MINERAL TAX INCENTIVES, MINERAL PRODUCTION AND THE WYOMING ECONOMY

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EXECUTIVE SUMMARY

The minerals industry accounts for a substantial share of tax revenues to the State and to local governments in Wyoming. In FY98, taxes directly paid by the minerals industry totaled $542 million and represented about 42% of State and local tax collections (Tax Reform 2000 Committee 1999). These revenues were obtained primarily from severance and property taxes levied against the value of production of oil, natural gas, coal, trona, uranium, and other minerals. Periodically, since 1983, the Wyoming Legislature has granted tax incentives (see Appendix A) to the minerals industries for the purpose of stimulating production, tax collections, and job creation across the State. Wyoming is not unusual in this regard: Other mineral producing states also grant a myriad of tax exemptions and incentives (usually discounts against existing tax liabilities) for special situations faced by operators. In 1999, the Wyoming Legislature appropriated funds for an econometric study of the effects of mineral tax incentives granted under current law (1999 Wyoming Session Laws, Chapter 168, Section 3). This report summarizes results of this study for the oil, gas, and coal industries.

By statute, and by agreement with the Legislative Subcommittee overseeing this project, this report must address two questions. First, to what extent do mineral taxes, tax incentives and environmental regulations increase or decrease tax collections to Wyoming entities as compared with amounts that would be collected in their absence? Second, to what extent do taxes, tax incentives and environmental regulations alter employment and other economic activity in Wyoming as compared with what would occur in their absence? These questions are interpreted broadly; for example, the term "Wyoming entities" refers to state government, political subdivisions (such as cities, towns, counties, and school districts), and other special districts. Employment and other economic activity in Wyoming refers to all sectors of the State's economy, not just those closely related to mineral extraction. Finally, and perhaps most importantly, the study not only evaluates existing incentives and regulations, it also develops a framework that can be used to support future decision-making on State tax policy.

Chapter 2 presents background by looking at the economic effects of all major types of taxes and royalties levied on the oil and gas industry by federal, state, and local governments in the United States. This background is important for three reasons. First, it provides the perspective needed to evaluate the incidence or ultimate burden of an increase in taxes or elimination of tax incentives. In the case of Wyoming oil and gas, taxes are shifted backward entirely to operators and resource owners. Wyoming oil and gas production represents only a tiny fraction of the world market for petroleum products and, therefore, producers in Wyoming are price-takers, not price-makers. Second, the review introduces the concept of an effective tax rate. Effective tax rates are particularly useful in accounting for effects of tax incentives, such as those that have been granted to oil and gas producers in Wyoming. For example, an effective severance tax rate on Wyoming oil production can be computed by dividing total oil severance tax payments by the value of oil production. Because this calculation focuses on actual tax payments, it fully accounts for all applicable tax incentives. All of the analyses presented in this report are based on effective rates of taxation so that tax incentives can be appropriately modeled.

Third, the review underscores the fact that different types of taxes have different economic effects. Important taxes levied on the oil and gas industry can be grouped into three broad categories; production (severance and *ad valorem*), property and income. Production taxes are levied on the value (or volume) of the oil and gas as it is extracted from the ground or at the point of first sale. This type of tax is seen by producers as an increase in production costs and tends to lower output by causing marginal wells to be shut-in at earlier dates than they would be in the absence of the tax. Conversely, a change in a property tax rate levied on reserves in the ground, or equipment, tends to increase the rate of current production as producers have an incentive to "mine out from under the tax." Finally, a state or federal corporation income tax levied on the accounting profits of the oil and gas firm (the difference between total revenue and total costs) would be predicted to have no effect on current production. The objective of the firm is to maximize profits, and therefore, a tax on net revenue should not alter the rate of output.

Reliance on these three types of taxes differs substantially between the eight states responsible for about 73% of U.S. oil and 83% of U.S. gas production (Alaska, California, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming). All states except California levy production taxes against the gross value of output. 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 and Kansas do not). Most states levy a corporate income tax on income that applies to oil and gas operators (Wyoming and Texas do not). Louisiana permits federal corporate income tax payments to be deducted against its state corporate income tax liabilities, but this feature is not currently available in the other five states that levy state corporate income taxes. All states define tax bases differently and levy taxes at different rates. Within states, counties apply their own mill levies to compute property taxes on above-ground and down-hole equipment at different rates. Tables 2.1 and 2.2 summarize differences in tax rates in selected years for the eight major oil and gas producing states. These comparisons use effective tax rates in order to account for differences in tax incentives between states. This report primarily analyzes changes in production taxes and production tax incentives. Wyoming relies heavily on production taxes at the state and local level to support public services. Also, tax incentives for oil and gas producers (see Appendix A) are discounts from production (severance) tax liabilities.

Chapter 3 develops an empirical framework that can be used to show how changes in taxes, tax incentives, and environmental regulations alter the timing of exploration and production by firms in the oil and gas industry in Wyoming and in other states. This framework embeds econometric estimates into Pindyck's (1978) widely cited dynamic model of exhaustible resource supply. The model is estimated using published data on drilling, production, reserves, and costs from industry sources including the American Petroleum Institute and from government sources including the U.S. Department of Energy. Federal, state, and local effective tax rates also are built into the model. Federal tax data also were obtained from published sources; however, state and local oil and gas tax data were mostly obtained from state government sources.

The model has seven advantages. First, it can be applied to any of 21 U.S. states (including Wyoming) that produce significant quantities of oil and gas. Second, the model can be used to assess the impact on drilling and production of a change in any tax or tax incentive that currently exists in any of these states. Third, the model accounts for interactions between taxes and tax incentives levied or offered by federal, state, or local governments. Fourth, the model can be used to compute the effects on drilling and production of any environmental regulation that affects oil and gas operations and interactions between regulations, taxes, and tax incentives are fully accounted for. Fifth, the model is based on a widely accepted theoretical framework that links exploration to development to extraction. Sixth, the model accounts for differences in the quality of oil and gas produced between states as well as differences in transportation costs by adjusting the wellhead price to reflect these aspects. Seventh, the model runs in Microsoft Excel and is therefore quite simple to use. For these reasons, the model is arguably superior to and more comprehensive than previous efforts to develop econometric and/or simulation models of taxation and regulation of natural resource exploration and production.

The model also has three limitations that ought to be recognized. First, data used to implement the model certainly are not perfect. Data on oil and gas extraction costs are particularly weak. However, the best quality public data available have been used to develop the model. Second, the model does not envision interactions between states that arise from changes in tax or regulatory policy. In other words, the model shows that a tax incentive offered in Wyoming may increase oil and gas drilling and production there, but does not indicate the source of these additional investment dollars. Correspondingly, the model shows that a tax incentive offered in, say, Oklahoma might affect exploration and production there, but does not allow for the fact that a portion of the effect might spill over into Wyoming. Simplifications must be made in the development of any model and these particular simplifications are made for two reasons. (1) Accounting for interstate effects would result in only minor changes in results presented. (2) A fully interactive analysis of oil and gas activity in different states would be quite complex and more difficult to develop. Third, the model does not account for deviations from a strict dollars and cents, profit-maximizing point of view of investment decisions. Business decisions in certain situations may have broader motivations than pure profit maximization; yet, profit maximization is probably the best single rule that can be used to predict how these decisions will be made. None of these limitations, however, are serious enough to invalidate the general conclusions presented in the report.

Chapter 4 uses the model to simulate the effects of changes in tax policy in Wyoming and in five additional oil and gas producing states. Effects of tax changes in Wyoming are heavily emphasized in the discussion, and results are reported for other states mainly for purposes of comparison. Four of these tax change scenarios deal with actual Wyoming production tax incentives and results are shown in Table ES.1. All of these scenarios assume that oil and gas prices will be maintained at current levels in real terms in perpetuity. Chapter 4 considers other possible future price trajectories, but these alterations have little or no effect on the results presented below.

One scenario considered envisions a once-and-for-all 2 percentage-point reduction in the state severance tax on Wyoming oil production. According to the model, this tax change results in only a small stimulus to production and drilling. Output of oil and gas would rise by a total of 50 million barrels of oil equivalent (BOE) (0.7%) over the next 60 years as compared with a base case in which taxes do not change. Regarding drilling, the effect of the tax change is somewhat greater. Over the 60-year life of the program, the tax cut contemplated would result in additional drilling of 1119 wells. This figure represents a 2.3% increase in total wells drilled as compared to the base case in which taxes do not change. This scenario would reduce the present value (at a 4% discount rate) of oil severance tax collections by 17% over the 60-year time considered, but would result in increased sales tax collections by about 2.3% because of the increase in drilling. A variant of this scenario also is considered in Chapter 4 that envisions a 2 percentage-point severance tax reduction on oil for one year and an elimination of this tax incentive after that time. This tax incentive results in a tiny increase in drilling activity over 60 years (13 wells) and virtually no change in production activity.

In a second scenario, the severance tax is reduced in perpetuity on all new oil and natural gas production by 4 percentage points. This tax incentive results in an increase in drilling by 5.6% and a 1.7% increase in natural gas output over a 60-year time horizon. However, this incentive results in a loss in present value (again using a 4% discount factor) of severance tax revenue of about 43%. This large reduction in severance tax revenue occurs because as time goes by, new production accounts for an increasing percentage of total production. Again, severance tax losses are partially offset by increased sales tax collections (due to increased drilling), but the overall story is one of a substantial net loss in tax revenue. Table ES.1 also shows results of additional simulations for a perpetual 2 percentage-point reduction in the severance tax on tertiary production and a perpetual 4 percentage-point severance tax reduction on well workovers and recompletions. As shown in the table, production, drilling, and tax consequences of these two incentives are smaller than for the previous incentives considered.

A key question regarding these simulation results is: Why is the response of oil and gas output so small when production taxes are changed or tax incentives are applied? There are four reasons why this is so. First, a reduction in production taxes (or an increase in tax incentives) offers no *direct* stimulus for exploration. This point is discussed more fully below. Second, production taxes and tax incentives are deductible against federal corporate income tax liabilities. Thus, when production tax rates fall (or production tax incentives are increased) federal corporate income tax liabilities rise and vice-versa. In fact, taxes or tax incentives should not be analyzed independently without reference to the entire tax structure applied by all levels of government; for example, a tax incentive granted at one level may be partially offset by increased liabilities at another level. Therefore, operators do not receive the full value of tax incentives that may be granted by Wyoming and other states. Third, and in a related vein, a reduction in production tax rates by, say, 2 percentage points has only a small impact on the net-of-tax price received by operators. For example, suppose that the wellhead price of oil is $25/bbl. and that the Wyoming oil severance tax rate declines by 2 percentage points. Based on tax data reported in Chapter 4, this tax reduction would increase the net-of-tax wellhead price seen by operators from $17.52 to $17.92, an increase of only $0.40/bbl. after all federal, state, and local taxes, tax incentives, and royalties are accounted for. Such a small increase in the net-of-tax price per barrel of oil is unlikely to have much impact on production.

Fourth, and most importantly, production of (as contrasted with exploration for) oil and gas is driven mainly by reserves, not by prices, production tax rates, or production tax incentives. This is a basic fact of geology and petroleum engineering and is easily illustrated by Wyoming's own history of oil production. For example, since 1970, Wyoming oil reserves steadily declined from 1 billion barrels to 627 million barrels in 1997. In other words, despite much exploration over the past 30 years, production has drawn down reserves faster than new discoveries have added to them, a trend that is likely to continue in the future. Also, during the past 30 years, oil production declined from 160 million barrels in 1970 to 70 million barrels in 1997. In fact, oil production continued to decline during the late 1970s and early 1980s even though oil prices rose by a factor of more than 10, from about $3/bbl. to more than $30/bbl.! Thus, even comparatively large price increases or tax reductions are not expected to call forth much additional output.

Another type of incentive that could be designed might be aimed at reducing drilling cost. For example, consider a hypothetical incentive that would reduce drilling cost by 5%. An example of such an incentive might involve state support for an applied research program leading to technological advance in exploration methods. If drilling costs were reduced by 5%, total wells drilled would rise by 9.3% and production would rise by 2.6% over the assumed 60-year life of the program. Notice that increasing incentives to explore for oil and develop oil reserves *directly* stimulate drilling through which new reserves can be identified. Increases in drilling activity, in turn, lead to production increases because production is largely driven by reserves. In general, "upstream" incentives given at the beginning of the exploration-development-production process provide a greater stimulus to production than "downstream" incentives given at the end of the process. Whereas an incentive for drilling directly stimulates that activity, a discount from the severance tax does nothing to directly stimulate drilling—operators get the benefit of this tax incentive only if they drill *and only if they are successful*.

The contrast between a tax incentive for drilling and a discount from the severance tax can be illustrated by considering changes in production tax collections resulting from each. As shown in Table ES.1, a once-and-for-all 2 percentage-point reduction in state oil severance taxes, assuming a 4 percent discount rate, results in a decline in the present value of Wyoming state severance tax collections by $562 million (from $3242 million to

$2680 million), a decline of over 17 percent. On the other hand, a tax incentive resulting in a 5% reduction in drilling costs results in additional severance tax collections of $58 million. Also, local *ad valorem* taxes would rise because of the incentive on drilling by $68 million because of the associated increase in output. Of course, a tax incentive for drilling would have to be paid for and if the state simply subsidized the cost of drilling each new well by 5% over the next 60 years, the present value of the resulting subsidy would be $616 million. This figure far exceeds the additional severance and *ad valorem* taxes that would be collected. However, if the "incentive" was designed to directly support for an applied research program, the return in production tax revenue may exceed the cost of the program. Of course, not all applied research programs are effective and this report takes no position regarding whether such a program should be initiated. Nevertheless, this type of program at least offers the prospect of leveraging the state's resources to provide program support, whereas, discounts from the severance tax hold out no such possibility.

As previously mentioned, it is important to recognize that changes in severance tax payments by oil and gas producers alter tax liabilities at the federal level because severance taxes are deductible in computing federal corporate income tax liabilities. If producers face a marginal federal corporate income tax rate of 35%, then a $1 reduction in severance tax payments results in a $0.35 increase in federal corporate income tax liabilities. Thus, a decline in state severance tax collections $562 million (as was the case with a permanent 2 percentage point reduction in the severance tax on oil) results in an increase in federal tax collections of about $197 million, holding everything else constant. A key conclusion here is that reduced severance tax rates shift public funds from the state to the federal government. Of course, when Wyoming is able to choose a tax incentive that increases tax collections, the transfer of public funds goes on the opposite direction, from the federal government to the State of Wyoming. Additionally, any production stimulus obtained from a tax incentive granted at the state level benefits local governments as *ad valorem* taxes rise.

Chapter 5 shows how oil and gas exploration and production decisions have been altered due to differences in stringency of application of environmental and land use policies on private and federal property. An important part of the analysis is a cost function estimated from 1390 wells drilled in the Wyoming Checkerboard over the period 1987-98. Estimates presented suggest that environmental and land use policies result in drilling costs that are at least 10% higher on federal property, thus retarding current development of oil and gas resources there as compared with costs that might be expected on private property. Implications of this result for future exploration and extraction of oil and gas then are developed by inserting these estimates into the model developed in Chapter 3. An advantage of this approach is that it accounts for the extent to which increased costs arising from regulation are deductible against tax liabilities faced by the industry.

The resulting model then is simulated to obtain effects of more stringent application of environmental regulations prevailing on federal property. Similar to the simulations for tax changes presented in Chapter 4, attention is directed to exploration and production. Two states are considered, Wyoming and New Mexico. These states were chosen because a comparatively large percentage of their oil and gas reserves are beneath federal property. The simulations show that environmental regulations have the effect of retarding exploration and production and shifting drilling to the future. Thus, a more stringent application of environmental regulations on federal land promotes removing only the best quality reserves and leaves more oil and gas in the ground at the end of the extraction program. Because environmental and land use regulations apply largely to drilling activity, they have sizeable effects on future drilling and production. In fact, reducing stringency of environmental and land use regulations would have similar effects to an improvement in technology that applies to drilling. Reducing stringency of application of environmental and land use regulations on federal property in Wyoming to the level of that found on private property would increase state and local production tax collections by 3.5% over the next 60 years.

Chapter 6 provides an overview of effects of changes in taxes and environmental regulations on the Wyoming coal industry. General industry trends considered include the rapid rate of industry growth, generally falling mine-mouth prices since the mid 1980s, the shift away from sales of coal on long-term contracts and towards sales in the spot market instead, and the penetration of new and more distant markets. Transportation issues also are discussed and focus here is on the behavior of railroads in the 1980s and 1990s after passage of the Staggers Act largely freed them from price regulation. Coal producing areas of Wyoming currently are served by at most two railroads; in consequence, an important issue concerns the possibility that lack of competition has led railroads serving Wyoming to hold considerable market power over both mines and utilities. Data from the Energy Information Administration (USDOE) indicates that coal transportation rates declined and typical shipment distances increased over the period 1980-93, yet the possibility of non-competitive freight rates for coal remains a possibility. This chapter also provides a brief discussion of the 1990 Clean Air Act amendments pertaining to coal-fired power plants, as well as an explanation of state and local taxation of this industry in Wyoming.

Chapter 7 builds on the descriptive information presented in Chapter 6 and develops a conceptual model showing how Wyoming's production of coal is affected by a change in production tax rates and by the imposition of a ton/mile tax on coal tonnage hauled by railroads. The model focuses on interrelationships between three important agents in the market for coal, mines, railroads, and electric utilities. Mines, of course, are the suppliers of coal and utilities are the main end users who use coal as an input in the generation of electricity. Railroads, which provide transportation of coal, are included in the model because freight costs may represent as much as 80% of delivered coal prices. Key aspects of the model are that coal mining is treated as a competitive industry, and railroads are assumed to exercise market power in setting transportation rates faced by utilities. This characterization may seem surprising because the exercise of market power by all players in the coal market has been a dominant theme in previous research; yet numerous changes in the industry in recent years (outlined in both Chapters 6 and 7) suggest that the framework adopted here captures the main features of the problem to be analyzed.

The conceptual model then is implemented by inserting empirical estimates of key parameters. These estimates are obtained using two confidential data sets, one on costs of surface coal mining in the Powder River Basin and the other on costs of hauling coal from various points in Wyoming to 244 electric power generation plants. Also, estimates of demand for Wyoming coal, obtained from publicly available data from the Federal Energy

Regulatory Commission, allow the economic market area for Wyoming coal to change with changes in the delivered price. For example, these estimates allow for an expansion of the "economic reach" of Wyoming coal as delivered prices fall. Using these estimates jointly with the conceptual model developed, numerical predictions are provided of effects of two tax changes, a 2 percentage-point reduction in the coal severance tax and the imposition of a $0.0001 per ton/mile tax on railroads hauling coal.

The effect of reducing the Wyoming severance tax by 2-percentage points from 7% to 5% of the value of coal produced causes output of coal to rise by 1.42 MMST (0.47%) and causes the mine-mouth price of coal to fall by about $0.12. Also, the average delivered price of coal falls by about $.02, so that the freight rate per ton of coal hauled along a route of average length rises by about $0.10 or 0.77%. Thus, the tax reduction has the effect of reducing mine-mouth prices seen by the coal industry, but the market power of railroads to set freight rates means that delivered prices seen by utilities change little. As a result, the increase in quantity of coal demanded by utilities is relatively small. On the other hand, the tax rate reduction would drive down coal severance tax collections by about 27%. The general conclusion, therefore, is that a 2 percentage-point coal severance tax rate reduction would result in a comparatively small increase in coal production and a comparatively large reduction in coal severance tax collections.

Also, the $0.0001 per ton/mile tax on railroads hauling coal leads to a 0.30 MMST reduction in the quantity of coal produced, a percentage decline of about 0.10%, while the mine-mouth price coal, its the delivered price, and the railroad freight rate are left virtually unchanged. The very low rate of tax explains why these effects are so small. However, higher ton/mile tax rates would lead to greater reductions in coal output and, perhaps more importantly, would lead to reductions in mine-mouth coal prices and increases in the delivered price of coal to utilities. Thus, railroad freight rates rise because their market power over both mines and utilities enables them to drive a deeper wedge between mine-mouth prices of coal and delivered prices of coal seen by utilities. In any case, an approximation to the total revenue to be collected from this tax (as adopted by the Wyoming Legislature) can be calculated by applying the effective rate of tax per ton to the quantity of coal produced in 1998. This calculation yields a value of total tax collection of \$7.63 million. (Note that this figure is a bit too high because some Wyoming coal is burned in mine-mouth, coal-fired electric power plants and a small percentage is trucked out of state.) However, because imposition of this tax will cause (small) reductions in coal production and mine-mouth prices, severance tax collections (in millions of dollars) will fall by about \$0.136 million. So, net of the decline in severance tax revenue, imposition of the ton-mile tax on railroads would produce an additional \$7.49 million in tax collections.

Current environmental issues facing the coal industry are treated in Chapter 8. The acid rain program created by Title IV of the Clean Air Act Amendments (CAAA) of 1990 introduces a sulfur dioxide (SO2) emissions permit market for the electric utility sector. In Phase I (1995-99), EPA began controlling aggregate annual emissions from the 263 dirtiest generating units in the US by issuing a fixed number of SO2 emissions permits. For every ton of SO2 it emits annually, a plant must surrender an emissions permit to the EPA. Each plant is provided an annual endowment of permits, at no charge, based on 2.5 pounds of SO2 per MMBTU's burned during a base period in the 1980's. Over time, the number of permits issued by the EPA will decline. Moreover, in Phase II

(2000 and beyond), virtually all existing and new fossil-fueled electric generating units in the US become subject to similar, but tighter, SO2 regulation. In Phase II, plants will be issued smaller annual permit endowments, based on 1.2 pounds of SO2/MMBTU.

The 1990 CAAA presents both opportunity and challenge for the Wyoming coal industry. As the overall emissions of SO2 are progressively restricted, Wyoming low sulfur coal is likely to be favored. However, increasing use of Wyoming coal is not certain for three reasons. First, compared to prior SO2 regulation, CAAA 1990 provides utilities with additional options in responding to SO2 emissions regulation, most notably switching to lower sulfur coal from other regions, installing fuel gas desulfurization equipment, and reallocating SO2 emissions over time. Depending on the relative costs of these options, plants may or may not decide to purchase more Wyoming coal in any given year. Second, besides Wyoming there are other important sources of low sulfur coal, including Colorado, Utah, and the central Appalachian region. For many plants, especially those distant from Wyoming, these other coals may have a price advantage. Several authors have suggested that greater SO2 emissions reductions by Phase I plants have resulted from the use of lower sulfur coal from other regions than from the use of Powder river Basin coal. Third, even if Wyoming coal can be delivered to a plant at a lower price than low sulfur coal from other regions, the plant may encounter substantial costs in retrofitting their boilers and coal processing facilities to accommodate the use of Wyoming coal.

This chapter implements an empirical model of power plants' choices about SO2 emissions, permit trading, and permit savings as well as their fuel choices. Holding power generation constant, there are three basic ways to comply with SO2 regulations: (1) The plant may engage in fuel switching by purchasing coal lower in sulfur, blending high and low sulfur coal, or cofiring with natural gas. (2) The plant may obtain additional permits from other plants owned by the same utility, or purchase permits on the open market or at EPA auctions. (3) The plant may install flue gas desulfurization equipment or retrofit existing equipment. The model allows for each of these possibilities and finds that in Phase II, Wyoming coal production may experience a 6.2% increase in output in current Phase I plants. Extending this prediction to all Phase II plants suggests that the demand for Wyoming coal will increase by about 7 –10%.

In Chapter 9, the 172-sector version of a model for Wyoming furnished by Regional Economic Models, Inc. (REMI) is used to estimate statewide economic effects of several tax incentives (see Table 9.2). For example, focusing first on a permanent 2 percentage-point severance tax cut on oil production, total employment in 2000 would rise by 313 persons and this employment increase steadily declines until 2035, when the tax reduction means that 123 additional persons would be employed. Income effects of the tax reduction are also are quite small. Real personal disposable income (in $1997) would be about $8 million larger in 2000 and about $5.8 million larger in 2035. Thus, in 2000, real personal disposable income per employee added to the state's economy would be $25,559 ($8 million/313) and the corresponding value for 2035 would be $47,154 ($5.8 million/123). This last calculation is of interest as it shows how the model accounts for expected real wage and salary increases due to productivity changes and related factors over the next 35 years. The model suggests that as employment and real incomes rise, Wyoming's population will rise as well. In 2000, the population increase resulting from the tax change would be 246 persons. By 2010, the Wyoming population would be 380 persons larger than without the severance tax reduction. These estimates reflect the fact that the effects of the tax change on population do not all occur in one year and instead accumulate over time as people's decisions to move into the state often require more than a year to be implemented. However, by the year 2035, the state population increase associated with the tax change is only 178 persons.

As a second example, a permanent 2 percentage-point reduction in the severance tax on coal would increase total employment in 2000 by 61 jobs, and contribute a total of about $2.5 million to the state's economy. Population would increase by about 70 persons. So, overall, the economic benefits to Wyoming's economy as a whole from a coal severance tax cut of this magnitude would be quite small. Other estimates from the REMI model show effects on employment, personal income, and population from the remaining tax changes and tax incentives considered in this report (see Table 9.2).

The overall story of the distinct, yet moderate economic effects should be expected for two reasons. First, the drilling incentive directly impacts exploration and the prospect of adding reserves, thus the more prominent effect. Second, the oil, gas and coal industries are not labor intensive. For example, based on data from the REMI model, the ratio of the change in output from the oil and gas production and field services sectors to the employment change in those two sectors is about $220,000. On the other hand, the increase in wage and salary distribution in the oil and gas and field services sectors, relative to the employment change there, is only about $27,000. Thus, at the margin each employee in those two sectors is associated with additional output valued at $220,000, but receives only $27,000, so labor's share of the additional output is a little more than 12%. Returns to owners of other factors of production such as capital and the reserves themselves account for the remaining 88%. Whereas workers employed in the Wyoming oil and gas industry are likely to live in the state, capital and reserve owners can live anywhere and therefore may not spend their increased incomes in Wyoming. As a result, changes in oil and gas activity do not benefit the Wyoming economy as much as they would if labor intensity were higher. Corresponding calculations for the coal industry yield similar conclusions. Therefore, income, employment, and population changes, resulting from tax incentives directed to the oil, gas, coal industries, are expected to be moderate as well.

Table ES.1

Simulated Tax Incentive Scenarios, Changes from the Base Case

	Change in Total <u>Production</u> MMBOE (%)	***Change in Total <u>Drilling</u> Wells (%)***	***Change in PV State Severance <u>Tax Collections</u> $Millions (%)***	***Change in PV Sales Tax <u>Collections</u> $Millions (%)***
1. Reduce Severance Tax on Oil by 2 % points	50.2 (0.68%)	1119 (2.28%)	-562.4 (-17.35%)	12.4 (2.29%)
2. Reduce Severance Tax on all <u>New</u> Well Production by 4 % points	122.3 (1.66%)	2768 (5.64%)	-1389 (-42.84%)	30.6 (5.65%)
3. Reduce Severance Tax on Tertiary Production by 2 % points	5.0 (0.07%)	99 (0.20%)	-55.9 (-1.72%)	1.2 (0.22%)
4. Reduce Severance Tax on Production resulting from Workovers and Recompletions by 4 % points	12.3 (0.17%)	239 (0.49%)	-136.9 (-4.22%)	3.0 (0.51%)

CHAPTER 1

INTRODUCTION

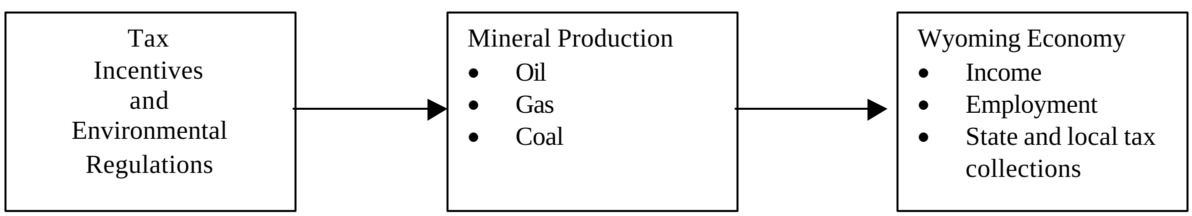
The minerals industry accounts for a substantial share of tax revenues to the State and to local governments in Wyoming. In FY98, taxes directly paid by the minerals industry totaled $542 million and represented about 42% of State and local tax collections (Tax Reform 2000 Committee 1999). These revenues were obtained primarily from severance and property taxes levied against the value of production of oil, natural gas, coal, trona, uranium, and other minerals. Periodically, since 1983, the Wyoming Legislature has granted tax incentives to the minerals industries (see Appendix A) for the purpose of stimulating production, tax collections, and job creation across the State. Wyoming is not unusual in this regard: Other mineral producing states also grant a myriad of tax exemptions and incentives for special situations faced by operators. In 1999, the Wyoming Legislature appropriated funds for an econometric study of the effects of mineral tax incentives granted under current law (1999 Wyoming Session Laws, Chapter 168, Section 3). This report summarizes results of this study. It focuses on the three largest mineral industries in Wyoming (oil, natural gas, and coal) and shows how changes in tax incentives and environmental regulations affect these industries as well as the State's economy.

By statute, and by agreement with the Legislative Subcommittee overseeing this project, this report must address two questions. First, to what extent have mineral tax incentives and environmental regulations increased or decreased tax collections to Wyoming entities as compared with amounts that would have been collected in their absence? Second, to what extent have tax incentives and environmental regulations altered employment and other economic activity in Wyoming as compared with what would have occurred in their absence? These questions are interpreted broadly; for example, the term "Wyoming entities" refers to state government, political subdivisions (such as cities, towns, counties, and school districts), and other special districts. Employment and other economic activity in Wyoming refers to all sectors of the State's economy, not just those closely related to mineral extraction. Finally, and perhaps most importantly, the study not only evaluates existing incentives and regulations, it also develops models that can be used to support future decision-making on State tax policy.

The methodology for linking tax incentives and regulations to mineral exploration and production to income, employment, and tax collections can be illustrated using the flow chart shown in Figure 1.1.

Figure 1.1

Overview of Research Methodology



As shown in Figure 1.1, the analysis first shows how taxes and environmental regulations affect mineral production and exploration. It then goes a step further to show how changes in mineral production and exploration affect the overall level of income and employment in Wyoming. Four contributions of the research are envisioned. First, it provides a comprehensive analysis of effects of taxation and environmental regulations on Wyoming's oil, natural gas, and coal industries. The oil and gas industries are obvious choices to study because they make up 63% of assessed valuation on Wyoming mineral production and because they have been targeted by most of the tax incentives identified in Appendix A. The coal industry is included because it represents an additional 29% of assessed valuation on Wyoming mineral production and because it could experience further changes in state tax treatment. Also, possible changes in environmental policy at the federal level have the potential to greatly affect the ability of Wyoming coal to compete with coal produced elsewhere as well as with other fuels.

Second, this report will present econometric models for analyzing effects of tax incentives and environmental regulations. This aspect is important for two reasons. First, effects of taxes and regulations must be quantified, not simply described in general terms. Second, different types of taxes and environmental regulations generally create different economic incentives for operators. For example, taxation of production might cause production to be shifted toward the future, whereas a property tax on reserves in the ground will cause production to be shifted toward the present. As a third example, environmental regulations can have different effects depending on whether they pertain to the exploration, development, and/or production of a resource. Also, environmental regulations and taxes interact with each other making it impossible to analyze individual taxes or regulations separately. Formal models are, therefore, needed to distinguish between effects of alternative taxes and regulations and to quantify their effects on exploration, development, production, and tax collections as well as incomes and employment levels in the economy statewide.

Third, the research takes account of market structure in determining the incidence of tax and regulations imposed on producers of Wyoming oil, gas, and coal. On the one hand, the large number of Wyoming producers of crude oil simply are price-takers, as their output represents only a tiny fraction of total output in the international marketplace. Likewise, the many operators of Wyoming natural gas wells face prices that are determined by forces beyond their control. In consequence, tax reductions and less stringent environmental regulations applied to oil and gas increase net prices seen by operators and encourage exploration and production. However, the extent to which exploration and production are stimulated and the length of time needed for the extra production to occur are major factors in determining whether tax incentives, for example, are cost-effective from the standpoint of the State's economy.

The market for coal, on the other hand, has numerous frictions that preclude the assumption of simple price-taking behavior. These frictions arise from differences in coal characteristics and the sensitivity of steam generators to their differences, from the way in which coal is sold (i.e., historical use of log-term contracts and the more recent importance of spot sales), and from the presence of powerful market agents. These agents potentially include electric utilities and their regulatory commissions, coal producers, railroads, and the states of Wyoming and Montana. The effects of potential changes in tax treatment of Wyoming coal will depend on the strength of these frictions and on the responses of other agents in the market.

Fourth, effects of taxes and regulations are further analyzed to estimate their economic contribution to the State's economy as a whole. A model developed by Regional Economic Models, Inc. (REMI) is used for this purpose. The Wyoming Business Council has leased REMI model for calendar year 2000. The 172-sector version of the model is appropriate for making the calculations needed for this project and can be used at no additional cost to the State.

The remainder of this report is organized into 8 chapters. Chapter 2 reviews and compares oil and gas tax policy in eight major producing states (Alaska, California, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming). The purpose of this review is to place oil and gas tax policy in Wyoming in context with corresponding policies pursued in other states and to provide a conceptual discussion of anticipated effects of different types of taxes that are levied. Chapter 3 specifies and econometrically estimates the oil and gas simulation model developed for use in this study. Chapter 4 shows how taxes are incorporated into the model and presents simulation results for a variety of tax incentive scenarios that apply to the Wyoming oil and gas industry. Chapter 5 examines how oil and gas exploration and extraction decisions are altered due to a more stringent application of environmental and land use policies on federal land. A simulation of the implications from the Wyoming Checkerboard is the centerpiece of this chapter.

Chapter 6, then, presents background information regarding the Wyoming coal production, the transportation of Wyoming coal, and the demand for this fuel by electric utilities. Chapter 7 outlines a conceptual model of interactions between mines, railroads, and utilities, and implements the model using empirical estimates obtained from three data sets. Two of these data sets, measuring coal mine and railroad costs, contain confidential information, so the estimates presented are truly new. This chapter also applies the model to predict the effects of a hypothetical reduction in Wyoming's coal severance tax by 2-percentage points as well as the recent imposition of a ton/mile tax on coal hauled by railroads operating in Wyoming. Chapter 8 presents an analysis of how recent Clean Air Act amendments have affected the demand by utilities for Wyoming coal. Finally, Chapter 9 gives an overview of the REMI model for Wyoming and describes the computation of statewide income and employment effects that occur in response to changes in taxes and tax incentives for oil, gas, and coal.

CHAPTER 2

TAXATION OF OIL AND GAS

2.1 Introduction

Changes in tax rates affect the net revenues received by oil and gas firms, and in turn, affect decisions on when and where to explore, develop, and produce oil and natural gas. As indicated in Chapter 1, one key objective of this study is to empirically assess the effects of changes in tax policy, particularly in Wyoming, on future oil and gas exploration and production. In Chapter 4, a simulation model is used to quantify these effects. However, before turning to the development of this model, it is useful to review the literature on taxation of nonrenewable resources and to describe the major taxes and special features of the tax code that affect the oil and gas industry. This background material is quite important as it suggests how to build this information into any model in a way that correctly reflects interactions between tax bases and the ultimate incidence of different types of taxes levied. As demonstrated below, these two issues are crucial to understanding what is likely to happen when a state chooses to change its tax structure or grant tax incentives as discounts from existing taxes. In fact, tax incentives should not be analyzed on a piecemeal basis. The best way to determine their effects is to see how they fit into a broader framework.

The remainder of this chapter is divided into three sections. Section 2.2 provides a detailed overview of the relevant economic literature. Section 2.3 describes the application of taxes by the federal government and by state and local governments in the eight states (Alaska, California, New Mexico, Texas, Oklahoma, Louisiana, Kansas, and Wyoming) that produce the largest shares of U.S. oil and gas. Section 2.4 reports calculations of effective tax rates (inclusive of tax incentives) by type of tax, by state and over time for the period 1970-97.

2.2 Overview of the Literature

Key taxes levied on nonrenewable resource development by various levels of government can be categorized into three main groups: taxes on production, property and income. Production (severance) taxes are levied on the net production value (or volume) of the resource as it is extracted from the ground or at the final point of sale. Property taxes are levied on the assessed (quasi market) value of equipment *above* and/or reserves *in* the ground. As depicted in section 2.4, above the ground property taxation is very small in relation to other taxes collected. Consequently, the focus of the literature is centered on a tax of unmined reserves. Finally, a state or federal income tax is levied against the accounting net income of extraction firms. The literature reviewed in this section is limited to *intertemporal* treatments and will be categorized based on the groupings outlined above.

Taxes on Production. The effects of a severance tax, because of its wide application, is the subject of a sizable literature. Hotelling's (1931) seminal analytic work considers a per unit severance tax in a model with endogenous price (net of constant extraction cost) and fixed-reserve total exhaustion. The severance tax levied is found to conserve the resource by extending the time of total pool exhaustion. Herfindahl (1967) extends this result with a model that features an extraction cost function that depends solely on output. The severance tax levied on a competitive model tilts production into the future thereby extending the pool life. The reserve is fully exhausted at a postponed terminal period.

Burness (1976) reformulates the dynamic framework by including severance tax rates that vary over time. In the presence of limited reserves, severance taxes can cause production rates to increase, decrease, or remain unchanged. In this model, price is exogenous, reserves are fully depleted, and extraction cost is a function of mine output only. The general proposition states that the severance tax will tilt production to the future if the tax rate is held constant or rises at a rate less than the discount rate. A severance tax that rises with the discount rate will be non-distortionary.

Levhari and Liviatan (1977) re-derived the optimal control theory of a mine allowing for an extraction cost function that depends on both current and cumulative production. The new model now exhibits the effects of exhaustion on extraction cost. As more resource is extracted over time, the more it costs to produce one more unit. This model reformulation now allows for an analysis of incomplete exhaustion of the reserve. The effect of a per unit severance tax on the terminal time is now ambiguous. If price is constant over time, it is shown that the terminal time of the mine is shortened and some form of "high-grading" may occur. Heaps (1985) uses the Levhari and Liviatan construct to examine taxation where the rates vary over time. If the present value of the severance tax is decreasing, the total recovery from the mine and the total life of the mine can either increase or decrease, but in opposite directions. Because the effects of the tax work in opposite directions, the tax effect on depletion cannot be determined.

If resource quality varies across pools but is the same within a pool, Conrad (1978, 1981) shows that production taxation affects total pool recovery and tilts the rate of extraction. The model incorporates resource grade into the price received. More formally

$$\max_{q,g} \int_0^T [P(g)h(g)q - E(q) - Z(g)q - tq]e^{-rt}dt\ , \tag{2.1}$$

subject to

$$\dot{R} = -q \tag{2.2}$$

$$q \geq 0,\quad \boldsymbol{a} < g < 1, \tag{2.3}$$

where q is the quantity of raw resource extracted, g denotes the proportion of raw resource that has value, $h(g)q$ denotes the actual quantity of resource sold, $E(q)$ denotes extraction cost, $Z(g)$ computes processing (quality) costs per unit, and t is the per unit severance tax. Properties of equation (2.1) include price increasing with quality ($P'(g) > 0$), processing costs increasing with quality ($Z'(g) > 0$, $Z''(g) > 0$), and $h'(g) < 0$. Using this general framework, Conrad (1978) shows analytically that mine lives are shortened and some lower quality resource is left in the ground when a per unit severance tax is levied.

Conrad and Hool (1981) develop a discrete time model including an extraction cost function that exhibits resource depletion effects. Three production taxes are examined: a per unit tax on total output, a per unit tax only on the 'valuable' output, and an ad valorem tax. The two ore-grade, two period analysis shows that low quality resource will remain in the ground and that the "cutoff" point for quality is affected by the tax policy. Because of the two period limitation, the life of the mine is fixed and cutoff grades rise when taxes are imposed. Conrad and Hool (1984) employ their 1981 model above to examine variable-rate taxation. Time-varying per unit and ad valorem severance tax rates are analyzed. In the case of per unit severance taxes, tilting production to the future is the result if the tax growth rate is less than the discount rate. This outcome mimics Burness (1976) though resource quality was not examined.

Krautkraemer (1990) examines the effect of taxation in a finite reserve model where resource quality varies *within* a given deposit. In addition to firms choosing the rate of extraction they also choose the marginal grade cutoff at each point in time. The severance tax induces high-grading at each point in time and not just at the end of the production program. Interestingly, the severance tax reduces total recovery from the mine and the low-grade resource left in the ground will not be recovered even if at some point in the future the severance tax is lifted.

Margaret Slade (1984) was the first to empirically simulate effects of taxation on a dynamic nonrenewable resource model. Data from the White Pine Copper mine in upper Michigan was used to empirically calibrate the functional form. The model specifies a fixed resource base and distinguishes raw resource produced from the final processed ore. The effects of royalties, severance taxes, and profits taxation were simulated separately without tax base interaction. Evidence of tilting is found under a fixed terminal time of $T = 16$ years. A $1 per ton severance tax reduces cumulative copper production by approximately 7%, under the assumption of a constant price, as compared to the no-tax base case.

In another numerical simulation, Gamponia and Mendelsohn (1985) focus on the intertemporal effects of a windfall profits tax. A per unit and ad valorem severance tax are also analyzed in this stylized model. A basic Hotelling model, including constant extraction cost, is employed. The model is simulated under various (arbitrary) parameter values for price, constant extraction cost, constant demand price elasticity, and discount rate. The comparison across types of taxes are of equal real yield. When applied, the unit and ad valorem severance tax delay final exhaustion of the fixed resource. Tax burden calculations are computed and show that the incidence of taxation falls primarily on the owners of the resource.

Uhler (1979) includes a brief examination, for the first time, of the effects of taxation on a nonrenewable resource when exploration is incorporated. This two stage, exploration and extraction, model is parameterized and compares simulated trajectories to actual paths for a small oil and gas region in Alberta, Canada. When a severance tax is imposed at a constant rate, operators decrease simulated production and exploration while endogenous price rises. Heaps and Helliwell (1985) likewise develop an analytical model including a mechanism for investment in new reserves. A severance tax is shown to reduce incentives to acquire new reserves.

Adapting the seminal model developed by Pindyck (1978), Yucel (1986,1989) numerically simulates the effects of imposing an ad valorem severance tax on gross production value. The model takes the form

$$\max_{l,w} \int_0^T [pl^{a_1} R^{a_2}(1-t) - p_1 l - p_2 w] e^{-rt} dt \tag{2.4}$$

subject to

$$\dot{R} = Aw^{b_1} x^{b_2} - l^{a_1} R^{a_2} \tag{2.5}$$

$$\dot{x} = Aw^{b_1} x^{b_2} \tag{2.6}$$

where l is extraction effort, w is exploratory effort, t denotes the severance tax rate, R is the level of reserves, x denotes cumulated reserve additions, and price is a function of output, $p = f(q)$ (linear demand used in the simulations). Two solutions are examined, competitive (Yucel 1986) and monopolistic (Yucel 1989). The model is calibrated to Pindyck's (1978) parameters from the Permian Basin in Texas. Severance taxes are found to reduce both extraction and exploration in all periods while shifting price paths upward. The shifts in price, extraction, and exploration effort are all more pronounced in the competitive model. The conservation outcome is not confirmed. The severance tax leads to a slower development of reserve additions but invokes faster depletion of the known reserve base.

Deacon (1993) adopts, again, the general construct developed by Pindyck (1978) to simulate the effects of the 3 general categories of taxation described above. Taxes are entered into the simulation model one at a time, all of equal real yield. Data used to calibrate the three crucial functions of the model (extraction cost, exploration cost, and reserve additions) are a time series (approximately from the 50's to 1987) of lower-48 state national averages for the oil industry. Data on extraction costs appears to be the weakest. The price path is exogenous and rises at a rate less than the 5 percent discount rate. Moreover, the truncated time horizon is fixed at 61 years. The imposition of an ad valorem severance tax, as compared to a free-of-tax base case, tilts production to the future (in contrast with Yucel 1986) and shortens the exploration program by approximately one year. As simulated, a 15 percent severance tax reduced production by 6.5 percent over the 61 year program.

Taxes on Property. Taxes on property, specifically reserves, has received little attention in the taxation of nonrenewable resource literature. One reason may be its practical complexity, case in point, only two states in the U.S. levy this type of tax (Texas and California). Hotelling (1931) formally shows that a constant tax on the value of reserves will induce firms to extract more rapidly. Using a model with constant extraction costs, Steele (1967) concurs with Hotelling. Burness (1976) considers a variable tax on the capitalized value of the firm which, in a sense, is a property tax. This method may undervalue the unmined assets and serves as a cursory examination with regard to policy. Nevertheless, depletion of the fixed reserve occurs at a much earlier terminal period as compared to a no-tax case.

Conrad and Hool (1981) show that a property tax works against conservation. The constant tax rate per unit of reserve encourages extraction of higher-grade resource in the early periods of the program. Interestingly, the cut-off grades are lower and tend to offset the increased early period extraction, thus extending the life of the mine. Heaps (1985) confirms Conrad and Hool's general proposition, however, mine life extension is not found. The property tax is also examined by Heaps and Helliwell (1985) in a model that allows for new reserve investment. The property tax is shown to tilt production to the present and retard investment in new deposits in order to avoid holding costs.

Gamponia and Mendelsohn (1985) simulate the effects of a fixed reserve tax and find significant tilting of the extraction path to the present. Deadweight loss calculations for each tax type (of equal real yield) simulated are compared. Distortions resulting from the property tax are more than two times those found by imposing a unit severance tax. Deacon (1993) simulates a reserve tax levied on an approximated market value of the resource in the ground. Drilling (exploratory effort) starting values decrease substantially (over 45 percent) as compared to the untaxed base case. Production trajectories tilt in the opposite direction, toward the early years of the 61 year program. Producers have an incentive to "mine out from under the tax". The estimated deadweight loss of the reserve tax is more than twice the loss found when a severance tax is levied. This result coincides with the estimates found by Gamponia and Mendelsohn.

Taxes on Income. As in the case of the property tax, an income tax levied on extractive firms has received very little focus in the nonrenewable resource literature.

Burness (1976) analyzes a profits tax and concludes that output trajectories will not change when the tax is applied at a constant rate. However, if the profits tax increases over time, firms will speed-up depletion of the fixed reserve. Conrad and Hool (1981) reaffirm that a pure profits tax, without percentage-depletion allowances, is non-distortionary. When depletion allowances are introduced, they act as a negative severance tax and tend to increase the rate of extraction. Sweeney (1977) provides a comprehensive review of the percentage-depletion incentive literature.

Conrad and Hool (1984) model analytically a progressive profits tax. The progressivity of the income tax confounds the neutrality with regard to extraction paths and grade-selection. Terry Heaps (1985) concurs with Conrad and Hool modeling a constant rate and progressive profits tax. Gaudet and Lasserre (1986), in a model where reserve additions are ignored, examine the impacts of the percentage-depletion allowance and various investment tax credits at the federal level. When taxable income more closely approximates the firms cash flow, income taxation is found to invoke little distortion.

Deacon (1993) simulates a structure broadly similar to federal income taxation. A key feature of this construct is the expensing of current and capitalized drilling costs. Investment in drilling (exploration) provides for future cash flow and the sizable finding costs should be expensed against future, not current period, revenues. Simulated paths of extraction, drilling effort and reserves show little distortion from the no-tax base case. When comparing equal real yield calculations of deadweight loss, the income tax is found to invoke the smallest loss as compared to other tax scenarios simulated.

In general, the taxation of nonrenewable resource literature finds, in the most common cases, that a tax on production will "tilt" activity to the future, a property (reserves) tax will accelerate extraction and significantly retard exploration and that a tax on net profits will invoke relatively neutral effects. In addition, analysis of the tax shifting, incidence (the ultimate burden of the tax) and interstate exporting of nonrenewable resource taxes has been the focus of considerable examination and should not be ignored here. For an overview of these interrelated topics, see Gerking and Mutti (1981), and Morgan and Mutti, (1983, 1985).

2.3 Description of Taxes, Measurement of Tax Rates, and Data Collection

This section more specifically describes the application of the types of taxes just reviewed at the federal, state, and local levels as well. Taxes here are treated broadly to include aspects of special features such as deductions for depletion and treatment of royalties from production on public land. Tax rate measurement and data collection procedures also are emphasized. To provide reference points for Wyoming's tax structure, tax structures in eight major energy producing states (Wyoming, Texas, Oklahoma, Louisiana, New Mexico, Kansas, Alaska, and California) are compared and used in the simulation analysis reported in Chapter 4. Alaska and California are included here because they are major oil producers, however they produce relatively small amounts of natural gas. Together, these states accounted for 73 percent of oil production and 83 percent of natural gas production in the United States in 1996 (U.S. Department of Commerce, 1998). Texas and Alaska are the major oil producing states, and Texas and Louisiana are the major gas producers.

2.3.a Federal Taxation

At the federal level, three main aspects of the U.S. tax code are included, the federal corporate income tax, the treatment of depletion, and the Windfall Profit tax. The federal corporate income tax is the most important business tax levied by the federal government. Incorporating it into the simulation model was simple in comparison to the steps needed to handle depletion and the Windfall Profit Tax. Annual information regarding federal corporate income tax rates is available from the Tax Foundation (various years). Depletion, which is unique to natural resource extraction, and the Windfall Profit tax, which is unique to oil production, are singled out for an extended discussion because of complexities that affect both data collection and their treatment in the simulation model. An explanation and analysis of both is included in Bruen, Taylor and Jensen (1996).

An important aspect of taxation of oil and gas is the treatment of depletion, particularly as it relates to the federal corporate income tax. Since the beginning of 1975, integrated oil and gas producers have been required to use cost depletion, but independent producers have been able to continue to use percentage depletion, although at lower rates. Congress in the Tax Reform Act of 1969 reduced percentage depletion allowance from 27½ percent of gross income from the property to 22 percent. In the Tax Reduction Act of 1975 it "eliminated percentage depletion altogether for oil and gas properties of the larger oil companies (i.e., those affiliated with retailing or refining more than certain limited volumes)…restricted the availability of percentage depletion for oil and gas properties of other taxpayers to properties located in the United States and to certain quantities of production; and provided a phasing down both in quantities of production eligible for percentage depletion and in the rate of percentage depletion." (Bruen, Taylor and Jensen, 1996, p. 7-4)

The Windfall Profit Tax was levied by the federal government during the period March 1980 through 1985 following price decontrol of oil at the wellhead. It was a production tax on the difference between the market price of oil and the former regulated price adjusted for inflation. The tax was authorized by the Windfall Profit Tax Act of 1980 and was repealed by the Omnibus Trade and Competitiveness Act of 1988 (Bruen, Taylor, and Jensen 1996, p. 10-3). The tax is a form of production tax levied on domestic production of crude oil, and was imposed to capture a significant portion of the price increases expected to result from price decontrol of crude oil. The tax is subject to deduction of the state severance tax. In turn, the Windfall Profit Tax is deductible in computing corporate income tax liabilities. There are three different categories into which taxable oil is classified, called tiers. The tax rates applied to the so called windfall profit differ by tier and also whether or not the tax is applied to independent producer oil or other oil, which includes oil produced by integrated oil companies. With certain minor exceptions, the term “integrated producer” as applied to the Windfall Profit Tax is the same as used in the application of depletion allowances.

Because information regarding the Windfall Profit Tax is not available on a state by state basis, the average effective windfall profit tax per barrel was calculated for each state on an annual basis for the period March 1980-1985. It was assumed that all oil subject to tax was Tier 1 oil, which consists of all taxable oil that is not classified as tier 2 or tier 3. It includes all nonexempt domestic oil other than newly discovered oil, heavy oil, incremental tertiary oil, oil from stripper well property, and oil from a Naval Petroleum Reserve (Bruen, Taylor, and Jensen 1996, p. 10-28).

The windfall profit tax per barrel was calculated using the following procedure. The windfall profit per barrel equals the average annual market price in state j minus the base price minus the quantity (severance tax rate in state j times the market price in state j minus the regulated price, referred to as the severance tax adjustment). The windfall profit tax per barrel equals the windfall profit per barrel times the windfall profit tax rate.

For tier 1 oil the tax rate used in this study for each state is the weighted sum of the tax rate applied to production by integrated producers (0.7) and the tax rate applied to production by independent producers (0.5). For example, in the case of Wyoming for 1984, the average effective windfall tax rate equals the share of production by integrated producers (0.67) times the tax rate for integrated producers (0.7) plus the share of production by independent producers (0.33) times the tax rate for independent producers (0.5), or a weighted windfall profit tax rate of about .63. The base price mentioned above is the May 1979 upper tier ceiling price under the March 1979 energy regulations, about $13 per barrel minus 21 cents. Adjustments to the base price were made each quarter for inflation occurring after June 30, 1979 by applying the gross national product deflator factor with a lag of two quarters. The inflation factors by quarter are listed in (Bruen, Taylor, and Jensen 1996, p. 10-41). Also, the severance tax rate referred to in the formula above applies to severance taxes levied at the state level. Local production taxes such as the local ad valorem tax in Wyoming are not included.

The calculated value of the windfall profit tax per barrel was adjusted to account for three features of the Windfall Profit Tax Act. First, the tax per barrel was reduced by five sixths in 1980 to account for the fact that the tax applied to oil produced after February 29, 1980. Second, the tax for Alaska was adjusted to account for the fact that the tax applied only to production at Prudhoe Bay. Third, the average effective weighted tax per barrel was adjusted downward in states with production from Indian lands to account for the fact that such production was exempt from the tax.

Finally, information on production by integrated and independent producers was required to calculate federal depletion allowances and Windfall Profit Tax liabilities. Annual data on production by firm were obtained from each state directly and/or from

Byrom Publishers. This information was used to identify the volume of production by integrated producers and independent producers, and in turn their shares of total production. Integrated producers were identified from information in the Oil and Gas Journal (various issues). The number and names of integrated oil and gas companies has changed over time because of mergers and acquisitions. The information published by Byrom Publishers was used to calculate the shares of total production for each type of firm for the states of New Mexico, Texas and Louisiana. The percentages for years for which data were not available were calculated by interpolation. The percentages from one year to the next are quite stable, although there are trends in the share over time. For example, the relative importance of oil production in Wyoming by independent producers has increased steadily since the 1970s. The most difficult and time consuming data collection task, aside from obtaining the tax information from the states, was identifying the integrated producers, and obtaining the volume of production of oil and gas for each integrated producer, by state and year.

2.3.b State and Local Taxation

This subsection provides an overview of state and local taxation of oil and gas in the eight states listed at the beginning of this section as well as an explanation of steps required to collect data. A more detailed state-by-state discussion is provided in Section 2.3.d. Alaska, New Mexico, Texas, Oklahoma, Louisiana, Kansas, and Wyoming levy production taxes on oil and gas, while California does not. Wyoming has a production tax levied by local governments, too. Conservation taxes, levied by virtually all energy producing states, are excluded from our analysis because revenues generated usually are distributed to an oil and gas reclamation fund rather than a general revenue fund. Additionally, the tax rate is quite small, a fraction of one percent of the value of production. All of the eight states levy a corporate income tax except Wyoming and Texas. In some states, the federal corporate income tax liability is deductible in computing state corporation income taxes and in others it is not. While most of the states utilize some form of a property tax on oil and gas extraction equipment, only Texas and California levy property taxes on oil and gas reserves. In addition to these taxes, royalties from production of oil and gas on federal and state lands are included in the analysis. In most states, these royalties are deductible in computing severance tax liabilities. All states grant numerous tax incentives for special situations faced by operators. A listing of tax incentives for Wyoming are contained in Appendix A.

Much of the data needed on state and local taxes for this study required directly contacting the agencies in the respective states because the data are not published or compiled in a common format. For example, data on state and local tax revenue from oil and gas production and property, and state royalties for each state are not compiled in a common format. These data were obtained directly from the tax and land agencies in the respective states. Most other information required for the analysis was available from published sources. Annual data on state corporate income tax rates were obtained from the Tax Foundation, annual volumes, as well as information on whether or not federal corporate income tax liabilities are deductible from state corporate taxable income. Data on royalty payments from oil and gas production on federal lands, which consists of onshore mineral leases, Indian mineral leases, and leases on military lands and National Petroleum Reserve Lands were obtained from the U.S. Department of the Interior, Minerals Management Service. The American Petroleum Institute and Department of Energy publish annual data on the average wellhead price of oil and gas and production in each state. The data used exclude oil and gas produced in the Outer Continental Shelf

(OCS) which is not subject to taxation by the states. The data on wellhead price and volume of production of oil and gas in each state were used to calculate the value of oil and gas production. These data were then used to calculate the annual effective rates of taxation for state production and property taxes, and effective royalty rates, the ratio of tax or royalty collections to the value of production.

One aspect of data collection of state and local taxes was to ensure that the production year was matched to the year of valuation of tax liabilities or collection of tax revenue. In the case of Wyoming, state severance taxes paid prior to 1981 were based on the previous year's production. Wyoming state severance tax has been based on current year production since 1981. Wyoming local ad valorem tax administration is more convoluted. For example, tax liabilities on production in calendar year 1999 can be paid one half in November of 2000 and one half in May 2001 or paid in full by December 31 of 2000. The lag between production and tax collection can be a combination of approximately eleven months and seventeen months or just twelve months. In an effort to stay consistent with all other annual data used in this study, a one-year lag is assumed regarding the ad valorem taxes. For other taxes and states the year of production and valuation were the same. This is due in part to the fact that the tax data were reported by many of the states in the form of tax liabilities rather than collections. Additionally, in the case of Texas and Louisiana adjustments were made to the tax revenue data to account for several large tax protests or appeals. In these states tax revenue is reported in the year of the legal settlement rather than adjusting revenue for the year in which the tax liability was generated. Accordingly, the data were adjusted to reflect the latter concept. Such an adjustment was not possible for the state of Alaska. In the case of Wyoming, tax revenue from tax protest and appeal settlements is assigned to the year the tax liability was created.

