ENVIRONMENTAL AND LAND USE REGULATION IN NONRENEWABLE RESOURCE INDUSTRIES: IMPLICATIONS FROM THE WYOMING CHECKERBOARD*

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ABSTRACT. This paper examines how the oil and gas industry responds to changes in environmental and land use regulations pertaining to drilling by examining differences in regulatory practices on federal and private land. A simulation model for Wyoming is used to estimate losses of oil and gas output over the next 60 years because of higher drilling costs found on federal property. This case study is of general interest because it shows that future production is more sensitive to changes in environmental regulations that apply to drilling than to changes in severance taxes levied on production. Also, the foregone value of oil and gas output is interpreted as a lower-bound estimate of the opportunity cost associated with more stringent protection of environmental resources on surface land.

I. INTRODUCTION

How do firms respond to changes in compliance costs imposed by environmental and land use regulations? A substantial volume of research addresses this question for the manufacturing sector (see Becker and Henderson 2000 for a recent example), however, only a few studies along these lines have been conducted for nonrenewable resource industries. Stollery (1985), for example, develops a theoretical model showing how pollution control affects optimal timing of extraction from known reserves by competitive firms. Jin and Grigalunas (1993a) show that increasing environmental compliance costs lead to cumulative reductions in exploration, investment, and extraction and in a related empirical study (1993b), assess consequences of environmental regulations on firms in the offshore oil and gas industry. Dension, Crocker, and Briand (1995) indirectly consider effects of environmental controls on oil production, reasoning that these effects should be similar to those of production and property taxes. Like Stollery, however, they do not consider the situation where environmental regulations directly affect exploration and development activities. In any case, the limited number of studies in this area and their narrow scope is surprising in light of the importance of environmental compliance costs to firms that produce from nonrenewable resources and because of the observation by Jaffe, Peterson, Portney, and Stavins (1995) that a study of effects of these costs in the mining sector could be rewarding.

This paper looks at how future oil and gas exploration and extraction decisions are altered in the face of changes in environmental and land use policies pertaining to drilling. The methodology involves development of a simulation model based on Pindyck's (1978) analysis of natural resource supply. While this model could be applied to any of 21 oil and gas producing states, Wyoming is singled out here for a case study in order to build on prior work (Kunce, Gerking, and Morgan 2002) showing that environmental compliance costs pertaining to drilling are significantly higher on federal property than on private property in that state. The present study makes use of this estimated cost difference and reaches two main conclusions. First, the discounted present value of reduced output statewide because of higher environmental compliance costs on federal property is about $800 million. Second, the analysis illustrates why production is more sensitive to increases in stringency of environmental regulations pertaining to drilling than to increases in production (severance) taxes.

II. REGULATORY BACKGROUND AND DRILLING COST DIFFERENCE ESTIMATES

Numerous federal statutes regulate oil and gas field activities in the U.S. These statutes include the National Environmental Policy Act, the Toxic Substances Control Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation, and Liability Act, the Antiquities Act, and the Threatened and Endangered Species Act. The U.S. Departments of Interior and Agriculture are responsible for interpreting these laws, coordinating activities with other federal agencies, and setting environmental and land use policies on federally managed lands. Federal regulatory agencies, such as the U.S. Environmental Protection Agency, figure prominently in environmental policy development regarding private land, but key state agencies such as oil and gas conservation commissions and game and fish commissions have had increasingly broad rule-making authority since the early 1980s. Also, states have passed their own environmental legislation concerning oil and gas development to increase stringency of certain standards, address local problems, and/or clarify the regulatory authority of their own agencies. Attempts have been made to calculate how much it costs to comply with this myriad of regulations (Stewart and Templet 1989), but these estimates apply only to hypothetical situations. There are no published estimates of compliance costs for the industry generally that parallel the PACE data available for manufacturing sectors.[1]

Federal environmental and land use regulations apply equally to all oil and gas activity regardless of land ownership, however, evidence from interviews of market participants (Gerking, Morgan, Kunce, and Kerkvliet 2000) and Congressional testimony (Committee on Resources 2001 and Hackett 2001) suggest that cultural and biological resources are more stringently protected on federal land than on private land. Regarding cultural resources, federal land managers are obligated under the Antiquities Act, for example, to identify and preserve Native American artifacts (i.e., arrowheads, pottery shards) and historic sites such as those along the original wagon trails. Private landowners, in contrast, have an incentive to view items of historical significance as their own and in some cases have refused to allow archeological surveys on their property. Thus, cultural resources appear to be better protected on federal property may not even be identified on private property. Also, federal land managers require greater precautions to protect biological resources. Conflicts between endangered species protection, private property rights and economic activity are well documented (Innes, Polasky, and Tschirhart 1998), but federal land managers appear to show greater concern for more prevalent species as well. Intrusions into antelope ranges in winter and protection of flowering plants in spring are examples that can be cited in this regard.

Extra precautions taken on federal property could translate into delays and added expense in all phases of oil and gas operations, but the interviews and congressional testimony cited above singled out drilling as particularly affected and did not mention the possibility that production costs might differ on private and federal land.[2] McDonald (1994) has discussed delays in issuing drilling permits and suggests that the federal government has been slow to release drilling areas on public land. Yet, the issue appears to be broader because the permits themselves frequently narrow the window of time during which drilling can occur to as little as a few months per year. A narrow drilling window can be disruptive and can lead to added costs in that it causes wells to be drilled incrementally in possibly inefficient phases (Hackett 2001; p. 7). Moreover, if drilling is permitted only in winter, higher labor and equipment costs would be expected in some parts of the U.S. as crews may be forced to deal with subzero temperatures and windy conditions.

These findings motivated a recent study by Kunce, Gerking, and Morgan (2002), which concludes that in the Wyoming Checkerboard, oil and gas drilling costs are significantly higher on federal land than on private land.[3] The Checkerboard, a center of recent oil and gas activity located in southwestern Wyoming, is a 40-mile wide strip of land, 20 miles on either side of the Union Pacific Railroad right-of-way extending about 200 miles westward from Rawlins to the Utah state line. As an inducement to establish rail service through Wyoming, the Pacific Railway Acts of 1862 and 1864 deeded to the railroad the odd-numbered (square-mile) sections of land in this area while retaining the even numbered sections as federal property. Thus, every federal section was surrounded on four sides by railroad sections and every railroad section was surrounded on four sides by federal sections giving maps of the area showing land ownership the appearance of a checkerboard. In the intervening years, the railroad sold their land to other private owners; nevertheless the alternating private-federal land ownership pattern is remarkably persistent to the present day and served as an experimental control used to identify an average drilling cost premium on federal land. Estimates of this premium, which differed significantly from zero at the 5% level, were: (1) \$53,000 for wells drilled to depths less than 9600 feet, (2) \$96,000 for wells drilled to depths between 9600 feet and 12,300 feet, and (3) \$268,000 for wells drilled to depths greater than 12,300 feet.[4] These estimates, which are used in developing the simulations reported in Section V, control for unmeasured site-specific characteristics left uncontrolled in earlier studies (Harder, John, and Dupont 1995 and Schultz 1998) and are consistent with the notion that narrow drilling windows on federal property increase costs disproportionately for deeper wells.

