

still – but it is still clear that in the absence of such an alternative policy, a higher gas tax would clearly boost economic efficiency.

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NINE

State Tax Policy and Oil Production

The Role of the Severance Tax and Credits for Drilling Expenses

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9.1 Introduction

Although most energy-producing states have levied taxes on the value of oil, natural gas, and coal production for many years, changes in these taxes have become headline news as state governments grapple with budget shortfalls brought about by the current recession. For instance, Alaska has increased the severance tax on the value of its oil production and attempted to stimulate future production by allowing a credit against this tax for expenditures on capital items, including drilling rigs, infrastructure, exploration, and facility expansion (Alaska Department of Revenue 2008). In late 2008, California Governor Arnold Schwarzenegger proposed levying a 9.9 percent production tax on the value of most onshore oil production to help close a projected \$24 billion budget deficit, but he subsequently reversed his position (Casselman 2009; Skelton 2009). The Pennsylvania legislature is considering a proposal to levy a 5 percent tax on the value of natural gas produced from the giant Marcellus shale deposit, but the bill is opposed by industry leaders who contend that it would result in 30 percent less drilling as well as revenue reductions to state and local governments totaling \$880 million over the next decade (George 2009).

These measures, both enacted and proposed, raise a number of long-standing and important questions about the effects of state energy taxes that go well beyond their potential to provide a solid revenue base to support public services. Given the overlapping tax bases claimed by states and the federal government, to what extent do state energy tax increases result in lower collections of federal tax revenues, including the federal corporate income tax? Do state energy taxes restrict production and encourage “high-grading” of energy reserves and by how much? Do state taxes tilt the time path of energy production to the present or to the future? How do upstream

subsidies for exploration and development work together with downstream taxes on production to influence the levels and time paths of production and tax collections? What are the implications of these taxes for the long-run sustainable use of nonrenewable natural resources? The analysis in this chapter bears directly on these questions. It also serves as a basis to examine proposed changes in federal tax policy, including the elimination of the percentage depletion allowance and the expensing of intangible drilling costs.

We adapt the Hotelling model developed by Pindyck (1978) to examine how a state's taxes and subsidies at different stages of resource exploration and production alter the behavior of oil producers and thus impact on exploration activity, additions to the reserve base, and the production of energy. In our model, returns to exploration are subject to diminishing returns, and the cost of production is affected both by the level of reserves and the level of output. Producers located in a given state are assumed to produce only a small fraction of world output and therefore face an exogenously determined price of oil. We calibrate the model using data from U.S. oil fields to evaluate the effects of alternative tax and subsidy policies on drilling and production, on tax revenue accruing to states and to the federal government, as well as on the time path of drilling expenditures and resource production.

A key result from the calibrated model is that oil production is closely linked to the size of the reserve base and is relatively insensitive to changes in oil prices. This outcome, which is broadly consistent with experience in the U.S. oil industry over the past 50 years, leads to the conclusion that the severance tax has little effect on production levels and serves mainly to redirect rents earned in the oil industry to the public sector. Thus, increases in severance taxes or a reduction in the subsidies provided to the oil and gas industry may lead to rent taxation and therefore have only marginal effects on the drilling and production of oil and few adverse impacts in terms of national security and increasing U.S. dependence on foreign oil.

Prior simulation studies (Deacon 1993; Kuncie et al. 2003) also have considered aspects of these issues, but a novel feature here focuses on effects of combining subsidies for exploration and development with taxes on the value of energy production. The rationale for subsidizing exploration and development is to expand the reserve base and ultimately to stimulate oil production in much the same way as an investment tax credit (see Chirinko 2000) might increase capital formation and boost output in manufacturing. As previously indicated, this type of tax policy has been adopted by Alaska, and it has been suggested as a model for other states (Headwaters Economics

2009). It may also bear on national energy tax policy in light of the interest in stimulating drilling for new reserves.¹ The simulations suggest that a drilling expense credit may cost more than the incremental severance tax revenue obtained, although such credits may be worthwhile concessions if a state's objective is to generate greater support for increasing the severance tax rate.

The remainder of the chapter is organized into six sections. Section 9.2 reviews the issue of oil taxation in twelve major oil-producing states in the United States. Section 9.3 summarizes findings from the literature regarding temporal economic effects of state energy tax policies. Section 9.4 describes the extended Pindyck (1978) model that is used as a conceptual basis for our tax policy simulations. Section 9.5 discusses the way in which the model was parameterized. Section 9.6 presents simulation results, and Section 9.7 concludes.

9.2 Overview of State Taxation of the U.S. Oil Industry

Key taxes on nonrenewable resource development levied by state and local governments can be divided into three main groups: taxes on production, property, and income. In its simplest form, the production or severance tax is levied on the gross value (or volume) of production of the resource as it is "severed" from the ground. The severance tax is the most widely adopted state tax specifically applying to the U.S. oil industry and will receive the most attention in the discussion. State and local governments also levy property taxes on the assessed (quasi market) value of equipment *above* ground and/or reserves *beneath* the ground. Income taxes are levied against the accounting net income of extraction firms. Although these taxes are generally aimed at extracting economic rents earned by producers from the sale of nonrenewable resources, their effects on production, exploration, and development can differ substantially (see Section 9.3). The discussion in this section briefly summarizes how these taxes are applied in major oil producing U.S. states and how they interact with each other and with other taxes on energy producers levied at the federal level. A more detailed

¹ At the Republican National Convention in 2008, Michael Steele, former Lieutenant Governor of Maryland and currently Chairman of the Republican National Committee, underscored his view that more exploration for energy resources is needed with his now famous line, "Drill, Baby, Drill." This sentiment was echoed by Republican Vice-Presidential nominee, Sarah Palin, who as Governor of Alaska, signed legislation granting a partial credit for drilling expenses against severance tax liabilities paid at an increased tax rate. For further details, see Ball (2008).

state-by-state survey of taxation and regulation of oil and gas production is available from the Interstate Oil and Gas Compact Commission (2007) and a more up-to-date survey can be constructed from a Lexis-Nexis search of state statutes. Hellerstein (1983) provides a useful discussion of the legal basis for state taxation of natural resources.

Table 9.1 presents data on oil production, nominal (legislated) oil severance tax rates, effective severance tax rates, and nominal corporate income tax rates for the twelve U.S. states that produced the most oil in 2007.²

As shown, production in these states ranged from a high of 397 million barrels in Texas to a low of 20 million barrels in Utah. Nominal severance tax rates varied widely across states as well. All states except California levied a severance tax against the value of production.³ As mentioned earlier, California is considering whether to adopt such a tax. In Alaska and Montana, nominal tax rates can exceed 10 percent. Other tax code features reflect important interstate differences.⁴ Severance taxes are generally levied against the "net value" of production, where each state has its own definition of this concept. Some states, such as Wyoming, tax the value of production at the wellhead (the top of the well), whereas others, like Utah, tax the value of production at the wellfoot (the bottom of the well), which in effect allows a deduction for lifting costs. Most states subtract royalty payments (computed as a percentage of gross value of production) for production on public land in computing net production value for determining severance tax liabilities (Louisiana does not). Public land royalties are relatively more important in Alaska, Colorado, New Mexico, Utah, and Wyoming than in other states owing to their large shares of publicly owned land. State energy tax codes are subject to frequent changes as well. For instance, Alaska now allows producers to take a credit against severance tax liabilities for capital expenditures used in exploration and development, whereas this feature was not available in 2007 and thus is not reflected in Table 9.1.

In New Mexico and North Dakota, the severance tax is actually the sum of two or more different levies on net production value. In Colorado, severance taxes are paid at graduated rates that depend on the gross income of operators, and in Alaska, Oklahoma, and Utah prevailing rates depend on the price of oil. In Colorado, Kansas, and Wyoming, local governments levy a substantial tax against the value of energy production. Although this tax is generally called a property tax by tax administrators, it is in

² The year 2007 is the most recent year for which effective tax rate data could be assembled (see discussion below).

³ California does levy a property tax on reserves in the ground (see below).

⁴ See footnotes to Table 9.1.