Tax administration procedures created problems in several states with respect to being able to obtain tax data, particularly information on local property tax liabilities. Property taxes are administered at the local government level, but in most states, at least in recent years, the state government has a certain amount of oversight. The oversight takes various forms from establishing property tax assessment procedures or assessing the property directly to collecting information and reporting statewide values of assessed property by category, including oil and gas extraction equipment, and average statewide mill levies for non-municipal property. In the case of Texas, oversight at the state level did not begin until 1981 with respect to school property taxes, which account for the majority of property taxes on the oil and gas industry. In consequence, the property taxes levied by over two hundred fifty counties plus special districts are not available prior to 1981. A similar problem exists with respect to the property tax on oil reserves in California prior to 1984, and royalties from production on school lands in Texas prior to 1974.

2.3.c Tax Rate Measurement

The myriad of exemptions, incentives, different tax bases, special features and frequent changes in tax laws, at both the state and federal government levels, create considerable complexity in understanding and tracking of tax law over time.[1] However, economists have a simpler and more straightforward way of dealing with taxes that does not require a detailed understanding of each state's tax law or an itemization of specific tax incentives. The key question to consider in this study is how changes in oil and gas tax policy affect present and future production. In consequence, one aspect of this analysis is to translate tax policy and the various changes in tax policy into what are called effective tax rates. Effective tax 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 effective tax rates fully account for all tax incentives granted against all types of taxes faced by industry.

Given the complexity of the federal, state and local tax laws, particularly as they apply to oil and gas operations, it was necessary to make certain simplifying assumptions in order to estimate the average effective federal and state corporation income taxes. First, it is assumed that all oil and gas companies are incorporated and subject to the federal and state (if applicable) corporate income tax. The majority of oil and natural gas is produced, refined and sold by incorporated firms. Second, all state corporate tax rates are applied at the highest marginal rate if more than one rate exists. The average effective federal corporate income tax rate, by year, for oil and gas extraction was calculated using data from the U.S. Treasury (various years) for returns with net income. The federal tax rate equals federal corporate income tax receipts from oil and gas extraction divided by business receipts minus (the sum of costs of sales and operations, taxes paid, amortization and depletion). This particular approach was used because it reflects corporate income tax receipts as a share of business receipts minus the costs that we are able to calculate. The historical financial analysis of the oil and gas industry presented here is focused on net operating income and costs. Using legal federal corporation income tax rates would vastly overstate the tax liability because we cannot account for a number of the costs, particularly fixed costs, which are deductible, such as interest paid, depreciation on buildings, compensation of officers and the category "other deductions". The highest nominal federal corporation income tax rate in 1997 was 35 percent, but the average effective rate calculated using the formula shown above is 10 percent.

The same reasoning was applied in the calculation of average effective state corporation income tax rates for oil and gas extraction. The nominal or legal state corporation income tax rate was reduced to account for deductions we cannot calculate or estimate. This was accomplished using Statistics of Income (SOI) data, dividing costs we can account for (the sum of costs of sales and operations, taxes paid, amortization and depletion) by total deductions for oil and gas extraction. Then, the average effective state corporation income tax rate used in the analysis was calculated by multiplying the highest state nominal corporation income tax rate by this percentage. For example, for Oklahoma in 1995, the nominal corporation income tax rate was six percent. Based on SOI data this tax rate was multiplied by 0.66, the share of total deductions represented in our state data set, to arrive at an average effective tax rate of four percent.

2.3.d State Tax Structures

The general aspects of the tax structure for each of the eight major producing states as it applies to oil and gas are outlined below. The tax structures differ by state depending on the particular taxes employed and the base for each tax. The taxes relevant to oil and gas and selected additional data collection issues are discussed for each state below.

Wyoming. The state of Wyoming levies a severance tax on oil and gas production and a production tax is levied at the local level, too (the local *ad valorem* production tax). In Wyoming, royalty payments from production on state and federal lands are deductible in computing production tax liabilities. Data on royalty payments from production on state lands were obtained from the State Land Office. Additionally, a local government property tax is levied on oil and gas equipment, including drilling rigs, oil and gas well equipment, gathering lines and tank batteries. Total property tax liabilities were estimated by year by multiplying the total statewide assessed valuation for oil and gas equipment combined by the average statewide mill levy for all purposes (not including municipality levies). The total estimated property tax liability for oil and gas equipment combined was portioned between oil and gas based on the annual volume of oil production and natural gas production in Wyoming, where oil and gas are converted to barrels of oil equivalent expressed in British Thermal Units (BTUs). In this calculation, 5,626 cubic feet of gas equals one barrel of oil expressed in BTUs. The average effective property tax rate on equipment is expressed as the ratio of the estimated tax liability for oil (or gas) equipment to the value of oil (or gas) production. Wyoming does not levy a state corporation income tax. The tax data were obtained from the Wyoming Department of Revenue. The average effective tax rate is expressed as the ratio of taxes collected to total value of production for both the state severance tax and the local *ad valorem* tax. The average effective Windfall Profit Tax is the calculated tax per barrel of oil.

Texas. The state of Texas levies a state severance tax on oil and gas production, and a property tax is levied at the local level on the estimated present value of minerals in the ground as well as structures and equipment. The taxation of oil and gas at the state level is similar to that of Wyoming. Severance tax revenue for oil and natural gas reported separately were obtained from published reports of the Railroad Commission of Texas and the Texas Comptroller of Public Accounts. The state does not levy a corporate income tax. Royalties from public lands are deductible in computing severance tax liabilities. Information on property taxes for oil and gas are not available from a central source. In addition to a school property tax, counties and special districts levy property taxes. School property tax revenue is available for oil and gas combined on an annual basis. At the recommendation of officials at the Texas Taxpayer and Research Association, school tax revenue was grossed up by five eighths to approximate total oil and natural gas property tax revenue statewide. This total was allocated between oil and gas based on the estimated gross value of oil reserves relative to gas reserves (price of oil, or gas, times the estimated volume of reserves, by year).

Royalties from production on state lands are allocated to The Permanent School Fund which was established to provide investment income to support public education for students in grades K-12, and the Permanent University Fund which has a similar purpose for public higher education in Texas. The data were obtained from the administrators of these funds. In the case of the University Fund, royalties from oil and gas production were reported separately for the period 1990-97 and for the earlier years the royalties were reported for oil and gas combined. The latter were portioned between oil and gas based on the total annual value of oil production and natural gas production in Texas. Similarly, School Fund royalties are reported separately for oil and gas from 1986-97. For the earlier years they were reported as an aggregate and were separated by us based on the total annual value of Texas oil production and natural gas production.

Louisiana. The state of Louisiana levies a severance tax on the value of oil and gas production and a corporation income tax. Royalties from production on public lands are not deducted in computing severance tax liabilities. The federal income tax is deductible in computing state corporate income tax liabilities. The property tax is levied on oil and gas wells and surface equipment, and it is administered at the parish (country) level. The State Department of Revenue, Severance Tax Division provided the severance tax information. Property tax information, which consists of a time series on the assessed value of oil and gas wells and surface equipment and the state-wide average weighted mill rate was provided by the Louisiana Tax Commission. These data were used to calculate property tax liabilities for oil and gas combined. These totals were portioned between oil and gas property tax revenue based on the total annual value of oil production and natural gas production. Information on royalties and production of oil and gas on state lands was provided by the State of Louisiana, Department of Natural Resources, Technology Assessment Division.

Oklahoma. The state of Oklahoma levies a severance tax on oil and gas production, and a corporate income tax is employed. Royalties from production on public lands are deductible in computing severance tax liabilities, but federal corporate taxes are not deductible in the computation of state corporate income tax liabilities. There is no tax on oil and gas properties. Severance tax revenue data were obtained from the Oklahoma Tax Commission. The data for the period 1988-97 were available in directly useable form while the data for the earlier years were compiled for oil and gas revenue combined. The latter were portioned between oil revenue and gas tax revenue based on the total annual value of oil production and natural gas production in Oklahoma. The Oklahoma Tax Commission provided the information to calculate the value of production from public lands, and the Commissioner of the Land Office provided the data on oil royalty and gas royalty from production on school lands in directly useable form.

Similar to Wyoming, Oklahoma enacted a tax incentive program for oil and gas production in an effort to increase the profitability of production. The new three-tiered gross production tax rate system became effective January 1, 1999, through June 30, 2001. The old tax rate was seven percent. Under the new system, the tax rate for oil is determined by computing the average price per barrel of sweet crude oil paid to the state's three largest producers during the preceding calendar month. If the average price equals or exceeds $17 per barrel, the tax rate is seven percent. If the average price is less than $17 but equal to or more than $14, the tax rate is four percent and if the average price is less than $14, the rate is one percent. After June 30, 2001 the tax rate reverts back to seven percent.

Kansas. In Kansas, the key taxes at the state level are a severance tax on oil and gas production and a corporation income tax. The severance tax was implemented beginning May 1983. Royalties from production on public lands are not deductible in computing severance tax liabilities. Royalties from production on state lands are unimportant, amounting to less than $80 thousand annually. Federal corporate tax liabilities were deductible in computing state corporate tax liabilities in 1970 but not thereafter. A local government property tax is levied on royalty and working interest and itemized equipment that is not part of the production equipment as of January 1 of the tax year.

The Kansas Department of Revenue, Mineral Tax Bureau provided data on severance taxes. Property tax information was obtained from the Kansas Department of Revenue, Mineral Tax Division. Property tax data were reported for the period 1993-97 for oil and gas separately. For 1989-92 tax totals were provided and portioned between oil and gas based on the state volume of production for oil and for gas. The data for 1983-88 were provided in directly useable form, and for the earlier years back to 1970 the property tax revenue for oil and gas were portioned between oil and gas property based on volume of production for oil and for gas.

Alaska. Alaska has a state corporation income tax, a severance tax and a property tax on capital improvements and equipment. Again, oil in Alaska was the focus of the tax analysis. Alaska is not an important producer of natural gas. The federal income tax is not deductible in computing state corporation income tax liabilities. Royalties from production on public lands are deductible in computing the severance tax. The state has an alternative minimum specific severance tax of $0.80 per barrel or oil. In consequence, when the ad valorem tax falls below $0.80, the specific tax is used. The Reserve Tax, known as the Early Development Incentive Credit was created for the years 1976 and 1977, whereby taxes were prepaid and credits were taken against the petroleum production tax during the years 1978, 1979, and 1980. The purpose of the Reserve Tax was to finance public expenditures associated with the construction of the oil pipeline. Aside from revenue generated by the Reserve Tax, the vast tax revenue and royalty payments associated with oil production in Alaska did not begin until 1978. Most of the tax revenue and royalty information is available on the internet at www.revenue.state.ak.us. An explanation of the data was obtained from officials at the Alaska Department of Revenue, Oil and Gas Audit Division.

California. The focus of the tax analysis for California is oil since California is not a major gas producing state. At the state level the key tax on the oil industry is the corporation income tax; the federal corporate income tax is not deductible. There is no severance tax in California. The property tax is administered at the county level and includes surface property, equipment and the estimated value of mineral reserves. Since there are no state-wide tax revenue data on oil property, information from Kern County, which accounts for seventy percent of oil production in California, was used to represent the state-wide average. A time series of the estimated property tax expressed in cents per barrel of oil produced was obtained from the Chief Appraiser, Oil and Gas Division of Mineral Rights, Kern County. Total state property tax revenue was estimated by multiplying the property tax per barrel times the total number of barrels of oil produced in California. Royalty information relating to production on public lands was obtained from the California State Lands Commission. The royalty rate for production on state lands is about eighteen percent with a floor of one sixth. However, this floor can be reduced if it can be demonstrated by a study that it is economically feasible for old wells to continue production if the royalty rate is reduced.

New Mexico. The state of New Mexico levies a number of separate production taxes on oil and gas, referred to as oil and gas extraction taxes. The taxes consist of the Oil and Gas Severance Tax, Oil and Gas Emergency School Tax, Oil and Gas A*d Valorem* Production Tax, and the Oil and Gas Production Equipment Tax. The revenues collected are reported for oil and gas combined. The totals were portioned to oil and gas based on the annual value of oil production and natural gas production. An additional tax is levied on natural gas, the Natural Gas Processors Tax. For purposes of the analysis here the separate taxes are combined to form one production tax whose effective tax rate is total tax collections per year divided by the annual value of production. The New Mexico Taxation and Revenue Department, Oil and Gas Division provided information concerning severance taxes. Royalties from production on public lands are deductible is establishing valuation for the production taxes. Information on royalties from production on state lands was obtained for the period 1995-97 from the State of New Mexico Commissioner of Public Lands. For earlier year the information was obtained from the Taxation and Revenue Department. There is no separate property tax on oil and gas equipment. Equipment is taxed through the Oil and Gas Production Equipment Tax mentioned above, where the assessed value is nine percent of the sales value of the product of each production unit. Additionally, the state of New Mexico levies a corporation income tax. Federal corporate income tax liabilities are not deductible in computing the state tax liability.

2.4 Comparison of Effective Rates of Oil and Gas Taxation

State tax structures are compared based on effective rates of taxation. These effective rates fully account for all tax incentives that have been granted to oil and gas operators in each state. Thus, the effective rates calculated generally are lower than the nominal rates of tax that would prevail if no incentives had been granted. Effective rates were computed annually for the period 1970-1997 and are shown in Table 2.1 for oil and Table 2.2 for natural gas for the years 1970, 1975, 1980, 1985, 1990 and 1997. As noted previously, for certain states some of the tax information was not available for some of the earlier years. In the case of production and property taxes, and state and federal royalties, the effective rate is the ratio of tax collections or liabilities to gross value of production. The effective rate for state corporate income taxes is the highest nominal (legal) rate reduced to account for tax deductions we cannot calculate directly by state for the oil and gas industry. Also shown is the Windfall Profit Tax, expressed in dollars per barrel of oil, by state. The final column in each table indicates the share of production of oil or natural gas accounted for by nonintegrated producers (NI), beginning in 1975.

Comparisons of the effective tax rates highlight the substantial differences in the tax structures of the energy producing states, and in the relative importance of production on public lands. Beginning with oil, Table 2.1 shows that Wyoming relies on state and local production taxes as major sources of oil revenue. Royalties from production on public lands are a major revenue source for the federal government, as a large share of

Wyoming's oil and gas production is on federal land. State production and local property taxes are the major revenue sources in Texas. In the case of Louisiana, state production taxes and royalties from production on state lands are the important sources of revenue. Louisiana also levies a state corporation income tax. In Oklahoma, the state production tax is most important. Oklahoma also levies a state corporate income tax. Property and production taxes are major revenue sources in Kansas and a corporate income tax is levied. The state production tax and royalties from production on state lands are most important in Alaska, and a corporate income tax exists. In California the property tax on reserves is most important and a corporation tax is levied. Royalties from production on state lands have diminished in importance in California during the 1990s. In New Mexico, production taxes and royalties from production on both federal and state lands are important, and a corporation income tax exists.

Another useful perspective is a comparison of each source of revenue across states. Regarding production taxes, the effective taxes are highest in Alaska, Wyoming (state and local combined) and Louisiana, all with effective tax rates in excess of ten percent in 1997. Effective rates are lowest in Kansas and Texas, and California does not levy a production tax. In 1997, effective property taxes were highest in Texas (4.4%), Kansas (4.3%), and California (3.4%). The highest effective tax rates on operating profits of the oil and gas extraction industry, and industry in general, are levied in Alaska and California. Again, Texas and Wyoming do not levy corporation income taxes. The key factor determining effective royalty rates is the volume of production on public lands. In 1997, Alaska (14%), and Louisiana (5.7%) had the highest effective state royalty rates. The highest effective federal royalty rate occurs in Wyoming, 8.2% in 1997, followed by New Mexico, 4.8%.

The Windfall Profit Tax varies across states for any given year primarily because of differences in market prices and the relative importance of production by independent versus integrated producers. The Windfall Profit Tax is much lower in Alaska because of lower market prices, which reflect the high cost of transporting oil to markets in the continental United States. The tax rates, shown in Table 2.1, for 1980 and 1985, are lower than for the intervening years when market prices of oil were higher, particularly in 1981 and 1982.

The federal corporation income tax rate used for all states equals corporation income tax receipts from oil and gas extraction divided by business receipts minus certain costs we were able to calculated by state. The effective tax rates are as follows: 1970 .31, 1975 .42, 1980 .21, 1985 .14, 1990 .10 and 1997 .10. The steady decline in these rates between 1974 and 1986 is due primarily to the decrease in nominal corporation income tax rates during this period and reflect the decrease in reliance on business-type taxes at both the federal and state levels, particularly during the 1980s.

The final column of Table 2.1 shows the share of oil production accounted for by nonintegrated producers. While the figure is important in calculating accounting profits and the Windfall Profit Tax, it also provides insight into the structure of the oil industry in the major energy producing states. In the states of Wyoming, Texas, Louisiana, Oklahoma, and New Mexico the share of production accounted for by independent producers has increased steadily since 1975, and in all of these states production by independents now accounts for over fifty percent of total production. The association between the major decline in the relative importance of production by integrated producers and their loss of percentage depletion beginning in 1975 is noteworthy. Independent producers have always dominated production in Kansas, a relatively unimportant oil producing state. Conversely, integrated producers have accounted for the vast majority of oil production in Alaska, concentrated at Prudhoe Bay. California is the only major oil producing state in which the share of production by integrated producers has increased significantly since 1975.

The tax structures for natural gas are quite similar to oil, although nominal production tax rates differ between oil and gas in some states. Notable differences occur in Kansas and New Mexico. Both states are important natural gas producing states, but relatively unimportant oil producers. In Kansas, effective property and production tax rates are higher for natural gas than oil. The pattern is similar for New Mexico, where production tax and royalty rates from public lands are considerably higher for natural gas than oil. In Louisiana, effective tax rates are considerably lower for natural gas than for oil, largely due to lower nominal or legal tax rates. Specifically, the legal tax rate on oil is 12.5 per cent and the rate for natural gas is not less than seven cents per one thousand cubic feet, adjusted annually. State corporate income tax rates, not shown again in Table 2.2, are the same for natural gas and oil. They are calculated for the oil and gas extraction industry.

A comparison of effective rates by tax across states shows a pattern somewhat similar to oil. In 1997, Wyoming (state and local combined) and New Mexico had the highest effective tax rates on natural gas production, 12% and 11%, respectively. Kansas had the highest effective property tax rate. Effective state royalty rates were highest in Louisiana and New Mexico, and federal rates were highest in Wyoming and New Mexico, reflecting the importance of production on public lands in these states.

Finally, the basic organizational structure of the natural gas industry differs somewhat from that of the oil industry in some states, at least in terms of extraction. For example, integrated producers account for the majority of natural gas production in Wyoming, but not oil production. However, in the major oil and gas producing states of Texas, Louisiana, and Oklahoma, independent companies account for the major share of production of both natural gas and oil, and their share of production has been rising steadily.

Extending the comparisons of taxes among the energy producing states further, to the point of ranking states in terms of their total or cumulative tax burden on the oil and gas extraction industry, is not particularly fruitful and may be misleading. As noted in the preceding section of this chapter, the three types of taxes, production, property and income, have different effects on production, exploration and development. Moreover, extraction, exploration and development costs differ among the energy producing states, too (estimates of these differences are presented in Chapter 3). Stated differently, state and local taxes are but one element affecting decisions to produce, explore and develop nonrenewable resources and should not be considered in isolation from other key factors.

One form of inter-state tax comparison, called hypothetical tax bill studies, is based on a profile of a hypothetical firm, producing a certain amount of product, generating a given amount of sales revenue with specified capital, labor and other costs. Hypothetical tax bills are calculated for this firm based on the tax structures of different states in which the firm might locate. There are several important problems associated with such studies. First, the analysis assumes that all costs except taxes are the same across states, and normally this is an incorrect assumption, particularly in the case of oil and gas exploration, development and production. Second, such studies assume that the firm uses the same factor inputs in the same proportions, such as capital and labor, irrespective of the geographic location. Stated differently, it is assumed that the production function is fixed and identical irrespective of where the firm locates. Again, this is usually an incorrect assumption, particularly since production costs differ across locations. Finally, the hypothetical firm seldom exists, and it is misleading to infer tax or other costs for other plant or firm profiles different from the hypothetical firm created for the tax comparison.

ENDNOTES

[1]For example, in Wyoming, there are certain exemptions or reductions in the state tax rate for oil and gas production and they are not necessarily cumulative. Their status as of January 2000 is described here. Tertiary production resulting from projects certified by the Wyoming Oil and Gas Conservation Commission after July 1, 1985 and before March 31, 2001 is exempt from the additional 2% mineral excise tax for a period of five years from the date of first tertiary production. (Ch. 72, Laws 1997; Sec. 39-14-205(c)). Oil and gas produced from wells drilled between July 1, 1993 and March 31, 2003 (except production from collection wells) is exempt from severance taxes for the first 24 months of oil production up to 60 barrels per day or its equivalency in gas production, which is six MCF gas production per one barrel oil production, or until the price received by the producer for the new production is equal to or exceeds $22 per barrel of oil, or $2.75 per MCF of natural gas, for the preceding six months (Sec. 39-14-205(f)). Further, an exemption from tax is available for incremental oil or gas production resulting from a workover or recompletion of an oil or gas well between January 1, 1997 and March 31, 2001 for a period of 24 months immediately following the workover or recompletion (Ch. 171, Laws 1997; Sec. 39-14-205(g)). Oil produced from previously shut-in wells is exempt from the basic mineral excise tax and two additional excise taxes (Sec. 39-14-205(h), Sec. 39-14-111) for the first 60 months of renewed production or until the average price received by the producer for renewed production is equal to or exceeds $25 per barrel of oil for the preceding six months, whichever occurs sooner. A 1.5 % excise tax is imposed on the extracted oil from wells that qualify for the exemptions (Sec. 39-14-204). Finally, for the period January 1, 1999 through December 31,2000 the Wyoming severance tax on crude oil production is effectively reduced to 4%. For the

above period, two components of the tax are each reduced to 1%, from 2%, unless the average monthly price received by Wyoming crude oil producers, as determined by the Department of Revenue, equals or exceeds $20 per barrel for three consecutive months, in which case the 1% rate will terminate. Ch. 168 H.B. 274, Laws 1999, effective January 1, 1999.

Table 2.1

Effective Oil Tax Rates, By State[a]

Wyoming

Year	Production State	Production Local	Royalties State	Royalties Federal	Property	WPT	Share NI Production
1970	0.009	0.049	0.009	0.076	0.002		
1975	0.036	0.048	0.009	0.076	0.001		.290
1980	0.032	0.052	0.007	0.076	0.001	4.07	.306
1985	0.053	0.061	0.008	0.077	0.002	3.93	.341
1990	0.047	0.061	0.007	0.080	0.001		.432
1997	0.057	0.062	0.008	0.082	0.002		.581

Texas

Year	Production	Royalties State	Royalties Federal	Property	WPT	Share NI Production
1970	0.042	0.003	0.00002			
1975	0.043	0.015	0.00001			0.227
1980	0.037	0.015	0.00002		4.21	0.367
1985	0.044	0.011	0.00005	0.024	5.24	0.432
1990	0.033	0.007	0.00012	0.031		0.495
1997	0.043	0.009	0.00058	0.044		0.611

Louisiana

Year	Production	Royalties State	Royalties Federal	Property	Corp. Income	WPT	Share NI Production
1970	0.068	0.055	0.001	0.0046	0.030		
1975	0.119	0.046	0.001	0.0033	0.032		0.05
1980	0.153	0.038	0.001	0.0018	0.057	3.20	0.122
1985	0.105	0.040	0.001	0.0033	0.050	5.08	0.406
1990	0.120	0.039	0.001	0.0036	0.050		0.456
1997	0.104	0.057	0.001	0.0040	0.056		0.523

Oklahoma

Year	Production	Royalties State	Royalties Federal	Corp. Income	WPT	Share NI Production
1970	0.052		0.004	0.03		
1975	0.080	0.002	0.004	0.03		0.661
1980	0.079	0.002	0.003	0.03	6.91	0.691
1985	0.061	0.002	0.003	0.03	4.10	0.808
1990	0.068	0.002	0.003	0.03		0.716
1997	0.065	0.002	0.004	0.04		0.853

Table 2.1
(Continued)

Kansas

Year	*Production*	*Federal Royalties*	*Property*	*Corp. Income*	*WPT*	*Share NI Production*
1970	.000	0.001	0.076	0.050		
1975	.000	0.001	0.058	0.055		0.961
1980	.000	0.000	0.044	0.048	8.78	0.968
1985	0.034	0.000	0.056	0.042	3.65	0.955
1990	0.026	0.001	0.029	0.043		0.976
1997	0.025	0.001	0.043	0.051		0.970

Alaska

		Royalties			*Corp.*		*Share NI*
Year	*Production*	*State*	*Federal*	*Property*	*Income*	*WPT*	*Production*
1970	0.031	0.145	0.0193	0.000	0.07		
1975	0.073	0.182	0.0168	0.018	0.07		0.031
1980	0.076	0.094	0.0005	0.017	0.07	1.52	0.009
1985	0.122	0.121	0.0008	0.011	0.06	0.00	0.002
1990	0.099	0.099	0.0004	0.009	0.06		0.003
1997	0.128	0.140	0.0004	0.007	0.07		0.005

California

	Royalties			*Corp.*		*Share NI*
Year	*State*	*Federal*	*Property*	*Income*	*WPT*	*Production*
1970	0.032	0.008		0.052		
1975	0.052	0.008		0.073		0.474
1980	0.050	0.006		0.064	5.25	0.496
1985	0.041	0.006	0.028	0.060	2.66	0.409
1990	0.025	0.006	0.033	0.059		0.339
1997	0.006	0.003	0.034	0.062		0.360

New Mexico

		Royalties		*Corp.*		*Share NI*
Year	*Production*	*State*	*Federal*	*Income*	*WPT*	*Production*
1977	0.041	0.025	0.042	0.045		0.262
1980	0.033	0.017	0.041	0.043	5.14	0.265
1985	0.060	0.032	0.036	0.045	5.22	0.319
1990	0.056	0.019	0.046	0.048		0.438
1997	0.055	0.019	0.048	0.053		0.654

[a] All effective rates are tax or royalty collections, or liabilities, divided by the gross value of production, except for corporation income and windfall profit taxes. The former is the highest nominal or legal state marginal tax rate reduced to account for tax deductions not reflected in the state data for the oil and gas extraction industry. The latter is expressed in dollars per barrel of oil.

Table 2.2

Effective Gas Tax Rates, By State[a]

Wyoming

	Production		Royalties			Share NI
Year	***State***	***Local***	***State***	***Federal***	***Property***	***Production***
1970	0.008	0.045	0.008	0.071	0.007	
1975	0.033	0.047	0.009	0.071	0.005	.450
1980	0.039	0.062	0.008	0.064	0.001	.422
1985	0.059	0.057	0.009	0.079	0.002	.337
1990	0.054	0.063	0.008	0.085	0.003	.341
1997	0.051	0.068	0.009	0.103	0.004	.431

Texas

		Royalties			Share NI
Year	***Production***	***State***	***Federal***	***Property***	***Production***
1970	0.082	0.004	0.00007		
1975	0.067	0.015	0.00003		0.416
1980	0.066	0.015	0.00001		0.428
1985	0.080	0.011	0.00007	0.019	0.548
1990	0.057	0.009	0.00012	0.019	0.667
1997	0.044	0.007	0.00170	0.024	0.713

Louisiana

		Royalties			Corp.	Share NI
Year	***Production***	***State***	***Federal***	***Property***	***Income***	***Production***
1970	0.109	0.033	0.0011	0.0065	0.030	
1975	0.142	0.031	0.0010	0.0062	0.032	0.077
1980	0.037	0.030	0.0004	0.0046	0.057	0.175
1985	0.024	0.035	0.0004	0.0089	0.050	0.335
1990	0.050	0.037	0.0013	0.0111	0.050	0.437
1997	0.034	0.041	0.0019	0.0130	0.056	0.579

Oklahoma

		Royalties		Corp.	Share NI
Year	***Production***	***State***	***Federal***	***Income***	***Production***
1970	0.052	N/A	0.003	0.03	
1975	0.080	0.003	0.003	0.03	0.5847
1980	0.079	0.003	0.003	0.03	0.6142
1985	0.061	0.003	0.004	0.03	0.7287
1990	0.068	0.003	0.004	0.03	0.7509
1997	0.065	0.003	0.003	0.04	0.8113

Table 2.2
(Continued)

Kansas

Year	*Production*	*Federal Royalties*	*Property*	*Corp. Income*	*Share NI Production*
1970	.000	0.002	0.076	0.050	
1975	.000	0.003	0.058	0.055	0.6
1980	.000	0.002	0.044	0.048	0.6
1985	0.065	0.002	0.131	0.042	0.6
1990	0.066	0.003	0.084	0.043	0.6
1997	0.042	0.004	0.064	0.051	0.6

New Mexico

		Royalties		*Corp.*	*Share NI*
Year	*Production*	*State*	*Federal*	*Income*	*Production*
1977	0.085	0.050	0.073	0.045	0.556
1980	0.082	0.041	0.074	0.043	0.559
1985	0.113	0.058	0.075	0.045	0.492
1990	0.134	0.045	0.068	0.048	0.496
1997	0.110	0.037	0.100	0.053	0.628

[a] All effective rates are tax or royalty collections, or liabilities, divided by the gross value of production, except for corporation income taxes. The latter is the highest nominal or legal state marginal tax rate reduced to account for tax deductions not reflected in the state data for the oil and gas extraction industry.

CHAPTER 3

TAXES, EXPLORATION, AND PRODUCTION IN THE U.S. OIL AND GAS INDUSTRY

3.1 Introduction

How do firms in exhaustible resource industries respond to changes in taxes? It is tempting to look for answers to this question in the empirical literature on tax competition (see, for example, Bartik 1985, Helms 1985, Papke 1991, 1994, and Holmes 1998), however these papers study behavior of manufacturing firms and assume that capital is mobile between geographic locations. In contrast, extractive firms are not free to go wherever they please because they are tied to a geographically immobile reserve base that makes up a key component of their capital stock. One option for such firms is to use time, rather than space, as the primary dimension across which to substitute in the face of changes in taxes levied. These substitutions in the time dimension, of course, will alter the proportions of exploration and production occurring at different locations. Yet, timing of activities is the fundamental aspect of the extractive firm's problem and information about location choices can be recovered as a by-product simply by comparing development paths of different reserves.

This chapter develops an empirical framework that can be used to show how changes in the use of alternative tax instruments alters the timing of exploration and production by firms in the U.S. oil and gas industry. This framework embeds econometric estimates into Pindyck's (1978) widely cited theoretical model of exhaustible resource supply, can be applied to any of 21 U.S. states that produce significant quantities of oil and gas, and allows for interactions between taxes levied by different levels of government. Thus, 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 do not demonstrate that their econometric equations are on solid theoretical ground. Pesaran (1990), on the other hand, 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. Additionally, simulation studies conducted by Yucel (1989) and Deacon (1993) consider different types of tax policies, but are aimed mainly at assessing the generality of theoretical results obtained in more limited settings, such as those obtained by Burness (1976), Conrad and Hool (1980), and Heaps (1985). Existing simulation studies also have the disadvantage of ignoring interstate differences in exploration and extraction costs, and do not allow for interactions between tax bases claimed by different levels of government.

The remainder of the chapter is divided into three sections. Section 3.2 presents the theoretical model used in the study. Section 3.3 presents empirical estimates of the model's parameters. These estimates are obtained using panel data from the 21 most important oil and gas producing states over the period 1970-1997. A brief conclusion is presented in Section 3.4. Chapter 4, then, presents simulation results showing how oil and gas exploration and production in major producing states varies over time in response to changes in production (severance) taxes and drilling costs.

3.2 Conceptual Framework

The analysis presented in this section extends Pindyck's (1978) model of nonrenewable resource development to incorporate key aspects of federal, state and local taxes facing the U.S. oil and gas industry. Because the basic model is familiar, discussion in this section is kept to a minimum. This model explicitly treats both exploration and production, but does not consider aspects such as uncertainty and grade selection (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 (known) future output prices and taxes as given and then choose optimal time paths for exploration and production. A single firm is used to represent the industry, so the common pool problem and well spacing regulations are ignored (McDonald 1994). Possible regulatory constraints on output, such as those imposed by the Texas Railroad Commission from the 1930s through the early 1970s (Moroney and Berg 1999) or via slow release of drilling areas on public land by government authorities (McDonald 1994) are ignored as well.

For simplicity and because of data constraints discussed in the next section, exploration here is defined 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 in the model represents a form of 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 (ignored here) and the treatment of joint production are discussed more fully by Bohi and Toman (1984, Chapters 3, 5) and Livernois (1987, 1988). However, differences in the quality of oil or differences in transportation cost are implicitly treated in the model by adjusting prices received by operators.

As noted in Chapter 2, institutional features of taxation facing oil and gas producers are complex. Incorporating these aspects into the model, however, is not difficult conceptually. The firm's maximization problem is

$$\max_{q,w} \Omega = \int_{\circ}^{\infty} [qp - C(q,R) - D(w) - gR]e^{-rt}\, dt \tag{3.1}$$

subject to

$$\dot{R} = \dot{x} - q \tag{3.2}$$

$$\dot{x} = f(w, x) \tag{3.3}$$

$$q \geq 0, w \geq 0, R \geq 0, x \geq 0 \tag{3.4}$$

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), 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), $D(w)$ denotes total cost of exploration for additional reserves net of taxes, w denotes exploratory effort, γ denotes a 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 BOE is related to the wellhead (pre-tax) price (p^*) according to $p = \alpha_p p^*$, where α_p is a function of federal, state, and local tax rates 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 functions of tax rates and lie on the unit interval. Also in this section, to make the model easier to explain, taxes are assumed fixed for the duration of the program. More complete discussion the tax parameters (α_j, $j=p,c,D$) as well as simulation of tax changes is deferred to Chapter 4. However, three aspects should be noted before proceeding further. First, 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 revenue. Second, α_D reflects, among other things the opportunity to expense intangible drilling costs. Third, the α_j are treated as independent of γ (see endnote 1).

The Hamiltonian for this problem is

$$H = qpe^{-rt} - C(q,R)e^{-rt} - D(w)e^{-rt} - \gamma Re^{-rt} + \lambda_1[f(w,x) - q] + \lambda_2[f(w,x)]. \qquad (3.5)$$

Properties of $C(\cdot)$ and $f(\cdot)$ include $C_q > 0$, $C_{qq} > 0$, $C_R < 0$, $C_{RR} > 0$, $f_x < 0$, $f_w > 0$, and $f_{ww} < 0$. These conditions imply that marginal extraction costs are positive and increase with q, and extraction costs rise as the level of reserves declines. Also, $f_w > 0$ and $f_{ww} < 0$ capture the idea that the marginal product of exploratory effort is positive and decreases with w, and $f_x < 0$ indicates that it becomes increasingly difficult to make new discoveries of reserves as exploration effort cumulates. The cost of exploratory effort, $D(\cdot)$, increases with w at a constant rate, $D_{ww} = 0$. Increasing marginal cost of exploration ($D_{ww} > 0$) would presume a monopsonistic rather than a perfectly competitive firm.

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

$$\dot{l}_1 = (C_R + g)e^{-rt} \tag{3.6}$$

$$pe^{-rt} - C_q e^{-rt} - l_1 = 0 \tag{3.7}$$

$$\dot{l}_2 = -f_x(l_1 + l_2) \tag{3.8}$$

$$-D_w e^{-rt} + f_w(l_1 + l_2) = 0. \tag{3.9}$$

In equation (3.7), l_1 is the discounted shadow price of the reserve state. It is easily shown that this shadow price can be decomposed into two components where $l_1 = (p - C_q)e^{-rT} - \int_t^T (C_R + g)e^{-rs}\, ds$. The term, $(p - C_q)e^{-rT}$, represents the present value of *future* operating profits at the margin. These are zero if $l_1(T) = 0$ (see the boundary condition discussion below). The second term, $-\int_t^T (C_R + g)e^{-rs}\, ds$, denotes the present value sum of future cost increases (for a sufficiently small g) resulting from marginally reducing the reserve stock today (Levhari and Leviation, 1977). In equation (3.6) $\dot{l}_1 < 0$ if $C_R < 0$, $C_{RR} > 0$, and g (the tax effect on reserves) is sufficiently small. Increases in g lower the time rate of change in l_1. From equation (3.8) and equation (3.9), the term$(l_1 + l_2)$ equals the discounted value of the marginal cost of adding another unit of reserves by exploration (discoveries) $[D_w / f_w]e^{-rt}$. Because $0 < a_D < 1$, this marginal cost is lower than in the pretax case. The shadow price of cumulative reserve additions, l_2, is expected to be negative (and small relative to l_1) for oil and gas because current reserve finds increase the amount of exploration needed in the future. The evolution of this shadow price is increasing, $\dot{l}_2 > 0$, because $f_x < 0$.

Optimal time paths for q and w can be obtained by manipulation the optimality conditions. The evolution of q is obtained by differentiating equation (3.7) with respect to time and setting the result equal to equation (3.6) to eliminate $\dot{l}_1$. This yields equation (3.10).

$$\dot{q} = \frac{-r(p - C_q) + \dot{p} - C_{qR}\dot{R} - (C_R + g)}{C_{qq}}. \tag{3.10}$$

In equation (3.10), the term $-r(p - C_q) < 0$ denotes the effect of discounting on the rate of change in production over time. Incentives to increase production in early periods prevail because future revenues, net of extraction costs, are discounted. If $a_p < a_c$, however, this incentive is reduced as firms attempt to minimize the impact of taxation on net revenue by tilting production to the future. If prices increase over time, $\dot{p} > 0$, the negative discounting effect can be at least partially offset, but even when $\dot{p} = rp$, where price rises with the discount rate, extraction still can decline over time depending on the relative magnitudes of the cost derivatives in the numerator of (3.10). The term, $-C_{qR}\dot{R}$, represents the marginal impact of reserve depletion over time. If reserves fall over time, marginal extraction costs rise, thus attenuating production. The term $-(C_R + g)$ relates to the decline in the shadow price of adding reserves. If $g > 0$, production is tilted to earlier periods as firms attempt to escape the impact of the tax by lowering reserves.

The optimal time path of w can be determined using equation (3.7) and equation (3.9) to solve for l_2, differentiating with respect to time to obtain an expression for $\dot{l}_2$, equating the result to equation (3.8) and rearranging terms.[2]

$$\dot{w} = \frac{D_w[(f_{wx} / f_w) \cdot f - f_x + \mathrm{r}] + (C_R + g) f_w}{[-D_w (f_{ww} / f_w)]} \tag{3.11}$$

The (positive) denominator of equation (3.11) is f_w times the derivative of the marginal cost of reserve additions with respect to w, $(\partial(D_w / f_w) / \partial w)$. Thus, if $g = 0$, the trajectory of exploratory effort is determined by a tradeoff between the cost of finding new reserves (D_w) and the extraction cost savings this new level of reserves brings. A property tax levied on reserves in the ground ($g > 0$), tends to offset the extraction cost savings effect and push exploration into the future. On the other hand, generous tax treatment of drilling expenses ($a_D < 1$) have the opposite effect, by providing an incentive to increase exploration in the early years.

Boundary conditions can be established by first assuming that $D_w / f_w = 0$ when $w = 0$ (see Pindyck 1978, pp. 846-47). In this situation, when production ceases at some terminal time T, exploration ceases at the same time because it is of no further value. Also, $l_2(T) = 0$ as long as there are no terminal costs associated with cumulative discoveries. In consequence, from equation (3.9), $l_1(T) = 0$ implies that operating profit on the last unit of reserves extracted is zero, $p = C_q$. An alternative terminal state centers on the case where $D_w / f_w = \Phi > 0$, when $w = 0$. In this situation, production will continue after exploratory effort ceases. Let $T_1 < T$ denote the time when $w = 0$. If exploratory effort is zero, $f_x = 0$, hence $\dot{l}_2(T_1) = 0$ and $l_2(T_1) = 0$. From (3.7) and (3.9), $p - C_q = l_1(T_1)e^{rt} = \Phi = D_w / f_w$ which indicates that exploration will stop just as $p - C_q$ approaches marginal discovery cost, Φ. These two alternative terminal conditions are discussed in the next section as well as in connection with the simulations presented in Chapter 4.

3.3 Estimation

As shown in equations (3.10) and (3.11), the evolutions of w and q are nonlinear functions of both the levels of these variables and the previously defined tax parameters. In consequence, rather than attempt to obtain econometric estimates of these two equations directly, 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, and α_D. Effects of tax changes then are obtained by simulation. Estimates of equations for D^* and f are treated together in Part a of this section because they are used to compute the marginal cost of reserve additions (D_w^* / f_w) which is a crucial function of the model described above. The equation for C^* is treated in Part b.

3.3.a 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 modeled in equation (3.12) as proportional to drilling effort.

$$D^*(w) = \phi w e^u \tag{3.12}$$

This approach ensures that the objective function (see equation 3.1) represents a perfectly competitive firm, as previously assumed. In equation (3.12), 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. 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 (see below) the number of wells drilled is positively correlated with total footage drilled (Pearson correlation = .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 3.2, cumulative reserve discovery (x) appears as an argument in the production function for new reserves (see equation 3.13 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 Chapter 4 and eliminates the need for arbitrary assumptions about historical average depth per well.

The production function for reserve additions is specified as

$$f(w,x) = Aw^{r} e^{-b\cdot x} e^{v} \tag{3.13}$$

where A, r, and b are parameters to be estimated and the multiplicative disturbance e^v is assumed lognormally distributed with mean of unity and variance s_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 previously discussed, data on cumulative reserve discoveries of oil and gas are unavailable, so the cumulative number of wells drilled by state was used as a proxy. As in the drilling cost function, the annual number of wells drilled is used as a measure of w.

Drilling cost and reserve production functions are estimated using annual data from 21 U.S. states for which complete information on wells drilled, drilling costs, reserve additions, and cumulative drilling could be assembled for the period 1970-97.[3] Regarding costs, operators report the total cost (both tangible and intangible) of each well completed (including dry holes) via the Joint Survey on Drilling Costs.[4] Oil and gas reserve additions are comprised of extensions, new field discoveries and new reservoir discoveries in old fields as defined by the U.S. Department of Energy, Energy Information Administration (DOE/EIA). As shown in Table 3.1, the 21 states included in the data set accounted for 97% of U.S. oil production, 94% of U.S. gas production, and 96% of BOE production of oil and gas. BOE production was calculated by noting that 5,626 cubic feet of gas is the BTU equivalent of 1 barrel of oil.

Data sources, definitions, and sample means of variables used in the analysis are presented in Table 3.2. Estimates of equation (3.12) used the natural logarithm of *TRCOST* as the dependent variable and estimates of equation (3.13) used the natural logarithm of *ADDED RESERVES* as the dependent variable. An instrument for the natural logarithm of *WELLS* was used as an explanatory variable in estimating both equation (3.12) and equation (3.13) with *CWELLS* entering equation (3.13) as the proxy for x. Instrumental variable estimation is appropriate because w is an endogenous variable in the model presented in Section 3.2. Construction of the instrumental variable for w is discussed momentarily. As shown in Table 3.3, *WELLS* varies substantially over time for given states. In Oklahoma and Texas, for example (also see Figures OK1 and TX1), drilling increased dramatically during the late 1970s and early 1980s and then simply collapsed as energy prices sharply declined in the mid-1980s. Variation in drilling activity over this period was not as pronounced in other major energy producing states and drilling activity in all states was generally lower through the 1990s than in the early 1980s.

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 3.4. Time-specific effects tested insignificant at conventional levels. *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. 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.

Estimates of equation (3.12) are obtained by *restricting* the exponent on w to unity in a two-way fixed effects framework. Following the assumption of perfect competition, this restricted estimation procedure is necessary and will yield constant marginal drilling costs. The two-way fixed effects 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 varying factors common to all states may include technological advancement and macroeconomic cycles. For the drilling cost equation, each state-specific effect for a given year, conveniently, becomes the state-specific estimate of f.

Estimates of equation (3.13) are obtained in a one-way fixed effects framework that yields common estimates of the slope coefficients across states and corrects for first-order serial correlation.[5] The one-way fixed effects estimation with correction for serial correlation is used for four interrelated reasons. First, this approach is a simple way to control for, yet avoid enumerating, unique aspects of states that affect reserve additions, but do not change over time. Second, time-specific effects are not jointly significant at conventional levels, making estimation in a two-way fixed effects framework unnecessary. Third, the random-effects specification, in which state-specific effects are treated as error components, is rejected by a Hausman (1978) test at the 5% level of significance (see Table 3.6). Moreover, conditional estimates of the effects on reserve additions obtained from fixed-effects are thought to be of greater interest than corresponding unconditional estimates obtained using random effects. Fourth, the null hypothesis of no serial correlation is rejected at the 1% level, hence, the equation was re-estimated with correction for first-order serial correlation.

Table 3.5 reports instrumental variable estimates of the drilling cost equation for 7 major producing states. The 1997 state-specific estimates of $\boldsymbol{f}$ have been corrected for the fact that the equation was estimated in logarithmic form (see Greene 1997, p. 279). As shown, R^2 is 0.92 with state and time-specific effects jointly significant under the appropriate F-tests. Results suggest that total drilling costs increase with w and that constant marginal drilling costs (D_w^*) differ substantially across the 7 states shown. Estimates of the reserve addition equation are shown in Tables 3.6 and 3.7. In Table 3.6, the coefficient of *LN(PREDWELLS)* is 0.48. This estimate is significantly different from one and zero at conventional levels. The value of R^2 is 0.85 and the state-specific effects are jointly significant under the appropriate F-test. Also, the negative coefficient of *CWELLS*, though insignificant at conventional levels, suggests that reserve additions decline with the passage of time as new reserves become more difficult to identify. Table 3.7 presents the corrected state-specific intercept terms for 7 major producing states. Results suggest that the marginal product of drilling (f_w) decreases with wells drilled and this marginal product would vary between states even if the number of wells drilled were the same in each.

Estimates of the two equations combined suggest that 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 3.8 shows how values of D_w^*, f_w, and D_w^*/f_w differ by state for seven of the major producing states, assuming that the sample mean of 1647 wells are drilled in each. Column 4 of Table 3.8 depicts the pre-tax *average* cost of adding a BOE of reserves, assuming the same 1647 wells are drilled. Pre-tax average cost is calculated by dividing total drilling cost ($D(w)$) by total reserve additions ($f(w,x)$). The last two columns of Table 3.8 show the marginal and average cost of reserve additions calculated with 1997 data. All cost calculations are made with the instrumental variable coefficients and adjust the state-specific estimates of ϕ and A for the fact that both the drilling cost and reserve additions equations were estimated in logarithmic form. As shown, values of D_w^* and f_w reflect considerable variation across the seven states. Estimates of marginal drilling cost range from $89,878 in Kansas to $1,125,920 in Louisiana. Marginal reserve additions from drilling (f_w) range from 8,754 BOE in Kansas to 112,328 BOE 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. Corresponding values of D_w^*/f_w for the other five states range from a low of $7.04 per BOE in New Mexico to a high of $11.24 per BOE in Texas. Likewise, average cost of reserve additions also vary across states from $5.09 in Oklahoma to $6.74 in Texas. As expected, average cost estimates are appreciably lower than their marginal counterparts. Estimates using 1997 data show how marginal and average cost of reserve additions vary when each state drills a different number of wells. The higher costs in Texas can be attributed to resource depletion and the diminished prospect of finding new reserves. As a consequence, Chapter 4 simulations for Texas are expected to reflect levels of drilling and production more in line with those sampled in the late 1990s rather than total sample means.

3.3.b Extraction Costs

Direct operating (lifting) cost for both oil and gas by region at depths of 2,000, 4,000, 8,000, and 12,000 feet are available from annual studies published by the U.S. Department of Energy, Energy Information Administration (EIA) for the period 1970-1997. 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 were calibrated as follows. Assume that production is represented by the Cobb-Douglas function, $q = Vn^mR^{1-m}$, where n denotes all non-reserve inputs to the process. The constant cost per unit of n is s, with the constant user cost per unit of reserves denoted as G. A firm's profit would take the form, $pVn^{m}R^{1-m}$ - $s\, n$ - GR, yielding the profit maximizing necessary condition,

$$s \quad n / GR = m/(1-m) \tag{3.14}$$

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

$$C(q, R) = kq^{e}R^{1-e} \tag{3.15}$$

where $e = 1/m$ and k is a function of V and the (constant) price of non-reserve inputs. Estimates for k and m are established from the data on operating cost, drilling cost, production, reserve additions, and reserve levels described above. Table 3.9 reports the time means of key variables used in this analysis.

Simply, $s\, n$ equals average total lifting costs (averaged over all depths per joint production, in \$1995) and GR represents the average total cost (in \$1995) of reserves held. Thus, the left-hand side of (3.14) is simply the cost share ratio of the two production inputs with the user cost per unit of reserves expressed as $G = (r + (q / R))S$. Here, r is the discount rate, q / R represents the depreciation rate of reserves, and S denotes average drilling costs (in \$1995) per BOE reserve additions (a proxy for the asset price of reserves). Finally, k is chosen as the value that drives the production cost modeled to an average level of *lifting costs* representative of the 1997 EIA surveyed estimates described above. 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 3.14. Table 3.10 depicts non-reserve input shares (m) and pre-tax marginal extraction costs (C_q) for the 7 major producing states. Oil production as a percentage of a state's total BOE production is included in the first column of Table 3.10 in order to put the marginal cost estimates into perspective. Surveyed oil lifting costs per BOE are markedly higher than those for gas, hence, the relatively higher proportional cost in California.

The 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 T. Likewise, the functional form invokes a strictly positive level of production given any positive level of reserves. Thus, simulations reported in Chapter 4 are based on the second of the two alternative boundary conditions discussed in Section 3.2. This condition implies that 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. Similar conditions are found in the simulations of both Yucel (1989) and Deacon (1993).

3.4 Conclusion

This chapter has developed a general theoretical model of profit-maximization over time in the oil and gas industry. This model extends Pindyck's (1978) seminal contribution on exploration and production from nonrenewable resources by allowing for different types of taxation by federal, state, and local governments. Theoretical results obtained from the model determine the optimal time path of exploration and production as well as how these paths are affected by alternative forms of taxation. Estimates of the model's underlying equations then were obtained using publicly available data on drilling, drilling costs, production, production costs, reserve additions, and other variables for 21 U.S. states over the period 1970-97. Chapter 4 uses this model to simulate effects of production (severance) tax changes in Wyoming and in 5 other major oil and gas producing states. Drilling incentives are also simulated.

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) 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 *g*. The extraction cost function derived from profit-maximization at a point in time subject to a production constraint would have *g* 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. (see Section 3.3).

[2]Equation (3.11) can be simplified by choosing a functional form for reserve additions such as the one used in Section 3.3 (see equation 3.13). In this case, $(f_{wx} / f_w) \times f - f_x = 0$.

[3]The Energy Information Administration (USDOE) and the American Petroleum Institute (1999) 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.

[4]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 (1996).

[5]Equation (3.13) was also estimated allowing for both state-specific intercepts and state-specific coefficients for $\boldsymbol{r}$ and $\boldsymbol{b}$. This strategy was unsuccessful as it yielded mostly insignificant estimates of state-specific slope interactions.

Table 3.1

Oil and Gas Production By State and U.S. Totals
1970-1997

State	***Oil Production (MMbbls)***	***Gas Production (Bcf)***	***Total Production (MMBOE)[a]***
Alaska	12,810	8,307	14,286
Alabama	484	4,552	1,293
Arkansas	427	4,252	1,182
California	10,026	10,797	11,945
Colorado	872	6,817	2,084
Florida	549	549	647
Illinois	647	33	703
Indiana	123	8	125
Kansas	1,702	19,183	5,112
Kentucky	183	1,943	528
Louisiana	6,559	75,522	19,983
Michigan	622	4,107	1,352
Mississippi	1,006	3,235	1,581
Montana	751	1,382	996
N. Dakota	937	1,301	1,169
Nebraska	176	64	188
New Mexico	2,274	32,173	7,993
Oklahoma	4,037	53,031	13,463
Texas	25,650	191,785	59,739
Utah	805	3,109	1,358
Wyoming	3,301	13,964	5,783
21 State Total	73,941	436,114	151,459
% of U.S. Total (Excluding Federal OCS production)	97%	94%	96%

[a]5,626 cf of gas is the BTU equivalent to 1 bbl of oil.

Source: U.S. Dept. of Energy, Energy Information Administration

Table 3.2

Data Sources, Sample Means, and Variable Definitions

Variable	***Definition***	***Source***	***Mean***
TRCOST	Total drilling cost in millions of 1995 dollars, by state and year, for all well types.	*Joint Association Survey on Drilling Costs*. Annual.	928.7
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.	US Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*. Annual.	116.4
WELLS	Total wells drilled in a state by year.	*Joint Association Survey on Drilling Costs*. Annual.	1646.8
CWELLS	Cumulative total wells drilled in a state beginning in 1859.	American Petroleum Institute, *Petroleum Facts & Figures*. 1971 Ed.	1.04E+5
PRICE	Average oil and gas price, by state and year, in 1995 dollars per barrel of oil equivalent.	American Petroleum Institute, *Basic Petroleum Data Book*. Annual.	19.22
PRICE2	Average real price per BOE squared.	- -	472.9
CWELLS2	Cumulative total wells squared.	- -	.414E+11
*PRICE * CWELLS*	Interaction of real price and cumulative total wells.	- -	.183E+7

Table 3.3

Wells Drilled in the 7 Major Producing States
1975,80,85,90,95

State	***1975***	***1980***	***1985***	***1990***	***1995***
California	2166	2466	3335	2178	1197
Kansas	3285	5516	6224	2596	1513
Louisiana	3085	5080	5486	1740	1354
New Mexico	1057	2031	1689	1278	858
Oklahoma	3616	8932	7244	2642	1796
Texas	12374	18824	23114	8487	7972
Wyoming	1246	1322	1463	756	444

Table 3. 4

One-Way Fixed Effects,
Construction of Instrument for *LN(WELLS)*

Explanatory Variable	***Coefficient*** (t-statistic)
PRICE	0.59E-1 (7.40)
PRICE2	-0.437E-3 (-3.14)
CWELLS	-0.135E-4 (-6.86)
CWELLS2	0.764E-1 (5.38)
*PRICE*CWELLS*	0.456E-7 (2.93)

SUMMARY STATISTICS

NT	588
R^2	.91
F(20,563)[a]	106.72
F(27,535)[b]	1.27

[a] Test statistic for joint significance of state-specific effects.
[b] Statistic for testing joint significance of time-specific effects after removing state effects.

Table 3.5

Two-Way Fixed Effects, Instrumental Variable
Estimates of the Restricted Drilling Cost Function

Corrected 1997 Estimates of f for 7 Major Producing States[a]

State	***Corrected Fixed Effect*** (t-statistic)
CALIFORNIA	0.256 (7.09)
KANSAS	0.09 (6.91)
LOUISIANA	1.126 (7.08)
NEW MEXICO	0.401 (6.04)
OKLAHOMA	0.360 (8.05)
TEXAS	0..377 (7.11)
WYOMING	0.524 (6.98)

SUMMARY STATISTICS

NT	588
R^2	.92
$F(20,567)$[b]	120.6
$F(27,539)$[c]	6.7

[a] Coefficient on *LN(PREDWELLS)* restricted to unity. See Greene (1997), p. 279 for specific details on intercept bias adjustment. 1997 time-effect added.
[b] Statistic for testing joint significance of state-specific effects.
[c] Statistic for testing joint significance of time-specific effects after removing state effects.

Table 3.6

One-Way Fixed Effects, Instrumental Variable
Estimates of the Reserve Additions Function

Explanatory Variable	***Coefficient*** (t-statistic)
LNPREDWELLS	0.48 (4.29)
CWELLS	-0.16 (-1.10)

SUMMARY STATISTICS

NT	588
R^2	.85
F(20,566)[a]	84.4
F(27,538)[b]	1.01
RHO	.428
Hausman[c]	6.81

[a] Statistic for testing joint significance of state-specific effects.
[b] Statistic for testing joint significance of time-specific effects after removing state effects.
[c] Statistic for testing consistency of corresponding random effects estimates.

Table 3.7

One-Way Fixed Effects, Instrumental Variable
Estimates of the Reserve Additions Function

Corrected Estimates of A for 7 Major Producing States[a]

State	***Corrected Fixed Effect*** (t-statistic)
CALIFORNIA	1.46 (2.31)
KANSAS	0.66 (1.09)
LOUISIANA	8.39 (2.71)
NEW MEXICO	3.06 (1.78)
OKLAHOMA	4.21 (1.84)
TEXAS	8.28 (2.11)
WYOMING	3.57 (2.12)

[a] See Greene (1997), p. 279 for specific details on intercept bias adjustment.

Table 3.8

Pre-tax Marginal Drilling Cost, Marginal Product of Drilling,
Marginal and Average Cost of Reserve Additions for 7 Major Producing States

State	D_w^* **(in $)**	f_w **(in BOE)**[a]	D_w^* / f_w [a]	***Ave. Cost***[a]	D_w^* / f_w [b]	***Ave. Cost***[b]
California	255,483	22,961	11.13	6.68	12.37	7.42
Kansas	89,878	8,754	10.27	6.16	10.15	6.09
Louisiana	1,125,920	112,328	10.02	6.01	9.93	5.96
New Mexico	401,158	57,007	7.04	4.22	6.04	3.63
Oklahoma	359,767	42,418	8.48	5.09	9.40	5.64
Texas	377,245	33,561	11.24	6.74	14.78	8.87
Wyoming	524,343	59,695	8.78	5.27	7.85	4.71

[a] Assumes each state drills the sample mean of 1647 wells. State-specific cumulative wells total is set to actual 1997 values in all calculations. The pre-tax average cost of reserve additions represents total modeled drilling cost divided by total modeled reserve additions.