III. MODEL

Implications of higher drilling costs on federal property are drawn from a simulation model based on Pindyck's (1978) analysis of non-renewable resource supply. Deacon (1993) and Yucel (1989) used a similar approach to evaluate effects of alternative tax treatments on oil production, but did not consider effects of changes in environmental policy. Although the basic model is well known, providing an overview here is useful because it provides a clear view of how environmental regulations that apply to drilling affect exploration and production over time. Also, as explained below, the model is used to integrate environmental regulations into a setting where the institutionally complex tax treatment of oil and gas is accounted for.[5]

The model treats both exploration and production, but does not consider aspects such as uncertainty and selection and/or discovery of heterogeneous grades (see Krautkraemer 1998 for a recent survey of these issues). Perfectly competitive producers maximize the discounted present value of future operating profits from the sale of resources. The firm's problem is to take future output prices, taxes, and regulations as given and then choose optimal time paths for exploration and production. This assumption is common in studies that examine the effects of changes in state tax or regulatory policy, but does not consider the possibility that taxes and environmental regulations are chosen endogenously (i.e., that governments choose such policies in light of the firm's behavior). A single firm is used to represent the industry, so the common pool problem and well spacing regulations are ignored (McDonald 1994). For simplicity, exploration here is defined to include resource development, although the two activities are certainly not the same (Adelman 1990). The aim of exploration is to add to the reserve base, which in the model represents a form of geographically immobile capital. Oil and gas are treated jointly in the analysis, rather than as separate industries, because wells are classified as oil or gas (or dry) only after the outcome of drilling is known and oil fields sometimes produce so-called associated gas. Problems of aggregating across fields (not considered here) and the treatment of joint production are discussed more fully by Bohi and Toman (1984, Chapters 3, 5) and by Livernois (1987, 1988).

More formally, the firm's maximization problem is

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

subject to

$$\dot{R} = \dot{x} - q \qquad [2]$$

$$\dot{x} = f(w, x) \qquad [3]$$

$$q \geq 0, w \geq 0, R \geq 0, x \geq 0 \qquad [4]$$

where a dot over a variable denotes a time rate of change, q denotes the quantity of oil and gas extracted measured in barrels of oil equivalent (BOE),[6] p denotes the exogenous market price per BOE 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),[7] $D(w)$ denotes total cost of exploration for additional reserves net of taxes, w denotes exploratory effort as total wells drilled, 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).[8]

In this formulation, the net-of-tax price per BOE is related to the wellhead (pre-tax) price (p^*) according to $p = \alpha_p p^*$, where α_p is a function, for example, of federal corporate income, state severance, and local production tax rates such that $0 < \alpha_p < 1$. Correspondingly, $C(q, R) = \alpha_c C^*(q, R)$ and $D(w) = (1+\tau)\alpha_D D^*(w)$, where α_c and α_D also are functions of tax rates and lie on the unit interval. In general, $\alpha_p < \alpha_c$ because production taxes and public land royalty rates, unlike corporate income tax rates, are applied to gross revenue rather than net operating income. The drilling tax parameter (α_D) includes, among other things, the opportunity to expense the costs of drilling dry holes along with certain other intangible drilling costs. The environmental regulation parameter, τ, which can be positive or negative, denotes the percentage change in drilling costs due to a change in environmental and land use regulations.[9] The simulations described below examine effects of changes in τ and account for the fact that these changes are to some extent offset by changes in liabilities from taxes levied by all levels of government. Also, notice that severance taxes and environmental regulations pertaining to drilling enter the model in different ways. Thus, changes in these policy parameters would be expected to have different effects on drilling, production, and reserve additions. This point will be explored more fully in the context of the model simulations presented in Section V. Also, a more detailed discussion of how the tax parameters were constructed appears in the Appendix.

The Hamiltonian for this problem is

$$H = qpe^{-rt} - C(q,R)e^{-rt} - D(w)e^{-rt} + \lambda_1[f(w,x) - q] + \lambda_2[f(w,x)]. \qquad [5]$$

Differentiating H with respect to R, q, x, and w yields

$$-C_R e^{-rt} + \dot{\lambda}_1 = 0 \qquad [6]$$

$$pe^{-rt} - C_q e^{-rt} - \lambda_1 = 0 \qquad [7]$$

$$f_x(\lambda_1 + \lambda_2) + \dot{\lambda}_2 = 0 \qquad [8]$$

$$-D_w e^{-rt} + f_w(\lambda_1 + \lambda_2) = 0, \qquad [9]$$

where letter subscripts denote partial derivatives. The shadow price λ_1 reflects the positive change in the present value of future profits from an additional unit of reserves. In equation [6] $\dot{\lambda}_1 < 0$ because $C_R < 0$. From equation [8] and equation [9], $(\lambda_1 + \lambda_2)$ equals the discounted value of the marginal cost of adding another unit of reserves by exploration (discoveries) $(D_w / f_w)e^{-rt}$. If τ initially is set higher (environmental regulations on federal land are more stringent), the after-tax marginal cost of reserve additions also is higher, but this effect is attenuated because $0 < \alpha_D < 1$. The shadow price of cumulative reserve discoveries, λ_2, is expected to be negative (and small relative to λ_1) because current reserve discoveries will increase the amount of exploration needed in the future. The evolution of this shadow price is increasing, $\dot{\lambda}_2 > 0$, because $f_x < 0$.

Optimal time paths for *w* and *q* can be obtained by manipulating the optimality conditions above. Evolution equations become,

$$\dot{w} = \frac{D_w[(f_{wx}/f_w)\cdot f - f_x + r] + C_R f_w}{[-D_w(f_{ww}/f_w)]}, \qquad [10]$$

$$\dot{q} = \frac{-r(p - C_q) + \dot{p} - C_{qR}\dot{R} - C_R}{C_{qq}}. \qquad [11]$$

Equation [10] shows that the trajectory of exploratory effort is determined by a tradeoff between the cost of finding new reserves and the extraction cost savings this new level of reserves yields. As specified in the model, environmental regulations increase the present value cost of finding new reserves. Moreover, these regulations work against the extraction cost savings effect by tilting exploration effort into the future. The numerator of equation [11] emphasizes the role reserves play in the optimal extraction path. As reserves are depleted, marginal extraction costs rise, thus attenuating production. Therefore, environmental and land use regulations may decrease incentives to explore, which limit future reserve additions thereby increasing extraction costs, which will reduce future production.

IV. Estimation of Model Parameters

This section presents estimates of the key equations of the model to be simulated. Estimates are obtained from publicly available, balanced panel data on 21 states over the

31-year period 1970-2000 (NT=651).[10] These states accounted for 98% of U.S. oil production and 95% of U.S. gas production over this time period. A more spatially disaggregated (sub-state or field level) approach would be superior to using state-level data because of the considerable variability within states in drilling depths, ease of drilling, sediment structure, and other cost-determining factors. However, constructing the simulation model for Wyoming at the sub-state or field-level data would be quite difficult because data on key variables at this level of geographic detail, either are proprietary or must be purchased. Nevertheless, the state-level analysis presented here still retains more spatial detail than Deacon's (1993) related study of state taxes that was carried out by calibrating a simulation model using national data.