Table 9.1. Oil production (in Mbbl) and tax rates for selected U.S. states, 2007

State	Production	Severance tax		Corporate income tax rate ^a
		Nominal rate	Effective rate	
Alaska	263,595	12.25–15% ^a	12%	1.0–9.4%
California	216,778	None	None	8.84%
Colorado	23,237	2–5% ^b	0.7%	4.63%
Kansas	36,490	4.33% ^c	3.0% ⁱ	4.0–7.35%
Louisiana	76,651	3.125–12.50% ^d	9.4%	4.0–8.0%
Montana	34,829	15.1% ^e	8.6%	6.75%
New Mexico	58,831	7.1% ^f	7.5% ^m	4.8–7.6%
North Dakota	45,058	5.0–11.5% ^g	— ⁿ	2.6–7.05%
Oklahoma	60,952	7.0% ^h	6.9%	6.0%
Texas	396,894	4.6% ⁱ	3.1%	1.0% ^p
Utah	19,520	3.0–5.0% ^j	2.4%	5.0%
Wyoming	54,130	4.0–6.0% ^k	5.3%	None

^a Lower rate applies to fields in production less than 5 years; higher rate applies to fields in production more than 5 years.

^b Rate depends on gross income of operator and excludes county ad valorem taxes at 4–10%.

^c Excludes county ad valorem taxes of approximately 4%.

^d Tax rate of 3.125% applies only to stripper well production.

^e Rate applies to nonworking interest owners; working interest owners pay lower rates that vary by type of well.

^f Rate is the sum of oil severance tax, oil school tax, and oil conservation tax; local ad valorem taxes at approximately 1.2% are excluded.

^g Depends on the level of an oil extraction tax that varies by type of well; tax rate on stripper well production is 0%.

^h Excludes ad valorem taxes that vary by county.

ⁱ Excludes county ad valorem levies and (small) state regulatory and conservation levies.

^j Lower rate applies to first \$13/bbl; higher rate applies above \$13/bbl. Excludes county ad valorem levies; stripper well production is not subject to severance tax.

^k Stripper well production taxed at 4%; other production taxed at 6%; excludes county levies at 5.9–7.7%.

^l Effective rate is for oil and natural gas combined.

^m Effective rate is for oil and gas combined.

ⁿ Insufficient information available.

^o Tax rates depend on level of income before taxes for most states.

^p This is the rate for a gross receipts tax that replaced the corporate income tax in 2007 (see Tax Foundation 2009a).

Sources: Production data from U.S. Department of Energy (2009b). Nominal severance tax rate data from Interstate Oil and Gas Compact Commission (2007). Effective severance tax rate data are authors' calculations (see text). State corporate income tax rate data from Tax Foundation (2009a).

effect a severance tax levied by local governments. Many states have granted innumerable exemptions and credits against state severance tax liabilities for special situations that may be encountered by operators. Production from stripper wells (wells that produce fewer than ten barrels per day), for example, is taxed at lower rates in some states than is production from better producing wells. Production from wells employing secondary or tertiary recovery methods is sometimes taxed at lower rates as well.

A further complicating feature in analyzing economic effects of state severance taxes is that states and the federal government levy other types of taxes on oil producers and tax bases interact, particularly at the state and federal levels. Except for Wyoming, all of the twelve states levy a corporate income or franchise tax that applies to oil producers. Nominal rates for this tax, taken from the Tax Foundation (2009a), are shown for each state in Table 9.1. State corporate income taxes often are levied on a similar base to that used in computing federal corporate income tax liabilities, but the state tax rates generally are lower than the top federal rates for this tax, which currently are in the 35 to 40 percent range (Tax Foundation 2009b). State corporate income tax payments are deductible against federal corporate income tax liabilities, and state and local production tax payments are deductible against both. In some states, federal corporate income tax payments are deductible in computing state corporation income taxes and in others it is not. Although local governments in most of the states utilize some form of a property tax on oil and gas extraction equipment, property taxes on reserves are levied only in relatively few states such as California and Texas.

State and local tax burdens on oil producers are endlessly compared in state tax commission and legislative hearings as industry representatives make their case for more favorable tax treatment. Yet, because of variations across states in the application of severance and other taxes, a comparison of nominal tax rates is not particularly useful. A judgment based on a comparison of nominal rates that one state's severance tax, for example, is higher than that in another state might easily be reversed once the potentially numerous exemptions, credits, incentives, deductibility, and other special features of tax law are accounted for. Instead, more meaningful comparisons across states can be obtained by computing effective tax rates expressed as the ratio of revenue collected from a particular tax to the value of production. The calculation of effective tax rates fully accounts for, without enumerating, state-specific aspects of tax treatment faced by producers and facilitates comparisons between states because the value of production is used as a common denominator.

Table 9.1 presents effective severance tax rates prevailing in 2007 for the twelve most important oil-producing states. Unfortunately, information regarding severance tax collections is neither available from a single source nor published in a common format. In consequence, data on severance tax collections needed for the numerators of the effective tax rates were obtained by searching state department of revenue reports available on the Internet and by directly contacting knowledgeable people in these agencies as questions arose. Estimates of the value of production in each state were obtained by multiplying production volumes by the average prevailing price per barrel of crude oil. State production volumes were obtained from the Energy Information Administration, U.S. Department of Energy (2009b). Average wellhead prices of oil in each state were taken from the American Petroleum Institute (2009). The price and production volume data exclude oil produced in the Outer Continental Shelf (OCS) that is not subject to state taxation. As shown in Table 9.1, among states that levy a severance tax, effective tax rates in 2007 vary from 0.7 percent in Colorado to 12 percent in Alaska. Because of the many special tax code features just discussed, these rates tend to be lower than corresponding nominal tax rates.

9.3 Prior Literature

A sizable literature deals with the economic effects of the three types of taxes discussed in the previous section. It may be useful to briefly describe this work before proceeding with the theoretical structure we assume in this chapter. Discussion is limited to intertemporal issues; thus, topics such as interstate tax shifting or "tax exporting" are ignored (Gerking and Mutti 1981; McLure 1969; Metcalf 1993). The severance tax is given the most detailed treatment because it has been widely adopted and because its effects are the focus of the simulations presented in Section 9.6.

9.3.1 Production Taxation

Hotelling's (1931) seminal analytic work considers a per unit severance tax in a model with an endogenous price (net of constant extraction costs) and the total exhaustion of fixed reserves. The severance tax is found to conserve the resource by extending the time it takes to exhaust the total pool. Herfindahl (1967) extends this result with a model that features an extraction cost function that depends on output. Under competition, the severance tax is shown to tilt production to the future (i.e., delay production), thereby

extending the life of the pool. The pool is fully exhausted at a postponed terminal period.

Burness (1976) reformulates the dynamic framework by including severance tax rates that vary over time. In this model, price is exogenous, reserves are fully depleted, and extraction cost depends only on output. The general proposition derived is that the severance tax will tilt production to the future if the tax rate is held constant or rises at a rate less than the discount rate. A severance tax that rises with the discount rate will not distort the time path of production. Conrad and Hool (1984) show that introducing varying grades of the resource into the model make no difference to this result.

Levhari and Leviatan (1977) allow for an extraction cost function that depends on both current and cumulative production so that as more of the resource is extracted over time, the more it costs to produce an incremental unit. Thus, in this model, the resource may not be fully exhausted. The effect of per unit severance taxation on time to exhaustion now is ambiguous. If the resource price is constant over time, terminal time is shortened and high-grading (removing ore of the highest grade while leaving lower grade ore in the ground) may occur. Nonetheless, if tax rates vary over time, then, as Heaps (1985) demonstrates, total recovery of the resource and the economic life of the resource can either increase or decrease but in opposite directions. Because these two effects of the tax work against each other, the net impact on depletion cannot be determined.

If resource quality varies across pools but is the same within a pool, Conrad (1978, 1981) shows that mine lives are shortened and lower-quality resource is left in the ground when a per unit severance tax is levied. Krautkraemer (1990) examines the effect of production taxation in a finite reserve model when resource quality varies within a given deposit. In addition to firms choosing the rate of extraction, they also choose the marginal grade cutoff at each point in time. A production tax induces high-grading at each instant of time and not just at the end of the production program. Interestingly, a production tax reduces total resource recovery and a low-grade resource left in the ground will not be extracted, even if at some point in the future the production tax is eliminated.

Uhler (1979) includes a brief examination, for the first time, of the effects of production taxation in a model of nonrenewable natural resource extraction with both production and exploration. The possibility of exploration means that the reserve base is no longer fixed. Also, when the model allows for exploration and reserve additions, the dynamics of the process become complex and equilibrium conditions no longer have closed form solutions.

Effects of production taxation, therefore, were examined with simulations. The model was parameterized for a small oil- and gas-producing region in Alberta, Canada. When a severance tax is imposed at a constant rate, operators decrease production and exploration in all periods while the endogenous price of the resource rises.