[b] Assumes wells drilled at the actual 1997 count. State-specific cumulative wells total is set to actual 1997 values in all calculations. Likewise, pre-tax average cost of reserve additions is modeled with 1997 sample data for each state.

Table 3.9

Time Means of Relevant State Variables

	Real Price (per BOE)	***Production (in BOE)***	***Reserve Additions (in BOE)***	***Reserves (in BOE)***	***Total Wells***	***Production / Reserves (in %)***	***Average Real Drilling Cost / Reserve Additions (per BOE)***
Alaska	15.04	510	74	12140	115	5	7.04
Alabama	21.78	46	23	389	278	14	7.43
Arkansas	17.27	42	25	427	434	10	5.88
California	19.19	427	100	5192	2001	8	7.66
Colorado	17.58	74	59	916	1129	8	6.66
Florida	22.64	23	7	136	21	17	5.71
Illinois	27.13	25	3	162	1124	16	39.00
Indiana	26.99	5	2	29	392	18	13.50
Kansas	14.36	182	44	2157	3465	9	9.93
Kentucky	16.93	19	6	183	1122	11	13.67
Louisiana	15.65	713	627	8863	3081	11	7.28
Michigan	21.23	48	33	369	609	13	6.12
Mississippi	18.74	57	30	435	401	13	11.70
Montana	19.75	36	18	363	506	10	10.28
N. Dakota	21.11	41	26	315	288	13	11.65
Nebraska	23.93	7	2	34	240	20	18.50
New Mexico	15.17	285	131	3155	1210	9	5.11
Oklahoma	15.43	481	254	3559	4302	14	9.54
Texas	16.17	2134	813	17860	12610	12	8.20
Utah	19.02	49	29	489	230	10	18.07
Wyoming	17.90	206	139	2345	1028	9	6.22
Sample Total	19.22	258	116	2834	1647	12	8.00

Table 3.10

Oil Production Percentage, Non-Reserve Production Input Share *m*, and Pre-tax Marginal Extraction Cost for 7 Major Producing States

State	***1997 Oil Production %***[a]	***m***	C_q[b]
California	85	.26	5.52
Kansas	25	.12	2.12
Louisiana	26	.17	3.63
New Mexico	20	.29	3.29
Oklahoma	22	.23	3.15
Texas	32	.27	3.75
Wyoming	36	.32	4.61

[a] As a percent of total BOE production in 1997.

[b] Calculated at 1997 levels for production and reserves.

CHAPTER 4

TAX AND COST SIMULATIONS

4.1 Introduction

The model presented can be simulated for a given state using the empirical estimates from Section 3.3 together with estimates of the tax parameters γ and a_j ($j = p$, C, D). Simulation results are simply forward-looking numerical solutions of optimal time paths, which can be altered and compared by varying key parameters. As indicated previously, this Chapter of the report considers the effects of altering production (severance) tax rates and granting tax incentives. This chapter is divided into six additional sections. Section 4.2 describes the general conditions that form the basis of comparison for all state simulations. Section 4.3 presents a detailed derivation of tax parameters for states simulated. State simulation results are compared in section 4.4. In an effort to test the sensitivity of the model, a tax scenario comparison for Wyoming is discussed in section 4.5. Impacts on production and drilling from reducing drilling costs, through state incentives or technological advancement, are presented in section 4.6. Brief summary comments are offered in section 4.7.

4.2 Baseline Conditions

All state simulations were performed with the discount rate, r, set at 4% to reflect the risk-free real rate of long-term borrowing. This figure is comparable to discount rates used in prior simulation studies of effects of taxation on nonrenewable resource exploration and extraction. Econometric estimates of equations (3.12) and (3.13) along with the state-specific calibrated production cost equation (3.15) are employed. The initial value of reserves and cumulative wells drilled are fixed to year-end 1997 levels for each state simulated.

A base case for each state is created by fixing the future price path to \$19.22 per BOE each year, representative of the 1970-97 U.S. national mean for the real wellhead price per BOE (see Table 3.2). This BOE real price denotes a national, oil and gas production share, weighted-average of the 1970-97 real sample means; \$24.60 per barrel oil and \$2.15 per Mcf gas. The perspective taken views the supply of a single state as a small fraction of a national or world market supply, therefore, taxes levied are assumed to have no impact on prevailing wellhead prices. Alternative price trajectories (rising and falling over time) are also considered.

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 (3.10) and (3.11) along with the state variable evolution equations (3.2) and (3.3). For example, the evolution of reserves, equation (3.2), can be approximated by the simple difference, $R_t - R_{t-1} = f_{t-1} - q_{t-1}$. Once the estimated functions are substituted into the difference equation approximations (see Appendix B), the model can be solved recursively by varying (iterating over) the initial values of the control variables, q and w, until transversality conditions are satisfied. As discussed in Section 3.3.b, production continues after incentives for exploration vanish. Thus, the terminal date for the program must be set arbitrarily; $T = 60$ years was selected.

4.3 Derivation of the Tax Parameters

For most states in most years, tax parameters can be specified by: 1) noting whether reserves are subject to a property tax (applicable to Texas and California only) and 2) evaluating equations (4.1)-(4.4)

$$g = \{(1 - t_{us})(1 - t_s)t_R\} \tag{4.1}$$

$$a_p = \{(1 - t_{us})(1 - t_s)(1 - t_r)(1 - t_p) + t_{us}(1 - t_r)d\} \tag{4.2}$$

$$a_C = \{(1 - t_{us})(1 - t_S)\} \tag{4.3}$$

$$a_D = \{(1 - t_{us})(1 - t_S)h\} \tag{4.4}$$

where t_{us} denotes the federal corporate income tax rate on operating profits, t_s denotes the state corporate income tax rate on operating profits, t_R denotes the property tax rate on reserves weighted by the per unit assessed value, t_r denotes the royalty rate on production from public (state and federal) land, t_p denotes the production (severance) tax rate, d denotes the federal percentage depletion allowance weighted by the percentage of production attributable to eligible producers (nonintegrated independents), and h denotes the expensed portion of current and capitalized drilling costs attributable to current period revenues. h is the sum of: 1) the percentage of current period drilling costs expensed, and 2) the estimated present value share of depreciation 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 and then depreciated over the life of the producing well (Bruen, Taylor and Jensen, 1996). See Appendix C for a detailed derivation of equations (4.1) – (4.4).

This formulation assumes that: 1) public land royalty payments are deductible in computing state production tax liabilities; 2) public land royalty payments, state production taxes, state reserve taxes, extraction costs, and certain drilling costs (described below) are deductible in computing both state and federal corporate income tax liabilities, 3) the federal percentage depletion allowance is applied to the production value net of royalties, and 4) state corporate income taxes are deductible against federal corporate income tax liabilities. Some of these assumptions do not apply universally across all states. For example, as previously discussed, royalty payments are not deductible against production taxes in Louisiana, and some states have permitted federal corporate tax payments to be deducted against state corporate income tax levies. In situations such as these, of course, equations (4.1)-(4.4) are modified.

Also, notice that this treatment incorporates the entire tax structure into the model and highlights the interactions between tax rates and tax bases. As discussed in Chapter 2, all tax parameters are interpreted as effective rather than nominal rates. As previously noted, states and the federal government grant numerous incentives, credits, and exemptions against tax levied, so nominal rates generally overstate amounts actually paid. Thus, effective rates fully account for all tax breaks granted. State tax collection data required for the calculation of the tax parameters are not compiled in a common format, therefore all data were obtained directly (previously described in Chapter 2) from local tax officials of the 8 largest producing states (Alaska, California, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming). Estimates of all state tax parameters, representative of the mid to late 1990s, are contained in Table 4.1. A more complete description of these tax parameters and how they entered the simulations is contained in the discussion of each state's simulation results below.

At the federal level, an analysis of data from the Statistics of Income (described in Chapter 2) for the oil and gas sector shows that federal corporate taxes paid averaged about 10 percent of net operating income in 1997. This estimate is used in simulations for all states. Also, following Deacon (1993), the expensed portion of current period drilling costs is estimated at 40 percent for the industry in all states and the present value of depreciation deductions for capitalized drilling cost is approximated by, $(q/R) / (r + (q/R))$, a formulation that assumes the ratio of production to reserves is constant. As specified in Chapter 3, r is the discount rate. The expensed share of current period drilling costs used here is 5 percentage-points lower than Deacon's (1993) industry estimate. Dry hole costs were proportionally lower in the mid to late 1990s as compared to prior 1987 industry estimates (U.S. Census Bureau, 1997 Economic Census, Mining Industry Series). The ratio of production to reserves (q/R) will vary across states but the industry expense share of 40 percent is used in each state simulation.

4.4 State Severance Tax Simulation Results

Initially, results are reported for the state of Wyoming. Simulated time paths show the outcome of a once-and-for-all reduction in the state severance tax on *oil* production by 2 percentage-points. Alternative severance tax incentive scenarios for Wyoming are deferred to section 4.5. As a base for comparison, Wyoming is of particular interest because of recent tax incentives enacted and then rescinded for oil production. Thus, simulation results presented have the advantage of showing how exploration and production might be expected to change over time in response to an *actual* policy change. Fixing the oil severance tax reduction over the 60 year program is necessary in order to generate results substantial enough to allow for a meaningful interstate analysis. Counterpart simulations for New Mexico, Oklahoma, Texas, Kansas, and Louisiana are also are presented and compared to the Wyoming results. California is omitted from the severance tax simulations because the state does not currently levy a severance tax on oil and/or gas production. The focus of this study centers on the lower 48 states; Alaska is excluded from all simulations due to the state's unique exploration and production experience.

The first figure for each state analyzed (WY1, NM1, OK1, TX1, KS1, and LA1) depicts the actual time paths of drilling, production, and reserves from 1970-97. This historical period is shown to place simulated results in perspective. In these figures, the vertical axis shows drilling (dotted line) in total wells, production (dashed line) in BOE $\times 10^5$, and reserves (solid line) in millions of BOE. In reviewing these data, several observations are noteworthy. Historical drilling appears extremely sensitive to price. In each state, total wells drilled increases markedly during the high price period of the early 1980s, with the most pronounced effects occurring in Oklahoma, Texas, and Kansas. Interestingly, Wyoming has experienced an increase in drilling starting in 1995 due to coal bed methane development. New Mexico and Wyoming are the only two states simulated where production has not declined over the entire 28 year period. Increasing extraction activity appears linked to the rising level of proved gas reserves in both states. Reserve levels in Kansas and Oklahoma show a gradual decline each year. Texas and Louisiana have experienced more substantial resource depletion, mainly attributed to oil.

Wyoming. As shown in Table 4.1, royalty rates (computed as the sum of state and federal royalty payments divided by the gross value of production) averaged 10 percent in 1997. This percentage is higher than for other oil and gas producing states because of the comparatively large share of Wyoming's production on public lands. Local production (ad valorem) tax rates are computed as total tax collections divided by the prior year's gross value of production net of public land royalties. The state severance tax base is the current period's gross production value. The sum of the two *average* effective rates in the mid to late 1990s totaled approximately 12 percent (local 6.5 percent and state 5.5 percent). Also, the current nominal percentage depletion rate of 15 percent applied to about 53 percent of Wyoming production in 1997, thus $\boldsymbol{d}$ = 8 percent. Wyoming's mid to late 1990s level of q/R was approximately 7 percent, therefore $\boldsymbol{h} = 0.4 + (1 - 0.4)*(0.07 / (0.04 + 0.07)) = 0.782$. For Wyoming, simplification of equations (4.1)-(4.4) is achieved because the state does not levy a corporate income tax ($\boldsymbol{t}_S = 0$) or a property tax against reserves in the ground ($\boldsymbol{t}_R = 0$).

The solid line in Figures WY2 - WY4 show the evolution of drilling, production, and reserves under the base case assumptions outlined above. Wells drilled fall steadily over time from 1071 in year 1 (1998) to 8 in year 60 (2057). Production also declines over this period from 228 MMBOE to 75 MMBOE with reserves declining from 2903 MMBOE to 662 MMBOE. To put these simulated values in perspective, Wyoming's production and drilling activity averaged approximately 206 MMBOE and 1028 wells over the sample period 1970-97 (see Table 3.9 and Figure WY1). The dotted lines in these figures show the effect of a once-and-for-all reduction in the state oil production tax by 2 percentage-points, which proportionally (oil's share is 49 percent of the mid to late

1990s value of total production) reduces the state effective rate from 5.5 percent to 4.52 percent and the total effective production tax rate from 12 percent to 11.02 percent. As shown, the tax reduction increases production for all years (50 MMBOE total, less than 1 percent above the base case). The tax reduction increases the net price to producers by less than 1 percent resulting in a relatively small production stimulus because of the interrelationships between tax bases (e.g., severance tax payments deductible against federal taxable corporate income). With regard to drilling, the effect of the tax change is somewhat greater. Over the 60-year life of the program, the tax cut contemplated would result in additional drilling of 1119 wells. This figure represents a 2.3 percent increase in total wells drilled as compared to the base case.

To make these effects more transparent, rearrange equation (3.9) for l_2 and substitute in equation (3.7) for l_1 yielding

$$l_2 = \frac{D_w}{f_w} e^{-rt} - [\,pe^{-rt} - C_q e^{-rt}\,]. \tag{4.5}$$

The tax reduction (slightly) increases the initial shadow price of reserves, l_1 (bracketed portion of equation (4.5)). This change directly decreases the initial shadow price of cumulative reserve additions, l_2. For the state of Wyoming, the base case after-tax initial value of the shadow price of cumulative reserve additions (l_2) is \$-0.31 per BOE and the after-tax initial value of the shadow price of reserves (l_1) is \$7.60 per BOE. Initially, l_2 is negative and small in relative magnitude, thus, an increase in l_1 results in a larger proportional effect on l_2. In any case, the tax reduction causes optimal starting values for q and w to be set higher than those in the base case with the effect on drilling, w, being more pronounced. Equation (4.5) becomes the centerpiece of the simulation model and highlights all *initial* effects of changes in price, production cost, and marginal cost of reserve additions. For example, to significantly impact initial production, the change in the price and/or marginal production cost must be large relative to the initial value of λ_1. Moreover, drilling is sensitive to the initial value of λ_2 and the effects of changes in the right-hand-side of (4.5).

The evolution of reserves in Figure WY4 follows the same general path as the base case depicting small increases in the reserve base in the later years (less than 0.5 percent in 2057) due to the increased drilling throughout the program. The largest changes associated with the 2 percentage-point reduction in state oil production taxes appear to come from production tax collections. Applying the discount rate of 4 percent, the tax change results in a decline in the present value of Wyoming *state* severance tax collections from $3242 million to $2680 million, a decline of over 17 percent. Alternatively stated, Wyoming would forego $502,234 in present value of severance tax revenue for each of the additional 1119 wells drilled.

It is important to observe that oil producers do not receive the full benefit of these reduced severance tax payments. Because severance taxes are deductible in computing federal corporate income tax liabilities, a reduction in severance tax payments results in an increase in tax payments at the federal level. In particular, if producers face a *marginal* federal corporate income tax rate of 35 percent, then a $1 savings on severance tax payments results in a $0.35 increase in federal corporate income tax liabilities, holding all other effects constant. Therefore, the 17 percent reduction in present value of severance tax collections described above, results in a reduction of state tax collections by $562 million ($3242 million - $2680 million) and an increase in federal tax collections of about $196 million. Thus, reduced severance taxes result in a transfer of resources from the state to the federal government. Notice that this transfer of state severance taxes to the federal government would be smaller if Wyoming levied a state corporate income tax that allowed for deductibility of severance taxes. Also, the 2 percentage-point oil severance tax decrease transfers state revenue to local governments because of the production stimulus. Discounted local production taxes increase by $22 million or 0.5 percent above the base case. The same can be said for discounted public land royalties which increase by 0.6 percent ($37 million) because of the increase in production.

New Mexico. As discussed in Chapter 2, the state of New Mexico levies a number of separate production taxes on oil and gas that, in total, yield an effective rate of 8.5 percent. Production taxes are applied to the value of production net of public land royalties, which are set at an effective rate of 9.2 percent. A considerable amount of oil and gas production and exploration takes place on public lands in New Mexico. The state levies a corporate income tax at an effective rate (as applied to operating income) of 5.3 percent and does not tax the value of reserves in the ground, thus, $\boldsymbol{t}_R = 0$. The current nominal percentage depletion rate of 15 percent applied to approximately 63 percent of New Mexico producers in 1997, therefore $\boldsymbol{d}$ = 9.5%. New Mexico's mid to late 1990s level of *q/R* was approximately 9%, therefore $\boldsymbol{h} = 0.4 + (1 - 0.4)*(0.09 / (0.04 + 0.09)) = 0.815$.

Figures NM2 - NM4 show the evolution of drilling, production, and reserves under the parameter assumptions outlined above. Base case after-tax values of the discounted initial shadow prices are $9.02 and $-0.53, respectively. The dotted lines in these figures show the effect of the once-and-for-all reduction in the state *oil* production taxes by 2 percentage-points, which proportionally reduces New Mexico's overall effective rate from 8.5 percent to 7.9 percent. Among the major producing states depicted in Table 3.10, New Mexico has the lowest production share attributable to oil thereby explaining the relatively small effects. As shown, the tax reduction increases production for all years (30 MMBOE total, less than 0.4 percent above the base case). Also, over the 60-year life of the program, the tax cut proposed would result in additional drilling of 1103 wells. This figure represents a 1.2 percent increase in total wells drilled as compared to the base case. The evolution of reserves in Figure NM4 maps the same general path as the base case depicting small increases in the reserve base in the latter years (less than 0.5 percent in 2057) due to the increased drilling throughout the program. As in Wyoming, the largest changes associated with the 2 percentage-point reduction in state *oil* severance taxes appear to come from production tax collections. Applying the discount rate of 4 percent, the tax change results in a decline in the present value of state severance tax collections from $6273 million to $5811 million, a decline of over 7.3 percent. New Mexico's discounted corporate income tax proceeds partially offset the production tax loss with an estimated increase of approximately 1 percent.

Oklahoma. The state of Oklahoma's basic tax structure is counterpart to New Mexico. Also, like Wyoming, Oklahoma recently enacted a production tax incentive program (described in Chapter 2) aimed at stimulating oil exploration and extraction. Royalties from production on public lands are deductible in computing production (severance) tax liabilities, although, impacts are minimal due to the small effective royalty rate of 0.7 percent. The effective rate of production taxes is set at 7.3 percent with the effective state corporate income tax rate pegged at 4.2 percent. Roughly 82 percent of Oklahoma's producers were eligible for the federal percentage depletion allowance in 1997, therefore, d = 0.123. The state's mid to late 1990s level of BOE production to reserves was 13 percent, the highest level attributable to the major producing states. As a consequence, h is set at 0.858.

Figures OK2 – OK4 show the results of the corresponding reduction in severance taxes on oil production. Effects of the tax change are somewhat lessened due to Oklahoma's decreased share of oil production (see Table 3.10). Base case after-tax values of the discounted initial shadow prices are $11.00 and $-0.69, respectively. Post tax-reduction drilling effort increases by 1320 wells over the base case program. This difference represents an increase of 1.2 percent. Dotted production and reserve paths both closely trace the base case trajectories. Increases in production occur each year but in total the difference is small (less than 0.4 percent). As in the other states, Oklahoma's discounted state severance tax collections also decrease by $377 million, a loss of 7.5 percent. The small production increase provides the state additional discounted corporate income tax revenue, above the base case, characteristic to New Mexico's experience.

Texas. Key institutional features for the state of Texas include no state corporate income tax along with a local property tax levied on the value of the minerals in the ground. The effective reserve tax rate is determined by dividing total property tax collections by the BOE reserve in the corresponding year. This method yields an effective rate of 6 percent, representative of the mid to late 1990s. An effective severance tax of 4 percent is levied on the value of production net of public land royalties. Production and exploration on public land is low, reflected in the effective rate of 0.8 percent. Moreover, the current nominal percentage depletion rate of 15 percent applied to about 67 percent of Texas's producers in 1997, thus d = 10 percent. Texas's mid to late 1990s level of *q/R* was approximately 12 percent, therefore $h = 0.4 + (1 - 0.4)*(0.12 / (0.04 + 0.12)) = 0.85$.

Figures TX2 – TX4 show the simulated evolution of drilling, production, and reserves under the parameter assumptions outlined above. Base case after-tax values of the discounted initial shadow prices are \$11.47 and \$-2.02, respectively. The larger negative value of l_2 in Texas, relative to the other states analyzed, reflects the substantial resource depletion in the state. Recall that l_2 represents the discounted marginal value of profits lost due to increased future drilling efforts required as the resource becomes harder to find. The dotted lines in Figures TX2 – TX4 show the effect of the once-and-for-all reduction in the state *oil* production taxes by 2 percentage-points, which proportionally reduces Texas's overall effective rate from 4 percent to 3.2 percent. As shown, the tax reduction increases production for all years (35 MMBOE total, less than 0.2 percent above the base case). Over the 60-year life of the program, the tax cut proposed would result in additional drilling of 4185 wells. This figure represents a 1.2 percent increase in total wells drilled as compared to the base case. The evolution of reserves in Figure (TX4) traces the same general path as the base case depicting substantial depletion in the first 15 years of the simulated program. Again, the largest changes associated with the 2 percentage-point reduction in state *oil* production taxes appear to come from production tax collections. Applying the discount rate of 4 percent, the tax change results in a decline in the present value of state severance tax collections from \$9118 million to \$7377 million, a decline of over 19 percent. Like Wyoming, Texas is not able to offset the production tax loss with additional state corporate income tax revenue.

Kansas. The prevailing oil and gas taxes in the state of Kansas are a severance tax on production and the state corporate income tax. The state enacted the production tax in the spring of 1983. Royalties from production on public lands (relatively small with the effective rate set at 0.2 percent) are not deductible in computing the severance tax liability. This institutional feature requires a modification of equation (4.2), where, $\boldsymbol{a}_p = \{(1-\boldsymbol{t}_{us})(1-\boldsymbol{t}_s)(1-\boldsymbol{t}_r - \boldsymbol{t}_p) + \boldsymbol{t}_{us}(1-\boldsymbol{t}_r)\boldsymbol{d}\}$. The effective production tax employed is 3.6 percent and the 1997 effective state income tax rate is estimated at 5.1 percent. In 1997, approximately 73 percent of oil and gas producers in the state were eligible for the federal percentage depletion allowance yielding $\boldsymbol{d}$ = 10.9 percent. The production to reserves ratio is estimated at 9 percent, therefore, $\boldsymbol{h}$ = 0.4 + (1 - 0.4)*(0.09 / (0.04 + 0.09)) = 0.815.

Figures KS2 – KS4 show the results of the 2 percentage-point reduction in severances taxes on oil production. Base case after-tax values of the discounted initial shadow prices are \$11.25 and \$-0.70, respectively. After tax-reduction drilling effort increases by 1189 wells over the base case program. This difference represents an increase of approximately 1.3 percent. Dotted production and reserve paths both closely trace the base case trajectories. Increases in production occur each year but the difference is small (less than 0.3 percent). As in the other states simulated, Kansas's discounted state severance tax collections substantially decrease by \$172 million, a loss of over19 percent over the 60 year program. Increases in discounted corporate income tax revenue provide a 0.9 percent offset to the severance tax cut.

Louisiana. Louisiana taxes production at an effective rate of 6.5 percent and corporate income at an effective rate of 5.6 percent. Public land royalties are not deductible in determining severance tax liabilities and federal corporate income taxes paid are deductible against state corporate taxable income. Incorporating these key institutional features into equations (4.2) – (4.4) yields the following base case tax parameters

$$\boldsymbol{a}_p = \{(1 - \boldsymbol{t}_{us} - \boldsymbol{t}_s + 2\boldsymbol{t}_{us}\boldsymbol{t}_s)(1 - \boldsymbol{t}_r - \boldsymbol{t}_p) + (1 - \boldsymbol{t}_s)\boldsymbol{t}_{us}(1 - \boldsymbol{t}_r)\boldsymbol{d}\} \tag{4.6}$$

$$\boldsymbol{a}_c = \{(1 - \boldsymbol{t}_{us} - \boldsymbol{t}_s + 2\boldsymbol{t}_{us}\boldsymbol{t}_s)\} \tag{4.7}$$

$$\boldsymbol{a}_D = \{(1 - \boldsymbol{t}_{us} - \boldsymbol{t}_s + 2\boldsymbol{t}_{us}\boldsymbol{t}_s)\boldsymbol{h}\}. \tag{4.8}$$

The current nominal percentage depletion rate of 15 percent applied to about 56 percent of Louisiana producers in 1997, thus $\boldsymbol{d}$ = 8.4 percent. Louisiana's mid to late 1990s level of *q/R* was approximately 11 percent, therefore $\boldsymbol{h}$ = 0.4 + (1 - 0.4)*(0.11 / (0.04 + 0.11)) = 0.84.

Figures LA2 - LA4 demonstrate the evolution of drilling, production, and reserves under the parameter assumptions outlined above. Base case after-tax values of the discounted initial shadow prices are \$10.64 and \$-0.62, respectively. The dotted lines in these figures show the effect of the once-and-for-all reduction in the state *oil* production taxes by 2 percentage-points, which proportionally reduces Louisiana's overall effective rate from 6.5 percent to 5.8 percent. As shown, the tax reduction increases production for all years (74 MMBOE total, less than 0.5 percent above the base case). Over the 60-year life of the program, the tax cut simulated would result in additional drilling of 1147 wells. This figure represents a 1.3 percent increase in total wells drilled as compared to the base case. The evolution of reserves in Figure (LA4) traces the same general path as the base case. The largest changes associated with the 2 percentage-point reduction in state *oil* production taxes come from production tax collections. Applying the assumed discount rate, the tax change results in a decline in the present value of state severance tax collections by $781 million, a decline of over 10 percent. Louisiana's state corporate income tax collections increase proportionately as compared to the other states levying this type of tax.

Table 4.2 presents a summary of incremental effects on total production, drilling and discounted state severance tax collections for each of the six states analyzed. Recognizing the many cost and taxation differences among states, simulation results are strikingly similar for each. The permanent 2 percentage-point incentive just slightly increases the net price prevailing in each state resulting in the small production stimulus. The largest change associated with the tax rate cut appears in severance tax collections. The present value loss in state severance taxes collected range from $172.0 million in Kansas to $1,741.6 million in Texas. States levying a corporate income tax are able to offset only a small fraction of this revenue forgone. The production inducement provided by the tax cut is simply too small. Tax losses, as compared to the base case, are to some extent lessened in the two states with the lowest share of production attributable to oil, New Mexico and Oklahoma. The interrelationships between tax bases are found to attenuate the effects on the optimal time paths of drilling and extraction. Moreover, as portrayed by equation (4.5), proportionality of specific taxes against other operating costs producers face becomes paramount in explaining the extent to which state and local tax changes affect industry investment over time.

4.5 Additional Wyoming Tax Scenarios

The sensitivity of the Wyoming model to seven additional severance tax scenarios is reported in this section. Table 4.3 explains the additional tax scenarios and presents related information about total production for the 60 year program, total oil and gas wells drilled, total discounted severance taxes collected, present value deadweight loss (DWL), and the ratio of discounted DWL to total discounted tax revenue in each case. Percentage changes from the base case are also presented to place the results in the perspective.

Assuming that Wyoming producers are price takers and demand is perfectly elastic, the entire burden of taxation will fall on resource owners. Taxation certainly represents additional costs to suppliers, but economists view the real (social) cost of taxes as the output-choice distortion induced by their presence. This societal cost, known as 'deadweight loss (DWL)', represents the value of cumulative output loss coupled with the value of output timing distortions (tilting) due to industry taxation at all levels. Given the supply and demand assumptions above, the deadweight loss calculation becomes the difference between discounted pre-tax operating profits, and, the sum of discounted total tax revenue and discounted after-tax operating profits. In effect, this present value operating profit difference can be thought of as the amount producers would pay to avoid taxes altogether. These taxes, however, raise revenue for governments and owners benefit from the public goods provided. It is difficult to measure the benefits gained from public goods, therefore it is assumed that the total tax revenue is given back to resource owners, or equivalently that the services provided are equal in value to the total revenue spent. The total pre-tax (base case) discounted profit of $47,881.7 million is used as the base in each deadweight loss computation. When comparing deadweight loss across tax scenarios, note that the simulated tax changes are not of equal real yield in the aggregate. The interrelation of tax rates and tax bases makes this type of total tax revenue targeting intractable. Similar deadweight loss computational methods are found in Yucel (1989), for monopoly producers, and Deacon (1993) for competitive producers.

Focusing on the first row of results shown in Table 4.3, Wyoming producers of oil and gas are assumed not taxed by any level of government for the 60 year life of the program. When comparing this untaxed regime to the base case (all layers of taxation included), untaxed total production increases by more than 14 percent and untaxed drilling increases by 55.8 percent. This result confirms the theoretical implications of the Chapter 3 analysis in that production in this industry is reserve driven and that drilling is relatively sensitive to changes in net price and costs.

The first tax incentive scenario presumes a 2 percentage-point reduction in the oil severance tax for *one year* only. The tax incentive is lifted after the first year with effective production tax rates increasing back to pre-incentive levels. This simulation is more in line with the circumstances surrounding the outcome of the 1999 Oil Producers Recovery Act (see Appendix A). As shown in Table 4.3, the effects of this tax incentive are minor. Production over the 60 year program increases by 13,000 BOE with drilling effort increases by only 27 wells. The largest change associated with the one year tax cut appears in the reduced state severance tax collections in that same year.

The second tax incentive simulated assumes a once-and-for-all 4 percentage-point reduction in state severance taxes levied against all *new* well production. This case approximates Wyoming Statute 39-6-302(s) but extends the application of the tax incentive over the 60 year life of the simulated program. Holding tax incentives (cases 2-

4) constant over the life of the simulated program is necessary in order to produce a consistent comparable result (e.g., see scenario 1 as compared to section 4.2 Wyoming results). New well production is defined as oil and gas extracted from reserves discovered within the dynamic model. This production represents approximately 60 percent of the total BOE simulated over the 60 year life of the program. Results show that total production increases by 1.7 percent and drilling increases by 5.6 percent. The tax cut contemplated substantially reduces the state severance taxes collected. Severance taxes and deadweight loss decrease by 42.8 percent and 31 percent, respectively.

Case 3 models a once-and-for-all reduction in state severance taxes of 2 percentage-points for all incremental production resulting from a tertiary project (WS 39-6-302(i)). According to the Wyoming Oil and Gas Conservation Commission, 1997 qualifying tertiary recovery accounted for less than 5 percent of total oil extracted. The simulation results presented assume a forward-looking estimate of 15 percent of total oil produced. This proportion follows the assumption made in the Wyoming Consensus Revenue Estimating Group's (CREG, October 2000) production and tax revenue forecasts through the year 2006. Simulated results are not that different from the base case reflecting the small share of the total production base affected.

Scenario 4 simulates the effects of a permanent reduction in state severance taxes of 4 percentage-points for incremental production resulting from a workover or recompletion of an oil and/or gas well (WS 39-6-302(t)). Results reflect the CREG assumptions (7 percent total) pertaining to the share of total production attributed to workovers and recompletions. Increased lifting cost issues are ignored in the analysis. As shown in Table 4.3, the tax reduction increases production by less that 2 tenths of one percent. Also, over the 60-year life of the program, the tax cut proposed would result in additional drilling of 239 wells. This figure represents a 0.49 percent increase in total wells drilled as compared to the base case. The largest changes associated with the 4 percentage-point reduction in workover and recompletion severance taxes appear to come from production tax collections. Applying the discount rate of 4 percent, the tax change results in a decline in the present value of state severance tax collections from $3242 million to $3105 million, a decline of over 4.2 percent.

The fifth scenario considered discontinues the use of the production tax at the state level. As shown in Table 4.3, this seemingly large tax cut only moderately increases production over the 60 year program (3.8 percent). Increases in total drilling effort are more pronounced with 6522 additional wells being drilled. The implication of equation (4.5) explains this characteristic result. As shown in the 6 state severance tax simulations in section 4.4, drilling is more sensitive to changes in net price than is production. The large decrease in deadweight loss (over 60 percent from the base case) is attributed to increased output and producer profitability. The state level severance tax cut provides an enlarged production base for *local* taxation where discounted revenue increased by $123 million, 3.2 percent above the base case. Additionally, discounted public land royalties increase by 3.3 percent ($209 million) and discounted federal tax collections rise by $307 million (10.5 percent).

The sixth scenario simulated for Wyoming involves replacing the state level severance tax with a tax on reserves in the ground of equal real yield. A constant weighted-effective rate of 8.2 percent is assessed against the simulated reserve level (in BOE) yielding the discounted tax collections of $3,242 million, equal to the base case state level production tax. Changing to a tax on reserves has a profound effect on the optimal time paths, very different from the common theme depicted in section 4.3. Figures WY5-WY7 show the time paths of drilling, production, and reserves for the base case condition along with the tax replacement scenario. The dotted trajectories show the effects of the tax swap, with Figure WY5 depicting drilling efforts lower than the base case revealing the disincentive to explore when reserves are subject to a holding cost. The reserves tax tilts production to earlier years optimally eroding the tax base absent the incentive to replenish. Production falls below the base case over time due the more rapid depletion of reserves thus increasing extraction costs. Reserves trace a substantially lower path over the life of the program as compared to the base case condition. Although production, drilling, and tax collections remain relatively unchanged as compared to the base case, the deadweight loss due to the reserves tax is 44 percent higher. This is a direct result of the production tilting which reduces long-run industry production and profitability.

The last alternative scenario illustrates the impact of raising the state severance tax by one full (effective) percentage point. As shown, the tax increase decreases total production (51 MMBOE, 0.7 percent below the base case) and moderately reduces drilling effort in each year of the program. The tax increase reduces the constant net price to producers by less than 1 percent resulting in the small production loss. Because of the interrelationships between the tax parameters (e.g., severance tax payments deductible against federal taxable income), time path effects are moderated. With regard to drilling, the effect is slightly more pronounced. Over the 60-year life of the program, the tax increase modeled would result in drilling 1093 fewer wells. This figure represents a 2.2 percent decrease in total wells drilled as compared to the base case. Discounted state severance tax collections increase by more than 17 percent over the life of the program with deadweight loss increasing due to the loss of output as compared to the base case. Because the cumulative production loss is small, present value local production tax, public royalty, and federal income tax collections are only slightly lower than the base condition.

In each scenario presented that discounts the severance tax producers pay, incremental new wells drilled will provide an additional sales tax revenue source for state and local governments. Additional sales tax revenue collected from this incremental drilling activity potentially provides an offset to the large state severance tax losses simulated. Estimates can be calculated by assessing a taxable value to each incremental well drilled over the 60-year simulated program. The estimated *real* average cost of drilling a Wyoming well, $524,343, (see Table 3.8) is employed. It is also assumed (perhaps overstated) that 80 percent of the incremental total average cost is subject to a 6 percent sales tax rate. Applying the 4 percent discount rate to the incremental sales tax estimates from the four key incentive scenarios (oil severance, new well production, tertiary projects, and workovers and recompletions) yields present value sales tax collections of $12.4 million (2.3 percent increase from the base case), $30.6 million (5.7 percent), $1.2 million (0.2 percent), and $3 million (0.6 percent), respectively. Any potential offset of the large severance tax losses simulated appears to be small.

4.6 Drilling Cost Reductions

In contrast to changes in production taxes, a more direct way to increase exploration (and expectantly reserves) is to lower drilling cost. These costs can potentially be reduced through technological advances or by state sponsored incentives that would eventually lead to a reduction in an operator's cost of drilling. A recent example of technological change that has reduced exploration costs industry-wide is the use of 3D seismic. An example of an incentive might involve state support for an applied research program leading to technological advancement in exploration methods. In order to illustrate the effects on production and exploration due to lower drilling costs, a simulation is performed assuming a 5 percent cost reduction. If this hypothetical drilling cost reduction is the result of an unsupported technological advancement, the cost to the state would be relatively small or zero. On the other hand, if this cost reduction is the result of some type of state incentive, it is assumed that the maximum offsetting cost for the state of Wyoming would be the present value of the total 5 percent cost savings for each well drilled.

The drilling cost reduction, resulting from either state incentive or technological change, increases total production by 187 MMBOE or 2.6 percent when compared to the base case. Drilling increases by 4535 wells or 9.3 percent. The production increase over the 60 year life of the program adds $58 million (1.8 percent) to the state's present value severance tax revenue with $68 million more (1.7 percent) going to local governments. This increased activity may not be free to Wyoming. The assumed maximum cost the state could bear, discounted at 4 percent, would total $616 million assuming an average cost per well drilled of $524,343. This figure far exceeds the additional severance and local *ad valorem* taxes that would be collected. However, if the "incentive" was designed to directly support for an applied research program, the return in production tax revenue may exceed the cost of the program. Of course, not all applied research programs are effective and this report takes no position regarding whether such a program should be initiated. Nevertheless, this type of program at least offers the prospect of leveraging the state's resources to provide program support, whereas, discounts from the severance tax hold out no such possibility.

4.7 Summary Comments

Altering production taxes changes the net price producers receive for their output. This price change enters the dynamic framework derived as a component of the shadow price of the reserve state (λ_1). As derived in Chapter 3, production responds to this shadow price which consists of the discounted value of *future* operating profits at the margin coupled with the present value sum of future extraction cost increases due to marginally depleting the reserve stock today. Net price impacts the first component where at the terminal time (*T*) marginal future operating profits approach or equal zero. This implies that the shadow price of the reserve state is dominated by the reserve degradation cost component (Levhari and Leviaton, 1977) and when faced with even large changes in net price, producers will respond inelastically. Clearly, one reason initial production responds so grudgingly to what appear as large changes in net price (e.g. in additional tax scenario 5) is the geological reality that proved reserves do not change instantaneously.

Drilling efforts, however, are found to be far more sensitive to changes in the shadow price of reserves or the marginal cost of reserve additions. This is a direct consequence of equation (4.5) and the fact that the shadow price of cumulative reserve additions (λ_2) is proportionately small relative to the shadow price of the reserve state. Even the slightest increase in net price will induce drilling, yet, in order to appreciably alter the *future* production path, this enhanced drilling effort must yield considerable reserve additions, hence, lowering future extraction costs (a lagged effect). For states like Wyoming and New Mexico, where the historical downward trend of BOE reserves is not observed (due to gas finds, see Figures WY1 and NM1), the prospect for this type of exploratory success is more promising than in, for example, the depleted 'Texas oil patch' (Moroney, 1997). Also, notice that increasing incentives to explore for (section 4.6) and develop reserves *directly* stimulate drilling through which new reserves can be identified. In general, "upstream" incentives given at the beginning of the exploration-development-production process provide a greater stimulus to production than "downstream" incentives given at the end of the process.

Chapter 5 examines the sensitivity of the oil and gas industry to changes in environmental and land use regulations by looking at differences in regulatory practices on federal and private land. An important part of the analysis is a cost function for oil and gas drilling estimated using data from 1390 wells in the Wyoming Checkerboard.

Table 4.1

Base Case Tax Parameters for the 7 Major Producing States

	t_r	t_p	t_R	t_s	t_{us}	d	h
California	0.017	0.000	0.036	0.062	0.100	0.054	0.800
Kansas	0.002	0.036	0.000	0.051	0.100	0.109	0.815
Louisiana	0.046	0.065	0.000	0.056	0.100	0.084	0.840
New Mexico	0.092	0.085	0.000	0.053	0.100	0.095	0.815
Oklahoma	0.007	0.073	0.000	0.042	0.100	0.123	0.858
Texas	0.008	0.040	0.060	0.000	0.100	0.100	0.850
Wyoming	0.100	0.120	0.000	0.000	0.100	0.080	0.782

Table 4.2

State Oil Severance Tax Reduction of 2%
Incremental Comparison to the 60 Year Base Case

	D Production ***MMBOE (in %)***	***D Drilling*** ***Wells (in %)***	***D PV State Severance Tax Collections*** ***$Millions (in %)***
Kansas	5.8 (0.26)	1189 (1.25)	-172.0 (-19.03)
Louisiana	73.6 (0.49)	1147 (1.29)	-781.2 (-10.04)
New Mexico	30.1 (0.35)	1103 (1.21)	-462.7 (-7.38)
Oklahoma	27.9 (0.40)	1320 (1.24)	-377.3 (-7.52)
Texas	35.5 (0.18)	4185 (1.16)	-1741.6 (-19.10)
Wyoming	50.2 (0.68)	1119 (2.28)	-562.4 (-17.35)

Table 4.3

Wyoming Simulated Tax Scenarios

	Total Production (MMBOE)	***Total Drilling (Wells)***	***PV State Severance Tax Collections ($Millions)***	***PV DWL[a] ($Millions)***	***PV DWL / PV Total Tax Revenue***
Untaxed Regime	8419.4	76434	0.00	0.00	
(Change from Base Case)	(14.42%)	(55.77%)			
60 Year Base-Case	7358.3	49069	3242.4	369.2	2.25%
2% point Reduction in Oil Severance Tax	7408.5	50188	2680.1	319.5	2.01%
(Change from Base Case)	(0.68%)	(2.28%)	(-17.35%)	(-13.46%)	
Additional Scenarios:					
1. 2% point Reduction in Oil Severance Tax, Year 1 only	7358.3[b]	49082	3203.5	327.1	2.00%
(Change from Base Case)	(0.00%)	(0.03%)	(-1.20%)	(-11.40%)	
2. Reduce Severance Tax on all New Well Production by 4 % points	7480.6	51837	1853.4	254.7	1.67%
(Change from Base Case)	(1.66%)	(5.64%)	(-42.84%)	(-31.01%)	
3. Reduce Severance Tax on Tertiary Production by 2 % points	7363.3	49168	3186.5	363.8	2.23%
(Change from Base Case)	(0.07%)	(0.20%)	(-1.72%)	(-1.46%)	
4. Reduce Severance Tax on all Production resulting from Workovers and Recompletions by 4 % points	7370.6	49308	3105.5	355.7	2.19%
(Change from Base Case)	(0.17%)	(0.49%)	(-4.22%)	(-3.66%)	

Table 4.3 (continued)

Wyoming Simulated Tax Scenarios

	Total Production (MMBOE)	***Total Drilling (Wells)***	***PV State Severance Tax Collections ($Millions)***	***PV DWL[a] ($Millions)***	***PV DWL / PV Total Tax Revenue***
5. Discontinue the State Level Severance Tax	7636.2	55591	0.00	143.0	1.04%
(Change from Base Case)	(3.78%)	(13.29%)	(-100.00%)	(-61.27%)	
6. Replace State Severance Tax with a Reserve Tax, Equal Real Yield	7382.8	49096	3242.4[c]	531.7	3.22%
(Change from Base Case)	(0.33%)	(0.06%)	(0.00%)	(44.01%)	
7. Increase State Severance Tax by 1% point	7306.8	47976	3809.0	425.0	2.53%
(Change from Base Case)	(-0.70%)	(-2.23%)	(17.47%)	(15.11%)	

[a] Present value deadweight loss (DWL) is discounted operating profit in the untaxed regime minus the sum of each scenario's discounted tax revenue and discounted after-tax operating profit.
[b] Actual increase of 13,000 BOE from the base case.
[c] Targeted present value of reserve tax collections.

Figure WY1. Wyoming (1970-97)

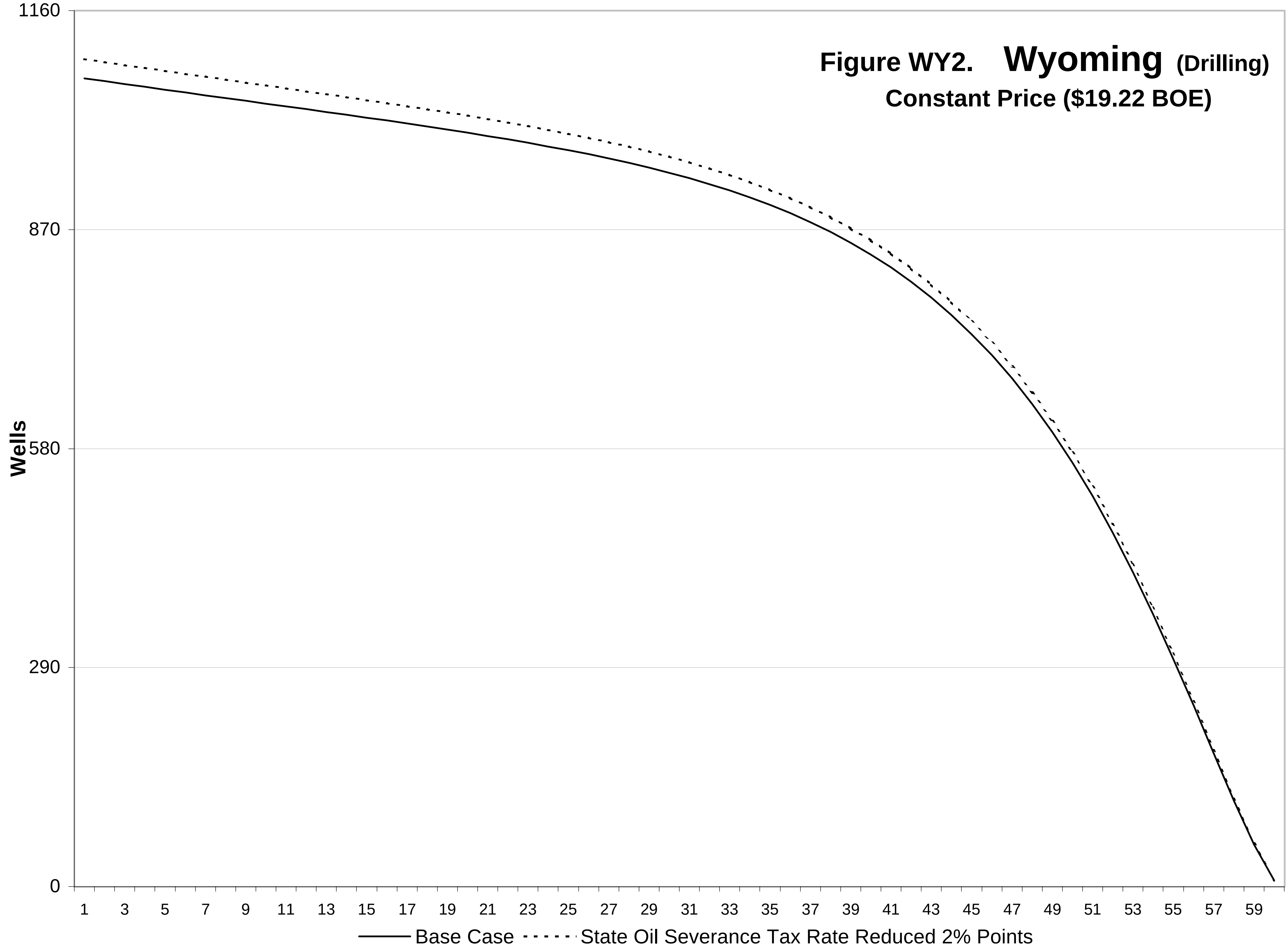
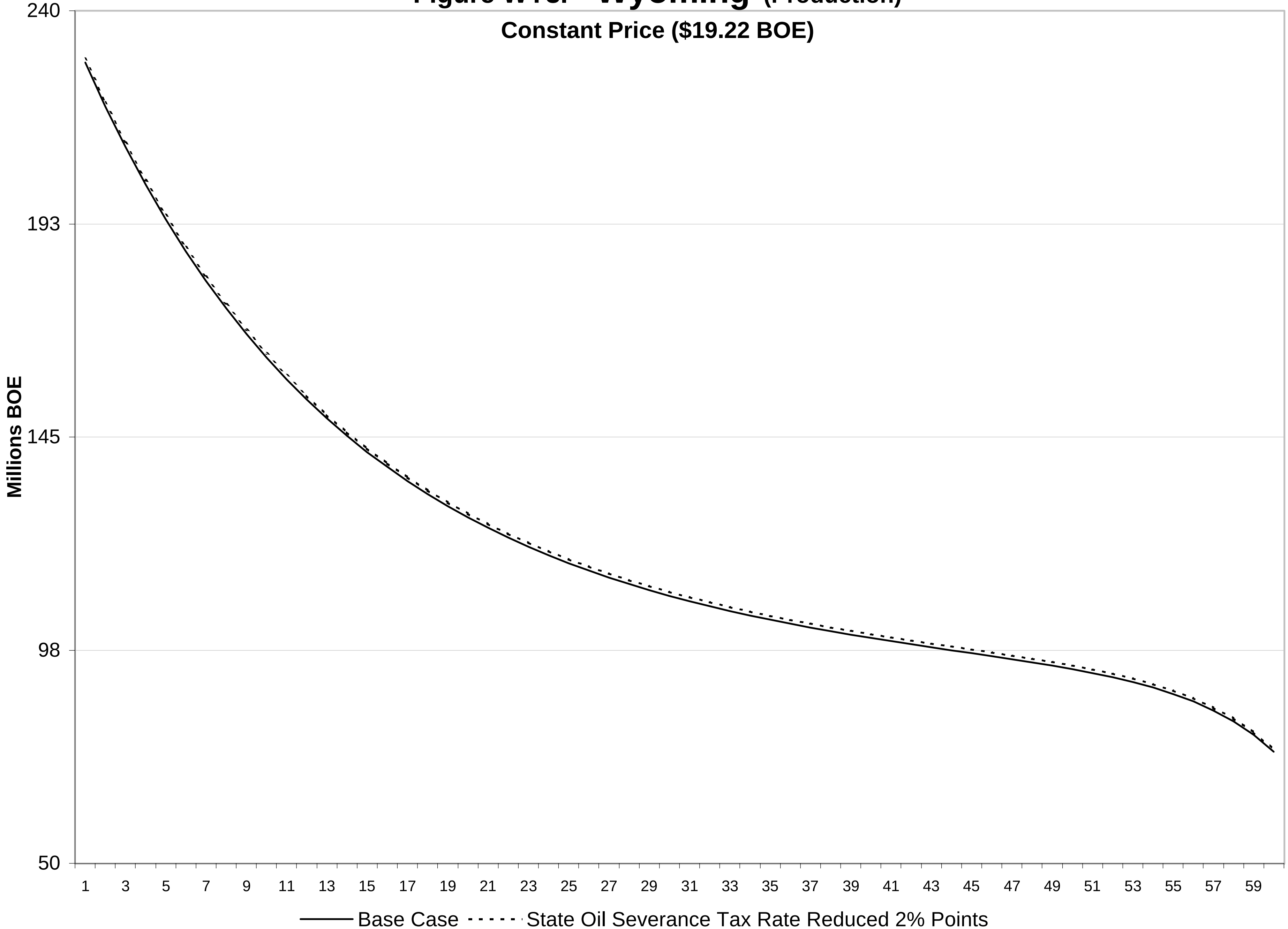


Figure WY2. Wyoming (Drilling)
Constant Price ($19.22 BOE)
Wells
1160
870
580
290
0
1
3
5
7
9
11
13
15
17
19
21
23
25
27
29
31
33
35
37
39
41
43
45
47
49
51
53
55
57
59
Base Case
State Oil Severance Tax Rate Reduced 2% Points

Figure WY3. Wyoming (Production)

Constant Price ($19.22 BOE)



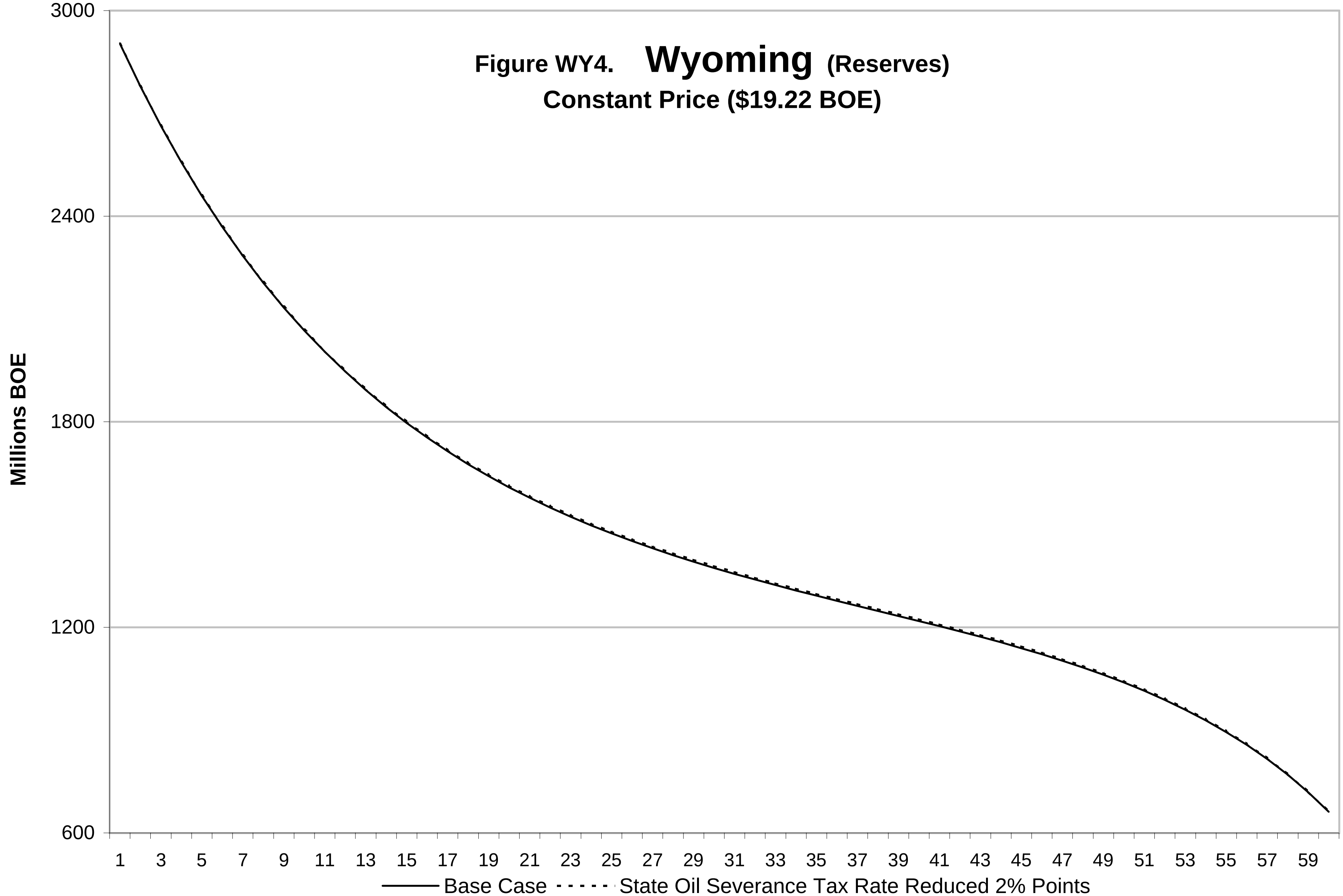


Figure WY4. Wyoming (Reserves)
Constant Price ($19.22 BOE)
Millions BOE
3000
2400
1800
1200
600
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47 49 51 53 55 57 59
Base Case
State Oil Severance Tax Rate Reduced 2% Points

Figure WY5. Wyoming (Drilling)

Constant Price ($19.22 BOE)

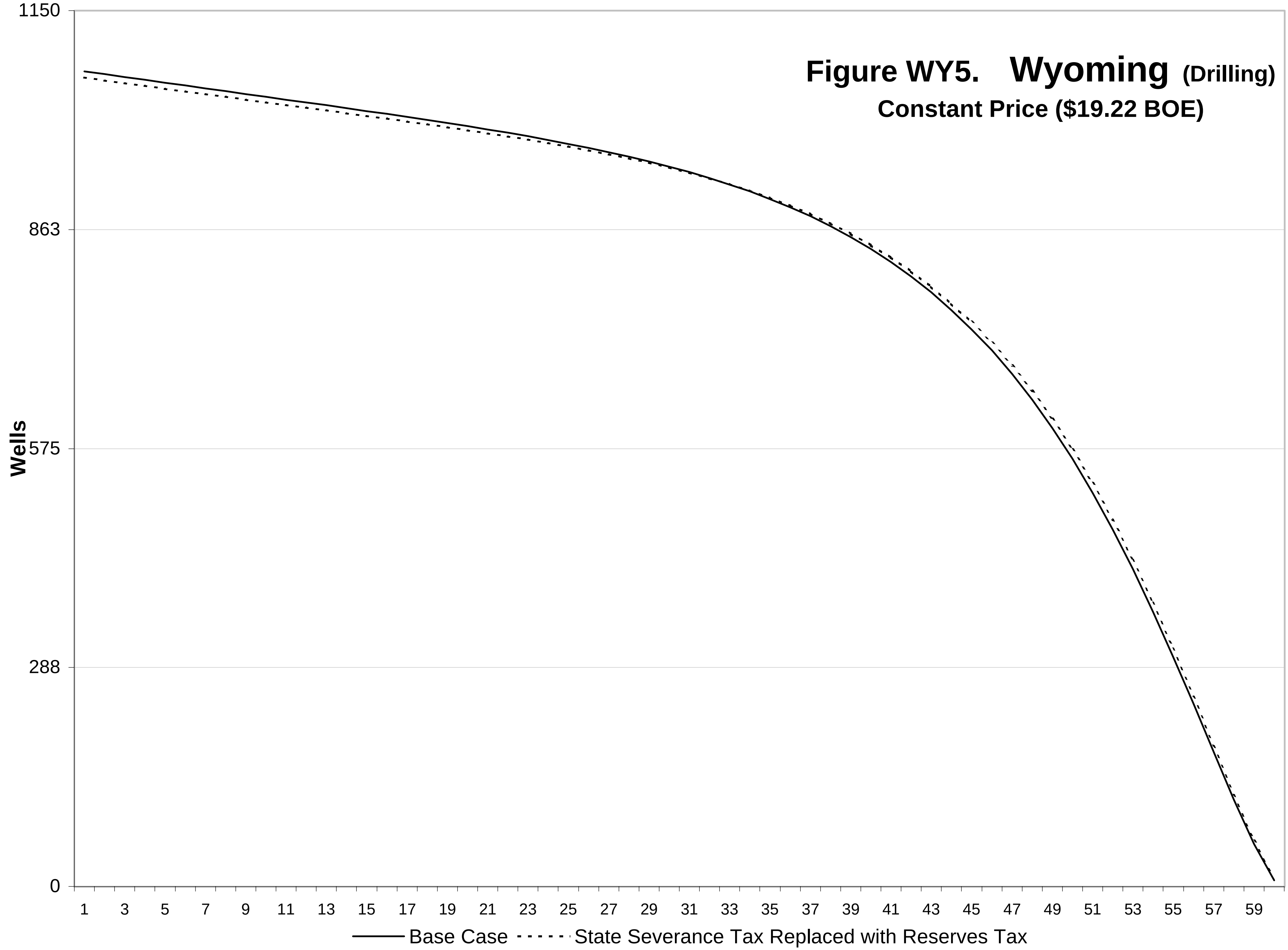


Figure WY6. Wyoming (Production)