More specifically, drilling cost information for individual wells are available commercially from I.H.S. Energy Group, but well locations are consistently provided only for wells drilled after the late 1970s. The U.S. Department of Energy, Energy Information Administration (EIA) collects data on oil and gas reserve additions by field, however, these data are aggregated up to the state level prior to public release due to confidentiality agreements with operators. California, which levies property tax on reserves, makes estimates of reserves by field (see California Division of Oil and Gas Annual Reports) and these data were used by Deacon, DeCanio, Frech, and Johnson (1990) in their study of the impact of a proposed severance tax on oil production in that state. Most oil and gas producing states including Wyoming, however, do not levy a property tax on reserves and do not make detailed reserve estimates such as those available for California. Of course, oil and gas operators have proprietary information about their own reserves, but attempts of obtain these data were not successful. Finally, data on extraction costs are particularly weak and available from EIA only for large oil and gas producing regions that sometimes do not correspond to states. Developing detailed sub-state or field-level production cost data would require a comprehensive survey and operators would have to release confidential cost information. Chermak and Patrick (1995) had access to such data from four anonymous companies for their study of the natural gas industry, however, extraction cost data are not generally available for individual wells.

Estimation of the model presented in the previous section can be approached in two ways. First, equation [10] and equation [11] could be estimated econometrically. Partly because they are nonlinear, estimating these equations directly poses certain econometric issues (see Pesaran 1990) and it is unclear how information from the transversality conditions would be incorporated. Second, an alternative strategy adopted here, would be to obtain estimates for D^*, f, C^*, and the tax parameters and then insert them into the model in order to simulate the effects of environmental policy changes, after imposing transversality conditions. A brief discussion of how equations for D^*, f, C^* were estimated follows.

Drilling costs are modeled as proportional to drilling effort.

$$D^*(w)=\phi we^u \qquad [12]$$

This approach yields constant marginal drilling costs, which ensures that the objective function (see equation [1]) represents a perfectly competitive firm. In equation [12], 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. Taking the natural log of equation [12] and rearranging yields,

$$ln\ D^*(w) - ln\ w = ln\phi + u, \qquad [13]$$

where the dependent variable is the natural logarithm of drilling cost per well. Data by state and over time on labor, capital, and other primary inputs to drilling are unavailable, so the annual number of wells drilled in a state is used as a measure of drilling effort (w). Data on footage drilled also could be used as a measure of w. However, in the data set applied the number of wells drilled is positively correlated with total footage drilled (Pearson correlation = 0.98). Also, total drilling cost is approximately proportional to both footage and the number of wells, so to some extent the two variables measure the same thing. As discussed in Section III, cumulative reserve discovery (x) appears as an argument in the production function for new reserves (see equation [14] below). A proxy for x can be constructed from available data (American Petroleum Institute, 1971) on the total number of wells drilled by state since 1859 (when the first oil well was drilled in Pennsylvania), whereas corresponding data on total footage drilled since that date are not available. Thus, use of number of wells as a measure of drilling effort simplifies the simulations presented in Section V and eliminates the need for arbitrary assumptions about historical average depth per well.

The production function for reserve additions is specified as

$$f(w,x) = Aw^{\rho}e^{-\beta \cdot x}e^{v} \qquad [14]$$

where A, ρ, and β are parameters to be estimated and the multiplicative disturbance e^{v} is assumed lognormally distributed with mean of unity and variance σ_v^2. The functional form selected for f 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. As just discussed, w is measured by annual wells drilled by state and x is proxied by total wells drilled by state since 1859.

Data sources, definitions, and sample means are presented in Table 1 for the 21 state panel and for Wyoming. All nominal values are converted to \$2000 using the GDP deflator. Estimates of the drilling cost equation are obtained by regressing the natural log of drilling costs per well on dummy variables for states and years (see equation [13]). This approach is a simple way to control for heterogeneity across states and over time. Examples of state-specific effects include geologic conditions, geographic remoteness of on-shore oil and gas resources, and whether drilling occurs in off-shore coastal waters (note that most states in the data set are landlocked). Time-specific effects include factors common to all states that vary over time, including technological advancement, macroeconomic cycles, and trends in average drilling depth. In the estimated equation, R^2 is 0.93 and state- and time-specific coefficients are each jointly significant at the 1% level. Time-specific coefficients, however, do not exhibit a consistent pattern, suggesting that they could reflect a number of different factors that vary in relative importance over the sample period. The corrected (from natural log conversion, see Greene 1997, 279) estimate of ϕ for Wyoming in the year 2000 (in \$2000) is \$657,047 ($t = 4.66$). This figure includes the federal land cost premium for the average well drilled in the state.

Equation [14] was estimated using additions to proved reserves as the dependent variable.[11] The number of wells drilled (w) is an endogenous variable in the model presented in Section III and a Durbin-Wu-Hausman test (see Davidson and MacKinnon 1993, 389-93) rejected the exogeneity of w at the 5% level. An instrument for w was obtained from the predicted values from a regression of the number of wells drilled by state and year on cumulative drilling and the wellhead price as shown in the Appendix. Estimates of the reserve addition equation 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 ($\rho = 0.399$).[12] The estimated equation with the Wyoming-specific constant term is shown in equation [15] with t-statistics shown in parentheses beneath the coefficients. For this equation, $R^2=0.74$.

$$\ln(\widehat{ADDED\ RESERVES}) = \underset{(2.63)}{\ln 1.2} + \underset{(9.23)}{0.53}*\ln(PREDWELLS) - \underset{(-1.11)}{0.000001}*CWELLS \qquad [15]$$

As shown, the coefficient of the instrument for wells (ln(*PREDWELLS*)) is 0.53 and it significantly differs from zero at conventional levels suggesting that the marginal product of drilling is positive. Also, the negative coefficient of cumulative drilling (*CWELLS*), though insignificant at conventional levels, suggests that reserve additions may decline with the passage of time as new reserves become more difficult to identify. Evaluating equation [15] using year 2000 values for predicted wells drilled and cumulative wells drilled yields a marginal product (f_w) of 48,072 BOE for Wyoming. Combining the marginal drilling cost (in \$2000) with the marginal product of drilling estimates for Wyoming yields a pre-tax marginal cost of reserve additions (D_w^* / f_w) of \$13.67 per BOE.

Regarding the extraction cost function (C^*), direct operating (lifting) costs for both oil and gas by region at various depths are available from annual studies published by the U.S. Department of Energy, Energy Information Administration for the period 1970-2000. However, these data are of limited value for two reasons. First, no cost estimates are reported for some states (Kansas and Alaska, for example) 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, values of extraction cost parameters were obtained using the procedure outlined in Deacon (1993). This procedure assumes that production (q) is Cobb-Douglas in reserve and non-reserve inputs. A representation for $C^*(q, R)$ then is derived based on profit maximization and parameter values are selected based on current estimates of operating and drilling costs, production, and reserves. Cost parameter calibration specifics are described in the Appendix. Results show that the marginal extraction cost for Wyoming evaluated with q and R set at year 2000 values is \$5.80 per BOE.

