Oil and Gas Leasing Policy: Alternatives for Alaska in 1977: a Report to the State of Alaska, Department of Natural Resources, and to the Alaska State Legislature, Interim Committee on Oil and Gas Taxation and Leasing Policy

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ALTERNATIVES FOR ALASKA IN

1977

A REPORT TO THE STATE OF ALASKA, JAY S. HAMMOND, GOVERNOR,

DEPARTMENT OF NATURAL RESOURCES, GUY MARTIN, COMMISIONER,

AND TO THE

ALASKA STATE LEGISLATURE, INTERIM COMMITTEE ON OIL AND GAS TAXATION

AND LEASING POLICY, CHANCY CROFT, CHAIRMAN

FEBRUARY 1977

MASON GAFFNEY

ECONOMIC POLICY ANALYSIS

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Summary

The purpose of this report is to be of service to the Alaska State Legislature and the Department of Natural Resources in their review of oil and gas leasing policy. It is written from the State's viewpoint. It treats the State's interests as being frequently adverse to those of the State's lessees, without being hostile to them. Where the State's interest is adverse to the federal interest, we take the State's position. Otherwise, the purpose is to be as objective as possible. The Report lists the pros and cons of alternative policies and indicates what the Legislature needs to do to make each policy work. Recommendations are made in a tentative way.

This is a survey rather than an intensive study of any one alternative. The purpose is to display the full range of alternatives and the full range of issues to be considered regarding each one, so as to keep individual matters in the larger perspective so that no one issue is overweighed. The purpose is to compare, and to show how different leasing elements complement or substitute for each other. The purpose is to serve as a springboard for legislative review and a guide to additional, more selective investigations.

As a unifying theme, the list of alternatives proceeds sequentially, showing how each more complex alternative emerges as an answer to faults perceived in prior ones.

As a set of criteria for judgment the Report seeks to lay on the table assumed goals of the State. These are the following:

- Business-like management. This is taken to mean in practice the maximization of discounted cash flow.

- Equity. This is taken to mean avoiding giveaways; reducing the lottery element in leasing; hewing to the productivity basis of distribution of income; collecting for the State the rent of its lands; basing industry incentives on productivity rather than acquisition of State assets;

and reducing the differential advantage accorded to accumulated wealth.

- Workability. This means a minimum of arbitrary regulation, achieved by binding the lessor and the lessee in a community of interests when writing the lease.

- Avoiding economic waste. In addition to physical waste, there are the wastes of producing at excessive cost and doing things at the wrong time. The Report suggests abandoning the criterion of maximizing ultimate recovery in favor of maximizing discounted cash flow; avoiding the dissipation of rent by overspending, particularly on capital. It warns against the twin dangers of using proven resources too slowly and searching out new ones too early.

- External impacts. These are seen as negative by environmentalists and as positive by developmentalists. The reconciliation lies in a wider distribution of benefits.

- Coordination with federal and Native landowners.

The Report now surveys leasing alternatives in sequence:

- Noncompetitive leasing is faulted for giving away too much and encouraging premature leasing and production.

- A high bonus partially cures these problems but creates a serious front-end filter problem. Professor Norgaard's postmortem analysis of bonus bidding in Alaska indicates that too little has been received for leases.

- A high annual rental cures the problem of the front-end filter by replacing it. It may over-accelerate production, however, unless made to dwindle over time. A rental whose level is set before discovery reduces the buyer's risk since he may drop the lease at will, but does not alleviate the State's risk of selling for too little. A rental based on assessed value avoids this problem and also dwindles over time.

- High royalty rates solve much of the risk problem. They eliminate the front-end

filter and they collect revenue. However, they allow too much speculation. They also put a drag on production, especially marginal production. Premature shutdown turns out to be a minor problem. Others are greater: slow production and future shift; leakage of rent into private hands from better deposits; excessive deferral of State revenues; and lower success ratios for exploration. These problems can be alleviated by imposing specific work terms, by using sliding scales, and by limiting the term of the lease.

- Specific terms. These must be used with high royalties to compensate for the disincentive effects. Mandatory liability for environmental damage is also suggested.
- Profit sharing. This means letting lessees write off costs against royalties and also raising the rate to compensate. This lets the State receive more per barrel from the richer deposits, and avoids sterilizing the marginal ones. It gets us into the same problems as administering an income tax: the rate is high, padding costs is likely, depreciation paths and lives must be determined according to complex and sometimes arbitrary formulas. There remains a loophole for unrealized capital gains.
- Rent-sharing. In addition to costs the lessee deducts interest on the value of his improvements by one of three methods: by allowing deduction of capital over time with interest at a specified rate; by allowing front-end recovery of capital and by applying an *ad valorem* charge to the assessed value of the leasehold interest. The first two alternatives engage us in severe auditing problems, and both are biased against exploration on long-shot ventures. The third alternative removes the auditing problem and replaces it with an assessing problem. It also puts a bite on unrealized capital gains. It avoids many faults seen in prior systems: it raises money; it defers payments but not excessively; it puts no drag on production; it requires little direct regulation; it imposes no shift towards the future; there is little opportunity to pad

expenses; and there is only a limited bias against long-shot exploration (because what is hard to find is often hard to produce and therefore low- valued). Its problem is discouraging post-leasing exploration. Some remedies are suggested.

- Regulating field operations. Some form of unitization is required. It is suggested that this will work much better if the State accepts the criterion of maximizing discounted cash flow, eliminating a conflict between the State and the operators. A two-tier system is suggested as an alternative to 100 percent unitization.

- Three alternatives are passed over lightly, although without prejudice. These are: checker-boarding; the sale of undivided interests; and the sale of a fixed volume of oil and gas.

- Handling information. The Report considers the pros and cons of the State's buying more information on contract as an alternative to relying on industry nomination. The weight of argumentation is in favor of the State's taking a more active role.

- Direct State intervention in the market is considered, primarily to aid in monitoring prices used as bases of evaluation for royalty and assessment purposes, and to guarantee to all lessees equal access to transportation.

Next a criterion and procedure is developed for timing lease sales. State lands are to be ranked according to maturity or "ripeness." Ripeness is defined as a condition where the percentage growth rate of the DCF of the State's interest slows down. The State's wealth is maximized by selling leases when this anticipated growth rate slows down below the rate of interest. The appropriate rate of interest should be the State's borrowing rate. The question is raised whether the State should set a reservation price when auctioning leases. The Report addresses the question of whether the proposed procedure will cause leases to be sold at a sufficiently even rate.

The Report considers the administrative load and personnel requirements associated with alternative leasing systems. The use of royalties entails ancillary regulation to compensate for the disincentive effects of the royalty on production. The profit share system entails an auditing staff to avoid the deduction of unjustified expenses. So, also, do the first two rent-sharing systems where capital costs with interest are deductible. The *ad valorem* charge system entails a staff of valuation engineers or appraisers, whose services are also required to operate a system of timing lease sales optimally.

Leasing is seen as supplementary to taxation, and taxation is not seen as an adequate substitute for leasing policy because taxation is addressed to persons or corporations while leasing policy is addressed to parcels of real estate. The exceptions to this are a net proceeds tax and a property tax, either of which might be used as a substitute for leasing policy.

Recommendations are submitted tentatively in light of the complexity of the subject and the several imponderables involved. I recommend screening out systems based on *ex ante* forecasts of resource values like the bonus bidding system, because of the front-end filtering out of leaner firms and because so much has to be gambled on so little information. We consider the lease elements whose value depends on actual disclosure of resource values and rank them in the following order: the *ad valorem* charge, the profit share, the sliding scale royalty, and the front-end recovery. We recommend a vigorous program of State-financed contract exploration with publicity of findings. We recommend scheduling lease sales according to the ripeness criterion described above. We prefer that unitization be administered by an organization of local leaseholders.

Our most immediate and unambiguous recommendation is for a greatly expanded program of information-collecting and valuation, to serve as a necessary base for all other decisions.

A. Reasons for this Study and Report

This study was commissioned by Guy R. Martin, Commissioner of Natural Resources, State of Alaska, in cooperation with the Legislative Interim Committee on Oil and Gas Taxation and Leasing Policy, chaired by Senator Chancy Croft. The present Report is part of a larger study being conducted by the Department of Natural Resources, a study described in Commissioner Martin's statement of July 10, 1976, entitled "Alaska Oil and Gas Leasing Study," copies of which have been submitted to the Legislature. The primary focus of the present study is Section 4 of the July 10th memo which reads as follows:

"A description and analysis (legal, economic, other as necessary) of all alternative systems which are practically applicable to State use in Alaska, with emphasis on broadening the State capability to employ alternatives rather than making final decisions on which systems to use. This task should consider the practical experience of other states and nations as well as leasing theory and research.

a. Special attention in the analysis should be given the risk element in alternative systems as it relates to public administration of oil and gas resources.

b. The analysis should include, in some form, an overview of this entire leasing issue of use to State officials and legislators."

This Report also responds to Section 5:

"An economic/legal analysis of the interrelationship of leasing (ownership interests) alternatives with taxation alternatives. Ongoing coordination with the taxation segment of the administration/legislative study."

This Report also responds to Section 7:

"Design of a system (a criterion) for decision-making by public administrators regarding various leasing alternatives. What information must be available; what factors should be considered; what process should be followed to decide between new alternatives."

In keeping with the spirit of the assignment, the tenor of this Report is expository and not advocatory. The main purpose is to lay out major alternatives in a systematic way to serve as a basis for legislative review, debate and decision. The report does offer its own recommendations at the end and the consultant offers his own judgments from time to time where it seems appropriate, and where they may be identified as such. The overall spirit of the Report, however, is to define and articulate alternatives, to spell them out in a logical sequence, stating the advantages of each, the faults of each, and what the Legislature would have to do to make each one work. Most of them will "work" --sort of-- and are in operation in various jurisdictions around the globe. It is a question of what might work better in light of your own objectives, circumstances, and visions of the future.

In developing alternatives, the Report proceeds from the simple and basic to the more complex and sophisticated, showing how each complexity develops as a logical effort to overcome some fault in the simpler system. Before breaking down in complexities, however, the effort is made to apply Adam Smith's dictum that the evolution of successful inventions is not, in the end, into greater complexity but greater simplicity -- an observation dramatized by Igor Sikorsky when he exhorted his engineers, "Simplicate, simplicate -- and then add more lightness!"

