables never exceeded 0.75 and their inclusion did not appreciably affect the estimates of γ and δ.

Production Cost

Existing data on U.S. production costs are insufficient to permit an econometric estimation of the extraction cost function. These limitations, and a brief description of the outcome of attempts to estimate a cost function econometrically, are described in the Appendix. In light of these obstacles the problem of specifying a cost function for petroleum extraction was approached by assuming an exact form for the production function. The Cobb–Douglas function

$$y_t = Ak_t^{\mu}R_t^{1-\mu} \tag{9}$$

is advantageous in this regard, where k stands for "non-reserve" inputs used in production, e.g., labor, equipment, and fuel. Given R, production cost is

$$C(y_t, R_t) = \theta y_t^{\varepsilon}R_t^{1-\varepsilon}, \tag{10}$$

where $\varepsilon = 1/\mu$ and θ is a function of A and the price of k, which is assumed constant in simulations.

Calibration of the cost function requires information on two parameters, μ and θ. The Cobb–Douglas form implies that μ equals the expenditure share of non-reserve inputs in total outlays for k and R. The estimate $\mu = 0.35$ was extracted from expenditure data pertaining to k and R used to support production during the mid 1980s. Given μ, θ was then chosen to equate $\theta y_t^{\varepsilon}R_t^{1-\varepsilon}$ to the mean production cost for operations in the onshore, lower 48 region during the 1980s. Details of this calibration exercise are reported in the Appendix.[14]

Discussion

The data problems that prevent incorporation of reserve heterogeneity in the production cost function are explained in the Appendix. Empirical evidence on the importance of heterogeneity and its effect on crude oil production costs in the United States is lacking, although Livernois and Uhler [21] provide some evidence for Alberta. It would be worthwhile to allow for this phenomenon in future investigations of this sort if requisite data become available.

Now that the general form and specific functions for the model have been presented, the reason for arbitrarily fixing the time horizon can be explained. Stated simply, the structure of the model used here implies that the optimal strategy produces ever-decreasing amounts of output forever, unless the process is arbitrarily stopped by fixing T. To see this, suppose T were fixed at T^1 and the optimal program computed. Since T^1 was arbitrary, it suffices to show that the present value of the program can be increased unambiguously by relaxing this constraint and allowing positive production in $T^1 + 1$. The Cobb–Douglas form for production cost guarantees that $C(\cdot)$ rises without bound as R approaches zero. This implies that a positive reserve will remain at the end of the program that

---

[14] The parameter values in (9) are $\varepsilon = 2.84$ and $\theta = \$189.1$, where R and y are measured in millions of barrels. For an intuitive notion of what these estimates imply, the associated average and marginal costs of production are \$4.50 and \$12.50 per barrel, respectively, using production and reserve levels prevailing in the late 1980s.

is optimal for $T = T^1$, so $R_{T^1+1} > 0$. The Cobb–Douglas form also guarantees that, given any positive reserve, one can find a strictly positive output level that yields revenue greater than extraction cost.[15] Since there exists a $y_{T^1+1} > 0$ that yields positive profit in period $T^1 + 1$, the present value of the program can be raised by allowing production beyond the imposed deadline. This implies that the optimal program with T unconstrained does not exhibit a finite "shutdown date," a date beyond which output is zero. The arbitrary horizon used here was chosen to be relatively long, 61 years, so that the resulting time paths would not be dominated by the imposed time limit.

4. DEFINITIONS OF TAX REGIMES SIMULATED

The structure of each tax examined can be represented by the equation for after-tax net revenue. Net revenue in an untaxed regime is rewritten here for reference:

$$\Pi_t \equiv p_t y_t - C(y_t, R_t) - D(w_t). \tag{11a}$$

The remainder of this section discusses each tax instrument examined and presents the after-tax net revenue expression for each. While taxes vary in application from state to state, the intent here is to examine tax policies that reflect typical practice.[16]

Severance Tax

All major oil-producing states except California levy significant severance taxes on petroleum. The predominant form for this tax is a fractional rate applied to the wellhead value of production; some states levy severance or conservation taxes as a fixed dollar amount per barrel, but these are unimportant exceptions. Consequently, after-tax net revenue with a severance tax is written

$$\Pi_t \equiv (1 - \tau_s) p_t y_t - C(y_t, R_t) - D(w_t), \tag{11b}$$

where τ_s is the severance tax rate.

Tax on Income from Mining

The corporate income of oil producers is taxed by the U.S. government. It also is taxed by state governments in all major producing states, although it takes the form of a relatively minor franchise tax in Texas and Wyoming. The tax modeled here broadly represents federal practice in the treatment of costs in the tax base. It differs in details from the income tax statutes of some states. Taxable mining income is defined to equal revenue, less production cost, less expensed drilling cost, less depletion of non-expensed drilling cost incurred in prior years, less

---

[15] The intuitive reason is that (10) implies that average cost approaches zero at zero output.

[16] Information on the tax instruments examined is drawn primarily from Deacon *et al.* [9].

interest. All costs associated with drilling dry holes, plus most intangible costs for completed wells, are expensed as incurred. Intangibles include outlays for wages, fuel, contract services, and tool rentals. The balance of drilling costs, i.e., tangible costs for completed wells, must be capitalized and recovered through cost depletion. With cost depletion the firm deducts the non-expensed portion of drilling cost as production proceeds; if x percent of a well's total reserve is extracted in a given year, the firm's cost depletion for that year is x percent of the non-expensed historic cost of drilling the well. Investments in drilling are assumed to be financed through equity rather than debt, so no interest deduction is incorporated in the tax base.[17]

Combining these factors, after-tax net revenue with an income tax is

$$\begin{aligned}\Pi_t \equiv\ & p_t y_t - C(y_t, R_t) - D(w_t) \\ & - \tau_i(p_t y_t - C(y_t, R_t) - (e + (1 - e)f)D(w_t)),\end{aligned} \tag{11c}$$

where τ_i is the tax rate on income, e is the fraction of drilling costs that are expensed for tax purposes, and f is the present value of cost depletion deductions per unit of depletable expense. The expensed fraction, e, was set at 0.45, which is consistent with recent experience. If the ratio of production to reserve is constant, it is easy to demonstrate that $f = d/(r + d)$, where r is the interest rate and d is the ratio of production to reserve. This formula was used in simulations, with d set at its mean value for the United States in the 1980s.

Property Tax on Reserves

The property tax, a source of revenue for local government, is applied to the value of petroleum mineral rights in California and Texas.[18] It is a levy on the assessed value of reserves, so cash flow net of property tax payments is

$$\Pi_t \equiv p_t y_t - C(y_t, R_t) - D(w_t) - \tau_p q_t R_t, \tag{11d}$$

where τ_p is the property tax rate and q_t is the assessed value per unit reserve in period t.

Local tax assessors attempt to assess reserves at market value. As explained earlier, the shadow value of the reserve is $-\lambda_t$, and this is the appropriate market value to attach to R_t. λ_t is determined as part of the solution to the maximization problem, however, which presents a problem. One cannot simply make the substitution $q_t = -\lambda_t$ in (11d) and proceed, because λ_t is not known when the simulation exercise begins. This problem was overcome by inserting an initial estimate for the time path of q_t into the objective function, solving the maximiza-

---

[17] In the early 1980s debt accounted for only about one-seventh of petroleum industry investments, aside from borrowing associated with merger activity. Data for more recent years are not yet available.