The resulting Cobb-Douglas form for extraction costs insures that these costs will rise without limit as reserves approach zero. This condition implies that a positive level of reserves will remain at any terminal time, denoted T_1. Likewise, the functional form invokes a strictly positive level of production given any positive level of reserves. Thus, production continues after incentives for further exploration vanish and that the terminal date for maximizing discounted operating profits must be set arbitrarily. This fixed program period could be interpreted as the producer's relevant planning horizon.

V. SIMULATION RESULTS

This section applies the model just described to simulate removal of the more stringent environmental and land use regulations on federal property for oil and gas drilling and production in Wyoming. An alternative approach would be to apply the more stringent federal land standards to drilling on private land. Because federal and private land drilling shares are about equal in Wyoming through the 1990s, following this alternative approach would produce results symmetric to those presented below. In any case, solution values reflect a situation where environmental regulations on comparable federal and private property are equally stringent. If the purpose of the regulations is to internalize externalities, then modeling equal enforcement on similar types of land would provide a useful comparison.

The model was constructed to make it as specific to Wyoming as possible given the limitations of available data. For example, the model uses the estimate of drilling cost per well (ϕ) for Wyoming from equation [13] together with the estimate of equation [14], which has a Wyoming-specific intercept. (Recall that Wyoming-specific slopes were no different that those for all other states.) Simulations show effects of the percentage reduction in drilling costs statewide that would result if environmental compliance costs on federal property are reduced to the level of those seen on private property. This percentage, $\tau = -5.72\%$, is calculated by weighting estimates of extra cost of drilling a well on federal property by depth range from the Checkerboard study (see Section II) by percentages of wells drilled on federal property in Wyoming for these same depth ranges in 1999. These statewide data, obtained from a special tabulation by I.H.S. Energy Group, show that 48.1% of wells were drilled on federal property and that most Wyoming wells are shallower than the average Checkerboard well.[13] Simulations with $\tau = -5.72\%$ are compared to a base case in which τ is set equal to zero.

Simulations were performed under five assumptions regarding the behavior of key variables. First, oil and gas producers are assumed to receive \$19.87 per barrel of oil equivalent (BOE) gross-of-tax at the wellhead (in real terms) in each year of the extraction and drilling program. This figure is the 1970-2000 U.S. national mean for the real price per BOE and for Wyoming, it is roughly the equivalent of assuming a real oil price of \$27/barrel and a real gas price of \$2.75/Mcf.[14] Both increasing and decreasing price evolutions also were simulated, but these alternative paths have little or no effect on the comparative results presented below. Second, the perspective taken is that Wyoming represents only a small fraction of total world (or U.S.) oil and gas supply. Thus, changes in taxes levied and regulations imposed there are assumed to have no impact on prevailing prices faced by other producers in other states or countries.[15] Third, in the simulations reported, the initial values of reserves and cumulative wells drilled were fixed at year-end 2000 levels for Wyoming (3433 MMBOE and 63,595 wells) and the discount rate, r, was set at 4% to reflect the risk-free real rate of long-term borrowing. Fourth, federal, state, and local tax treatment of oil and gas exploration and production make use of effective tax rates for the year 2000 that account for the generous federal tax treatment of drilling costs as well as several important exemptions and credits granted through the Wyoming tax code to oil and gas producers. The after-tax impact of a reduction in environmental regulatory costs is a little more than two-thirds of the pre-tax impact, $\alpha_D = 0.71$. Other tax parameters for Wyoming are $\alpha_P = 0.71$, and $\alpha_C = 0.89$ (see the Appendix for details). Fifth, results presented do not reflect the possibility of technological advancement in finding, developing, or extracting oil and gas reserves over the simulation period. However, the interaction between technological advancement and differential enforcement of environmental regulations on private and federal land is a potentially important issue and will be discussed later on.

In order to obtain numerical solutions for the time paths of drilling, production, and reserves, difference equation approximations are derived for the optimal first-order differential equations [10] and [11] along with the state-variable evolution equations [2] and [3]. For example, the evolution of reserve additions, equation [3], can be approximated by the simple difference, $x_t - x_{t\text{-}1} = f_{t\text{-}1}$. Once the estimated functions are substituted into the difference equation approximations, the model can be solved recursively by varying (iterating over) the initial values of the control variables, q and w, until transversality conditions ($p - C_q = \lambda_1(T_1)e^{rt} = D_w / f_w$) are satisfied (see Pindyck 1978, 846-47). As discussed in Section IV, production continues after incentives for exploration vanish. Thus, the terminal date for the program must be set arbitrarily; $T_1 =$ 60 years was selected because drilling effort effectively ceases after this point. The Generalized Reduced Gradient nonlinear optimization algorithm found in Microsoft Excel was used to obtain numerical solutions.

The initial values of the shadow prices λ_1 and λ_2 in the base simulation were, respectively, \$7.81 (decreasing with time but never negative) and \$-0.153 (increasing to zero with time but never positive). Starting values for the control variables q and w were 272 MMBOE and 1032 wells drilled. To put these base solution simulated starting values in perspective, Wyoming's production and drilling activity averaged roughly 208 MMBOE and 1139 wells over the sample period (see Table 1). After removing the federal land drilling cost premium, λ_1 and λ_2 become \$7.81 and \$-0.172. No change in λ_1 occurs because altering τ affects net drilling costs ($D(w) = (1+\tau)\alpha_D D^*(w)$) rather than net price or marginal extraction costs (see equation [7]). Thus, the starting value of production remains at 272 MMBOE. On the other hand, the 12.4 percent reduction in the shadow price of cumulative reserve discoveries (λ_2) significantly impacts the initial control value for drilling—which increases to 1170 wells. Also, because of discounting, the constant drilling cost reduction is worth more to firms today, thus, it increases incentives to explore in the early periods of the simulated program.

To see these effects more clearly, comparative simulation results for drilling, reserves, and production are presented in Figures 1 - 3. Figure 1 shows that removing the more stringent environmental regulations pertaining to drilling on federal property in Wyoming (dotted lines in Figures 1 - 3) would substantially increase this activity overall and tilt it to the present. More specifically, setting τ = -0.0572 increases drilling by more than 6235 wells (or 12.9 percent) over the 60-year simulation horizon. With increased drilling, additional new reserves are developed (roughly 341 MMBOE, 4.3 percent above the base solution) and the reserve level declines less rapidly, as shown in Figure 2. The elasticity of reserve additions to drilling averaged approximately 0.33 over the simulated program. With new reserves now identified, the volume of oil and gas extracted rises with time by about 324 MMBOE or 3.9 percent above the base solution (see Figure 3). This difference is roughly equal to the 341 MMBOE in reserve additions brought about by the drilling cost reduction.