A purpose is to cut down the seeming number of alternatives without reducing the real number by boiling proposals down to their essentials and showing how few of them there really are. The number of possible combinations is still extremely high because there are so many

elements in a lease but the number of reasonable combinations is much smaller because they need to be combined so as to balance each other and countervail each other's faults.

A correlative purpose is to develop commensuration, that is, conversion factors among the apples and the oranges. By doing so, we develop a common tongue for communication, a common currency for trade-offs, and a unitary standard for decision-making.

Alaska's interest in this topic is timely and in step with a worldwide trend to study and improve leasing systems. This is a natural result of increased valuation of oil and gas resources in the ground. As the retail price rises there is enormous leverage on field prices. The farther the field is from the gas pump the greater the leverage, so that the percentage increase in the field value of Alaska's resources is at a rate so high that few would have credited it a few years ago. Field prices everywhere are rising out of all proportion to other costs. This is reflected in extremely high bonus bids offered for tracts which were previously considered marginal or sub-marginal. A recent survey indicated that costs of land acquisition by oil and gas companies increased by nearly 700 percent from 1970 to 1974 (Joint Association Survey, 1976) in comparison with all other costs which increased by considerably less than 100 percent. Clearly, the world is recognizing the high value of remaining oil and gas lands and it behooves any prudent landowner to protect his interests and to economize on the resource with much greater care than ever before.

Most analysts now foresee continued upward pressure on energy prices and this consultant, although forecasting is not his forte, is inclined to agree. This is the more reason to guard our future interests by using care in drawing leases now. The lease contract is binding and irrevocable, unlike tax policies. No legislature can bind or limit the tax power of a future legislature; but neither can a legislature in the United States, with its strong tradition of judicial

review, rewrite a lease contract executed by its predecessors. Other nations may force renegotiation of contracts considered unfair in the light of changed circumstances. This is not unknown even in the United States but much rarer and harder than in countries of different traditions.

The result is a growing interest in public landowners' participating in future profits from oil and gas. For generations past, many governments virtually gave away land simply to get it used; while private landowners sold their future rights for a little money up front. Now these attitudes are changing drastically and there is ferment everywhere. The U.S. Congress has entertained several bills in both branches calculated to increase government participation in future profits in spite of the government having secured large revenues from bonus bids following the OCS Act of 1953. There has been some support for a federal oil and gas corporation to explore in advance of leasing. Equity participation in corporations has been a strong trend, exemplified for example in Norway, in Canada, in Saudi Arabia and elsewhere. Indonesia has pioneered its own interesting leasing system, characterized by rapid capital recovery to the lessee followed by very high royalties. Papua-New Guinea has recently adopted the same principle in more sophisticated form, basing its law on the careful advice of economists Ross Garnaut and Anthony Clunies-Ross. The academic world which ignored this tonic for many Years past is beginning to spawn several research projects and will soon be awash with reports and articles and proposals and econometric studies and models and new philosophies. The world is moving. Alaska is in step, although perhaps a step behind. The present assignment indicates intent to catch up or pull ahead.

B. Objectives of the State

Only individuals, it is said, can have objectives. By "objectives of the State" this Report means the objectives of the effective majority of Alaska's voters as expressed through their political representatives and other leaders. No one thinks that representative government can completely succeed in representing everyone or, perhaps, anyone. But it is what we have, and this report addresses these leaders as though they were the State.

The Report does not presume to say what the State's objectives should he. It, rather, purports to distill what the consultant observes them to be; and to articulate and organize ambient ideas which are often heard but want greater system and organization. This entails some interpretation by the consultant. Those with more data and better interpretation may improve on this Report. The present report only begins the job of laying out our goals on the table.

A further purpose is to begin to define and expand on their specific implications. This inevitably entails even more interpretation, and perhaps even some presumption by the consultant. Seeing these implications as he interprets them, one may sometimes recoil and say "no! --That's not what I really want." So be it -- then we may go back and spell out more realistic objectives we can live with and we are well down the road to our present goal which is to be prepared for decision-making.

The following are what I take to be the State's objectives in framing a leasing policy:

1. <u>Business-like management of State property</u>

The State holds property in trust for the people of the State and has a duty to manage it prudently for their maximum benefit. This means several things but one is certainly money. The State is a landlord. It wants to secure maximum income. It does not do this by fostering maximal use of resources but optimal use -- that is, it encourages lessees to maximize the bottom line,

recognizing that income is net of costs. "Maximum income" is still ambiguous, however, because rival schedules of land use and income differ in their time-distribution: a fast start means a slow finish and vice versa. To resolve this ambiguity we deduct interest on capital between the dates capital is committed and later recovered.

This goes far towards resolving ambiguities but still leaves a large one, the treatment of the investment in withholding unproduced reserves from year to year. The final resolution is achieved by maximizing the Net Present Value of future cash flows. This procedure is also called maximizing wealth; and also called maximizing Discounted Cash Flow (DCF).[1] This report uses the last, which seems to be in common use in Alaska. Business-like management means adopting the criterion of maximizing DCF.

Maximum DCF is not to be applied rigidly or dogmatically or narrowly as a standard. It does not always comprehend all relevant values and factors. It does, however, comprehend a great many more than critics of the "almighty buck" might realize because it is the net balance arrived at after a long process of adding and balancing all manner of pluses and minuses. In addition, it provides a logical analytical framework within which newly recognized goods and bads may be added to the analysis in carefully measured perspective. One of these, on the minus side, is environmental damage. Some environmental damages are measurable in reduced cash flow. Damage to commercial fisheries is an example. Others are indirectly measurable in the marketplace. For example, the loss of residential and recreational amenities on privately owned

[1] There are references in Alaska reports to maximizing the "DCF rate of return." This usage seems ambiguous since the rate of return is held fixed at a rate determined by outside markets when one discounts the cash flow. It is the present value of the cash flow that one maximizes. It is mathematically quite possible and simple to hold the present value fixed and maximize the rate of return instead, using the same mathematical formulae, but treating the interest rate as the unknown to be maximized rather than as a "given." Sometimes this is done when one is out of contact with outside capital markets but there is no need for it here; and it would not affect the findings anyway because, as a rule, maximizing the internal rate of return as it is called will not lead to strikingly different results from maximizing the Discounted Cash Flow, so long as one makes no mistakes in mathematics.

land which reduces their service flow is measured in reduced selling prices of titles to the real estate.

Damage to sports fishing reduces an amenity service-flow which is harder to measure than cash flow but no less important on that account. Economists are developing techniques for measuring such service-flows. These techniques are still imperfect, like the rest of this world, but they at least let us set an upper and lower bound on the values and so let us begin to measure them in the same balance with other things.

On the plus side, increased payrolls and commercial sales deriving from oil and gas income will increase residential and commercial values in some areas. Part of this increase is a "secondary benefit" from oil and gas development and should also be entered into the balance. This obviously gets complicated and extended. It is beyond the scope of this Report to resolve all such issues. The present point is that the use of the crassly materialistic and narrow concept of Discounted Cash Flow does not in any way box us in and preclude us from broadening the scope of the analysis when we have the will and resources to do so. It provides a framework of analysis which is almost indefinitely extensible to comprehend as many variables as we have the ambition to try to consider.

The concept of "discounting the future" disturbs many people, but it is only the choice of words which is unfortunate. Discounting does not imply neglecting, abusing or short-changing the future but, rather, charting the most advantageous path into the future. The mechanism discounts poorer paths to the future because there are better ones -- "better" meaning a higher rate of increase of wealth. It is not prodigal to decline a three percent path in preference to a 10 percent path.

It is often suspected that discounting the future leads us always in the direction of faster resource use. Not so. We will see that this criterion may well lead the State to retard lease sales and production, so long as the anticipated proceeds to the State are growing faster than money in the bank. On marginal and sub-marginal lands these net proceeds begin growing from a base near zero. From such a low base they need not grow much in order to grow faster than money in the bank.

Discounting the future requires a discount rate. The State's rate needs be no higher than its borrowing rate but it can be a good deal lower when Alaska has surplus funds to invest. There is no suggestion here that the "social" rate of discount is lower than the market, a concept wanting in both precision and rationale. It is, rather, a practical question. If the State cannot invest its surplus for high returns then an investment in the growing value of oil and gas in the ground may be a superior alternative.

Maximizing DCF as a criterion solves two problems for us, problems of timing. One is the optimal rate of production from proven reserves. These timing decisions are largely in the hands of lessees except to the extent that the State interferes with their natural desire to maximize DCF by controlling the rate of production. An equally or more important timing decision is when to begin production. Here the State is in the saddle with its decision of when to sell leases. The DCF criterion says that we should sell leases at that time when we expect that their future value will be growing more slowly than money in the bank. This rationale has been developed in the consultant's previous work, "Extractive Resources and Taxation." The relevant pages are attached as Appendix A.

The State's concern with money is not narrowly centered on lease-hold income but includes tax revenues of course. On the minus side, there will be associated public costs with

increased economic activity. An exclusive or unbalanced attention to either the revenues or the costs without the other will always be misleading. It is the net balance of advantage that we seek to maximize. This should provide a reasonable basis for compromise between the advocates of growth on the one hand and restraint on the other.

While leasing policy should help to protect State revenues, the State has minimal interests in protecting federal revenues from oil and gas. Since the federal rate is much higher than the State rate, especially after the Multistate Tax Compact (MTC) sharing formula is applied, leasing policy may often achieve a net increase of State revenues by being bent to consider the foibles of federal tax law applied to oil and gas, a law which the State follows. Much as we may deplore the peculiar federal tax treatment of income from oil and gas, there seems little reason for the State in its capacity as a landlord to conduct its affairs so as to maximize federal taxation of lessees where that would cut into State revenues from its property.

2. <u>Equity</u>

There is a strong feeling that the distribution of benefits from oil and gas production in Alaska should be equitable. Equitable does not mean equal although there is some suggestion of that in it and it might be more equal than now. There is support for the productivity theory of distribution, however. This means that rewards should be shared in relation to productive contributions rather than other factors like luck of the draw and the weight of superior wealth accumulated in the past.