Constant Price ($19.22 BOE)

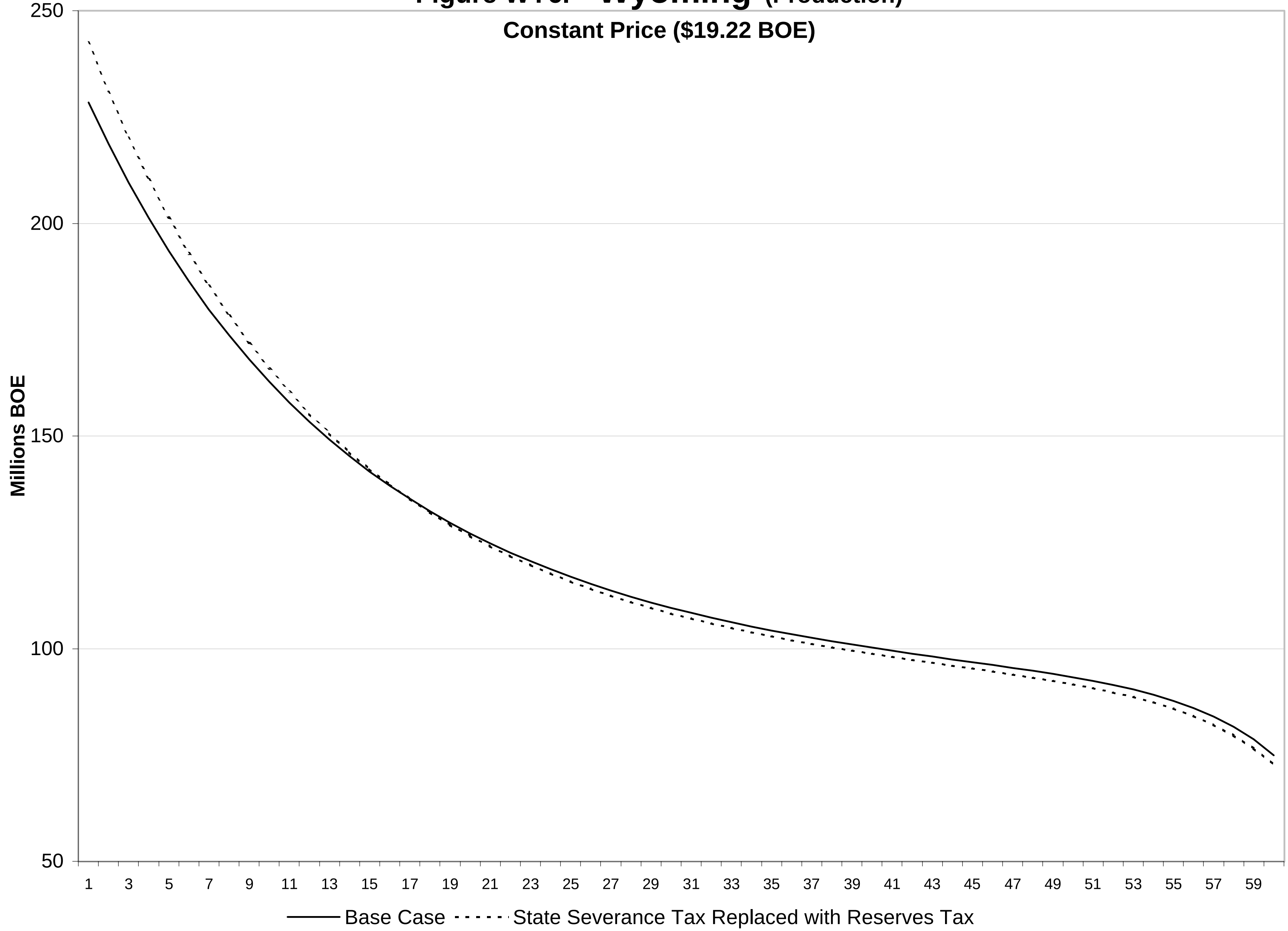


Figure WY7. Wyoming (Reserves)

Constant Price ($19.22 BOE)

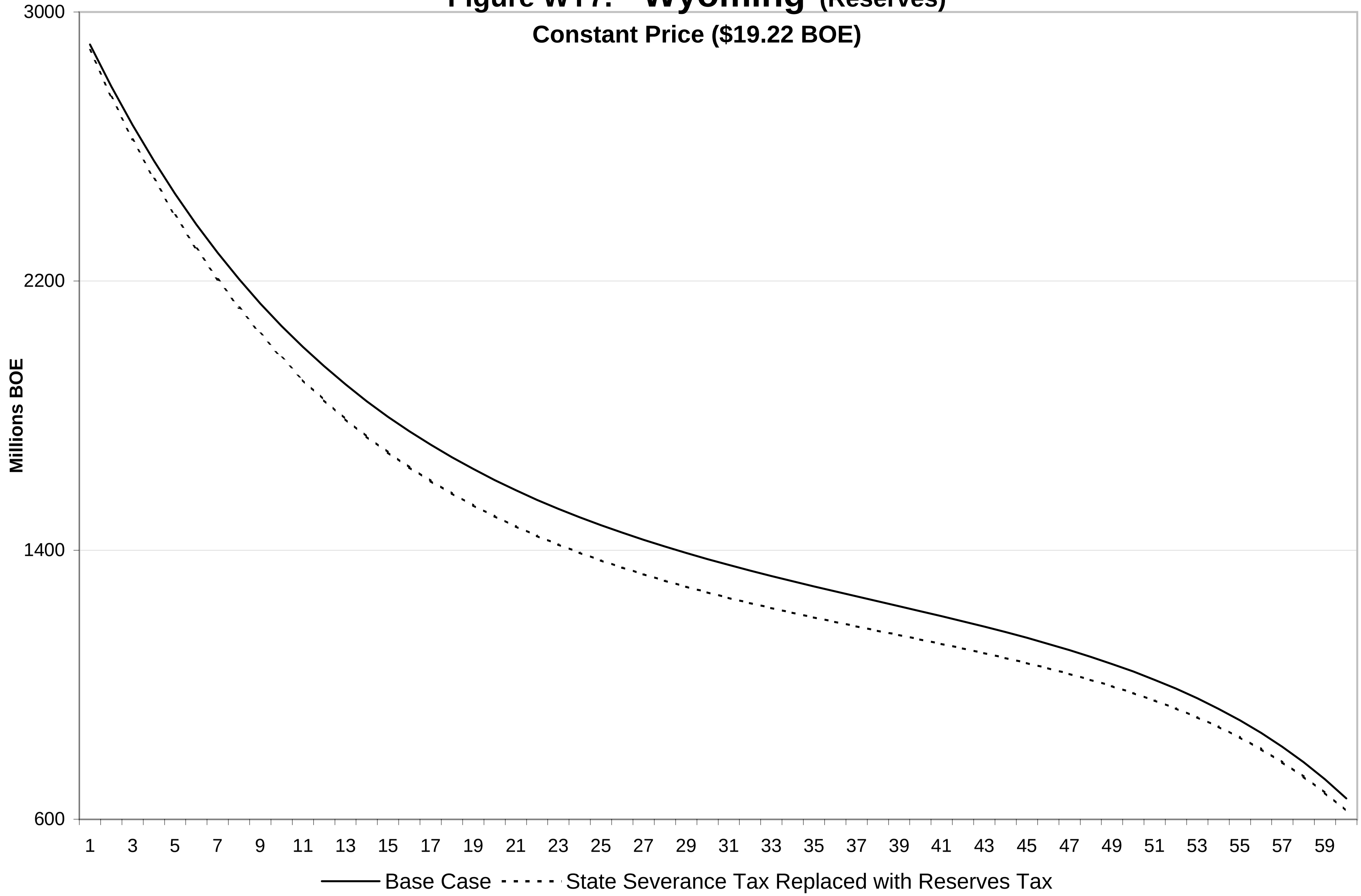
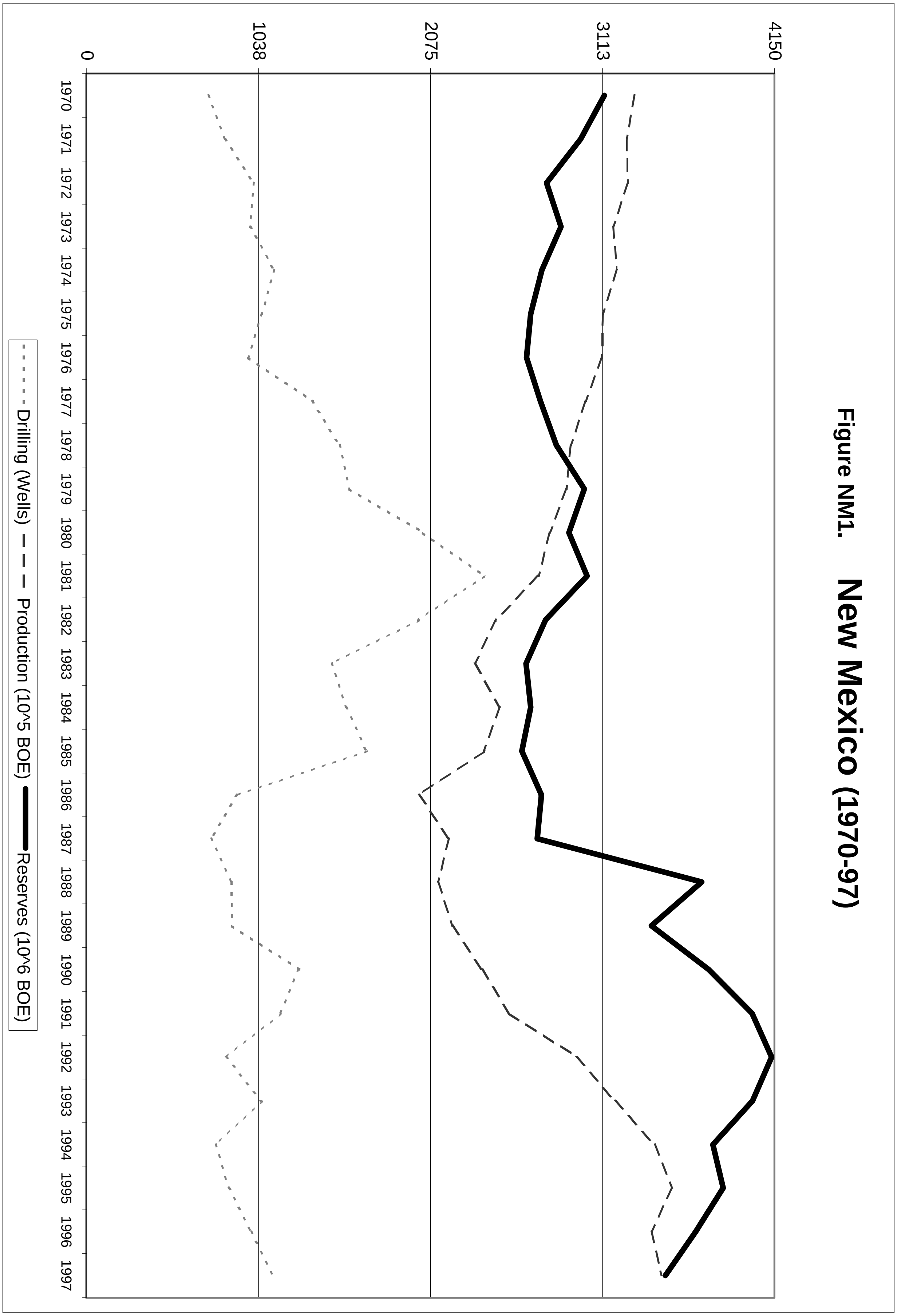


Figure NM1. New Mexico (1970-97)



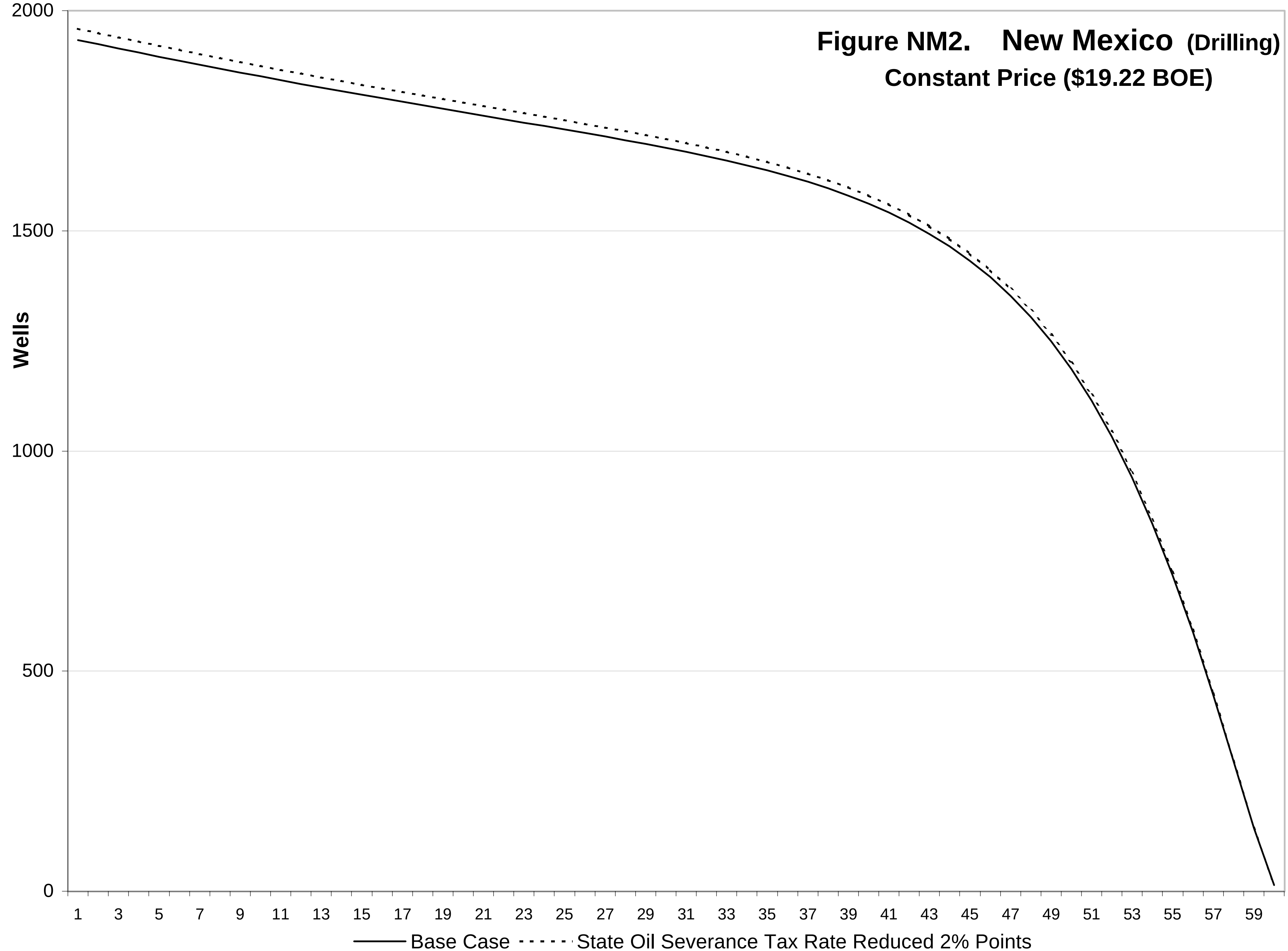


Figure NM2. New Mexico (Drilling)
Constant Price ($19.22 BOE)
Wells
2000
1500
1000
500
0
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47 49 51 53 55 57 59
Base Case
State Oil Severance Tax Rate Reduced 2% Points

Figure NM3. New Mexico (Production)

Constant Price ($19.22 BOE)

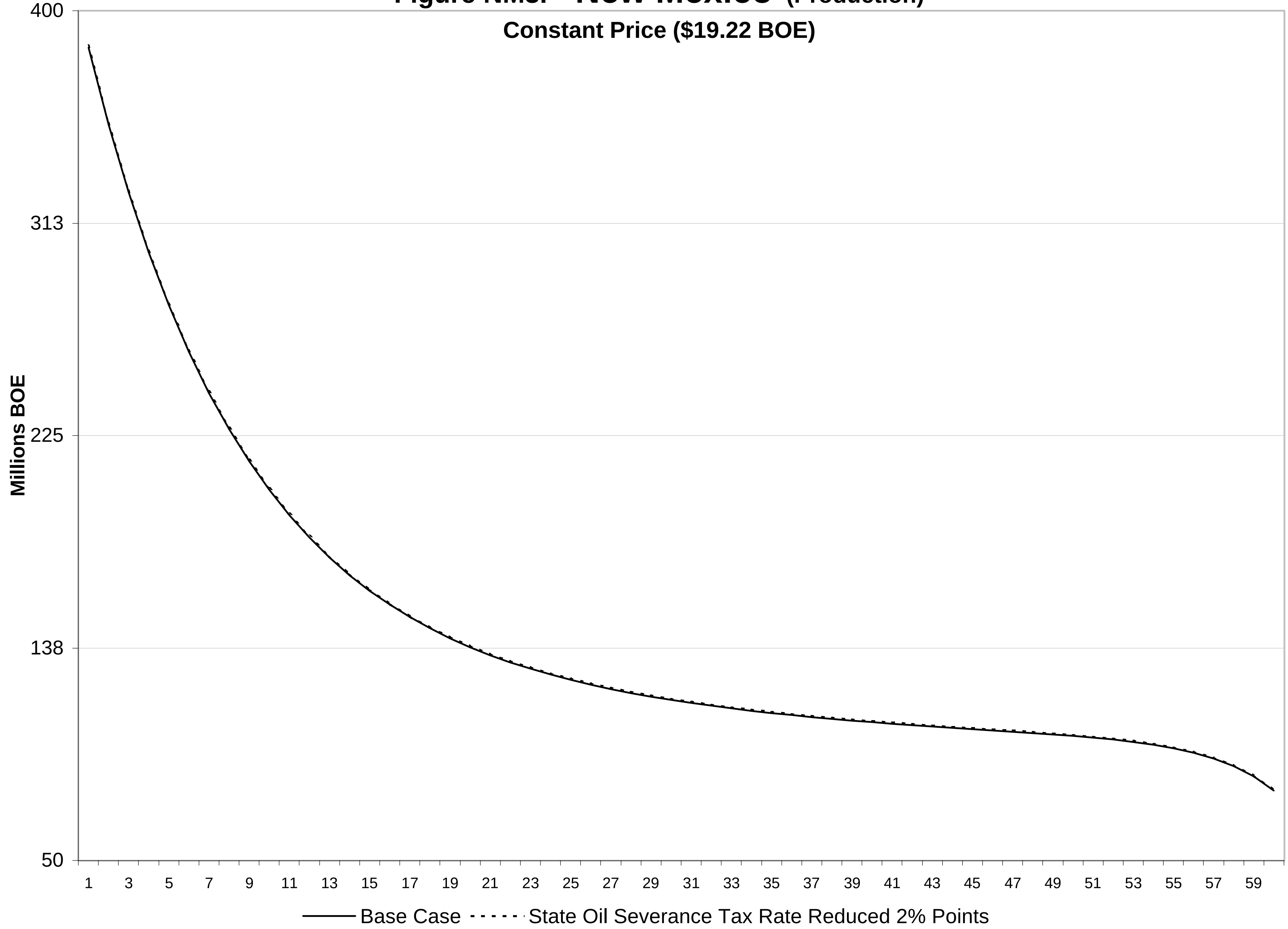


Figure NM4. New Mexico (Reserves)

Constant Price ($19.22 BOE)

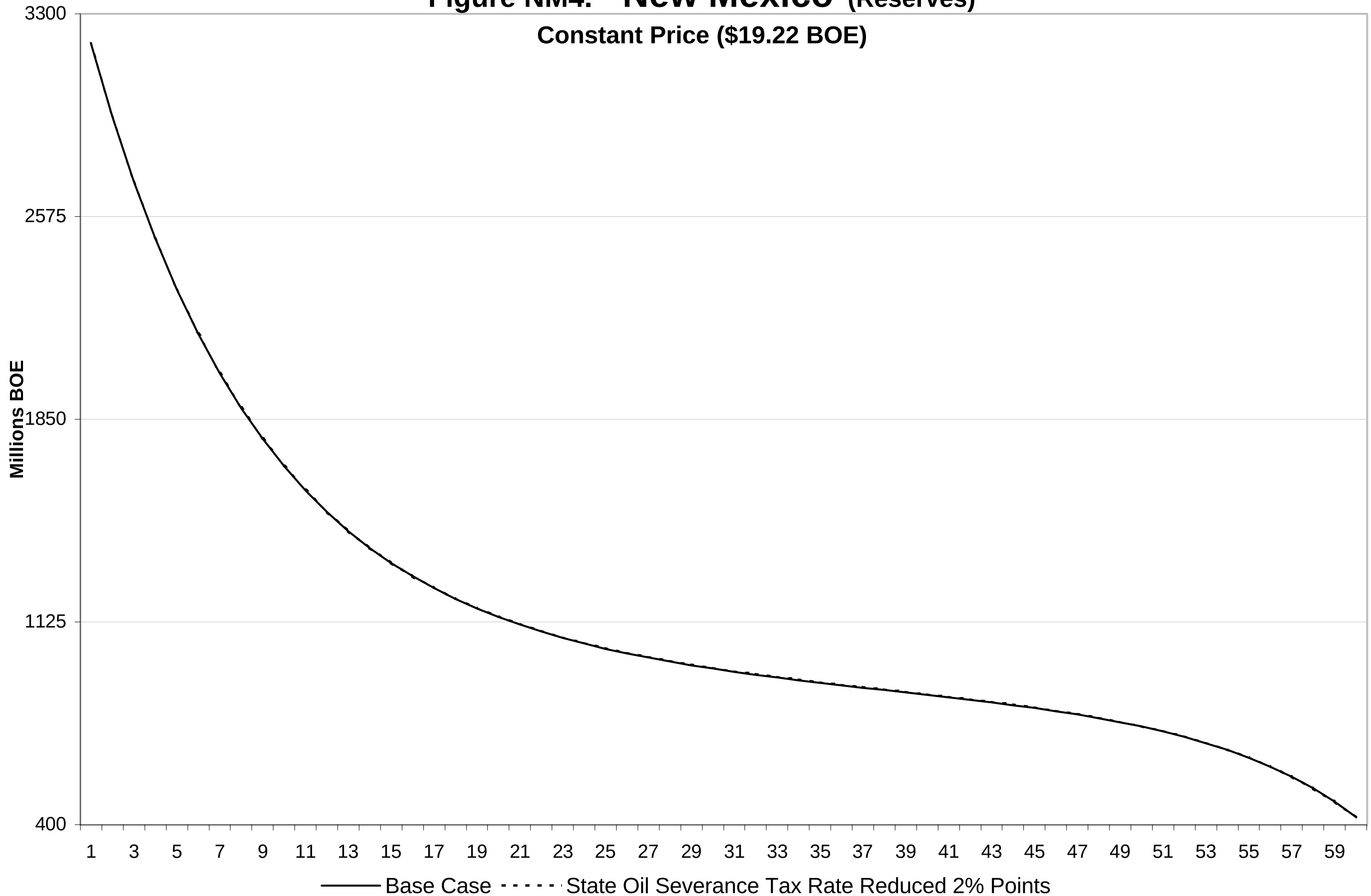
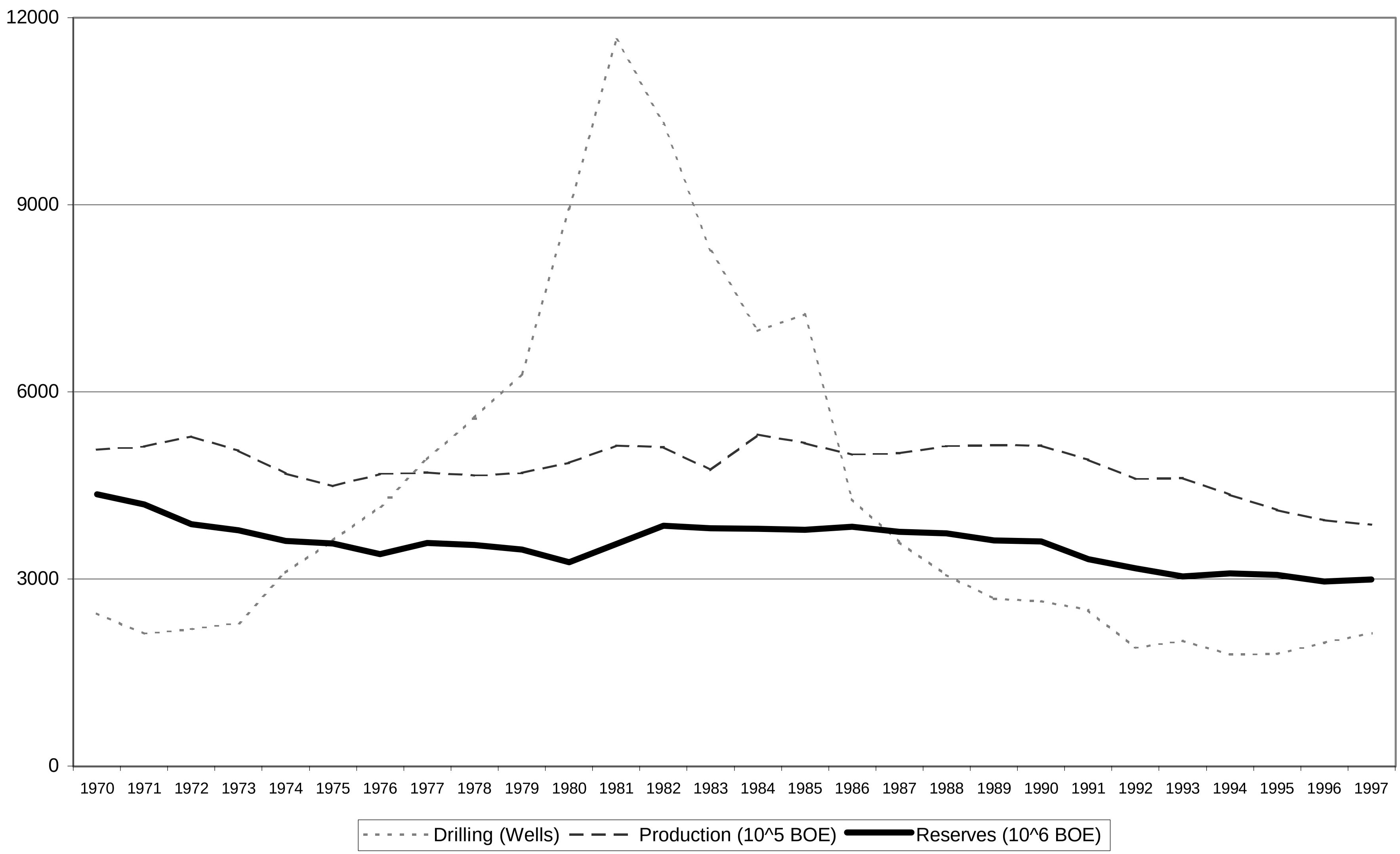


Figure OK1. **Oklahoma (1970-97)**



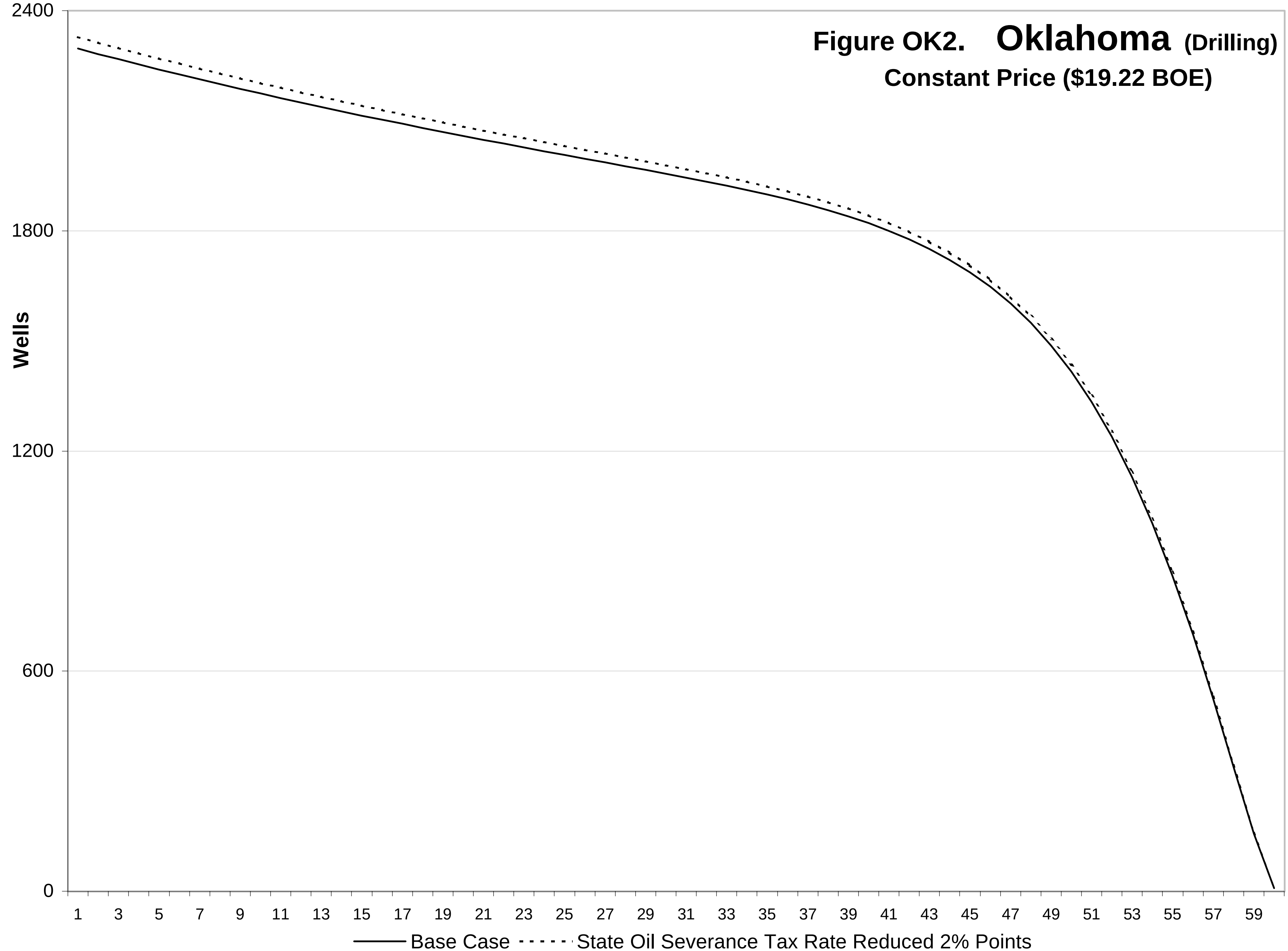


Figure OK2. Oklahoma (Drilling)
Constant Price ($19.22 BOE)
Wells
2400
1800
1200
600
0
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47 49 51 53 55 57 59
Base Case
State Oil Severance Tax Rate Reduced 2% Points

Figure OK3. Oklahoma (Production)

Constant Price ($19.22 BOE)

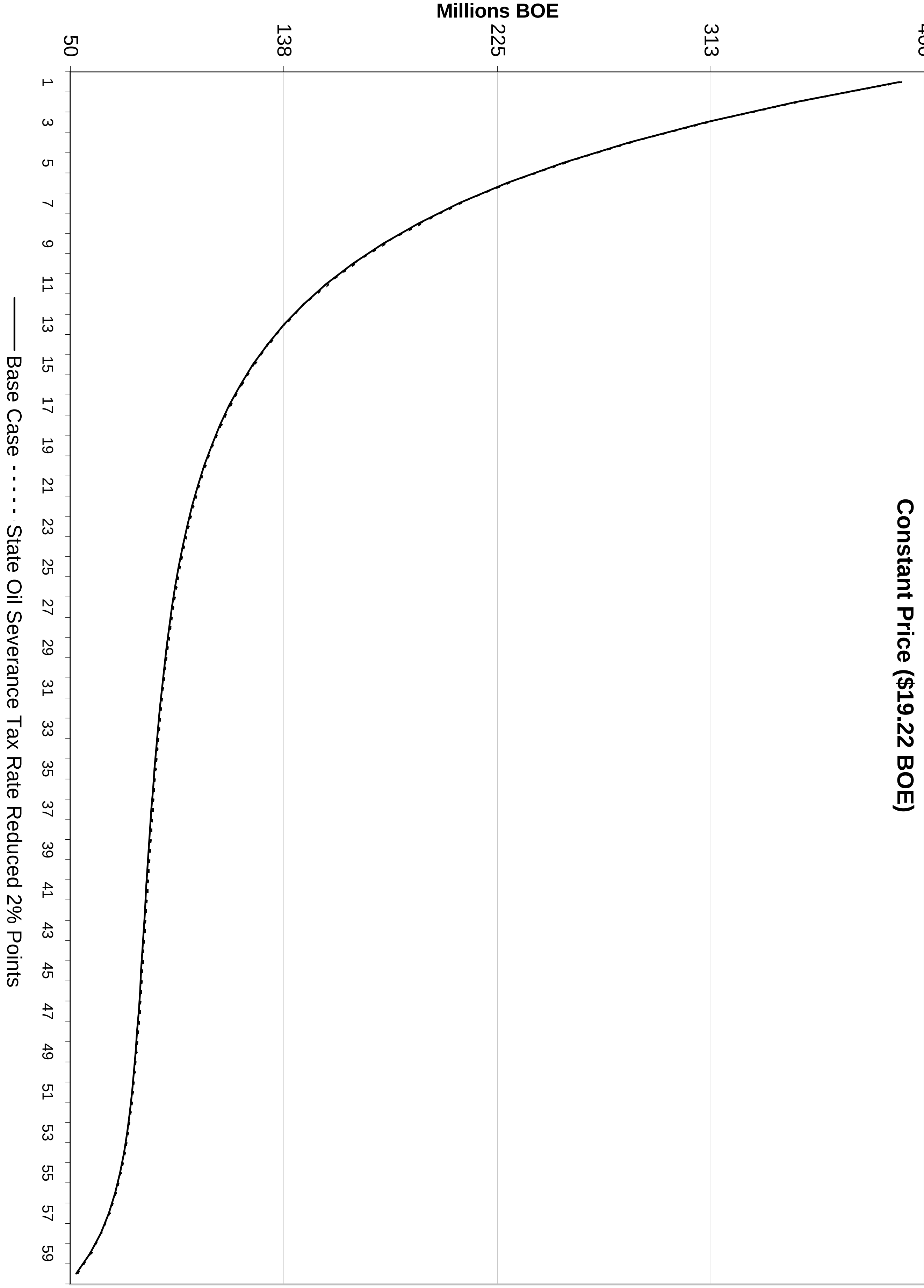
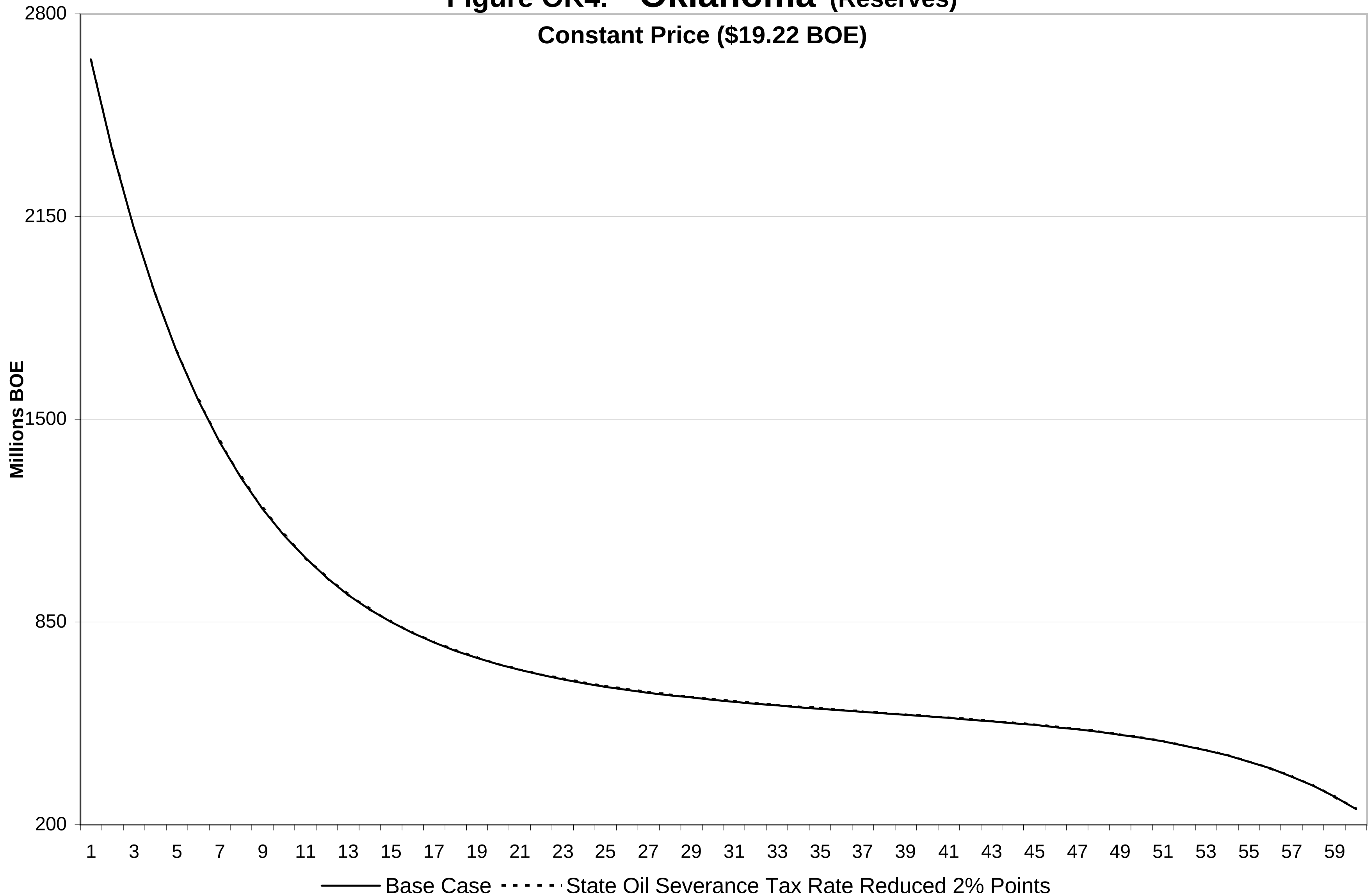


Figure OK4. Oklahoma (Reserves)

Constant Price ($19.22 BOE)



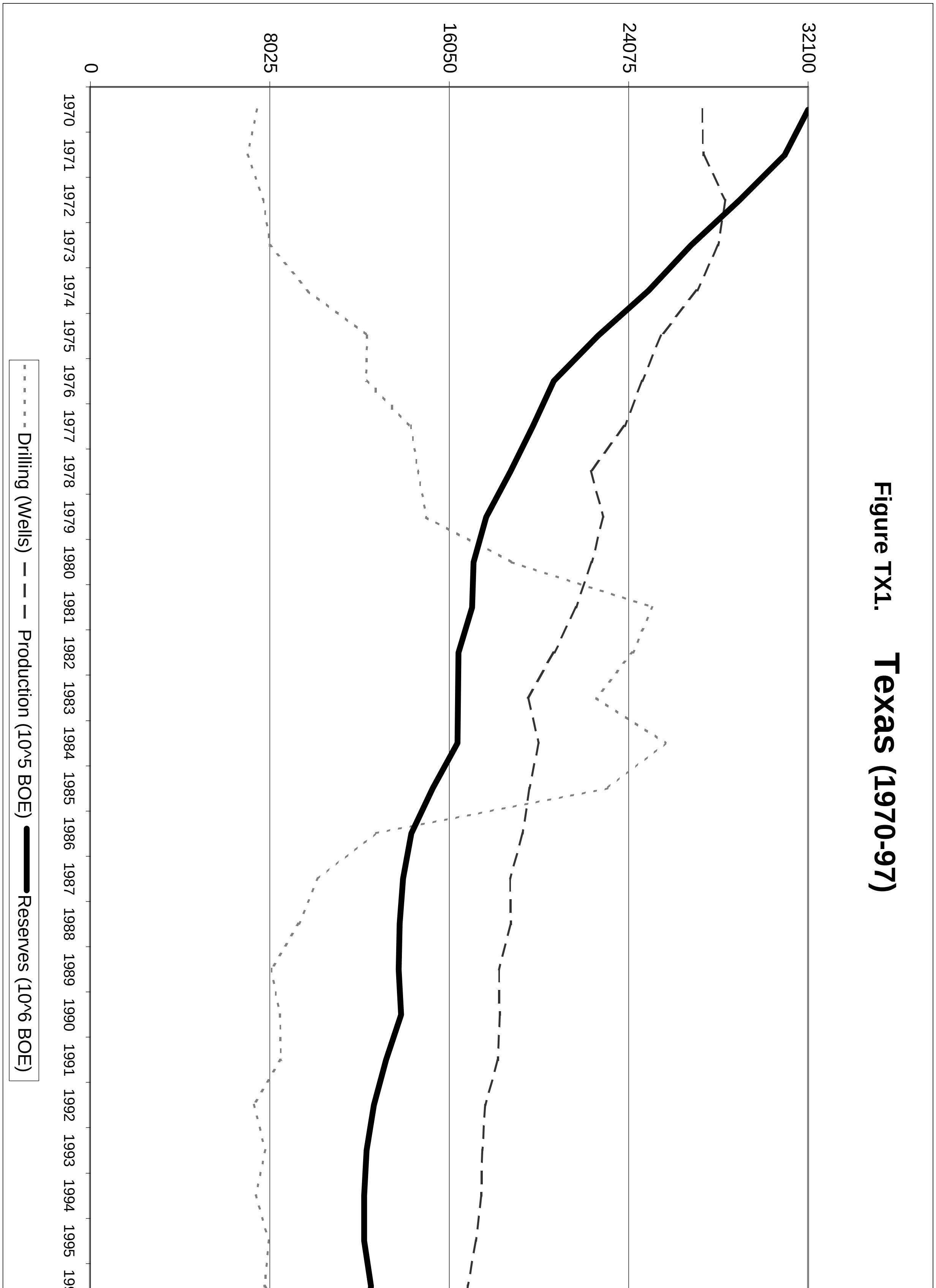


Figure TX1. Texas (1970-97)
0
8025
16050
24075
32100
1970 1971 1972 1973 1974 1975 1976 1977 1978 1979 1980 1981 1982 1983 1984 1985 1986 1987 1988 1989 1990 1991 1992 1993 1994 1995 1996 1997
Drilling (Wells)
Production (10^5 BOE)
Reserves (10^6 BOE)

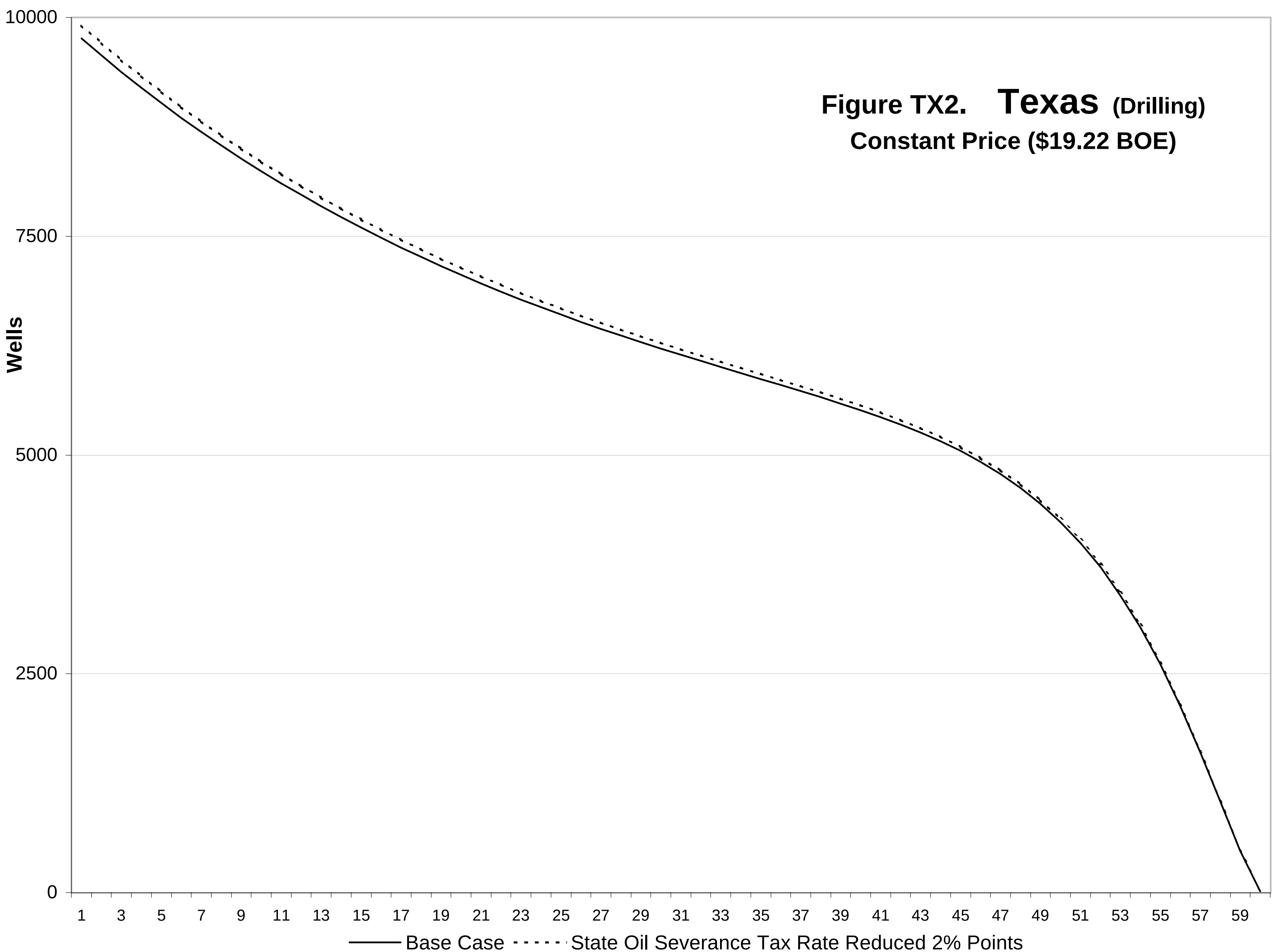


Figure TX2. Texas (Drilling)
Constant Price ($19.22 BOE)
Wells
10000
7500
5000
2500
0
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47 49 51 53 55 57 59
Base Case
State Oil Severance Tax Rate Reduced 2% Points

Figure TX3. Texas (Production)

Constant Price ($19.22 BOE)

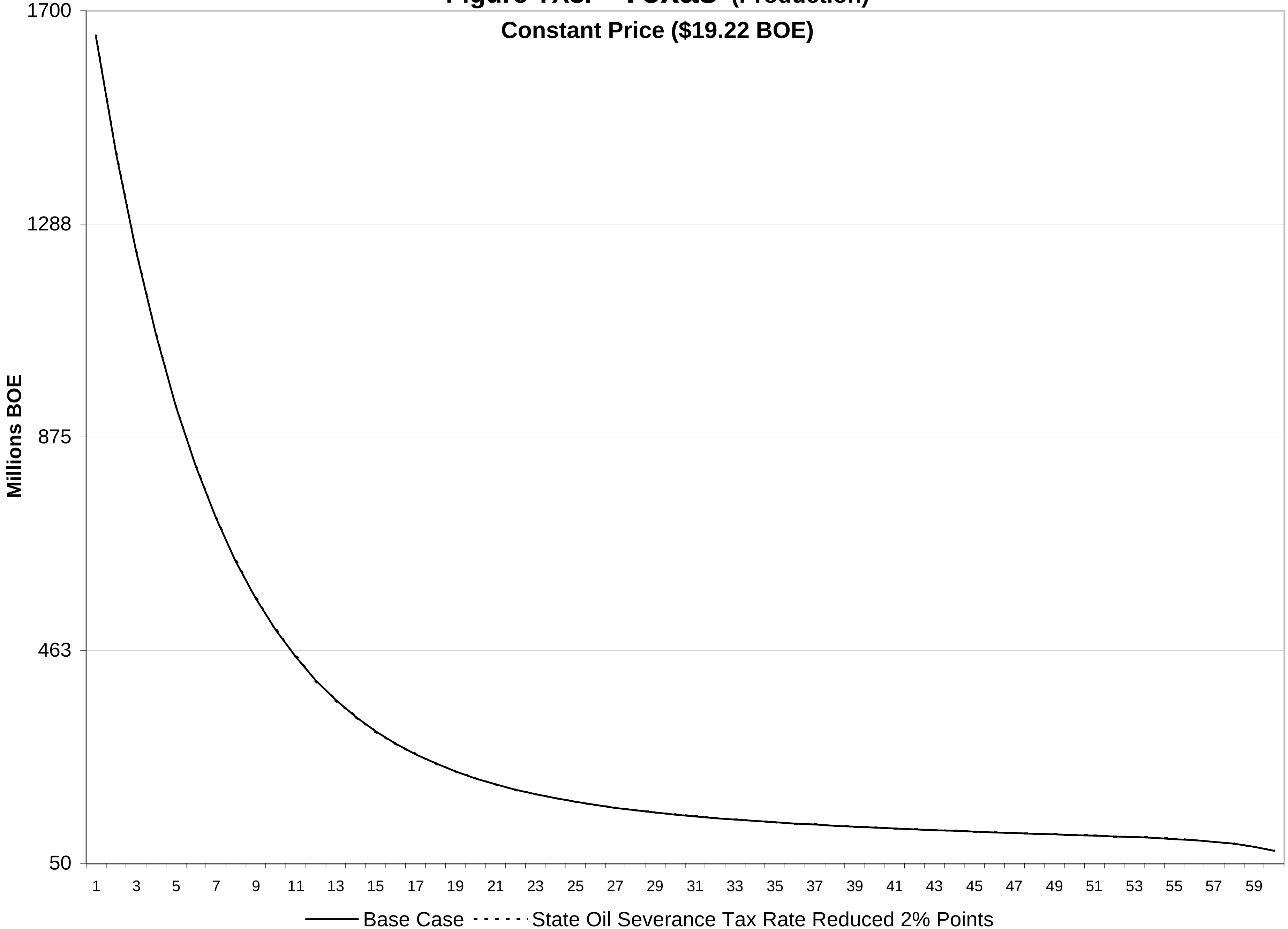


Figure TX4. Texas (Reserves)

Constant Price ($19.22 BOE)

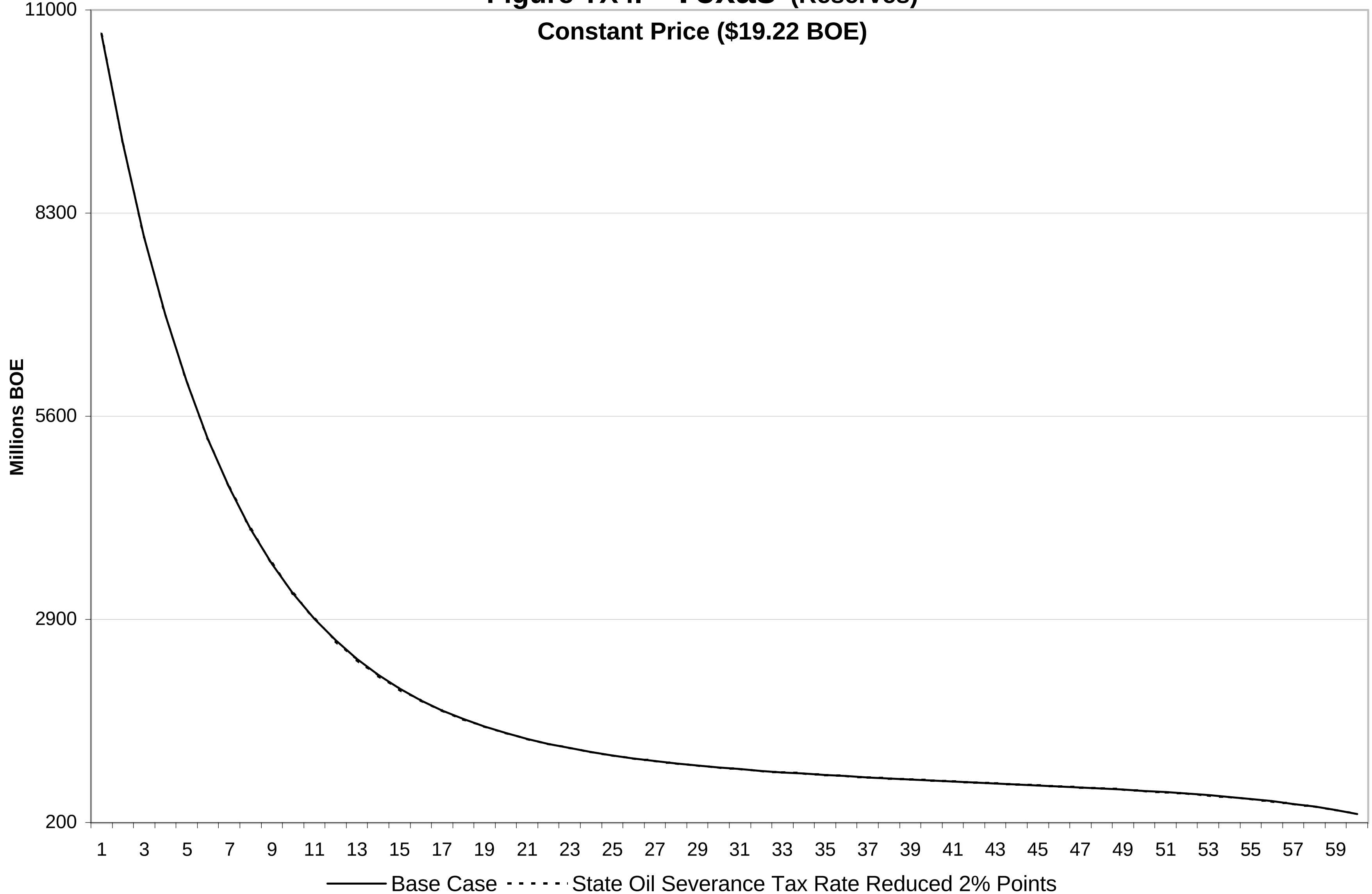
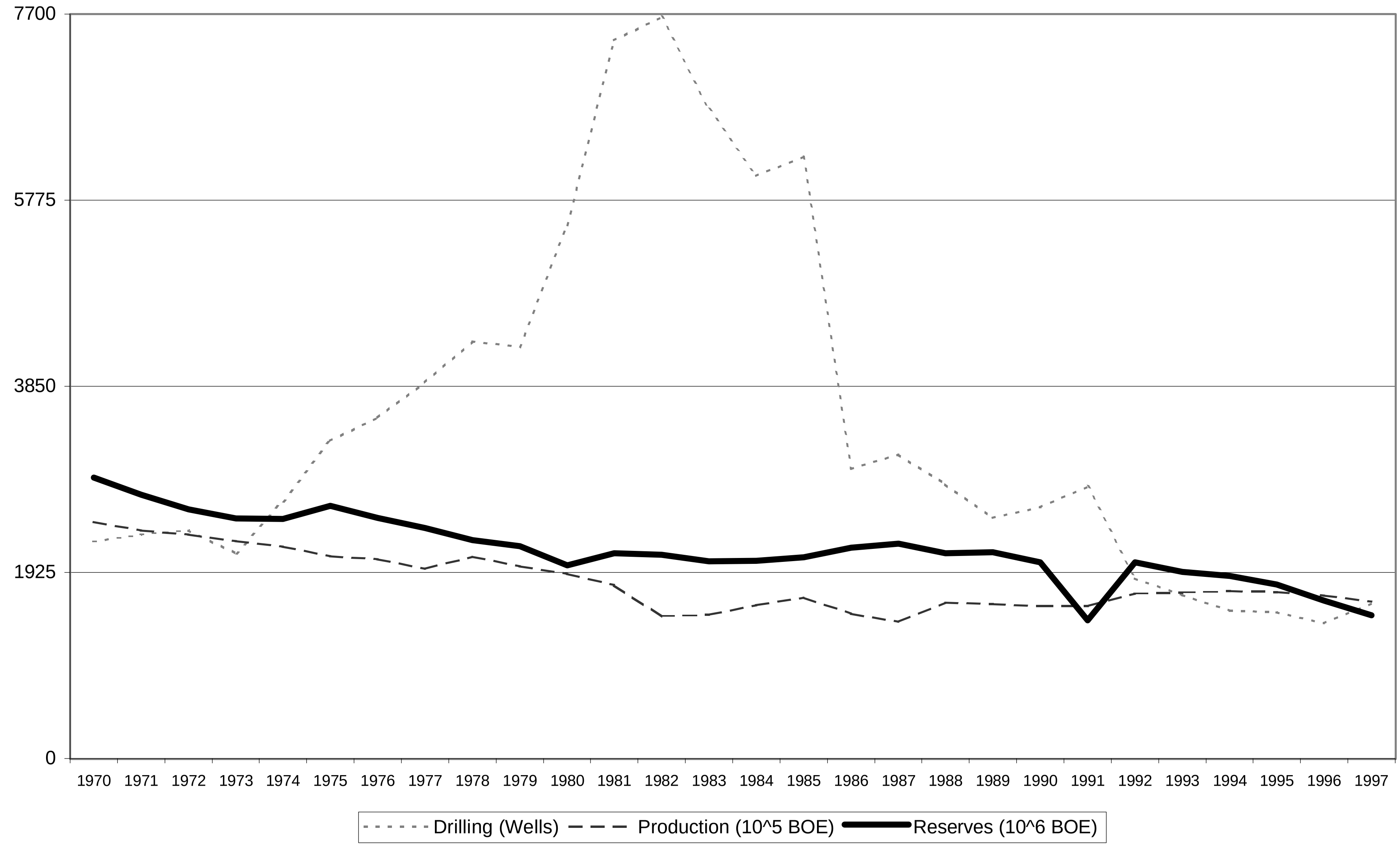


