THE ECONOMICS OF ACCELERATED OUTER CONTINENTAL SHELF LEASING

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Introduction

Recent world events have highlighted the growing dependence of the United States on imported crude oil and petroleum products. To illustrate, the portion of petroleum to gross energy consumed (on a BTU basis) in the United States has increased from 34 percent in 1947 to 46 percent in 1973, while crude oil and petroleum product imports increased from 3 to 17 percent of this total over the same time period. Domestic production of crude oil, on the other hand, began a decline in 1973 and this decline has continued at an accelerated rate through the first quarter of 1974 [23].

Although scarcity of proven domestic petroleum reserves is a contributing factor to potential energy problems, economic, technical, institutional and political factors have influenced the rate of new discoveries. With the depletion of proven on-land petroleum deposits, governmental policy with respect to energy resource leasing on federal lands has been and will continue to be a key factor guiding private market forces. Of particular importance are the potential petroleum reserves located on our Outer Continental Shelf. Although leasing of such lands has been underway for over 20 years, less than 5 percent of the acreage available for lease has been opened for bid. Moreover, it is estimated that approximately 50 percent of our domestic oil and gas resources are located on the Outer Continental Shelf [24]. Recognition of this fact, and of the potential importance of

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this policy variable to future domestic petroleum discoveries and production, has led to a rapid change in governmental policy over the past 12 months. Presidential directives have been taken which would increase the annual offshore acreage leased for exploration from 1 million acres per year in 1972 to 10 million acres per year in 1975. Regardless of the annual lease sale size, however, the resulting market effects will be dependent upon the geophysical aspects of the acreage leased and associated public policies which are adopted. The former, which can be partially influenced by the schedule and location of potential lease sales, determines the amount of oil in place available for discovery. For unexplored or "wildcat" areas the amount of oil in place is largely the educated guess of petroleum geologists [7]. Given any stipulated amount of potential petroleum reserves, however, other public policies can have a major influence on the timing of oil production, the amount of ultimate recovery, and the magnitude of governmental revenue collected through the bidding and production royalty system. Continued controversy has surrounded the public discussion of policies related to such issues. Included in such discussions have been questions related to the appropriate lease term options (such as bonus bidding, royalty bidding, or profit sharing plans), the effect of various taxation policies such as the oil depletion allowance, and the role of governmental actions affecting market prices for petroleum [6].

In this paper, we set forth a theoretical framework which is designed to encompass the elements of expected market behavior when public lands are offered for lease to the private sector. The framework outlined includes a consideration of basic economic elements as well as the interrelationships between such elements and the geophysical, and engineering aspects of any petroleum extraction process. In addition, taxation policies and the role of uncertainty are incorporated. The resulting analytical model is calibrated and verified with historical data and then utilized to evaluate relevant leasing policy alternatives. Included is an analysis of the rate and timing of petroleum production, estimates of governmental revenue, and investment requirements for the various alternatives, as these factors relate to potential petroleum reserves of a given magnitude.

Analytical Framework

In recent years several economic models of the petroleum investment and production decision process have been developed [1, 4, 5, 12, 16]. However, none are directly applicable to the analysis of alternative leasing strategies. Moreover, previous formulations have often failed to consider the interface between economic and engineering phenomena relevant to such decisions. For example, with few exceptions, the dependence of recoverable reserves upon the rate of production is ignored [10]. More importantly, possible control of production decline rates, within reasonable limits, by petroleum producers is generally not recognized by empirical studies [26]. Finally, important economic considerations, such as risk and taxation, are seldom accounted for in a comprehensive manner.

The analytical framework presented here incorporates the above factors in a model of aggregate private market response to public energy leasing strategies. Engineering and economic considerations are included so that a wide range of public policy alternatives, as well as physical phenomena, related to petroleum production and investment decisions may be quantitatively examined.