This amount of output is an estimate of the oil and gas left in the ground because of more stringent environmental and land use regulation on federal property. This output can be valued by multiplying each year's output loss by that year's discounted shadow price of the resource in the ground ($\lambda_1(t) = (p(t) - C_q(t))e^{-rt}$) from the simulation and then summing. For Wyoming, the total comes to \$800 million. This value is interpreted as a lower-bound estimate of the opportunity cost of more stringent regulation on federal property. It is a lower-bound estimate because the value of lost oil and gas output may only be a portion of the opportunity cost stemming from more stringent enforcement of environmental regulations on federal property. Another component could be foregone recreational activities if differential enforcement of regulations imposes restrictions on access to federal property. In any case, the opportunity cost of more stringent regulation on federal property must be balanced against benefits of increased protection of environmental resources to society as a whole. Nevertheless, monetary estimates of these benefits are not well established and further research may be warranted to determine whether the current regulatory structure should be made more or less stringent and whether enforcement should be made more uniform in its application between federal and private lands, particularly when they are contiguous.

As previously indicated, estimates of the value of lost output from more stringent environmental and land use regulation on federal property ignore the possibility of technological advance over the simulation period. Estimates presented in the previous section based on state-level data provide little basis for identifying the rate of technical change that may have occurred either in drilling or extraction over the period 1970-00. Also, analysis of data from individual wells in the Wyoming Checkerboard shows no evidence of systematic reductions in drilling costs over the period 1987-99 that might be associated with technological advancement (Kunce, Gerking, and Morgan 2002, see footnote 6). Nevertheless, improvements in directional drilling and 3-D seismic imaging became more important in the late 1980s and 1990s and these factors together with other advances in exploration, development, and production will surely lead to declines in the marginal cost of reserve additions (D_w / f_w) and marginal extraction costs (C_q) over the next 60 years.

To get a better understanding of how technological advancement in exploration and development might interact with changes in enforcement of environmental and land use regulations, the comparative simulation was re-run assuming an annual reduction in the marginal cost of reserve additions by 2 percent. In this case, reducing stringency of enforcement of environmental regulations on federal property to the level seen on private property would have a greater absolute effect than in the situation where technology does not change. Compared to the base simulation, equalizing enforcement of environmental regulations on the two types of property increases drilling by 13,178 wells and production by 388 MMBOE above the base simulation. These effects are larger than those reported for the case in which technology is assumed not to change. Intuitively, at unchanged stringency of environmental regulations pertaining to drilling, a decline in the marginal cost of reserve additions stimulates drilling and production on both federal and private property by roughly the same percentage. Thus, equalizing regulatory stringency on federal and private property would have a greater absolute effect on drilling and production in a world with declining marginal costs of reserve additions than in a world where these marginal costs are constant. In other words, the original simulation results presented above may well underestimate effects considered because they do not account for technical change.

The overall increase in production resulting from the removal of the federal drilling cost premium affects taxes and royalties collected by all levels of government. In Wyoming, state and local governments levy production taxes with effective rates totaling approximately 12.1 percent of the value of production net of public land royalties. In the no technological change case, applying these rates to the increased production valued at

\$19.87 per BOE and discounting at $r = 0.04$, yields an estimate of the present value of additional tax revenue of \$223 million over the 60-year time horizon. This figure represents a 2.7 percent increase in the present value of state and local production tax collections. Present value state and federal royalty revenues also increase in total by \$205 million or 2.8 percent above the base solution. Effective discounted federal income tax revenues decrease by \$18 million (roughly 1 percent) mostly attributed to the increased deductions that would be taken for state and local production taxes, federal royalties, and federal percentage depletion allowance. Thus, changes in environmental regulations have implications for tax collections at all levels of government and the state and local tax revenue implications illustrate why politicians in states that fund public services from energy production tax revenues frequently are vocal opponents of more stringent environmental regulations on oil and gas. But these local objections to federal policy seldom consider broader issues such as the benefits of environmental regulation that accrue to people outside the state and/or whether a state like Wyoming would experience an efficiency gain from relying more heavily on other types of taxes such as taxes on income (Gerking and Morgan 1998).

These results show that drilling is more sensitive than both reserve additions and production to changes in environmental regulation costs. The average elasticities (in absolute value when changing τ) over the 60-year program for drilling, reserve additions, and production are roughly 2.25, 0.75, and 0.69 respectively. A reduction in environmental compliance costs significantly increases incentives to drill early in the program, but in an average year the marginal product of drilling falls with the number of new wells drilled. Also, over time, the marginal product of drilling falls as exploration and development activity cumulate, although in the simulations, this effect is small. As a consequence, average reserve additions respond inelastically to the increased drilling effort. Thus production, which is driven by the size of the reserve base (see Pindyck 1978), also changes by a smaller percentage than drilling activity—roughly paralleling reserve additions.

As indicated in Section III, changes in drilling costs from altering τ may have different effects than changes in taxes levied on production. A related study (Kunce, Gerking, Morgan, and Maddux 2002) focuses more directly on issues related to taxation of nonrenewable resources, but it is useful to illustrate this difference by applying the model presented in this paper. In particular, a simulation was conducted showing effects of a 10% reduction in Wyoming's *ad valorem* production (severance) taxes on oil and gas. A key aspect of these results is that over the 60-year simulation period, the average elasticities (in absolute value) of drilling, reserve additions, and production with respect to changes in the production tax are 0.19, 0.08, and 0.07 respectively. These elasticities are substantially lower than those presented above for changes in environmental regulations pertaining to drilling. Although the comparison drawn here is not direct or of equal real yield, it appears that oil and gas field activity is more sensitive to changes in drilling costs than to changes in severance taxes. Intuitively, "upstream" incentives given at the beginning of the exploration-development-production process provide a greater stimulus than "downstream" incentives given at the end of this process. Whereas a drilling cost reduction directly stimulates that activity, a reduction in severance tax rates does nothing to directly stimulate drilling. A severance tax decrease amounts to a reduction in production costs and would lead to increased exploration and development only if operators use the proceeds of the tax cut to finance additional drilling.

VI. CONCLUDING REMARKS

A major conclusion of this study is that in the case of natural gas and oil, drilling and future production are sensitive to changes in costs associated with environmental and land use regulations. A state-level simulation model is used to estimate losses of oil and natural gas output over the next 60 years because of more stringent application of environmental and land use regulations on federal land than on private property in Wyoming. This study shows that the discounted present value of reduced output statewide because of higher environmental compliance costs on federal land is about $800 million. This figure is interpreted as a lower bound estimate of the opportunity cost of more stringent enforcement of regulations prevailing there. The value of reduced output from all federal lands in the U.S. because of more stringent enforcement of environmental regulations may be considerably larger.

The simulation model used in this study includes and interacts federal taxes, state and local taxes, royalty payments, and environmental and land use regulations. In consequence, it is possible to compare the effects of changes in environmental regulations with energy taxes. The most important state-local energy tax is the production (severance) tax. Both a less stringent application of regulations and a reduction of production tax rates will stimulate oil and natural gas activity. The comparison made here shows that oil and natural gas activity is more sensitive to changes in the application of environmental regulations on drilling than to changes in production taxes. Incentives that affect drilling costs, at the beginning of the exploration, development and production process, provide greater stimulus than incentives offered at the final production stage when the production tax is levied.