Figure KS1. **Kansas (1970-97)**



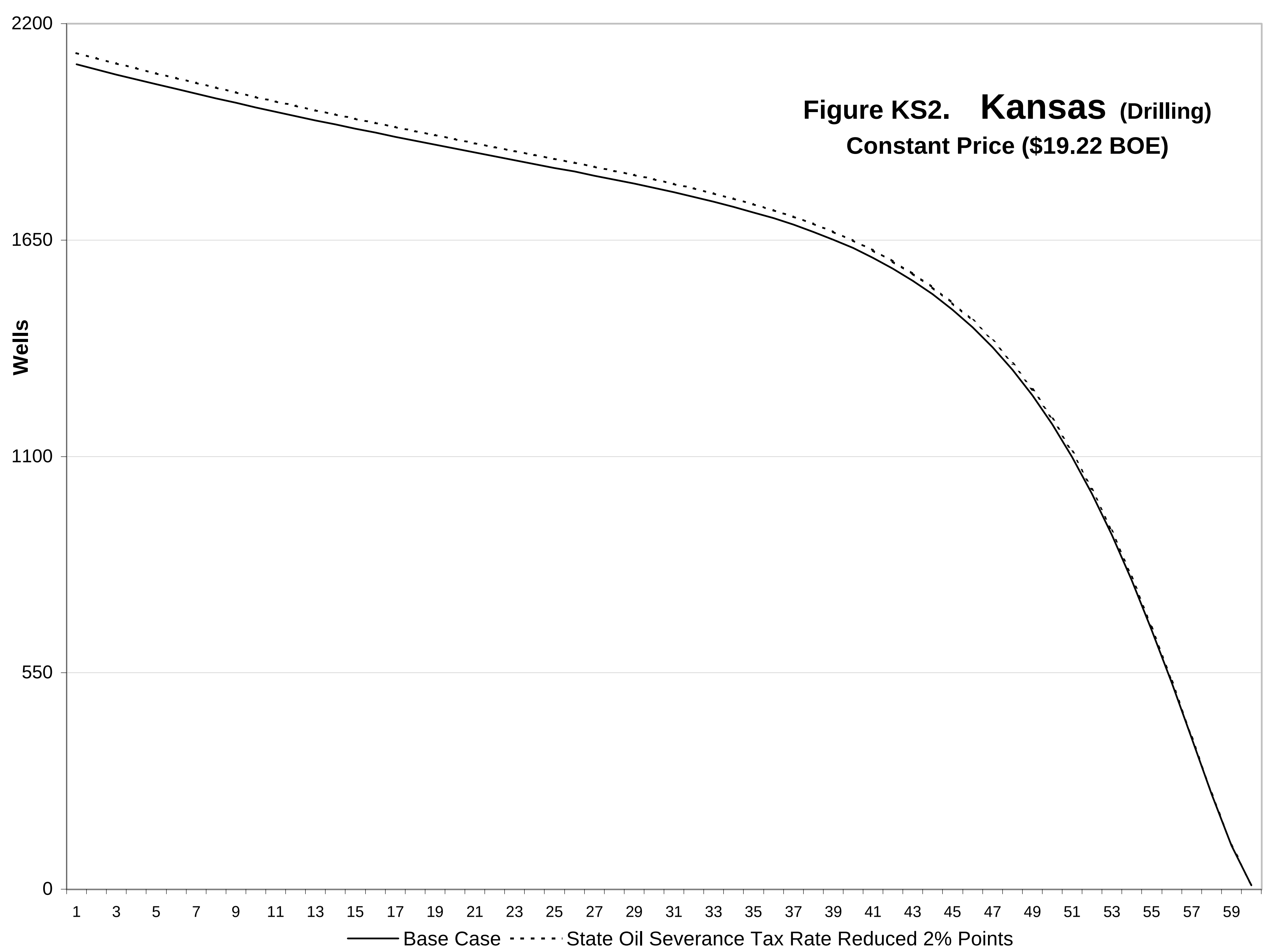
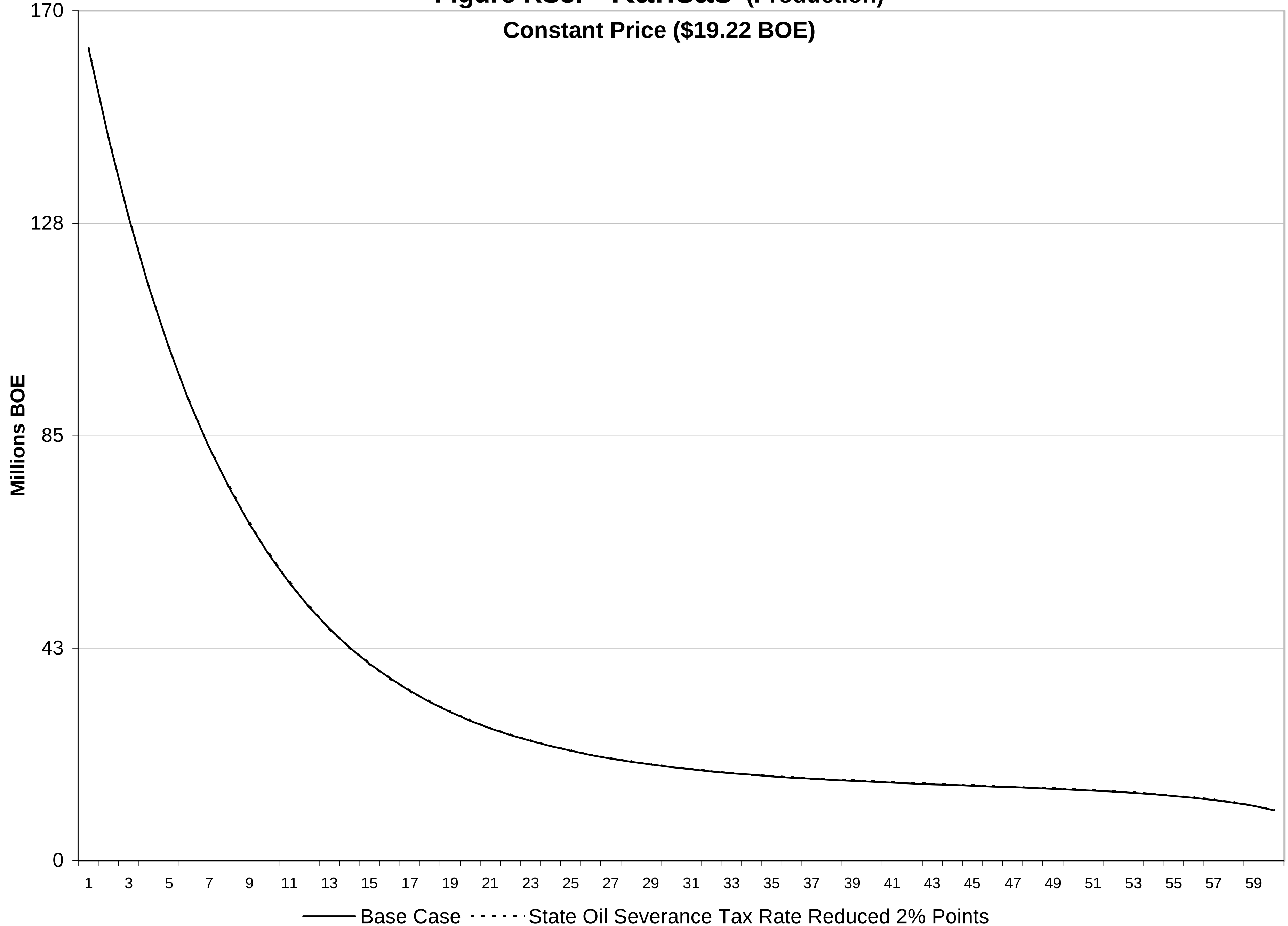


Figure KS2. Kansas (Drilling)
Constant Price ($19.22 BOE)
Wells
2200
1650
1100
550
0
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47 49 51 53 55 57 59
Base Case
State Oil Severance Tax Rate Reduced 2% Points

Figure KS3. Kansas (Production)

Constant Price ($19.22 BOE)



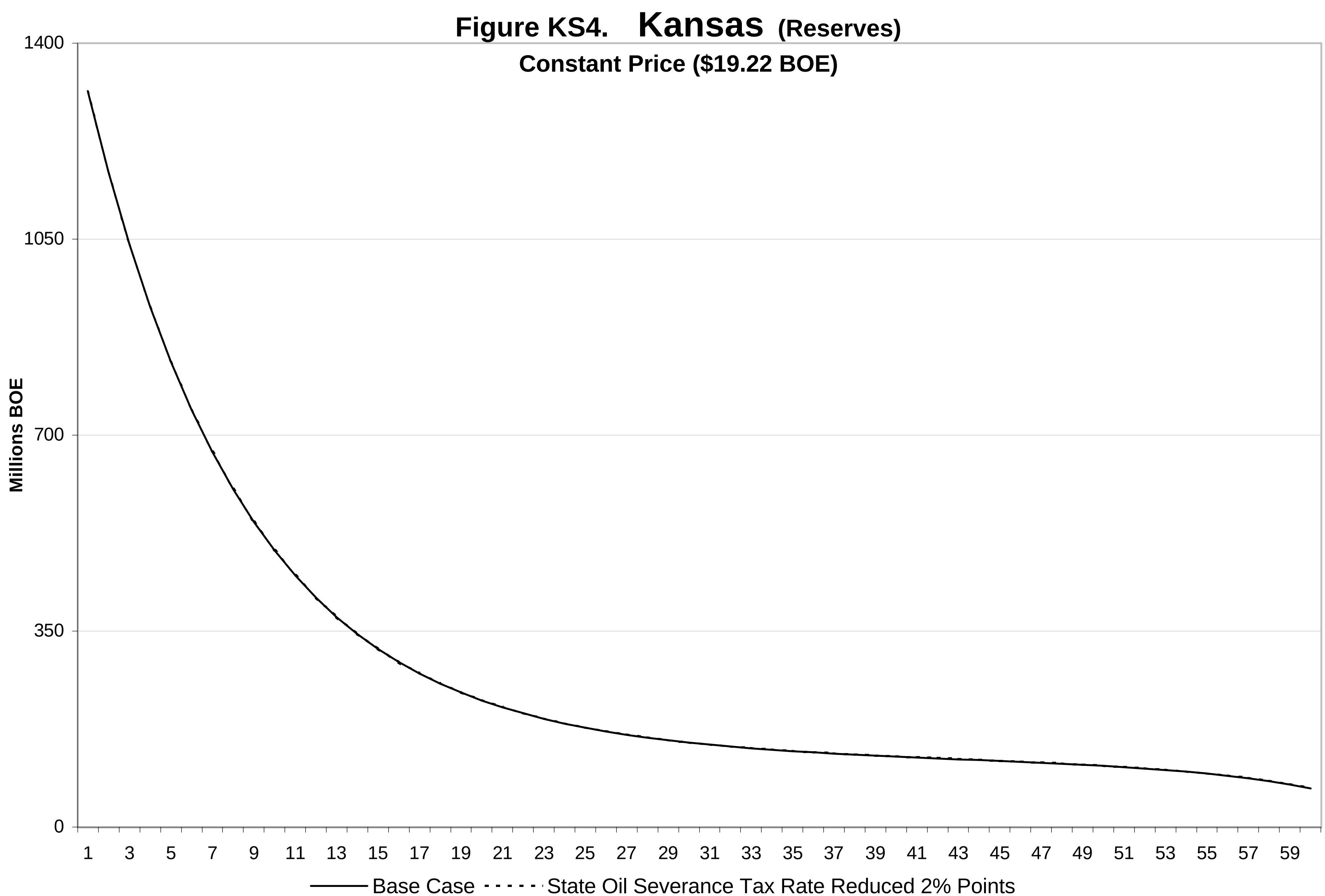
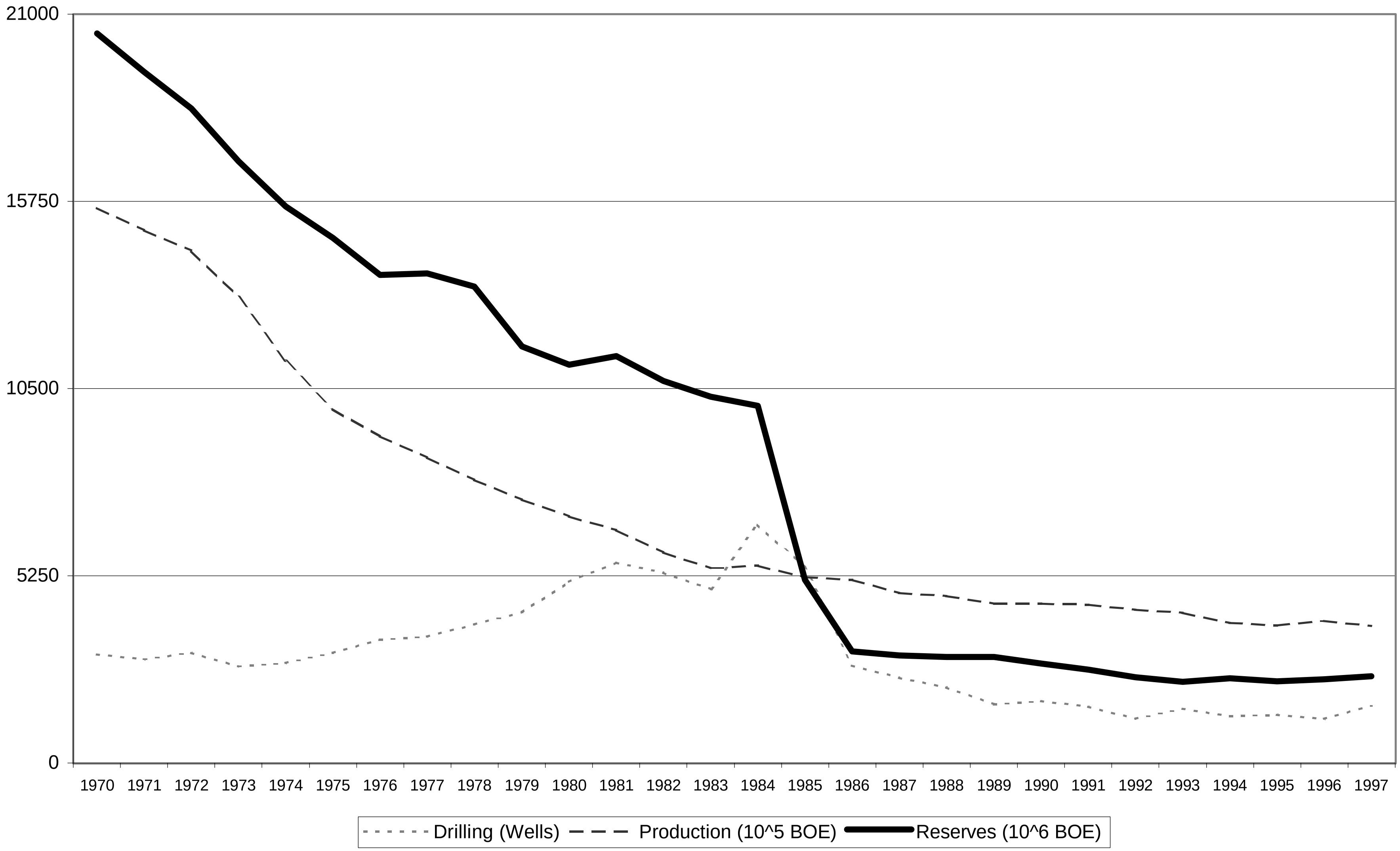


Figure KS4. Kansas (Reserves)
Constant Price ($19.22 BOE)
Millions BOE
1400
1050
700
350
0
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47 49 51 53 55 57 59
Base Case
State Oil Severance Tax Rate Reduced 2% Points

Figure LA1. **Louisiana (1970-97)**



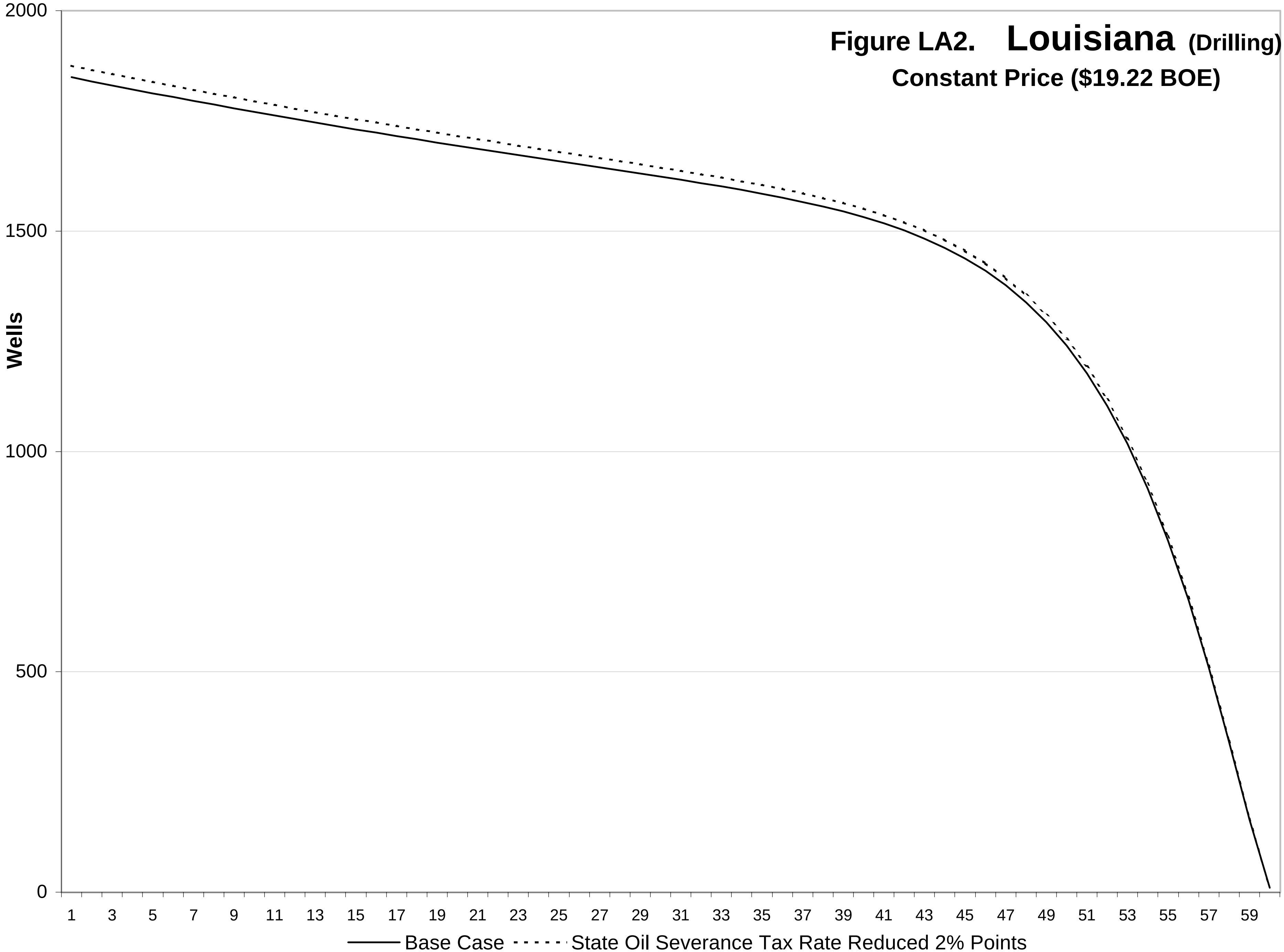


Figure LA2. Louisiana (Drilling)
Constant Price ($19.22 BOE)
Wells
2000
1500
1000
500
0
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47 49 51 53 55 57 59
Base Case
State Oil Severance Tax Rate Reduced 2% Points

Figure LA3. Louisiana (Production)

Constant Price ($19.22 BOE)

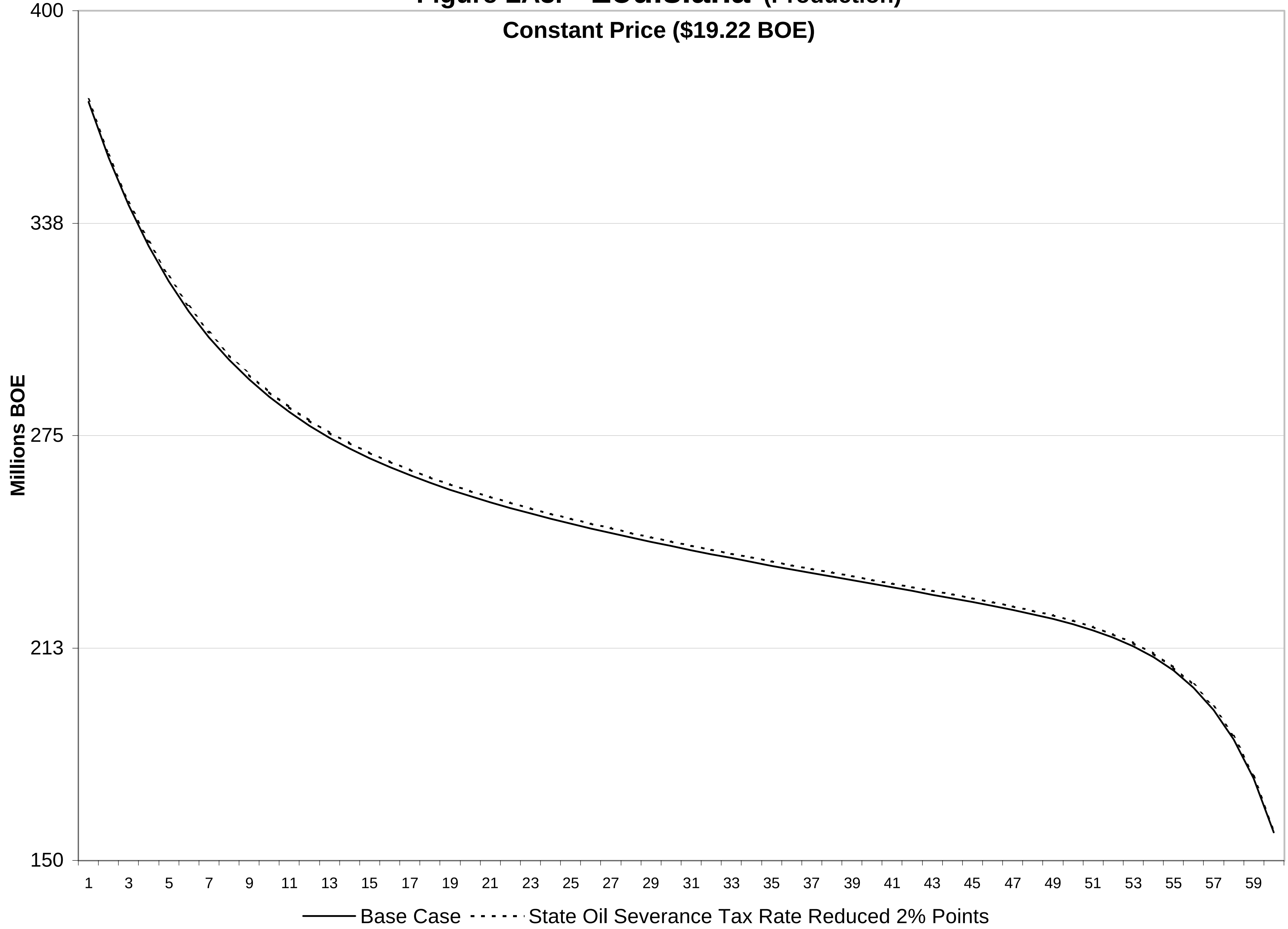
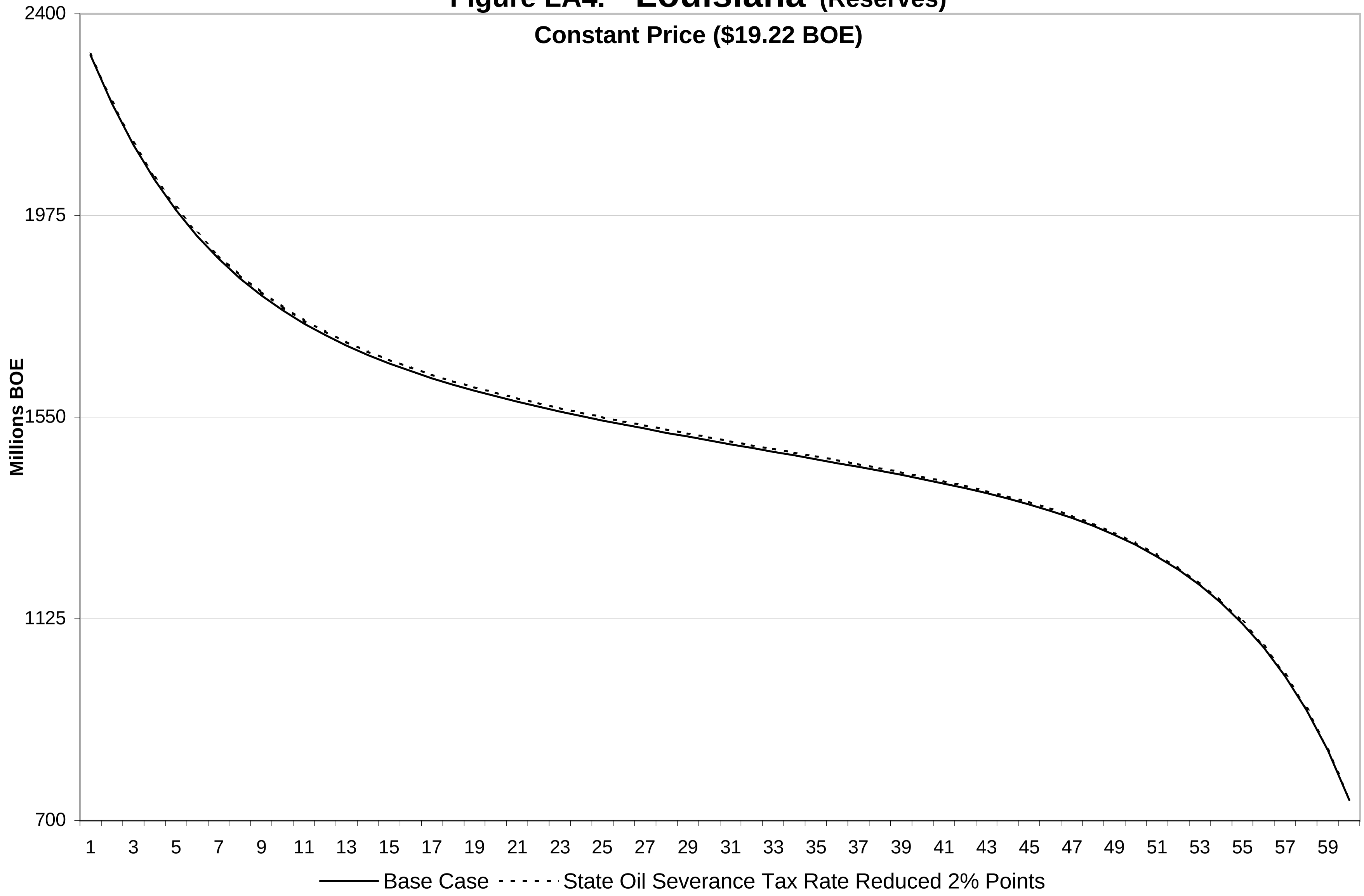


Figure LA4. Louisiana (Reserves)

Constant Price ($19.22 BOE)



CHAPTER 5

ENVIRONMENTAL AND LAND USE REGULATIONS, EXPLORATION, AND PRODUCTION OF OIL AND GAS

5.1 Introduction

How do firms respond to increased costs arising from environmental and land use regulations imposed by government at all levels? Recent studies have addressed this question in the context of manufacturing (Levinson 1996, Becker and Henderson 2000), but there is no corresponding work on extractive industries even though Jaffe, Peterson, Portney and Stavins (1995, pp. 135-36) suggest that a study of mining could be rewarding. Moreover, as argued in Chapter 3, extractive firms face a fundamentally different problem than manufacturing firms when confronted by changes in public policies because they are tied to an immobile reserve base that represents a key component of their capital stock.

This chapter examines for the first time how oil and gas exploration and production decisions are altered when environmental and land use policies change by looking at differences in regulatory practices on private and federal land. Studying effects of regulations by looking at how they are applied on different types of land is broadly similar to the approach taken by Becker and Henderson (2000), who consider differences in behavior of manufacturing firms in attainment versus nonattainment counties defined in regard to the federal ground-level ozone standard. An important part of the analysis in this paper is a cost function estimated from data on oil and gas drilling in the Wyoming Checkerboard over the period 1987-98. The Checkerboard, a major U.S. site of recent oil and gas activity, is a 40 mile wide strip of land, 20 miles on each side of the Union Pacific Railroad right-of way, extending westward approximately 200 miles from Rawlins in south central Wyoming to the Utah state line. The Pacific Railway Acts of 1862 and 1864 conveyed to the railroad both surface and mineral rights to the odd-numbered sections of land in this area, while retaining the even-numbered sections as federal property.[1] Thus, four private (railroad) sections surrounded each federal section and four federal sections surrounded each private section, giving land ownership maps of this area the appearance of a checkerboard. Since the 1860s, some of the land has changed hands; however, the alternating federal-private ownership pattern is remarkably persistent to the present day and serves as a crucial control used to identify differences in environmental compliance costs on federal and private property.[2] Estimates presented suggest that protection of cultural and biological resources as well as other aspects of environmental and land use policy result in drilling costs that are about $110,000 higher on federal property than on private property.

Implications of this result for future exploration and production of oil and gas then are developed by inserting these econometric estimates into the model developed in Chapters 3 and 4. An advantage of this analysis is that it incorporates important aspects of federal, state, and local oil and gas taxation and thus accounts for the extent to which increased costs arising from regulation are deductible against tax liabilities faced by the industry. Simulations of the model over a 60-year horizon for Wyoming show that more stringent environmental and land use regulations retard drilling and extraction overall and tilts drilling toward the future.[3] This case study is of general interest because it shows that drilling and production are quite sensitive to changes in costs imposed by environmental regulation on all types of land and promote more oil and gas in the ground at the end of the extraction program. Reducing current exploration and extraction and pushing these activities away from federal property may meet with approval by conservationists concerned only with characteristics of surface land; however, the outcome of reduced overall extraction rates may well conflict with their own longer-term objectives. Permanently reduced output from known reserves is not only a source of deadweight loss to society, it also increases incentives to drill in more environmentally sensitive reserves in National Parks and the Alaskan National Wildlife Refuge where the payoff from further exploration and development may be very high.

The plan of the remainder of this chapter is to begin in Section 5.2 by reviewing what (little) is known about differences in environmental and land use regulatory policy on federal and private land and presenting other background for the study. Section 5.3, then presents empirical estimates of drilling costs in the Wyoming Checkerboard. Section 5.4 draws out implications of these results in a simulation study. Section 5.5 concludes.

5.2 Background

Oil and gas field activities in the U.S. are affected by federal statutes such as 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 statutes, 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 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 for industry to comply with this myriad of regulations (Stewart and Templet 1989), but these are quite general and deal with hypothetical situations. There are no published estimates of compliance costs for the industry generally that might parallel the PACE data available for manufacturing sectors.[4]

Impressionistic evidence suggesting that costs faced by the oil and gas industry are higher on federal land than other types of land is presented in Table 5.1. This table reports calculations of the ratio of wells drilled to reserves as well as the percentage of wells drilled on federal land. Of course, many possible factors including geologic conditions, the amount of environmental resources to be protected, local attitudes toward development, and whether deposits are located in remote areas may be responsible for the substantial interstate variation in the ratio of wells drilled to reserves. It is nonetheless interesting, however, that the three states (Alaska, New Mexico and Wyoming) with the lowest well to reserve ratios are the three states with the highest percentages of drilling on federal property. This example proves little, but it does provide a basis for speculation that differences in environmental compliance costs could be partly responsible, and further analysis of the issue is warranted.

The focus of this study is on environmental and land use regulations pertaining to drilling rather than those pertaining to production for three reasons. First, although environmental contamination can occur at any stage in the life cycle of oil and gas wells, drilling is thought to be the activity of greatest risk because of the large volumes of potentially hazardous gases and fluids brought to the surface (Carls, Fenn, and Chaffey 1994). Second, data on drilling costs, collected by the *Joint Association Survey on Drilling Costs* (various years), is much richer than the highly aggregated data on production costs reported by the Energy Information Administration, U.S. Department of Energy (various years). Third, drilling is a one-time activity, whereas production from a given well may last for many years. Production cost conditions can change over time as subsurface pressure declines causing wells to lose their natural drive. Thus, it would be easier to model drilling costs than production costs even if the quality of data on both activities were equal.

Two studies (Harder, John, and Dupont 1995 and Schultz 1998) have examined drilling costs for four specific sites (none of them in Wyoming), finding that environmental compliance costs are higher on federal property than on nearby private land. Reasons advanced to explain this cost disparity can be grouped into the following four categories: (1) permitting procedures, (2) well and site construction and supervision, (3) drilling waste disposal, and (4) restrictions on site access. Permitting procedures include development of impact studies and operation plans covering a broad range of issues ranging from soil erosion and fugitive dust to biological issues such as endangered species protection as well as plans for liability mitigation (influenced by the Oil Pollution Act of 1990). Well and site construction and supervision includes added labor costs needed to meet regulatory stipulations, as well as costs of site inspections, pit liner monitoring, and separating and flaring gases. Drilling waste disposal costs include payments to third party contractors for handling mud and cuttings in addition to installation of closed-loop drilling systems designed to reduce waste generation. Site access restrictions apply mainly to route planning and road construction. Conclusions drawn from these two studies, however, are difficult to interpret because they did not control for the fact that federal properties examined (under management of the National Park Service) apparently had more environmental resources to protect as well as other possible differences in unmeasured site-specific attributes.

Interviews with government and industry officials familiar with the Wyoming Checkerboard also suggest that drilling costs on federal land are higher than on private land. Factors identified in the two studies above were cited, although respondents tended to focus more heavily on differences in protection of cultural and biological resources. Regarding cultural resources, federal land managers are obligated under the Antiquities Act to identify and preserve Native American artifacts (i.e., arrowheads, pottery shards) and historic sites, such as those along the Oregon Trail. 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 that might be protected on federal property simply are never identified on private property. Also, federal land managers require greater precautions than private landowners to protect biological resources. Conflicts between endangered species protection, private property rights and economic activity are well-documented (Innes, Polasky, and Tschirhart 1998, Turner and Rylander 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 were examples cited in this regard.

Extra precautions taken on federal property translate into delays and added expense, but vary greatly from one location to another. McDonald (1994) has discussed delays in issuing 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 in which drilling can occur to as little as a few months per year. A narrow drilling window can be disruptive and lead to added costs. Moreover, if drilling is permitted only in winter, higher labor and equipment costs would be expected as crews must deal with subzero temperatures and windy conditions. Also, cultural and biological resources are not distributed evenly over space and federal land managers appear to have broad discretion in determining protection requirements.[5] Thus, additional costs of environmental compliance on federal land can vary considerably between locations. As a consequence, it is not possible to develop an estimate of the difference in drilling costs on federal versus private property that would be applicable at each location in the Checkerboard.

5.3 Oil and Gas Drilling Costs in the Wyoming Checkerboard

This section reports estimates of the extent to which drilling costs on federal property are higher than those on private property in the Wyoming checkerboard. Data are taken from two sources. First, the American Petroleum Institute (various years), through the Joint Association Survey on Drilling Costs, tabulates drilling cost data obtained from a survey of operators on each completed well drilled in the United States, including dry holes. The survey is conducted by mail and in 1996 had a response rate of over 41% (of total wells drilled), but operators who responded represented more than half of total drilling expenditures ($10.9 billion). Wells with unreported costs are assigned estimates from a statistical model fitted with the surveyed data (see, for example, the 1996 Joint Association Survey on Drilling Costs, Section 3 for model details). Types of costs reported for each well drilled include variable cost items such as labor, materials, supplies, machinery and tools, water, transportation, fuel, and power. Also, information about costs of direct overhead such as for permitting and site preparation, road building, drilling pit construction, erecting and dismantling derricks/drilling rigs, hauling and disposal of waste materials, and site restoration is obtained. Thus, the survey appears to include major elements of costs associated with environmental and land use regulation discussed in the previous subsection. Second, I.H.S. Energy Group, Inc. (dba Petroleum Information/Dwights LLC) compiles supplementary data on characteristics of all wells (e.g., depth, exploratory or development) completed each year in the U.S. I.H.S. adds the surveyed drilling costs to their data base by matching wells up by their state designated API identification number. Routinely, I.H.S. provides its data to industry (e.g., American Petroleum Institute) and government (e.g., U.S. Department of Energy, Energy Information Administration) users and has made specific data sorts available for the present study.

The entire data set available from I.H.S. contains information on more than 321,000 completed onshore wells drilled between 1987-98.[6] Characteristics measured for each well include drilling cost, depth (in feet), surface land ownership (private, federal, state, tribal, or land for which ownership is contested), well type (oil, gas, and dry) and well location (in latitude and longitude coordinates).[7] Thus, the complete data set has a large number of observations with information regarding each well drilled, but a disadvantage is that components of total cost are not individually itemized. Thus, the environmental compliance component of drilling cost cannot be identified and standard methods applied in the empirical cost function literature cannot be used to estimate a drilling cost function. Instead, the approach taken here is to characterize wells by depth, with controls for surface land ownership and well type, and then to recognize that well depth is produced by applying capital, labor, and other inputs subject to geological and technological constraints. For given geological and technological conditions, deeper wells require greater applications of productive inputs and at any particular location, total cost of a well is expected to increase (perhaps at an increasing rate) with depth.

As indicated in the introduction, data from the Wyoming Checkerboard are used to identify differences in drilling costs due to differences in environmental and land use regulations on federal and private land. This strategy is adopted because these cost differences cannot be directly measured and because the land ownership pattern in the Checkerboard provides natural control for four factors that would otherwise contaminate the resulting estimates: (1) remoteness, (2) environmental resources, (3) regional differences in attitudes toward resource development and (4) management. In general, federal land tends to be located at greater distances from cities and towns than rural private land and most tracts of federal land have been set aside for specific purposes (e.g., parks, forests, recreational areas) that rule out use for permanent settlements. Thus, drilling costs may be higher on federal land simply because it is less accessible to drilling contractors and well service firms. Also, there may be differences in the quantity of environmental resources to protect on federal versus private lands. Differences between scenic attributes of National Park and National Forest lands and rural private land may be most obvious, but less immediately noticeable ecological differences may be important, too. In fact, some federal lands have been set aside to protect specific unique or diverse environmental resources. Regarding management, the U.S. Department of Interior (National Park Service and Bureau of Land Management (BLM)) manages some federal lands, while the U.S. Department of Agriculture (National Forest Service) manages others so it is useful to control for possible policy differences between agencies. Finally, regional differences in regional attitudes toward resource development may affect decision making on both federal and private lands. Henderson (1996) recognized the possible importance of this aspect in a manufacturing context.

In the Checkerboard, the pattern of current land ownership is almost entirely determined by the land grant provided by the Pacific Railway Acts of 1862 and 1864. These acts predate broad scale environmental concern in the United States by as much as a century and predate even the first U.S. National Park (Yellowstone), which was established in 1872. In the past 135 years, certain sections have changed hands; for example, federal sections have been sold or traded for private sections to accommodate expansion of towns, to permit better access to water for agriculture, as well as for other purposes. In a few cases, the state of Wyoming traded land owned in other locations for federal sections in the Checkerboard. Also, the Union Pacific Railroad has sold sections to other private owners, mainly for use in agriculture. These land transactions, however, have not greatly disturbed the original alternating federal-private ownership pattern established by the Pacific Railway Acts. Figure 5.1 illustrates this point by depicting a 384 square-mile subsection of the Checkerboard surrounding the small town of

Wamsutter, Wyoming. This recent map designates federal land by the darker shaded sections and highlights 1987-1998 well location with white triangles. Notice the more pronounced federal land areas in the northeast along with the larger private ownership sections where the annotation 'Sweetwater County' appears. Areas of this type are not considered part of the Checkerboard in the econometric estimates described below. Although the map in Figure 5.1 does not show this, climate and topography of this area (and the total Checkerboard) are relatively homogeneous (high altitude desert). This feature, together with the prevailing land ownership pattern throughout, means that that remoteness and the quantity of surface environmental resources on each type of land in the checkerboard should be roughly equal. Moreover, BLM is responsible for all federal land there and the area is small enough that public attitudes toward development are unlikely to vary between locations.

Oil and gas drilling has been scattered throughout the Checkerboard over the period 1987-98, although there are specific areas that have received relatively more attention. In total, data are available on 1390 wells drilled there. Three BLM districts divide the area roughly into thirds; drilling in the Rawlins (easternmost) district represented 45% of the total, while drilling in the Rock Springs and Kemmerer (westernmost) districts represented 31% and 24% of the total, respectively. Thus, there has been a tendency in recent years for drilling intensity to be greater in the eastern portions of the Checkerboard. One reason for this outcome is that wells are deeper, and therefore more costly, in the west than in the east, with an average depth in the entire Checkerboard of 10,580 feet. In Wyoming, average well depth over the period 1987-98 was 6586 feet, and the average depth of onshore U.S. wells during this time was 4904 feet. Interestingly, 42% of Checkerboard wells were on federal land, 4% were on state land, and 54% were on private land. A higher proportion of drilling on private land would be expected if drilling costs on federal property are higher, or if delays in obtaining needed permits are longer. Most of the wells drilled (82%) found commercially valuable quantities of natural gas, 6% found oil and 12% were dry. The relatively low percentage of dry wells suggests that development wells outnumbered exploratory wells and reflects recent technological advances such as three-dimensional seismic reservoir identification methods.

Table 5.2 reports results from a nonlinear least squares regression of total real drilling cost (in \$million) on explanatory variables discussed previously. Definitions and means of explanatory variables also are shown. Nominal values of cost were converted to \$1992 using the GDP deflator. *FEET* was transformed using a Box and Cox (1964) transformation to account for an expected nonlinear relationship between well depth and cost. Location-specific effects are controlled using dummies indicating the BLM regional office territory (*RAWLINS, ROCK SPRINGS, KEMMERER*) in which the well was located. Time-specific effects were controlled using dummies for the year in which the well was drilled. Additional dummies indicated well type (*OIL, GAS, DRY*) and surface land ownership (*PRIVATE, STATE, FEDERAL*). Coefficients of all dummy variables are interpreted as dollar amounts. This specification is particularly appropriate for the surface land ownership indicators because more stringent application of environmental and land use regulation of federal property appear to have an additive rather than, for example, a proportional effect on drilling costs.

Estimates suggest that drilling costs increase at an increasing rate with well depth, as the coefficient of *FEET* is positive and the value of Box-Cox transformation parameter (*LAMBDA*) exceeds 2. Differences in cost between BLM regional office territories appear to be unimportant. Real drilling costs declined abruptly in 1992 and then remained permanently lower than in prior years, perhaps reflecting effects of technological advance. Gas wells tend to be more expensive than oil wells, while dry wells tend to be less expensive. This outcome would be expected because gas wells must be engineered to handle greater underground pressures than oil wells. Also, operators have an obvious incentive to give up when core samples suggest that further drilling will not yield a positive result. Finally, results indicate that drilling on federal land is significantly more expensive than on private land and that differences in cost between state land and private land are unimportant.

In light of effects controlled by the regression and by restricting attention to the Wyoming Checkerboard, the positive coefficient of *FEDERAL* is cautiously interpreted as the result of differences in stringency of application of environmental and land use regulations on federal and private property. Moreover, the coefficient estimate (0.111) suggests that the drilling cost premium on federal property is $111,000 per well. Evaluated at mean drilling costs for the Checkerboard between 1987-98 ($967,000/well), this premium represents a cost increase of nearly 12%. These estimates, however, are subject to at least four qualifications. First, unmeasured differences between federal and private property may remain in spite of the essentially randomized land ownership pattern created by the Pacific Railway Acts. Second, as previously discussed, environmental resources to protect in the Checkerboard vary greatly over space, so the estimates represent an average cost premium, rather than an extra cost applicable to all drilling sites on federal property. Third, a number of wells might be drilled in a particular lease area and operators may have difficulty in allocating fixed costs (including those associated with environmental compliance) between wells. This problem arises on both federal and private property, but is a factor that would reduce the precision of the estimates presented. Fourth, wells drilled in the Checkerboard tend to be deeper and more expensive than wells drilled in other locations in Wyoming and in other states. Thus, the cost premium estimated would represent a larger percentage increase in drilling costs in other locations.

5.4 Simulation Results

This section applies the model described in Chapter 3 to simulate removal of the more stringent environmental and land use regulations on federal property for oil and gas drilling and production in the state of Wyoming.[8] Simulations depicted in this section utilize the same baseline condition developed in Chapter 4 along with the following convenient re-derivation of equation (4.4)

$$a_D = \{(1 - t_e)(1 - t_{us})(1 - t_s)h\} \tag{5.1}$$

where t_e denotes the effective cost premium embedded in the surveyed drilling costs for wells on federal land.[9] In the base condtion, $t_e = 0$. Solution values reflect a situation where environmental regulations on federal and private property are equally stringent. In the case considered here t_e = (\$111,000 / (\$524,343 - (0.51×\$111,000)))0.051 = 0.12, where \$111,000 represents the incremental estimated cost of drilling a well (see Section 5.3), \$524,343 is the average cost of drilling a well in the state in 1997 (see Table 3.8), and 0.51 represents the fraction of wells drilled on federal property in 1997 (see Table

5.3). This calculation uses the average cost of drilling a well in Wyoming, which is about 54% of the cost of drilling a well in the Checkerboard and the estimated incremental cost of drilling on federal property in the Checkerboard is assumed to apply statewide. Also, the simulation accounts for the generous federal tax treatment of drilling costs. The, after-tax impact of a reduction in environmental regulatory costs is a little more than two-thirds of the pre-tax impact (i.e., $t_e(1 - t_{us})(1 - t_s)h = 0.12\times0.704 = 0.084$).

Results of the simulation are presented graphically in Figures WY8-WY10. Figure WY8 shows that removing the more stringent environmental regulations on federal property (dotted path) pertaining to drilling have the effect of increasing this activity overall and tilting it to the present. More specifically, setting $t_e = 0.12$ increases drilling by more than 9,000 wells (19.8%) over the 60-year simulation horizon. With increased drilling, additional new reserves are developed (see Figure WY10) and production declines less rapidly, as shown in Figure WY9. During the life of the program, eliminating the added environmental regulatory costs on federal property (dotted path) in Wyoming would appear to increase the volume of oil and gas extracted by about 387 million BOE (5.2%). These outcomes show that drilling is more sensitive than production to regulatory changes. In the case at hand, a reduction in environmental compliance costs increases incentives to drill, but in any given year the marginal product of drilling falls with the number of 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. Thus, production, which is driven by the size of the reserve base, changes by a smaller percentage than drilling activity during the program.

In any case, the permanently reduced output of oil and gas over the life of the extraction program has a variety of implications. For example, production tax revenue to the state varies with extraction rates, holding prices constant. Currently, Wyoming state and local governments levy production taxes with an effective ad valorem rate totaling approximately 12.0%. Applying this rate to the lost output valued at $19.22 per BOE and discounting at $r = 0.04$, yields an estimate of the present value of foregone tax revenue of $259 million. This figure represents a 3.5% reduction in the present value of state and local production taxes collected. Thus, it is easy to see why states with large amounts of federal property that rely heavily on mineral production tax revenue to finance public services frequently are opponents of more stringent environmental and land use regulation. More generally, oil and gas left in the ground because of the regulatory process represents a cost to society that must be balanced against the benefits resulting from enhanced environmental protection. An estimate of this cost, obtained by valuing the lost output each year using estimates of $l_1(t) = (p(t) - C_q(t))e^{-rt}$ (the discounted shadow price of the resource in the ground) from the simulation, comes to $968 million. This figure, of course, represents the value of lost output of oil and gas from the more stringent environmental and land use regulations prevailing on federal property. A corresponding calculation of lost output resulting from all environmental regulation of oil and gas activities on all types of property would be larger.

5.5 Conclusion

This chapter has presented a theoretical and empirical framework for analyzing the relationship between environmental and land use regulation, and exploration and production in the oil and gas industry. Effects of environmental regulations were obtained using observations on the cost of drilling oil and gas wells in the Wyoming Checkerboard. The main idea behind the investigation was to estimate the extent to which the more stringent environmental regulations prevailing on federal land lead to increased drilling cost. Higher costs indeed were found: These regulations add more than $100,000 to the cost of drilling a well of average depth, representing a substantial percentage increase in drilling cost.

Effects on exploration and extraction of these regulations were obtained by performing a simulation reflecting the removal of the federal cost premium. Wyoming was used for a case study in this regard because it has the greatest percentage of oil and gas drilling on federal property. An advantage of this approach is that effects of environmental and land use regulation can be measured in an appropriate theoretical framework that accounts for major features of the U.S. tax code facing oil and gas operators. The main findings from the simulations are if these regulations are maintained, future exploration for oil and gas in Wyoming will be nearly 20% lower and output of oil and gas will be as much as 5.2% lower. This reduced output represents a cost to U.S. residents that must be balanced against the benefits of the environmental regulations. Chapter 6 turns the attention of the study to coal.

ENDNOTES

[1]For a colorful account of this unusual land transaction and other inducements granted by the federal government to support construction of the transcontinental railroad through Wyoming, see Larson (1965).

[2]Detailed maps showing that the current ownership pattern of land around the Union Pacific railway line in southwestern Wyoming still resembles a checkerboard are available from the Wyoming Spatial Data and Visualization Center at http://wims.sdve.uwyo.edu.

[3]Deacon (1993) conducted related simulations to assess impacts of various types of taxes on drilling and production of oil, however, he did not consider effects of regulatory costs.

[4]The American Petroleum Institute, 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 1997, for example, API estimates that the exploration and production sector of the industry spent approximately $1.7 billion to protect the environment.

[5]This view is borne out by examining stipulations attached to Bureau of Land Management leases in the checkerboard and in other Wyoming locations. The so-called "stips" broadly indicate that required precautions in one location are unnecessary in others, but do not precisely indicate what mitigation efforts are necessary. Instead, leaseholders are required to develop mitigation plans for agency approval.

[6]Data for earlier years also are available, but measures of cost are not complete for all wells and the location of wells are missing or at least appear to be less precise than for 1987-98. See Table 5.3.

[7]Longitude and latitude coordinates provided are accurate to five decimal places and pinpoint each well to within one meter of its exact location.

[8]Simulations also were carried out for New Mexico using a counterpart cost premium estimate however these turned out to be quite similar to those for Wyoming and are not reported here.

[9]This formulation re-expresses effects of more stringent regulations as a proportional, rather than additive (see Section 5.3), cost increase to simplify both the presentation and simulations in this section. 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.

Table 5.1

Data on Drilling Rates: Selected States, 1996.

STATE	***TOTAL WELLS DRILLED***	***OIL AND GAS RESERVES (in quads of BTUS)***	***WELLS TO RESERVES RATIO***	***% WELLS DRILLED ON FEDERAL LAND***
Alaska	189	40.17	4.70	44.87[a]
California	1399	22.08	63.36	7.86
Kansas	1403	9.48	148.07	0.08
Louisiana	1289	13.66	94.40	0.06
New Mexico	1084	21.31	50.87	43.70
Oklahoma	2036	17.14	118.75	0.75
Texas	8258	72.73	113.55	0.16
Wyoming	615	16.20	37.96	50.85

[a] Federal, State, and Tribal land drilling comprise approximately 98% of Alaska's total activity.

Table 5.2

Cost Function For Oil and Gas
Drilling in the Wyoming Checkerboard[a]
(n=1390)

EXPLANATORY VARIABLE	***DEFINITION***	***MEAN***	***COEFFICIENT (t-STATISTIC)***
CONSTANT	---	---	0.330 (3.42)
FEET[b]	Depth of well in thousands of feet	10.58	0.320E-05 (21.12)
PRIVATE	=1 if well on private property; 0 otherwise	0.54	---[c]
FEDERAL	=1 if well on federal property; 0 otherwise	0.42	0.111 (4.630)
STATE	=1 if well on state property; 0 otherwise	0.04	0.055 (0.95)
OIL	=1 if well is an oil well; 0 otherwise	0.06	---[c]
GAS	=1 if well is a gas well; 0 otherwise	0.82	0.125 (2.37)
DRY	=1 if well is dry; 0 otherwise	0.12	-0.253 (-4.31)

Table 5.2
(Continued)

EXPLANATORY VARIABLE	***DEFINITION***	***MEAN***	***COEFFICIENT (t-STATISTIC)***
ROCK SPRINGS	=1 if well is in Rock Springs BLM District; 0 otherwise	0.31	---[c]
RAWLINS	=1 if well is in Rawlins BLM District; 0 otherwise	0.45	0.046 (1.46)
KEMMERER	=1 if well is in Kemmerer BLM District; 0 otherwise	0.24	0.027 (0.82)
1987	=1 if well was drilled in 1987; 0 otherwise	0.01	---[c]
1988	=1 if well was drilled in 1988; 0 otherwise	0.04	0.187 (1.75)
1989	=1 if well was drilled in 1989; 0 otherwise	0.04	0.173 (1.63)
1990	=1 if well was drilled in 1990; 0 otherwise	0.07	0.114 (1.11)
1991	=1 if well was drilled in 1991; 0 otherwise	0.06	0.246 (2.37)
1992	=1 if well was drilled in 1992; 0 otherwise	0.11	-0.067 (-0.67)

Table 5.2
(Continued)

EXPLANATORY VARIABLE	***DEFINITION***	***MEAN***	***COEFFICIENT (t-STATISTIC)***
1993	=1 if well was drilled in 1993; 0 otherwise	0.13	-0.036 (-0.36)
1994	=1 if well was drilled in 1994; 0 otherwise	0.11	-0.076 (-0.76)
1995	=1 if well was drilled in 1995; 0 otherwise	0.08	-0.124 (-1.21)
1996	=1 if well was drilled in 1996; 0 otherwise	0.10	-0.111 (-1.09)
1997	=1 if well was drilled in 1997; 0 otherwise	0.12	-0.049 (-0.48)
1998	=1 if well was drilled in 1998; 0 otherwise	0.13	0.07 (0.704)

[a] Dependent variable is total drilling cost in millions of $1992.

[b] The estimate of the Box-Cox transformation parameter applied to FEET was 5.514 (t-statistic = 209.85).

[c] Denotes omitted dummy variable.