The framework is based upon the assumption that there is a known probability distribution of the size and location of original oil in place, R, such that the expected value and variance of R in any given area may be estimated.[1] The total resource or production constraint can then be represented by:

$$(1) \qquad R(x) \geq \int_0^T q_{(t)} dt$$

Where R represents original oil in place, x is a percentage indicating the maximum oil in place that is physically recoverable given current technology, T is the production time horizon, and $q_{(t)}$ the rate of production. Theoretically, when public lands are offered for lease, an optimum is obtained by the private sector through maximization of net present value revenue subject to this constraint [10]. The complexity of this optimization problem is largely due to the unknown function $q_{(t)}$. However, for the purpose of empirical analysis, the problem is simplified if $q_{(t)}$ is expressed as a function of the initial capacity installed and the production decline rate such that [1, 3, 4]:[2]

$$(2) \qquad q_t = q_o e^{-at}$$

Where q_o represents initial installed capacity, and "a" the rate of decline in production. This relationship is based upon the premise that as petroleum is extracted, natural or artificial reservoir pressure is reduced so that production declines through time at the rate "a" [10, 14]. The rate of pressure reduction, and hence production decline, is a direct function of a

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[1]For a discussion of procedures useful for the derivation of such probability distributions see [2, 20].

[2]Depending upon the physical characteristics of the petroleum province and the technology utilized, alternative function forms may be specified [3, 18].

number of geological factors including the permeability and porosity of the strata. Of greater importance, however, is that natural or artificial pressure decline may be offset by selection of appropriate completion technology and operating procedures [10, 18]. Thus, producer control over production decline rates as well as initial capacity levels, within reasonable limits, can be presumed. This control is of particular importance since resource recovery is generally a negative function of the rate of production [8, 10, 14]. For the purpose of exposition, it is postulated that recovered reserves, R_o, may be expressed as:

$$(3) \qquad R_o = Rx - \beta q_o e^{-a}$$

Where β is a physical parameter related to geological conditions and $q_o e^{-a}$ the initial rate of production.[3] The cumulative output may then be written as:

$$(4) \qquad R_o = \int_0^T q_o e^{-at} dt$$

Where R_o equals $Rx - \beta q_o e^{-a}$ from (3). For a given production time horizon, equation (4) states that cumulative output is equal to the magnitude of reserves which may be recovered at a given rate of production. In the subsequent analysis, this assumption is applied over all alternative bid systems.

Given any expected R, a projection of the optimum level of investment or initial capacity "q_o", the production decline rate "a", and the production

[3]Recovered reserves are expressed as a linear function of the rate of production since for any given set of geological conditions determining the value of β, the faster the rate of production, the lower the volume of petroleum that is recovered. This results because reservoir pressure is inefficiently utilized at high rates of production. Although the form of this relationship has been the subject of substantial debate, the concept is usually ignored in empirical studies [8, 10, 14].

time horizon "T" must be made by a potential lessee before determining his bid. Economic theory indicates that this projection will be based upon the maximization of after-tax net present value revenue [19]. For the purposes of leasing policy analysis, relevant cost components entering the after-tax net revenue calculation include investment cost (which can be defined as a direct function of the capacity installed), operating costs, royalties, the depletion allowance, the deduction for intangible drilling and development expenses, and other relevant tax provisions.[4] After-tax net revenue taken over the anticipated production period and discounted, then equals the anticipated economic rent for the resource on a present value basis.

The theoretical framework can be expressed in the form of two basic relationships. The first defines the production time horizon limit as a function of physical, as well as economic, parameters. Theoretically, this limit is obtained when current expenses per unit equal revenue per unit. This relationship may be written in reduced form as:

$$(5) \qquad 0 = (P_o + P_1 t)(1-\lambda)(1 - \phi + \phi z) - (1-\phi)K_o e^{(\theta+a)t}$$

Where P_o represents initial price per unit of production, P_1 the annual anticipated change in unit price, λ the royalty rate, ϕ the corporate income tax rate, z the percentage depletion allowance, K_o the initial operating costs per unit of capacity, and θ is a physical parameter related to initial reservoir conditions.[5]

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[4]In certain applications, investment cost may also be expressed as a function of reserves to account for economies of scale. For a discussion of taxation see [9, 14, 25].