Deacon (1993) also simulates effects of severance taxation using the model developed by Pindyck (1978) and later applied by Yücel (1986, 1989). In Deacon's formulation, the oil industry is taken to be competitive, so the time path of the resource price is treated as exogenous. In the simulations, the resource price is assumed to rise in the early years of the production program, but at a rate less than the assumed 5 percent discount rate. Similar to the analytic results derived by Burness (1976) and others in models that abstracted from exploration, the application of an *ad valorem* severance tax tilts production to the future in comparison to a no-tax base case. Over the life of the program, however, the tax reduces output, implying that an important effect of the production tax is to induce high-grading. In addition, simulations show that a production tax reduces drilling in all periods and that drilling shuts down prematurely in comparison to the no-tax case.

Kunce et al. (2003) also simulate effects of production taxation using the Pindyck (1978) framework, but they parameterize the model for a single state (Wyoming) rather than the nation as a whole, as was the case in the Deacon (1993) study. They consider the effect of doubling the state's production tax on oil extraction in a setting where oil producers are assumed to be price takers. A key feature of this study was to embed the production tax in a broader tax system that allowed for interactive tax bases and tax shifting between the local, state, and federal governments. Simulations demonstrate that a hypothetical doubling of Wyoming's production tax leads to reduced drilling and reduced oil production in each subsequent period. Estimated production declines, however, are comparatively modest; the response of production with respect to the tax change turns out to be highly inelastic (-0.06). Thus, the main effects of the tax increase would be to rather dramatically increase Wyoming's severance tax revenue and to reduce federal corporate income taxes paid by producers.

9.3.2 Property Taxation

Taxation of property, specifically reserves, has received little attention in the literature on production from nonrenewable resources. One reason for this may be the practical complexity of levying such taxes. Nonetheless, Hotelling (1931) demonstrates that a constant percentage tax on the value of reserves

will induce firms to extract more rapidly as they attempt to "mine out from under the tax." Conrad and Hool (1981) show that a constant tax rate per unit of reserves encourages extraction of higher-grade resource in the early periods of the program, but the cutoff grades are lower, thus extending the life of the mine. The property tax is also examined by Heaps and Helliwell (1985) in a model that allows for new reserve investment. The tax is shown to tilt production to the present and to reduce investment in new deposits to avoid holding costs. Simulations by Gamponia and Mendelsohn (1985) show that a property tax on reserves results in tilting production to the present. Deacon (1993) obtains the same outcome in his simulation study and also confirms the Heaps and Helliwell (1985) result by showing that the property tax on reserves results in lower levels of drilling in the early years of the program.

9.3.3 Income Taxation

Burness (1976) analyzes a profits tax on a nonrenewable resource producer with fixed reserves and concludes that output trajectories will not change when the tax is applied at a constant rate. If the tax rate increases over time, however, firms will speed up depletion of the fixed reserve. Conrad and Hool (1984) model a progressive profits tax, finding that such a tax will not exhibit the neutrality of a flat rate profits tax with regard to the extraction path and grade selection. Deacon (1993) simulates a structure broadly similar to federal corporate income taxation with expensing of current and capitalized drilling costs. Simulated paths of extraction, drilling effort and reserves show little distortion from the no-tax base case. These results suggest that income taxation is the least distortionary among the three types of energy taxes imposed by U.S. states.

9.4 Conceptual Framework

We propose a simple dynamic model in the tradition of Hotelling (1931) and Pindyck (1978) with some modifications. The idea is to examine the producers' response when states or a social planner imposes a menu of taxes and subsidies on oil production. We consider three tax/subsidy instruments – a severance tax, a corporate income tax, and a subsidy on drilling expenditures. Producers choose the optimal amount of drilling (and therefore reserve additions) and production of oil to maximize profits.

The model is dynamic, with a known discount rate and no uncertainty. Resource producers face an output price of the commodity that is

exogenously determined. Ideally, output prices should be endogenously determined through the process of dynamic optimization, as in Pindyck (1978). However, because our goal is to examine the effect of various tax regimes under assumptions of alternative petroleum prices and a single U.S. state produces only a small fraction of world output, the exogenous price assumption may be a reasonable approximation. In any case, a partial equilibrium model with endogenous prices may leave too many factors that critically affect oil prices out of the model (e.g., international financial markets, world economic growth).

Let the output price of petroleum be given by $p(t)$ where the argument t denotes time. Then the social planner imposes a set of taxes $(1 - \alpha_p)$ such that the net price received by the producer is the fraction α_p times the price.⁵ Thus, the production revenue accruing to producers of energy is given by $\alpha_p p q$ where q is the quantity of oil sold by the producer. We assume that whatever is extracted is sold – there is no storage.

Because we distinguish between production and exploration, we define reserves R at any given time t and the cumulative addition to the stock of petroleum given by x . The relationship between stocks and reserves is given by the differential equation

$$\dot{R}(t) = f(w, x) - q \quad (9.1)$$

That is, the change in reserves is equal to the addition in reserves net of production, as in Pindyck (1978). The function f represents the addition to reserves as a function of drilling effort w and cumulative additions to the stock x and we assume that $f_1 > 0$; $f_{11} > 0$; $f_2 < 0$; $f_{22} > 0$ and $f_{12} < 0$. More drilling effort (w) leads to higher reserve additions, but at a decreasing rate. Higher cumulative discoveries x cause current reserve additions to decline (at a decreasing rate). It is more difficult to add to the reserve base, the higher the discoveries made in the past. Finally, the marginal effect of reserve additions as a function of drilling decline with increases in cumulative stock. For convenience we assume that the stock of resource grows linearly with drilling effort. However, the cost of drilling increases in a convex fashion with drilling effort, given by $k(w)$ where $k'(w) > 0$; $k''(w) \geq 0$ and $k(0) = 0$. Finally, the total cost of extraction is given by $c(q, R)$ with $c_1 > 0$, $c_2 < 0$, $c_2 < 0$, $c_{22} > 0$ and $c_{12} < 0$.⁶ That is, the total "lifting" cost increases with quantity produced – for instance,

⁵ The tax parameter α_p and two other tax parameters to be defined momentarily are empirically specified in the next section.

⁶ In Pindyck's (1978) original formulation, both average and marginal lifting costs depended on R but not on q .

as oil is extracted from greater depths – and it also decreases concavely with current reserves. This specification follows from the view that oil is produced using reserves (a form of capital) and nonreserve inputs (i.e., physical capital other than reserves and labor), so that extraction costs are positively related to output and negatively related to reserves. The cross-partial derivative c_{12} is assumed to be negative.

We introduce two other tax/subsidy parameters in this framework, namely, the portion $(1 - \alpha_c)$ of the production cost that is deductible in computing tax liabilities, so that the net production cost faced by firms is $\alpha_c c(q, R)$ and the part $(1 - \alpha_D)$ that is deductible by the firm, which implies that the net drilling cost payable by the firm is given by $\alpha_D k(w)$. The major goals in this chapter are to examine how the three different tax/subsidy policy instruments, given by α_p , α_c and α_D , affect drilling activity, reserve additions, and production, as well as to compare their corresponding revenue and welfare implications.

Finally, given a fixed discount rate $r > 0$ the social planner solves the following problem:

$$\text{Max}_{q, w, x, R} \int_0^{\infty} [\alpha_p p q - \alpha_c c(q, R) - \alpha_D k(w)] e^{-rt} dt \quad (9.2)$$

which is subject to the following equations:

$$\dot{x} = w \quad (9.3)$$

and

$$\dot{R} = f(w, x) - q \quad (9.4)$$

The current value Hamiltonian for this problem is

$$H = \alpha_p p q - \alpha_c c(q, R) - \alpha_D k(w) + \lambda w + \theta [f(w, x) - q] \quad (9.5)$$

so that the first-order conditions are given by

$$\alpha_p p \leq \alpha_c c_q + \theta (= \text{iff } q > 0) \quad (9.6)$$

$$\theta f_w \leq \alpha_D k_w - \lambda (= \text{iff } w > 0) \quad (9.7)$$

$$\dot{\lambda} = r\lambda - \theta f_x \quad (9.8)$$

$$\dot{\theta} = r\theta + \alpha_c c_R \quad (9.9)$$

along with transversality conditions not shown here. The co-state variable λ represents the shadow price of an additional unit of discovered oil. Note that the higher the cumulative discoveries, the lower the additions to reserves. Hence, the shadow price λ will be negative. The shadow price θ represents the discounted increment to profits resulting from the addition of one unit of reserves. Reserves decrease the cost of production and therefore θ should be positive.

An important implication of the model (see equation (9.6)) is that the firm will decide to produce ($q > 0$) if the discounted after-tax wellhead oil price net of marginal extraction costs exceeds the present value of future profits from an additional unit of reserves (θ).⁷ Condition (9.7) equates the marginal benefits and costs of an additional well drilled. The benefits are in the form of an increase in reserve additions, which are given by the expression θf_w . The costs are twofold: the marginal cost of drilling net of drilling subsidies denoted by the term $\alpha_D k_w$ plus the negative effect on reserve additions from an addition to the cumulative resource stock given by λ .

