STATE TAXATION, EXPLORATION, AND PRODUCTION IN THE U.S. OIL INDUSTRY*

Mitch Kunce
Department of Economics and Finance
University of Wyoming
Laramie, WY 82071-3985
mkunce@uwyo.edu

Shelby Gerking
Department of Economics
University of Central Florida
Orlando, FL 32812-1400
sgerking@bus.ucf.edu

William Morgan
Department of Economics and Finance
University of Wyoming
Laramie, WY 82071-3985
wemorgan@uwyo.edu

Ryan Maddux
University of Wyoming
Laramie, WY 82071-3985

November 26, 2001

* This research was partially supported by an appropriation from the Wyoming Legislature (1999 Wyoming Session Laws, Chapter 168, Section 3). However, this paper may or may not reflect the views of public officials in the State. Gerking acknowledges the hospitality of CentER, Tilburg University, where portions of this paper were completed, as well as support from visiting grant B46-386 from the Netherlands Organization for Scientific Research (NWO). Maddux acknowledges the support of a student EPSCoR research fellowship from the University of Wyoming. We thank Laura Marsiliani and John Livernois for a number of constructive suggestions on earlier drafts.

STATE TAXATION, EXPLORATION, AND PRODUCTION
IN THE U.S. OIL INDUSTRY

Abstract

How do firms in nonrenewable resource industries respond to changes in state taxes? This paper employs state-specific estimates of Pindyck's (1978) widely cited model of natural resource supply to simulate effects of changes in state production (severance) tax policy on the timing of exploration and output by firms in the U.S. oil industry. The framework developed can be applied to any of 15 states that produce significant quantities of oil, and allows for interactions between taxes levied by different levels of government. Results of this study suggest that oil production is highly inelastic with respect to changes in production taxes. A production tax rate increase is shown to decrease early period exploration effort, affect little change in reserve additions and future production, and substantially increase discounted tax revenue. Policy implications of this outcome suggest that state officials may consider raising production tax rates as a way to increase revenue while risking little in the way of loss to future oil activity.

1. *Introduction*

How do firms in nonrenewable resource industries respond to changes in state taxes? It may be tempting to look for answers to this question in the empirical literature on effects of state taxation (see, for example, Bartik 1985, Helms 1985, Papke 1991, 1994, and Holmes 1998). These papers focus on firms with mobile capital that choose where to locate on the basis of factors affecting revenues and costs. This perspective, however, is not particularly relevant when looking at the behavior of firms extracting nonrenewable natural resources. Such firms cannot change location because they are tied to a geographically immobile reserve base that makes up a key component of their capital stock. On the other hand, extractive firms can and probably do alter the timing of their activities when state taxes and other public policies change. Yet, little is known about the extent to which they do this even though commercially valuable deposits of natural resources are found in most U.S. states and some states such as Texas, Oklahoma, Louisiana, Wyoming, and Alaska rely heavily on taxation of oil, gas, and/or coal production to fund public services.

This paper uses state-specific estimates of Pindyck's (1978) widely cited model of natural resource supply to simulate effects of changes in state production (severance) tax policy on the timing of exploration and output by firms in the U.S. oil industry. The framework developed can be applied to any of 15 states that produce significant quantities of oil, and allows for interactions between taxes levied by different levels of government. It is arguably superior to and more comprehensive than previous efforts to develop econometric and/or simulation models of taxation and natural resource exploration and production. For example, Deacon, DeCanio, Frech, and Johnson (1990) and Moroney (1997) focus only on one state (California and Texas, respectively), and estimate econometric equations that may not be consistent with a dynamic profit-maximizing framework. Pesaran (1990) estimates an econometric model of offshore oil production in the UK that can be better justified theoretically, but does not consider the role of taxes. Simulation studies conducted by Yucel (1989) and Deacon (1993) examine effects of various types of tax changes on exploration and production, but do not consider interactions between tax bases claimed by different levels of government. Additionally, these studies do not allow for possible interstate differences in exploration and extraction costs and are aimed mainly at assessing the generality of theoretical results obtained in more limited settings (see, for example, Burness 1976, Conrad and Hool 1980, and Heaps 1985) rather than analyzing possible outcomes of changes in state tax policies.

Results of this study suggest that oil production is highly inelastic with respect to changes in production taxes so deadweight losses from altering these taxes are likely to be small. As a consequence, state officials may consider raising production tax rates as a way to increase revenue. It is worth noting in this context that because state production taxes are deductible against federal corporate income tax liabilities, increases in production tax rates increase state revenues partly at the expense of federal tax collections. These points are more fully discussed in Section 3 after developing the framework for the simulation model in the next section.

2. The Simulation Model

This section shows how Pindyck's (1978) model of nonrenewable resource development is adapted to simulate effects of state production tax changes. The discussion begins with a brief overview of the Pindyck model and then discusses estimation of key equations and tax parameters.

Conceptual Model

The model assumes that perfectly competitive producers maximize the discounted present value of future operating profits from the sale of resources and because one such firm is chosen to represent the industry, the common pool problem and well-spacing regulations are not considered (see McDonald 1994 for discussion of these issues). The firm's problem is to take the future time path of output prices and taxes as given and then choose optimal time paths for exploration and production. This approach is similar to that taken in previously cited econometric studies of effects of changes in state tax policy on state economic growth and ignores the possibility that choices of tax bases and rates are endogenous (i.e., that governments consider the firm's objective function in choosing taxes that maximize community welfare). Also, the model defines exploration to include resource development, although the two activities clearly are not the same (Adelman 1990). The aim of exploration is to add to the reserve base, which as indicated in the introduction, is a form of geographically immobile capital.

The firm's maximization problem is

$$\max_{q,w} \ \Omega = \int_{0}^{\infty} [qp - C(q,R) - D(w) - \gamma R]e^{-rt} \ dt \tag{1}$$

subject to

$$\dot{R} = \dot{x} - q \tag{2}$$

$$\dot{x} = f(w, x) \tag{3}$$

$$q \geq 0, w \geq 0, R \geq 0, x \geq 0 \tag{4}$$

where a dot over a variable denotes a time rate of change, q denotes the quantity of oil extracted measured in barrels, p denotes the exogenous market price per barrel net of all taxes, $C(\cdot)$ denotes the total cost net of taxes of extracting the resource, which is assumed to depend on production (q) and reserve levels (R), $D(w)$ denotes total cost of exploration for additional reserves net of taxes, w denotes exploratory effort, γ denotes the net of all tax constant effective property tax rate on reserves, r denotes the discount rate which represents the risk-free real rate of long-term borrowing, x denotes cumulative reserve additions (discoveries), $f(\cdot)$ denotes the production function for gross reserve additions ($\dot{x}$), and $\dot{R}$ denotes reserve additions net of production (q).[1] In this formulation, the net-of-tax price per barrel is related to the wellhead (pre-tax) price (p^*) according to $p = \alpha_p p^*$, where α_p is a tax policy parameter such that $0 < \alpha_p < 1$. Correspondingly, $C(q,R) = \alpha_c C^*(q,R)$ and $D(w) = \alpha_D D^*(w)$, where α_c and α_D also are tax policy parameters that lie on the unit interval. These tax policy parameters are discussed more fully later on in this section.