[18] Other major oil-producing states exempt the value of subsurface oil and gas mineral rights from the tax base. Wyoming collects what it terms a property tax on petroleum but it is actually a levy on the value of production in the preceding year. It is, therefore, a delayed severance tax. Property taxes on above-ground capital equipment are excluded from this analysis due to data limitations.

tion problem, and then using the resulting time path for λ_t to adjust the estimate of q_t.[19]

5. SIMULATION RESULTS

Simulations were carried out under the following baseline conditions. The interest rate used to discount after-tax receipts is 5% and the time horizon is 61 years. The price of crude oil starts at $20 per barrel, rises 2.5% per year until it reaches $40 per barrel, and remains constant thereafter. No predictive significance is claimed for this price path. The sensitivity of results to these price and interest rate choices is reported near the end of this section. Initial values for the state variables, W and Y, were set at actual 1987 levels. All tax rates were calibrated to attain the same present value tax revenue target, 15% of the gross revenue earned in an untaxed regime. This target was suggested by the fact that combined federal, state, and local tax receipts on oil production have amounted to about 15% of gross revenue in recent years.[20] The numerical method used to compute solutions is outlined in the Appendix.

Untaxed Regime

Time paths for output and drilling in an untaxed regime are shown in Fig. 1, together with the assumed price path. The scale on the vertical axis gives price in dollars per barrel, output in tens of millions of barrels, and drilling in millions of feet. Price first hits the $40 limit in Year 29; output peaks 2 years earlier; and drilling peaks 5 years earlier. During the second half of the program price remains constant, while output and drilling decline monotonically. Note that drilling ceases 4 years before the end of the program.

In Fig. 2 the vertical axis shows cumulative output in tens of billions of barrels, the reserve in billions of barrels, and the reserve-to-output ratio in years of production. The reserve grows during the first 13 years and then declines. The reserve-to-output ratio declines rapidly during the period of price growth, as a consequence of growth in output. It remains roughly constant during the period of constant nominal price and then declines as the terminal date is approached. Cumulative output is 129.75 billion barrels in the initial year and grows by 70.59 billion barrels, to 200.29 billion barrels, by Year 61. According to the estimated reserve addition function, the limiting value for cumulative output is 230.60 billion barrels. The simulated terminal value for cumulative output falls short of this limit by 30.31 billion barrels, or 13%.

The most interesting portion of the program is the first half, the period of rising current price. The reserve is built up during the first 15 years and is relatively high

---

[19] This general problem results from the fact that the property tax erodes its own base, in the sense that the tax reduces the price of the taxed asset. The initial estimate used for q_t is the time path of λ_t from the untaxed regime, and for simplicity these two variables are assumed proportional to one another. This is an approximation, but one whose accuracy is quite high. After completing the property tax simulation the simple correlation between q_t and the costate variable λ_t was found to be 0.9995.

[20] The federal corporate income tax liability for domestic oil producers is about 7–8% of gross revenue. Deacon *et al.* [9] report an average state–local tax burden that amounted to about 8% of gross revenue in 1981.

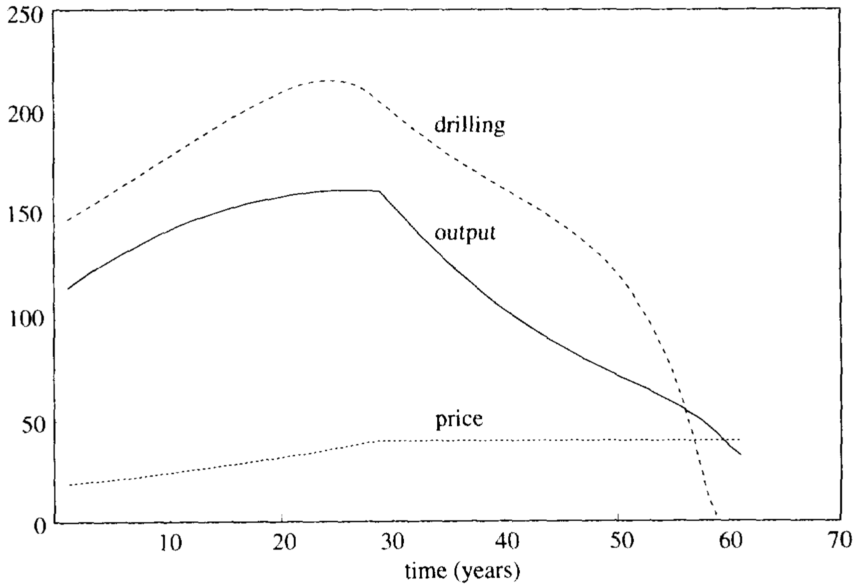

FIG. 1. Untaxed time paths for drilling (feet × 10^6), output (barrels × 10^7), and price ($/barrel).

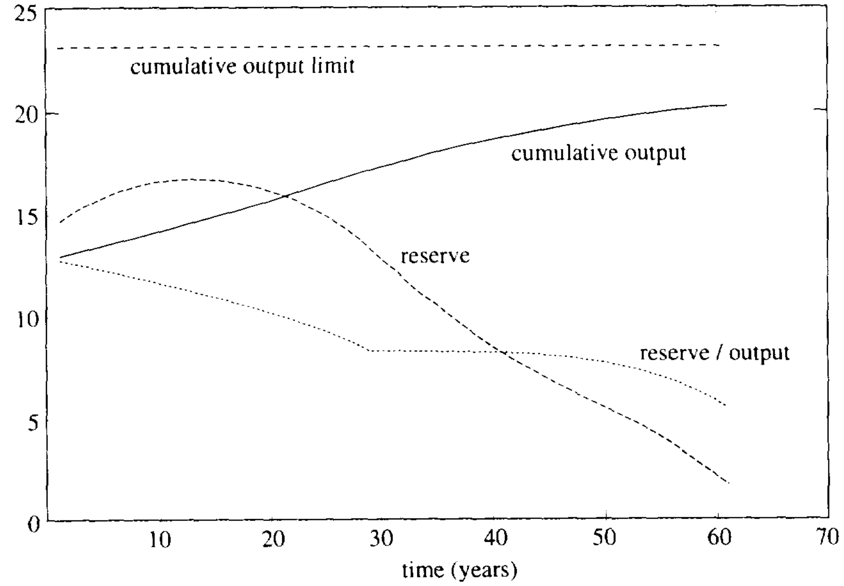

FIG. 2. Untaxed time paths for cumulative output (barrels × 10^{10}), reserve (barrels × 10^9), and reserve-to-output ratio (years).