Tolerance of gambling and the lottery principle has not altogether died. There are residuals of it in the lottery system for allocating noncompetitive leases which are filed on "simultaneously," that is, within one 30-day period, and of course there are lottery elements in the bonus-bidding system. There is a growing interest, however, in shifting from Lady Luck to

productivity as a basis for distributing wealth. This is a corollary of a desire for greater equality since productivity is usually more equally distributed than luck, and certainly more so than accumulated wealth. The Alaska attitude is Jeffersonian: "...there is a natural aristocracy among men. The grounds of this are virtue and talent....There is also an artificial aristocracy, founded on wealth and birth, without either virtue or talent....The natural aristocracy I consider the most precious gift of nature, for the instruction, the trust, and the government of society." (Letter to John Adams, October 28, 1813.)

The implication of this is that we should seek to identify and measure that value which belongs to the State, that is the rent of land, and then collect it. At the same time we leave to lessees all the other values, the ones which they create. Jefferson continued, "What is needed is a wise and frugal government, which shall restrain men from injuring one another, which shall leave them otherwise free to regulate their own pursuits of industry and improvement, and shall not take from the mouth of labor the bread it has earned." (First Inaugural Address, March 4, 1801.)

As a happy corollary, if we succeed in this we will protect necessary incentives to the industry and other lessees. A skillful system of discriminating rent collection will leave more incentive to lessees than a blunt instrument such as a royalty accomplishes. A rent-collecting device will take more from the flush deposits in their flush years and less or none from the marginal deposits, leaving incentives unimpaired.

Collecting rent will, to be sure, reduce certain kinds of incentives--but these are ones that should be reduced in the interests of efficiency. Resource economists have repeatedly observed that the failure of landlords to collect rent results in overstimulation of resource use by interlopers, resulting in the dissipation of rent, as on the open sea fishery, or an open range. In

such a case, reducing incentives is a good thing. It is not enough for incentives to be large; they should motivate people to allocate resources productively.

The prevailing concept of equity also implies that rewards should he related to ability and application more than to the weight of accumulated wealth. In practice this amounts to a suspicion that the present bonus-bidding system with its high requirements for money up front is filtering out large numbers of potential lessees whose productivity might be high but whose accumulated wealth is low.

A corollary concept here is that reducing the bonus money screen would increase the number of competitive bidders. This, if properly handled, should allow the State to increase its revenues.

3. <u>Practicality</u>

Alaska has traditionally operated with a minimal bureaucracy. While it is increasingly recognized that some additional staff may be very productive, beginning from this low base, there is a presumption against any proposed system that presupposes a large and elaborate and expensive bureaucracy. It is also desirable that there be a low burden of compliance in the form of paper work imposed on lessees and that minimum policing be entailed.

Alaskans have traditionally left considerable latitude of judgment to their higher public officials as well as to technical specialists like reservoir engineers. There is a growing interest in stating objective criteria for these persons to follow, minimizing the burden of judgment and making it easier to evaluate the performance of individuals.

A practical system will be as automatic as possible, minimizing direct regulations and controls which are required when people have to be forced to go against what they perceive to be their economic interests. This is accomplished by drawing leases so as to bind the contracting

parties in an identity of interests. The lease should make the interests of the lessee as nearly as possible identical with those of the State, so he is moved to act in the State's interest by economic incentives rather than orders controlling his rate of production, work commitments, spacing, diligence, and on.

A very simple system like a royalty system without other features might seem to avoid many problems, but in fact has the shortcoming of involving the lessor in extensive direct regulation in order to offset the disincentive effects of the high royalty rate. A profit share system, allowing for extensive deduction of costs by the lessee, precludes such direct regulations but on the other hand requires extensive audit of expenditures. A rental which is proportional to the appraised value of reserves like the Alaska Reserves Tax avoids the foregoing sets of problems but requires personnel with the ability to place a value on reserves. It is hardly possible to avoid demands for additional personnel under any system designed to protect the interests of the State. It will be a question of determining which system is least costly and most effective to administer.

4. <u>Avoiding economic waste</u>

There is a new and explicit concern with avoiding "economic waste." This is quite a change from, and quite an improvement over the prevailing concepts which are limited to preventing "physical waste." The State presently legislates against various kinds of physical waste, for example against flaring and venting gas; against producing from "rate sensitive" reservoirs too fast to maximize "ultimate recovery." In this legislation waste is perceived only in concrete, materialistic terms.

Any subsidy to the industry tends to prevent the "physical waste" of not producing submarginal oil and gas. The State has extended a few such subsidies such as a tax holiday to a

pipeline in Cook Inlet. Non-uniformity in taxation is a type of subsidy to those taxed less, and the term "tax subsidy" is commonly applied to it nowadays. Federal income tax law traditionally extends enormous tax subsidies to the oil and gas industry through preferential treatment. The State has followed along by adopting the federal tax law and in addition has joined the Multistate Tax Compact (MTC) whose allocation formulas minimize State tax revenues from oil and gas. The attitude might perhaps be summed up as "as much as possible, as early as possible."

Producing sub-economic reserves entails not only the economic waste of the excess of costs over revenues, there is also the waste of selling the reserves when they are cheap, instead of later when they probably will have become dear. Our initial criterion of maximizing Discounted Cash Flow (DCF) would tell us to hang on to reserves as long as their value was growing faster than money in the bank.

Past policy in administration has been disposed to take an "infant industry" posture towards oil and gas. Raising money or maximizing State wealth has been secondary to attracting activity and capital. Lease sales have occurred at the initiative of industry nominations more than the State's, with the State not much disposed to hold back for the best price. Encouraging and establishing the industry was *ipso facto* a good thing.

A policy of leasing on demand will undoubtedly stimulate early exploration, which will result in locating deposits that might otherwise not be produced, at least for a while. This might he construed as minimizing physical waste -- the waste of not finding something. There has been little concern about the economic waste inherent in premature and duplicative pre-leasing exploratory investments. In an earlier phase this was carried to even greater extremes when noncompetitive leases were issued. But leasing on demand at the rather low prices that have been received is only a halfway step between noncompetitive leasing of the free entry, first-come first-

served, variety and an economical system which would maximize the discounted cash flow of the State.

As to duplication of effort, this is generally rationalized on the grounds that a second explorer might use a different concept from the first and therefore find something overlooked by the first. That is beautiful so long as cost is no object, but it is really no substitute for a benefit cost analysis that would at least purport to tell us how the cost of a second pass at the shot lines relates to its probability of success.

In regulating field production the concept of maximum efficient rate (MER) has been accented rather uncritically with the thought that it might be good to maximize ultimate recovery. MER has been accepted not for what might be the legitimate reason that prices are rising or the partly legitimate reason that it requires fewer wells and that saves capital, but rather almost entirely on the grounds that faster flow might cause physical waste. In this case the goal "as early as possible" clashes with the goal "as much as possible" and the latter wins.

The net result of overstimulating pre-leasing investigation, and decelerating production, is to attract lots of capital into the industry and slow down the rate of recovery. Capital must be paid for every year that it is tied up without being recovered. This payment necessarily detracts from the surplus that remains to be captured by the State. This is a kind of economic waste which I believe the State would like to learn to avoid. It dissipates rent.

The traditional conservationist feeling in favor of wide spacing developed at a time when the land surface was subdivided into small, private properties, smaller than most oil-bearing structures, so that some offset was needed. The result today is rather one-sided, preaching for the benefits of wide spacing without due note of its costs. Such preaching, which is widespread in the literature of this business, also suggests more solicitude for lessees than lessors because the

interest of lessors is generally to have lessees apply more capital rather than less, where royalty is being charged. This bias is understandable in an industry where lessees have traditionally dominated lessors by virtue of being larger and fewer; and lessees' agents have written the books.

Where there is a high royalty rate the lessors' interest is to see prompt in-filling at high density. The lessee, on the other hand, might prefer to invest capital by stepping out to someone else's land while dawdling on this.

There is a growing awareness in the State that exclusive preoccupation with physical waste is a one-track goal which lacks adequate balancing of benefits against the costs of achieving them. There should be an equal awareness that the problem of one-track goals is not peculiar to oil and gas. Specialists in any resource or activity become interested parties and tend to overvalue it and undervalue the costs of promoting it -- since costs represent a sacrifice of the interests of specialists in other resources and activities. This is a universal problem in an overspecialized world.

Legislators are called on to he generalists, arbitrating among the claims of competing specialists. There is no suggestion here that oil and gas interests are better at this game than other specialists, that their technical inside language is more obscure or intimidating than that used in other professions, or that their high "standards" are more unreasonable than those imposed by other groups of whom we could all supply examples. Focusing on "physical waste" is an over-pleading technique not peculiar to the oil and gas industry. We bear down on oil and gas here because it is our subject matter and not because it is outstandingly bad. No industry or profession has any monopoly on self-serving, special pleading, and careerism.

Economic waste occurs whenever we prevent physical waste at a cost higher than the value of the oil saved. This would be simple enough to see and correct if all costs were present

costs and all production flows occurred right away. The problem is more subtle because it usually involves the factor of time and therefore questions of capital and compound interest. Some major economic wastes of timing are described in what follows. Please note that I speak not only of what has been and what is but also of what might be if we adopt certain alternative leasing policies that have been sponsored.

a. Slow use of proven reserves

Slow production occurs if the State requires it through MER regulation or if it simply fails to build a fire under lessees whose cost of waiting is virtually nil when there is no substantial delay rental, and who might be "stepping out" with other leases which preoccupy them from attending to this one. Not maximizing DCF means ignoring the cost of interest -- first, the cost of drilling wells and equipping the lease and, second, the holding cost of the unproduced reserves. To schedule production this way is the same as assuming that no profit is required on investments, an assumption inconsistent with the idea usually accepted that some very high rate of return is required in order to interest lessees in taking a lease. This paradox is too often resolved by sloughing the cost onto the State in the form of lower bids for leases, from which lower base the lessee can still earn a good rate of return. This clearly is a bad resolution for the State.