Model Implementation

To implement the model, equations for exploration costs (D^*), production of reserve additions (f), and extraction costs (C^*) are estimated and then substituted into the model along with estimates of the tax parameters α_p, α_c, α_D, and γ. Effects of tax changes then are obtained by simulation. Estimates of the tax parameters are described first followed by discussion of estimates of equations for D^*, f, and C^*.

Tax Parameters

General considerations in developing estimates of the four tax policy parameters for major oil producing states are briefly outlined below and technical details are described in Appendix A. Among major oil producing states, tax structures vary considerably and tax bases interact, particularly between the state and federal level. For example, among the eight states responsible for about 89% of U.S. oil production (Alaska, California, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming), all states except California levy production taxes against the value of output. Production taxes dominate other forms of local taxation in Alaska, Wyoming, and Louisiana. Most states do not levy property taxes on the value of reserves in the ground (Texas and California do). Most states treat royalty payments (computed as a percentage of gross value of production) for production on public land as deductible items in computing severance tax liabilities (Louisiana does not). Public land royalties are prominent in Alaska, New Mexico, and Wyoming due to the large shares of publicly owned land. Most states levy a corporate income tax that applies to oil operators (Wyoming and Texas do not). Also, states have granted innumerable exemptions and credits (which differ by state) against various tax liabilities for special situations that may be encountered by operators. Within states, counties apply their own mill levies to compute property taxes on equipment at different rates. However, taxation of structures and equipment are usually less important than other sources of revenue and are ignored below.

Regarding federal taxes, all incorporated producers file federal corporate income tax returns that allow deductions for various types of operating costs and for state and local tax payments. Independent producers (those without downstream refining or retail interests) are permitted to take a percentage depletion allowance, while major producers are allowed only cost depletion, which is significantly less generous. Both major and independent incorporated producers can expense intangible drilling costs incurred on their federal corporate income tax returns. The fact that some smaller producers are not incorporated and may therefore face alternative state and federal tax treatment is ignored.

The myriad of state-specific special features described above creates considerable complexity in tracking tax law over time. Rather than itemize tax code details, effective tax rates are used to translate dynamic tax policy into a tractable form. Effective rates can be expressed as the ratio of taxes (or royalties) collected from a particular tax to the value of production. Thus, the calculation of specific effective tax rates fully account for exemptions, incentives, different tax bases, and frequent changes in tax law both at the state and federal level. For a detail account of the taxation of the oil industry see Gerking, Morgan, Kunce, and Kerkvliet (2000), Chapter 2.

Marginal Cost of Reserve Additions

The before-tax marginal cost of reserve additions (D_w^* / f_w) is computed from estimates of equations for drilling costs and for the production of reserve additions. Drilling costs are assumed to be proportional to drilling effort as shown in equation (5)

$$D^*(w)=\phi w e^u \tag{5}$$

where ϕ is the parameter to be estimated and the disturbance term e^u is lognormally distributed with mean of unity and variance σ_u^2. The production function for reserve additions is specified as

$$f(w,x) = Aw^{\rho} e^{-\beta \cdot x} e^{v} \tag{6}$$

where A, ρ, and β are parameters to be estimated and the disturbance e^v is assumed lognormally distributed with mean of unity and variance σ_v^2. Equation (6) is similar to the equation describing the discovery process proposed by Uhler (1976) and later adopted by Pindyck (1978) and Pesaran (1990). The idea behind this equation is that the marginal product of exploration declines as reserve discoveries cumulate.

Estimation used annual data from the 15 U.S. states for which complete information on variables needed could be assembled for the period 1970-98.[2] These states accounted for 96.5% of total U.S. oil production over this time period. Drilling costs are measured by total real costs (both tangible and intangible) of each well completed, including dry holes.[3] Nominal cost values were deflated using the 1995 GDP deflator. Oil reserve additions are defined as extensions, new field discoveries and new reservoir discoveries in old fields. The total number of wells drilled for each state since 1859 (when the first oil well was drilled in Pennsylvania) is used as a proxy for x. Data sources and sample means of variables used in the analysis are presented in Table 1.

Equation (5) and equation (6) were estimated in natural logarithms. Both equations used an instrument for the number of wells drilled because w is an endogenous variable in the model presented in Section 2. The instrument was obtained from the predicted values from a regression of the number of wells on cumulative drilling and the wellhead price as shown in Appendix A. Estimates of the drilling cost equation, equation (5), are obtained by regressing drilling cost per well on dummy variables for states and years. Coefficients of state and year dummies are jointly significant at the 1% level and the R^2 is 0.90. The idea behind using this approach is to get state- and time-specific estimates of ϕ. This parameter is expected to vary across states because of differences in geologic conditions, geographic remoteness of on-shore oil resources, and whether drilling occurs in off-shore coastal waters (note that most states in the data set are landlocked). Time varying factors common to all states may include technological advancement and macroeconomic cycles. State-specific estimates of ϕ test different from each other, except Texas and Oklahoma, at the 5% level.

Estimates of equation (6), shown below in equation (7), allow for state-specific intercept terms (time-specific effects were jointly insignificant), common slope coefficients across states, and are corrected for first-order serial correlation (ρ =0.431).

$$\ln(\mathit{ADDED\ RESERVES}) = \ln A + \underset{(5.33)}{0.69} * \ln(\mathit{PREDWELLS}) - \underset{(-1.37)}{0.000006} * \mathit{CWELLS}\,. \qquad (7)$$
$$(t)$$

State-specific estimates of A are jointly significant at the 1% level and $R^2 = 0.40$.[4] These results show that the marginal product of drilling (f_w) decreases with wells drilled as well as with cumulative drilling, although the coefficient of cumulative drilling is insignificant at conventional levels.