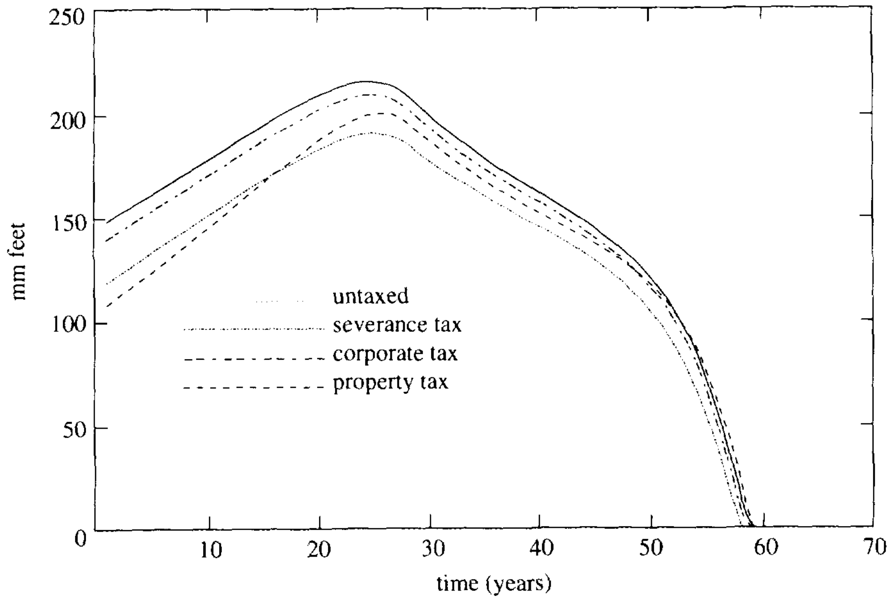

FIG. 3. Time paths for drilling.

as price approaches the $40 limit. This occurs because the optimal program calls for output to peak as price reaches this limit, and the enhanced reserve serves to mitigate production costs during the period of high output. It is somewhat surprising that output and drilling rise during the first half of the program, in light of the monotonic decline in the present value price of crude oil and the general reduction in drilling productivity that occurs as attractive drilling prospects are exhausted.

Taxed Regimes

Time paths for drilling and output under alternative tax instruments are shown in Figs. 3 and 4. Consider, first, the income tax, which causes only minor deviations from the untaxed solution. Its general effect is to lower the levels of both drilling and output in virtually all periods, but the magnitude of reallocations is small. One explanation for this virtual neutrality is the allowance for expensing outlays for dry holes and intangible spending for completed wells. This causes the corporate tax to approach a tax on cash flow, which is known to be neutral [3, p. 328].[21] The expensing and depletion rate assumptions adopted here imply that 82% of the present value of investment costs are deductible from taxable income. Consequently, the effective rate of tax on the return to marginal investments in drilling is very low. An alternative explanation lies in the fact that the simulation program inherits a sizeable reserve in the initial period. Because the cost of acquiring this reserve is sunk, the corporate levy can tax the return to this initial

---

[21] As noted in the following section, Smith [26] reaches a similar conclusion.

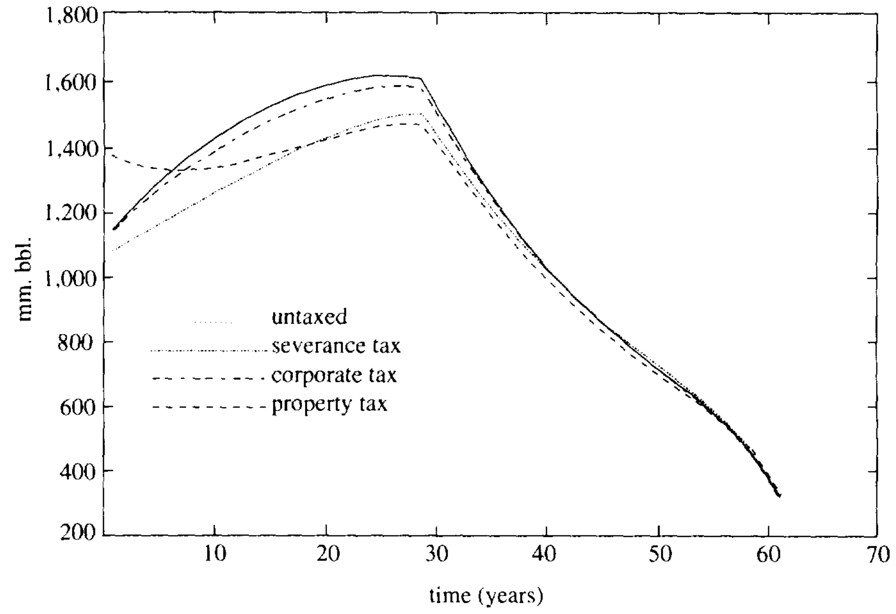

Fig. 4. Time paths for output.

capital stock with no penalty for reduced efficiency. These two hypotheses are examined further in the discussion of sensitivity analysis.

The severance tax alters drilling and output to a much greater degree. When compared to the untaxed path it reduces drilling in all periods, reduces it more in early periods than in the distant future, and causes the drilling activity to shut down prematurely. The severance tax cuts output substantially in early years and by smaller amounts in intermediate years. During years 42–56 the taxed output path actually exceeds the untaxed path, but the amount of the excess is very small. Thus output is tilted toward the future, a result that is prominent in fixed reserve models. The dominant effect of the tax is high-grading, however; resources that would otherwise be explored, added to reserves, and produced are rendered sub-economic by the severance tax.

The property tax is perhaps the most interesting of the three because there has been little theoretical or empirical discussion of its effect on non-renewable resources. Figure 3 reveals that a property tax on the reserve reduces drilling dramatically in early years of the program and this shortfall declines over time. Hence, drilling is tilted toward the future. The tax tilts output in the opposite direction, toward the present. Output with the tax actually exceeds untaxed output in very early periods. By Year 7 the taxed output path lies below the untaxed path, however, and by Year 20 it is the lowest of all paths shown. The clear rationale for this pattern of slow drilling and rapid extraction is to reduce the industry's taxable reserve, and hence its tax liability.[22]

[22] During the last 5 years of the program drilling in the property tax regime is very slightly higher than drilling without the tax.

Untaxed and taxed reserve paths are shown in Fig. 5. Of course, these paths follow directly from the paths for drilling and production just discussed. Again, the corporate income tax appears to be nearly neutral. The severance tax clearly tilts the reserve available in each period, causing it to be low in early years and high in later years. The effect of the property tax is dramatic. It prevents the reserve from rising during any portion of the program and, except for years near the terminal date when all curves converge, it causes the reserve to be significantly lower than in any of the other regimes examined.

Undiscounted tax revenue paths are shown in Fig. 6. Both income and severance tax collections peak in Year 29 when price first hits its limiting value. This occurs because the present value maximizing strategy causes output to peak at about the same time that prices reaches its upper bound. The time path of property tax receipts is, by comparison, tilted toward the present. Recall that the property tax also tilts output toward the early years of the program. When compared to the severance or corporate taxes, then, the property tax favors private and public sector consumption in early years at the expense of the future.

Table I summarizes the effects of all three taxes on cumulative output produced over the 61-year horizon. The third and fourth columns of figures summarize the high-grading effect, the tendency for taxes to discourage production of marginal resources. By this measure the severance tax has the strongest effect; the total output loss, 4590 million barrels, represents about 4 years of output, at production levels that prevail in the first few years of the program.

Two estimates gleaned from the geologic literature on recoverable petroleum resources compare favorably to these results and thus support the plausibility of the model. First, Nehring [22] assumes essentially the same future price scenario adopted in the present simulations when estimating potential cumulative petroleum liquids recovery. His mean estimate for the lower 48 states, onshore, implies 63 billion barrels of additional production. Second, the U.S. Geologic Survey places the remaining crude oil production potential for the onshore portion of the lower 48 states at 82.7 billion barrels.[23] By comparison, the simulation results in Table I indicate cumulative production of 65.9–70.5 billion barrels during the 61-year horizon examined.

Before discussing deadweight loss estimates, recall that the market model underlying this exercise assumes the demand for crude oil produced in the onshore region of the lower 48 states to be perfectly elastic, at prices given by the assumed price path. As noted earlier this view is supported by the observation that crude oil is traded worldwide and the fact that the production and total reserves of the region studied here are small fractions of worldwide totals. Changes in tax policy thus have no effect on the price of crude oil or on the refined product prices paid by consumers. The entire burden of taxation falls on resource owners in this case, and the deadweight loss due to taxation is measured by the difference between profit in the untaxed regime and the sum of tax revenue and after-tax profit in various taxed regimes.