[5]Total operating costs in any time period are constant, within reasonable limits, regardless of the decline rate. Thus, unit costs would increase at an exponential rate as production declines through time [3, 8]. However, given initial reservoir conditions, it can be postulated that unit, as well as total, operating costs increase through time by the factor θ. This phenomena is due to equipment obsolescence as well as increasing utilization of secondary recovery techniques [18]. Product prices, however, are expected to increase at a linear rate [16].

The second relationship maximizes after-tax net present value revenue subject to the production time horizon constraint represented by equation (5). For the purpose of exposition this function is written in two parts. The first part, which represents net present value revenue before taxes is expressed as:

$$(6) \qquad NPVBT = q_o \int_0^T (1-\lambda)(P_o + P_1 t)e^{-(a+r)t}dt - q_o \int_0^T K_o e^{[\theta-r]t}dt - bq_o$$

Where q_o equals $a(Rx)/(1-e^{-aT} + \beta a e^{-a})$ from equations (3) and (4), b represents investment cost per unit, and r is the discount rate.

The present value of taxes payable may be expressed as:[6]

$$(7) \qquad TAX = q_o \phi \Big\{ \int_0^T (1-\lambda)(P_o + P_1 t)e^{-(a+r)t}dt - \int_0^T K_o e^{[\theta-r]t}dt -$$

$$\left[\sum_{i=1}^{n} \left[\frac{\frac{n-i}{n^2 + n/2}}{(1+r)^i} \right] [yb(1-\alpha)] \right] - z\int_0^T (1-\lambda)(P_o + P_1 t)e^{-(a+r)t}dt$$

$$- (1-y)b \Big\} - \Omega q_o b$$

Where ϕ represents the tax rate, n the time horizon for depreciation, z the depletion rate, y the percent investment which is tangible, α the percent investment salvageable at n, and Ω the investment tax credit rate. Equations (6) and (7) may then be combined and salvage value is added to obtain after-tax

[6] The sum of the years digits depreciation method is used. Tax treatment of bonuses is ignored here for the purpose of exposition. This ommission is consistent with the industry decision process and does not substantially alter the empirical results [18].

net present value revenue.[7] To this basic framework, risk of an actuarial nature may be incorporated by replacing R with expected R, (ER). For certain applications, a risk adjusted discount rate may be readily incorporated.[8]

For implementation, the framework may be restated such that after-tax net present value revenue is maximized subject to the cumulative production and time horizon constraints set forth in equations (4) and (5).[9] The solution is then accomplished through the use of a computerized constrained search algorithm. Products of the solution are the optimum decline rate a^*, the time horizon T^*, the optimum initial capacity q_o^*, annual production, cumulative production, and the present value of after-tax revenue. By manipulation of the latter value, various bidding options can be simulated. For example, under a bonus bid system the expected bid plus royalties should equal present value of the economic rent given pure competition and known probabilities for R. Under a royalty bid system, cumulative royalty payments equal the anticipated economic rent. Thus, after-tax net present value revenue can be constrained to zero with the royalty rate, λ, being determined.

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[7] For policy analysis, taxes payable are calculated separately for the first year and, then, for the remaining production time horizon. As mandated by statute, the depletion deduction is limited to 50 percent of net income before depletion. First year tax deductions in excess of those that can be utilized against lease revenue are assumed to be applied against gross revenue and/or taxes (as the case may be) on other company operations (with the exception of percentage depletion which cannot be used in this manner). In essence, these excess tax write-offs are credited as additions to the after-tax net present value of the lease. For simplicity, a one-year lease development schedule was assumed. Consequently, given tax legislation, excess tax write-offs only accrue in the first year. This assumption provides a consistent and reasonable basis for comparing policy alternatives.