Equations (9.8) and (9.9) give the time path of the derivatives for the two shadow prices λ and θ . The rate of increase in the shadow price λ has two components – the discount rate r and the fact that taking out a unit of resource increases the “cost” in the future through lower marginal reserve additions. Because f_x is assumed to be negative, the first term $r\lambda$ is negative and the second term $-\theta f_x$ is positive. At least initially the latter term is likely to be large because of the high value of reserve additions, in which case $\dot{\lambda}(t)$ is likely to be positive and the value of λ , which is negative, will decline over time. In this model, then, additions to stock adversely impact reserve formation; hence, the interpretation is completely different than in the standard Hotelling model with no exploration activity. The extra cost of drilling is that it decreases the future benefit of drilling. The time path of the marginal value of a unit of reserve θ also increases at the rate of discount but is tempered by its effect on lifting costs – additions to reserves have the added benefit of helping reduce the cost of production, net of production subsidies. This is given by the negative term $\alpha_c c_R$.

In this chapter we do not focus on the analytics of this model, which is similar to the model developed by Pindyck with some key differences. The

⁷ Notice that condition (9.7) differs from the corresponding condition derived by Pindyck (1978) in that marginal lifting costs increase with increases in q . Consequently, rather than producing at some maximum rate subject to constraints given by reserve levels, geology, and technology, the firm pays attention to how its lifting costs are affected by the level of output.

main difference is that his production costs are independent of reserves, whereas in our case, production costs decline with cumulative reserves. Moreover, here the focus is on the three tax/subsidy instruments, and we show how they play different roles in influencing production and drilling behavior by firms.

9.5 Calibration of the Simulation Model

Simulations from the model developed in the previous section are constructed based on estimates of the drilling cost, lifting cost, and reserve additions equations, specifying values for the tax/subsidy and other parameters.

9.5.1 Equation Estimates

Estimation of $k(w)$ and $f(w, x)$ are treated together because they are used to compute the marginal cost of reserve additions (k_w/f_w), a key relationship in the model described above. Drilling cost per foot is assumed to be linearly related to footage drilled, as shown in equation (9.10):

$$k(w)/w = \phi w + u \quad (9.10)$$

where ϕ is the parameter to be estimated and the disturbance term u is normally distributed. This specification ensures that the marginal cost of drilling is positive and increasing in footage drilled as long as $\phi > 0$. Using annual data for the United States from 1959 to 2007, with drilling cost per foot measured in year 2000 dollars and footage drilled measured in millions of feet, the least squares estimate of ϕ is 1.23 with t-statistic of 8.17.⁸

The production function for gross reserve additions is specified as

$$f(w, x) = A w^\rho e^{-\beta x} e^v \quad (9.11)$$

where A , ρ , and β are parameters to be estimated and the disturbance term e^v is assumed lognormally distributed with mean of unity and variance σ_v^2 . Equation (9.11) is similar to the one describing the discovery process proposed by Uhler (1976) and later adopted by Pindyck (1978). The idea behind this equation is that the marginal product of drilling declines as footage drilled accumulates. Estimation of equation (9.11) used annual data from seven important oil-producing U.S. states (California, Kansas,

⁸ Data were taken from American Petroleum Institute (2009).

Louisiana, New Mexico, Oklahoma, Texas, and Wyoming) for which complete information on the requisite variables was assembled for the period 1970–97.⁹ Oil reserve additions are defined as extensions, new field discoveries and new reservoir discoveries in old fields. The footage drilled variable was defined as in equation (9.10) and the cumulative footage variable was created by adding year-by-year over the sample period for each state. After taking natural logarithms of equation (9.11) and with state-effects included, we obtain least squares estimates of $\rho = 0.95$ (t-statistic = 14.18) and $\beta = 0.000437$ (t-statistic = 1.37). The value of A (28.78) was selected so that the equation predicted U.S. reserve additions in 2007. This equation shows that the marginal product of drilling (f_w) decreases with footage drilled as well as with cumulative drilling, although the coefficient of cumulative drilling is insignificant at conventional levels.

Because data on oil extraction costs are weak, $C(q, R)$ could not be econometrically estimated. Instead, this equation was calibrated for the United States with a Cobb-Douglas functional form using methods described in Deacon (1993). Results show that if the output elasticity of nonreserve inputs is 0.35, then for 2007, $C/q = 458.1(q/R)^{1.86}$. The value of 458.1 is selected so that the right-hand side will predict average U.S. operating cost per barrel in 2007 of \$7.56.¹⁰ Note that the Cobb-Douglas form implies that extraction costs rise without limit as reserves approach zero and fall as production declines.

9.5.2 Specification of Tax/Subsidy Parameters

Values for the parameters α_j ($j = p, c, D$) were specified by choosing representative rates of state and federal taxes faced by oil producers and then inserting these values into equations (9.12) through (9.14).

$$\alpha_p = (1 - \tau_{us})(1 - \tau_s)(1 - \tau_r)(1 - \tau_p) + \tau_{us}(1 - \tau_r)\gamma \quad (9.12)$$

$$\alpha_c = (1 - \tau_{us})(1 - \tau_s) \quad (9.13)$$

$$\alpha_D = \{(1 - \tau_{us}\eta - (1 - \tau_{us})\delta)\} \quad (9.14)$$

In equations (9.12), (9.13), and (9.14), τ_{us} denotes the federal corporate income tax rate, τ_s is the state corporate income tax rate, τ_r denotes the royalty rate on production from public (state and federal) land, τ_p is the

⁹ Data were taken from American Petroleum Institute (various years).
¹⁰ Data were taken from U.S. Department of Energy (2009a).

state severance tax rate, and δ represents the percentage of drilling costs that may be taken as a credit against state severance tax liabilities. This credit is a prominent tax code feature in Alaska. Also, γ represents the federal percentage depletion allowance weighted by the percentage of production attributable to eligible producers (nonintegrated independents), and $\eta = e + (1 - e)f$ denotes the expensed portion of current and capitalized drilling costs attributable to current period revenues for purposes of computing federal corporate income tax liabilities, where e is the percentage of current period drilling costs expensed for tax purposes and f is the present value of cost depletion deductions per unit of depletable expense (see Deacon 1993 for further details).

These equations do not capture all aspects of the tax code facing oil producers. Instead, they merely reflect important tax features and relationships between taxes affecting the oil industry in most states and at the federal level: (1) severance taxes are levied on the wellhead price of oil; (2) royalty payments for production on public land are deductible in computing state severance tax liabilities; (3) public land royalty payments, state severance taxes, and extraction costs are deductible in computing state corporate income tax liabilities; and (4) public land royalty payments, state severance taxes, and state corporate income taxes are deductible in computing federal corporate income taxes. Federal corporate income tax payments are adjusted because of the percentage depletion allowance and special treatment of drilling costs. These equations highlight interaction between tax bases and are more detailed than the corresponding treatment given by Moroney (1997) and Deacon et al. (1990). The equations incorporate the entire tax structure into the model, rather than simply analyzing one tax at a time as in Deacon (1993). Equations (9.12) through (9.14), however, ignore local taxes on the value of production as well as possible property taxes on reserves (levied by relatively few states). As noted in Section 9.2, state tax treatment of the oil industry is not uniform; the specification of the parameters α_j ($j = p, c, D$) would require reformulation to represent the tax structure of a particular state.

9.5.3 Values of Tax/Subsidy Parameters Used in Simulations

Four simulations of the model are considered in the following section. The base case simulation considers a situation in which no taxes are levied and no subsidies are allowed (No-tax Model A); the values for the tax parameters are $\alpha_p = 1$, $\alpha_c = 1$, $\alpha_D = 1$. The Low-tax Model B considers a situation in which the nominal severance tax rate is $\tau_p = 0.12$, the state corporate income

tax rate is $\tau_s = 0.06$, and public land royalty payments as a fraction of total production value is $\tau_r = 0.09$. These choices for state corporate income tax and severance tax rates are broadly representative of actual nominal rates for these taxes (see Table 9.1). The public land royalty payment fraction is similar to actual values for oil-producing states in the western United States (Gerking 2005). At the federal level, the effective federal corporate income tax rate is set at $\tau_{us} = 0.30$. The current nominal depletion rate of 15 percent applies to about 60 percent of U.S. oil production; thus, $\gamma = 0.09$.¹¹ The expensed portion of current period drilling costs is approximately 40 percent for the industry, and the present value of depletion deductions for capitalized drilling cost can be approximated by $(q/R)/(r + (q/R))$, assuming that it is approximately 8 percent; therefore $\eta = 0.40 + (1 - 0.4) \cdot (0.08/(0.04 + 0.08)) = 0.8$. The parameter δ is set to zero. Thus, the tax policy parameters for Model B are $\alpha_p = 0.55$, $\alpha_c = 0.67$, $\alpha_D = 0.76$.