Items labeled DWL in the second column of Table II are simulated deadweight losses for each tax. These losses are expressed in the third column as percentages

---

[23] The U.S.G.S. estimate is reported in American Petroleum Institute [1]. The 82.7 billion barrel figure represents 1987 reserves, plus indicated and inferred reserves, plus the mean estimate of undiscovered recoverable resources.

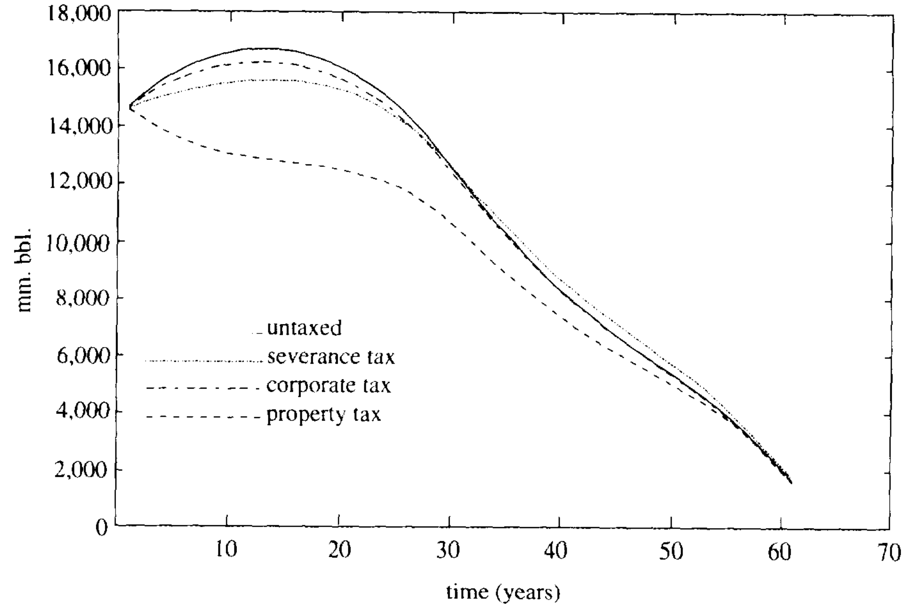

FIG. 5. Time paths for reserve.

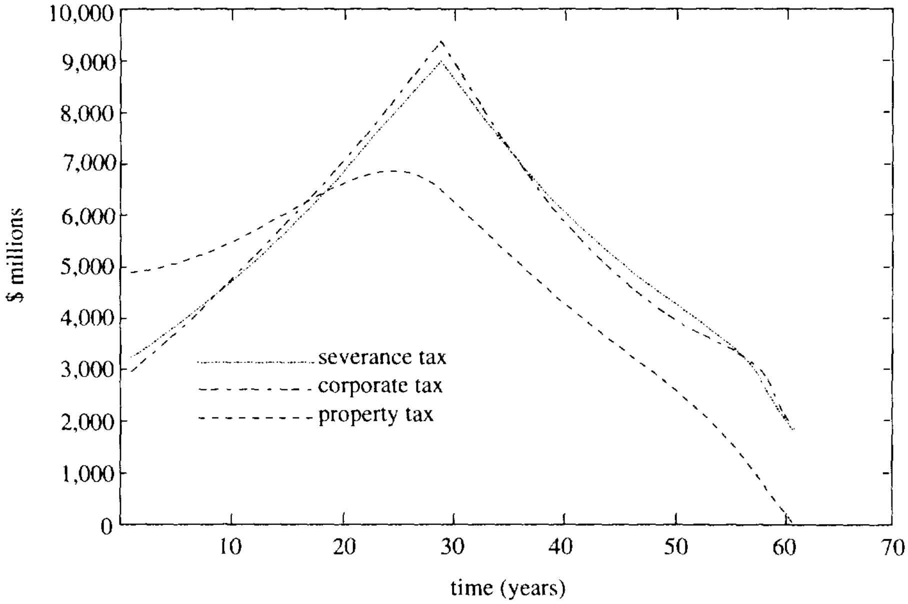

FIG. 6. Time paths for tax revenue.

TABLE I

Effect of Taxes on Total Production over Entire Program

Tax instrument	Total Production (mm. bbl.) Untaxed	Taxed	Difference	Percentage difference
Severance	70,540	65,950	4590	6.5
Corporation income	70,540	69,390	1150	1.6
Property	70,540	67,140	3400	4.8

TABLE II

Deadweight Losses for Alternative Equal Yield Taxes

Tax instrument	Tax rate	DWL ($ bill.)	Average DWL (%)	Marginal DWL (%)
Severance	0.1500	4.83	4.52	5.97
Corporation income	0.2122	0.29	0.27	0.77
Property	0.0238	10.17	9.58	20.49

Note. Deadweight loss (DWL) is computed as profit in the untaxed regime minus the sum of tax revenue and after-tax profit in each taxed regime. Average DWL is DWL/tax revenue; marginal DLW is the change in DWL associated with a marginal increase in tax revenue. The present value of profit in the untaxed regime is $463 billion and the target revenue for all taxes is $106.7 billion.

of total tax revenue. The last column shows the approximate marginal loss associated with the last dollar of tax revenue raised. The finding that the corporate tax imposes by far the smallest loss comes by now as no surprise. Note also that the income tax, which causes cumulative output to fall by 1.6%, imposes an economic loss that represents less than 0.1% of profit in the untaxed regime. Thus the resources lost to high-grading in this case are "very marginal" indeed. The estimated loss from property taxation is large in absolute terms, and is over twice as large as the loss due to severance taxation. This is just the reverse of the cumulative output effect shown in Table I. The difference in these two patterns originates in the extreme tilting that the property tax induces. In particular, the property tax pushes output toward early years when price is low.

Sensitivity Analysis

The sensitivity of these findings to individual parameters was tested by computing solutions to the model under five alternative sets of parameter values. Each new scenario altered the value of a single parameter, holding other parameters unchanged.

Table III explains the parameter changes and reports the average deadweight loss and cumulative production that results in each case. Under scenario 1 the initial reserve is reduced from 14.4 billion barrels to 5.0 billion barrels. The intent is to test the hypothesis that the income tax appears near neutral only because it taxes the return to a stock of capital that is in place at the beginning of the program. Table III shows that the income tax remains relatively distortion-free, however, with the small initial reserve. The average deadweight loss, 1.69 percent,

TABLE III

Results of Sensitivity Tests

Scenario (parameter change)		Tax regime			
		Untaxed	Severance	Corporation Income	Property
1.	Average DWL(%)	—	5.35	1.69	10.42
(R_0 = 5 bill. bbl.)	$Y_{T+1} - Y_0$	69.57	64.78	67.07	66.04
2.	Average DWL(%)	—	6.23	0.67	6.50
(r = 0.10)	$Y_{T+1} - Y_0$	67.68	61.68	65.03	63.78
3.	Average DWL(%)	—	3.62	0.12	13.36
(r = 0.03)	$Y_{T+1} - Y_0$	71.55	67.45	70.86	68.46
4.	Average DWL(%)	—	6.94	0.36	8.47
(p = \$20, fixed)	$Y_{T+1} - Y_0$	51.86	46.11	50.54	46.66
5.	Average DWL(%)	—	3.78	0.21	11.22
(maximum p = \$80)	$Y_{T+1} - Y_0$	76.32	72.60	75.49	73.30

Note. $Y_{T+1} - Y_0$ is cumulative output over the entire time horizon, in billions of barrels. Baseline simulations used the following parameter values: initial reserve, R_0 = 14.4 bill. bbl.; r = .05; p begins at \$20 per barrel, rises at 2.5% per year until it reaches \$40 per barrel, and then remains constant.

exceeds the 0.27 percent figure from the baseline scenario where the initial reserve was nearly three times as large, but it is still far smaller that the losses for severance or property taxes. The cumulative output loss caused by the income tax is increased under this scenario, but it is still the smallest of the three tax alternatives.