[8] Conceptually, the risk adjusted discount rate is a function of the variance of expected payoff as well as the attitude toward risk [11, pp. 129-58].

[9] Two assumptions are implicit. First, that unitization is imposed so that externalities associated with the private exploration of common property resources may be ignored [13]. Second, user or opportunity costs associated with resource exhaustion in the pure Ricardian sense are not incorporated.

The framework posed serves to point out several issues which have obvious policy implications. First it is clear that the economic rent is directly related to the expected level of reserves. This factor is in turn a function of the schedule and location of lease sales. Second, the royalty rate, production rate restrictions (based on maximum efficient rate regulations), tax policy, and government policy affecting market prices are all important factors affecting petroleum production and investment decisions. Third, producer control over production decline rates and initial investment levels are important determinants of production profiles and government revenues under alternative resource allocation systems.

Policy Evaluation

The framework set forth above was calibrated and tested using historical data. Unpublished governmental statistics of oil reserves and development-operating costs, along with engineering estimates of physical parameters, for recent lease sale areas in the Gulf of Mexico were utilized. A complete ex post analysis is not yet possible, since the production phase is in the early stages for most of these areas. All resulting bid estimates, however, were within 10 percent of actual values and other independent variables were reasonable and consistent with current experience in the Gulf [18, 21, 22].[10]

Given an acceptable degree of accuracy in the ex post application of the analytical framework, we now turn to an evaluation of public leasing

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[10] As an example, the MAFLA sale in 1973 consisted of 146 lease tracts and brought forth bonus bids of $1,491,065,230 [17]. Of course no production has taken place on this acreage to date. However, using an $8.00 per barrel oil price, the model calculated a total bid of $1,570,000,000. The results assumed current tax legislation, a 10 percent discount rate, an $.08 per year price increase for oil and costs estimates relevant to the forecast structures and water depths of the sale area [21]. Forecast initial capacity installed was 1.07×10^8 barrels with a decline rate of .01 and cumulative production of $.139 \times 10^{10}$ barrels.

policy alternatives which have been widely suggested as superior to the current bonus system [6]. These include a bonus system with an increase in the fixed royalty rate, a royalty bid system, a profit share system and the elimination of the depletion allowance. The first two alternatives have been advocated as a means of reducing the initial cash bonus to encourage exploration by small independent producers. It is also argued that such systems may result in increased government revenue. On the other hand, a royalty based resource allocation method may lead to inefficient production decisions, as well as increased administrative costs. Theoretically, such inefficiencies might be avoided through the implementation of a profit share resource allocation system. However, in the long run, this system could lead to a misallocation of resources among industries. Finally, continued controversy surrounds the effect of the depletion allowance upon the rate of resource development, economic rents, and allocative efficiency [9, 15].

The various systems were analyzed by assuming that offshore acreage located in less than 300 feet of water and containing an estimated 1.5 billion barrels of recoverable oil in place were being offered for lease. Assumptions regarding product prices, costs, tax structure and physical parameters are identical to those used for the MAFLA sale evaluation (see footnotes 7 and 10). Table 1 displays the results of model runs on the various scenarios.

As shown in Table 1, an increase in the fixed royalty rate to 50 percent and a royalty bid system[11] both lead to a reduction in investment and initial capacity installed as compared to the current system. At the same time, the production rate is reduced which results in an increase in recovery

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[11] When left to competitive forces with no bonus bid required, the royalty rate expected as a bid under the assumptions used was 54 percent.