The MER standard developed historically as a reaction to the rule of capture and has had at times a useful history therefore, lending some aura of engineering "authority" to restrictions on production. But it became abused and harnessed to the purpose of helping rationalize price maintenance restrictions; and then it became habitual and traditional, applied in a rote way. It is not appropriate to Alaska today. It can easily become another case of a fixed professional "standard" applied without regard to circumstance or cost, forgetting that "cost" means more than

money. It means an invasion of the standards of other professions and other people who have to make the economic sacrifice.

b. Premature investment

We noted above how a noncompetitive claim-staking system based on priority of claim leads to premature and duplicative investment; and that a system of leasing upon industry demand or nomination halfway resembles a simple claim-staking system. The result is to sink too much capital too soon in the initial phases of exploration, proving up, social infrastructure, equipping leases, mobilizing support facilities, and so on. Money at 10 percent doubles every seven years. Money at 20 percent doubles every four years. To advance investment by a few years, therefore, is the same as doubling the costs.

But as well as neglecting cost -- and often more serious --premature investment neglects price, the price of the product reflected in the price of the lease. The lessees who buy early aren't neglecting it for they can ride up the escalator, having obtained a lease and being under little pressure to produce quickly. It is the State that is neglecting price when it sells leases too soon at too low a figure. It then plays the lessees' game if it permits or, worse, requires them to produce slowly and at the same time encourages them to go out and acquire more leases.

There should he no implication that the State should hold onto its unsold leases indefinitely, waiting for the top dollar. To everything there is a season and a time for every purpose. The criterion of maximizing DCF is in keeping with the wisdom of *Ecclesiastes* for it tells us exactly the best time to sell, namely when the anticipated selling proceeds stop growing faster than money in the bank. Early sale may waste the resource by releasing it for a low price. Later sale may conserve the resource but waste the capital tied up in it. Optimal timing balances the two considerations.

Some things are happening too soon and others are happening too late. Is this just random confusion with no pattern? No, there is a pattern which may be summarized as slow recovery of capital. Capital is put in too soon and taken out too late. The cost of all those extra dollar years of capital time is borne by the State.

A waste imposed by slow turnover is loss of flexibility and adaptability. Each time capital is recovered and replaced it may he brought up to date with new technological developments. The advantage of flexibility is perhaps most obvious in respect to contractual commitments. "Old" gas may be subject to Federal Power Commission (FPC) regulation and tied to a particular pipeline, or it may in any event be under a long-term contract. In an inflationary period there is always an advantage of bringing new supplies on the market at new prices.

There are also more fundamental reasons not dependent on inflation. I have analyzed these in the work already cited and append the relevant pages as Appendix B.

Another route to understating costs is to accept the plea of those with an interest in supplying oil fields that one man's cost is another man's income and therefore to cancel these out. The result of heeding these arguments is to conceive of benefits in gross rather than net terms. This almost always results in premature development inasmuch as the gross value of a resource is not only greater than the net value but it is positive during that early period when the net value is negative. This kind of argument can be carried even farther by some "economic base analysts who compute "multipliers" of still more extended benefits proliferating downstream and upstream and sidestream from the resource development, all being dependent on it. If there is much unemployed labor and idle industrial capacity such a case might sometimes he made. In Alaska, which imports labor and oil field materials and steel, there seems little basis for it.

Unfortunately, economic development which is sought after by some and shunned by others is defined by none. This leaves the door open to considerable uncertainty. The extreme pro-development posture is that resource discovery creates value and then provides an economic base for multiple benefits all around. Current thinking seems to be moving away from this. Discovery does not create value all alone. It is a cash-register payoff from the larger development of infrastructure, community support facilities, and so on. All activities are mutually supportive, discovery no more so than others; and the other contributors need support, too. The new emphasis on the problems of community impact is some acknowledgment of this.

It is not surprising that people who see mainly the costs of development and disregard the benefits are disposed to wait a longer time before permitting it to take place. They, too, may get carried away and overstate their position, becoming like Oscar Wilde's crabbed economist who "knew the cost of everything and the value of nothing." In this Report we will not try to resolve these complex and extended issues, but treat the question of multipliers and extended benefits and costs as something of a standoff, except where very specific external costs or benefits may be identified and measured.

Another economic waste to guard against is "cross-subsidy." This is a generic term for what occurs whenever accounts are consolidated and costs are deductible so that high-cost and losing ventures may be rolled in with low-cost and winning ventures. Cross-subsidy is a hazard in every profit-sharing scheme such as the corporate income tax, and it would be a hazard in any profit-sharing lease resembling the corporate income tax. It is a hazard in any lease that resembles utility rate regulation where a lessee is guaranteed a rate of return. The resulting overinvestment of capital is known in the trade as "goldplating," or more formally as the "Averch-Johnson -effect."

Goldplating today might often take the seductive form of an excessive lack of resistance to the claims of some worthy cause like environmentalism. The caribou lobby specialists may overvalue that, the energy specialists may overvalue energy but they can join forces in undervaluing the costs of having both, the costs being shifted to others.

Perhaps the commonest manifestation of cross-subsidy is the overextension of sub economic feeder lines. This is nearly universal elsewhere and will undoubtedly happen here without vigorous efforts to prevent it.

When we combine this pattern of waste with the pattern of improper timing described earlier, they tend to reinforce each other in a general pattern of over decentralization. Too much capital is applied too early to expand exploration and allied transportation lines. Too little is applied and too late to more intensive development in and around proven reserves. The overall pattern has much in common with imperialism. All of this can he avoided by hewing faithfully to the concept of businesslike management with maximum DCF. That will be our lodestar.

5. External impacts

To allow for the externalities of oil and gas production both positive and negative, the State seems evenly divided between those who perceive more pluses and those who perceive more minuses. This is appropriate since there are both kinds. The issue between the polarized parties is sharper, however, than can be resolved by such devices as measuring the value of the sports fishery, for example, and trading off these values for equivalent energy values because some of the very things seen as positive by some like added payrolls, added spending, and increased property values seem negative to others. Change viewed as progress by some is seen as retrogression by others. To measure and then reconcile these attitudes would he far beyond our scope.

We need not, however, leave the matter completely unresolved. A key to reconciliation is in the distribution of gains and losses. There are probably more gains than losses from general economic development since the actors reinforce one another, but the gains are not equally distributed. One man's windfall is another man's wipeout. Many gains are unearned and received by absentee investors. As the problem is distributive so is the probable solution. Wide distribution of the benefits of oil and gas development will make it much more acceptable. Leasing policy can contribute to this solution, although it is by no means the whole story.

Another external cost imposed on society by extractive industries is frequently instability, and many people fear the boom and bust characteristics of oil and gas and other mining industries. This consideration argues for leases that yield steady revenues and encourage steady activity and it also may argue for a steady flow of lease sales. Neither of these is an absolute, obviously, and must be balanced against the question of getting top dollar by turning production and sales on and off.

6. <u>Coordination with leasing on federal and native lands</u>

Federal and native lands will share common transportation lines and support bases with State lands. They may be on the same structures. State and federal lands especially have extraordinarily long common boundaries in oil-prone areas. The State evinces strong desires not to be led by federal policy and to have some input into federal policy.

At the same time, there is no drainage treaty or compact between the different landowners even though England and Norway have managed to work this out on an international basis. Until this is done, clearly a strike near the boundary will force a drainage sale on the other side. If the Feds and the natives get and keep ahead of the State, the State might do very well by specializing in drainage sales, a policy favored by many. But there is an uncomfortable feeling

that this loss of initiative might also impose high costs by letting others determine the location of activity as well as the timing. There is also some fear that division among the three kinds of landlords might divide them for easier conquest by the industry. The State's objective therefore is clearly to achieve a higher degree of cooperation.

C. Elements of Leasing

There are several elements in a lease, most of which are optional and variable along a wide spectrum. Kinds of leases are frequently distinguished by identifying the bid variable; but the constant elements may be more important than the bid variable where they are set at very high rates. Thus we discuss the pros and cons of each element in leasing first, and only at the end discuss the choice of a bid variable.

1. Prior claim: the noncompetitive system

A substantial acreage in Alaska remains under noncompetitive lease. Figures forwarded by Mr. Denton of the DNR for noncompetitive acreage of "oil companies" totaled to 625,000 acres. In addition there is acreage held by individuals. Ranking the companies in order of their net acreage held, we find that the top 10 percent hold 58.9 percent of the noncompetitive net acreage. This compares with 64 percent when we do the same thing for competitive net acreage. Major holders of noncompetitive acreage are Texaco, Union, Cities Service, Amoco, and Atlantic Richfield. (Major holders of competitive acreage are the same firms plus Sohio, Phillips, BP Alaska, Exxon, Standard of California, and Mobil.) (See Appendix C.)

Noncompetitive systems are widespread outside the United States. Major faults appear to be that they give away State property without payment, and so encourage premature claims and, where there is a work requirement, premature use. The claim-staker rather than the State gets in on the ground floor of the elevator and holds the resource while it appreciates from a zero value up to whatever value its natural richness warrants. Any rate of return beginning from a base equal to 0 is mathematically infinitely high and therefore not to be lightly given away.

We append an analysis by Professor Michael Crommelin, Faculty of Law, University of Melbourne, Australia (Appendix D).

2. <u>The bonus</u>

There are several advantages to using a high bonus in allocating leases and it has many staunch advocates, including Walter Mead and Milton Lipton. Advantages of a high bonus include:

a. Large commitment by the lessee -- he will not walk away.

b. There is no marginal disincentive imposed on the lessee.

c. The State receives its money up front.

d. Major corporations have access to market funds at rock bottom interest rates, about 7.5 percent on bonds today, and therefore presumably will discount future expectations at correspondingly low rates. Some of them have access to internal funds whose opportunity cost or alternative use may be even lower in the event the management is embarrassed with more assets than it can manage effectively. Some utilities, in seeking to support their rate bases, have advanced money to invest in leases. This last kind of investment is being cross-subsidized by the profit-making parts of the firm and may yield extremely low marginal rates to the company. Historical evidence presented by Mead from the Gulf of Mexico indicates rates of return of about 7.5 percent.

e. If the State should be exploited inadvertently it can use the tax mechanism later on to compensate.

f. The transfer is complete and there is no need for policing prices later on, auditing costs and so on.