The High-tax Model C sets all taxes equal to their Model B values, except for the severance tax, which is set at $\tau_p = .25$. Hence, $\alpha_p = 0.47$, $\alpha_c = 0.67$, $\alpha_D = 0.76$. The Drilling Subsidy Model D sets all tax parameters equal to their Model C values, except that δ is set to 0.22, so that $\alpha_p = 0.47$, $\alpha_c = 0.67$, $\alpha_D = 0.61$.

9.5.4 Other Parameters

Each model uses a discount rate of $r = .04$, an oil price of $p = \$70$ per barrel, and is run for 110 periods at which point drilling all but ceases in the four models because it is no longer profitable. The initial value of reserves (R) was set to 20 billion barrels. This value approximates the quantity of proven reserves for the United States in 2007. The initial value of cumulative footage drilled was arbitrarily set to 2 billion feet, which is roughly equal to the cumulative footage for oil wells drilled in the United States in the past 30 years.

9.6 Discussion of Simulation Results

Results of simulations are obtained from solving the first-order equations of the model (equations (9.6) and (9.9)) after substituting values of the

¹¹ The percentage of production accounted for by nonintegrated independents was approximated by subtracting from unity the ratio of oil and natural gas liquids production by producers subject to USDOE financial reporting system (FRS) requirements to total oil and total natural gas liquids production. For 2007, this ratio was 0.612. Data were taken from U.S. Department of Energy (2009c, 2009d, 2009e).

Table 9.2. Selected values from solutions for the four models: Year 1

	Model A	Model B	Model C	Model D
Production in billions of barrels (q)	2.33	2.16	2.03	2.03
Drilled footage in millions of feet (w)	92.44	72.21	63.43	74.26
After-tax price per barrel received by producers ($\alpha_P P$)	\$70.00	\$38.50	\$32.90	\$32.90
After-tax marginal extraction cost of one additional barrel ($\alpha_C C_q$)	\$24.03	\$13.98	\$12.46	\$12.46
Reserve additions from drilling an additional million feet in billions of barrels (f_w)	0.0091	0.0092	0.0093	0.0092
Total reserve additions in billions of barrels (wf_w)	0.841	0.664	0.588	0.683
After-tax marginal cost of drilling one additional foot ($\alpha_D k_w$)	\$227.40	\$135.00	\$118.59	\$111.43
Beginning reserves in billions of barrels (R)	20	20	20	20
Ending reserves (R)	18.55	18.50	18.56	18.65
θ	\$45.80	\$24.50	\$20.50	\$20.50
λ	\$227.00	\$135.00	\$119.00	\$111.00

tax/subsidy parameters and specific equations for drilling costs (equation (9.10)), reserve additions (equation (9.11)), and lifting costs. Table 9.2 shows selected solution values for year 1 for the four models.

In year 1 for Model A, for example, solutions for the level of production and footage drilled are 2.3 billion barrels per year (6.4 million barrels per day) and 92.44 million feet, respectively. These values, together with initial reserves set to 20 billion barrels and $P = \$70$, imply that the marginal cost of extracting an additional barrel of oil is $c_q = \$24.03$ and the marginal cost of drilling an additional foot is \$227.40. Over the course of year 1, reserves fall because production exceeds reserve additions. The present value of future profits from an additional barrel of reserves is $\theta = \$45.80$ (see equation (9.6)), and the present value of drilling cost reductions from an additional unit of reserves is the negative of $\lambda = \$227$ (see equation (9.7)). Both of these two shadow prices steadily converge toward zero over time.

Values presented in Table 9.2 for Models B and C are interpreted similarly. In these two models, production and drilling are lower than in Model A, in part because the severance tax causes prices received by producers to fall disproportionately relative to extraction and drilling costs. In Model D, production is the same as for Model C because tax rates and initial values

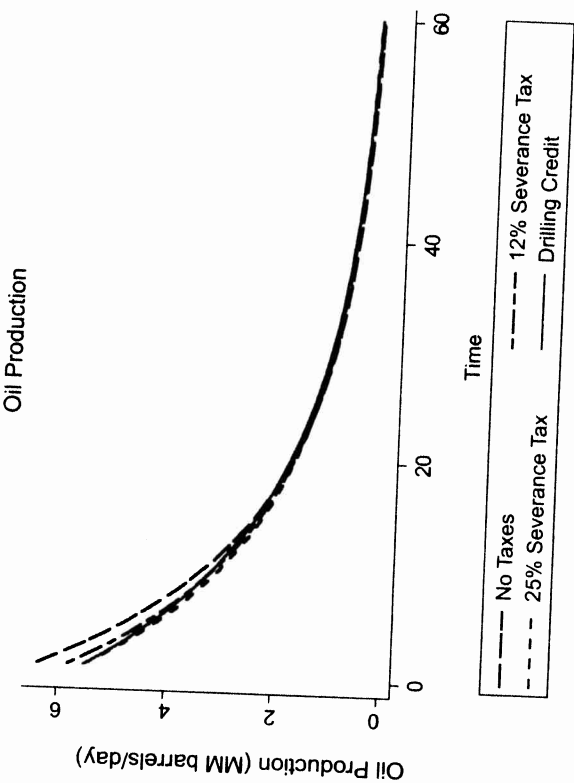


Figure 9.1. Oil production is quite insensitive to the tax structure in the U.S. case.

of reserves are the same, but footage drilled is higher because of the drilling expense subsidy. In all three models, the shadow values λ and θ converge toward zero over time, just as in Model A.

Figure 9.1 shows the time profile of oil production in millions of barrels per day for each of the four models.

In each model, production declines substantially over time. The no-tax case (Model A) shows the highest production rates. The introduction of taxes in Model B tilts production (slightly) to the future, as predicted by models of extraction from fixed reserves (see Section 9.4). Numerical calculations indicate that production rates for Model B are lower than for Model A until year 26, at which point production rates become higher for Model B than for Model A. In Model C, tilting of production to the future is more pronounced in comparison to Model A than it is for Model B because of the higher severance tax rate assumed. Production in Model C is lower in the early years of the program, but begins to exceed production in Model B by year 27. Introduction of the subsidy for drilling expenses tilts production back to the present in comparison with Model C. Model D production initially exceeds that for Model C, but is lower than that for Model C after year 48.

Figure 9.1 also shows that production is relatively insensitive to changes in tax rates and therefore to changes in prices received by operators. Cumulative production figures for the 110-year program period confirm this result (Table 9.3).

More specifically, comparing Model A with Model C, the arc elasticity of cumulative production with respect to a change in severance tax rates $((\Delta q/q)/(\Delta \tau_p/\tau_p))$ is only $(-1.4/38.7)(0.125/0.25) = -0.02$. This outcome implies that the arc elasticity of cumulative production with respect to a change in prices received by operators is $(-1.4/38.7)(56.7/-26.6) = 0.05$. Of course, these simple elasticity calculations are based on cumulative production totals and do not take the timing of production into account, but as shown in Figure 9.1, the time path of production does not differ greatly across the four models.

Oil production also would be insensitive to changes in the percentage depletion allowance rate (η) that can be used by nonintegrated independent producers in computing federal corporate income tax liabilities. As shown in equations (9.12) through (9.14), a reduction in either η or an increase in the severance tax rate τ_p lowers α_p while leaving α_c and α_D unchanged. In fact, given the values of the tax parameters used for Models B, C, and D, eliminating the percentage depletion allowance would have the same effect on production as a four percentage point increase in the severance tax. This parallel between changes in severance tax rates and the changes in the percentage depletion allowance may be of interest in light of the Obama Administration's proposal to eliminate the latter tax preference (see Krueger 2009). Of course, changes in the severance tax and changes in the oil depletion allowance will not have equivalent effects on the collection of other taxes at the state and federal levels.

Insensitivity of oil production to severance tax increases would be to some extent expected in these simulations because a key effect of the tax simply is to reduce industry profits. The assumed price of oil (\$70/bbl) is relatively high by historical standards; thus, discounted profit is a relatively large percentage (80 percent) of discounted total revenue. In consequence, the array of taxes imposed in Model B can cut into profits without substantially altering drilling or production. Kuncie et al. (2003) found somewhat greater responsiveness of oil production to changes in severance tax rates when setting P ($P = \$23$) at a lower value than the one used in this study. In their simulations, which envision a lower ratio of profit to total revenue, the long-run elasticity of production to changes in the severance tax rate was -0.06 .