Estimates of equations (5) and (6) combined show that the marginal cost of reserve additions (D_w^* / f_w) increases with drilling activity. As w increases, the marginal cost of drilling is constant, but the marginal product of drilling in finding new reserves (f_w) falls. Table 2 reports values of D_w^*, f_w, and D_w^*/f_w by state for seven major oil producing states. These estimates use 1998 values for numbers of wells drilled and cumulative drilling and are corrected for conversion from logarithms (see Greene 1997, p. 279). Estimates of D_w^* and f_w reflect considerable variation across the seven states. Estimates of marginal drilling cost range from $127,943 in Kansas to $1,218,758 in Louisiana. Marginal reserve additions from drilling (f_w) range from 7,460 barrels in Kansas to 64,862 barrels in Louisiana. Thus, while drilling in Louisiana is relatively more expensive than in Kansas, Louisiana experiences a greater payoff from these more costly exploration and development efforts. Values of D_w^*/f_w for the seven states range from a low of $17.15 per barrel in Kansas to a high of $26.04 in Texas.

Extraction Costs

Because data on oil extraction costs are weak, $C(q, R)$ could not be econometrically estimated. Instead, this equation was calibrated for each state with a Cobb-Douglas functional form using methods described in Deacon (1993). Cost parameter calibration specifics are described in Appendix A. Results show that the 1998 marginal extraction costs range from a low of $4.89 per barrel in Kansas to a high of $8.81 per barrel in Louisiana. Additionally, the Cobb-Douglas form implies that extraction costs rise without limit as reserves approach zero and that a positive level of reserves will remain at any terminal time T. Thus, boundary conditions used in the simulations reported in Section 3 allow production to continue after incentives for further exploration vanish so that the terminal date for the exploration/production program must be set arbitrarily. This fixed program period could be interpreted as the producer's relevant planning horizon.

3. Simulation Results

The model presented in Section 2 can be simulated to obtain responses of exploration and production to changes in various types of taxes in any of 15 oil producing states. Simulations presented below focus on production tax changes in Wyoming. The production tax is the most important tax levied on the oil industry by oil producing states (see Section 2) and changes in production taxes turn out to have quite similar effects in all major oil producing states so results from one state are used to represent the others (for results of tax changes in other major oil producing states, see Gerking, Kunce, Morgan, and Kerkvliet 2000). Also, simulations reported are based on the assumption that tax changes in one state do not affect the wellhead price of oil seen by operators in other states. This assumption probably is not unreasonable in view of the fact that oil prices are internationally determined and even the largest producing U.S. state (Texas) accounts for only a small percentage (4.2% from 1970-98) of world output.[5] Moreover, as shown below, tax changes considered lead to comparatively small changes in output, so these interstate effects are not likely to be important in any case.

Simulations for Wyoming were performed using the instrumental variable estimates of equations (5) and (6), the calibrated production cost function and the tax parameters, both derived in Appendix A. The discount rate, r, was set at 4% to reflect the risk-free real rate of long-term borrowing and the future price path was fixed at \$23.00 per barrel each year reflecting the real sample mean for all 15 states. Other price trajectories were simulated, but the alternative paths have little or no effect on the comparative results presented below. The initial value of reserves and cumulative wells drilled were fixed to year-end 1998 levels at 550 million barrels and 40,439 wells, respectively. To obtain numerical solutions for the optimal time paths of drilling, production, and reserves, difference equation approximations are derived for the time rates of change in exploratory effort ($\dot{w}$), production ($\dot{q}$), and for the state variable evolution equations (2) and (3). For example, the evolution of reserves, equation (2), is approximated by the difference, $R_{t+1} - R_t = f_t - q_t$. The model is then solved recursively by iterating over the initial values of the control variables, q and w, until transversality conditions are satisfied. Under these base conditions, exploratory effort approaches zero after approximately 40 years, thus the terminal time is set to 40 periods. The solver algorithm in Microsoft Excel was used to generate numerical solutions.

Before the simulation results are discussed, a historical analysis of Wyoming's oil experience is warranted. Figure 1 depicts the actual time paths of real price, drilling, production, and reserves for Wyoming from 1970-98. In this figure, the vertical axis shows price per bbl (dotted line) in $1995 $\times$ 10, drilling (dashed line) in total wells, production (solid line) in bbls $\times$ 10^5, and reserves (bold line) in millions of barrels (MMbbls). In reviewing these data, several observations are noteworthy. Historical drilling appears sensitive to price. Total wells drilled increases markedly during the high price period of the early 1980s. Extraction activity, however, appears to map the declining proved reserve level in the state. In fact, oil production continued to decline during the late 1970s and early 1980s even though real prices increased 2 1/2 fold. The increased drilling experienced in the early to mid 1980s failed to replenish the depleting oil reserve in the state and production closely followed the reserve decline.

This apparent historical insensitivity of production to changes in price raises an interesting policy question: If severance tax changes are reflected in net price (as modeled in section 2), what are the effects of a severance tax increase? Many oil states, as previously described — including Wyoming, rely heavily on production taxes to fund local public goods and officials may have incentives to raise production taxes for the revenue. The inherent trade off to severance tax increases is the purported loss of economic activity generated by the industry within the state. To examine this, the first simulation conducted shows the effects of *doubling* Wyoming's effective state severance tax rate for the full 40-year program. Results detailing the simulated differences in the timing of drilling, production, and discounted severance tax revenue for the full tax interaction model (outlined above) are presented in the top section of Table 3. Comparative individual program year results, divided into 10-year increments, show that doubling the state severance tax markedly decreases early period drilling. Drilling decreases by 19.4% in the first year of the simulated program and this difference converges to zero by year 40. Interestingly, 10 year fractional results show that 63.8% of the total 1208 well decrease occurs in the first 20 years of the program. Figure 2 graphically compares the effects of the tax increase (dotted line) to the base drilling solution (bold line). With less drilling in the early years of the program, fewer new reserves are identified and, as shown in Figure 3, future production of oil slightly diverges downward from the base solution. Production results presented in Table 3 show this gradual divergence — a 2.4% drop in year one falling to an 11.8% decline in year 40. Through the life of the program, doubling the state severance tax decreases total production by about 48 MMbbls or 5.7% below the base solution.

The largest change associated with doubling the state oil severance tax appears to come from discounted severance tax collections. As shown in Table 3, the tax increase results in an increase in the present value of Wyoming severance tax collections from $609 million to $1165 million, an increase of over 91%. The majority (87.6%) of this $556 million increase occurs in the first half of the simulated program due to the relatively small production loss generated by the tax increase and discounting. Because severance taxes are deductible in computing federal corporate income tax liabilities, discounted tax payments to the federal government decrease by $60 million or about 11% below the base simulation. Also, the severance tax increase transfers local government revenue to the state because of the production decline. Discounted local production taxes decrease by $34 million or 5% below the base solution. The same can be said for discounted public land royalties which decrease by 4.6% ($50 million) because of the decrease in future production.