An alternative explanation for the near neutrality of the corporate tax is that the special provisions allowed for deducting capital outlays cause it to approximate a tax on cash flow. This hypothesis was examined by eliminating the provision for expensing a share of exploration outlays and cutting the present value of depreciation deductions per dollar of investment from \$0.72 to \$0.50.[24] The results of this test, not shown in Table III, were to raise the average deadweight loss to 1.32% from the 0.27% loss in the baseline case.

On balance, both the large initial reserve and the allowance for expensing investment outlays partially explain why the income tax is approximately neutral. The corporate tax still looks highly efficient, however, when these two advantages are drastically reduced. In that sense, neither of the preceding hypotheses provides a complete explanation for the near neutrality of this tax. Rather, it simply appears that income taxation is a relatively efficient revenue instrument when judged against severance and property taxes, even if one eliminates allowances for

---

[24] The scenario was formulated in this way to simulate the effect of a corporate tax as typically imposed on non-mining investments, i.e., one that excludes some of the special provisions that surround the treatment of income from mining. Thus, the share of expensed capital outlay was set equal to zero. The present value of depreciation deductions was set equal to 0.5 to approximate a policy of allowing straight-line depreciation for 30 years, a typical lifetime for an investment in reserve development.

expensing investments and mitigates the effect of inheriting an initial stock of capital.

Scenarios 2 and 3 in Table III examine the effect of changing the interest rate; scenarios 4 and 5 show the effect of altering the time path of price. Certain common themes emerge from these results. In each tax regime, cumulative output is relatively large when the interest rate is low and when the upper limit on price is high. This is not at all surprising. In all five scenarios, the corporate income tax imposes the smallest deadweight burden and causes the smallest loss in cumulative output of the three taxes considered. The property tax always imposes the largest deadweight loss and the severance tax always causes the largest loss in cumulative output. In general, then, the initial results reported in Tables II and III are quite robust.

Beyond providing such general corroboration, Table III indicates that the property tax imposes relatively large deadweight losses in scenarios 3 and 5. These cases are characterized by a low interest rate and a high future price path, respectively. The property tax shifts output away from the future and toward the present and this is particularly costly in these circumstances; hence, the large deadweight losses. The severance tax, on the other hand, causes relatively small losses in these scenarios. The severance tax behaves differently because it shifts output toward the future and the cost of this is low when the discount rate is low or the path of future prices is relatively high.[25]

6. COMPARISONS TO THE LITERATURE

The *ad valorem* severance tax was first studied in the context of a fixed initial reserve and an extraction cost function that is independent of the remaining reserve. A competitive industry always produces the entire reserve in this case so questions of high-grading cannot be addressed. Herfindahl [16] pointed out that an *ad valorem* severance tax unambiguously tilts output toward the future in this context. Gamponia and Meldelsohn [12] confirmed these theoretical results by simulating a model with a constant cost and a fixed reserve. Burness [5] demonstrated analytically that Herfindahl's result is a special case of a more general proposition: the severance tax tilts output toward the future if the effective tax per unit output rises slower than the rate of interest. The intuition of this result is straightforward. In an untaxed equilibrium producers are indifferent to marginal reallocations of output between present and future. Introducing a severance tax in which the present value tax per unit output declines over time favors reallocation toward the future, to reduce the present value of tax payments.[26]

---

[25] Space limitations prohibit an extensive description of sensitivity results. In general, peaks in drilling and output paths are softened when the interest rate is high and sharpened when the interest rate is low. Under scenario 2, where $r = 0.10$, the output path declines monotonically. Under the constant price scenario 4, both drilling and output paths decline monotonically. Under scenario 5, where price grows to \$80 per barrel, drilling grows and output remains roughly constant over most of the horizon. A few years before price reaches its limit, drilling falls sharply; a few years later output falls sharply. Detailed results are available from the author.

[26] Slade [25] and Lewis and Slade [18] extend this basic framework by requiring ore to be processed before final sale. A severance tax alters the ratio of output to ore in this case, a high-grading issue not treated here.

High-grading can be examined only in the context of models that permit variations in the total amount extracted. This can occur if extraction cost varies with the size of the remaining reserve or if the model allows exploration for new reserves. Heaps [14] introduced the first of these effects into a theoretical model with a fixed reserve and found that the *ad valorem* severance tax reduces total extraction, but reached no clear conclusion on tilting of the output path. Slade [24] simulated a model with essentially the same features and found tax-induced output reductions in all periods, but no consistent evidence of tilting. Conrad and Hool [7, 8] incorporated varying grades and incomplete extraction of a fixed initial reserve in a two-grade, two-period model. They confirmed the high-grading effect but their results on tilting were again ambiguous. Heaps and Helliwell [15] developed a theoretical model with investment in reserves and showed, not unexpectedly, that the severance tax reduces reserve acquisitions. Overall, in severance tax models were high-grading is possible, the literature confirms that it occurs, but reaches no clear conclusion on tilting.[27]

The present simulations generally agree with the received severance tax literature. The high grading effect exists, as it logically must in a model that permits reserve additions, and it is significant for the resource modeled here; in the baseline case a 15% severance tax caused a 6.5% reduction in simulated output. The baseline simulations found evidence for tilting as well; tax-induced output reductions are dramatic in early years and minor in later years. This is a consequence of the assumed price path, which rises slower than the rate of interest during the first 29 years and is constant thereafter. Present value prices fall over time, which causes present value severance tax payments per unit output to fall as well. Postponing output, and hence severance tax payments, is entirely sensible in this circumstance.

The severance tax results presented here are most directly comparable to those reported in Yucel [32, 33], who simulated the effects of severance taxation in a model with very similar structure. Yucel [32] found that the tax reduces output and drilling in all periods and observed some tendency for output to be pushed toward the present. The latter result contrasts with the pattern reported here. Deadweight losses were found to be 4–6% of tax revenue in most simulations, which is roughly similar to the losses reported in Tables II and III.

The tax on corporate income from mining has received less attention in the natural resource literature. The principal theoretical work on this subject is Gaudet and Lasserre [13]. They specify an extraction cost function that depends only on the rate of output, but incorporate potential high-grading effects by allowing for a variable initial reserve. The corporate tax instrument they examine differs substantially from the one studied here, however, and their central conclusions have no direct counterparts in the present analysis.[28] As administered in the United States, where provisions for expensing capital outlays are generous, the

---

[27] Cairns [6] and Krautkraemer [17] examine the effect of a severance tax on the cut-off grade in a situation where the extraction process exhibits a form of irreversibility. They find that the tax raises the cut-off grade and reduces the quantity of ore extracted from a given deposit—a form of high-grading. The irreversibility in their model has no counterpart in the present paper, however, so the two high-grading results are distinct.