The results presented here have at least three important policy implications. First, if the purpose of the environmental and land use regulations is to internalize the negative externalities associated with exploration, drilling and development of natural gas and oil wells, the enforcement should be similar on similar types of land. Whether the current greater degree of enforcement on federal land than on other types of land is more appropriate is not clear. Second, the higher regulatory costs on federal lands reduce the incentive to develop existing and potential domestic fields, and, more generally, to reduce domestic production. As a result, lost production increases the incentive to rely more on imported energy resources. While increased domestic production of traditional energy resources will not eliminate the need for imports, a more accurate assessment of the incremental costs and benefits of the current application of environmental and land use regulations, irrespective of land ownership, should be an important aspect of U.S. national energy policy. Environmental policy, domestic energy production, and the U.S. balance of payments are intertwined. Third, oil and gas producing states rely on production taxes and federal payments in lieu of taxes to finance state and local public services. Federal policies that reduce oil and natural gas production force states such as Wyoming, New Mexico and Alaska (with substantial federally owned mineral lands) to reduce expenditures on public services or to fund them with higher tax rates on energy resources or on other revenue sources.

Footnotes

[1] The American Petroleum Institute (1990-99), since 1990, has published results of an industry questionnaire regarding costs related to prevention, control, and abatement of pollution from *all* petroleum operations. The report entitled, *U.S. Petroleum Industry's Environmental Expenditures*, estimates aggregate expenditures *only* for the following sectors: refining, exploration and production, transportation, and marketing. In 1999, for example, API estimates that the exploration and production sector of the industry spent approximately $1.8 billion to protect the environment.

[2] This impressionistic finding suggests only that extra production costs arising from environmental regulations are similar on private and federal property. It does not imply that effects of environmental and land use regulations on production costs are unimportant. To the contrary, in recent years operators have been required to reinject or treat produced waters and have faced increasingly strict air quality standards.

[3] A study of effects of environmental regulations and oil and gas production costs also may be worthwhile, however such a study would have to overcome significant limitations in available data (see Kunce, Gerking, and Morgan 2002).

[4] For these three depth ranges, drilling costs on federal property exceeds that on private property by 10.6%, 12.3%, and 18.9%, respectively.

[5] Federal, state, and local taxes and royalty payments and their interactions are included in the model because they affect the oil and gas industry's net revenue and decisions to explore, develop, and produce. Another strand of the tax literature, not considered in this paper, deals with the broader issue of efficiency or welfare effects of taxes in a fiscal federal system. For a recent treatment of this subject, see Inman and Rubinfeld (1996).

[6] Volumes of gas can be expressed in terms of barrels of oil by noting that 5,626 cf of gas is the BTU equivalent of 1 barrel of oil.

[7] Pindyck's (1978) original specification of the extraction cost function is retained here in spite of the issues discussed by Livernois and Uhler (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. These complications are ignored in the analysis below because of data constraints on estimating the extraction cost function.

[8] This formulation can be extended to allow for a property tax on oil and gas in the ground. This aspect is suppressed here because Wyoming does not levy this type of tax.

[9] This formulation expresses effects of more stringent regulations as a proportional cost increase to simplify both the presentation in this section and the simulations described in Section IV. Also, effects of environmental regulations pertaining to extraction also could be incorporated into the model; however, this aspect is not pursued in light of previous discussion emphasizing the relative importance of regulations that apply to drilling.

[10] 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 10 smallest producing states. The 21 states included are AK, AL, AR, CA, CO, FL, IL, IN, KS, KY, LA, MI, MS, MY, ND, NE, MN, OK, TX, UT, and WY.

[11] Proved reserves, as defined by the U.S. Department of Energy, Energy Information Administration (2000), are those volumes of oil and gas that are recoverable with reasonable certainty under existing economic and operating conditions. Estimates of these reserves are prepared annually. Estimates of broader definitions of oil and gas in-place are more speculative and are not used to implement the model. Nevertheless, estimates presented in equation (15) show the productivity of additional drilling in moving these resources into the proved reserves category.

[12] Equation [14] also was estimated allowing for Wyoming-specific estimates of ρ and β. The null hypothesis that these parameters are the same for Wyoming as for all other states is not rejected at conventional significance levels.

[13] The I.H.S. data, available commercially, show that in 1999, 91.3% of wells were drilled to depths of less than 9600 feet, 6.0% of wells were between 9600 and 12,300 feet, and 2.7% of wells exceeded 12,300 feet in depth. In these three depth ranges, percentages of wells drilled on federal property were 47.3%, 51.6%, and 65.7%, respectively.

[14] Wyoming's 1999-2000 BOE production value is comprised of about 66% gas and 34% oil.

[15] This assumption means that changes in environmental regulations on federal property have no effect on oil and gas prices, and thus no effect on exploration and production incentives elsewhere. Because of the relatively small amount of oil and gas production on U.S. federal property in comparison to national (or world) production, this assumption is probably not unreasonable. Nevertheless, generalizing this assumption to allow an endogenously determined future price path would be a useful extension.

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APPENDIX

Tax Policy Parameters

Restating the producer's problem (bracketed terms in text equation [1]) accounting for all tax effects yields

$$\begin{aligned} & qp^{*} - qp^{*}\tau_r - qp^{*}(1 - \tau_r)\tau_p - C^{*} - \eta D^{*} - \tau_s[qp^{*} - qp^{*}\tau_r - qp^{*}(1 - \tau_r)\tau_p - C^{*} \\ & \quad - \eta D^{*}] - \tau_{us}\{ qp^{*} - qp^{*}\tau_r - qp^{*}(1 - \tau_r)\tau_p - qp^{*}(1-\tau_r)\delta - C^{*} - \eta D^{*} \\ & \quad - \tau_s[qp^{*} - qp^{*}\tau_r - qp^{*}(1 - \tau_r)\tau_p - C^{*} - \eta D^{*}]\} \end{aligned} \qquad [A1]$$

which reduces to

$$\alpha_p = \{(1-\tau_{us})(1-\tau_s)(1-\tau_r)(1-\tau_p) + \tau_{us}(1-\tau_r)\delta\} \qquad [A2]$$

$$\alpha_C = \{(1 - \tau_{us})(1 - \tau_S)\} \qquad [A3]$$

$$\alpha_D = \{(1 - \tau_{us})(1 - \tau_S)\eta\}. \qquad [A4]$$

In [A1]-[A4], τ_{us} denotes the federal corporate income tax rate, τ_s denotes the state corporate income tax rate, 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. The parameter 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. Equations [A1]-[A4] can be simplified because Wyoming does not have a state corporate income tax (τ_s=0).