Table 5.3

State Summary of Key Variables (Mean (STD), 1987 – 1998)[a]

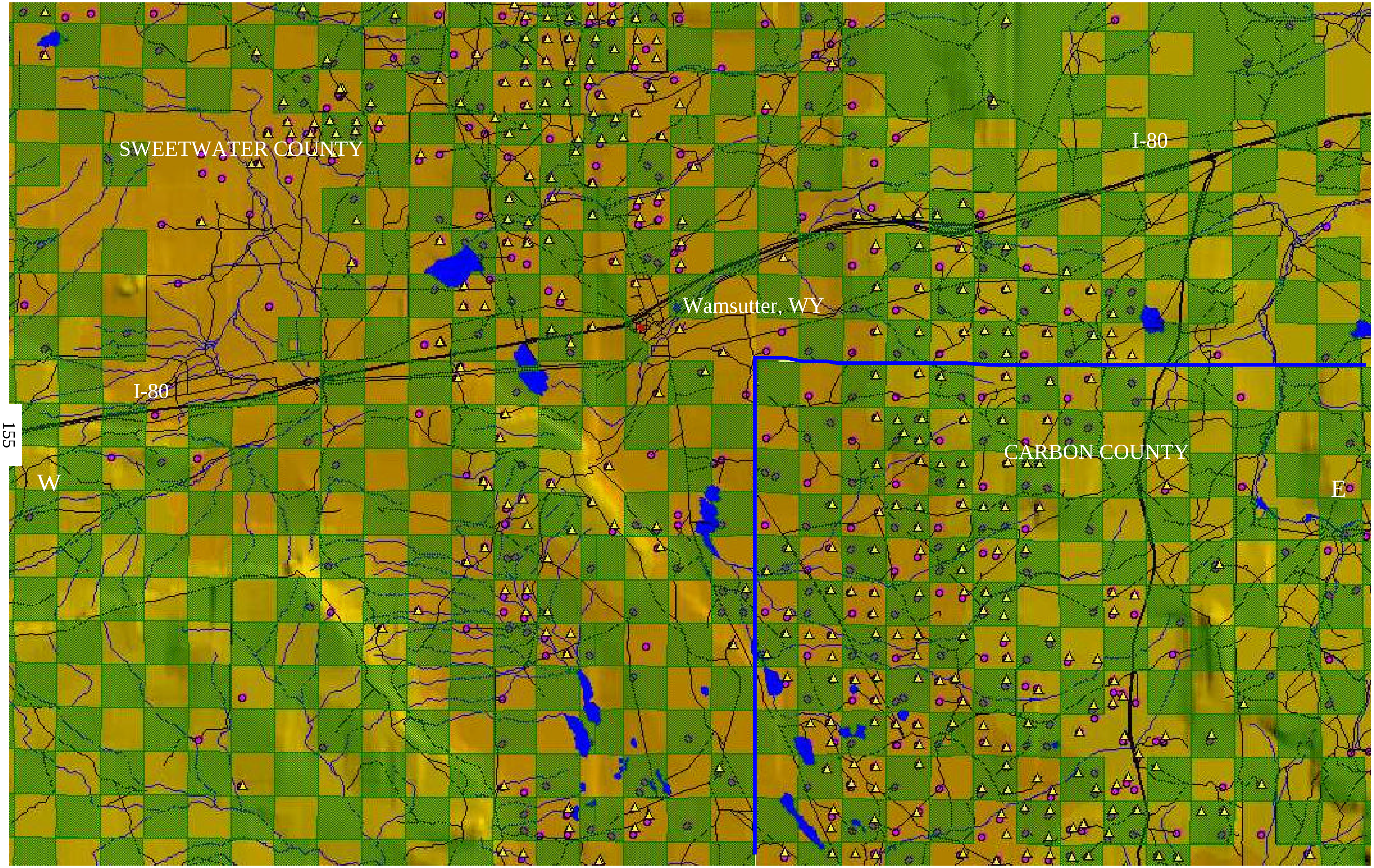
STATE	COST/FT[b]	AVE. DEPTH (in ft)	% FEDERAL[c]	% TOTAL WELLS[d]
Alaska	579.40 (450.30)	8692 (3680)	44.87 (17.18)	0.56
Alabama	71.37 (45.39)	7123 (5225)	0.75 (7.20)	1.71
Arkansas	49.53 (65.16)	4924 (2255)	1.57 (8.02)	1.03
Arizona	62.07 (19.93)	2959 (899)	4.17 (10.21)	0.01
California	82.94 (29.82)	5067 (2280)	7.86 (24.20)	6.14
Colorado	42.27 (22.58)	4933 (1966)	10.22 (23.54)	4.04
Florida	82.29 (56.11)	13250 (3672)	11.54 (32.58)	0.02
Georgia	29.11 (3.87)	3100 (1019)	0.00 (0.00)	e
Iowa	27.86 (24.38)	1925 (949)	0.00 (0.00)	e
Idaho	226.90 (67.31)	8736 (10560)	100.00 (0.00)	e
Illinois	27.49 (10.66)	1952 (1203)	0.56 (6.34)	2.27
Indiana	30.50 (25.55)	1422 (715)	2.18 (13.48)	0.58
Kansas	25.87 (8.46)	3180 (1474)	0.08 (.72)	8.18
Kentucky	31.09 (14.31)	1809 (1093)	0.04 (.63)	3.79
Louisiana	90.82 (63.33)	7984 (3475)	0.06 (.75)	4.48
Michigan	75.27 (45.15)	3989 (2493)	6.08 (21.29)	2.79
Mississippi	68.43 (57.64)	9249 (3945)	2.64 (12.22)	0.83
Montana	48.37 (20.62)	4629 (2858)	16.45 (28.26)	1.06
N. Dakota	56.99 (27.91)	7996 (2556)	11.17 (23.47)	0.78
Nebraska	21.89 (10.43)	4609 (1290)	0.35 (2.16)	0.36
New Mexico	70.50 (38.22)	4617 (2573)	43.70 (35.05)	4.05
Nevada	81.28 (48.88)	5556 (2278)	71.67 (35.30)	0.08

Table 5.3
(Continued)

STATE	***COST/FT***[b]	***AVE. DEPTH (in ft)***	***% FEDERAL***[c]	***% TOTAL WELLS***[d]
New York	35.72 (8.54)	2983 (1537)	0.00 (0.00)	0.46
Ohio	29.70 (6.34)	3662 (1478)	0.12 (1.31)	3.89
Oklahoma	52.24 (25.89)	5355 (3215)	0.75 (3.99)	9.24
Oregon	57.13 (23.49)	2353 (305)	0.00 (0.00)	0.02
Pennsylvania	36.57 (23.63)	4049 (1679)	1.07 (6.66)	3.37
S. Dakota	72.96 (115.0)	4358 (2360)	35.65 (38.16)	0.05
Tennessee	31.94 (9.52)	2031 (693)	0.00 (0.00)	0.32
Texas	59.22 (33.40)	5862 (2532)	0.15 (2.08)	33.07
Utah	107.50 (75.64)	5633 (3429)	59.57 (32.84)	0.87
Virginia	36.17 (5.99)	3565 (1279)	1.75 (13.25)	0.40
W. Virginia	35.85 (8.84)	4164 (1280)	0.29 (2.52)	2.61
Wyoming	69.46 (36.62)	6586 (2837)	50.85 (26.80)	2.94
Total Sample	55.74 (73.44)	4904 (3156)	5.21 (18.92)	321,370 Total Wells

[a] State summaries aggregated on county-level averages.
[b] Surveyed drilling cost per foot in 1992 dollars.
[c] Percentage share of total wells drilled in a state on federal lands.
[d] Percentage share of total wells drilled in a state within the sample.
[e] Small share not reported.

Figure 5.1 Checkerboard Map



Darker Sections - BLM Land, Triangles - New Wells Drilled Post 1987, Dark Dots - Existing Wells

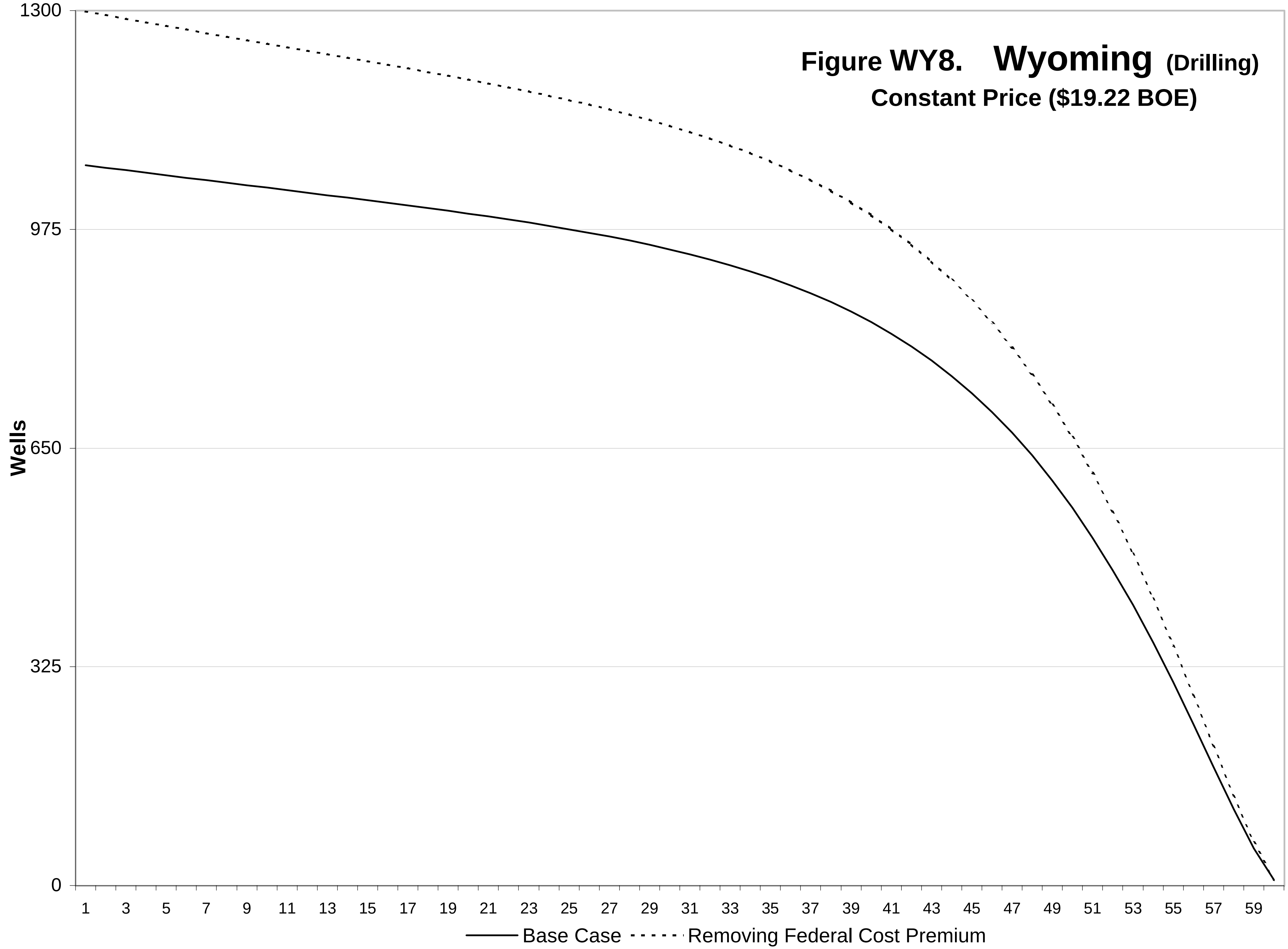


Figure WY8. Wyoming (Drilling)
Constant Price ($19.22 BOE)
Wells
1300
975
650
325
0
1
3
5
7
9
11
13
15
17
19
21
23
25
27
29
31
33
35
37
39
41
43
45
47
49
51
53
55
57
59
Base Case
Removing Federal Cost Premium

Figure WY9. Wyoming (Production)

Constant Price ($19.22 BOE)

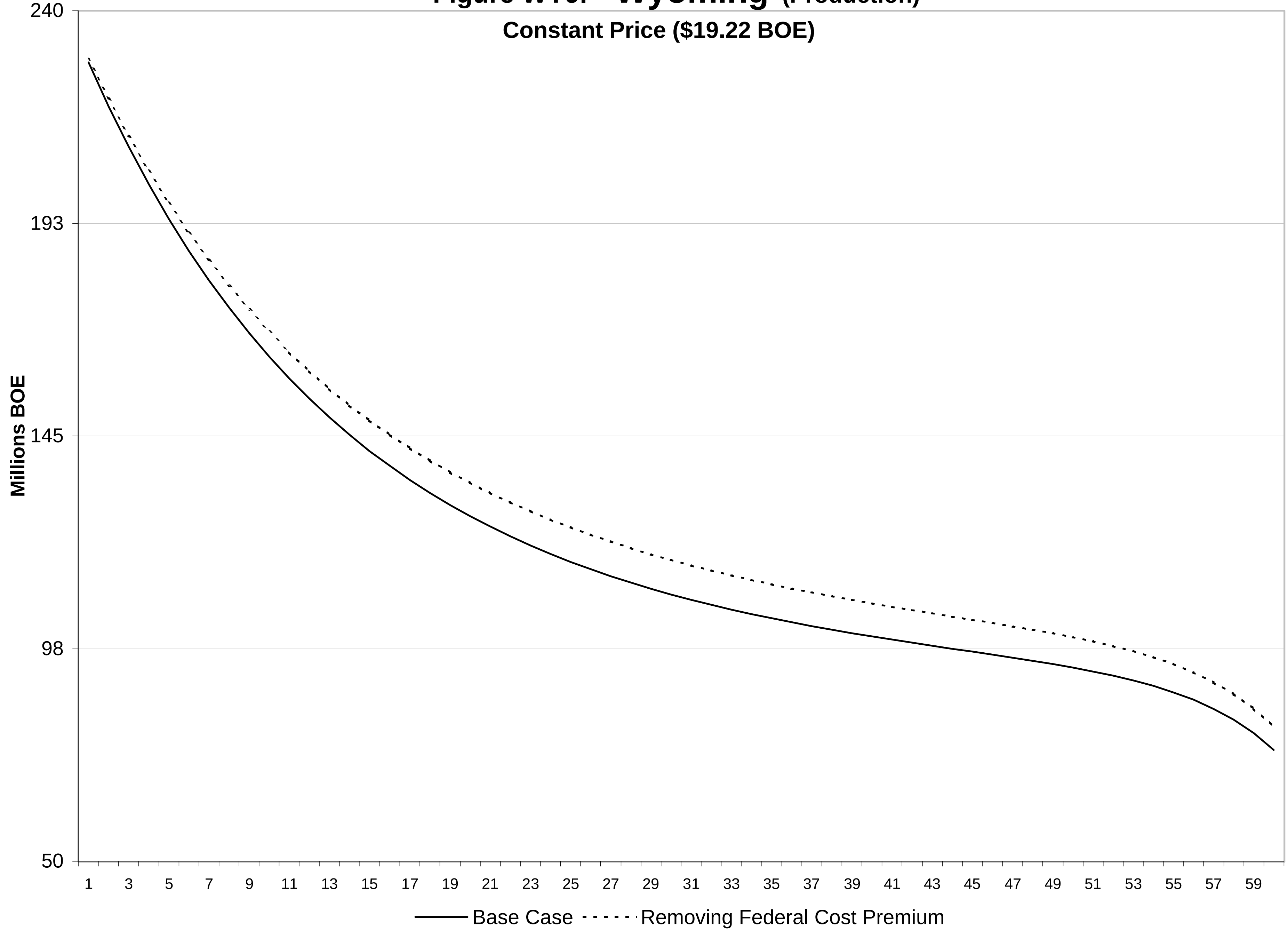
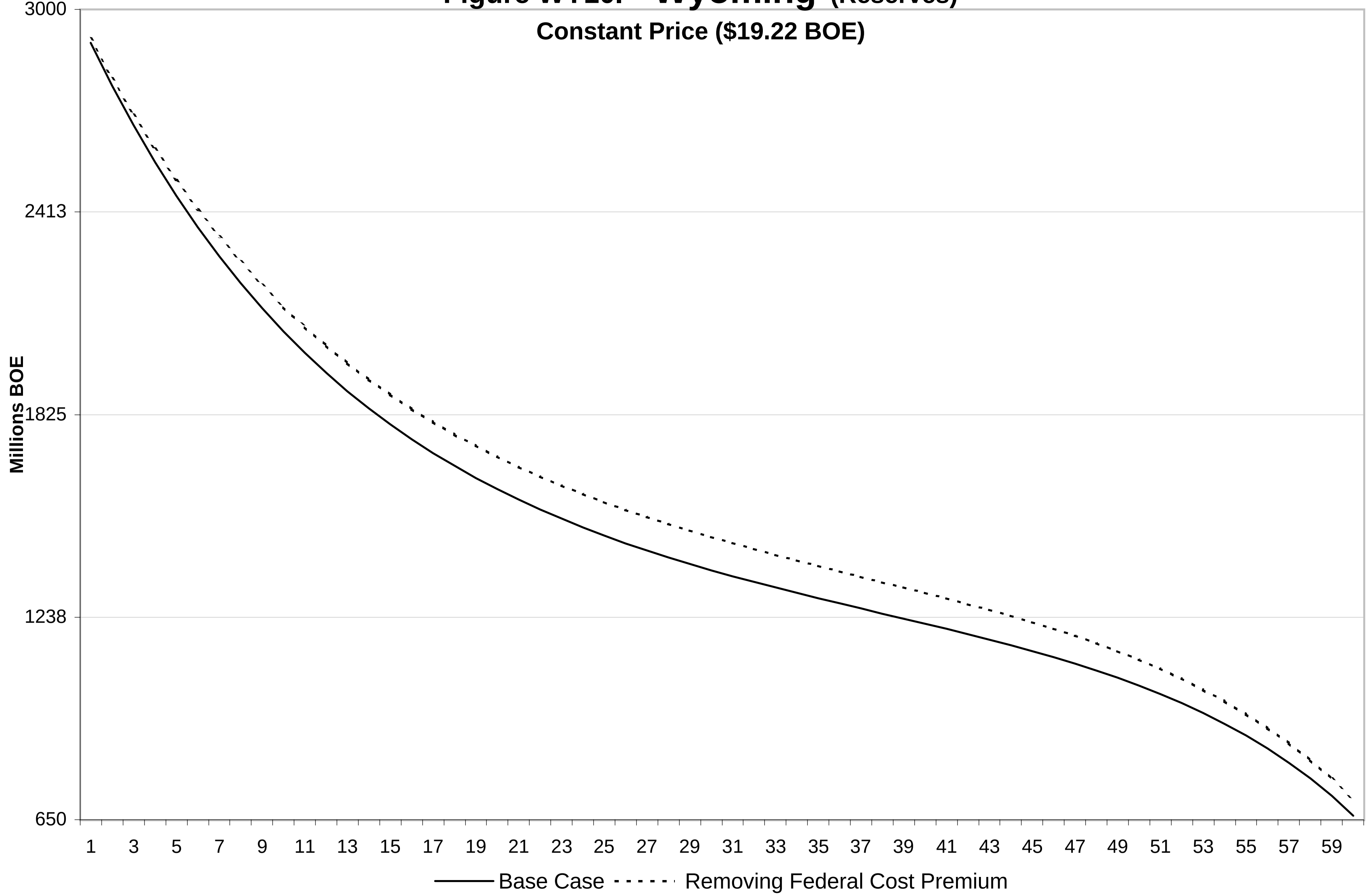


Figure WY10. Wyoming (Reserves)

Constant Price ($19.22 BOE)



CHAPTER 6

THE WYOMING COAL MARKET

6.1 Introduction

Major changes have occurred in energy markets since the early 1970's. Many of these changes have affected the market for Wyoming coal. The next decade promises to bring forth further developments influencing the Wyoming coal industry. These developments will, in turn, influence Wyoming's economy, employment, and environment. The purpose of this part of the overall study is to develop an understanding of the market for Wyoming coal, so that the effect of various tax incentives and environmental regulations on Wyoming's coal production can be analyzed. This chapter introduces and discusses salient aspects of the Wyoming coal market, both with regard to changes that have occurred since the 1970's and expected future developments. Section 6.2 focuses on the changes in the Wyoming coal industry, particularly in the last two decades. Section 6.3 shifts the attention to the railroads and describes key coal transportation cost issues. Section 6.4 looks at electric utility fuel buying strategies, the types of new contracts involved and potential new markets affecting Wyoming coal demand. Sections 6.5 and 6.6 overview some of the many institutional aspects of environmental and tax policy. Chapter 7, then, presents a theoretical model of the interactions between the major players in the Wyoming coal market - coal producers, railroads, and electric power plants. Key model equations are econometrically estimated and numerical solutions to specific tax rate changes are presented. Finally, chapter 8 presents and estimates an *initial* model of changes in Wyoming coal demand in response to sulfur dioxide regulation under the 1990 Clean Air Act Amendments.

6.2 Change in the Wyoming Coal Industry

Recently, important changes affecting the Wyoming coal industry have occurred. Many of these (and perhaps others) will continue unfolding in the near future. Outlining these changes helps us to be aware of important factors to be considered in making predictions about the behavior of Wyoming coal buyers, sellers, and transporters. The Wyoming coal industry is intricately tied to the electricity industry, since 1997, 97 percent of Wyoming coal is used for steam electric power generation. The dependence on electricity also links Wyoming coal to the oil and gas industry (because these fuels can be substituted for coal), to the railroads (because most electric utility customers are located far from Wyoming mines and rail shipment is predominant), and to environmental regulations affecting electric utilities.

The most evident change in the Wyoming coal industry is its growth. Wyoming's coal production has grown from 7 million tons in 1970 to nearly 336 million tons in 1999 (Coal Industry Annual, EIA/DOE). Most of this growth has occurred in the Powder River Basin (PRB). Between 1988 and 1999, PRB coal production has nearly doubled, increasing from 162 to approximately 319 million tons. Accompanying this rapid growth has been an increasing dominance of PRB coal in the national coal market. While the share of the nation's coal from Appalachia and the Midwest has fallen since 1988, production in Wyoming has grown from 17 percent of national production to around 28 percent currently. In contrast, Montana, has shown little growth in its coal production, from 38 million tons in 1988 to approximately 43 million in 1999 (see Figure 6.1). Earlier studies (e.g., Kolstad and Wolak, 1983) portrayed Montana as Wyoming's major western coal competitor. However, the proprietary mine cost data made available for this study suggests otherwise. Specifically, coal production costs are significantly lower at the mines in the Wyoming PRB and a substantial share of Montana coal is sold to power plants near the mines (captive mines). Conversely, Wyoming coal has experienced increased competition from producers in other western states, notably Colorado and Utah, whose combined output has increased by 59 percent, from 3.6 percent of national production to 4.9 percent (EIA/DOE).

As production has risen, coal prices have fallen. Declining coal prices are related to improvements in coal mining technology, changes in the prices of other fuels, changes in the structure of coal contracts with electric utilities, and increases in competition both within and outside the coal industry, especially rail transportation. At the mine-mouth level, the average price of Wyoming coal has fallen by over 50 percent since the mid-1980's (see Figure 6.2). Moreover, as shown in Table 6.1, the decline in prices is concurrent with falling coal prices from other states and nationally, but the Wyoming decline is the largest. In 1985, only 5 percent of Wyoming coal sold for $5.00/ton or less at the mine mouth; by 1997 nearly 75 percent sold at this low price and nearly 100 percent will sell at below $5.00 by 2002 (Wyoming Coal Information Committee, 1998)

Of course, the price of coal per ton will vary with the characteristics of that coal. Currently, the two most important characteristics are heat and sulfur content. Heat content is measured in BTU/lb. Sulfur content is measured as a percentage of weight. Generally, prices for PRB coal are lower because of its low heat content (ranging 8000-9000 BTU/lb) and higher due to its low sulfur (SO2) content. Coal from other western states tends to have higher heat content and higher sulfur content. Table 6.2 shows that the mine-mouth prices of coal from Wyoming and its major western competitor states reflect these coal characteristics.

Coal prices at the mine-mouth are most relevant for taxation purposes because Wyoming coal severance taxes are based on the FOB prices that coal producers receive. However, the most relevant price for Wyoming coal buyers is the delivered price of coal. The difference between the mine-mouth price and delivered price to an electric utility is the price of transportation. Delivered prices have not fallen as much as FOB prices. This is evident from Table 6.3, which shows the average delivered price of coal to electric utilities in the various regions where Wyoming coal is sold. For example, the average delivered price of coal to Wyoming coal's largest customers in the West South Central Region (Arkansas, Louisiana, Oklahoma and Texas) has fallen by less than 15 percent since 1988, much less than FOB prices have fallen.

6.3 Transportation Costs

For utility buyers, the salient price in their fuel supply decisions is the delivered price of Wyoming coal. The difference between the FOB price of coal and its delivered price is the price of rail transportation. For Wyoming coal, it is not unusual for transportation costs to comprise 70 percent or more of the delivered price. Table 6.4 presents an analysis of the rail rate to delivered price ratio for the years 1988, 1993, and 1998. Notice how rail rates comprise a larger percentage of the Wyoming delivered price in 1998 versus 1988. Previous research has suggested that the railroads servicing Wyoming coal customers may charge prices that exceed those of a competitive market (Atkinson and Kerkvliet, 1986). However, since this research was done, important changes have occurred. Rail rates have fallen considerably and an additional railroad now provides service to part of the PRB. Conversely, railroad mergers have occurred and the 1980 Staggers Act has largely freed railroads from price regulation.

Only two railroads serve the PRB and other Wyoming coal basins are served by a single railroad. The possibility of non-competitive rail rates for PRB and other coal has been the subject of continual concern and some research (e.g., Stagg Engineering Services, Inc., 1996; Interim Report on Coal Transportation, EIA/DOE, 1995). The EIA reports that the U.S. average transportation costs for contract coal fell 19 percent between 1988 and 1993, while the typical distance coal is shipped has increased. The average transportation rate for coal from the Western coal supply region (including Wyoming) to plants located in the Midwest fell from 18.2 mills per ton mile in 1979 to 17.2 mills in 1986 to 9.5 mills in 1993. For plants located in the South, the corresponding rates are 16.5, 17.4, and 11.4 (EIA/DOE, 1995). The EIA concludes that falling rail rates have resulted from technological and organizational advancements and from increasing competition in fuel and transportation markets. Conversely, a report prepared for the Montana Governor's office (Stagg Engineering, 1996) is not so sanguine. This report suggests that rail rates out of the northern PRB may be non-competitive and that the single railroad serving the Northern PRB is likely to exercise considerable economic power.

6.4 Utility Demand and Fuel Strategies

Electric utilities employ a variety of strategies in order to meet their goals of minimizing fuel costs. Utilities will generally take advantage of all market opportunities in order to reduce the risk of fuel supply disruptions and will attempt to mitigate the ability of few suppliers to charge higher prices. Utilities are now, more than ever, aggressively managing their fuel supply arrangements. One way this management is manifest is in the pursuit of a portfolio of fuel suppliers. These portfolios manage risk by obtaining coal from a variety of coal suppliers and producers of different types of fuels (e.g., oil and gas). Coal supply variety may be in the dimensions of regions, coal BTU content, coal impurities content, and the railroads transporting the coal.

Current portfolios are in sharp contrast with the behavior of many Wyoming coal customers in the 1980’s. In the past, most power plants depended on one or two Wyoming mines for 80-95 percent of their fuel supplies (Atkinson and Kerkvliet, 1989). Three anecdotal examples of current diversification behavior tend to reflect the new point of view: 1) Alabama Power has new supply arrangements with four suppliers, one each from Virginia, southern Illinois, Kentucky and Venezuela (Coal Week, Jan 5, 1998); 2) San Antonio (TX) City Public Service Board, a long-time PRB coal customer, is considering purchasing coal from two Colombian mines. This is in response to slower than desirable delivery times from PRB suppliers (Coal Week, Jan 19, 1998); and, 3) In January 1998, Springfield (MO) City Utilities announced an agreement with ARCO to supply 1.1 million tons per year until 2001. Coal from the PRB will be mixed with coal from the utility’s long-standing suppliers from other regions (Coal Week, January 12, 1998). This type of fuel portfolio diversification is expected to intensify in this decade.

6.4.a Spot Markets

In the 1970's and 1980's, nearly all sales of Wyoming coal were conducted under the terms of long-term contracts. These contracts ranged from 5 to 50 years duration and contracts signed with PRB mines in 1980 averaged 18 years in duration. By 1984 new contracts averaged only 4 years in duration and the 1990’s saw even further declines in duration (Kerkvliet and Shogren, 1998). In the 1990's one-time (spot) sales are now an important component of the coal market, comprising approximately 20 percent of total sales in 1998 (FERC Form 423, Wyoming Coal Information Committee, 1998). Some spot market sales are made to utilities who are not traditional Wyoming coal customers, but many are made to customers who also hold long term contracts with Wyoming coal mines. These customers are taking advantage of lower spot market prices to reduce their fuel costs. For example, the Jim Bridger plant in Wyoming is located near a coal mine, but it also purchases spot market coal from more distant Wyoming mines. It is possible that spot market sales are more sensitive to price, than contract sales, and less sensitive to coal characteristics. The prices for spot market Wyoming coal are consistently lower than prices for coal sold under long-term contract. In 1998, spot market Wyoming coal prices averaged $1.09/ MMBTUs (Millions of BTU's) while long-term contract prices averaged $1.19 (FERC Form 423).

6.4.b Contracts

Most contracts with PRB suppliers were initially signed in the mid to late 1970's. Many of these contracts had durations of around 20 years so they are, or soon will be, expired. In addition, some customers have chosen to breach or renegotiate old contracts, often replacing them with agreements of shorter duration. This trend mirrors the national trend, where the percentage of coal tonnage sold under contracts of 10 years or less duration has increased from 22 percent in 1979 to 34 percent in 1993 (The U.S. Coal Industry in the 1990's, EIA/DOE, 1999). With contract expiration, utilities are looking at new coal supply options, including other PRB suppliers, suppliers from regions other than the PRB, and alternative fuel suppliers.

Two examples illustrate this phenomenon. Omaha Public Power's (OPP) contract with the PRB's Caballo mine expired in 1999. In 1998, OPP solicited bids to conduct test burns of 2-3 different PRB coals (Coal Week, March 9, 1998). Secondly, when Hastings Utility's contract with Peabody/Caballo expired in 1998, it sought bids from alternative suppliers with coal specifications not especially well suited to the PRB (Coal Week, May 4, 1998).

6.4.c New Markets

In the 1980's, the flexibility of coal purchasers to seek alternative or multiple suppliers of coal was somewhat constrained by the heterogeneity of coal and the sensitivity of power plant efficiency to differences in coal characteristics. Utility boilers are commonly designed to burn coal of a specific grade and chemical composition. Because PRB coals differ substantially in SO2, ash, moisture content, levels of trace elements, and ash fusion temperatures, the use of an alternative coal involved costly retrofitting, deterioration of boiler performance, and may have been just technically impossible. However, with recent technology and fuel prices differing enough, utilities are demonstrating a willingness to experiment with coal switching and/or blending. What was once a long-term question has now shifted to an intermediate term reality.

The boilers for steam-electric generation are idiosyncratic in that a boiler will perform differently depending on the type of coal it is fed. When utilities contemplate changes in their fuel supply arrangements for an existing plant, a common method is to conduct test burns. A trainload or so of coal (10,000 tons) is ordered from a particular supplier. The coal is burned and the performance of the boiler is evaluated. This information is then used, in conjunction with price, contract terms, and portfolio considerations, to decide on fuel supply arrangements. Between 1989 and 1995, utilities test burned western (Wyoming, Montana, Colorado and Utah) coal in 34 generating units (Coal Outlook Supplement, December 5, 1995). In some cases these experiments have resulted in new Wyoming coal customers (Ellerman, et al., 1997).

In the last decade, PRB coal has successfully penetrated into geographic regions where no sales were made in the 1970's and 1980's. This market penetration often involves large contracts of long duration and follows a period of test burns, bid solicitation, and/or spot market purchases of PRB coal. Sales to these new markets have increased from 730,000 tons/year in 1989 to 14,100,000 tons/year in 1995 (Coal Outlook, Supplement, December 4, 1995). Table 6.5 details power plant purchasers of Wyoming coal in 1997. First time 1997 purchases of Wyoming coal penetrated new markets in Arizona, North Carolina, Georgia, and even Los Angeles.

6.5 Environmental Issues

Since the 1970 Clean Air Act, the coal market has been strongly impacted by environmental regulation. Beginning with the 1972 Clean Air Act Amendments (CAAA), utilities have been subject to a variety of command-and-control regulations including the kind of technology to use (usually flue gas desulfurization equipment, or scrubbers) and/or the requirement to reduce sulfur dioxide (S02) emissions to 1.2 lbs of sulfur per MM BTUs of fuel burned (see Forster, 1993). The latter requirement favored low sulfur coal from the PRB and other regions, while the scrubbing requirement favored high sulfur coal producers, largely in the Midwest.

With the 1990 CAAA, utilities face a new set of decisions regarding environmental regulation (see Schmalensee, et al. 1998). The Acid Rain Program (Title

IV) of the 1990 CAAA initiated Phase I. Here, utilities with 445 boilers, all west of the Mississippi, were provided with initial allocations of permits to emit S02. For these Phase I boilers, each ton of S02 emitted requires that the emitting utility provide the EPA with a permit. The permits are tradable; that is they can be bought and sold. This new method of tradable permits allows utilities to decide how to best meet the restriction that emitted tons of S02 be matched with an equal number of permits. The utility can pursue one of three strategies, or combinations thereof. First, it can use the permits it is allocated by the EPA and perhaps purchase some more to match its S02 emissions. Second, it can install flue gas desulfurization (FGD) equipment to reduce its S02 emissions by 60-95 percent. Third, it can reduce its S02 emissions by purchasing coal or other fuels that are low in sulfur. With the second and third strategies, the utility is free to sell its unused permits. S02 permit markets are now fully operational (Joskow, et al., 1998). In 1991 permit prices were about $300. Since then the price has fluctuated from a low of $70 in March 1996 to $220 in December 1998 (Environmental Protection Agency, 1999).

Phase II of the 1990 CAAA began this year, 2000. In Phase II, over 2000 boilers, owned by nearly all utilities in the country will face the similar, but tighter, S02 regulations compared to Phase I (Solomon, 1999). Phase II regulations are tighter because the initial permit allocations will be reduced by about 50 percent. Relative costs will determine which strategy, or combination or strategies, utilities will choose to comply with 1990 CAAA. Collectively, these decisions have had and will have an impact on the market for Wyoming coal, as some utilities may chose to purchase low-sulfur PRB coal, and thereby decrease the number of permits they would have to purchase, increase the number of permits available for sale, or avoid the costs of installing scrubbing equipment.

The effect of the 1990 CAAA on Wyoming coal sales will likely depend on the price of S02 permits. It is likely that higher permit prices will favor Wyoming coal since a lower price makes it more likely that burning low sulfur PRB coal will be less expensive than burning higher sulfur coal and purchasing permits. However, low sulfur coal is also available from other regions, and some utilities have pursued this fuel switching strategy by purchasing coal from these other regions, including Central Appalachia, Colorado, and Utah (EIA/DOE, 1997). Indeed, Ellerman, et al. (1997) report that 24 percent of the observed Phase I reductions in S02 emissions came from utilities switching from high sulfur lower sulfur coal from these later regions, while 13 percent of the SO2 reduction came from switching to PRB coal.

The strategies chosen by utilities to comply with 1990 CAAA are further complicated in two ways. First, utilities are able to either use their allocated or purchased permits in the current year to offset current SO2 emissions, or they may save these permits for use in future years. This so-called "banking" has proven to be popular with utilities and accounts for some of the over-compliance with emissions levels on the part of some utilities (Solomon, 1999). Second, the means by which utilities in various states are regulated may influence utilities' compliance strategy choices. Some states (notably Illinois and Indiana) have attempted to force utilities to use locally produced high sulfur coal rather than switch to low sulfur coal from outside the state. Other state regulatory authorities differ in the way they allow utilities to treat the costs or revenues resulting from buying or selling permits (see, for example, Winebrake, et al., 1995).

The following decisions of various utilities, to date, help to reveal the beginning of an interesting, but complex story. American Electric Power is likely to install a scrubber on its 630 MW Kammer plant. A major reason listed for this choice is the market for by-products that can be produced with a scrubber, namely gypsum and/or ammonia-based fertilizers (Coal Outlook, July 3, 1995). Pennsylvania Power and Light weighed fuel switching options against the cost of scrubbing two units of its Montour plant. In doing so, it tested about 250,000 tons of low-sulfur coals in 1995, some from as far away as Utah (Coal Outlook, July 3, 1995). Tampa Electric Company has announced its intention of installing scrubbers on the two plants of its Big Bend Generating Station. The cost of scrubber installation is estimated to be $90 million (Coal Week, June 22, 1998, v. 24, n. 25). Pennsylvania Power and Light tested coal from Utah in its Brunner Island plant. It is likely that the fuel switching strategy will be used for this plant, with coal obtained from Central Appalachia and the PRB (Coal Outlook, December 11, 1995).

Table 6.5 indicates the power plants purchasing Wyoming coal that are under Phase I regulation. For the most part, these plants were purchasing Wyoming coal before 1995. However, five of these Phase I plants (Cardinal, Bailey, Tanners Creek, Wansley, and Kincaid) commenced Wyoming coal purchases in 1995 or later. Whether Phase I regulations were decisive in these decisions is not transparent. Between 1993 and 1995, PRB coal deliveries to Phase I plants increased from 43.7 to 73.3 million tons (FERC Form 423). However, how much of this increase can be attributed to the 1990 CAAA is uncertain, since some may have resulted from declining PRB delivered coal prices and the expiration of utilities coal contracts with Midwestern producers (Ellerman, et al., 1997). Sales from 1993-1995 of low sulfur coal from other low sulfur coal producing areas (Utah, Colorado, and Central Appalachia) also increased, by about 11 million tons

(Ellerman, et al. 1997).

6.6 Taxes

Coal taxes are important because these proceeds provide substantial revenue to Wyoming government at the state and local level. As they also affect prices, taxes may be a determinant of the level and location of Wyoming coal production and sales. Wyoming coal competes for customers with coal from other states, so differences between Wyoming coal taxes and taxes in other states may also be important.

All coal produced in the U.S. is assessed Black Lung taxes on a tonnage basis. In addition, all coal produced from federal leases is assessed a 12.5 percent federal royalty tax, half of which is returned to the mining state. Wyoming levies several taxes on coal, beginning with a state severance tax at the surface mine-mouth of 7 percent of the FOB price. Other state taxes, including ad valorem, sales and use, state royalties, and other state and local taxes, combined approximately equal the severance tax in percentage terms (Wyoming Coal Information Committee, 1998). In addition, many mines have paid substantial bonus bids for several key federal leases. In the Wyoming 2000 legislative session, WS 39 Chapter 20 creates an excise tax on commercial transportation of coal, produced in Wyoming, levied at the rate of 0.0001 for each ton transported per mile *in* the state. An estimate of the effective per ton rate can be constructed by calculating a weighted average rail mile trip in the state. According to the 1998 Surface Transportation Board Carload Waybill Sample, approximately 38 percent of Wyoming (Powder River Basin) coal rail shipments were outbound north/east at an average distance of 109 miles. The balance of the sampled shipments headed south/southeast at an average distance of 338 miles. This data yields a weighted average trip of approximately 250 miles or a per ton rate of 0.025.

Wyoming coal taxes constitute about 37 percent of the FOB coal price, but the percentage of the delivered price is much smaller (Wyoming Coal Information Committee, 1998). For illustration, consider the average FOB price of coal in 1997, \$5.83/ST (1993 dollars), or about \$0.34/MMBTU. Of this price, about 37 percent, or \$0.126/MMBTU is made up of coal taxes. However, coal taxes account for about 11 percent of the average 1997 delivered coal price of \$1.17/MMBTU. The reason for the difference is the high percentage of the delivered price that is composed of transportation changes. The difference will be smaller, and the percentage of the delivered price attributable to coal taxes larger, for nearby coal customers in and near Wyoming.

Montana's tax structure affecting coal is quite different. In addition to federal taxes and royalties (and their tribal equivalents), the effective state severance tax rate in Montana is about 10 percent of the FOB price for surface and 3 percent for underground coal. In addition, Montana levies a gross proceeds tax of about 3.3 percent of FOB price and a Resource Indemnity and Ground Water Assessment tax of .25 percent. Also, Montana recently increased its property tax on railroad cars. The effect of this tax was to increase tax levies on coal shippers by as much as 250 percent (Stagg Engineering, 1996). In addition, Montana levies general property taxes on the market value of real property. The translation of the two latter taxes into percentages of FOB or delivered price is not clear, but it appears that overall, Montana coal taxes are 3-5 percent of FOB price higher than Wyoming's coal taxes (Stagg Engineering, 1996).

The state of Colorado assesses a \$0.65/ton severance on coal, after exempting the first 25,000 tons produced by each mine in each quarter (Santos, 2000). In addition, Colorado assesses property taxes and state royalty fees, while coal produced from federal leases pay federal royalties. Overall, Colorado coal was taxed at a rate of $2.63/ton or about 14 percent of the average FOB price of Colorado coal. For an average Colorado coal heat content of 11,300 BTU/lb, this translates into taxes of about $0.11-0.12 per MMBTU, or about the same level of taxation for Wyoming coal.

6.6.a Changing Taxes

There are two critical elements wrought by tax changes. The first is the responsiveness the quantity of Wyoming coal demanded to changes in the delivered price of coal. The second is the effect of tax changes on the prices paid by purchasers and received by coal suppliers. Combined, these effects are termed tax incidence. Tax incidence will depend on the responsiveness of coal demand to price changes and the effect of changing output on the costs incurred by Wyoming mines and coal-hauling railroads.

Although a tax may be placed on Wyoming coal at the mine mouth or on the transportation of Wyoming coal, the price paid by coal buyers may reflect none, a portion, or all of the tax, depending on tax incidence. Morgan and Mutti (1981) and Mutti and Morgan (1983) show that tax incidence depends on the cost structures of mines and railroads, on coal buyers' demand characteristics, and on the degree to which suppliers exercise market power by adjusting their prices in response to tax changes. Forward shifting, that is tax increases resulting in some increase in the price paid by plants, is facilitated by two quite different conditions. First, taxes will be more completely forward shifted the more that mines and railroads have marginal costs that vary little over a wide range of output. Similarly, taxes will be more fully forward shifted the less responsive quantity demanded is to price changes. The second condition making forward shifting more likely is the exercise of market power by mines and/or railroads. The more suppliers are able to set prices, the more complete will be tax forward shifting. Forward shifting is also enhanced by unresponsive demand and a greater dominance of Wyoming coal in individual fuel markets (Morgan and Mutti, 1981).

Morgan and Mutti identify four factors that increase the possibility that coal taxes will be forward shifted through the exercise of market power. First, coal's heterogeneity limits buyers' flexibility to buy coal of a different chemical composition. Second, high transportation costs may segment national markets into regional markets. Third, long term contracts may require buyers to purchase fixed quantities of coal, with price increases sometimes passed forward to electricity buyers. Fourth, railroads may possess market power because they are monopoly or duopoly sellers in all Wyoming coal basins. As such, railroads may price discriminate and charge higher prices to customers with less price responsive demands. In addition, if taxing authorities, mines, and railroads possess market power, each may react to the others' price and tax changes by raising or lowering their own prices (Mutti and Morgan, 1983).

The opposite of forward shifting is backward tax shifting, where tax changes are reflected in changes in the prices received by mines and railroads and in the resulting changes in the quantity of coal produced and transported. Marginal costs that increase with output and/or inputs that are fixed in quantity are the conditions for backward incidence. In the long run, taxes will be completely backward shifted and reflected in lower payments to suppliers of fixed inputs. At present, these suppliers are the owners of coal reserves, largely the federal government, since 90 percent of Wyoming coal is mined from federal leases and these resources have limited alternative uses (Morgan and Mutti, 1981; Wyoming Coal Information Committee, 1998). Chapter 7 develops a conceptual model that incorporates major aspects introduced in this chapter.

Table 6.1

Average Mine Price of Coal, 1988-1998

STATE OR REGION	***1998***	***1997***	***1996***	***1995***	***1994***	***1988***
WYOMING	4.80	5.34	5.81	6.10	6.50	10.63
MONTANA	7.32	8.76	9.04	8.93	9.89	11.69
COLORADO	15.35	16.43	16.28	17.86	18.80	26.61
WESTERN	7.77	8.47	9.10	9.41	10.06	14.60
U.S. TOTAL	15.68	16.14	16.78	17.47	18.47	25.63

Source: Coal Industry Annual, Energy Information Administration/DOE
(REAL 1992 DOLLARS PER SHORT TON)

Table 6.2

Representative Mine-Mouth Prices by State,
Heat Content and Sulfur Content
(NOMINAL PRICES)

State	***BTU/lb***	***SO2 Content, Percent***	***1/98 Price Range, FOB Mine***	***1/97 Average Price, FOB Mine***
Wyoming	8400	0.5	$3.15-3.40	$3.08
	8800	0.5	4.00-4.40	3.88
	10000	0.6	13.50-14.00	12.75
	10500	0.6	14.00-14.75	12.50
Montana	8600	0.7	4.74-5.50	5.13
	9300	0.4	5.30-6.00	5.65
Utah	11500	0.6	16.00-17.25	16.13
Colorado	10700	0.5	12.00-12.50	12.00
	11300	0.8	13.50-14.00	13.50
	11600	0.5	14.75-15.50	14.88

Source: Coal Week, January 5, 1998, v. 24, n. 1.

Table 6.3

Average Delivered Price of All Coal, 1988-1998
(NOMINAL DOLLARS PER SHORT TON)

REGION	***1998***	***1997***	***1996***	***1995***	***1994***	***1988***
WEST NORTH CENTRAL	14.91	15.39	15.53	16.10	16.76	20.11
WEST SOUTH CENTRAL	19.34	19.69	20.13	20.66	20.79	23.08
MOUNTAIN	20.83	21.52	21.82	21.51	21.83	21.32
EAST NORTH CENTRAL	27.51	27.68	28.29	29.67	30.56	35.70
U.S. TOTAL	25.64	26.16	26.45	27.01	28.03	30.46

Source: FERC Form 423.

Table 6.4

Average Rail Rates, Delivered Prices, and Distance, 1988, 1993, 1998
In $1995

	1988		**1993**		**1998**
Rail Rate per Ton[a]	20.25		16.88		13.28
Average Delivered Price/Ton of Wyoming Coal to Electric Power Plants[b]	31.61		24.51		18.41
Rail Rate ÷Average Delivered Price	.64		.69		.72
Average Railmiles from a Wyoming Origin to a Power Plant Destination[c]	989		991		964

[a]Carload Waybill Sample, Surface Transportation Board, 1988-98. Defined as freight revenue.
[b]FERC Form 423.
[c]Carload Waybill Sample, Surface Transportation Board, 1988-98. 50 carloads or more in a delivery.

Table 6.5

Plants Purchasing Wyoming Coal, 1997

(* indicates a Phase I plant)

Name of Company	*Name of Plant*
Alabama Power Co (SC)	James Miller
Ames, City of	Ames
Arizona Public Service	Cholla
Arkansas Power and Light (MSU)	Whitebluff
Arkansas Power and Light (MSU)	Independence
Associated Electric Coop	Madrid
Associated Electric Coop	Hill
Basin Electric Power Coop	Leland Olds
Basin Electric Power Coop	Laramie River
Black Hills Corporation	Neil Simpson
Cajun Electric Power Coop	Big Cajun No.2
Cardinal Operating Co(AEP)	Cardinal*
Carolina Power and Light	Rox Boro
Carolina Power and Light	Mayo
Central Illinois Public Service	Newton
Central Electric Power Coop-Missouri	Chamois
Central Illinois Light	Edwards
Central Louisiana Electric	Rodemacher
Central Power and Light(CSW)	Coleto Creek
City Public Service-San Antonio	JT Deely/Spruce
City Utilities of Springfield	James River
City Utilities of Springfield	Southwest
Cleveland Electric Illum. Co	Avon Lake
Cleveland Electric Illume Co	Lake Shore
Colorado Springs Dept Pub Utilities	Nixon
Commonwealth Edison	Crawford
Commonwealth Edison	Joliet
Commonwealth Edison	Kincaid*
Commonwealth Edison	Powerton
Commonwealth Edison	Waukegan
Commonwealth Edison	Will County
Commonwealth Edison	Fisk
Commonwealth Edison	State Line
Consumers Power	Cobb-Sandusky Sg
Consumers Power	Campbell*
Consumers Power	Weadock-Sandusky
Consumers Power	Whiting
Dairyland Power Cooperative	Alma-Madgett
Dairyland Power Cooperative	Genoa No.3*
Detroit Edison Co	Harbor Beach
Detroit Edison Co	Monroe
Detroit Edison Co	River Rouge
Detroit Edison Co	St Clair
Detroit Edison Co	Trenton Channel
Detroit Edison Co	Belle River
Electric Energy*	Joppa
Empire District Electric	Riverton
Empire District Electric	Asbury*
Fremont Dept of Public Utilities	Wright
Georgia Power (Southern Co)	**Wansley***
Georgia Power (Southern Co)	Scherer
Grand Island Utilities	Platte

Gulf State Utilities	Nelson
Hastings Utilities	Hastings
Houston Lighting and Power	Limestone
Houston Lighting and Power	Parish
IES Utilities	6th St
IES Utilities	Sutherland
IES Utilities	Burlington*
IES Utilities	Ottumwa
Illinois Power	Baldwin*
Illinois Power	Havana
Illinois Power	Wood River
Indiana and Michigan Power(AEP)	Rockport
Indiana Michigan Power (AEP)	Tanners Creek*
Indiana-Kentucky Electric Corp	Clifty Creek*
Interstate Power	Lansing
Iowa Electric Light and Power	Prairie Creek 1-4*
Iowa-Illinois Gas and Electric	Louisa
Kansas City Bd Public Utilities	Kaw
Kansas City Bd Public Utilities	Quindaro*
Kansas City Bd Public Utilities	Nearman
Kansas City Power and Light	Hawthorne
Kansas City Power and Light	Montrose*
Kansas City Power and Light	Iatan
Kansas City Power and Light Co	La Cygne
Kansas City Power and Light Co	Lawrence
Kansas City Power and Light Co	Tecumseh
Kansas Power and Light Co	Jeffrey Energy Center
Lansing Board of Water and Light	Eckert
Lansing Board of Water and Light	Erickson
Los Angeles Dept of Wtr and Pwr	Intermountain
Lower Colorado River Authority	S Seymour-Fayette
Manitowoc Public Utilities	Manitiwoc
MidAmerican Energy	Riverside
MidAmerican Energy	Council Bluffs
Midwest Power Inc.	George Neal ¼*
Mississippi Power(Southern Co)	Watson*
Montana Power Co	Corette
Muscatine Power and Water	Muscatine
Nebraska Public Power System	Sheldon
Nebraska Public Power System	Gerald Gentleman
New England Power(NEES)	Brayton
Northern Indiana Public Service	Bailly*
Northern Indiana Public Service	Mitchell
Northern Indiana Public Service	Michigan city*
Northern Indiana Public Service	Rollin Schahfer
Northern States Power	Black Dog
Northern States Power	High Bridge*
Northern States Power	King
Northern States Power	Riverside
Northern States Power	Bay Front
Northern States Power	Sherburne County
Oklahoma Gas and Electric	Muskogee
Oklahoma Gas and Electric	Sooner
Omaha Public Power District	North Omaha
Omaha Public Power District	Nebraska City
PacifiCorp	Johnston
PacifiCorp	Naughton
PacifiCorp	Wyodak
PacifiCorp	Jim Bridger
Platte River Authority	Rawhide
Portland General Electric	Boardman
Public Service Co of Oklahoma (CSW)	Northeastern
Public Service Co of Colorado	Araphoe

Public Service Co of Colorado	Comanche
Public Service Co of Colorado	Valmont
Public Service Co of Colorado	Pawnee
Public Service Co of Indiana	Gibson Station*
Rochester Dept Public Utilities	Silver Lake
Sierra Pacific Power	North Valmy
Sikenston Board of Mun Utilities	Sikeston
Southwestern Electric Power	Pirkey
Southwestern Electric Power (CSW)	Flint Creek
Southwestern Electric Power (CSW)	Welsh Station
Southwestern Public Service	Harrington
Southwestern Public Service	Tolk
St Joseph Light and Power	Lakeroad
Sunflower Electric Power Corp	Holcomb Unit #1
Takoma Dept of Public Utilities	Steam No.2
Tampa Electric	Davant Transfer
Tennessee Valley Authority	Paradise
Tennessee Valley Authority	Shawnee
Tennessee Valley Authority	GRT Terminal
Tennessee Valley Authority	Cora Transfer
Tennessee Valley Authority	Cahokia III.
Texas Municipal Power	Gibbons Creek
Texas Utilities Electric Co	Monticello
Toledo Edison Co	Bay Shore
Union Electric	Labadie*
Union Electric	Meramec
Union Electric	Sioux*
Union Electric	Rush Island
United Power Association	Stanton
UtiliCorp United Inc	Sibley
West Texas Utilities (CSW)	Oklaunion
Western Farmers Electric Coop	Hugo
Wisconsin Electric Power	Presque Isle
Wisconsin Electric Power	Oak Creek*
Wisconsin Electric Power	Pleasant Prairie
Wisconsin Power and Light	Edgewater*
Wisconsin Power and Light	Nelson Dewey*
Wisconsin Power and Light	Rock River
Wisconsin Power and Light	Columbia
Wisconsin Public Service Corp	Pulliam*
Wisconsin Public Service Corp	Weston

Figure 6.1 Coal Production 1970-99

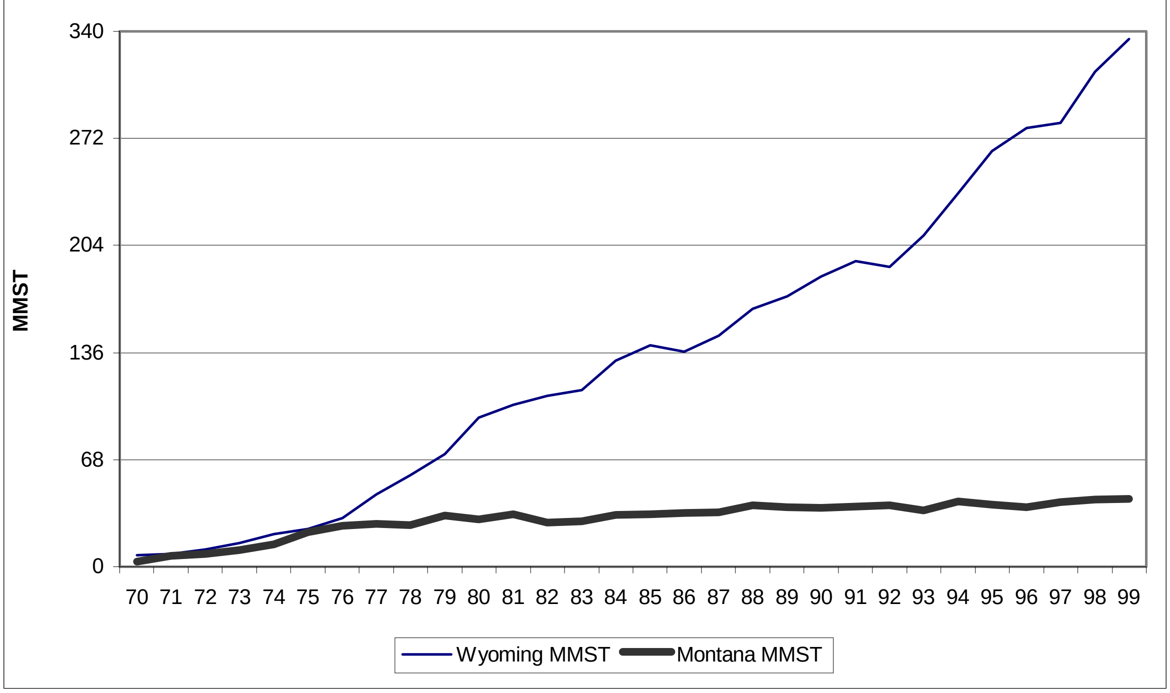
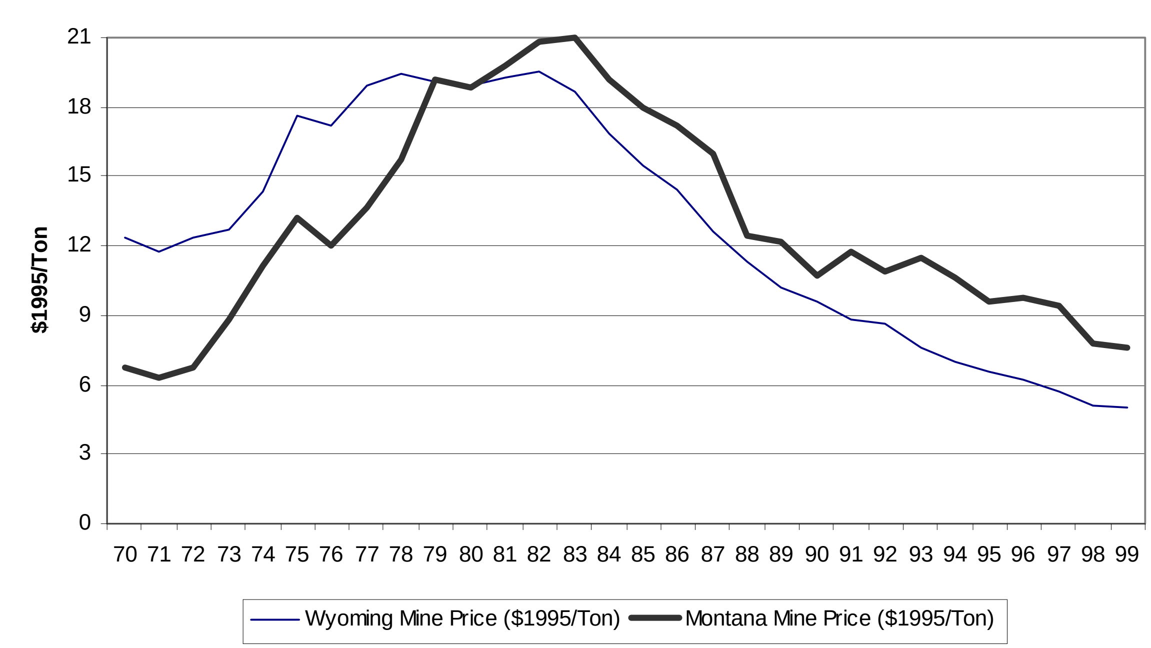


Figure 6.2 Weighted Average Mine Price 1970-99



CHAPTER 7

MODELING THE WYOMING COAL MARKET AND PREDICTING TAX EFFECTS

7.1 Introduction

This chapter begins by discussing factors that determine effects of a change in Wyoming's coal severance tax. These factors are shown to be the responsiveness of the quantity of coal demanded to changes in coal's price, the degree to which railroads' and coal mines' marginal costs change when the level of output changes, and the important question of whether or not power plants, Wyoming coal mines, and railroads exercise market power. Then, evidence on the market structure for Wyoming coal is examined and a stylized model is developed of interactions between a competitive coal industry, price taking power plants, and a monopolist/monopsonist railroad. The model developed is comparative-static, as contrasted with the dynamic model for oil and gas. This approach was taken for two reasons. First, exploration is less of an issue in the case of coal than it is for oil and gas. Wyoming and, more generally, the U.S. have vast coal reserves and the location of these reserves is known. Second, economic interactions between mines, railroads, and utilities at a point in time are thought to be more important to capture in a model than the optimal exploitation of coal over time. In any case, based on this model, theoretical predictions are derived of the effects of a reduction in the coal severance tax and the imposition of a ton/mile tax on railroads on changes on the quantity of coal produced, mine-mouth coal prices, railroad freight rates, and delivered prices of coal.