Table 9.3. Total drilling, production, tax collections, profits, and reserves for four models over the 110-year program

	Model A no taxes	Model B 12% severance tax	Model C 25% severance tax	Model D 25% severance tax with drilling subsidy
Total production (in billions of barrels)	39.4	38.5	38.0	38.6
Total footage drilled (in billions of feet)	4.5	3.9	3.6	3.9
Discounted public land royalties (in billions of dollars)	\$0	\$131.0	\$126.3	\$129.3
Discounted severance tax Collections (in billions of dollars)	\$0	\$159.0	\$319.2	\$307.5
Effective severance tax Rate	0	0.109	0.228	0.212
Discounted state corporate income tax revenue (in billions of dollars)	\$0	\$60.9	\$49.6	\$50.8
Discounted federal corporate income tax revenue (in billions of dollars)	\$0	\$230.0	\$182.5	\$188.4
Discounted depletion allowance deductions (in billions of dollars)	\$0	\$119.2	\$114.9	\$117.7
Discounted pre-tax total revenue (in billions of dollars)	\$1,544	\$1,456	\$1,403	\$1,437
Discounted extraction costs (in billions of dollars)	\$186.3	\$151.8	\$130.1	\$133.0
Discounted drilling costs (in billions of dollars)	\$125.6	\$84.4	\$68.3	\$88.3
Discounted firm profits (in billions of dollars)	\$1,231	\$638	\$527	\$539
Beginning reserves (in billions of barrels)	20	20	20	20

In any case, the inelasticity of production with respect to severance tax and price changes suggests that severance tax collections computed as $s = \tau_p(1 - \tau_r)pq - \delta k(w)$ should increase roughly in proportion to changes in the tax rate when $\delta = 0$. As shown in Table 9.3, discounted (at 4 percent) severance tax collections over the 110-year program period total \$159.0 billion for Model B and \$319.2 billion for Model C. Effective severance tax rates for these two models are 0.109 and 0.228, respectively. These figures suggest that the arc elasticity of discounted severance tax collections with respect to a change in the effective tax rate is 0.95 (assuming unchanged royalty rates and oil prices). Model D, which includes the credit ($\delta = 0.22$) for drilling expenses, reflects smaller severance tax collections than Model C.

Table 9.3 indicates that severance tax rate increases result in lower collections of both state and federal corporate income taxes. Because of the deductibility of severance tax payments against these two taxes, discounted state corporate income tax collections fall from \$60.9 billion in Model B to \$49.6 billion in Model C, and discounted federal corporate income tax collections fall from \$230.0 billion in Model B to \$182.5 billion in Model C. Notice that the decline in federal corporate income tax collections is cushioned by declines in depletion allowance deductions (\$119 billion to \$114.9 billion) and in deductions for current and capitalized drilling costs. The value of these two deductions declines because both production and drilling are lower in Model D than in Model C. Also, discounted oil industry profits fall sharply when all taxes are imposed (compare Model A with Models B and C). In any case, the main effects of severance tax rate increases are to redirect (1) oil industry profits to the public sector and (2) tax payments from the federal level to the state level.

Although the specific way in which the model is parameterized may be responsible for the relative insensitivity of production to changes in oil prices and severance tax rates, results shown in Figure 9.1 and Table 9.3 are broadly consistent with U.S. experience over the past half-century. Figure 9.2 shows this by plotting total U.S. proven reserves (in billions of barrels), total U.S. production from proven reserves (in hundred millions of barrels), and the real price of crude oil (in year 2000 dollars).

Proven reserves stood at roughly 30 billion barrels from 1959 to 1970, increased to nearly 40 billion barrels in 1971 with the discovery of oil in Prudhoe Bay, and then declined steadily thereafter to 20.9 billion barrels in 2007. Over this time period, production followed a similar pattern, remaining between 8 percent and 11 percent of reserves in each year; on average, production represented 9.2 percent of reserves with standard error

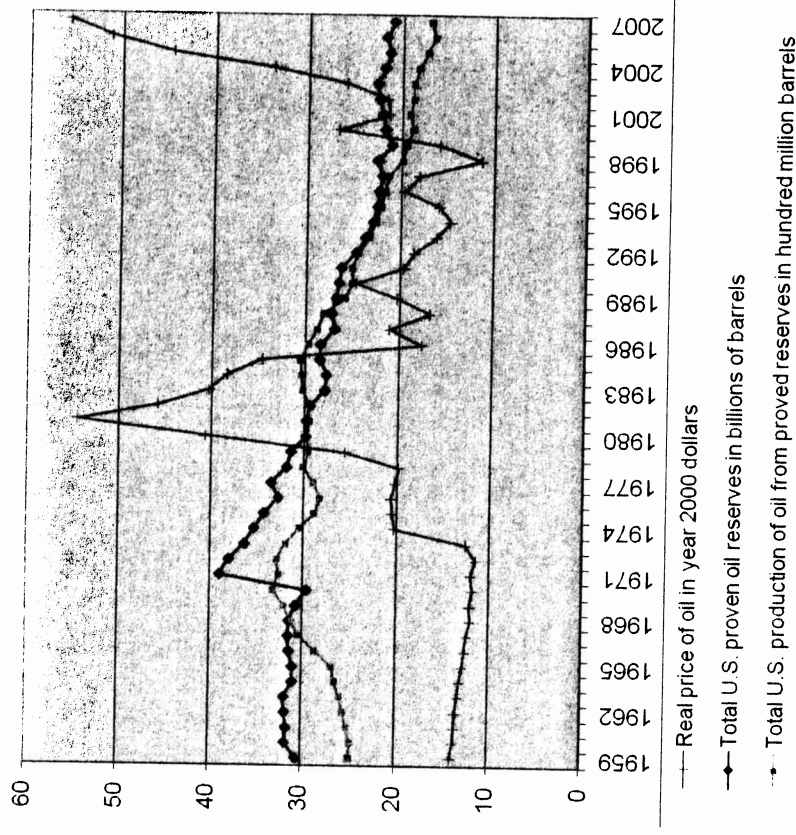


Figure 9.2. U.S. oil production has been insensitive to oil prices over the past 50 years.

of 1.34. Real crude oil prices, on the other hand, exhibited greater variability, but neither the spike in the late 1970s and early 1980s nor the price increase seen in recent years appears to have had much effect on production.

Drilling activity during the 110-year program shows greater percentage differences across the four models (see Figure 9.3 and Table 9.3) than were computed for production.

Model A has the most drilling in each year of the simulation period. Total drilling in Models B and C are lower by 13.3 percent and 20.0 percent, respectively, than in Model A, because the imposition of severance taxes reduces the future payoff from this activity. The effect of the 22 percent drilling expense credit in Model D is to increase drilling above the levels predicted for Model B, but still 13.3 percent below the level predicted for Model A. Total drilling over the 110-year simulation period (net of the starting value of 2 billion feet) is 4.5 billion feet for Model A, 3.9 billion feet for Model B, 3.6 billion feet for Model C, and 3.9 billion feet for Model D.

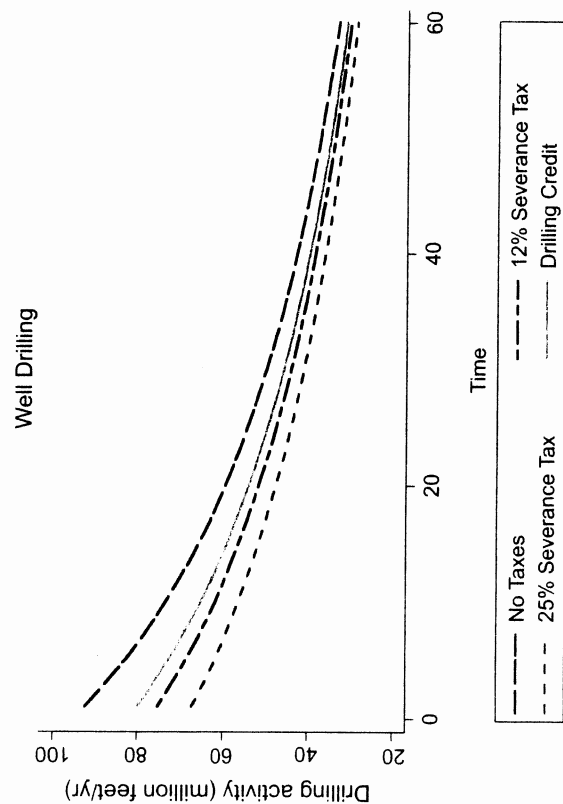


Figure 9.3. Drilling activity is more sensitive to the tax regime.