The tax interactions described above highlight a key feature of the model developed here — oil producers do not face the full effect of an increase in the severance tax rate. As shown, tax base and rate interactions partially offset the pure-effect of the severance tax rate increase. To illustrate this clearly, counterpart simulations were conducted where all tax effects, other than state level production tax rates, were effectively *zeroed out*. The lower section of Table 3 presents the counterpart Wyoming results. When all tax interactions are ignored, doubling the state severance tax decreases relative drilling by 32.8% and production by 11.2%, a decrease in activity roughly 2 times larger than found in the full tax interaction model examined above. Timing effects are similar to the full tax interaction model results. Because the severance tax increase now invokes a larger production loss, discounted state severance taxes increase by 83% as compared to the 91% increase in the full tax interaction model. Analyzing taxes individually appears to overstate the affects on exploration and production by ignoring potential offsets and tax base interactions. These results suggest that taxes should not be analyzed independently without careful reference to the entire tax structure applied by all levels of government.

General results of this study suggest that oil production is highly inelastic with respect to changes in production taxes. This inelastic response may provide incentives for state officials to substantially increase these taxes risking little in the way of reduced industry activity while gaining much needed tax revenue. State severance tax increases clearly reduce the net price faced by producers but it is reserves, not net price, that drives production in this industry. Moreover, the effects of increased state severance taxes are partially offset by reduced tax collections by all other levels of government.

4. Conclusions

This paper has adapted Pindyck's (1978) model of nonrenewable natural resource production to take account of taxation at the federal and state-local government levels. Equations of the model are estimated from panel data on production, exploration and reserve additions for 15 states over the period 1970-98. The model is designed so that effects of changes in existing state production tax rates on the timing and evolution of exploration and production can be simulated into the mid-21st century. Results of this study suggest that oil production is highly inelastic with respect to changes in production taxes. A production tax rate increase is shown to decrease early period exploration effort, invoke little change in reserve additions and subsequently future production, and substantially increase discounted tax revenue. Policy implications of this outcome suggest that state officials may consider raising production tax rates as a way to increase revenue while risking little in the way of loss to future oil activity.

Endnotes

[1]Pindyck's (1978) original specification of the extraction cost function is retained here in spite of the logical inconsistencies discussed by Livernois and Uhler (1987), Livernois (1987), and Swierzbinski and Mendelsohn (1989). These authors argue that Pindyck's extraction cost function is defensible when reserves are of uniform quality but in the presence of exploration, reserves must be treated as heterogeneous because the most accessible deposits are added to the reserve base first. They show that aggregation of extraction costs across heterogeneous deposits is not valid except under special circumstances. Another problem with this function is that extraction costs should be a function of γ. The extraction cost function derived from profit-maximization at a point in time subject to a production constraint would have γ as an argument because the reserve base is an input to oil and gas production. These complications are ignored in the analysis below because of severe data constraints on estimating the extraction cost function.

[2] The Energy Information Administration and the American Petroleum Institute report annual production data for 31 states over this period, but data on reserve additions, cumulative drilling, and drilling costs are not available in all years for the 16 smallest producing states. The 15 states included in the panel are Alaska, Alabama, California, Colorado, Kansas, Louisiana, Michigan, Mississippi, Montana, North Dakota, New Mexico, Oklahoma, Texas, Utah, and Wyoming.

[3] Major cost items are for labor, materials, supplies, machinery and tools, water, transportation, fuels, power, and direct overhead for operations such as permitting and preparation, road building, drilling pit construction, erecting and dismantling derricks/drilling rigs, drilling hole, casing, hauling and disposal of waste materials and site restoration. For additional details, see Joint Association Survey on Drilling Costs, Appendix A (1998).

[4] Corrected (see Greene 1997, p. 279) state-specific intercept terms (and t-statistics) for 7 major producing states are: CA 0.17(2.01), KS 0.06(1.06), LA 0.57(2.21), NM 0.19(1.68), OK 0.07(1.94), TX 0.01(1.11), WY 0.29(2.03). Equation (6) was also estimated allowing for both state-specific intercepts and state-specific coefficients for ρ and β. This strategy was unsuccessful as it yielded mostly insignificant estimates of state-specific slope interactions.

[5]Source of world oil production for 1970-98, www.eia.doe.gov/emeu/international/ petroleu.html.

References

Adelman, Morris A. 1990. "Mineral Depletion, with Special Reference to Petroleum," Review of Economics and Statistics 72: 1-10.

American Petroleum Institute. Basic Petroleum Data Book. Annual. Washington, D.C.

American Petroleum Institute. Joint Association Survey on Drilling Costs. Annual. Washington, D.C.

American Petroleum Institute. Petroleum Facts and Figures. 1971 ed. Washington, D.C: 16-23.

Bartik, Timothy J. 1985. "Business Location Decisions in the United States: Estimates of the Effects of Unionization, Taxes, and Other Characteristics of States," Journal of Business and Statistics 3:14-22.

Burness, H. Stuart. 1976. "On the Taxation of Nonreplenishable Natural Resources," Journal of Environmental Economics and Management, 3:289-311.

Conrad, Robert F. and B. Hool. 1980. "Resource Taxation with Heterogeneous Quality and Endogenous Reserves," Journal of Public Economics, 16.

Deacon, Robert, Stephen DeCanio, H.E. Frech III, M. Bruce Johnson. 1990. Taxing Energy: Oil Severance Taxation and the Economy. New York: Holmes & Meier.

Deacon, Robert T. 1993. "Taxation, Depletion, and Welfare: A Simulation Study of the U.S. Petroleum Resource," Journal of Environmental Economics and Management, 24:159-87.

Gerking, S., W. Morgan, M. Kunce, and J. Kerkvliet. 2000. Mineral Tax Incentives, Mineral Production and the Wyoming Economy. Report to the State of Wyoming. http://w3.uwyo.edu/~mkunce/StateReport.pdf

Greene, William H. 1997. Econometric Analysis. 3rd Edition. Saddle River, New Jersey: Prentice Hall.

Heaps, Terry. 1985. "The Taxation of Nonreplenishable Natural Resources Revisited," Journal of Environmental Economics and Management, 12:14-27.

Helms, L. Jay. 1985. "The Effect of State and Local Taxes on Economic Growth: A Time-Series Cross Section Approach," Review of Economics and Statistics 67:574-82.

Holmes, Thomas J. 1998. “The Effect of State Policies on the Location of Manufacturing: Evidence from State Borders,” Journal of Political Economy, 106:667-705.

Kunce, M., S. Gerking, and W. E. Morgan. 2001. “Environmental Policy and the Timing of Drilling and Production in the Oil and Gas Industry,” *in* Recent Advances in Environmental Economics, (John A. List & Aart de Zeeuw, Eds.) Edward Elgar Publishing. Forthcoming.