After estimating relevant cost and demand functions, the theoretical model is operationalized by inserting empirical estimates of key parameters. These estimates are obtained using two confidential data sets, one on costs of surface coal mining in the Powder River Basin and the other on variable costs of hauling coal from various points in Wyoming to 244 electric power generation plants. Also, estimates of demand for Wyoming coal, obtained from publicly available data from the Federal Energy Regulatory Commission, are novel in that they allow the market area for Wyoming coal to change with changes in the delivered price. Using these empirical estimates jointly with the conceptual model developed, numerical predictions are provided of effects of the two tax changes. In general, effects of tax changes considered on production of coal, the mine-mouth price of coal, railroad freight rates, and delivered prices of coal are quite small in comparison to probable changes in tax collections. For example, the coal severance tax reduction considered leads to a reduction in severance tax collections by about 27%.

7.2 Model

7.2.a Background

The model developed in this section shows how Wyoming's production of coal is affected by changes in ad valorem production tax rates and the imposition of a specific tax on tonnage hauled by railroads. The model focuses on interrelationships between three important agents in the market for coal, producers, railroads, and electric utilities. Producers, of course, are the suppliers of coal and utilities are the main end users who use coal as an input in the generation of electricity. Railroads, which provide transportation of coal, are included in the model because freight costs may represent as much as 80% of delivered coal prices. Key aspects of the model are that coal producers are treated as perfect competitors, railroads are assumed to exercise market power in setting transportation rates faced by utilities, and utilities are assumed to have little bargaining leverage in their purchases of Wyoming coal.

This characterization of industry structure may seem surprising because the exercise of market power by all agents in the coal market has been a dominant theme in previous research. Atkinson and Kerkvliet (1986 and 1989), for example, suggest that sources of market power at the mine level include entry barriers due to restrictions on federal coal leasing, long lead times required to obtain permits and to construct a mine, and economies of scale that had been achieved by only a few mines at the time of their studies. At the mine-power plant interface, investments in heterogeneous coal reserves and coal-specific power plants conveyed potential market power to both mines and plants. Moreover, the long-term contracts designed to protect these investments limited effective competition, a situation that was exacerbated when these contracts contained price escalation, take-or-pay, or similar provisions. Atkinson and Kerkvliet (1989) find that power plants can gain market power by purchasing dominant shares of the production of individual mines. Similar sources of market power were identified for railroads. In addition, only a single railroad served each of the coal basins in Wyoming, but railroad rates were regulated prior to the passage of the Staggers Act in 1980. Also, Kolstad and Wolak (1983) examine the market power that the states of Wyoming and Montana can use to extract rents through severance taxes and find that they could gain substantial tax revenues by increasing rates even in the absence of collusion.

Much has changed, however, since these early studies were conducted. For mines, the barriers to entry resulting from the 1980's moratoriums on federal coal leases have eased somewhat. The number of large Wyoming mines has increased; 19 owners now operate 28 mines in Wyoming. There are 10 owners operating 17 mines in the PRB. Of these, 11 mines are likely to be fully exploiting scale economies with annual production of more than 10 million tons each (Lyman and Hallberg, 1999). Also, transaction-specific investments associated with heterogeneous coal also appear to have diminished in importance, which, in turn, has reduced the potential for monopoly pricing by coal suppliers and monopsony behavior by plants. Three types of evidence suggest that there have been engineering advances in mixing different types of coal. First, as discussed in Chapter 6, plants are increasingly using diversified portfolios of coal and other fuel suppliers to meet their fuel requirements. Second, most Wyoming coal buyers now buy from more than one Wyoming mine. In 1995, 80 percent of the plants for which all Wyoming coal sales could be identified purchased coal from more than one Wyoming mine. On average plants purchased coal from 2.8 Wyoming mines. Third, there is evidence that individual plants have learned to successfully mix bituminous coal from other states with sub-bituminous coal from Wyoming (Ellerman, et al., 1997).

Furthermore, as described in Chapter 6, long-term contracts have diminished in importance, while spot market purchases and shorter-term contracts are now the norm. Nearly all new coal sales occur at the low prices of $6.00 per ton or less and are governed by contracts of 4 years duration or less (Kerkvliet and Shogren, 1998; Wyoming Coal Information Committee, 1998). Current Wyoming coal contracts leave sellers and buyers more exposed to market forces because contracts are now more likely to contain market-based re-opener provisions and less likely to contain price escalation or take-or-pay provisions.

Turning to railroads, Wyoming coal transportation rates have fallen substantially since deregulation occurred with passage of the Staggers Act in 1980. Recent research suggests three reasons for this decline. First, railroads costs have fallen due to technological change (Wilson, 1997). Second, deregulation ended the practice of charging high cost shippers less than marginal cost and making up the deficit by charging low-cost shippers rates exceeding marginal costs. This allowed railroads to concentrate more on low-cost traffic, such as unit train shipments of coal, and increase traffic densities. This in turn led to decreases in overall rail costs, reduced union power, and ultimately lower real wages (MacDonald and Cavalluzzo, 1996). Third, the entry of the Chicago and Northwestern railroad into the PRB led to immediate decreases in rail rates of 30 percent or more and further decreases in subsequent years (EIA b; Atkinson and Kerkvliet, 1986). Yet, it remains the case the many utilities that purchase Wyoming coal are served by one, or at most two, railroads.

7.2.b Specification

In the model outlined below, coal producers are price-takers, operate identical mines located at a single point in space, and maximize profits after taxes. Profits ($\boldsymbol{p}_M$) of a representative mine are given by

$$\boldsymbol{p}_M = P_M Q - G(Q) - tP_M Q \qquad 0 \leq t < 1 \tag{7.1}$$

where P_M denotes the price of coal faced by all producers, Q denotes the mine's output, $G(Q)$ is the mine's extraction cost function, and t_M denotes the ad valorem production tax rate. Extraction costs rise with increases in Q. The first order condition determining the mine's output decision is

$$d\pi_M/dQ = P_M - G_Q - t_M P_M = 0 \tag{7.2}$$

or

$$P_M = G_Q/(1-t_M) \tag{7.3}$$

where G_Q is the marginal cost of producing another unit of coal. Thus, mines produce coal up to the point where the after tax price received is equal to marginal cost, provided the second order condition for a profit maximum holds (i.e., if marginal cost is increasing in Q, or $G_{QQ}>0$). Additionally, the representative mine's supply curve is the portion of the marginal cost curve that lies above the average cost schedule and the industry supply curve for coal ($H(Q)$) can be obtained by horizontally summing these individual mine supply curves. Industry output of coal (Q^*) is determined where

$$P_M = H(Q)/(1-t). \tag{7.4}$$

A single railroad hauls coal produced by the mines along a single track to a large number of identical coal-fired electric power generation plants. All power plants are located at the end of the track, are the same distance from the mines, and have no other sources of coal. Thus, the railroad has both monopsony power over the mines and monopoly power over the power plants. Electric power is produced for a national market and plants receive a fixed price for each unit of power produced. Each plant has an identical inverse demand function for coal in which the delivered price, P_D, is negatively related to the quantity of coal purchased. These individual demand functions can be horizontally summed to yield the electric power industry's aggregate inverse demand schedule for coal, $P_D=f(Q)$. The railroad's per unit freight charge, P_F, is equal to the difference between the delivered price of coal and the mine-mouth price (i.e., $P_F=P_D-P_M$).

The railroad decides how much coal to haul to the power plants and how much to charge for its services. Its profit function is

$$\pi_R = P_F Q-C(Q)-t_R Q \tag{7.5}$$

where $C(Q)$ denotes the railroad's cost function for hauling coal and t_R denotes the tax rate per unit of coal hauled. Using the fact that $P_D=P_F+P_M$ and substituting equation (7.4) yields

$$\pi_R = P_D Q-C(Q)-t_R Q-P_M Q =Qf(Q)-C(Q)-t_R Q-QH(Q)/(1-t) \tag{7.6}$$

which gives railroad profits in terms of utility demand for coal, railroad costs, and the industry supply of coal by the mines. The first order condition for a profit maximum requires

$$\partial\pi_R/\partial Q=Qf_Q+f(Q)-C_Q-t_R-QH_Q/(1-t_M)-H(Q)/(1-t_M)=0 \tag{7.7}$$

and the second order condition for a profit maximum is

$$\partial^2\pi/\partial Q^2=Qf_{QQ}+2f_Q-C_{QQ}-QH_{QQ}/(1-t_M)-2H_Q/(1-t_M)=\Delta<0 \tag{7.8}$$

Equation (7.7) states that the railroad hauls coal up to the point where the marginal revenue obtained from utilities ($Qf_Q+f(Q)$) is equal to the marginal tax-inclusive cost (C_Q+t_R) of transporting the coal plus the marginal tax-inclusive expense of supplying another unit of coal by the coal industry ($d(QH(Q)/(1-t_M))/dQ= QH_Q/(1-t_M)+H(Q)/(1-t_M)$). This result reinforces the idea that the railroad acts as both a monopsonist in its decisions of how much coal to haul and as a monopolist in its ability to set freight rates (and, thus, delivered prices) seen by the utilities. Both monopoly and monopsony power act to limit the amount of coal hauled between mines and power plants and to drive a larger wedge between P_M and P_D than would exist if transportation of coal was a perfectly competitive industry. Second order conditions are satisfied if the marginal revenue schedule cuts the aggregate marginal expense schedule (defined as the marginal coal expense schedule plus railroad marginal cost) from above. If the second order condition is satisfied, equation (7.7) can be manipulated to show the effect of changes in t_M and t_R on the production of coal (Q) and the three prices (P_M, P_D, P_F).

7.2.c Comparative Static Results

To obtain comparative static effects of changes in t_R and t_M on Q, totally differentiate equation (7.7) and solve for dQ/dt_R and dQ/dt_M as shown in equation (7.9) and equation (7.10).

$$dQ/dt_R = 1/D \tag{7.9}$$

$$dQ/dt_M = (QH_Q + H(Q))/(1-t_M)^2 D \tag{7.10}$$

In equation (7.9), $dQ/dt_R<0$ if $D<0$ and in equation (7.10) $dQ/dt_M<0$ if $D<0$ and if the coal supply schedule is positively sloped ($H_Q>0$). Thus, increases in t_R and t_M lead to reductions in the quantity of coal produced, a general conclusion that can be further elaborated from three perspectives. First, dQ/dt_R will be larger for smaller values of D. In other words, the magnitude of dQ/dt_R increases as the slopes of the marginal revenue and the aggregate marginal expense schedules become flatter (see equation (7.8)). Second, the magnitude of dQ/dt_M also depends on D, but the denominator of equation (7.10) is reduced by the factor $(1-t_M)^2$, which varies inversely with the level of the initial production tax, and the numerator is the mine's marginal expense of supplying an additional unit of coal before taxes. In consequence, dQ/dt_M will be greater the smaller is D, the larger is the initial ad valorem tax rate, and the larger is the marginal expense of hauling an additional unit of coal. Notice that larger values of the marginal coal expense correspond to larger values of marginal cost of coal production (*H(Q)*) and that D does not depend on *H(Q)* (see equation (7.8)). These relationships imply that for given values of t_M and D, dQ/dt_M will increase with coal's share of aggregate marginal expense.

Equations (7.9) and (7.10) also are useful in computing effects of the two types of taxes on P_M,P_D, and P_F. Differentiating equation (7.4) holding t_M constant and substituting equation (7.9) shows how P_M responds to a change in t_R.

$$dP_M/dt_R=(dP_M/dQ)(dQ/dt_R)=H_Q/(1-t_M)D<0 \tag{7.11}$$

Also, differentiating the utility demand function for coal and substituting equation (7.9) shows the effect on P_D of a change in t_R.

$$dP_D/dt_R=(dP_D/dQ)(dQ/dt_R)=f_Q/D>0 \tag{7.12}$$

In other words, the increase in t_R raises the aggregate marginal expense of hauling coal and reduces the amount of coal that the railroad is willing to haul. Utilities now buy less coal and pay a higher price per unit. Also, mines produce less coal and cut prices because their marginal costs fall as output contracts. Thus, the increase in t_R drives a deeper wedge between P_D and P_M that allows the railroad to increase its freight rates in such a way that a portion of the tax is shifted in both directions. The change in the railroad freight rate is shown in equation (7.13).

$$dP_F/dt_R=dP_D/dt_R-dP_M/dt_R=(1/(1-t_M)D)[(1-t_M)f_Q-H_Q]>0 \tag{7.13}$$

Effects on P_M, P_D, and P_F resulting from a change in the ad valorem production tax on mine output (t_M) can be obtained in a similar fashion, however, results are somewhat more algebraically complex and details are presented in Appendix D. Differentiating equation (7.4) and substituting equation (7.10) yields

$$dP_M/dt_M = (dP_M/dQ)(dQ/dt_M) = (H_Q/(1-t_M))(dQ/dt_M) + H(Q)/(1-t_M)^2 \qquad (7.14)$$

In equation (7.14), the first term on the right-hand-side is negative (because $dQ/dt_M<0$), while the second term is positive. However, Appendix D shows that $dP_M/dt_M>0$ if $d(QH_Q/H(Q))/dQ>0$. This derivative, which measures whether H_Q grows faster or slower than $H(Q)/Q$ when Q rises, is positive provided $H_Q>0$ and $H_{QQ} \geq 0$, an outcome that is similar to the familiar demonstration that the slope of a marginal cost curve is greater than the slope of an average cost curve over the range of output for which marginal cost is increasing. Moreover, equation (7.15) shows that an increase in t_M also increases the delivered price of coal:

$$dP_D/dt_M = (dP_D/dQ)(dQ/dt_M) = f_Q(dQ/dt_M) > 0 \qquad (7.15)$$

Because P_M and P_D both move in the same direction when t_M changes, the sign of dP_F/dt_M is, in general, ambiguous. However, subtracting equation (7.14) from (7.15)

$$dP_D/dt_M - dP_M/dt_M = dP_F/dt_M = (f_Q - H_Q/(1-t_M))(dQ/dt_M) - H(Q)/(1-t_M)^2 \qquad (7.16)$$

shows that rail rates rise with increases in t_M provided that the utility's demand schedule for coal is more steeply sloped than the coal industry supply function and $H(Q)$ is small enough. In any case, numerical calculations of dP_F/dt_M are presented in Section 7.4 on the basis of econometric estimates of the parameters of the model developed in the next section.

7.3 Estimation

The model developed in the previous section can be used to quantify effects of production tax changes on output and prices of coal. The idea here is to econometrically estimate key model parameters and then use these values to compute the derivatives obtained in the previous section. Estimation procedures, of course, must recognize that the actual market for coal has many features that were disregarded in the model. For example, electric power plants can burn fuels other than coal (such as natural gas) and they are obviously not all located at the same distance from the mines. Railroad freight costs are related not only to quantity of coal hauled, but also to the distance it must travel. Coal produced by the mines is not homogeneous and mine costs are not identical. Thus, estimation methods must control for these as well as other important factors in order to obtain the desired relationships. This section has three parts that report estimates of: (1) coal supply, (2) railroad costs, and (3) utility demand.

7.3.a Coal Supply

This subsection estimates a net-of-tax supply schedule of coal (*H(Q)*) produced in the Powder River Basin of Wyoming. The Powder River Basin accounts for an overwhelming percentage of Wyoming's coal output and an even larger percentage of coal shipped out-of-state. Estimates of the supply function make use of proprietary and confidential mine-specific cost data furnished by Hill and Associates (1999). This firm annually collects detailed cost estimates and production information on currently operating, recently closed, and proposed new coal mines in the Powder River Basin and other coal producing regions in Wyoming and in other U.S. states. At present, only cost data for Powder River Basin mines are available. These data are used to prepare forecasts at 5-year intervals over the next 20 years of direct mining costs per ton for each mine assuming operation at capacity. The analysis below is based on the direct cost estimates for the period 2000-2004. Regarding cost data, capacity operation is defined as an economic limit to production and, for all mines, lies below maximum allowable annual production permitted under state air quality regulations. Direct mining costs include anticipated wages and salaries of labor, expenses for materials and supplies, and capital costs required to deliver coal from the mine to a railcar. These cost estimates, which do not include corporate overhead, royalties, taxes, final reclamation accruals, or depreciation, differ substantially between mines. Cost differences are due to variations in mine ratios (overburden thickness), capital intensity, mining methods, and other factors.

The estimate of the supply function presented below exploits the differences in direct costs between mines because no information is available on production costs at output levels below capacity. The key assumption here is that direct production costs per ton vary little with output up to the point of capacity operation and then turn sharply higher. Thus, for each mine, direct cost per ton would (approximately) equal marginal cost per ton at output levels below capacity and mines would choose to produce at capacity whenever the FOB mine price exceeds direct cost per ton. Also, the Powder River Basin supply curve for coal can be visualized as a step function by first ordering mines from lowest to highest in direct cost and then plotting the direct cost of each mine against cumulative output. Advantages of this approach are that it identifies the mines that would be operational at a given FOB mine price, identifies mines that would open (or reopen) if the price rises, and identifies mines that would close if the price falls.

A continuous approximation to the Powder River Basin coal supply function was obtained by regressing the natural logarithm of direct operation cost in dollars (*COST)* on cumulative output in millions of short tons (*CUMTONS)*. This functional form was chosen because the plot of the step function described above suggests an exponential relationship between cost and cumulative output. Results are shown in equation (7.17)

$$\underset{}{ln(COST)_j = CONSTANT + \underset{(6.813)}{0.0011}\ CUMTONS_j + e_j} \qquad (7.17)$$

where the subscript j indexes mines, e_j, is a measured residual, the t-statistic of the coefficient of *CUMTONS* is shown in parenthesis, and the estimate of *CONSTANT* has been suppressed so as not to disclose the value of direct cost for the lowest cost producer. Also, this regression uses data from 22 mines, 17 of which are in current operation, and $R^2=0.70$. Including observations on 5 relatively high cost, nonoperating mines is warranted because they provide information about the shape of the cost curve at output levels above current production. As shown in equation (7.17), the coefficient of *CUMTONS* is positive and significantly different from zero at conventional levels, suggesting that incremental cost of coal production in the PRB increases at an increasing rate with output; i.e., $H_Q>0$ and $H_{QQ}>0$. Discussion of the appropriate level of output at which to evaluate these derivatives is deferred to Section 7.4.

7.3.b Utility Demand

Demand functions for both Powder River Basin coal and coal from all producing areas in Wyoming are estimated by applying an adaptation of Heckman's (1979) two-step estimator to data on fuel purchases by utilities. In the first step, equations are estimated to predict whether a utility will purchase Powder River Basin or Wyoming coal and in the second step, demand equations for Powder River Basin and Wyoming coal are estimated for utilities that purchased this fuel. The idea here is to account for the fact that coal produced in Wyoming competes in a marketplace with other fuels such as natural gas and coal produced in other U.S. states and that transportation costs increase with distance and often represent a large fraction of its delivered price. For example, as a utility's distance from Wyoming rises, the probability that it will purchase Wyoming coal is expected to fall (other things constant). Also, as the mine-mouth price of Wyoming coal falls relative to prices of other fuels, the economic market area for Wyoming coal is expected to expand. Thus, the demand schedule must not only allow for current buyers to increase coal purchases as the mine-mouth price falls, but also for the "economic reach" of Wyoming coal to expand. Correspondingly, as delivered coal prices rise, the demand schedule must account both for current buyers to substitute against Wyoming coal and in favor of other fuels for the most distant utilities to discontinue buying altogether.

More specifically, first step probit equations are estimated using panel data on a total of 416 U.S. electric power plants over the period 1983-98 and are used to predict the probability that a utility purchases Powder River Basin or Wyoming coal. Plants are included in the sample if they burned coal from any source in at least one year between 1983-98. Nuclear and hydroelectric power stations are excluded from the sample because they were not designed to use coal. Also, the panel is unbalanced because some coal-fired plants did not operate in each year (i.e., older plants were retired and new plants came on line during the sample period). A total of 6238 observations are available, rather a sample size of 6656 that would be expected if the panel was balanced. The dependent variable is binary and equals one if coal is purchased (see below), and is zero otherwise.

Estimation of this equation raises two general issues. The first deals with how best to exploit the panel structure of the data. Random effects estimation was chosen because the probit model does not lend itself well to a fixed effects treatment of heterogeneity among cross-sectional units (see Greene 1997). Yet, heterogeneity among electric power plants is important to consider because they exhibit substantial differences in unobserved engineering characteristics that contribute to explaining whether low sulfur, low BTU Wyoming coal might be purchased. The second issue deals with how to measure the cost of Wyoming coal faced by utilities. Two aspects are important here. First, the decision of whether or not to purchase Wyoming coal may be determined simultaneously with its delivered price. Second, the delivered price is known only for utilities that actually purchased Wyoming coal.

To avoid both of these problems, instruments for the real delivered price were constructed using the predicted values from a regression of this variable on the straight-line distance (in miles) between each plant and Gillette, Wyoming (the community at the center of coal mining activity in the Powder River Basin). These regressions were run in a Box-Cox (see Greene 1997) framework by applying nonlinear least squares to all available observations on plants that purchased Wyoming coal. Predicted values of real delivered price, then, were assigned to all plants (whether they purchased Wyoming coal or not) based on the distance variable. Two regressions were estimated, one for utilities using Powder River Basin Coal and the other for utilities using Coal from any Wyoming mine. Outcomes for these regressions are shown in equation (7.18) and equation (7.19).

$$\begin{array}{ll} RDPRICE_{PRB}=\underset{(6.95)}{12.24}+\underset{(6.23)}{0.056}DISTANCE^{*}+e & \underset{(16.50)}{\lambda=0.83} \end{array} \qquad (7.18)$$

$$\begin{array}{ll} RDPRICE_{WYO}=\underset{(7.76)}{14.14}+\underset{(7.25)}{0.050}DISTANCE^{*}+e & \underset{(19.82)}{\lambda=0.86} \end{array} \qquad (7.19)$$

The Powder River Basin regression in equation (7.18) used 1389 observations and the Wyoming regression in equation (7.19) used 1569 observations. t-statistics are shown in parentheses beneath coefficient estimates and λ is the estimate of the transformation parameter applied to *DISTANCE*. Thus, $DISTANCE^{*}=(DISTANCE^{\lambda}-1)/\lambda$. Both equations show that the real delivered price of coal increases at a decreasing rate with the distance it is shipped (i.e., coefficients of $DISTANCE^*$ are positive and significant and values of λ are significantly less than unity at conventional levels).

In any case, sample means, definitions, and data sources for explanatory variables used in the probit regressions are presented in Table 7.1. Explanatory variables include the predicted delivered price of coal (discussed above), the real price of natural gas (a substitute for coal in electricity generation), size of the power plant in number of kilowatt hours generated, and a dummy variable indicating whether the observation was after 1990 (the date of amendments to Federal Clean Air Legislation that limited sulfur emissions, see Chapter 8). All data described in Table 7.1 are taken from publicly available government and industry sources.

Table 7.2 presents results from two probit regressions. Column (1) shows the outcome when the dependent variable indicates whether coal is purchased from a Powder River Basin mine. In column (2), the dependent variable indicates whether coal is purchased from any Wyoming mine. The estimates of the ratio of the power plant variance component to the sum of all variance components ($\rho = 0.80$) highlight the importance of accounting for cross-sectional heterogeneity. Marginal effects of explanatory variables, rather than the underlying probit coefficients, are presented because they are easier to interpret. In both regressions, the marginal effect of the instruments for delivered price (*RDPRICEHAT)* is negative and highly significant indicating that more distant power plants face higher delivered prices and are thus less likely to buy Wyoming coal. For example, the probability that a power plant will purchase Powder River Basin coal declines by about 1.5% for a $1 increase in delivered price, when evaluated at the means of all variables. Remaining results suggest the probability that a power plant will burn Powder River Basin coal or coal from any Wyoming mine is positively related to the size of the plant (*GENER)* and the price of substitute fuels (*RGASPR).* Also, the positive marginal effect of (*D1990)* indicates that demand for Wyoming coal expanded after passage of the federal Clean Air Act amendments. This aspect is further analyzed in Chapter 8.

Table 7.4, then, shows the outcome from second-step coal demand regressions of the quantity of coal delivered to utilities on various explanatory variables (including the delivered price of coal) using panel data for the period 1983-98. This equation was estimated as an ordinary demand function, rather than an inverse demand equation as specified in the conceptual model, in order to facilitate calculations of effects of prices, and ultimately taxes (see below). Again, estimates of two equations are shown; one for coal deliveries from the Powder River Basin (see Column (1)) and another showing coal deliveries from all producing areas in Wyoming (see Column (2)). Of course, the sample sizes are now smaller than those used in the Table 7.2 regressions because observations are limited to only those utilities that actually bought coal from a Wyoming mine. These regressions use information from the previously discussed probit regressions (the inverse Mills ratio (*MILLS*)) as explanatory variables to control for the likelihood that a utility buys either from the Powder River Basin or from any Wyoming mine. The two equations reported in Table 7.4 were estimated using one-way fixed effects. In both equations, two-way fixed effects estimation was tried, however, time effects were jointly insignificant at conventional levels when added to an equation already containing cross-sectional controls. Controlling for sources of heterogeneity among power plants (such as distance from Wyoming) is quite important in this regard because the conceptual model presented in Section 7.2 assumed that all utilities are located at the same distance from the mines. In fact, coefficient estimates in Table 7.4 are interpreted conditionally on the fixed effects; thus, they show effects on coal purchases holding distance (and other fixed factors) constant.

The dependent variable in both of the Table 7.4 regressions is the natural logarithm of quantity of coal purchased. Definitions, sample means, and data sources for explanatory variables are presented in Table 7.3. Explanatory variables include the real delivered price of Wyoming coal, the real prices of two substitute fuels (natural gas and coal obtained from a state other than Wyoming), plant size measured in kilowatt hours of electricity generated annually, and the inverse Mills ratio computed from the first stage probit regression. Results of a Hausman (1978) test indicate that a random effects specification of these two equations is rejected at conventional levels of significance. F-tests indicate that cross-sectional effects are jointly significant in both the Wyoming and Powder River Basin regressions. Values of R^2 were 0.83 and 0.73 for the Powder River Basin and Wyoming regressions, respectively.

Coefficient estimates from both regressions are broadly similar. The real delivered price of coal is inversely related to the quantity of coal purchased and positively related to the real natural gas price. Coefficients estimated are interpreted as percentage changes; for example, if the delivered price of Powder River Basin coal increases by $1, the quantity of coal demanded falls by about 1.4%. Alternatively stated, the price elasticity of demand for Powder River Basin coal evaluated at the means of delivered price ($24.18) and annual quantity purchased per year (1.97 MMST) would be quite low, about -0.33. It is important to observe, however, that this price elasticity applies only to plants that are existing buyers of Wyoming coal and disregards the expansion or contraction of the market area when the price changes, a related aspect that will be considered momentarily. In any case, existing buyers of Wyoming coal do not greatly alter their use of this fuel in the face of price changes. Relatively fixed engineering characteristics of boilers used in the generation of electricity may be partly responsible for this outcome. Also, in both regressions, the coefficient of *(OTHERCOAL)* is negative and but not significantly different from zero at conventional levels. This outcome provides weak evidence that non-Wyoming coal and Wyoming coal are complements and may reflect the fact that many plants are engineered to burn a blend of coals from two or more sources. The coefficient of *GENER* is positive and significant in both regressions, indicating that the quantity of coal sold to a utility is an increasing function of the amount of electricity that it generates. Coefficients of the real price of natural gas are positive and significantly different from zero as well, suggesting that natural gas is a substitute for Wyoming coal. Finally, the coefficient of the inverse Mill's ratio (*MILLS*) is positive and significant at conventional levels in the Powder River Basin regression and positive and significant at the 5% level using a one-tail test in the Wyoming regression.

The coefficient estimates of *MILLS* are of interest because they suggest the importance of incorporating the coal demand function estimates into a selection model. A practical advantage of a selection model in this context is that it allows changes in the market area for Wyoming coal in addition to changes in quantity demanded by existing purchasers (see Greene 1997 for further discussion, examples, and computational details). Intuitively, this point is easiest to see when estimating the second stage equation as an ordinary, rather than as an inverse, demand function because *MILLS* is a function of the delivered price. More specifically, in the estimates presented, the “market area” effect is considerably larger than the “existing purchasers” effect. For example, in the Powder River Basin equation, the “market area” effect of a change in delivered price on natural logarithm of quantity purchased would be calculated by differentiating *MILLS* with respect to delivered price (-0.27) and multiplying by the coefficient of *MILLS* (0.70) from the regression equation. This yields a value of about -0.189, which exceeds the corresponding “existing purchasers” effect discussed above of -0.014 by a factor of more than 13.5. Also, this calculation suggests that after combining the two effects, the price elasticity of demand (evaluated at means of delivered price and quantity) is –2.23. These two types of effects will be further drawn out in Section 7.4, which presents calculations of effects of tax rate changes.

7.3.c Railroad Costs

Data used to estimate railroad costs are taken from the 1988-1997 Carload Waybill Sample from the Surface Transportation Board of the Interstate Commerce Commission. These data are confidential, but are available for a given state when officially requested for research purposes by that state’s government. Data consist of a random sample of railroad shipments either originating, terminating, or passing through Wyoming. For each year, the data were filtered to eliminate non-coal shipments and coal shipments consisting of fewer than 50 cars of coal. The latter filter was applied to eliminate intermittent coal shipments to various steam and processing plants where the associated costs are likely be different than those for regular shipments to power plants. Each year, the filtered waybill sample captured shipments of 65-141 million tons of Wyoming coal, representing between 35-45 percent of total Wyoming coal shipments.

For the shipments remaining in the sample after the filters were applied, Standard Point Location Codes (SPLC) were used to identify the originating Wyoming mine and the destination power plant. The resulting mine/plant pairs are the units of observation in the analysis presented below.

Two regressions were run using these data; one for rail shipments of Powder River Basin coal and the other for rail shipments of coal from all Wyoming mines. In the Powder River Basin regression, a total of 207 mine/plant pairs were identified for coal shipments between 1988 and 1997. In the Wyoming regression, 244 mine plant pairs were identified. Transactions did not occur for some of these mine/plant pairs in some years, so the data for each regression consisted of unbalanced panels of 1060 observations and 1322 observations for the Powder River Basin and Wyoming regressions, respectively. Data were applied in a two-way fixed effects framework to obtain an estimate of the railroad cost function for coal transportation $C(Q)$. Thus, the estimates automatically control for distance (and other time invariant mine/plant characteristics) along each transportation route. This aspect of the estimation procedure is crucial, as noted in the previous subsection, because of the way that the conceptual model was formulated.

The dependent variable in each regression is the natural logarithm of the railroad's reported variable cost of operation associated with hauling coal along a particular route in a given year. The Surface Transportation Board (1998) computes this cost measure on the basis of railroad-specific accounting and operating data using the Uniform Railroad Costing System (UCRS). It does not include general and administrative expenses and averages about 63% of the reported freight charges for all

244 routes over the 11-year sample period. Only two explanatory variables were used in the analysis because available data contain few variables that vary both across transportation routes and over time. These variables measure: (1) quantity of coal shipped along a route in a particular year and (2) whether the railcars used were privately owned. Sample means and more complete definitions of variables used are presented in Table 7.5.

Regression results are presented in Table 7.6. As shown, both mine/plant-specific and time-specific effects jointly differ significantly from zero at conventional levels and values of R^2 are a bit below 0.90 in both regressions. Additionally, the coefficients of *QUANTITY* and *CAROWN* are positive and highly significant. Because mine/plant-specific factors are controlled by fixed effects estimation, the coefficient of *QUANTITY* measures the incremental effect on variable cost arising from shipping an additional million tons of coal along each route. Thus, for given values of Q, values for C_Q and C_{QQ} needed to compute effects of tax changes discussed in Section 7.2 can be computed. These calculations are described in Section 7.4 to follow.

7.4 Estimating Changes in Coal Purchases and Prices

This section uses the empirical estimates in the previous section together with the conceptual model developed in Section 7.2 to make calculations of effects of tax changes on both Powder River Basin and total Wyoming coal production, the mine-mouth price of coal, the delivered price of coal, railroad freight charges, and Wyoming coal severance tax collections. As previously indicated, two specific tax change scenarios are considered: (1) a 2-percentage point reduction in the Wyoming coal severance tax, from 7% to 5% and (2) the imposition of a ton-mile tax on railroads of $0.025/ton (see Chapter

6). Although, the method used to evaluate these tax changes is straightforward, it is helpful to clarify several aspects of procedures used. First, estimates of effects of the two taxes on total Wyoming production are computed using equation (7.9) and equation (7.10) together with estimates of utility demand for Wyoming coal (see Table 7.4), railroad costs (see Table 7.6), and the estimated mine cost function (see equation 7.17). Second, recall that the mine cost function could be estimated using data only from Powder River Basin mines, so it is assumed that this mine cost function applies to all Wyoming mines. Third, the mine cost function and its derivatives were evaluated at Wyoming's 1998 sample output level of 305 MMST. Fourth, because the empirical analysis of railroad costs treated mine/plant pairs as the unit of observation, derivatives of the railroad cost function were evaluated at the 1998 average quantity of coal hauled along the 244 routes considered (1.1 MMST).

Fifth, treatment of utility demand parameters requires a bit more explanation. Recall from the discussion in Section 7.3.b that the effect of a delivered price change on quantity of Wyoming coal purchased is divided into two parts, an "existing plant effect" and a "market area effect." Also, note that the conceptual model is based on the inverse demand function for coal, whereas estimates of an ordinary demand function were presented in Table 7.4. In consequence, after computing the two types of effects, they were combined in the estimated ordinary demand equation and then an inverse demand function was derived using the implicit function theorem. Derivatives of this inverse demand function, then, were evaluated at the 1998 average quantity of Wyoming coal purchased by plants that bought this fuel in positive amounts (2.2MMST).

Table 7.7 presents results from computing the various quantities needed to evaluate equations (7.9) and (7.10) from the conceptual model. Six features of these calculations warrant further comment. First, notice that $D = -12.64$, implying that the model's second order conditions are satisfied. Second, evaluating $H(Q)$ at $Q=305$ MMST gives a value for marginal cost of coal production of \$5.09, which is slightly below the average price 1998 coal price of $P_M=\$5.48$. This outcome suggests an incentive to open additional mines, provided that their marginal costs of operation at capacity are less than P_M and provided that this price is expected to hold into the future. Third, Table 7.7 reveals evidence of the monopsony power of railroads. As discussed in connection in Section 7.2, the marginal expense of supplying another unit of coal is $H(Q)+QH_Q$. Substituting values from Table 7.7 and using $Q=305$ MMST suggests that this value is \$6.22, which exceeds marginal cost ($H(Q)=\$5.09$) by \$1.13, or by about 22%. Fourth, railroad's monopoly power over utilities also can be illustrated using the figures in Table 7.7. Marginal revenue is given by $f(Q)+Qf_Q=\$18.47-\$5.24=\$13.23$, when the utility demand function for Wyoming coal is evaluated at $Q=2.2$ MMST. Fifth, Table 7.7 shows that the current Wyoming severance tax rate on surface mined coal is 7%. The current severance tax rate on underground coal mined in Wyoming is lower, however, surface mined coal accounts for virtually all of the state's production. In consequence, the distinction between surface and underground coal is ignored in the calculations below. Sixth, the ton/mile tax on railroads that goes into effect in 2001 has an effective rate per ton of \$0.025 (see Chapter 6).

Table 7.8, then, shows the effect of reducing the Wyoming severance tax by 2-percentage points from 7% to 5% of the value of coal produced. As shown, output of coal rises by 1.42 MMST (0.47%) and the mine-mouth price of coal falls by about \$0.12 from P_M=\$5.48 to P_M=\$5.36. Also, the average delivered price of coal falls by about \$.02 from P_D=\$18.47 to P_D=\$18.45, a decline of about 0.12%. Thus, the freight rate per ton of coal hauled along a route of average length ($P_F=P_D-P_M$) rises by about 0.77% from \$18.47-\$5.48=\$12.99 to \$18.45-\$5.36=\$13.09. Thus, effects of this tax change on quantities of coal produced and relevant prices appear to be quite small, especially when measured as percentage changes. The largest effect of this tax reduction would be on coal severance tax collections. Using values from Table 7.7, these tax collections can be approximated by $T_M=t_MP_MQ$=0.07x\$5.48x305=\$117 million before the tax cut and the change in tax collections (in millions of \$) due to the tax cut can be found by substituting values from Table 7.8 into equation (7.20).

$$\begin{aligned} dT_M&=P_MQdt_M+t_MP_MdQ+t_MQdP_M= \\ &-(0.02)(5.48)(305)+(0.07)(5.48)(1.42)-(0.07)(305)(0.12)= \\ &-\$33.43+\$2.56-\$0.54=-\$31.41 \end{aligned} \tag{7.20}$$

This equation shows that the change in coal severance tax revenue can be broken down into three components: (1) the loss in tax revenue that arises due to the rate reduction (\$33.43 million), (2) the gain in tax revenue because of the increased quantity of coal produced (\$2.56 million), and (3) the loss of tax revenue due to the decline in the mine-mouth price (\$0.54 million). Thus, in total the state loses \$31.41 million in coal severance tax revenue, a decline of about 26.9% in collections. Notice that the decline in tax revenue due to reducing the rate at unchanged P_M and Q is by far the largest component of the calculation and that this tax loss is not greatly offset by the effect of increased production at unchanged P_M and t_M.

Table 7.9 shows the effect of imposing the ton/mile tax on railroads. As discussed previously, the effective rate of tax per ton is \$0.025 (see Chapter 6). Imposing the tax at this rate, and leaving the severance tax rate unchanged at 7% leads to a 0.10% reduction in quantity of coal produced, or about 300,000 tons. Also, the mine-mouth price, its the delivered price, and the railroad freight rate are left virtually unchanged. The very low rate of tax explains why these effects are so small. An approximation to the total tax revenue to be generated from this tax can be calculated by applying the effective rate of tax per ton to the quantity of coal produced in 1998; i.e., $T_R=t_RQ$=\$0.025x305=\$7.63 million. (Note that this calculation is a bit too high because some Wyoming coal is burned in mine-mouth, coal-fired electric power plants and a small percentage is trucked out of state.) However, because imposition of this tax will cause (small) reductions in coal production and mine-mouth prices, severance tax collections (in millions of dollars) will fall by

$$\begin{aligned} dT_R=t_MQdP_M+t_MP_MdQ&=-(0.07)(305)(.001)-(0.07)(5.48)(0.30)= \\ &-0.0214-0.1151=-\$0.136 \end{aligned} \tag{7.21}$$

So, net of the decline in severance tax revenue, imposition of the ton-mile tax on railroads would produce an additional \$7.49 million in tax collections.

7.5 Conclusion

This chapter has developed a theoretical framework for evaluating the effects of taxes faced by the Wyoming coal industry and implemented it using empirical estimates constructed from three data sets, two of which were provided on a confidential basis to support this research. The overall conclusion reached in this analysis is that Wyoming coal production is relatively insensitive to comparatively small changes in taxes levied on the coal industry or on railroad transportation of coal. Tax collections, on the other hand, can fall substantially with reductions in tax rates. As demonstrated in the example of the hypothetical coal severance tax rate reduction by 2-percentage points from 7% to 5%, coal output was predicted to rise by only about 0.50%, whereas coal severance tax collections were predicted to fall by about 27%. Also, a byproduct of the analysis yields calculations of the extent of monopsony power exerted by railroads over the Wyoming mines and the extent of monopoly power railroads exert over the electric utilities. Further study of these issues may well be productive in that they lead to lower production of coal in Wyoming than would be otherwise be the case if transportation of coal was competitively provided.

Table 7.1

Demand Data Description, Source, and Means
Stage I Probit

Variable	*Description and Source*	*Means* PRB	*Means* Wyoming
DISTANCE	Distance between Gillette, Wyoming and all Wyoming coal buying power plants. In miles as the "crow flies."	760	764
RDPRICEHAT	Predicted Delivered Price in $1995. See Equations (7.18) and (7.19).	33.94	36.31
RGASPR	Weighted, average-annual, natural gas price paid by plants that burn coal, 1983-98. In $1995/MMBTU using the GDP deflator. Source: *FERC Form 423, Annual*.	3.015	3.015
GENER	Net annual electric power plant (coal) generation, 1983-98. In billions of Kwh. Source: *Monthly Power Plant Report, EIA/DOE, Annual Summaries.*	3.994	3.994
D1990	Dummy variable = 1 if year is 1990-98, 0 otherwise.	0.575	0.575

Table 7.2

Stage I Random Effects Probit Models[a]

	Marginal Effects (t)	
Variable	***PRB***	***Wyoming***
CONSTANT	-0.396	0.102
	(-0.86)	(4.04)
RDPRICEHAT	-0.015	-0.011
	(-16.40)	(-10.39)
RGASPR	0.012	0.006
	(3.12)	(2.65)
GENER	0.107	0.051
	(8.36)	(7.03)
D1990	0.027	0.017
	(3.78)	(3.95)
<u>Summary Statistics</u>		
CHI-SQUARED (1 df)	3044.6	3252
PSUEDO R^2	0.55	0.56
N	6238	6238
RHO	0.818	0.805

[a] Dependent variable is binary and equals one if a power plant purchased either PRB or Wyoming coal in a given year, zero otherwise. Unbalanced panels for 416 coal buying power plants.

Table 7.3

Demand Data Description, Source, and Means
Stage II Ordinary Demand

Variable	***Description and Source***	***Means*** ***PRB***	***Wyoming***
RDPRICE	Weighted, average-annual, delivered price of Wyoming Coal, 1983-98. In $1995/ST using the GDP deflator. Source: *FERC Form 423, Annual.*	24.14	27.98
QUANTITY	Annual Wyoming coal purchased by a power plant, 1983-98. In MMST. Source: *FERC Form 423, Annual*.	1.969	1.752
RGASPR	Weighted, average-annual, natural gas price paid by plants that burn Wyoming coal, 1983-98. In $1995/MMBTU using the GDP deflator. Source: *FERC Form 423, Annual*.	2.828	2.863
OTHERCOAL	Weighted, average-annual, price of non-Wyoming coal. In $1995/MMBTU using the GDP deflator. Source: *FERC Form 423, Annual*	1.596	1.615
GENER	Net annual electric power plant (coal) generation, 1983-98. In billions of Kwh. Source: *Monthly Power Plant Report, EIA/DOE, Annual Summaries.*	4.07	4.05
MILLS	Inverse Mills Ratio. Heckman (1979)	1.447	1.456

Table 7.4

Ordinary Demand, One-Way Fixed Effects Estimates[a]

Variable	***Coefficient (t)*** ***PRB***	***Wyoming***
RDPRICE	-0.014 (-2.19)	-0.012 (-2.95)
RGASPR	0.234 (3.12)	0.264 (3.07)
OTHERCOAL	-0.163 (-0.45)	-0.347 (-0.83)
GENER	0.509 (1.70)	0.643 (1.84)
MILLS	0.71 (4.34)	0.30 (1.66)
<u>Summary Statistics</u>		
R^2	0.83	0.73
F TEST, PLANT EFFECTS (df)	32.7 (171,1186)	21.4 (178,1502)
F TEST, PLANT AND TIME EFFECTS (df)	1.1 (15,1170)	1.1 (15,1486)
HAUSMAN	36.8	45.7
N	1362	1685

[a] Dependent variable is the natural log of quantity. Unbalanced panels with 172 and 179 power plants, respectively.

Table 7.5

Rail Cost Data Description, Source, and Means

Variable	***Description and Source***	***Means*** ***PRB***	***Wyoming***
RAILCOST	Sampled annual (coal) rail variable-cost, railhead to railhead, 1988-98. In millions of $1995 using the GDP deflator. Computed by the Surface Transportation Board using the Uniform Railroad Costing System. Source: *Carload Waybill Sample, Surface Transportation Board, 1988-98.*	8.246	6.788
QUANTITY	Sampled (annual) Wyoming coal delivered to a power plant, 1988-98. In MMST. Source: *Carload Waybill Sample, Surface Transportation Board*	0.950	0.783
CAROWN	If rail cars are privately owned = 1, 0 if owned by the Railroad. Source: *Carload Waybill Sample, Surface Transportation Board.*	0.84	0.78
RAILMILES	Rail miles between origin Wyoming railhead and destination power plant railhead. Source: *Carload Waybill Sample, Surface Transportation Board.*	978	940

Table 7.6

Rail Cost, Two-Way Fixed Effects Estimates[a]

	Coefficient (t)	
Variable	***PRB***	***Wyoming***
CONSTANT	-0.399 (-4.54)	-0.806 (-10.77)
QUANTITY	.98 (21.64)	1.22 (27.74)
CAROWN	0.497 (5.53)	0.481 (5.83)
Summary Statistics		
R^2	0.89	0.87
F TEST, RAILHEAD PAIR EFFECTS (df)	9.7 (206,852)	8.6 (243,1077)
F TEST, RAILHEAD AND TIME EFFECTS (df)	4.9 (10,841)	6.4 (10,1066)
HAUSMAN	29.2	15.7
N	1060	1322

[a] Dependent variable is the natural log of the real rail variable-cost.

Table 7.7

Wyoming Model, Component Estimates, 1998 Data

Component	***1998 Estimates***
$P_D = f$	18.47
f_Q	-2.38
f_{QQ}	1.08
C_Q	9.12
C_{QQ}	10.032
H	5.09
H_Q	0.00372
H_{QQ}	0.00008
t_M	0.07
P_M	5.48
D	-12.64

Table 7.8

Wyoming Model, Effects of the Severance Tax Reduction

Effect	***1998 Estimates***
Δ in Production MMST (%)	1.42 (0.47 %)
Δ in Mine Price $ (%)	$-0.12 (-2.15 %)
Δ in Delivered Price $ (%)	$-0.02 (-0.12 %)
Δ in Freight Rate $ (%)	$0.10 (0.77 %)
Δ in Severance Tax Rev. $M (%)	$-31.4 (-26.9 %)

Table 7.9

Wyoming Model, Effects of Levying a Ton/Mile Tax

Effect	***1998 Estimates***
Δ in Production MMST (%)	-0.302 (0.10 %)
Δ in Mine Price $ (%)	$0.0 (0.0 %)
Δ in Delivered Price $ (%)	$0.01 (0.03 %)
Δ in Freight Rate $ (%)	$0.0 (0.03 %)
Δ in Severance Tax Rev. $M (%)	$-0.14 (-0.12 %)
Δ in Ton/Mile Tax Rev. $M (%)	$7.6 (100%)

CHAPTER 8

MODELING PHASE I WYOMING COAL DEMAND

8.1 Introduction

The acid rain program created by Title IV of the Clean Air Act Amendments (CAAA) of 1990 introduces a sulfur dioxide (SO2) emissions permit market for the electric utility sector. In Phase I (1995-99), EPA began controlling aggregate annual emissions from the 263 dirtiest large generating units in the US by issuing a fixed number of SO2 emissions permits. For every ton of SO2 it emits annually, a plant must surrender an emissions permit to the EPA. Each plant is provided an annual endowment of permits, at no charge, based on 2.5 pounds of SO2 per MMBTU's burned during a base period in the 1980's. Over time, the number of permits issued by the EPA will decline (Schmalensee, et al., 1998). In Phase II (2000 and beyond), virtually all existing and new fossil-fueled electric generating units in the US become subject to similar, but tighter, SO2 regulation. In Phase II, plants will be issued smaller annual permit endowments, based on 1.2 pounds of SO2/MMBTU (EIA, 1997).

The 1990 CAAA presents both opportunity and challenge for the Wyoming coal industry. As the overall emissions of SO2 are progressively restricted, Wyoming low sulfur coal is likely to be favored. However, increasing use of Wyoming coal is not certain for three reasons. First, compared to prior SO2 regulation, CAAA 1990 provides utilities with additional options in responding to SO2 emissions regulation, most notably switching to lower sulfur coal from other regions, installing fuel gas desulfurization (FGD) equipment, and reallocating SO2 emissions over time. Depending on the relative costs of these options, plants may or may not decide to purchase more Wyoming coal in any given year. Second, besides Wyoming there are other important sources of low sulfur coal, including Colorado, Utah, and the central Appalachian region (EIA 1997). For many plants, especially those distant from Wyoming, these other coals may have a price advantage. Ellerman, et al. (1997) note that more SO2 emissions reductions by Phase I plants have resulted from the use of lower sulfur coal from other regions than from the use of PRB coal. Third, even if Wyoming coal can be delivered to a plant at a lower price than low sulfur coal from other regions, the plant may encounter substantial costs in retrofitting their boilers and coal processing facilities to accommodate the use of Wyoming coal (EIA 1997; Ellerman, et al., 1997).

The purpose of this chapter is to implement an empirical model of cost minimizing Phase I plants purchasing Wyoming coal. We focus on plants' choices about SO2 emissions, permit trading, and permit savings as well as their fuel choices. At the end of the chapter, the empirical results are used to predict changes in Wyoming coal production induced by 1990 CAAA.

8.2 Phase I Choices

Holding power generation constant, there are three basic ways to comply with SO2 regulations: (1) The plant may engage in fuel switching by purchasing coal lower in sulfur, blending high and low sulfur coal, or cofiring with natural gas. (2) The plant may obtain additional permits from other plants owned by the same utility, or purchase permits on the open market or at EPA auctions. (3) The plant may install FGD equipment, or retrofit existing FGD equipment. Other, less important, options include refiring boilers, retiring boilers, or using previously implemented controls (EIA 1997). A recent survey of utilities found that 41 percent of utilities use fuel switching, or plan to do so, while 28 percent purchase, or plan to purchase, additional allowances. The remainder will choose other options or combinations of options. Ellerman, et al. (1997) estimate that 55 percent of the emissions reductions of Phase I plants resulted from fuel switching, while 45 percent came from the use of new or retrofitted FGD equipment. The choices made by utilities are based largely on cost. For example, the annualized costs per ton of SO2 abated averages \$113 for fuel switching compared to \$225-\$322 for installing FGD equipment (EIA 1997; Ellerman, et al., 1997)

Since implementation of Phase I, three salient features have emerged. First, the price of permits and the volume of permit trading are lower than expected. Before 1990, analysts predicted permit prices between \$1500 and \$3000, but the actual prices are much lower. In 1993 prices were about \$170, falling to \$130 in 1995, falling further to \$65 in 1996, increasing to \$105 to in 1997, and currently at about \$130 (EPA Acid Rain). The volume of permit trading was initially very low, but has progressively increased (Schmalensee, et al., 1998). Ellerman, et al. (1997) argue that low permit prices are partly due to excessive FGD equipment installed when permit prices were expected to be much higher than realized prices.

Second, the saving or banking SO2 permits for later use in Phase II has emerged as an important phenomenon. Each permit carries a vintage year. A permit with a given vintage year (say 1995) can be used to compensate the EPA for emissions in that year or in any later year (say 1996, 1997, ...). Permit savings allow a plant to defer more expensive SO2 reductions for later years. Ellerman, et al. (1997) find that 3.4 million of the 8.7 million permits allocated in 1995 were saved. It is estimated that, by 2000, utilities will save up to 15 million permits for use at a later time (EIA 1997). The most plausible explanations for high levels of savings are high transactions costs in learning about the market for permits, uncertainty about market fundamentals in Phase II, and lower than expected abatement costs due to decreasing low sulfur coal prices and transportation rates (EIA 1997 and Schmalensee, et al., 1998).

Third, concern has surfaced that CAAA 1990 implementation will be adversely affected by regulatory policies at the state level. Indiana and Illinois have passed laws requiring plants within the states to use in-state coal, rather than fuel switch. But the courts overturned these laws (EIA 1997). Moreover, asymmetric regulatory treatment of the costs and revenues from permit trading compared to the costs of other inputs may induce distortions in plants' input choices or emissions levels. Simulation studies have suggested that these distortions may be substantial (Fullerton, et al., 1997 and Winebrake, 1995), but Ellerman, et al. (1997) discount their importance. We are not aware of any empirical studies of the regulatory effects on Phase I plants' choices.

8.3 Phase I Wyoming Coal Purchasers

Among Wyoming coal purchasers, 39 plants have come under Phase I of 1990 CAAA. As shown in Table 6.5, these plants are all located in Midwest, except Jim Bridger. These Phase I plants have a combined capacity of 39,615 MW, about 33 percent of the capacity of all current Wyoming coal customers, and purchase about 23 percent of all Wyoming coal. Phase I regulation applies to individual generating units, while plants often contain multiple generating units. Consequently, only a fraction of the total capacity of a given plant (averaging 70 percent in our sample) may be subject to Phase I regulation, although all capacity will be subject to Phase II regulation.

Some indication of the changes brought about by Phase I can be seen in Tables 8.1 and 8.2, which give descriptive statistics for Phase I plants before and after 1995. Since the beginning of Phase I, the average delivered price of Wyoming coal has fallen slightly, while Wyoming coal purchases have increased by 15 percent. Concurrently, Wyoming coal's share of total expenditures on fuel and labor increased on average from .41 to .52, while the share of other fuel decreased from .43 to .32. This suggests that Phase I plants use fuel switching to Wyoming coal for Phase I compliance. However, over the same time period, similarly located non-Phase I plants have also increased their purchases of Wyoming coal, but at a lower rate.

The permit trading and savings decisions of Phase I plants are summarized in Table 8.3. In each year, Phase I plants purchasing Wyoming coal have been, on average, net sellers of SO2 permits. After increasing from 7371 in 1995 to 8506 in 1996, average sales fell to 6305 in 1997. Total lagged savings, or permit savings from prior years, has increased from 0 in 1995 to 695,000 tons in 1997, while annual savings increased from an average of 9000 per plant in 1995 to nearly 24,000 in 1997. Clearly, permit savings are an important part of Phase I plants' compliance strategies.

8.4 Model Specification and Data

For each year and for each ton of SO2 emitted, Phase I plants must pay the EPA one permit. The annual permit requirement may be met by purchasing permits on the open market or at EPA auction at price P_E, or from an annual endowment of permits, W, or from banked permits from previous years, S_{-1}. In addition, denote the number of permits not used in the current year and saved for use in later years as S. Permits that are paid to the EPA or saved could have been sold on the market, also at price P_E, so that the total cost of emissions is given by

$$P_E Y = P_E[E-(W+S_{-1}-S)]\,, \tag{8.1}$$

where Y is quantity traded and E is amount of SO2 emitted. Note that $W + S_{-1} + Y - E = S$. Burning Wyoming coal and other fuels (except gas) produces SO2, and the quantity of SO2 emitted depends on the fuels used and their sulfur content. So SO2 emissions are given by

$$E = E(X_{WC}, X_{OF}, \rho_{WC}, \rho_{OF}), \tag{8.2}$$

where $E(X_{WC}, X_{OF}, \rho_{WC}, \rho_{OF})$ is the emission function, and ρ_{WC} and ρ_{OF} are the sulfur contents of Wyoming coal and the other fuel, respectively. Thus, the cost of emission is

$$P_E Y = P_E\,[E(X_{WC}, X_{OF}, \rho_{WC}, \rho_{OF}) - G], \tag{8.3}$$

where $G = W + S_{-1} - S$ is the number of permits that can be used net of the amount traded. $P_E\,[E(x) - \mathrm{G}]$ is the plants' total cost of emissions including the revenue that it forgoes when it produces a ton of SO2 rather than selling a permit.