Table 1. Impact of Alternative Policies[a]

Impact Categories	Units	Current Bonus Bid System	Increase in Fixed Royalty	Royalty Bid	Elimination of Depletion Allowance	Profit Share System[b]	Profit Share System[c]
Royalty Rate	$	.16 2/3	.50	.54	.16 2/3	.16 2/3	.16 2/3
Profit Share Rate	%	0	0	0	0	.27[d]	.27[d]
Time Horizon	Yr.	14.0	24.0	28.0	15.0	14.0	18.0
Initial Capacity	MMBBL/Yr.	106.73	67.18	59.03	100.54	106.73	85.90
Production Decline Rate	%	.01	.01	.01	.01	.01	.01
Investment	$	2.67	1.68	1.48	2.51	2.67	2.15
Total Recovery	MMBBL	1394.3	1433.5	1441.6	1400.5	1394.3	1415.0
Royalty	$	1.03	2.43	2.38	1.00	1.03	.91
Bonus Bid	$	1.57	.19	.00	1.12	1.14	.47
Taxes Paid	$	.57	.00	.00	1.02	1.00	1.61
Total Government Revenue	$	3.17	2.62	2.38	3.14	3.17	2.99

[a]All monetary values are present values (discounted at 10 percent) in billion dollars.

[b]Income base includes the depletion deduction.

[c]Income base excludes the depletion deduction.

[d]For purposes of illustration, a 27 percent rate applied to the respective taxable income bases was used. Thus, a corporate tax rate of 75 percent results.

(or cumulative production), as well as a longer production time horizon. In other words, anticipated production is lower in the first few years and higher in later periods as compared to the present system. This result, when coupled with the accelerated OCS lease sale schedule, has obvious implications for the timing and level of imports as well as balance of payments considerations.

Both royalty based resource allocation systems lead to a decrease in the bonus bid. However, the present value economic rent, which is traditionally defined as royalty plus bonus bid revenue, increases as the royalty rate is raised from 16 to 50 percent. In the cases presented, this is partially due to distortions inherent in the tax system as well as the specific tax assumptions used (see footnote 7). Given the structure specified above, the bonus bid is defined to equal after-tax net present value revenue. Thus, the bonus bid is reduced by the calculated present value of tax payments. As the royalty rate is increased, taxes payable under the assumptions specified are reduced, and may, as in the examples presented, fall to zero. Thus, the appropriate comparison under the alternative systems is the level of total government revenue. On the basis of this comparison, both royalty based resource allocation systems lead to a decrease in government revenue on a present value basis.

However, it must be recognized that the interaction between a, q_o, and T can, under the assumption of resource recovery utilized, result in total government revenue being greater under the royalty bid systems than under cash bonus bids. Changes in the relationship between total recovery and the production rate and/or changes in the limits to producer control over the range of the production decline rate (because of geophysical factors) may cause such a phenomena.[12]

Elimination of the current 22 percent depletion allowance also results in a reduction in the initial capacity installed as well as total investment. However, due to the alteration in the timing of production, as well as the increased taxes paid, total government revenue on a present value basis is slightly decreased over the current system. These results tend to support the hypothesis that the depletion allowance results in higher investment levels and production rates. The analysis also suggests that the depletion allowance tends to swell economic rents [8, 9].

In the case presented, the impact of a profit share system depends largely upon the profit share base as well as the assumption regarding first year tax deductions. For example, under the assumptions specified, if the base includes the depletion allowance, the initial capacity installed is not affected. However, a significant decrease in capacity results if the base excludes the allowance. This result may be expected since, in the former case, an increase in the profit share rate leads to an increase in the effective depletion allowance per unit of production.[13] Hence, there is an incentive to maintain investment levels.

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[12] MER restrictions are based upon the fact that the decline rate can be altered [16]. Although the degree of control over this rate is a function of individual reservoir characteristics, as well as the completion technology, for empirical purposes a lower bound of .01 is utilized in this analysis. Since in the cases presented, it is implicitly assumed that the value of b and/or θ is independent of the decline rate, after-tax net present value revenue is maximized at the lower bound for all systems.