On the con side, major problems with high bonus payments are the following:

a. High capital barrier to entry, reducing the number of bidders. This is undesirable both because of the concentration of wealth and power which it implies but also because reduced

competition might prevent the State's receiving fair value. Data supplied by Mr. Denton when ranked by net acreage indicate that the top 10 percent of the holders of competitive net acreage have 64 percent of the acreage. These top 10 percent consist of Arco, Phillips, Union, SoCal, Exxon, Sohio, Mobil, and Cities' Service. While this degree of concentrated control is not unusual in other places and other industries, it is still higher than many would consider socially desirable.

b. As low as the industry's internal cost of capital may be, the State's effective rate is probably lower. This is a considerable change from the past and calls for a change in policy. The State is no longer desperate for front money but on the contrary is looking for outlets for its permanent fund. The industry, on the other hand, may be entering an era of higher internal interest rates. It is freely alleged that figures like 20 percent are used in determining bonus bids although this is difficult to nail down. It is certain, however, that monumental capital requirements are projected for oil and gas related investment requirements in the next decade, presaging increasing tightness of capital and therefore lower bonus bids relative to resource values.

c. The bonus aggravates the cash crunch since it is synchronized with the need to find capital for drilling and equipping. This may result in underallocation of money to the latter, especially for small firms.

d. The time preference and therefore the production scheduling of different firms is ruled by their internal interest rates which vary from one firm to another. The allocation of credit among companies is based not on marginal productivity but on collateral security. The result is too much time pressure on some lessees and too little on others. The one may depend on extremely rapid use while the other may depend on speculation and delay above and beyond the

social interests.

e. The payment is determined and made before enough is known about actual reserves. There is a large lottery element in the outcome and the outcome is not closely correlated with the price paid. The State might sell $10 billion worth of oil for $6 million as it apparently did at the 1965 auction at Prudhoe Bay. At the same time it sells some barren land for a high price. The rule of caveat emptor is applied, frequently intentionally by the seller. This constitutes a fraud with malice aforethought, which would not be tolerated in private business dealings and it is questionable if the State should observe a lower level of elementary morality than is expected of private sellers.

f. The distribution of petroleum reserves in nature is extremely unequal as among different deposits and tracts. The result is extreme inequality in the distribution of gains to wealth when all the payments are made up front and the results of successful and unsuccessful gambles fall entirely on the lessee.

g. If, as is generally believed, most investors are risk-averse, then the lottery element in having a high bonus acts as an additional filter screening out possible entrants. This leads to higher concentration and less active competition in the bidding for State property. Also, to the extent that accumulated wealth and a positive attitude towards gambling are factors determining the high bidder, productivity and cost control are less determinant.

h. Use of bonus bidding lends itself to preemptive, preclusive buying by wealthier firms concerned with controlling the market and discouraging competitors.

i. Once a bonus is paid and then a discovery made it is hard and costly to deny production if the Environmental damage turns out to be high relative to the value of production. We have just lucked out of one such trap; we might do worse another time.

j. Transfer or sale of lease for a high bonus is a *de facto* sale of land but without much property tax liability imposed on capital or land (notably excepting the special Alaskan reserves tax). The capital invested in drilling and equipping is partly exempt and the intangible capital developed from exploratory drilling is not taxed. The leasehold interest itself is not always taxed. While such tax relief should result in higher bonus bids, this exacerbates the problem of the front-end filter.

k. The front-end filter becomes even tighter when lease sales are large and there is no slide bidding and the usual 20 percent advance bonus is required.

l. If oil and gas prices are regulated, and of course they are vulnerable to this risk, a bonus paid in the past is not treated as a current cost and not rolled in, resulting in lower prices received, whereas certain kinds of subsequent participation demands by the State might be treated in the regulatory mechanism as costs. In distinguishing between old oil and new oil, regulation may also distinguish between old costs and new costs.

Our worst suspicions of bonus bidding are confirmed by the brilliant, succinct and damning analysis of Alaska's past experience researched and written by my associate, Professor Richard Norgaard of the School of Resource Economics, University of California, Berkeley (Appendix E). Bonuses captured only from 9 percent to 16 percent of the surplus DCF value above costs and royalties in Cook Inlet. There were too few bidders to assure effective competition. Outcomes were wildly unrelated to bonuses bid and paid. Bidders have successfully used advanced gaming strategies and statistical analyses to take advantage of a State without expert staff in these fields. The State has not set adequate reservation prices or screened out fishing bids and over nominations: only two percent of the offshore Cook Inlet tracts leased through 1968 have produced. Dr. Norgaard recommends drastic changes.

3. The delay rental

Delay rentals are the smallest of the three major payments in the usual bid, the other two being bonus and royalty. They have been by no means negligible, however, and in Alberta, for example, have run at 50 percent as much as royalties and bonuses at various times. In addition, as compared with royalties they come earlier, and when we figure compound interest are blown up into an even larger figure.

Delay rentals are usually an annual yearly payment that ceases when production and royalties begin but there is room for many variations. They might continue until production ends, for one. For another, they need not be at a fixed level but might increase in proportion to some index such as cost of living or they might be made proportional to the assessed value of reserves, giving them the character of a property tax on reserves. Another possibility is to pay the bonus on the installment plan over several years. Yet another possibility is the production bonus, a contingent payment which is due only when and if commercial pay-rock is struck. This has some of the character of a bonus and some of the character of a rental and will be treated here.

The advantages of delay rentals and other rentals are the following:

a. Payment is deferred. This has the same effect as extending credit to payers of bonuses and letting them pay on the installment plan. This is of greater advantage to the leaner interloping firms and tends to increase competition.

b. The payment is fixed with respect to production and places no drag on it therefore. Thus it achieves two goals at once that the State is seeking. It shifts payments into the future and it does so without disincentive effect. If anything, it applies positive leverage to accelerate production.

c. At present when the firms need more time they simply request that leases be

extended and the request is frequently granted. This involves arbitrary exercise of judgment by officials. It would be better for lessees to pay so much a year and make their own decisions. The pressure would be on them, of course, to accelerate production once the lease was signed. Firms would be less anxious to nominate acreage and insist on lease sales many years in advance of the availability of transportation.

d. Alaska has millions of acres out under lease. It could all be returning more money each year or else be relinquished for future sale at a more propitious time. Alaska is getting $1.00 per acre year for these lands. OCS lands are yielding $3.00 per acre year in practice and go higher on drainage and development tracts. Norwegian rentals go up to $21 per acre year.

e. Most capital is subject to property taxation and must therefore yield a return high enough to cover both interest and property taxes. The investment in withholding oil reserves from production, however, need only yield a competitive interest rate. A delay rental serves to compensate for the lack of property taxation so that the same discount rate is applied in both cases.

f. A rental is terminable in practice when a lease is dropped due to lack of interest. This reduces the risk imposed on the lessee considerably and should result in higher bids on the bid variable, whatever that might be.

g. A delay rental is smoothly convertible to an *ad valorem* base at such time as enough is known about the reservoir and its contents to allow reasonably accurate assessment. Thus, instead of being a fixed amount per year it would be a fixed percentage of the assessed value of the reserves, still retaining its key qualities of shifting payments into the future and not varying as a function of production.

On the negative side are the following considerations:

a. Early shutdown. This traditional argument against fixed charges would apply only to one of the several alternative forms of rental, the nonterminable level payment. It can be prevented by adopting one of the declining forms. Professor Rooney's studies (Appendix F) indicate that the problem of early shutdown is not a serious one in general unless there is a substantial bias against investments in pressure maintenance. A constant rental contains no such bias. An *ad valorem* rental based on the value of as yet unproduced minerals would exempt the value of capital in place and therefore leave the lessee with a substantial investment even at such time as the rental charge approached zero.

b. Rentals are traditionally lowest of the three kinds of lease payments. This suggests that the industry doesn't like them and would not accept them readily. While this point is often made, this consultant discounts it because of other evidence, presented later (Section 7c).

c. Some federal tax provisions favor delayed production, advantages which might be lost by any lease provision which promotes early production.

d. A lessee might promise to pay a high rental and then walk away from the lease in a short number of years if it proves to be unproductive. Some would consider this to be a disadvantage of the system although it is included among the positive aspects as well.

e. The rental is normally fixed *ex ante*. It therefore has the same lottery qualities as a bonus.

The pros and cons discussed above indicate there are alternative forms of rental, which are listed here:

a. One might pay the bonus on the installment plan over a specified number of years at a specified rate of interest.

b. The traditional "delay rental" terminates when production begins and royalties are

paid. It is usually at some fixed level per acre independent of value, although BLM policy permits figures of $3.00, $5.00 and $10.00 per acre, depending on the class of acreage.

c. A rental might increase yearly at a fixed or an accelerating rate during the preproduction period in order to emphasize the landlord's intent to force action.

d. A rent might be level for the term of lease. This is the pattern that must be faulted for forcing early shutdown.

e. A rental might be a specified percentage of the bonus bid, for a fixed number of years. If the percentage were rather high, say 20 or 30 percent, the effect would be nearly the same as option (a.), that is paying the bonus on the installment plan, but with a substantial down payment. If the rate were 100 percent you would have exactly the same effect as an installment plan payment.

f. The rental might be a specified percentage of the appraised value of the unproduced minerals in the ground. This is an *ad valorem* charge (AVC). It closely resembles the *ad valorem* property tax in its impact and administration. Administrative aspects of this form of levy, mainly the technique of assessing minerals in the ground, have been ably discussed before this body by Robert Paschall. Basic principles of the application of such a charge are laid out in Appendix H with a numerical example showing how one would use the data in the Van Poollen report on the Sadlerochit Formation to levy the charge, and how it would diminish over time.

The *ad valorem* charge differs sharply from those discussed previously in that it is based on progressive disclosures of the value of minerals actually present while the others are based, like bonus bids, on *ex ante* surmising about what might be there. The *ad valorem* charge (AVC) is *ex post* discovery, while the other forms of rental are *ex ante*.

Thus AVC has some of the good and some of the bad qualities of a royalty. Like a royalty, it is based on what is actually in the ground rather than an uninformed guess as to what might be there, and is a function of actual outcomes. It therefore prevents many of the distributive inequities which flaw the system of high bonuses.