The figures presented in Table 9.3 imply that the long-run arc elasticity of footage drilled over the 110-year program with respect to the severance tax changes contemplated in Models B and C is -0.07 . The corresponding price elasticity is 0.91 . Thus, in percentage terms, drilling is more responsive to tax and price changes than is production. Figure 9.4 shows that these results are roughly consistent with the observed relationship between drilling footage and real oil prices (defined as in Figure 9.2) in the United States over the past 50 years.

As shown, drilling footage responds positively to changes in the real oil price, and a regression of the natural logarithm of footage drilled on the natural logarithm of the real price of crude oil yields a coefficient of the latter variable of 0.44 (t -statistic $= 3.38$). This estimate compares favorably with estimates produced by the simulation model.

Another perspective on the results for the time path of drilling and production can be obtained by focusing on the behavior of reserves. In all four models, initial reserves are set to 20 billion barrels. Drilling leads to annual reserve additions, and reserve additions are highest when more drilling is carried out. In consequence, reserve additions tend to be higher for Model A than for either Models B or C. Reserve additions also are higher for Model D than for Model B, again illustrating the effect of the drilling expense

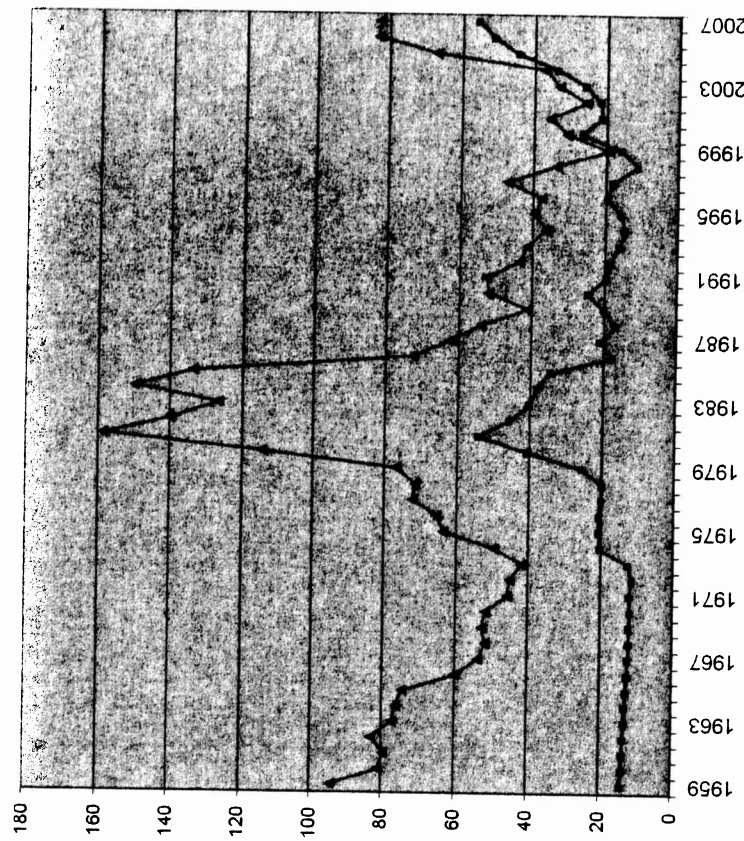


Figure 9.4. Price movements coincide with changes in footage of wells drilled.

subsidy. In all four models, however, annual reserve additions always are exceeded by annual production and thus reflect declining reserves over time. This outcome can be seen in Table 9.3 by comparing beginning reserves with the much smaller corresponding figures for ending reserves.¹² Moreover, this outcome is consistent with the previously discussed trends presented in Figure 9.2, which illustrate that U.S. proven reserves have declined by about 50 percent over the past half-century.

Table 9.3 presents additional information concerning the effect of the 22 percent drilling expense credit subsidy on drilling, production, reserves, and tax collections.¹³ As discussed previously, the credit spurs drilling over

¹² The ending values for reserves reflect high-grading brought about by the severance tax, as discussed in the theoretical literature. For instance, ending reserves in Models B and C are 38 percent and 63 percent higher, respectively, than for Model A.

¹³ Results presented below concerning effects of a drilling expense credit may also inform the current debate about the proposed elimination of the possibility to expense intangible

the life of the program, which adds to the reserve base and raises production (compare Models C and D). Discounted drilling expenditures rise by 29 percent (\$20 billion), but because drilling expenditures rise at an increasing rate with footage drilled (see equation (9.10)), footage drilled rises by a smaller percentage (8 percent or 0.3 billion feet). The 0.6 billion barrel increase in production associated with the credit approximately offsets the effect on production of increasing the severance tax rate from 12 percent to 25 percent (compare Models B and D). Application of the credit results in 14 percent fewer remaining reserves at the end of the program (compare Models C and D) and roughly offsets the effect on ending reserves that results from the severance tax increase in Model C as compared with Model D.

The incremental production resulting from the drilling expense credit results in an increased present value of severance tax collections (gross of the credit) in Model D (\$326.9 billion) as compared with Model C (\$319.2 billion). Once the present value of drilling expense credits are subtracted, however, the net-of-credit present value of severance tax collections in Model D (\$307.5 billion) ends up lower than in Model C by 3.7 percent, yet they are 93.4 percent higher in Model D than in Model B. Comparing Models D and C, \$1.2 billion in lost severance tax revenue is regained through increased state corporate income tax collections; however, \$5.9 billion in lost severance tax revenue is transferred to the federal government in the form of higher federal corporate income tax payments. In any case, the drilling expense credit results in a net loss in discounted state tax revenue of \$10.5 billion. It costs about \$17.50 in lost discounted state tax revenue (both severance tax and state corporate income tax) to produce an additional barrel of oil and about \$35.00 of lost discounted state tax revenue to drill an additional foot. Additionally, each dollar of discounted state tax revenue lost because of the credit is associated with a \$1.90 increase in drilling expenditures.

This outcome raises a question as to whether other public policy instruments, such as support for research to lower drilling costs or to increase finding rates, might spur drilling at lower cost to the state. Nonetheless, if a state's objective in granting the drilling expense credit is to gain support for increasing the severance tax rate from 12 percent to 25 percent, it is a relatively inexpensive concession. On the other hand, a state that expects the drilling expense credit to more than pay for itself through severance

drilling costs in computing federal corporate income tax liabilities. Both types of policies operate through α_D while leaving the other two tax parameters unchanged.

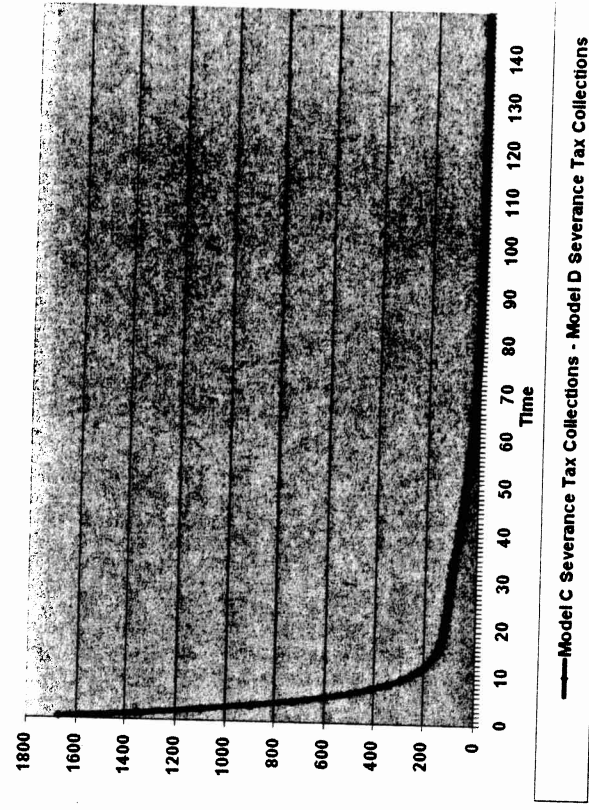


Figure 9.5. Discounted severance tax losses from the drilling expense credit accumulate over time.

tax collections will be disappointed because it simply generates too little incremental oil production. In fact, the drilling expense credit is not only cost-ineffective when evaluated over the entire program, it is cost-ineffective in each program year, as shown in Figure 9.5.

As can be seen from Table 9.2, the credit results in a 17 percent increase in drilling in year 1 (compare Models C and D), but no additional production and thus no additional revenue. Model D production begins to reflect the additional drilling in year 2 and exceeds that for Model C until year 48. During these years, severance tax losses in Model D compared to Model C are smaller than the value of the credit. As indicated, beginning in year 49, production in Model C is larger than that for Model D. Thus, in years 49 to 110, the loss in severance tax revenue in Model D compared to Model C exceeds the value of the credit.