Livernois, John L. 1987. “Empirical Evidence on the Characteristics of Extractive Technologies: The Case of Oil,” Journal of Environmental Economics and Management, 14: 72-86.

Livernois, John L. 1988. “Estimates of Marginal Discovery Costs for Oil and Gas,” Canadian Journal of Economics, 21: 379-93.

Livernois, John L. and Russell S. Uhler. 1987. “Extraction Costs and the Economics of Nonrenewable Resources,” Journal of Political Economy 95: 195-203.

McDonald, Stephen L. 1994. “The Hotelling Principle and In-Ground Values of Oil Reserves: Why the Principle Over-Predicts Actual Values,” The Energy Journal 15: 1-17.

Moroney, John R. 1997. Exploration, Development, and Production: Texas Oil and Gas, 1970-95. Greenwich, Connecticut: JAI Press.

Papke, Leslie E. 1991. “Interstate Business Tax Differentials and New Firm Location,” Journal of Public Economics 45:47-68.

Papke, Leslie E. 1994. “Tax Policy and Urban Development,” Journal of Public Economics 54:37-49.

Pesaran, M. Hashem. 1990. “An Econometric Analysis of Exploration and Extraction of Oil in the U.K. Continental Shelf,” Economic Journal, 100:367-90.

Pindyck, Robert S. 1978. “The Optimal Exploration and Production of Nonrenewable Resources,” Journal of Political Economy, 86:841-61.

Swierzbinski, Joseph E. and Robert Mendelsohn. 1989. “Exploration and Exhaustible Resources: The Microfoundations of Aggregate Models,” International Economic Review 30:175-86.

Uhler, Russel S. 1976. "Costs and Supply in Petroleum Exploration: The Case of Alberta," Canadian Journal of Economics, 29:72-90.

U.S. Department of Energy. Energy Information Administration. Cost indices for domestic oil field equipment and production operations. Annual. Washington, D.C.

U.S. Department of Energy. Energy Information Administration. U.S. crude oil, natural gas, and gas liquids reserves. Annual. Washington, D.C.

U.S. Deparment of Treasury. Statistics of Income. 1996-98. Washington D.C.

Yücel, Mine K. 1989. "Severance Taxes and Market Structure in an Exhaustible Resource Industry," Journal of Environmental Economics and Management, 16:134-48.

Table 1
Variable Definitions, Data Sources, and Sample Means
(Excludes federal OCS activity.)

Variable	***Definition***	***Source***	***Mean***
TRCOST	Total drilling cost in millions of 1995 dollars, by state and year.	American Petroleum Institute, *Joint Association Survey on Drilling Costs.* Annual.	427.6
ADDED RESERVES	Oil reserve extensions, new field discoveries and new reservoir discoveries in old fields, by state and year in millions of barrels.	US Energy Information Administration, *U.S. Crude Oil, Natural Gas and Gas Liquids Reserves Annual Report.* Annual	42.0
WELLS	Oil wells drilled in a state by year.	American Petroleum Institute, *Joint Association Survey on Drilling Costs.* Annual.	943
CWELLS	Cumulative total wells drilled in a state beginning in 1859.	American Petroleum Institute, *Petroleum Facts & Figures.* 1971 Ed.	1.07E+5
PRICE	Average well head oil price, by state and year, in 1995 dollars per barrel.	American Petroleum Institute, *Basic Petroleum Data Book.* Annual.	22.80
PRICE2	Average real price per barrel squared.	- -	656.3
CWELLS2	Cumulative oil wells squared.	- -	4.3E+10
*PRICE * CWELLS*	Interaction of real price and cumulative wells.	- -	2.5E+6

Table 2
Pre-Tax Marginal Drilling Cost, Marginal Reserve Additions,
and Pre-Tax Marginal Cost of Reserve Additions for 7 Major Producing States

State	D_w^* **(in \$)**	f_w **(in bbls)**[a]	D_w^* / f_w [a]
California	274,675	11,464	23.96
Kansas	127,943	7,460	17.15
Louisiana	1,218,758	64,862	18.79
New Mexico	485,698	22,148	21.93
Oklahoma	345,706	15,223	22.71
Texas	342,266	13,144	26.04
Wyoming	593,162	34,627	17.13

[a] Assumes wells drilled at the actual 1998 count. State-specific cumulative wells total is set to actual 1998 values in all calculations.

Table 3
Timing of Drilling, Production,
and Discounted Severance Tax Revenue

Full Tax Interaction Model

	Individual Program Year:					
	Year 1	***Year 10***	***Year 20***	***Year 30***	***Year 40***	***Total***
Drilling (Base Solution, in wells)	211	203	187	132	2	6274
Drilling (Double Tax)	170	165	152	116	2	5066
Change from Base	-19.4 %	-18.7 %	-18.7 %	-12.1 %	0.0 %	-19.2 %
Production (Base, in MMbbls)	57.7	27.0	15.9	12.1	7.6	834.3
Production (Double Tax)	56.3	25.9	14.7	10.8	6.7	786.6
Change from Base	-2.4 %	-4.1 %	-7.5 %	-10.7 %	-11.8 %	-5.7 %
Severance Tax Revenue (Base, $MM)	66.6	21.3	8.2	4.2	1.9	608.6
Severance Tax Revenue (Double Tax)	130.2	41.0	15.2	7.4	3.3	1165.2
Change from Base	95.5 %	92.5 %	85.4 %	76.2 %	73.7 %	91.5 %

	10 Year Fractions of Total Change from Base Solution:			
	Years 1-10	***Years 11-20***	***Years 21-30***	***Years 31-40***
Drilling	33.0 %	30.8 %	25.9 %	10.3 %
Production	21.2 %	24.8 %	27.0 %	27.0 %
Severance Tax Revenue	67.2 %	20.4 %	8.4 %	4.0 %

No Tax Interaction Model

	Individual Program Year:					
	Year 1	***Year 10***	***Year 20***	***Year 30***	***Year 40***	***Total***
Drilling (Base Solution, in wells)	283	271	249	175	1	8363
Drilling (Double Tax)	189	183	168	119	1	5624
Change from Base	-33.1 %	-32.6 %	-32.4 %	-32.0 %	0.0 %	-32.8 %
Production (Base, in MMbbls)	59.6	28.8	18.0	14.2	9.0	911.0
Production (Double Tax)	57.0	26.4	15.3	11.4	7.2	809.3
Change from Base	-4.4 %	-8.3 %	-15.0 %	-19.7 %	-20.1 %	-11.2 %
Severance Tax Revenue (Base, $MM)	75.6	24.9	10.2	5.3	2.5	714.3
Severance Tax Revenue (Double Tax)	144.7	45.9	17.4	8.6	3.9	1307.8
Change from Base	91.4 %	84.3 %	70.6 %	62.3 %	56.0 %	83.1 %