On the negative side, again like a royalty, it has some disincentive effect on discovery since discovery and proving of reserves result in higher assessments. The effect is much weaker here than with a royalty, however, because the *ad valorem* charge is based only on the value of the resource in situ whereas the royalty is also, in effect, a charge on all the costs of extracting the deposit as well. In the extreme, on a marginal deposit the *ad valorem* charge will be zero whereas a royalty, could it be collected, would be substantial. Similarly, at the end of life the *ad valorem* charge falls to zero while royalties continue with a fixed rate.

The two more substantial weaknesses of the *ad valorem* charge appear to be, first, there is some question about whether assessments can be tolerably accurate in practice, and second, there is some disincentive effect on exploratory drilling. These weaknesses may be substantially overcome by a combined system which would work as follows: There would be two stages in the life of a lease, before and after the discovery of commercial petroleum. Before discovery, the rental would be a specified percentage of the bonus bid (as in paragraph (e.) above). Following discovery, the same percentage would be applied to the assessed value of the discovered reserves. It would progressively rise as more reserves were proven and decline as they were exhausted (see Appendix H).

The presence of several lessees on any one structure would probably prevent substantial concealment of reserves. However, if experience suggested such concealment to be a problem, it might be offset by programs of compulsory disclosure, State participation in drilling, penalties

for concealment, and so on. Professor Norgaard (Appendix E) and Professor Rooney (Appendix F) both suggest schemes for State exploration.

Lease terms might be quite short, say five years, with rents "renegotiable" at that time. Such "renegotiation" would be rather unilateral with the State holding the upper hand and would seem to impose unreasonable risks on lessees. Unilateral renegotiation of terms is - actually practiced in many countries around the world in the wake of multiplying petroleum prices which made the original lease terms seem egregiously favorable to the lessees. Even American law occasionally permits change of contracts in the face of gross unforeseeable, external change of conditions. In general, however, this seems an unsystematic and arbitrary approach and less desirable than AVC which, although it might be criticized for some arbitrariness in the assessment process, is subject to objective administration and evaluation of performance.

4. The royalty

Production-based royalties are traditionally a large element in mineral leases. The most frequently heard proposal for reducing high front-end bonuses today is to increase royalty rates either directly or through making them the bid variable. The advantages of high royalties would be the following:

a. Payment is deferred. This eases entry for leaner firms and conserves front money for actual drilling and equipping leases. It increases competition and aids small business.

b. Major payments are contingent on the lessee's finding commercial petroleum and are in proportion to the volume, although not the value of what he finds. This reduces the risk element in lease bidding. It also reduces the premium now placed on prior knowledge of what is there and reduces the advantage of firms that can afford extensive early investment in preleasing surveys.

c. It removes the possibility of the lessee's paying a high price for something that is not present and removes the probability of windfalls when more is present than the market expected.

d. The State now has a lower discount rate than many potential bidders and can better afford to participate in future income at the expense of immediate cash. This must be tempered with the thought that the median voter is poorer than the median corporate shareholder and has a higher time preference. On the other hand, the State is free from federal income tax so that a given percentage return on investment is more attractive to the State than it is to a taxable private body. If it were just a matter of avoiding State taxes this advantage would be spurious, but if the State can successfully avoid federal taxes where private lessees cannot there appears to be a net advantage from the State's own viewpoint. Countering this is the observation that some large energy corporations have succeeded in lowering their effective federal income tax rates to a low percentage of profit, but the answer to that is that it is not an objective of the State to encourage a small number of large firms but to maximize the number of potential entrants into the field, including those too small to take full advantage of tax loopholes.

e. A royalty is the exact opposite of the depletion allowance. Oil and gas firms, in their eagerness to secure depletion allowances, will be willing to pay higher royalties than otherwise, a relationship which might be exploited to benefit the State. However, this again runs counter to the desire to benefit smaller firms inasmuch as the depletion allowance is now limited to smaller wells and is programmed to shrink progressively over the next few years.

f. A properly attuned royalty might substitute for unitization of a common pool. It may also substitute for direct controls on well- spacing and rates of flow.

In spite of its attractive features, the royalty has a long list of problems.

a. There is no commitment by the lessee. He may tie up land at little cost by merely promising to pay high future royalties and wait for a free ride on his neighbor. A successful bidder who overbids may abandon the lease, but there is no symmetry. The bidder who successfully underbids cashes in at the expense of the lessor, who cannot back out.

b. Marginal deposits are made submarginal and marginal effort on rich deposits is made submarginal. This applies to entire tracts, to the high-cost fringes of low-cost deposits, to the extra wells and capacity needed to give better control of timing, to equipping the lease, to work-overs, to the date of beginning production, to the stretch-out of the entire period of production, to the date of terminating production, to pressure maintenance and secondary recovery, to exploration for smaller and marginal deposits, and to production during high-cost seasons. Vastly more is involved here than the problem of early shutdown usually emphasized.

Royalties are not automatically passed on to consumers. Prices are determined by supply and demand in world markets. The burdens of the royalty system are borne primarily by the landowner in the form of lower net income.

c. A good deal of leakage of surplus cash flow is suffered by the landlord on the low—cost flush deposits, especially during their flush years when the surpluses are yielded. To be sure the prospect of winning these surpluses tends to raise bids all round but as noted, high royalties on low-value deposits may be uncollectible whereas low royalties on low-cost deposits are irretrievable.

d. The lessee's incentive to defer production is exaggerated. There is a strong future shift. The mathematics of this are developed in Appendix J. The basic idea may be simply expressed: It costs more to produce faster, and royalties discourage incurring costs (because the resulting output is shared with the landlord but the costs are borne entirely by the lessee). In

addition, there is an exaggerated motive to wait for higher prices. A royalty makes a marginal field or unit of production submarginal, but by waiting for higher prices the lessee can wait until it becomes somewhat better than marginal even after paying the royalty.

By the same token, if fluctuating prices are expected or experienced, the lessee's motivation to turn production on and off at his convenience is exaggerated. The lessor's royalties are therefore afflicted by instability beyond what would be an optimal adjustment to changing markets. Instability also has negative external effects on impacted communities, of course.

It may be shown mathematically (see Appendix J) that the disincentive of a royalty operates with greatest force on investments that are incurred immediately before their effects are felt in increased production. That is, it strikes hardest at work-overs, at pressure maintenance, secondary recovery, and so on. Its effects are relatively less in respect to investments that occur well in advance of production such as exploration. The overall result of this pattern is a stretch-out of the commitment of unrecovered capital between first outlay and ultimate recovery. This pattern increases overall capital requirements which in turn works to the advantage of wealthier firms and helps to screen out the leaner firms. Thus the royalty system works to the disadvantage of the very firms that it is designed to help.

e. The deferral of revenues hurts the State, of course. The additional deferral caused by the future shift of production hurts even more. Deferral of State revenues is acceptable if it serves the function of encouraging more competitive firms; but deferral of revenues after discovery serves little or no such function. The lessee who discovers commercial pay-rock may cash out immediately in several ways. Companies regularly borrow or issue stock on the basis of discoveries. Not only does this take cash out of them, it does so without incurring any federal tax liability and is thus substantially subsidized by the workings of income tax law. Economists

regard the nontaxation of unrealized capital gains to be a major source of bias in tax law. Unrealized gains are an unpreempted potential tax source. It is a good principle of State policy to go after unpreempted revenue sources, as noted earlier, and a royalty fails to do this. On the contrary, it widens the loophole.

f. The lessee may shortchange the lessor by understating the price of produced oil and gas. This has to be policed carefully at some expense.

g. Environmental damage from oil and gas production is more a function of the fact that some production is taking place than it is a variable function of the flow of volume in any year. The royalty-induced stretch-out therefore increases the total environmental damage.

h. There are many more little finds to be discovered than big ones, more poor ones than rich ones. The effect of royalties is to screen out the little ones. This greatly reduces the success ratio where success is defined as simply finding a commercial find that is producible. It screens out the little ones without succeeding in capturing all the rent on the big ones. It tends, therefore, to reduce sharply the number of viable firms since the expected success ratio is an important consideration, especially for the leaner firms which cannot afford a large number of failures. Once again it fails in one of its primary objectives, which is creating an economic environment more favorable to the leaner firms.

The discussion of pros and cons of royalties has centered on the simple concept of a high royalty rate. Some of the disadvantages may be overcome by the use of step royalties, sliding scale royalties, and using royalty as the bid variable which results in different rates on different deposits. Professor Rooney has outlined a workable step-royalty system (Appendix F). In our recommendations we include this among the workable alternatives.

There are many drawbacks, however. The problem with sliding scales is that they slide only with volume, and volume is only one of several factors that need to be considered. In addition, a scale which is progressive with respect to volume worsens the tendency of royalties to shift production into the future, since the high rate brackets may be avoided by reducing production now and stretching it out. If the rate is progressive per well it may be avoided by drilling more wells.

If it is progressive per tract it also depends arbitrarily on the size of the tract. It causes future shift. And it has a built-in bias against the marginal fringes of superior tracts which may exist where the tract is fractured and complicated.

It takes no account of cost differences which are independent of the volume factor. Thus, a high-volume well in a difficult, remote location gets a high rate while a low-volume well in a convenient location without much depth gets a low rate. It is a blunt instrument.

It makes no distinction between high volume which is the result of natural pressure achieved at no cost, and high volume which is the result of costly pressure maintenance such as that now experienced in several Cook Inlet fields whose volume has been maintained over the years at some cost.

It might be possible to adjust for all these and other variable factors by an extensive and complex system of variable rates based on extended observation of particular circumstances. All this would accomplish is the same thing that might be accomplished generally and accurately by letting costs be deducted. Deducting costs, however, has its own problems, and this lets us avoid them.

One problem with royalties may be solved by the use of a State marketing board. That is the problem of price determination if it appears that the lessees are fiddling the transfer prices

which are used to determine the State's share. This is the approach taken by British Columbia in marketing its natural gas through a provincial marketing board. The royalty is taken as an excess profit of the marketing board. Unfortunately, this only solves one of the several problems of the royalty system. The British Columbia experience has been one of having progressively to raise the field price and reduce its profits in order to stimulate more exploration and production. The basic fault is that it fails to distinguish between the low-cost and the high-cost deposits.

A very useful adjustment in a royalty system is to let the rate increase as a function of an index of petroleum prices. This offsets part of the future shift problem since it removes the incentive to hold back waiting for higher prices. It fails to account for cost changes, however.