A possible concern about these calculations is that they pertain to a model that is parameterized using U.S. oilfield data. In particular, one conjecture might be that a drilling credit might be financially more attractive in an area that has been less extensively explored, so that the marginal product of drilling in identifying new reserves would be higher. To check this idea, the simulation model was recalibrated by assuming that cumulative drilled footage prior to the start of the program was 500 million feet, rather than

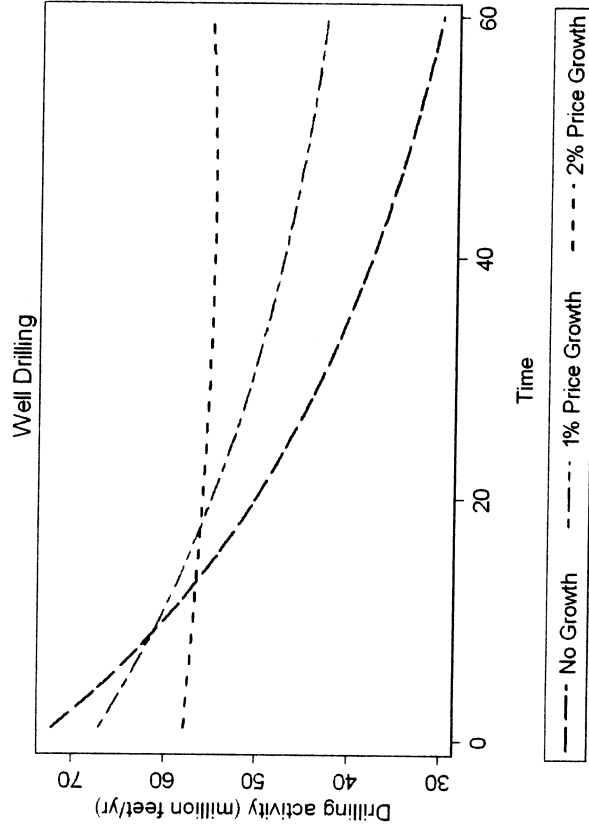


Figure 9.6. Oil drilling tilts to the future with exogenous growth in oil prices.

2 billion feet. This alteration roughly doubles the marginal product of drilling in identifying new reserves, which in turn stimulates drilling, reserve additions, and production. Therefore, Model C discounted severance tax collections are higher than those shown in Table 9.3. Model D discounted severance tax collections also are higher than in Table 9.3, but still lower than the comparable value for Model C. Thus, in both absolute and percentage terms, severance tax losses from the drilling expense credit are larger when cumulative footage drilled totals 500 million feet as compared with 2 billion feet.

It would also be of interest to construct a simulation using the actual path of oil prices over the last several decades. This price, however, exhibits sharp increases and decreases over time (see Figure 9.2), causing the simulation algorithm to break down. As a second choice, we performed a set of sensitivity analyses to reflect a forecast that oil prices will rise over time, at two exogenously given rates. Of course, with perfect foresight, prices cannot go up faster than the rate of discount, because then oil production will be postponed to the future. We thus assume exogenous growth rates in oil prices of 1 percent and 2 percent. As shown in Figure 9.6, drilling activity flattens out with a 2 percent growth in prices.

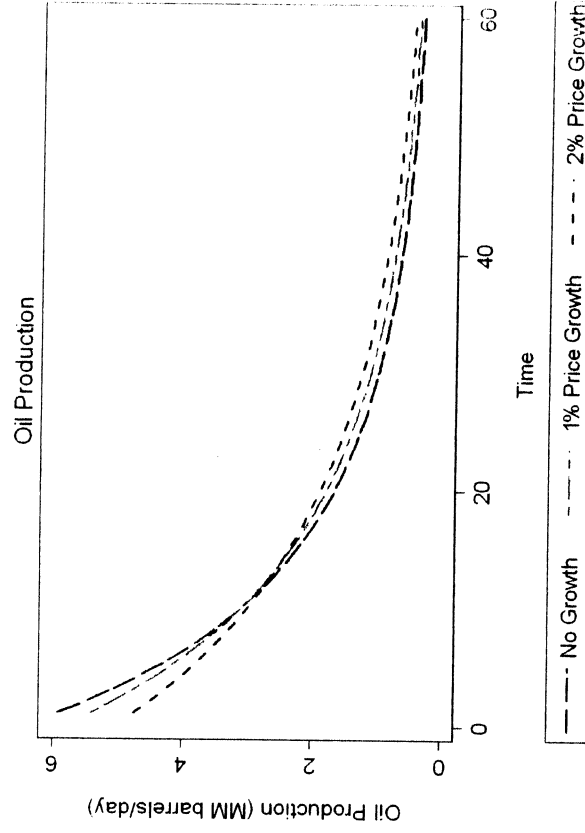


Figure 9.7. Oil production does not change appreciably with growth in oil prices.

However, oil production is relatively insensitive to oil price growth, as shown in Figure 9.7. This is because even though drilling activity shifts out to the future with an increase in prices, the decline in returns from cumulative drilling keeps production from leveling out in time. Production continues to fall, as in the case with constant prices. Figure 9.8 shows the change in reserve additions in the price growth scenario.

9.7 Concluding Remarks

This chapter described tax policies pursued by U.S. states that impact the oil industry. Three types of taxes are discussed: (1) the severance or production tax, (2) the property tax, and (3) the corporate income tax. The severance tax then is further analyzed in light of its widespread use in energy-producing states and its potential to generate revenues to support public services. The analysis is carried out using an adaptation of a conceptual model (Pindyck 1978) of exploration/development and production of exhaustible resources in which oil prices are taken as exogenous. This perspective is a useful simplification for an analysis of state taxes because no state produces enough oil to appreciably affect the world price. Simulations obtained from calibrating the model suggest that oil production volumes will be quite insensitive to

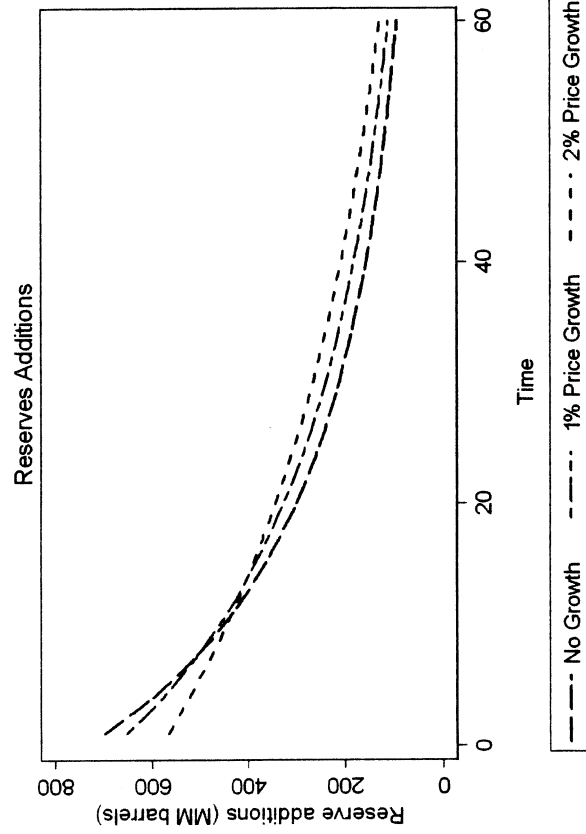


Figure 9.8. Reserve additions change only marginally with growth in oil prices.

price and severance tax rate changes. Thus, an increase in the severance tax rate is seen to generate proportionally more severance tax revenue, as its main effect is to redirect economic rents earned in the oil industry towards the public sector. An implication of this result turns out to be that the proposed elimination of the percentage depletion allowance, available to nonintegrated independent oil producers, may have much the same effect on production as a severance tax increase, although changes in the two types of tax measures may have quite different effects on the distribution of tax revenue between the state and federal levels of government.

Simulations based on the U.S. experience demonstrate that the credit for drilling expenses does turn out to increase drilling as intended. However, if the credit is applied in the United States, particularly in areas where a great deal of drilling has already occurred, its contribution to identifying new reserves may be rather limited. In other words, much of the continental United States has been extensively explored, so the chances of large oil discoveries probably are small. Simulations of the model show that the drilling expense credit does not generate enough incremental severance tax revenue to pay for itself. Additional work needs to be carried out to see whether alternative public policies to stimulate exploration and development might be more cost-effective as well as the extent to which the results presented continue to hold when the model is parameterized differently.

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