	10 Year Fractions of Total Change from Base Solution:			
	Years 1-10	***Years 11-20***	***Years 21-30***	***Years 31-40***
Drilling	33.2 %	30.9 %	25.9 %	10.0 %
Production	21.0 %	25.1 %	26.9 %	27.0 %
Severance Tax Revenue	68.1 %	20.1 %	8.0 %	3.8 %

Figure 1. Wyoming Oil, 1970-98

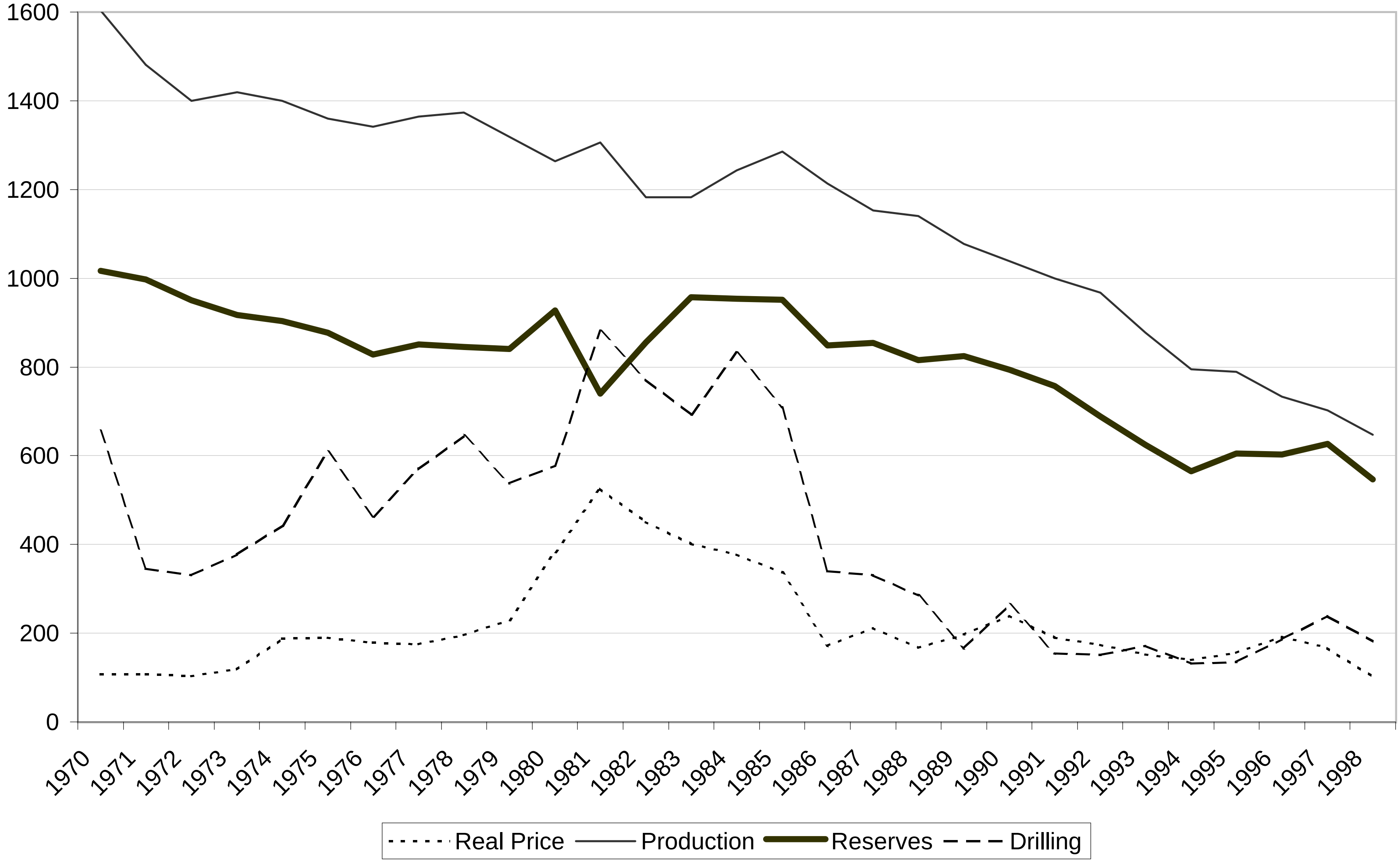
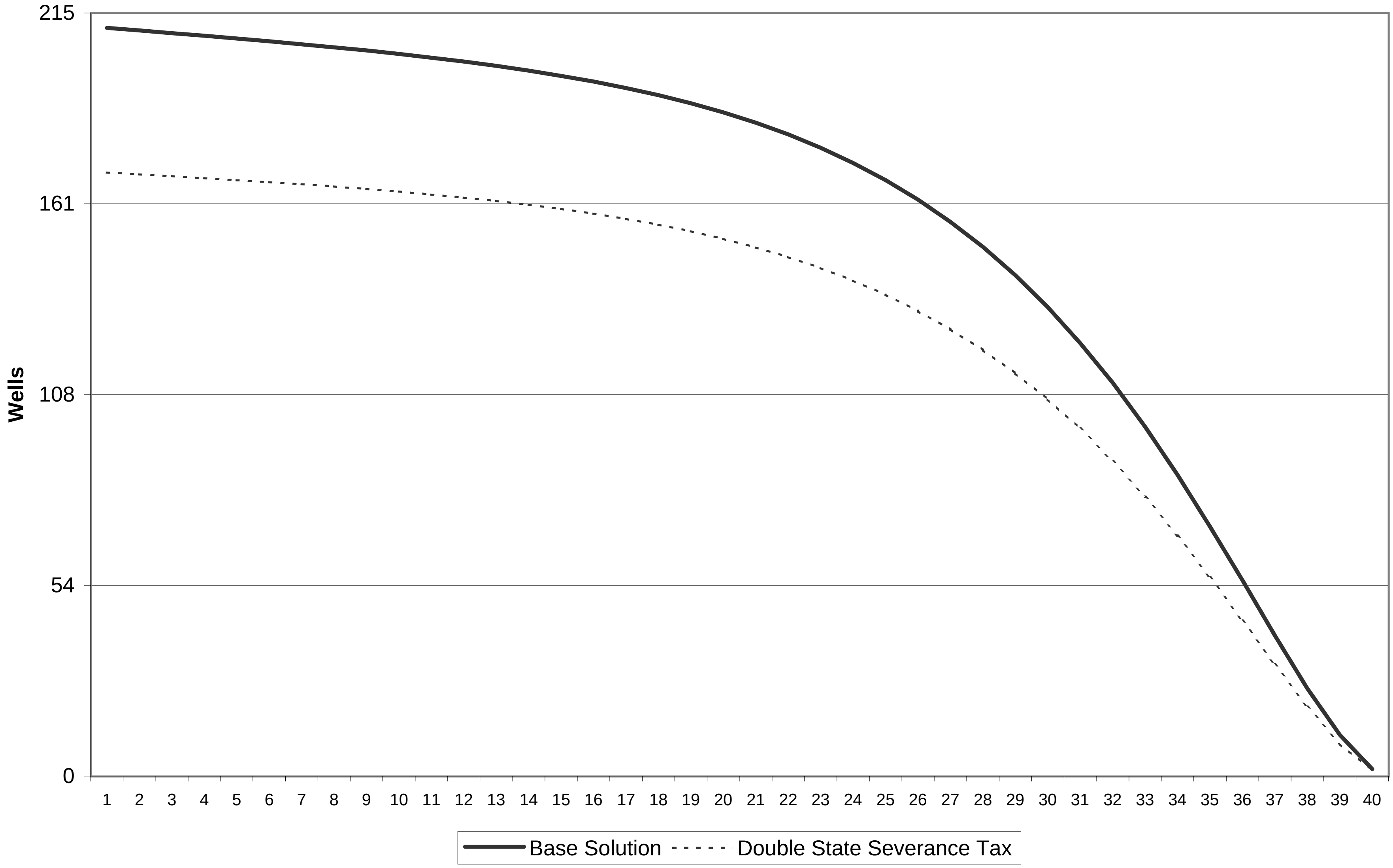