[13] If a corporate profits tax rate of 75 percent is imposed, the after-tax value of the depletion deduction is increased from 11 to 16 1/2 percent of the value of expected production.

In all cases presented, an optimum is obtained by maximization of after-tax net present value revenue, subject to the constraints representing resource availability and the production time horizon. Thus, the industry may adjust the production decline rate, the initial capacity installed, and/or the production time horizon, as the bid system changes in order to maximize net present value revenue. For example, initial capacity may be reduced, and the time horizon increased, as occurred when the royalty rate was increased from 16 to 50 percent, to satisfy the objective function.

This result is contrary to previous studies which are based upon the assumption of a constant production profile [18, 26]. Given this assumption, any increase in the royalty rate reduces marginal revenue and thereby lower resource recoveries and government revenues may be obtained.[14] This approach, however, fails to recognize flexibility in terms of the initial capacity installed, the production time horizon, as well as the production decline rate.

Of particular importance is the range within which the production rate can be varied by petroleum producers. If that range is limited by physical conditions or institutional factors such as MER restrictions, net present value revenue is altered for all lease systems analyzed. Thus, the absolute level of government revenue cannot be specified a priori since it depends on the geophysical-institutional-economic interactions discussed above.

Moreover, the impact of all bid systems upon government revenue is subject to several qualifications. First, for each alternative it is assumed that a 1.5 billion barrel expected reserve will be discovered. If it turns

[14]For example, if the production profile is fixed at the level calculated to prevail under the current bonus bid system, production does not occur if the royalty rate is increased to 50 percent.

out, ex post, that this value was greater than that actually discovered, royalty collections and/or profit shares would obviously be reduced whereas the bonus bid collected would remain unaltered.[15] However, if the value is less than discovered, royalty revenues and/or profit shares would be increased. The final result with respect to government revenue depends on the level of actual reserves discovered, the relationship of the lease system to uncertainty evaluation by the industry,[16] and the interaction between reduced revenues and the tax-royalty structure. Second, lease profitability (and consequently, development feasibility) depends both upon the level of the royalty rate and product prices. For example, under a 50 percent fixed royalty system and a $5.00 per barrel oil price, no bids would be generated for the acreage offered under the assumptions discussed previously. However, a bonus bid would, at current royalty rates, be offered.[17]

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[15] In addition, if actual reserves are less than expected, the field may be abandoned under a royalty bid system. For example, once lease acquisition takes place by cash bonus, it is profitable to produce (ceritus paribus) if actual reserves total at least 623 million barrels. However, reserves must total at least 1,258 million barrels for production to be profitable under the royalty bid system.

[16] A full evaluation of this aspect is not present here. The framework used does, however, permit these factors to be incorporated. For example, under a royalty system, a prospective bidder may bid the full value of the estimated resource because relatively little cost is entailed in the event of a dry hole. On the other hand, the bonus bidder may discount his bid since the risk is higher. However, in the analysis presented, risk of an actuarial nature is assumed throughout. This assumption is based upon the premise that the investment decision is viewed as one of a large number of independent decisions. Therefore, expected value is an appropriate risk adjustment in all cases [11, pp. 137-158].

[17] Inefficiencies of this type are not associated with a pure royalty bid system.

Summary

The analysis presented points out that policies which tend to increase costs per unit of production tend to decrease investment. Conversely, policies which decrease per unit cost may be expected to result in increased investment. However, as investment rates increase, production profiles tend to shift toward the present with an associated reduction in total recovery. Of perhaps equal importance, is the conclusion that geophysical factors associated with individual reservoir characteristics can alter production profiles in ways which make it impossible to specify an optimal bid system with respect to the maximization of government revenue. Under any given bid system, government revenue appears to depend upon factors specific to individual reservoirs. Thus, the model presented highlights both the trade-offs implicit in various leasing strategies and the geophysical-economic interactions which must be accounted for in any resource management situation.

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