[28] Much of their analysis centers on the effects of percentage depletion and investment tax credits, both of which have ceased to be factors in U.S. corporate taxation of oil. They also exclude provisions for expensing drilling investments, a prominent feature of the present analysis.

taxable income from mining approximates the industry's cash flow, so the tax causes few distortions. Smith [26] concurs in this finding. Reporting on simulations undertaken to estimate the incentive effects of various tax systems, he concludes "the shorter the write-off period of capital investments, the smaller the disincentive.... In fact, immediate write-off of capital investment destroys any disincentive effect from income taxation [26, p. 19]." While the present model indicates that the income tax reduces drilling and output and shifts production toward the future, the small magnitude of these distortions is the principal finding.

The property tax also has received little attention in the literature. Conrad and Hool [7] examined the effects of a property tax levied as a fixed dollar amount per unit of reserve, independent of the reserve's economic value. This tax tends to accelerate production. The property tax also is considered in Heaps and Helliwell [15], who concluded that it tilts production toward the present and discourages investment in new reserves. Finally, Gamponia and Mendelsohn [12] simulated the effect of a property tax on a fixed reserve and found that it tilts production toward the present and causes a larger deadweight burden than an equal yield severance tax. The present simulations are in general agreement. The property tax suppresses exploration and production of marginal resources and shifts output toward the present. The combined effect is to reduce the reserve markedly in early years of the program. When compared to other regimes, the property tax reallocates production toward the present and imposes a larger welfare loss than other tax instruments.

7. CONCLUSIONS

As is always the case, the model developed here relies on several assumptions and simplifications and the results obtained must be qualified accordingly. Two limitations seem particularly noteworthy. First, Alaska and the outer continental shelf are important components of the extensive margin of petroleum development in the United States and both regions were excluded from this exercise. The natural environments in these regions give rise to significantly different drilling and operating conditions than are found onshore in the lower 48 states. It was deemed inappropriate to aggregate drilling and production cost data from all such areas in a single set of functions for drilling and production. There is no guarantee, of course, that the results reported here would apply to the excluded regions as well.

A second limiting feature of the analysis is its purely deterministic nature, and this results from a compromise dictated by practical considerations. On the one hand, it clearly would be desirable to allow uncertainty to enter the model, either in the time path of future prices, costs, or reserve additions. The dynamic analysis of models that incorporate uncertainty quickly becomes intractable, however, unless their structure is constrained to exhibit certainty equivalence.[29] With

---

[29] This discussion of uncertainty relies heavily on Bohi and Toman [4, pp. 63–67]. In particular, see their discussion of the difficulty of obtaining stochastic exhaustible resource specifications that exhibit certainty equivalence. For modern treatments of uncertainty in exhaustible resource supply models that do satisfy certainty equivalence, see Epple [11] and Walls [31].

certainty equivalence, optimal drilling and production decisions are comparatively straightforward since they depend only on expectations of stochastic variables, and exclude higher moments. On the other hand, imposing certainty equivalence limits the form the model may take, particularly the representation of depletion effects in functions for production cost and reserve additions, and excludes the class of functions used here. It also rules out the possibility of binding non-negativity constraints, e.g., as displayed by the drilling variable in the preceding simulations. The modeling approach used here opted for a relatively free rein in choice of functional forms at the expense of suppressing uncertainty. It is entirely possible, of course, that the general magnitudes of high-grading effects and deadweight losses, and their rankings across tax instruments, could change substantially if uncertainty were introduced. The general outcome would depend on the form of the uncertainty—whether additive of multiplicative, whether attached to prices, costs, or reserve additions, etc.—and on the structure of the model that incorporates it.

Keeping these and other appropriate caveats it mind, reconsider the partial equilibrium welfare loss measures presented in Tables II and III. They indicate that taxing the income from U.S. petroleum production is nearly neutral, while severance and property taxation impose significant excess burdens. This suggests overall welfare gains from a switch toward heavier reliance on income taxation and a reduced role for severance and property taxes. Such a switch would also push the consumption and tax revenue earned from the domestic resource base into the future, a redistribution that many would find unobjectionable.

There are two reasons why one should be skeptical of any such prescription. First, at a practical level, the three taxes are the separate provinces of federal, state, and local governments. Substituting federal income taxation for property and severance taxes would require some method of revenue sharing, to avoid the opposition of lower levels of government. This institutional consideration suggests that any such switch would be accomplished most easily at the state level, e.g., by replacing a state's severance tax with a higher rate on the state's corporate income tax.[30]

Second, in a world characterized by other taxes, subsidies, and incomplete markets, it is risky to base judgements concerning tax policy on partial equilibrium reasoning. The tax shift contemplated here would attract additional investment into petroleum exploration and development. If this caused capital to be withdrawn from sectors where the before-tax return is higher, the reallocation would lower welfare.

Notwithstanding the latter complication, the structure of the petroleum market and the scale of its operation in the United States lend support to the partial equilibrium prescription for heavier reliance on income taxation. For the sake of argument, suppose severance and property taxes on petroleum were abolished and the corporate tax rate were increased to restore total government revenue. The switch in tax policy would raise domestic exploration and development, and thereby increase output. On the consumption side, the resulting increase in

---

[30] This suggestion must be tempered by the fact that many states use unitary apportionment formulae in assessing income taxes. There is no guarantee that a unitary tax would exhibit the same near neutrality as the corporate income tax modeled here.

domestic output should have no appreciable effect on petroleum price because the change would be a tiny fraction of worldwide supply. The rise in domestic output would displace some imports, but without any change in the price of petroleum or petroleum products there would be no cause for consumers to substitute among consumption goods.

On the input side, it seems safe to presume that many of the factors used in exploration and development, such as exploration crews and drilling rigs, are in highly elastic supply to the United States, at least in the long run. This conjecture is supported by the fact that markets for many of these inputs are multinational in scope, as are the operations of the firms that undertake these investments. If so, a rise in the after-tax return to United States petroleum investments would cause a reallocation of these investments away from exploration and development of foreign resources and toward the United States, with no changes in domestic input prices.

With relevant input and output prices and the after tax return to petroleum investments fixed internationally, independent of U.S. tax policy, the tax reform scenario runs as follows. More efficient taxation of domestic petroleum raises exploration and development of the domestic resource base, which adds to domestic production. Imports of exploration and development capital rise for a while, and are offset by a corresponding drop in imports of crude oil. Overall, more complete utilization of the domestic resource base is achieved, which reduces reliance on foreign petroleum resources and increases the incomes of domestic mineral rights owners.

APPENDIX

This Appendix reports definitions and computation methods for data used in models of reserve additions, drilling costs, and production costs. Detailed data sources are excluded but may be obtained from the author. This Appendix also explains the numerical method used to compute solutions.

Reserve Additions Data

The reserve addition model was estimated with time series on cumulative drilling for oil and cumulative reserve additions for the period 1946–1987. Cumulative reserve additions as of 1946 were computed as cumulative oil production through that year plus the 1946 level of reserves. Reserve additions for subsequent years were obtained from reports of the American Petroleum Institute (API).

Cumulative drilling footage was computed from series on cumulative numbers of wells drilled for oil and average depth per well. Numbers of wells drilled each year since 1859, by type (oil, gas, dry), were obtained and a share of dry holes (equal to the fraction of oil wells in completed oil plus gas wells in each year) was attributed to oil drilling. Average depths for oil wells and dry holes drilled onshore in the lower 48 states during 1947–1987 were taken from API and from historical accounts. The cumulative drilling series includes service wells because such wells often are associated with secondary recovery projects, which clearly add to reserves.