This formulation captures several aspects of the U.S. tax structure as it applies to the oil and gas industry. (1) Federal royalty payments are deductible in computing state production tax liabilities. (2) Federal royalty payments, state production taxes, state property taxes, 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. State level tax treatment of the oil and gas industry is not uniform and there are a number of situations in which these equations would have to be modified. The framework described above is commensurate with Wyoming. 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 [A2]-[A4] 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 Wyoming. 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 9.8

percent for oil and gas in 2000. 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 comprised of both state severance and local ad valorem rates. Local ad valorem rates are computed as total tax collections divided by the *prior* year's gross value of production net of public land royalties. The sum of the two *average* effective rates in 2000 totaled approximately 12.1 percent (local 6.8 percent and state 5.3 percent). At the federal level, data from Statistics of Income (U.S. Department of Treasury 2000) for the oil and gas sector show that federal corporate taxes paid averaged about 11 percent of *net operating* income in 2000. Also, the current nominal percentage depletion rate of 15 percent applied to about 49 percent of Wyoming oil and gas producers in 2000, thus $\delta = 7.4$ percent. Also, the expensed portion of current period drilling costs is approximately 41 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 the ratio of production to reserves is constant (Deacon 1993). Wyoming's mean value of q/R was approximately 7.4% for 2000, therefore $\eta = 0.41 + (1 - 41)*(0.074 / (0.04 + 0.074)) = 0.793$. The base tax policy parameters for Wyoming are $\alpha_p = 0.71$, $\alpha_c = 0.89$, $\alpha_D = 0.71$.

Estimate of an Instrument for WELLS

An instrument for the natural logarithm of *WELLS* was used as an explanatory variable in estimating text equation [14] with *CWELLS* entering equation [14] as the proxy for *x*. Instrumental variable estimation is appropriate because *w* is an endogenous variable in the model presented in Section III. 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 A1. Time-specific effects tested insignificant at conventional levels and $R^2 = 0.89$. *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 text Table 1 for descriptions). All estimated coefficients are significantly different from zero. 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 A1
Construction of Instrument ln*(PREDWELLS)*

Explanatory Variable	***Coefficient*** (t-statistic)
PRICE	0.048 (5.88)
PRICE2	-0.24E-3 (-1.75)
CWELLS	-0.15E-4 (-7.57)
CWELLS2	0.84E-11 (5.83)
*PRICE*CWELLS*	0.44E-7 (2.71)

Extraction Cost Function

Following Deacon (1993), values of extraction cost parameters are as follows. Assume that production is represented by the Cobb-Douglas function, $q = Vn^{\mu}R^{1-\mu}$, where n denotes all non-reserve inputs to the process. The constant cost per unit of n is σ, with the constant user cost per unit of reserves denoted as Γ. A firm's profit would take the form, $pVn^{\mu}R^{1-\mu} - \sigma n - \Gamma R$, yielding the profit maximizing necessary condition,

$$\sigma n / \Gamma R = \mu / (1-\mu) . \tag{A5}$$

Given the level of reserves, a cost function can be derived taking the form

$$C(q, R) = \kappa q^{\varepsilon} R^{1-\varepsilon} \tag{A6}$$

where $\varepsilon = 1/\mu$ and κ is a function of V and the (constant) price of non-reserve inputs. Estimates for κ and μ are established from the data on operating cost, drilling cost, production, reserve additions, and reserve levels described in the text.

Simply, σn equals average total lifting costs (for an average depth per joint production, in \$2000) and ΓR represents the average total cost (in \$2000) of reserves held. Thus, the left-hand side of [A4] is simply the cost share ratio of the two production inputs with the user cost per unit of reserves expressed as $\Gamma = (r + (q / R))\Sigma$. Here, r is the discount rate, q / R represents the depreciation rate of reserves, and Σ denotes average drilling costs (in \$2000) per BOE reserve additions (a proxy for the asset price of reserves). Finally, κ is chosen as the value that drives the production cost modeled to an average level of *lifting costs* representative of the 2000 EIA surveyed estimates described in the text. In an effort to avoid 'double-counting' reserve acquisition costs, the user cost per unit of reserves enters the production cost analysis solely to calibrate the production function input shares depicted by the right-hand-side of equation [A5]. For Wyoming, $\varepsilon = 3.128$ and κ is set to 476. This calibration produces a marginal cost of extraction equal to \$5.80 when q and R are set to 2000 BOE levels.

TABLE 1

Variable Definitions, Data Sources, and Sample Means

Variable	**Definition**	**Source**	**Sample Mean**	**Wyoming Mean**
TRCOST	Total drilling costs in millions of 2000 dollars, for all well types by state and year.	American Petroleum Institute. *Joint Association Survey on Drilling Costs*. Annual.	942.5	885.3
WELLS	Total wells drilled in a state by year.	American Petroleum Institute. *Joint Association Survey on Drilling Costs*. Annual.	1573	1139
CWELLS	Cumulative total wells drilled in a state beginning in 1859.	American Petroleum Institute. *Petroleum Facts & Figures.* 1971 ed.	1.06E+5	0.46E+5
TRCWELL	Total drilling cost per well drilled, by state and year, in millions of 2000 dollars.	American Petroleum Institute. *Joint Association Survey on Drilling Costs*. Annual.	0.836	0.743
FTWELL	Total footage per well drilled, by state and year.	American Petroleum Institute. *Joint Association Survey on Drilling Costs*. Annual.	6016	6816
PRICE	Average oil and gas wellhead price, by state and year, in 2000 dollars per barrel of oil equivalent.	American Petroleum Institute. *Basic Petroleum Data Book*. Feb. and Aug. Annually.	19.87	18.52
ADDED RESERVES	Oil and gas reserve extensions, new field discoveries and new reservoir discoveries in old fields, by state and year in millions of barrel of oil equivalent.	U.S. Energy Administration. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*. Annual.	116	151
RESERVES	Proved reserves by state and year in millions of barrel of oil equivalent.	American Petroleum Institute. *Basic Petroleum Data Book*. Feb. and Aug. Annually.	2753	2425
PROD	Production by state and year in millions of barrel of oil equivalent.	American Petroleum Institute. *Basic Petroleum Data Book*. Feb. and Aug. Annually.	253	208
PRICE2	Average real price squared.	--	502	--
CWELLS2	Cumulative total wells squared.	--	4.3E+10	--
PRICE CWELLS*	Interaction of real price and cumulative total wells.	--	1.9E+6	--