Figure 2. Wyoming Drilling



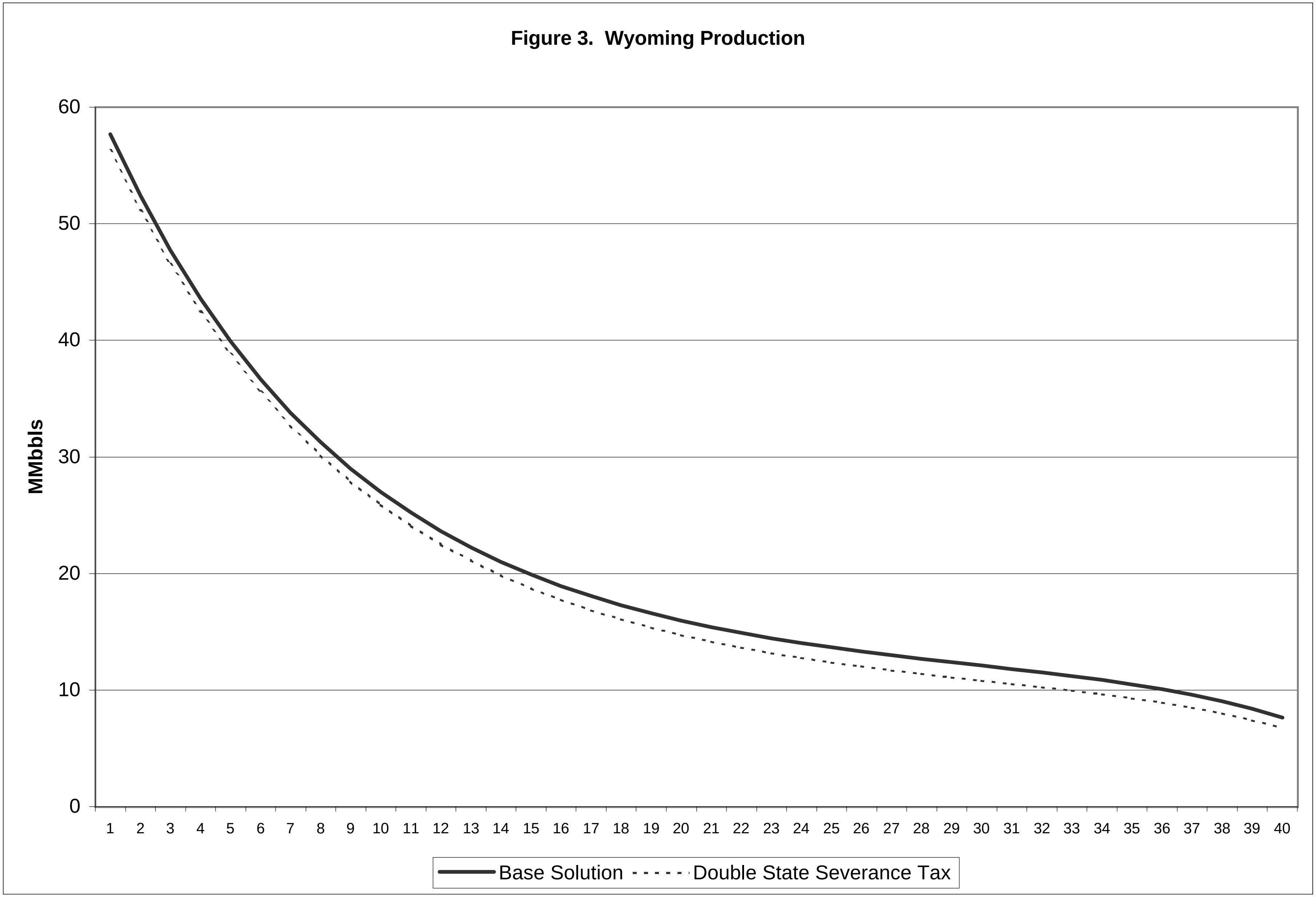


Figure 3. Wyoming Production
MMbbls
60
50
40
30
20
10
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40
Base Solution
Double State Severance Tax

Appendix A

Tax Policy Parameters

For most states in most years, γ and α_j *(j=p,c,D)* can be specified by noting whether reserves are subject to a property tax (see text equation (1)) and then evaluating equations (A.1)-(A.4).