Drilling Cost Data

The estimated drilling cost function relied on annual observations for total drilling cost and footage drilled for oil from 1959 to 1987. Estimation of an appropriate cost function should use data that include a representative mix of completed wells and dry holes. Drilling footage and drilling cost for oil wells, gas wells, and dry holes, were taken from API reports. A share of dry hole footage and dry hole cost in each year was attributed to oil drilling; the shares were computed in a fashion similar to that described in the preceding paragraph.

The API series on drilling cost excludes the cost of certain pre-drilling exploration activities, geological and geophysical scouting, for example. It also excludes expenses for acquisition and installation of lease equipment beyond the "Christmas tree," items such as downhole lift equipment, flow lines, separators, and secondary recovery fixtures. These items are, however, included in exploration and development cost data reported by the U.S. Bureau of the Census. A comparison of these two data sources indicated that the series reported by API should be increased by 25.75% to account for the missing cost items. Consequently, predicted drilling cost from the estimated drilling cost equation was increased by 25.75% for incorporation in the simulation model.

Attempts to Estimate the Production Cost Function Econometrically

The calibration approach to the production cost function was chosen only after attempts were made to estimate a cost function econometrically. The discussion in this section briefly describes these attempts and discusses limitations in available cost data.

The longest series of consistently reported data on production costs is that available from the U.S. Bureau of the Census and the American Petroleum Institute. These sources both report "direct operating expenditure" for onshore operations in the lower 48 states, and when the series are linked one obtains 15 annual observations for the period 1973–1987.[31] Neither of these sources report separate extraction cost information for oil versus gas wells. In estimation, it was assumed that the oil share of total extraction cost equals the oil share of total wellhead value, an assumption that is algebraically convenient but lacking in economic justification.

Most of the period for which data are available is problematic for institutional reasons. U.S. crude oil production was price controlled between 1971 and 1981, and the regulations during the period 1973–1980 distorted incentives in a way that prevented the industry from producing oil in a cost-minimizing fashion. Radically different wellhead prices were allowed for wells discovered at different points in time, for properties operated by large versus small producers, and for reserves subject to high versus low extraction costs. (The last of these distinctions came about through regulatory provisions that allowed high sales prices for production from stripper wells.) The fact that different properties sold output at radically

---

[31] The American Petroleum Institute also reports costs for the period 1961–1972, but these data seem to include some indirect costs, e.g., overhead and taxes, in operating costs. In addition, this source fails to disaggregate cost data for operations in Alaska versus the lower 48 states or for onshore versus offshore operations.

different prices at the same time implies that the industry's costs and outputs during that period cannot be represented by a standard neoclassical cost function. These regulatory provisions prevailed, in varying degrees, from 1973 to 1980.

Despite such limitations an attempt was made to estimate a cost function from these data for the period 1973–1987. Cost was specified to depend on the current rate of extraction, the size of the reserve, and a measure of cumulative extraction. The last variable was considered for inclusion to incorporate the point explained in the text, that the industry rationally will tend to produce low cost deposits before high cost deposits. The results obtained were generally unstable, sensitive to rather minor variations in model specification or sample period. While this may be partly attributable to the data limitations described above, the central reason is the presence of a strong correlation among the right-hand-side variables in the cost function. For the sample period 1983–1987, the absolute values of simple correlations among these variables ranged from 0.942 to 0.995. It is not terribly surprising, therefore, that the search for a stable set of parameter estimates met with little success. Attempts were made to respecify the model and redefine variables in ways that would reduce this problem. Even slight respecifications, e.g., adding a factor price to the model or substituting cumulative output for cumulative reserve additions, caused the coefficients of interest to shift markedly.

In the end a simple "calibration" approach, one that is relatively transparent and requires estimation of only a single parameter, was chosen over any of the econometric estimates obtained. This obviously is less than ideal and no strong claims are made for the accuracy of the Cobb–Douglas form or the resulting cost function. A data base that would support precise econometric estimation of the cost function that applies to this industry is not presently available, however, and until (or unless) one becomes available an accurate assessment of the structure of extraction costs in the U.S. petroleum industry will remain elusive.

Calibration of Production Cost Parameters

The production function parameter, μ, was estimated as follows. Recall that the production function is written $y_t = Ak_t^{\mu}R_t^{1-\mu}$, where k_t represents labor, equipment, fuel, and other "non-reserve inputs" used in production, and R_t is the reserve. Let the price per unit k_t be σ_t, and let ρ_t stand for the opportunity cost of using R_t. If ownership of reserves and production equipment were separate, ρ_t would be a rental price for R_t. When both are jointly owned ρ_t is imputed. The firm's profit in period t is

$$p_t A k_t^{\mu} R_t^{1-\mu} - \sigma_t k_t - \rho_t R_t. \tag{A.1}$$

With ρ_t correctly valued, the present value-maximizing production strategy maximizes this profit each period, which implies

$$\sigma_t k_t / \rho_t R_t = \mu/(1-\mu). \tag{A.2}$$

The left-hand side of this expression is the ratio of cost shares for k and R.

Given this setup, the task is to extract an estimate of μ from historic data on expenditures for reserve additions and non-reserve inputs for onshore, lower 48 operations. Expenditure on non-reserve inputs, $\sigma_t k_t$, is equivalent to "lifting cost" as defined by the U.S. Energy Information Administration, which averaged about \$5.30 per barrel in the mid 1980s.

Estimating a value for $\rho_t R_t$ is more complex. ρ_t is the user cost per unit for reserves held in year t and it is expressed in the familiar user cost formula

$$\rho_t = (r + \delta)\omega_t, \tag{A.3}$$

where r is the interest rate, δ is the depreciation rate, ω_t is the asset price of R_t, and capital gains have been ignored. In the present context the depreciation rate equals the fraction of the reserve extracted in a given year, hence

$$\rho_t R_t = (r + (y_t/R_t))\omega_t R_t. \tag{A.4}$$

The asset price ω_t was set equal to the per unit exploration and the development cost of reserves held by the industry in 1987 was expressed in present value as of that year. It was assumed that the reserves in use in 1987 were discovered during 1960–1982. The exploration and development cost per unit reserve addition was computed for each year of this period from yearly data on exploration expenditure, development expenditure, and reserve additions.[32] The resulting unit costs were then converted to present value as of 1987, and the mean of these for the period 1960–1982 was used as the estimate of ω_t. This yielded the estimate ω_t = \$7.20 for reserves held in 1987.

Given ω_t, the imputed expenditure on reserves was computed from (A.4) after setting $r = 0.05$ and $y_t/R_t = 0.13$, the mean U.S. production/reserve ratio for onshore, lower 48 operations during for the mid 1980s. When combined with the asset price shown above, the non-reserve expenditure noted earlier, and (A.2), the implied cost shares for non-reserve inputs and for the reserve are 0.35 and 0.65, respectively.

Estimating θ is the final step in parameterizing the production cost function. It was set at \$189.1, a level that caused the model's predicted production cost for the mid 1980s to equal the reported lifting cost in 1987.

Expensed Share of Drilling Cost

Simulation of the effect of the corporation income tax requires an estimate of e, the expensed share of drilling cost. This was computed from data reported in U.S. Bureau of the Census, which reports details on exploration and development costs, and from information on tax codes and definitions of tangible and intangible costs. All dry hole costs were deemed expensible and all land acquisition costs were deemed depletable. The remaining cost was assumed to be 75% intangible and 25% tangible. Seventy percent of intangible costs were counted as expensible items; remaining intangibles plus all tangibles were counted as depletable. When applied to cost data for the period 1978–1982, this categorization yielded an expensible cost share of 45%.