Another device similar to a royalty would be taxation levied on a major pipeline. There is a case against any taxation of pipelines, especially underutilized ones, because of their economies of scale.[2] The "six-tenths rule" implies that optimal rates would cover only 60 percent of costs. This implies the need for a subsidy, rather than a tax. I.C.C. regulation is not geared to accommodate this kind of thinking, so we can forget about the subsidy idea. There is also a special case for taxing TAPS, to recoup the windfalls at Prudhoe. In general, however, taxing pipelines has the same faults as a royalty. (Inflating pipeline rates for reasons other than taxation, as I.C.C. regulation seems to do, has all the bad effects of a royalty without the benefit of raising revenue.)

Another feature of a royalty which may be an advantage or disadvantage is that it may be taken in kind and marketed by the State. This has aroused great enthusiasm in Alaska recently but the kind of enthusiasm suggests the kind of problems that would be encountered, namely domestic use at low productivity in preference to export at higher prices. This is a subsidy. The

[2] There is an engineering rule of thumb, the "six-tenths rule," that the cost of incremental capacity is 60 percent as high as the unit cost of the capacity before the increment. The rule is inaccurate and not universal but gives a rough notion of what is normal.

recipient has to take his subsidy in the one form of underpriced petroleum products and will use them wastefully. Industries which use lots of cheap energy do not constitute an unusually seminal economic base. Energy-intensive industries tend to be capital- intensive, and frequently polluting. Located *in rem*ote areas, they generate a minimum of associated activity. As an example there is Kitimat, British Columbia, with its hot house aluminum industry dependent on underpriced power. What would be the effects of reallocating this power to a more diversified community in a more attractive area where it would attract more labor-intensive industry?

5. <u>Specific terms</u>

Here we treat specific terms that are not generally specified in money; but we do not treat field regulations, which are in Section 8. The use of specific terms generally runs counter to the goals of administrative simplicity and objectivity, since terms tend to be arbitrary or discretionary and are usually discrete with sharp black and white boundaries as opposed to incremental pressures which run along a spectrum.

The present treatment is abbreviated in order to reserve more time and space for matters of higher current priority.

a. The term in years

i. The term before beginning production. Five years is usually allowed subject to discretionary extension. It might be better to substitute a delay rental increasing at an increasing rate. Lessees naturally will argue in favor of longer terms. That is their interest. Ours is to sit on the landlord's side of the table. From this position there is much to be said for holding feet to the fire.

ii. The term after beginning production. The practice, of course, is to let the term continue as long as production continues. An alternative is to terminate the lease after the lessee

has recovered a volume of reserves previously agreed upon. This is discussed in a later section.

b. Size limits

i. Size per parcel. Professor Stephen Cheung, an authority on leasing systems, has emphasized the landlord's advantage in keeping parcels small. This helps to assure that each lessee, in making a viable operation, will apply a certain minimum of labor and capital to the landlord's land. Lessees argue in favor of larger parcels. Again that is clearly their interest, but it is adverse to the landlord's.

ii. Cumulative total acreage by state and by substate region. There is an argument for limiting the holdings of one firm in any area, in order to increase the operating base of as many potential competitors as possible. This also assures closer attention to each individual parcel. There are nine firms who currently hold more than 200,000 acres each of competitive leases in Alaska. It is not clear that one firm can effectively explore and operate that many acres at once. However, acreage maxima are difficult to enforce, so that in general we prefer the use of general economic incentives rather than acreage limitations.

iii. A "market-structure impact statement." The State might reasonably mount a substantial antitrust operation, presumably in the Attorney-General's department. Winning bids might be rejected if the Attorney-General's office determined that accepting the bid might tend to reduce competition.

c. Joint bidding

There is a good case for prohibiting joint bidding, which reduces the number of competitors. Professor Norgaard's statement (Appendix E) speaks to this point. Like Professor Mead in an earlier study, Professor Norgaard found that the number of independent bidders is a most important variable determining the size of bids. The counter-argument that joint bidding

permits bids to occur which would not otherwise be made, owing to high capital requirements, is unpersuasive where the bidders are large multinational firms, which are simultaneously bidding elsewhere in Alaska and the world.

d. Liability for environmental damage

It would make sense for environmental damages anywhere in Alaska to be made a first lien on the lease from which the offending oil originated. We might further introduce a progressive element in this by making the liability a first lien on all leases held by the offending company.

For damages beyond the amount thus recoverable, it probably is desirable to make participation in environmental damage insurance a mandatory feature of all State leases.

None of these terms should be imposed in a punitive or negative spirit. The objective is never to damage the industry, but to help the State. The objective is never to penalize larger firms for being large, but to open the door to help smaller firms. We should carefully avoid referring to "the industry" as a block, and praising or blaming it as a whole. Lease terms which favor small business over big business are not hostile to "the industry." They are, rather, designed to help most firms in the industry by offsetting unfair advantages enjoyed by the large and wealthy firms. Whenever the State can help itself by helping the industry it should do so. Whenever the State can help itself by weakening oligopolistic elements in the industry in order to strengthen competitive elements in the industry, it should do so. None of this is "hostile to industry" in general.

In addition, the State's interest as landlord is generally adverse to that of the industry as tenant. In asserting its legitimate property interests, the State is adverse to industry without being hostile to industry. These are all important distinctions which should be held firmly in mind to

avoid confusion. The American Petroleum Institute, in one of its publications, argues in favor of larger parcels, bigger sales at one time, longer terms, and the absence of any reservation price. In opposing the Institute's position, the State is not being "hostile." Rather, it is asserting its own legitimate interests and at the same time being friendly to smaller firms whose interests seem neglected in the API positions.

6. Profit sharing

To overcome the weaknesses of the royalty system the lessor may allow the lessee to deduct from royalty payments an allowance for costs. In return he raises the basic rate charged per barrel. Thus the royalty, which resembles a sales tax, is converted into a profit share resembling an income tax.

The concept is simple enough in regard to regular expenses of operation and routine maintenance which are deducted from production payments in the year in which they are incurred. The allocation of deductions becomes more complicated with respect to capital outlays, and since these are normally quite high relative to ongoing expenses the matter cannot be overlooked.

Capital outlays must be deductible over a considerable period of years, presumably the useful life of the capital. This immediately engages us in a number of complexities and tricky questions which we will discuss under the negative aspects of the proposal.

Since we are dealing with a lease and not a tax on the total income of the multinational corporation, only those costs can be deductible which are expended on site, or in such close conjunction with it that we have no difficulty identifying them. This means that overhead expenses are not deductible. Neither are federal taxes. The proposal thus resembles what is called a "net proceeds" tax rather than a pure income tax. The distinction is important and fundamental.

The income tax is *in personamm*; that is, it is levied on a person or corporation as such. The net proceeds tax, on the other hand, is *in rem*: it is levied on the income and expenses attributable to a particular "thing," in this case the leasehold.

This also means that interest payments are not deductible. The deduction is based on the value of the capital applied to the site regardless of whether it is debt financed or equity financed. It might seem preferable to allow some deduction for the cost of capital whether it be equity capital or debt capital, but this proposal is considered in the following section, #7.

The lessee might recover his capital on a per year basis or, alternatively, on a per barrel basis. If the latter, it must be subject to some yearly maximum to avoid his recovering his capital all in one or two years as would happen with a flush producer. Such accelerated recovery would mean in effect that the lessee's capital would not be tied up for any appreciable number of years and that there was no base remaining on which he could legitimately be said to be contributing to the profit. This in turn would convert the arrangement from profit sharing to simple rent collecting, which is discussed in Section 7. The present proposal is that the State share in the lessee's profits, which presupposes that the lessee still have some unrecovered capital outstanding which contributes to the joint profit.

The per barrel recovery basis resembles the depletion allowance of the income tax and may be thought of in similar terms with this difference: the present proposal limits the depletion allowance to recovery of costs actually incurred. On the surface the per barrel basis might seem much superior to the per year basis of cost recovery, because the per barrel cost credit comes in the form of a depletion allowance and would offset the disincentive effects of the royalty element. Actually this is a minimal advantage for two reasons. One is that there must be an upper limit per year in any event to keep this a profit share system, and the other is that the deduction

of current expenses eliminates the disincentive effects of the royalty in the short run in any event. In fact, adding to this a per barrel depletion allowance would have a slight tendency to accelerate production.

Therefore, we do not sharply distinguish between the per barrel basis and the per year basis in discussing the pros and cons.

The advantages of the net proceeds or profit sharing approach are the following:

a. Allowing costs to be deducted overcomes the problems that plague the royalty system without incurring the problems that plague the bonus system. It succeeds in binding the lessor and the lessee in much more of a common interest -- they share the profits and they also share the costs.

This means that we succeed in preserving incentives at the margins, both intensive and extensive, and reduce (without eliminating) the "deadweight loss" that is caused by the disincentive effects of a royalty. Second, we can and indeed we must charge a basically higher rate which rifles in on the flush producers who have little cost to deduct per barrel and succeeds in extracting a large amount of rent which leaks away when we depend on royalties.

b. Because costs themselves are deducted, this approach obviates the complex schemes of sliding scales and so on which one might use to modify the royalty system to make it approximate a cost sharing system.

c. This approach sustains over a long period of time the union of interests between lessor and lessee.

d. The nonacknowledgement of overhead costs creates minimal bias since this merely results in lower bids for the bid variable. Overhead costs will be roughly proportionate to on-site costs for many firms. For some others, overhead costs will be large relative to on-site

costs and they will be discriminated against, but it may be desirable to discourage such firms since their overhead costs will be incurred outside the State and since they tend to be the larger firms. The intent is not to discourage larger firms but to encourage smaller ones relatively.

e. The income received by the State from different leases will be now made progressive with respect to profitability. That is, the State's share per barrel on marginal oil will be zero while its share per barrel on profitable oil will be quite high.