$$\gamma = \{(1-\tau_{us})(1-\tau_s)\tau_R\} \tag{A.1}$$

$$\alpha_p = \{(1-\tau_{us})(1-\tau_s)(1-\tau_r)(1-\tau_p) + \tau_{us}(1-\tau_r)\delta\} \tag{A.2}$$

$$\alpha_C = \{(1-\tau_{us})(1-\tau_S)\} \tag{A.3}$$

$$\alpha_D = \{(1-\tau_{us})(1-\tau_S)\eta\} \tag{A.4}$$

A derivation of equations (A.1)-(A.4) can be found in Gerking, Morgan, Kunce, and Kerkvliet (2000), Appendix C. In (A.1)-(A.4), τ_{us} denotes the federal corporate income tax rate, τ_s denotes the state corporate income tax rate, τ_R denotes the property tax rate on reserves weighted by the per unit assessed value, τ_r denotes the royalty rate on production from public (state and federal) land, τ_p denotes the production (severance) tax rate, δ denotes the federal percentage depletion allowance weighted by the percentage of production attributable to eligible producers (nonintegrated independents), and η denotes the expensed portion of current and capitalized drilling costs attributable to current period revenues. η is made up of two components: (1) the percentage of current period drilling costs expensed and (2) the estimated present value of cost depletion deductions for the capitalized portion of current and past drilling expenditures. Producers are allowed to expense costs associated with drilling dry holes along with certain intangible costs (e.g., labor and fuel) for completed wells as they are incurred. All direct (tangible) expenditures for completed wells must be capitalized then depleted over the life of the producing well. In the illustration at hand, equations (A.1)-(A.4) can be simplified because Wyoming does not have a state corporate income tax ($\tau_s=0$) and does not levy a property tax against reserves in the ground ($\tau_R=0$).

This formulation captures several aspects of the U.S. tax structure as it applies to the oil industry. (1) Federal royalty payments are deductible in computing state production tax liabilities. (2) Federal royalty payments, state production taxes, state property taxes on reserves, extraction costs, and certain drilling costs (described above) are deductible in computing both state and federal corporate income tax liabilities. (3) State corporate income taxes are deductible against federal corporate income tax liabilities. As noted in text section 2, state tax treatment of the oil industry is not uniform and there are a number of situations in which these equations would have to be modified. Notice that this treatment of taxes in the model highlights the interaction between tax bases and is more detailed than the corresponding treatment given by Moroney (1997) or Deacon, DeCanio, Frech, and Johnson (1990). Also, the entire tax structure is incorporated into the model, rather than simply analyzing one tax at a time as in Deacon (1993).

All tax parameters in equations (A.1)-(A.4) are effective rather than nominal rates. States grant numerous credits and exemptions against taxes levied, so nominal rates generally overstate amounts actually paid. State and local data required for these effective rate calculations are neither available from a central source nor compiled in a common format, so they were obtained directly from tax officials in each state (see Gerking, Morgan, Kunce, and Kerkvliet 2000, Chapter 2). In developing the *base* *solution* for Wyoming, royalty rates are computed as the sum of state and federal royalty payments divided by the gross value of production and averaged 9% for oil in the late 1990s. This percentage is higher than for other oil producing states because of the comparatively large share of Wyoming's production on public lands. Production tax rates are computed as total production tax collections divided by the prior year's gross value of production net of public land royalties. In Wyoming, there are both local and state levies against this one-year-lagged net value of production. The sum of the two average effective rates in the late 90's totaled approximately 11.9% (local 6.7% and state 5.2%). At the federal level, data from Statistics of Income (U.S. Department of Treasury, 1997-1998) for the oil and gas sector show that federal corporate taxes paid averaged about 10% of *net operating* income in 1998. Also, the current nominal percentage depletion rate of 15% applied to about 58% of Wyoming oil producers in 1998, thus δ = 8.7%. Also, the expensed portion of current period drilling costs is approximately 40% 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 the ratio of production to reserves is constant (Deacon 1993). Wyoming's mean value of q/R was approximately 8% for the sample period 1996-1998, therefore $\eta = 0.40 + (1 - 0.4)*(0.08 / (0.04 + 0.08)) = 0.8$. The base tax policy parameters for Wyoming are $\alpha_p = 0.73$, $\alpha_c = 0.90$, $\alpha_D = 0.72$, $\gamma = 0$.

Estimate of an Instrument for WELLS

An instrument for the natural logarithm of *WELLS* was used as an explanatory variable in estimating both text equations (5) and (6) with *CWELLS* entering equation (6) as the proxy for x. Instrumental variable estimation is appropriate because w is an endogenous variable in the model presented in Section 2. An instrument for w was obtained by predicting the natural logarithm of the number of wells drilled from the one-way fixed-effects regression reported in Table A.1. Time-specific effects tested insignificant at conventional levels and $R^2 = 0.91$. *PRICE* and *CWELLS* were included as explanatory variables because they are exogenous variables in the model. *PRICE2*, *CWELLS2*, and *PRICE*CWELLS* were included to account for non-linearities expected in light of relationships in the model (see Table 1 for descriptions). All estimated coefficients are significantly different from zero except the interaction term *PRICE*CWELLS*. The marginal effect of *WELLS* with respect to *PRICE* increases at a decreasing rate. The Pearson correlation between the actual values of ln*(WELLS)* and the corresponding predicted values, ln*(PREDWELLS)*, is 0.96.

Table A.1
Construction of Instrument ln*(PREDWELLS)*

Explanatory Variable	***Coefficient*** (t-statistic)
PRICE	0.064 (6.49)
PRICE2	-0.45E-3 (-2.90)
CWELLS	-0.22E-4 (-5.19)
CWELLS2	0.15E-10 (4.17)
*PRICE*CWELLS*	0.18E-7 (1.51)

Extraction Cost Function

Direct operating (lifting) cost for oil by region at depths of 2,000, 4,000, 8,000, and 12,000 feet are available from annual cost index studies published by the DOE/EIA for the period 1970-1998. However, these data are of limited value for two reasons. First, cost estimates are not always disaggregated to the state level and cost estimates for other states may not be representative of all production. Second, through the mid-1980s, price controls on oil and/or gas distorted production incentives, making historical extraction costs difficult to compare with extraction costs in more recent years. As a compromise, following Deacon (1993), values of extraction cost parameters are calibrated for the following Cobb-Douglas function,

$$C(q, R) = \kappa q^{\varepsilon} R^{1-\varepsilon} \, , \tag{A.5}$$

where $\varepsilon = 1/\mu$, μ is the production share of non-reserve inputs, and κ is a constant value that drives the production cost modeled to an average level of *lifting costs* representative of the 1998 DOA/EIA surveyed estimates described above. State-specific estimates for μ are established from the data on operating cost, drilling cost, production, reserve additions, and reserve levels described above (see Kunce, Gerking, and Morgan 2001 for specific calibration methods). Marginal extraction costs per barrel using 1998 data for 7 major producing states are: CA $6.12, KS $4.89, LA $8.81, NM $6.27, OK $6.89, TX $6.71, and WY $6.43. The 1998 calibrated oil production cost parameters for Wyoming are $\varepsilon = 2.93$ and $\kappa = 141$.