---

[32] Costs associated with land acquisition were excluded from exploration and development costs on the theory that such items are really rents rather than opportunity costs; see Uhler [30, p. 270]. Certain reported expenditures that represent transfers within the industry also were excluded.

Numerical Methods

Given the known values of initial stocks, W_0, Y_0, and guessed initial values for the costate variables, ϕ_0^g, λ_0^g, one can solve the first-order conditions recursively to obtain a unique feasible time path for the control and state variables. (The resulting time path is four $T + 1$ element vectors, w_t, y_t, W_t, Y_t, for $t = 0, \dots, T$). Let $\chi = \chi(\phi_0^g, \lambda_0^g)$ denote the time path that results from a given pair of initial values for the costate variables.

A solution to the present value maximization problem is found by completing the following steps: (i) compute a feasible path, $\chi(\phi_0^g, \lambda_0^g)$, for an initial guess, ϕ_0^g, λ_0^g; (ii) compute the present value of net cash flow along this path, denoted $V(\chi(\phi_0^g, \lambda_0^g))$; (iii) use a Newton–Raphson procedure to maximize $V(\chi(\phi_0^g, \lambda_0^g))$ with respect to ϕ_0^g, λ_0^g. This process was continued until the proportional change in the present value for successive iterations was less than 0.0000001.

The resulting feasible path, χ^*, satisfies the first-order conditions (6a)–(6d) by construction. The fact that χ^* maximizes $V(\chi(\phi_0^g, \lambda_0^g))$ ensures that it satisfies the transversality conditions (6e) and (6f) as well. Since the objective function is concave and the constraint set is convex, the result is a global maximum.

All computations were carried out with PC Matlab.

REFERENCES

1. American Petroleum Institute, "Basic Petroleum Data Book," Vol. 9, No. 2, American Petroleum Institute, Washington (1989).
2. A. J. Auerbach, Taxation, corporate financial policy, and the cost of capital, *J. Econom. Literature* **XXI**, 905–940 (1983).
3. R. W. Boadway and D. E. Wildasin, "Public Sector Economics," 2nd ed. Little, Brown, Boston (1984).
4. D. R. Bohi and M. A. Toman, "Analyzing Nonrenewable Resource Supply," Resources for the Future, Washington (1984).
5. H. S. Burness, On the taxation of nonreplenishable natural resources, *J. Environ. Econom. Management* **3**, 289–311 (1976).
6. R. D. Cairns, A model of exhaustible resource exploitation with ricardian rent, *J. Environ. Econom. Management* **13**, 313–324 (1986).
7. R. F. Conrad and R. B. Hool, Resource taxation with heterogeneous quality and endogenous reserves, *J. Public Econom.* **16**, 17–33 (1981).
8. R. F. Conrad and R. B. Hool, Intertemporal extraction of mineral resources under variable rate taxes, *Land Econom.* **60**(4), 319–327 (1984).
9. R. T. Deacon, S. J. DeCanio, H. E. Frech III, and M. B. Johnson, "Taxing energy: An economic analysis of the crude oil severance tax," Holmes and Meyer, New York (1990).
10. S. Devarajan and A. C. Fisher, Exploration and scarcity, *J. Polit. Econom.* **90**(6), 1279–1290 (1982).
11. D. Epple, The econometrics of exhaustible resource supply: a theory and an application, *in* "Energy, Foresight, and Strategy" (T. J. Sargent, Ed.), Resources for the Future, Washington (1985).
12. V. Gamponia and R. Mendelsohn, The taxation of exhaustible resources, *Quart. J. Econom.* 165–181 (February 1985).
13. G. Gaudet and P. Lasserre, Capital income taxation, depletion allowances, and nonrenewable resource extraction, *J. Public Econom.* **29**, 241–253 (1986).
14. T. Heaps, The taxation of nonreplenishable natural resources revisited, *J. Environ. Econom. Management* **12**, 14–27 (1985).
15. T. Heaps and J. R. Helliwell, The taxation of natural resources, *in* "Handbook of Public Economics," (A. J. Auerbach and M. Feldstein, Eds.), Vol. 1, pp. 421–472, Elsevier Science, Amsterdam (1985).

16. O. C. Herfindahl, Depletion and economic theory, *in* "Extractive Resources and Taxation," (M. Gaffney, Ed.), University of Wisconsin Press, Madison (1967).
17. J. A. Krautkraemer, Taxation, ore quality selection, and the depletion of a heterogeneous deposit of a nonrenewable resource, *J. Environ. Econom. Management* **18**, 120–135 (1990).
18. T. R. Lewis and M. Slade, The effects of price controls, taxes, and subsidies on exhaustible resource production, *in* "Progress in Natural Resource Economics," (Anthony Scott, Ed.), pp. 203–227, Clarendon Press, Oxford (1985).
19. J. R. Livernois, Empirical evidence on the characteristics of extractive technologies: the case of oil, *J. Environ. Econom. Management* **14**, 72–86 (1987).
20. J. R. Livernois, Estimates of marginal discovery costs for oil and gas, *Canad. J. Econom.* **XXI**(2), 379–393 (1988).
21. J. R. Livernois, and R. S. Uhler, Extraction costs and the economics of nonrenewable resources, *J. Polit. Econom.* **95**(1), 195–203 (1987).
22. R. Nehring, "The discovery of significant oil and gas fields in the United States," The Rand Corporation, Santa Monica (1981).
23. R. S. Pindyck, The optimal exploration and production of nonrenewable resources, *J. Polit. Econom.* **86**, 841–861 (1978).
24. M. E. Slade, Tax policy and the supply of exhaustible resources: theory and evidence, *Land Econom.* **60**(2), 133–147 (1984).
25. M. E. Slade, Taxation of non-renewable resources at various stages of production, *Canad. J. Econom.* **XIX**(2) 281–297 (1986).
26. R. T. Smith, A comparative study of state taxation of oil and gas: the lessons for Montana, paper presented at the conference "Taxation and the Montana Economy," Helena, Montana, September 5–6, 1986.
27. R. M. Solow and F. Y. Wan, Extraction costs in the theory of exhaustible resources, *Bell. J. Econom* **7**, 359–370 (1976).
28. J. L. Sweeney, Economics of depletable resources: market forces and intertemporal bias, *Rev. Econom. Studies* **44**, 125–142 (1975).
29. J. E. Swierzbinski and R. Mendelsohn, Exploration and exhaustible resources: The microfoundations of aggregate models, *Internat. Econom. Rev.* **30**(1) 175–186 (1989).
30. R. S. Uhler, The supply of natural gas reserves in Alberta, *in* "Progress in Natural Resource Economics" (Anthony Scott, Ed.), Clarendon Press, Oxford (1985).
31. M. A. Walls, "Forecasting Oil Market Behavior: Rational Expectations Analysis of Price Shocks," Discussion Paper EM 87-03, Resources for the Future, Washington (1989).
32. M. K. Yucel, Dynamic Analysis of Severance Taxation in a Competitive Exhaustible Resource Industry, *Resour. Energy* **8**, 201–218 (1986).
33. M. K. Yucel, Severance taxes and market structure in an exhaustible resource industry, *J. Environ. Econom. Management* **16**, 134–148 (1989).