Figure 1. Wyoming Drilling

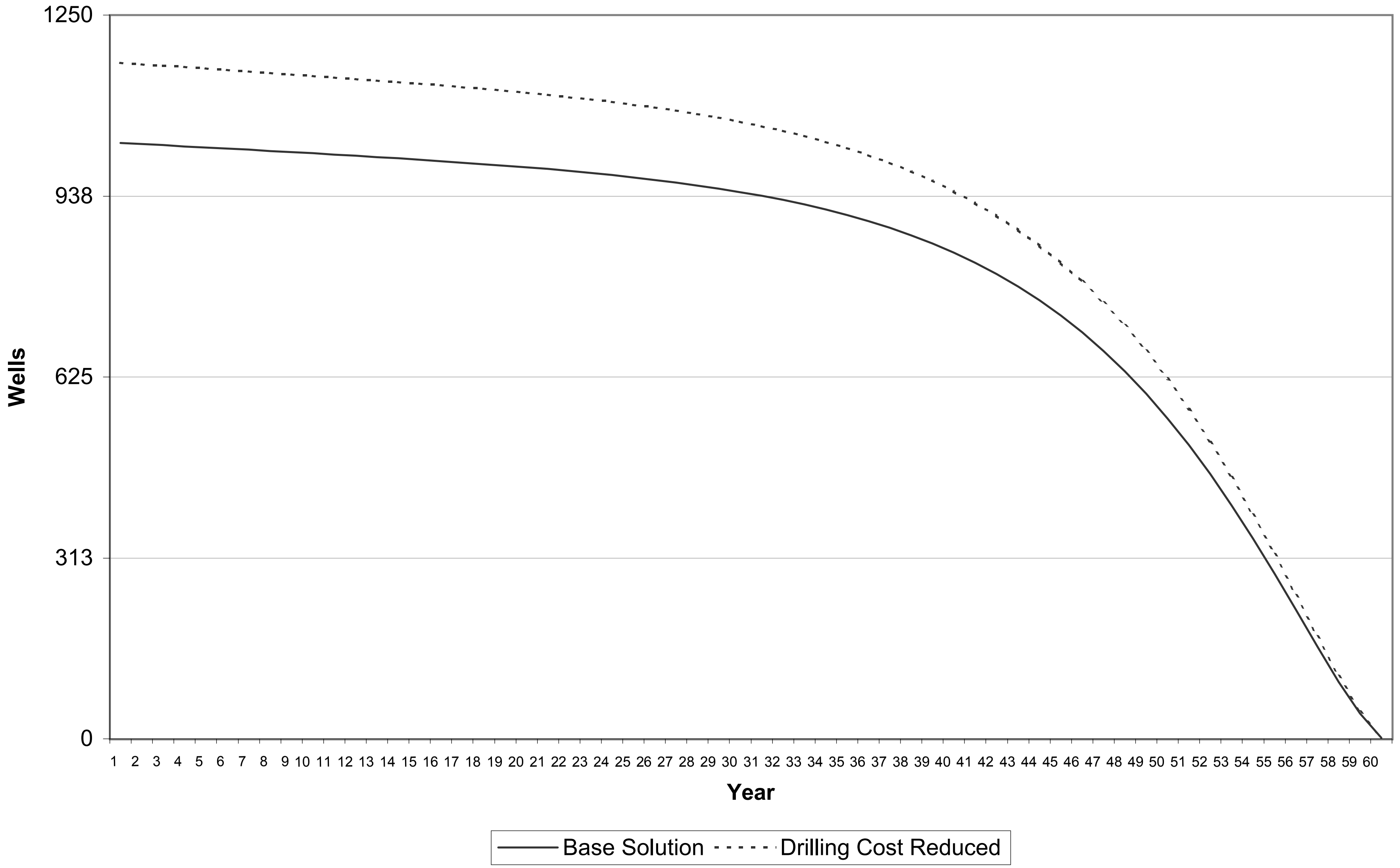

Figure 2. Wyoming Reserves

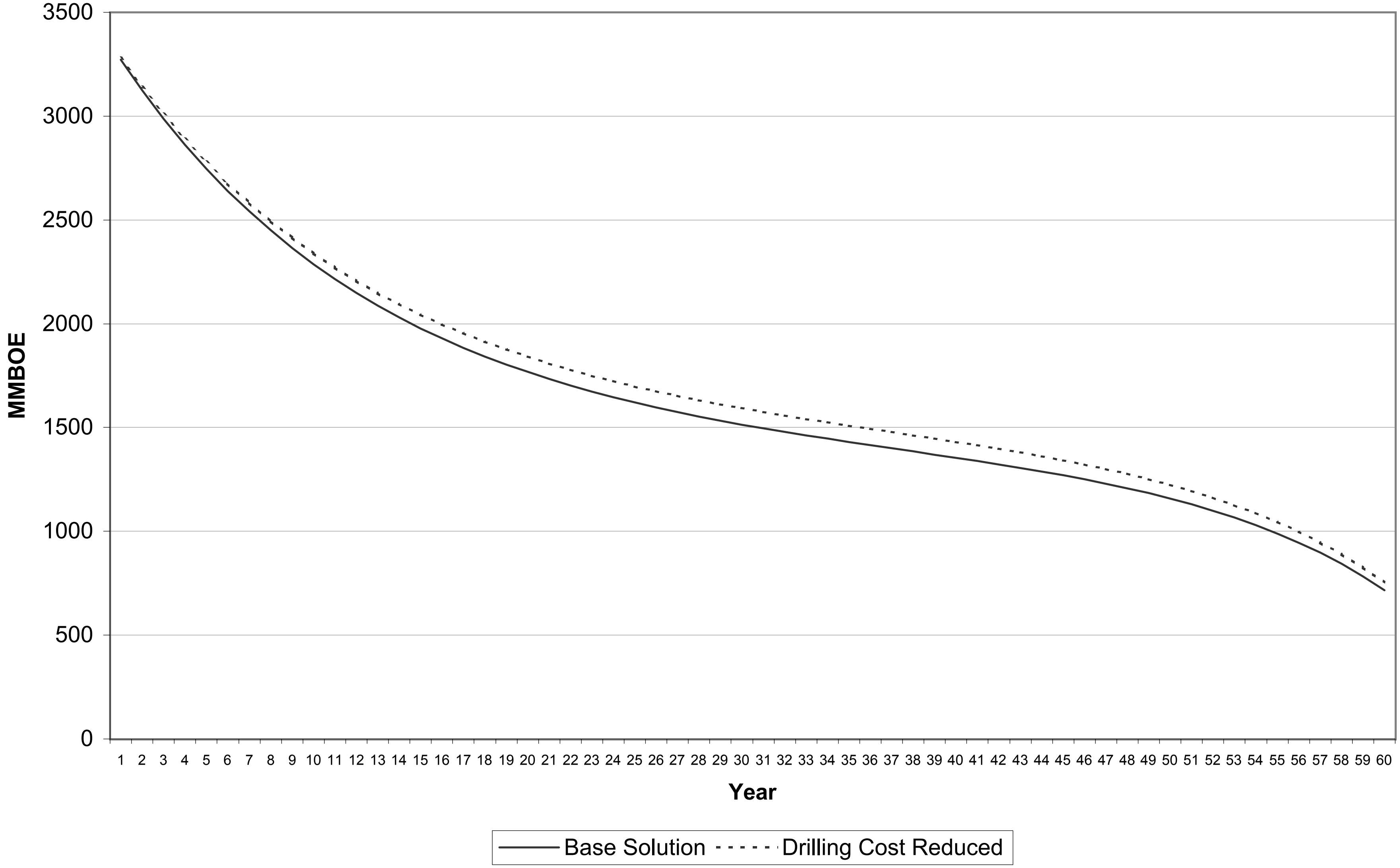

Figure 3. Wyoming Production