The plant's problem is then to minimize the sum of its input and emissions costs, while meeting its fixed output constraints and the constraint that it has all of the permits it requires. Formally, the plant's constrained cost minimization problem is

$$Min\;\; L = P_{WC}X_{WC} + P_{OF}X_{OF} + P_{NW}X_{NW} + P_E[E(X_{WC}, X_{OF}, \rho_{WC}, \rho_{OF}) - G] \tag{8.4}$$

$$- \;\lambda_1(Q(X_{WC}, X_{OF}, X_{NW}; M) - Q^*) - \;\lambda_2(W + S_{-1} - S - G^*)\,,$$

Q^* and G^* are given amounts of G and Q, and λ_1 and λ_2 are Lagrangian multipliers. Solving the first order conditions for (8.4) yields the optimal quantities of X_i (i=WC, OF, and NW) and E as functions of P_{WC}, P_{OF} , P_E, $\boldsymbol{r}_{WC}$, $\boldsymbol{r}_{OF}$, Q^* , G^*, M. In (8.4), we assume that S_{-1} and S are given, so the plant's problem does not span multiple time periods. Substituting the optimal X_i and E into the relevant part of the cost function, $P_{WC}X_{WC}$ + $P_{OF}X_{OF}$ + $P_{NW}X_{NW}$ + P_E $E(X_{WC}, X_{OF}, \boldsymbol{r}_{WC}, \boldsymbol{r}_{OF})$, gives the minimum cost function

$$C = C\,(P_{WC}, P_{OF}, P_{NW}, P_E, \boldsymbol{r}_{WC}, \boldsymbol{r}_{OF}, M, Q^*, G^*) \tag{8.5}$$

To estimate equation (8.5), we specify the translog cost function as a flexible approximation. The translog cost function is

$$\begin{aligned} \ln C = {} & \boldsymbol{a}_0 + \boldsymbol{a}_t t + \sum_i \boldsymbol{a}_i \ln P_i + \ln \sum_k \boldsymbol{a}_k \ln \boldsymbol{r}_k + \boldsymbol{a}_M \ln M_1 + \boldsymbol{a}_E \ln M_E + \boldsymbol{a}_G \ln G + \boldsymbol{a}_Q \ln Q \\ & + \sum_i \sum_j \boldsymbol{a}_{ij} \ln P_i \ln P_j + \sum_i \boldsymbol{a}_{iQ} \ln Q + \sum_i \boldsymbol{a}_{iG} \ln G \\ & + \frac{1}{2} \boldsymbol{b}_{QQ} (\ln Q)^2 + \boldsymbol{b}_{QG} \ln Q \ln G + \frac{1}{2} \boldsymbol{b}_{GG} (\ln G)^2 + \boldsymbol{b}_t t_c\,, \end{aligned} \tag{8.6}$$

where M_1 is the fixed capacity of the non-Phase1 units of the plant, M_E is the capacity of units in Phase I[1], Q is the annual output, $\boldsymbol{r}_k$ is emission charge rate ($k = WC, OF$), P_i and P_j represents prices ($i,j = WC, OF, NW, E$) and t is a time trend to capture annual changes of optimizing behavior (t = 95, 96, 97). We include only first order terms for capacities, t, and ñ$_k$ to avoid estimation problems caused by a large number of explanatory variables.

To increase the efficiency of the estimates, we also estimate the equations for each input's expenditure share to the total cost. These share equations are given by

$$M_i = \boldsymbol{a}_i + \sum_j \boldsymbol{a}_{ij} \ln P_j + \boldsymbol{a}_{iQ} \ln Q + \boldsymbol{a}_{iG} \ln G_i\,, \tag{8.7}$$

where i,j = WC, OF, NW and E.

The cost is a function of the given amount of $G = W + S_{-1} - S$. For a given year, the endowment, W, and previous savings, S_{-1}, are predetermined. However, the current period's saving, S, is likely to also be chosen by each utility as part of an intertemporal strategy to comply with Phase I and an uncertain Phase II. Therefore, G may be an endogenous variable. To mitigate potential endogeneity biases, we estimate a savings equation simultaneously with (8.6) and (8.7). The savings equation is specified as

$$S = h_0 + h_1(P_E - dP_{E+1}) + h_f \, perfgd + h_M M + h_{ME} M_E + h_t t + \sum_m h_m SD_{m\,s}\,, \tag{8.8}$$

where d is the discount factor, P_{E+1} is expected permit price in the next period, and *perfgd* is the percentage of SO2 removed by the plants FGD equipment (=0 if FGD is not installed). We include the price difference between two periods, $P_E - dP_{E+1}$, as an explanatory variable for savings. If the allowance market is perfectly competitive with no transaction costs in the permit market, and the plant is not subject to profit regulation, the first order condition from inter-temporal dynamic optimization is

$$- P_{Et} + dEP_{Et+1}. \tag{8.9}$$

There is no interior solution for savings only according to this first order condition, which implies that if permits are more valuable later than they are today, the firm will only save permits. In equilibrium, the plant is only willing to bank permits if the permit price rises with the rate of interest[2]. However, high transactions costs, regulatory distortions, and future uncertainty may invalidate this condition and enable each plant to obtain the optimal savings as an interior solution. In our estimation, we assume perfect foresight and use actual permit price in a subsequent year as next period's expected permit price.

We also include M_1 and M_E in the saving equation. If some portion of savings can be capitalized and used directly for emissions abatement, capacity levels may influence savings. We include a set of state dummy variables, SD_m, to capture state-specific differences[3] in regulation, m = GA, IA, IL, IN, KS, KY, MI, MN, MO, OH, WI, WY. The reference state is MN. Finally, we also capture temporal effects with the time variable, t.

8.5 Estimation Results and Discussion

We simultaneously estimate equations (8.6), (8.7), and (8.8) after imposing the restrictions for linear homogeneity of the cost function in prices and dropping one share equation (see Berndt, 1991, for details). Our sample of Phase I Wyoming coal customers contains annual 83 observations from the years 1995-97. We used the average U.S. bond for each year as proxy for the discount rate. Data on emissions, permit endowments, savings, and regulated capacity are from EPA Acid Rain.

The parameter estimates are provided in Table 8.4 and 8.5. The model fits the data quite well, with a pseudo R^2 =0.85121[4]. Values of R^2 for the individual equations are also quite high, ranging from .81 for the cost equation, 0.58 for the emissions share, and 0.21 for the labor share. The estimation results show that the cost function is monotonic, as theory requires, as each share is positive when evaluated at sample mean. The permit price difference has a negative impact on savings as theory suggests, but, again the effect is not statistically significant.

We conduct a test of the null hypothesis that coefficients of states dummies are not all jointly different from zero using a likelihood ratio test. The test statistic is 55.11, compared to the critical ÷ $^{2}_{df=11}$=19.68, leading us to reject the null hypothesis (á < .01) that state regulation of the revenues and costs of permit trading does not influence savings behavior and emission levels. This suggests the existence of asymmetric transaction costs across states and/or market distortions in the permit market caused by different regulatory treatments has influenced Phase I plant's savings decisions. The evidence is strongest for Illinois, with a positive and statistically significant coefficient.

The parameter estimates can be used to estimate changes in Wyoming coal purchases in response to changes in SO2 permit prices, changes in annual permit endowments, and in Wyoming coal prices. The demand for Wyoming coal is a function not only of prices, including P_E, but also G, while G also depends on S. Therefore, the cross price elasticity of X_{WC} and P_E can be expressed as the composite term as

$$E_{WCPE} = \frac{dX_{WC}}{dP_E} \cdot \frac{P_E}{X_{WC}} = \frac{\partial X_{WC}}{\partial P_E} \cdot \frac{P_E}{X_{WC}} + \frac{\partial X_{WC}}{\partial G} \cdot \frac{\partial G}{\partial S} \cdot \frac{\partial S}{\partial P_E} \cdot \frac{P_E}{X_{WC}}$$

$$= \frac{\boldsymbol{a}_{WCE} + M_{WC} M_E}{M_{WC}} + E_{WCG} \cdot (-\boldsymbol{h}_1) \cdot \frac{p_E}{G} \tag{8.10}$$

From equation (8.7) $M_{WC} = P_{WC} X_{WC}/C$ and taking logs gives $\ln X_{WC} = \ln M_{WC} + \ln P_{WC} - \ln C$. Then elasticity of X_{WC} and G is thus

$$E_{WCG} = \frac{\partial \ln X_{WC}}{\partial \ln G} = \frac{\partial \ln M_{WC}}{\partial \ln G} + \frac{\partial \ln C}{\partial \ln G} \tag{8.11}$$

If we substitute (8.11) into (8.10), we obtain the cross price elasticity E_{WCPE}. We also estimate the own price elasticity of demand for Wyoming coal. Table 8.6 gives the elasticity estimates when evaluated at the sample mean. The estimate of E_{WCPE} =.062 is positive and statistically different from zero. This suggests that, if permit prices continue their recent increases, the quantity of Wyoming coal purchased by these plants will also increase. However, the effect will be small unless permit prices increase dramatically. The estimate of E_{WCG} =.033 is also positive, but is not statistically different from zero. This result suggests that the decrease in annual endowments commencing with Phase II will not have a substantive effect of Wyoming coal purchases unless permit prices also change. The estimated own price elasticity of demand for Wyoming coal is -.960.

8.6 Predicting Changes from SO2 Regulations

Beginning with Phase II this year, virtually all steam electric power plants in the U.S. will be subject to the SO2 regulations of the 1990 CAAA. Wyoming is the predominant supplier of low sulfur coal in the U.S. and fuel switching to PRB coal has proven to be a popular method used by Phase I plants. It seems likely that Wyoming coal output will be positively affected by Phase II.

It is tempting to predict the effects of Phase II on Wyoming coal output by simply extrapolating from the behavior of Phase I plants. Phase I plants in 1997 purchased about 15 percent more coal, on average, than they did in 1994. A simple approach would be to predict a similar increase for the new plants entering Phase II. Such a prediction would probably be misleading for several reasons. First, nearly all Wyoming coal customers increased Wyoming coal purchases between 1994 and 1997, by 9 percent on average. So not all of the 15 percent increase in demand should be attributed to SO2 regulation. Second, some of the increase in Phase I plants' Wyoming coal purchases can be attributed to lower Wyoming coal prices and transportation rates and expiring or renegotiated contracts between Phase I plants and Midwestern coal suppliers (Ellerman, et al., 1997). Given the differences in the demand increases between all plants and Phase I plants, a conservative estimate is that SO2 regulation has accounted for a 3-6 percent increase in Wyoming coal demand for Phase I plants.

Third, many plants new to SO2 regulation under Phase II differ substantially from Phase I plants. Phase I plants were the most polluting plants in the country, are located in primarily in the Midwest, and are among the most aged. Phase II plants are more heterogeneous. Some were built quite recently and a higher proportion are fitted with FGD equipment. Most importantly, a much higher proportion of Phase II plants are located outside the Midwest and burn natural gas, containing little or no sulfur, as an alternative fuel. Phase II status will not induce fuel switching to Wyoming coal for gas-using plants; the opposite effect is more likely. Fourth, the location of Phase I plants gave Wyoming coal an advantage that may not be repeated for Phase II. Wyoming coal has traditionally competed in states such as Nebraska, Minnesota, Illinois, and Missouri. Higher transportation costs make it less likely that it can compete similarly in other, more distant, states. Fifth, Phase II will differ from Phase I in that the initial allocation of permits, based on prior fuel usage, will be decreased by about one half. The results presented here suggest that this exogenous decline in initial permit allocations will have a negative effect on Wyoming coal purchases, but the estimate is not statistically different from zero.

Finally, a critical determinant of the effect of Phase II is the price of SO2 permits. As discussed, permit prices are much lower than analysts predicted, but have increased somewhat in recent years. Currently, permits prices are about $130 per ton of SO2, but it is unlikely that these are long run equilibrium prices.

Ellerman, et al. (1997) provide convincing evidence that the long run price of permits will equal the incremental cost of removing a ton of SO_2 with FGD equipment. Current engineering estimates suggest that these costs are $225-250 per ton of SO_2, or nearly a one hundred percent increase over current permit prices. The estimated the elasticity of Wyoming coal purchases with respect to changes in permit prices, E_{WCPE} =.062 (standard deviation=.024) .

Using this estimate of E_{WCPE} and assuming that the permit prices increase 100 percent in the long run, the predicted effect on Wyoming coal production is a 6.2 percent increase in output, ceterius paribus, for Phase I plants. Extending this prediction to all Phase II plants currently purchasing Wyoming coal requires that we take into account natural gas as an alternative fuel, where increases in permit prices can be expected to have a negative or zero effect on the demand for Wyoming coal. Assuming the latter for the approximately one third of Wyoming coal tonnage that currently competes directly with natural gas, implies that a doubling of permit prices will increase the demand for Wyoming coal by 4.09 percent (6.2*.66).

Combining this estimate with the 3-6 percent increase in Wyoming coal purchases attributable to Phase I status, and assuming the permit prices do move to the predicted levels, Phase II will result in a 7 to 10 percent increase in Wyoming coal production.

ENDNOTES

[1] If the plants have both units in table 1 and not in table 1, the cost minimization problem becomes

$$L = P_{WC}(X_{WC} + X_{WCE}) + P_{OF}(X_{OF} + X_{OFE}) + P_{NW}(X_{NW} + X_{NWE}) + P_E[E(X_{WCE}, X_{OFE}, \boldsymbol{r}_{WC}, \boldsymbol{r}_{OF}) - G]$$

$$- l_1(Q_{NE}(X_{WC1}, X_{OF1}, X_{NW1}; M_1) + Q_E(X_{WCE}, X_{OFE}, X_{NWE}; M_E) - Q^*) - l_2(W + S_{-1} - S - G^*),$$

where $Q_{NE}(\cdot)$ and $Q_E(\cdot)$ are production functions of non-table1 units and table1 units, respectively, X_{iE} is quantity of input i in production function $Q_E(\cdot)$, and M_E is the fixed capacity of production function $Q_E(\cdot)$. Here, X_{iE} is solved as function of P_{WC}, P_{OF} , P_E, $\boldsymbol{r}_{WC}$, $\boldsymbol{r}_{OF}$, G^*, M_1, and M_E. Therefore, the cost is an explicit function of M_E.

[2] See M. Cronshaw and J. Kruse (1996).

[3] For example, penalties on low-sulfur fuel purchases appear in Illinois, Indiana, Kentucky, Ohio, and Pennsylvania. Policies in New York sought to limit in state purchases, but also sales to upwind areas (D. Fullerton, S. McDermott, and J. Caulkins 1997)

[4] System R^2 = 1- (LR/LU), where LR and LU are restricted and unrestricted log of likelihood ; restriction is all coefficients in each equation in the system of equation are zero.

Table 8.1

Descriptive Statistics for Phase I Plants (1993-1994)

VARIABLE NAME	***MEAN***	***STANDARD DEVIATION***
P_{NW}	673.635	77.18424
P_{WC}	1.07020	0.23333
P_{OF}	1.92910	1.07837
M_{NW}^{A}	0.15878	0.073082
M_{WC}^{A}	0.41036	0.31668
M_{OF}^{A}	0.43085	0.32098
X_{WC}	$2.86955*10^{7}$	$3.71083*10^{7}$

Table 8.2

Descriptive Statistics for Phase I Plants (1995-1997)

VARIABLE NAME	***MEAN***	***STANDARD DEVIATION***
P_{NW}	695.961	81.30621
P_{WC}	1.00001	0.20930
P_{OF}	1.94953	1.06294
M_{NW}^{A}	0.14876	0.087615
M_{WC}^{A}	0.52521	0.31691
M_{OF}^{A}	0.32603	0.31257
X_{WC}	$3.31269*10^{7}$	$3.77660*10^{7}$

Table 8.3

Annual Changes in Savings and Trading

MEAN(SUM)	***Total MEAN (SUM)***	***1995 MEAN (SUM)***	***1996 MEAN (SUM)***	***1997 MEAN (SUM)***
LAGGED SAVING	12041 (999416)	0 (0)	10493 (304319)	21063 (695097)
ENDOWMENT	39484 (3277241)	42325 (888843)	34224 (992500)	42299 (1395898)
SAVING	17485 (1451255)	8956 (188096)	16669 (483416)	23628 (779743)
TRADING	-7344 (-609563)	-7371 (-154792)	-8506 (-246689)	-6305 (-208082)
NUMBER OF OBSERVATIONS	88	23	31	34

Table 8.4

Parameter Estimates of the Cost Function

Parameter	***Estimates***	***Standard Error***	***t-statistic***
Constant	17.6945	0.2620	67.5414
lnP_{WC}	0.5499	0.0670	8.2049
lnP_{OF}	0.2590	0.0827	3.1321
lnP_{NW}	0.1074	0.0276	3.8924
lnP_{E}	0.0837	0.0382	2.1904
lnM_{1}	0.0506	0.0723	0.6997
lnM_{E}	0.0062	0.1379	0.0453
$ln\ g_{WC}$	-0.1945	0.2284	-0.8516
$ln\ g_{OF}$	0.0135	0.0115	1.1663
lnG	0.0708	0.1445	0.4899
lnQ	0.9858	0.2406	4.0973
t	0.1112	0.0680	1.6347
$(lnP_{WC})^2$	-0.3448	0.1135	-3.0392
$lnP_{WC}\ lnP_{OF}$	0.3448	0.1135	-3.0392
$lnP_{WC}\ lnP_{NW}$	-0.1037	0.0524	-1.9787
$lnP_{WC}\ lnP_{E}$	-0.0092	0.0463	-0.1995
$lnP_{WC}\ lnG$	-0.0189	0.0383	-0.4951
$lnP_{WC}\ lnQ$	0.0489	0.0669	0.7317
$(lnP_{OF})^2$	-0.2655	0.1294	-2.0519
$lnP_{OF}\ lnP_{NW}$	-0.3345	0.0274	-1.2227
$lnP_{OF}\ lnP_{E}$	-0.0459	0.0493	-0.9301
$lnP_{OF}\ lnG$	-0.0109	0.0534	-0.2048
$lnP_{OF}\ lnQ$	0.0485	0.0742	0.6537
$(lnP_{NW})^2$	0.1415	0.0559	2.5296
$lnP_{NW}\ lnP_{E}$	-0.0045	0.0300	-0.1502
$lnP_{NW}\ lnP_{E}$	-0.0045	0.0300	-0.1499
$lnP_{NW}\ lnG$	-0.0121	0.0185	-0.6556
$lnP_{NW}\ lnQ$	-0.0375	0.0247	-1.5199
$(lnP_{E})^2$	0.0596	0.0612	0.9746
$lnP_{E}\ lnG$	0.0420	0.0224	1.8734
$lnP_{E}\ lnQ$	-0.0599	0.0260	-2.3088
$(lnQ)^2$	0.2541	0.2347	1.0831
$lnQlnG$	-0.1212	0.1496	-0.8107
$(lnG)^2$	-0.0176	0.1242	-0.1418

Table 8.5

Parameter Estimates of Savings

Parameter	***Estimates***	***Standard Error***	***t-statistics***
Constant	-7875.85	20529.3	-0.383639
P_E - dP_{E+1}	-55.6739	138.439	-0.402154
Pergd	6957.82	.183775E+07	0.378605E-02
M_1	-2906.95	19902.3	-0.146061
M_E	18434.0	15797.0	1.16693
t	2663.58	5022.11	0.530370
SD_{IL}	51407.8	17722.7	2.90067
SD_{IN}	18657.7	18187.6	1.02585
SD_{KS}	-3734.00	21636.4	-0.172580
SD_{KY}	10207.4	79201.2	0.128880
SD_{MI}	-20304.0	20527.3	-0.989121
SD_{GA}	55231.1	.118888E+09	0.464565E-03
SD_{MO}	1200.44	16125.7	0.074443
SD_{OH}	-6996.25	21474.7	-0.325790
SD_{WI}	6457.72	25138.2	0.256889
SD_{IA}	8212.52	39548.5	0.207657
SD_{WY}	-8445.96	.121739E+07	-0.693773E-02

Table 8.6

Estimates of Elasticities

Parameter	***Estimate***	***Standard Error***	***t-statistic***	***P-value***
E_{WCPE}	0.062	0.024	2.57	[.000]
E_{WCG}	0.03298	0.144	0.24	[.819]
E_{OPWC}	-0.961	0.226	-4.25	[.000]

CHAPTER 9

EFFECTS OF TAX CHANGES AND TAX INCENTIVES ON INCOME AND EMPLOYMENT

This chapter presents estimates of the impact of state tax changes and tax incentives on income, employment, and population in Wyoming. These estimates are computed using information on the changes in oil, natural gas, and coal production that were computed in Chapters 4 and 7 together with a model provided by Regional Economic Models, Inc. (REMI). This model is quite detailed and tracks activity in 172 economic sectors of the Wyoming economy. This chapter begins by giving an overview of the model and concludes by comparing the extent to which various taxes and tax incentives translate into jobs and incomes for Wyoming residents. These results represent the total economic contribution of the incentive in that they are inclusive of all multiplier effects.

The REMI model is one of several competitor models that can be used to estimate the economic contribution of tax and tax incentive changes in Wyoming's energy industries. This model was selected for use in the present study for the following reasons. First, its overall approach to forecasting and simulation has been extensively reviewed in the regional economics literature. For example, the editor of the *International Regional Science Review* referred to the model as an extraordinary success in the history of economic modeling. This comment was made in the introduction to a special issue of the *Review* (1992) devoted to evaluating performance of alternative economic forecasting models. Also, in a $200,000 study commissioned by the State of California, researchers at the Massachusetts Institute of Technology concluded that the methodology employed by the REMI model is theoretically sound and flexible enough for application in alternative modeling settings. The model has been applied by a large number of users under diverse conditions and has been proven to perform acceptably. Moreover, the model has benefited from a number of technical improvements made in recent years.

Second, contracting for use of an existing and tested model is more cost-effective than developing a new forecasting model from scratch or adapting a model that was built for another purpose. Third, unlike many competitor models, the model applied here is specifically calibrated using Wyoming data. In other words, this model is not merely an adaptation of a national model or a model that has been developed for another region of the U.S. Rather, it has been customized for use in Wyoming and is based on the most recent measurements of characteristics of this state's economy as well as its history. Fourth, the Wyoming Business Council leased both the 53-sector and 172-sector versions of the REMI model for a one-year period, beginning in January 2000. The 172-sector version of the model is more appropriate to use with oil, gas, and coal applications, and as a consequence was selected for use in this project. Terms of the lease permitted use of the model for this project as well as for a number of other purposes. Thus, the model could be used for this project at no cost over and above that already incurred for the lease.

The REMI model contains a large number of equations, however, it can be adequately described using the diagram in Figure 9.1. The model is designed to use information on value of oil, gas, and coal production and oil and gas drilling expenditures as input data. Also, the model allows each type of activity to have a different pattern of expenditures; in consequence, much of the detailed information that was obtained in the analyses in Chapters 4 and 7 is preserved. The upper left block of Figure 9.1 shows that data about Wyoming changes in production and drilling are fed into a 172-sector input-output model of Wyoming along with variables measuring national and international economic conditions. This input-output model calculates the value of output for all sectors, which can be summed to obtain an estimate of gross state product. The level of output in each sector then is translated into estimates of labor demand. Labor demands by sector then are compared to estimates of labor supply based on data concerning the size of Wyoming's population. Labor supply and demand, then, are balanced and in the process population is adjusted through in/out migration. Finally, the model produces estimates of wages, incomes, and employment by sector and uses these to calculate local consumption expenditures made by Wyoming residents.

The model is particularly useful in estimating the incremental contribution of changes in state taxes and tax incentives to the Wyoming economy. First, the model is used to make a control forecast showing how the Wyoming economy has operated in the recent past, and is likely to operate in the future, assuming that no major structural changes in the economy occur; i.e. the economy operates with business as usual. Second, the model can be applied to show what the Wyoming economy would be like if value of production and drilling expenditures by the oil, gas, and coal industries change because of the change in taxes or costs.

Table 9.1 presents a summary of control estimates for the State of Wyoming using the REMI model. The control estimates show the behavior of the Wyoming economy as it presently exists with no changes in the oil, gas, or coal industries. 1997 is the latest year for which complete data are available so actual values are presented for that year along with simulated values from the model. Forecasts from the model for 1998 and beyond are presented for total employment, real disposable personal income (in $1997), and population for selected years. Employment figures used include full, part-time, and seasonal jobs. The REMI model incorporates the actual 1997 state data and then creates a control forecast for the following years. Overall, the comparison of estimates to actual values for 1997 suggests that the REMI model accurately tracks the Wyoming economy and provides a useful starting point for computing the contribution of the three energy industries to the Wyoming economy. Also, the model suggests that this State's economy will exhibit modest growth in gross state product, employment, and personal income through the early years of the new millenium. Most observers of Wyoming's economy probably would not find this conclusion unreasonable. As shown in Table 9.1, Wyoming's population is predicted to decline each year reaching 427,000 persons by the year 2035. This forecast is quite pessimistic and suggests that Wyoming will continue to lose population to other states offering relatively better economic opportunities. current economic woes may well continue.

Table 9.2 presents estimates of the contribution of various tax changes and tax incentives that were analyzed in Chapters 4 and 7. These are: (1) a permanent 2 percentage-point reduction in the severance tax on oil, (2) a hypothetical 5 percent incentive for drilling, (3) a permanent severance tax reduction of 4 percentage-points on *all new* well production of oil and natural gas, (4) a permanent severance tax reduction of 4 percentage-points on incremental production resulting from qualified workovers and recompletions, (5) a permanent severance tax reduction of 2 percentage-points on incremental production from qualified tertiary projects, (6) a 2 percentage-point reduction in the severance tax on coal, and (7) the imposition of a ton-mile tax on rail transportation of coal. More information about these tax changes and tax incentives may be found elsewhere in the text of this report, in Appendix A, and in the Wyoming Statutes. Whereas a 60-year time horizon was used in the oil and gas simulation model developed in Chapter 4, the REMI model is capable of simulating only for a period of 35 years, so simulations for oil and gas tax changes are presented for the period 2000-2035. In particular, the simulations account for the time path of additional oil and gas production and drilling activity that arises due to the incentives considered. Incremental oil and gas production was valued at $19.22 per BOE to maintain consistency with the simulations in Chapter 4. Additional simulations with alternative assumptions regarding the expected path of future energy prices (rising and/or falling over time) yield similar results to those shown and are omitted from the present discussion. Drilling expenditures were computed by multiplying the estimates of wells drilled by Wyoming values for cost per foot drilled and average depth per well reported in Table 5.3. An example of the 35-year forecast of production value and drilling expenditures that are used as input data for the 2 percentage-point severance tax reduction on oil case (1) are presented in Table 9.3.

Regarding coal, recall that the coal model presented in Chapter 7 is not dynamic; it provides only comparative static changes in output and price changes at a point in time instead of an estimate of the future time path for these variables. In consequence, the production change figures obtained in Chapter 7 for the 2-percentage point severance tax reduction and the imposition of a ton/mile tax on railroads were assumed to occur in each of the next five years. In any case, the REMI simulations for policy changes pertaining to the coal industry were run with a five-year horizon, rather than the 35-year horizon used for oil and gas.

Resulting estimates of economic contribution, then, are interpreted as the total impact of the incentives on the Wyoming economy based on considering the incentives one at a time. This interpretation has two implications. First, it means that each tax change and tax incentive is considered independently, as if the others do not exist. Of course additional simulations could be performed that would examine effects of applying two or more incentives simultaneously. This strategy, however, was not pursued because a good approximation to the economic changes arising from a combination of tax features can be obtained by summing their individual effects.

Second, it means that estimates of economic contribution presented are inclusive of multiplier effects. In this context, a multiplier is a number that accounts for the fact that dollars received by the energy industries are at least partially re-spent in the state. As this re-spending process continues, total incomes, the number of jobs, gross state product, and size of population continue to rise. A multiplier, therefore, represents the magnitude of increase in these variables for every dollar of income or job created. The multiplier is larger for personal income than for employment because personal income is more sensitive to economic shocks, such as tax changes than is employment. In the face of changes in business climate, employers often are reluctant to lay off workers in bad times and/or make commitments to additional workers if conditions suddenly improve.

Table 9.2 indicates that economic effects felt throughout the state in response to all incentives and tax changes considered are relatively modest. For example, regarding a permanent 2-percentage point severance tax cut on oil production, total employment in

2000 would rise by 313 persons. This estimated employment increase steadily declines until 2035, when the tax reduction means that 123 additional persons would be employed. Income effects of the tax reduction are also are quite small. Real personal disposable income (in $1997) would be about $8 million larger in 2000 and about $5.8 million larger in 2035. Thus, in 2000, real personal disposable income per employee added to the state's economy would be $25,559 ($8 million/313) and the corresponding value for 2035 would be $47,154 ($5.8 million/123). This last calculation is of interest as it shows how the model accounts for expected real wage and salary increases due to productivity changes and related factors over the next 35 years. The model also suggests that as employment and real income rise, Wyoming's population will rise as well. In 2000, the population increase resulting from the tax change would be 246 persons. By 2010, the Wyoming population would be 380 persons larger than without the severance tax reduction. These estimates reflect the fact that the effects of the tax change on population do not all occur in one year and instead accumulate over time as people's decisions to move into the state often require more than a year to be implemented. However, by the year 2035, the state population increase associated with the tax change is only 178 persons.

A drilling incentive or technological change (as described in Chapter 4) that would lead to a 5 percent decrease in real drilling cost has a larger effect on the Wyoming economy as compared to the severance tax cut just described. Total employment in the year 2000 would increase by 1028 jobs with 950 of them appearing in the private non-farm sector. Income effects are also comparatively larger. Real disposable personal income increases by roughly 3.5 times the income generated in the severance tax case for each of the years listed in Table 9.2. As described in Chapter 4, the drilling incentive has the greatest impact on exploration in the early years of the program. As a consequence, the effects of the incentive on employment and income would be expected to decline through time as shown.

Table 9.2 also shows impacts on employment, personal income and population of tax incentives for new production of oil and gas, tertiary production, and workovers and recompletions of existing wells. As shown, the tax incentive for new well oil and gas production has the largest effect among these three on the state's economy. Note, however, that this scenario (as with all simulations unless otherwise noted) assumes the incentive permanently applies to *all new* well production simulated over the 60 year project life. In the year 2000, this tax incentive stimulates employment by 832 jobs, increases personal income by about $21 million, and adds 654 people to Wyoming's population. Notice, however, that these economic benefits taper off over time. In the year 2035, for example, the economic impact of this tax incentive falls by more than half. Tax credits for tertiary production and workovers and recompletions have a relatively smaller impact because they apply to relatively small fractions of production. For example, in 1997, qualifying tertiary projects accounted for approximately 5% of state oil production (Wyoming Oil and Gas Conservation Commission, 1997). As previously discussed in chapter 4, the Wyoming Consensus Revenue Estimating Group (CREG, 2000) assumptions were employed in the tertiary, workover and recompletion simulations.

Table 9.2 also presents results from the REMI model regarding the economic contribution of a 2-percentage point severance tax reduction on coal production as well as the effect of imposing a ton/mile tax on railroads. In the first year of a coal severance tax cut, total employment would increase by 61 workers statewide, personal income would rise by about $2.5 million, and population would rise by about 70 persons. These results are consistent with the idea developed in Chapter 7 that a reduction in coal severance taxes leads to little additional production. Also, as would be expected, imposition of a ton/mile tax on railroads would lower employment, personal income, and population as output of coal would be expected to fall. However, these economic losses would not be large. Notice that in the first year of this tax, Wyoming would lose 21 jobs, personal income of about $0.8 million, and 25 persons would move out-of-state.

This overall pattern of economic effects from tax changes and tax incentives considered should be expected for three reasons. First, regarding oil and gas, production tax changes and tax incentives have only an indirect effect on incentives for exploration, whereas an incentive for drilling directly affects incentives to engage in this activity. As demonstrated in Chapter 4, reserve levels, not by prices, drive production and the only way to add reserves is to explore. Thus, a drilling incentive would be expected to have correspondingly larger effects than an tax incentive applied to production. Second, as discussed in Chapter 7, a 2-percentage point reduction in coal severance taxes has only a small effect on production costs per ton. Third, Wyoming's energy industries are not labor intensive. For example, based on data from the REMI model, the ratio of the change in output from the oil and gas production and field services sectors to the employment change in those two sectors is about $220,000. On the other hand, the increase in wage and salary distribution in the oil and gas and field services sectors, relative to the employment change there, is only about $27,000. Thus, at the margin each employee in those two sectors is associated with additional output valued at $220,000, but receives only $27,000, so labor's share of the additional output is a little more than 12%. Returns to owners of other factors of production such as capital and the reserves themselves account for the remaining 88%. Whereas workers employed in the Wyoming oil and gas industry are likely to live in the state, capital and reserve owners can live anywhere and therefore may not spend their increased incomes in Wyoming. In any case, changes in oil, gas, and coal production do not benefit the Wyoming economy as much as they would if labor intensity were higher. Therefore, income, employment, and population changes, resulting from any taxes and tax incentives directed to the state's energy industries, are expected to be moderate as well.

Table 9.1

Control Forecast: State of Wyoming

	Actual	Forecast						
	1997	1997[a]	2000	2001	2005	2010	2020	2035
Total Employment (in Thousands of jobs)	315[b]	315	315	317	321	326	329	328
Total Private Nonfarm Employment (in Thousands of jobs)	242[b]	242	243	246	251	258	262	263
Real Disposable Personal Income (in Millions of $1997)	$9,780[b]	$9,548	$9,749	$9,836	$10,201	$10,814	$12,096	$12,939
Population (in Thousands of persons)	481[b]	480	463	456	436	425	435	427

[a]Estimated 1997 data are taken from a REMI model based on actual 1997 data and are therefore not directly comparable with the estimates for the 1999, 2000, and 2002 control years.

[b]Data furnished by the Division of Economic Analysis 2000.

Table 9.2

Contribution of Tax Incentives to the Wyoming Economy

	INCENTIVE	2000	2001	2005	2010	2020	2035
Total Employment	1. Oil Severance	313	296	246	206	163	123
	2. Drilling	1028	1007	926	818	656	485
	3. New Production	832	787	654	547	432	327
	4. WO and Recom.	42	39	32	26	21	17
	5. Tertiary Oil	35	33	27	23	18	13
	6. Coal Severance	61	57	45	-	-	-
	7. Coal Ton/Mile	-21	-20	-16	-	-	-
Total Private Nonfarm Employment	1. Oil Severance	288	266	207	168	137	106
	2. Drilling	950	911	790	674	550	417
	3. New Production	766	708	551	445	362	281
	4. WO and Recom.	38	35	27	22	18	14
	5. Tertiary Oil	32	29	23	19	15	12
	6. Coal Severance	54	50	37	-	-	-
	7. Coal Ton/Mile	-19	-18	-13	-	-	-
Real Disposable Personal Income (in Millions of $1997)	1. Oil Severance	$8.036	$8.036	$7.881	$7.302	$5.941	$5.802
	2. Drilling	$26.310	$27.170	$29.070	$28.500	$23.960	$22.390
	3. New Production	$21.37	$21.38	$20.94	$19.4	$15.77	$15.42
	4. WO and Recom.	$1.052	$1.041	$1.00	$0.916	$0.739	$0.738
	5. Tertiary Oil	$0.887	$0.88	$0.875	$0.814	$0.665	$0.641
	6. Coal Severance	$2.483	$2.377	$1.913	-	-	-
	7. Coal Ton/Mile	$-0.811	$-0.791	$-0.698	-	-	-
Population	1. Oil Severance	246	294	383	380	267	178
	2. Drilling	775	954	1351	1436	1092	704
	3. New Production	654	783	1020	1012	710	473
	4. WO and Recom.	33	39	48	47	32	23
	5. Tertiary Oil	27	32	42	42	30	20
	6. Coal Severance	70	77	91	-	-	-
	7. Coal Ton/Mile	-25	-28	-33	-	-	-

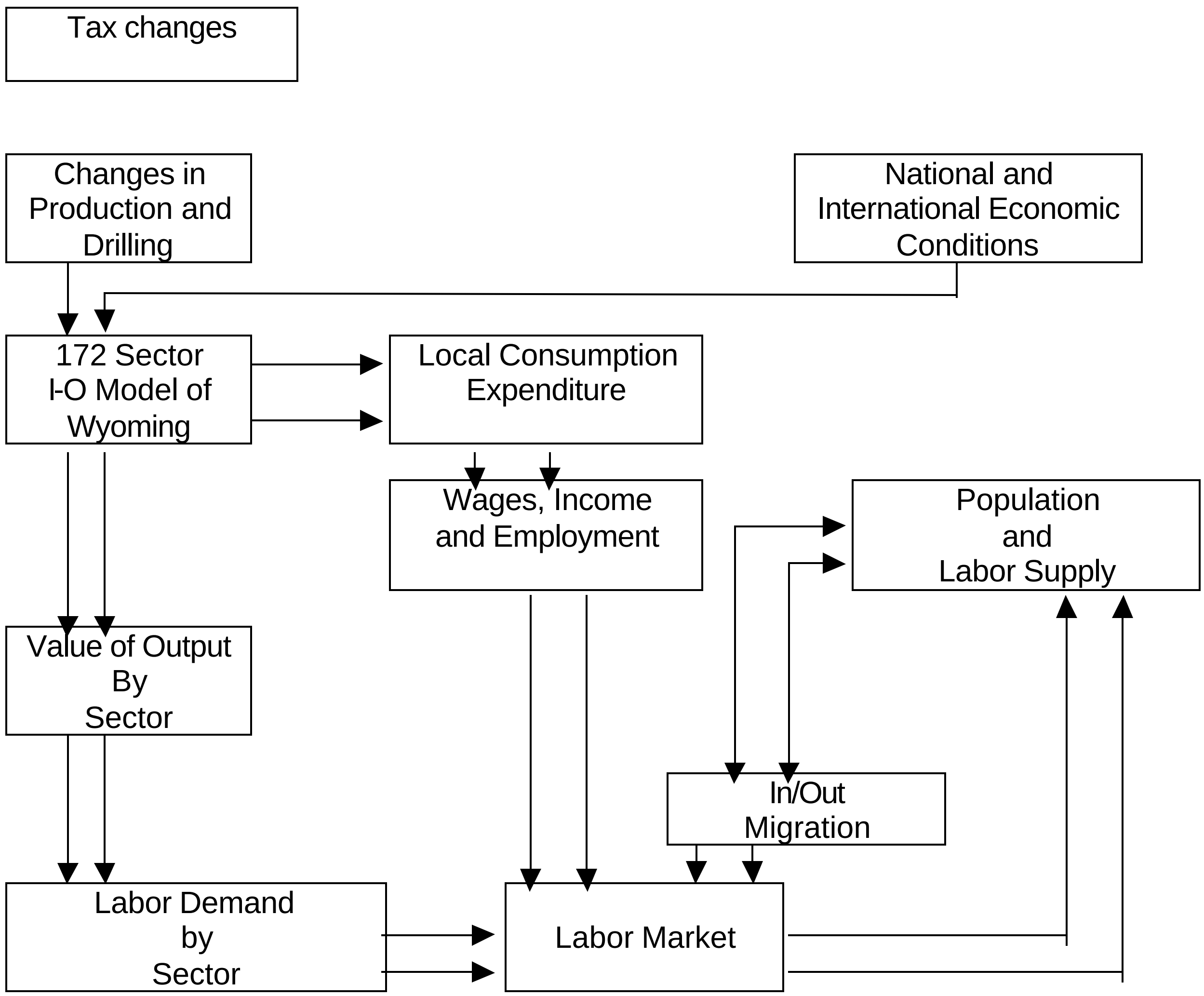
Table 9.3

Example of REMI Input Values for Oil Severance Tax Scenario (1)

Year	***Value of Production ($1997 in millions)***	***Drillings Expenditures ($1997 in millions)***
1998	16.913	10.753
1999	16.584	10.680
2000	16.314	10.608
2001	16.096	10.537
2002	15.921	10.467
2003	15.783	10.398
2004	15.676	10.330
2005	15.595	10.263
2006	15.535	10.197
2007	15.492	10.132
2008	15.463	10.068
2009	15.445	10.005
2010	15.436	9.943
2011	15.432	9.881
2012	15.432	9.820
2013	15.435	9.760
2014	15.440	9.700
2015	15.444	9.641
2016	15.447	9.582
2017	15.449	9.524
2018	15.448	9.465
2019	15.445	9.407
2020	15.438	9.348
2021	15.429	9.289
2022	15.415	9.229
2023	15.398	9.168
2024	15.377	9.106
2025	15.352	9.043
2026	15.324	8.978
2027	15.292	8.910
2028	15.257	8.840
2029	15.218	8.766
2030	15.177	8.688
2031	15.132	8.606
2032	15.085	8.518
2033	15.036	8.424
2034	14.985	8.322
2035	14.932	8.211

Figure 9.1

THE REMI MODEL



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APPENDIX A

Wyoming Mineral Tax History and Incentives **(in bold)**
1969 - July 2000

Year	***Chapter***	***Explanation***
1969	193	Imposed the first severance tax on gold, silver, other precious metals, soda, saline, coal, trona, uranium, bentonite, petroleum, natural gas, and crude mineral oil. 1% rate based on property tax valuation.
1974	HJR2A	Created the Permanent Wyoming Mineral Trust Fund. 1.5% severance tax on coal, oil, natural gas, shale and other such minerals as designated by the legislature.
1974	19	Increased severance tax rate to 3% on trona, coal, oil, natural gas, and oil shale.
1975	125	Increased severance tax rate to 4% on trona, coal, oil, natural gas, and oil shale.
1975	120	Imposed a coal impact severance tax on a graduated scale until $120 million was collected.
1977	189	Increased severance tax on coal until $160 million was collected. (Total 10.1%)
1977	155	Increase severance tax on coal, uranium and trona until $250 million was collected.
1981	49	Increased severance tax on oil and gas by 2%. (6% total)
1983	**173**	**Decreased severance tax on underground coal by 3.25%.**
1985	**182**	**Decreased severance tax on collection wells from 6% to 1.5%.**
1986	3	¼ of proceeds from severance taxes diverted to worker's compensation fund.
1987	**97**	**Coal Equity Tax Act of 1987. Limited severance taxes.**
1987	**29**	**Tax credits allowed on CO2 injected in oil production.**
1987	**241**	**4% severance tax exemption for wildcat wells.**

Year	*Chapter*	*Explanation*
1988	**93**	**Allowed deduction for return on investment for certain capital investments.**
1988	73	Implemented 3 tier system for assessing property.
1988	72	Budget reserve account diversion of severance taxes begins.
1989	**35**	**Extended Coal Tax Equity Act to 1991.**
1989	**172**	**Exempted coal used in processing from property and severance taxes.**
1989	**287**	**Exemptions for tertiary oil production.**
1989	36	Created municipal rainy day account.
1989	57	Repealed return on investment deduction (1988).
1989	120	Continued budget reserve diversion.
1989	**144**	**Decreased severance tax on uranium by 2%.**
1990	**22**	**Extended 1.5% severance tax on collection wells.**
1990	13	Budget reserve account diversion extended.
1991	**13**	**Coal Tax Equity Act extended to 1995.**
1991	**237**	**Extension of 2% severance tax exemption on tertiary production.**
1991	**239**	**Exempted specified underground mining equipment from property tax.**
1991	**42**	**Exempted uranium from severance tax as long as the price was under $17 per pound.**
1991	**139**	**Extended wildcat well exemption.**
1992	4	Reallocation of revenues to public school foundation program.
1993	**167**	**Exempted oil and gas from severance tax under certain conditions between 1993 and 1996.**
1994	6	Extended budget reserve account diversion to 1996.

Year	*Chapter*	*Explanation*
1995	**141**	**Granted 50% credit against natural gas severance tax for research projects to enhance gas production.**
1995	**48**	**Coal Tax Equity Act Extended to 1999.**
1995	**55**	**Exempted oil produced from previously shut-in wells.**
1995	59	Extended budget reserve account diversion to 2000.
1995	**76**	**Extended tertiary production exemption to 1996.**
1995	**104**	**Extended uranium severance tax exemption and lowered spot price target to $14 per pound.**
1995	**74**	**Extended severance tax break to collection wells.**
1995	**75**	**Extended reduced severance tax rate on oil and gas wells (new production) through 1999.**
1997	**171**	**4% severance tax exemption for oil and gas produced from workovers and recompletions to 1998.**
1997	**72**	**Extended tertiary production exemption to 2001.**
1998	**16**	**Specified collection well property tax exemption applied to production.**
1998	**47**	**Extended reduced severance tax rate on oil and gas wells (new production) through 2003.**
1998	**48**	**Extended uranium severance tax exemption to 2003.**
1999	**64**	**Coal Equity Tax Act Extended through 2003.**
1999	**168**	**Oil Producers Recovery Act. Reduced severance tax on oil by 2 percentage points. Price threshold is $20 per barrel. Granted sales tax exemption for sales of power to oil extraction.**
1999	121	Extended budget reserve account diversion to 2004.
2000	na	Repeal of Oil Producers Recovery Act.
2000	31	Rail Mile Tax - imposed a 7-cent tax on each train mile traveled.

Year	***Chapter***	***Explanation***
2000	na	Removes 4% severance tax break granted for new production from “shallow” gas wells (mainly affects coalbed methane).
2000	20	Imposes a one-mill per ton of coal tax on the commercial transportation per mile or portion thereof.

Source: Wyoming State Legislature, Legislative Service Office.

APPENDIX B

This appendix derives the functional form difference equation approximations, of text equations (3.2), (3.3), (3.10), and (3.11), used to simulate the time paths of drilling, production, and reserves.

B.1 Exploratory Effort (Drilling) Cost

Recall equation (3.12) from the text used to derive the following derivative relationships

$$D_w = \boldsymbol{f} \tag{B.1}$$

$$D_{ww} = 0\,. \tag{B.2}$$

Note in equation (B.2) that $D_{ww} = 0$ allows for convexity in w.

B.2 Reserve Additions

Using (3.13) from the text to derive

$$f_w = \boldsymbol{r} A w^{r-1} e^{-bx} \tag{B.3}$$

$$f_{ww} = (\boldsymbol{r} - 1)\boldsymbol{r} A w^{r-2} e^{-bx} \tag{B.4}$$

$$f_{wx} = -\boldsymbol{b}\boldsymbol{r} A w^{r-1} e^{-bx} \tag{B.5}$$

$$f_x = -\boldsymbol{b} A w^{r} e^{-bx} \tag{B.6}$$

and the following relationship

$$\frac{f_{wx}}{f_w} f - f_x = \frac{-\boldsymbol{b}\boldsymbol{r} A w^{r-1} e^{-bx}}{\boldsymbol{r} A w^{r-1} e^{-bx}} (A w^{r} e^{-bx}) - (-\boldsymbol{b} A w^{r} e^{-bx}) = 0\,. \tag{B.7}$$

From equation (B.4) see that $0 < \boldsymbol{r} < 1$ implies strict concavity in w.

B.3 Marginal Cost of Reserve Additions

Constructing the ratio of (B.1) over (B.3) yields the function for marginal cost of reserve additions

$$\frac{D_w}{f_w} = \frac{f}{rAw^{r-1}e^{-bx}}, \tag{B.8}$$

with the derivative of (B.8) with respect to *w* becoming

$$\frac{\partial \frac{D_w}{f_w}}{\partial w} = \frac{(1-r)f}{rA} w^{-r} e^{bx}. \tag{B.9}$$

B.4 Production (Extraction) Cost

Recall equation (3.15) from the text used to derive the following

$$C_q = ekq^{e-1}R^{1-e} \tag{B.10}$$

$$C_{qq} = (e-1)ekq^{e-2}R^{1-e} \tag{B.11}$$

$$C_{qR} = (1-e)ekq^{e-1}R^{-e} \tag{B.12}$$

$$C_R = (1-e)kq^{e}R^{-e} \tag{B.13}$$

$$C_{RR} = -e(1-e)kq^{e}R^{-e-1}. \tag{B.14}$$

Notice in equations (B.11)-(B.14) that $e > 1$ insures $C_{qq} > 0$, $C_{qR} < 0$, $C_R < 0$, and $C_{RR} > 0$.

B.5 Evolution of Reserves

Differencing equation (3.2) from the text and substituting in text equation (3.13) yields

$$R_t = R_{t-1} + A(w_{t-1})^{r} e^{-b(x_{t-1})} - q_{t-1} \tag{B.15}$$

where the initial values (t -1 = 0) for reserves (R_0) and cumulative wells drilled (x_0) are fixed at 1997 levels for each state. Differencing text equation (3.3) yields

$$x_t = x_{t-1} + A(w_{t-1})^r e^{-b(x_{t-1})}. \tag{B.16}$$

B.6 Evolution of Exploratory (Drilling) Effort

Differencing equation (3.11) from the text and substituting in (B.1) - (B.4), (B.7), and (B.13) yields the dynamics of exploratory effort

$$w_t = w_{t-1} + \frac{\boldsymbol{f} \cdot r + [(1-\boldsymbol{e})\boldsymbol{k}(q_{t-1})^e (R_{t-1})^{-e} + \boldsymbol{g}]\,\boldsymbol{r}A(w_{t-1})^{r-1} e^{b(x_{t-1})}}{-\boldsymbol{f}(\boldsymbol{r}-1)(w_{t-1})^{-1}}. \tag{B.17}$$

Recall that all cost function relationships are net of tax effects and that initial values for drilling effort (w_0) and production (q_0) are optimally set by numerical methods discussed below.

B.7 Evolution of Production

Using equation (3.10) from the text and substituting in (B.10)-(B.13) and (B.15) gives

$$\begin{aligned} q_t = q_{t-1} + \{[-r(p_{t-1} - \boldsymbol{ek}(q_{t-1})^{e-1}(R_{t-1})^{1-e}) + (p_t - p_{t-1}) - \\ ((1-\boldsymbol{e})\boldsymbol{ek}(q_{t-1})^{e-1}(R_{t-1})^{-e})(A(w_{t-1})^r e^{-b(x_{t-1})} - q_{t-1}) \\ -(1-\boldsymbol{e})\boldsymbol{k}(q_{t-1})^e (R_{t-1})^{-e} - \boldsymbol{g}]/[(\boldsymbol{e}-1)\boldsymbol{ek}(q_{t-1})^{e-2}(R_{t-1})^{1-e}]\} \end{aligned} \tag{B.18}$$

recalling that the net-of-tax price path is exogenously determined.

B.8 Numerical Methods

Given a fixed program period T and equations (B.15)-(B.18) for time periods (t = 1,….,T), initial values of w_0 and q_0 are iterated until the boundary condition

$$\frac{f}{rA}(w_T)^{1-r} e^{b(x_T)} = p_T - ek(q_T)^{e-1}(R_T)^{1-e} \tag{B.19}$$

is satisfied. Note that the right-hand-side of (B.19) is $l_1(T)e^{rt}$. Due to the discreet (annual) time differencing, w_T will approach but not equal zero. The Cobb-Douglas form for production cost will invoke a positive terminal residual value of $l_1(T)e^{rt}$, thus, production will cease only under a truncated terminal time. The present value shadow price of cumulative reserve additions, l_2, must initially be less than zero and evolve (increase) over the time period to equal zero at time T, insuring (B.19) will hold. The specific method used to obtain solutions of this numerical system involves the Generalized Reduced Gradient (GRG2) nonlinear optimization algorithm developed by Leon Lasdon, University of Texas at Austin, and Allan Waren, Cleveland State University contained within Microsoft's Excel software.

APPENDIX C

This appendix derives the (generalized) constant tax parameters numbered (4.1) – (4.4) in the text. Restating the producer's problem (bracketed terms in text equation (3.1)) accounting for all tax effects yields

$$\begin{aligned} & qp^* - qp^*\boldsymbol{t}_r - qp^*(1 - \boldsymbol{t}_r)\boldsymbol{t}_p - C^* - \boldsymbol{h}D^* - \boldsymbol{t}_R R - \boldsymbol{t}_s[qp^* - qp^*\boldsymbol{t}_r - qp^*(1 - \boldsymbol{t}_r)\boldsymbol{t}_p - C^* \\ & \quad - \boldsymbol{h}D^* - \boldsymbol{t}_R R] - \boldsymbol{t}_{us}\{ qp^* - qp^*\boldsymbol{t}_r - qp^*(1 - \boldsymbol{t}_r)\boldsymbol{t}_p - qp^*(1 - \boldsymbol{t}_r)\boldsymbol{d} - C^* - \boldsymbol{h}D^* - \boldsymbol{t}_R R \\ & \quad - \boldsymbol{t}_s[qp^* - qp^*\boldsymbol{t}_r - qp^*(1 - \boldsymbol{t}_r)\boldsymbol{t}_p - C^* - \boldsymbol{h}D^* - \boldsymbol{t}_R R]\} \end{aligned} \qquad \text{(C.1)}$$

where * denotes the pre-tax price or cost, $\boldsymbol{t}_{us}$ denotes the federal corporate income tax rate on operating profits, $\boldsymbol{t}_s$ denotes the state corporate income tax rate on operating profits, $\boldsymbol{t}_R$ denotes the property tax rate on reserves weighted by the per unit assessed value, $\boldsymbol{t}_r$ denotes the royalty rate on production from public (state and federal) land, $\boldsymbol{t}_p$ denotes the production (severance) tax rate, $\boldsymbol{d}$ denotes the federal percentage depletion allowance weighted by the percentage of production attributable to eligible producers (nonintegrated independents), and $\boldsymbol{h}$ denotes the expensed portion of current and capitalized drilling costs attributable to current period revenues. $\boldsymbol{h}$ is the sum of: 1) the percentage of current period drilling costs expensed and, 2) the estimated present value share 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. The ratio of well extraction to well reserves, known as the units of production method, is required by the U.S. tax code to determine the percentage of cost depletion allowed in a given year (Bruen, Taylor and Jensen, 1996).

This formulation assumes that: 1) public land royalty payments are deductible in computing state production tax liabilities; 2) public land royalty payments, production taxes, state reserve taxes, extraction costs, and certain drilling costs (described above) are deductible in computing both state and federal corporate income tax liabilities, 3) the federal percentage depletion allowance is applied to the net-of-royalty value of production, and 4) state corporate income taxes are deductible against federal corporate income tax liabilities. These assumptions do not apply universally across all states. For example, as previously discussed, royalty payments are not deductible against production taxes in Louisiana, and some states have permitted federal corporate tax payments to be deducted against state corporate income tax levies. In situations such as these, of course, equation (C.1) would have to be modified.

Collecting terms from (C.1) gives

$$(1 - \boldsymbol{t}_{us})(1 - \boldsymbol{t}_s)[qp^* - qp^*\boldsymbol{t}_r - qp^*(1 - \boldsymbol{t}_r)\boldsymbol{t}_p - C^* - \boldsymbol{h}D^* - \boldsymbol{t}_R R] + \boldsymbol{t}_{us}\, qp^*(1 - \boldsymbol{t}_r)\boldsymbol{d} \tag{C.2}$$

which reduces to

$$qp^*\{(1 - \boldsymbol{t}_{us})(1 - \boldsymbol{t}_s)(1 - \boldsymbol{t}_r)(1 - \boldsymbol{t}_p) + \boldsymbol{t}_{us}(1 - \boldsymbol{t}_r)\boldsymbol{d}\} - C^*\{(1 - \boldsymbol{t}_{us})(1 - \boldsymbol{t}_s)\}$$

$$- \boldsymbol{h}D^*\{(1 - \boldsymbol{t}_{us})(1 - \boldsymbol{t}_s)\} - \boldsymbol{t}_R R\{(1 - \boldsymbol{t}_{us})(1 - \boldsymbol{t}_s)\}. \tag{C.3}$$

For a single BOE unit of q and R, (C.3) becomes

$$\boldsymbol{a}_p\, p^* - \boldsymbol{a}_c\, C^* - \boldsymbol{a}_D\, D^* - g. \tag{C.4}$$

where

$$g = \{(1 - \boldsymbol{t}_{us})(1 - \boldsymbol{t}_s)\boldsymbol{t}_R\} \tag{C.5}$$

$$\boldsymbol{a}_p = \{(1 - \boldsymbol{t}_{us})(1 - \boldsymbol{t}_s)(1 - \boldsymbol{t}_r)(1 - \boldsymbol{t}_p) + \boldsymbol{t}_{us}(1 - \boldsymbol{t}_r)\boldsymbol{d}\} \tag{C.6}$$

$$a_C = \{(1 - t_{us})(1 - t_s)\} \quad \text{(C.7)}$$

$$a_D = \{(1 - t_{us})(1 - t_s)h\} \quad \text{(C.8)}$$

equate to equations (4.1) – (4.4) in the text.

APPENDIX D

This appendix (related to Chapter 7) demonstrates more fully that $dP_m / dt_m > 0$. As shown in equation (7.11)

$$\frac{dp_m}{dt_m} = \frac{H_Q}{(1-t_m)}\frac{dQ}{dt_m} + \frac{H(Q)}{(1-t_m)^2} \tag{D.1}$$

Substituting from equation (7.9) yields

$$\frac{dP_m}{dt_m} = \frac{H_Q}{(1-t_m)}\left[\frac{QH_Q + H(Q)}{(1-t_m)^2\Delta}\right] + \frac{H(Q)}{(1-t_m)^2} = \frac{Q[H_Q]^2 + H_Q H(Q) + \Delta(1-t_m)H(Q)}{\Delta(1-t_m)^3} \tag{D.2}$$

Substituting from equation (7.7) yields

$$\frac{dP_m}{dt_m} = \frac{Q[H_Q]^2 + H_Q H(Q) + (1-t_m)H(Q)[Qf_{QQ} + 2f_Q - C_{QQ} - QH_{QQ}/(1-t_m) - 2H_Q/(1-t_m)]}{\Delta(1-t_m)^3}$$

$$= \frac{Q[H_Q]^2 - H_Q H(Q) - QH(Q)H_{QQ} + (1-t_m)H(Q)[Qf_{QQ} + 2f_Q - C_{QQ}]}{\Delta(1-t_m)^3}$$

$$= \frac{(1-t_m)[H(Q)]^3[Qf_{QQ} + 2f_Q - C_{QQ}] - d(QH_Q / H(Q))/dQ}{[H(Q)]^2(1-t_m)^3\Delta} \tag{D.3}$$

Thus, $dP_m / dt_m > 0$ if: (1) $\Delta < 0$, (2) the demand schedule for coal is downward sloping, (3) railroad marginal costs of hauling coal are increasing in Q, and (4) $d(QH_Q / H(Q))/dQ > 0$.