On the negative side, we now create some new problems and are left with some old ones:

a. The basic problem of the royalty system is only partially solved because a large share of the economic costs remains undeductible, that is, the interest on the lessee's investment. This is normally a high figure compared with current operating costs because in this industry capital costs are very high relative to operating costs. As a result, there will still be some deadweight loss because some marginal opportunities will be made subeconomic and there will also be some leakage of rents because the basic rate cannot be set high enough to extract all the rent from the best deposits.

b. The problem of future shift, which is so exaggerated in the royalty system, is compensated for by cost deduction but not 100 percent compensated for. This point requires mathematical exposition and is treated in Appendix J.

c. There are new and formidable administrative problems in allowing cost deductions, several of which have been suggested above. Substantial staff will be required to frame the system properly in all its details initially and then to administer it. Administrative problems will resemble and approximate those involved in the corporate income tax. They might be considerably ameliorated by legislation requiring disclosure of corporate income tax returns to DNR personnel. This is not altogether on the negative side. Information about the costs of the

industry would be of great aid to DNR personnel and administrators in performing their functions effectively. On the negative side, the industry would avoid such exposure and this might reduce bids.

d. The slow recovery of capital allowed, which is an inherent feature of this system, will be harder on the leaner firms which we want to encourage. Of course, the fact that some capital is recoverable is attractive to all. The fact that it is recoverable only slowly is more acceptable to the richer firms than it is to the leaner ones.

e. The ability to deduct exploratory costs is not worth much where the probability of success is low. Thus, if the success ratio is one in ten, only 10 percent of the preproduction exploratory costs will ever be eligible for deduction. On the other hand, the costs of working over a producing field would all be deductible. This constitutes a large bias in the treatment of different kinds of costs and different parcels, which would need to be compensated for although there may be no simple and administrable way of doing so. It constitutes a serious drawback to a parcel-by-parcel system.

f. There will be some padding of costs and some gold plating which will leak through our best efforts to prevent them. These problems will be greatest on drainage tracts where production is a sure thing. Professor Rooney indicates that padding of costs is a very serious problem in the profit share leases in Long Beach, California.

g. If there is no inflationary adjustment made, the actual capital recovery allowance will be less in constant dollars than the amount of capital invested.

h. The allowance of fixed capital recovery has a negative leverage effect on incentives. It is the opposite from a regular fixed charge which has a positive leverage effect. After the lessee has recovered his allowable capital quota for the year, his incentives will be less.

And after he has recovered it for the life of the deposit, his incentives will be permanently less. This pattern is bound to create some distortions.

Another and very different approach to profit sharing is through the State's taking an equity participation in one or more private corporations, as Canada has done with Panarctic Oils and Great Canadian Oil Sands, Limited. This does not directly solve the problem of land disposal, however, unless the State secures its equity by trading land for shares in the corporation. This, however, then makes the State a partner in all the affairs and ventures of the corporation around the world and gets far beyond the basic question of leasing policy which this study addresses.

A distantly related proposal is that offered by Phillips Petroleum that the bonus bid should be recoverable by the lessee as a deduction from royalties. This would either constitute a net cost to the State or else result in higher initial bonus bids in anticipation of later recovery. The latter has no particular advantages and would raise the bonus higher than otherwise and worsen the problem of the front-end filter.

7. Rent-sharing

We have seen how the landlord may share the lessee's costs in effect by letting him write them off against royalties. We've discussed profit sharing where the lessee may write off his operating costs and also his capital costs. The next and last logical step is to let him write off interest on his capital costs as well. What remains, then, for the landlord is the net contribution of the land; that is, the contribution to output which may be attributable to the resources which the landlord contributed. In theory this divides the product exactly as it should be. The lessee gets a return in proportion to his investment and the landlord gets a return based on the value of his contribution. The question is whether this theoretical ideal can be approached in practice.

There are three basic approaches which are sufficiently different that we will discuss them separately:

a. Guaranteed rate of interest

In this scheme the lessee may deduct from his royalty base the operating costs, the capital costs, plus interest on unrecovered capital. The interest rate would be set at some market-derived figure like 8 or 9 percent. The capital could not be written off immediately. It would have to be depreciated over several years. There are many alternative rates of depreciation and many alternative ways of selecting the life over which capital may be depreciated. Were we to opt for this alternative, we would have to give detailed consideration to the complex choice of depreciation paths and life. An extended discussion of this is premature at this point, however. We would also have to decide whether to allow carry-forward of unused depreciation in years of no production.

b. Front-end recovery of capital

We can let the lessee have the first cut at production, letting him keep the entire proceeds until such time as he shall have recovered all of his deductible capital expenses. In a flush producer this will occur so rapidly that the question of interest rate is not critical. His capital is tied up for such a short period that interest on it is not a large amount. Following this, the State takes the lion's share of the operating profit, leaving 15 or 20 percent to the operator as an incentive. There will be a bid variable, probably a bonus, to soak up any residual net advantage which operators anticipate.

(An unnecessary variation on this scheme would be to let the bonus also be deductible. As discussed in Section 6, this merely adds to the capital which the lessee has to put in and take out without achieving any particular purpose. Another elegant variation would be to let operators

write off their capital outlays against the bonus. This, too, would result in inflating bonus bids and simply constitute lost motion with little net effect. We do not, therefore, discuss these bonus recovery options any further.)

c. *Ad valorem* charge based on reserves in place

This method has been alluded to earlier in Section 3, dealing with rentals. Like a rental it is based on time rather than production, but unlike the traditional concept of a delay rental it is not determined simply *ex ante* or per acre, but is based on a continuing assessment of the capacity of a reservoir to produce. It is determined *ex post* the disclosure of reservoir contents rather than *ex ante*. Therefore we continue and complete the discussion of it in this section.

There are pros and cons of rent sharing by whichever of the three methods, and then they have their individual pros and cons. First we consider all three collectively. On the positive side, they all have the following benefits:

1. There is a theoretically attainable degree of perfection where there is no deadweight loss. This theoretical perfection is not attainable in practice but is worthy of note because other systems would impose deadweight losses on the State, even if they could be perfectly administered at zero cost, because of fundamental conceptual defects. In the rent-share schemes every cost of developing any resource is deductible. On marginal resources where the costs just equal the gains the rent share equals zero, so there is no charge levied to have a disincentive effect on the producer.

2. The counterpart of zero deadweight loss is zero leakage of State income into private hands. This again presupposes perfect administration and administrability. Rent is exactly the income properly attributable to the State's share in the joint effort, that is, the share contributed by land which the State owns.

3. The rent share is progressive with respect to profitability, like the profit share, only more so. Oil produced from strictly marginal deposits where costs equal gains yields the State no share whatsoever. But oil produced after the lessee has recovered his capital from rich tracts goes nearly 100 percent to the State. The State gets a higher share from the more "profitable" -- only now we should say "rentable" --deposits because the basic rate can be so much higher. By virtue of allowing the deductibility of all costs, including interest on investment, we can now increase the basic rate nearly to 100 percent (subject to administrative feasibility).

Ideally, the State's share will be progressive only with respect to that profitability that derives from the land input. Extra profits that come from more efficient management, cutting costs and so on should accrue to the operator. Whether this can be accomplished depends on how effectively we can audit the deduction of costs. Under alternatives (1.) and (2.) especially, this poses serious problems which we discuss later.

4. Rent sharing is based on *ex post* disclosures of the outcomes of exploration rather than *ex ante* guessing.

On the negative side, there are these problems:

1. Rates must be much higher than under other systems. This accentuates incentives to evade, and it makes all valuation questions more critical.

2. By virtue of its efficacy in collecting rents, the system reduces incentives for preleasing exploration. This forces us either to provide substitutes or to come to a decision that the present level is economically excessive and costly. Even if we do so conclude, this will leave a number of firms with a substantial investment in preleasing information subject to some capital loss, which they will resist.

a. Capital recovery with fixed interest

The proposal is to let the lessee write off capital investments against royalties at so much per year. He may write off capital together with interest on unrecovered capital at a fixed rate of interest like 8 or 9 percent. The advantages of this arrangement are the following:

1. The State starts recovering money right away. The lessee's capital continues to work for the State and the lessee remains entangled for a considerable period of time.

2. There is an upper limit on what the lessee can get. He is guaranteed a reasonable rate of return on his investment and little more. He is not relieved of all risks because the guarantee depends on production.

3. In case the State's share is left too low, there is a safety valve in the fact that there is still a bid variable, like the bonus, to soak up any excess of expectations.

4. The guarantee of interest reduces risk, and so reduces any risk premium needed or alleged to attract capital.

5. Full cost recovery with interest eliminates the tendency to slow down production which the royalty imposes (Appendix J).

6. There is no intertemporal bias against early costs incurred long before there is income from the lease. Exploratory drilling is recoverable. Compound interest accrues and may finally be recovered. (This does pose severe auditing problems, however.)

7. There is no temptation to pad capital costs in the declining years, because they can only be taken at so much per year.

Disadvantages are the following:

1. Padding expenses and gold plating. With a high basic royalty rate and generous deductions allowed with interest, the temptation towards boondoggling is at a maximum. The

landlord may expect severe problems of monitoring, surveillance and evaluation. This system makes a lessee think and act like a regulated utility. This probably gives some practical notion of its impact. We have learned to survive with regulated utilities even though utilities pad their rate bases. We might similarly learn to survive with this system, in spite of its problems.

There are special aggravated problems *in rem*ote areas where "base maintenance," rather than drilling per se, is the largest cost. "Base maintenance" comprises a wide range of the necessities, amenities, follies and recreations of life, a bottomless sink of unauditable expenses.

2. Just as with profit sharing schemes, there is underrecovery of capital on long-shot, wildcat acreage. The British and Canadians have tried to compensate for this by extending somewhat beyond the individual parcel the area in which accounts may be consolidated, so that the costs of losers may be written off against the gains of winners over some considerable area. They call the boundary of this area the "ring fence." They are vague about how this fence line is drawn. Their system delegates more arbitrary power to civil "servants" than ours does, and may not be tolerable here (or there).

To be sure, federal income taxation contains a bias in favor of risky ventures; leasing upon industry demand, as Alaska has done, has a similar bias. It is difficult to evaluate countervailing biases and this has not been undertaken. If this idea is one that the Legislature wishes to pursue such an investigation would be desirable.

3. The guaranteed interest rate is the same for all firms regardless of their own cost of capital. This is a relative advantage to the wealthier firms whose cost of capital is lower. It is not as great an advantage, however, as that in the bonus element, because the discounted present value of the bonus is derived by discounting all future revenues, not simply those imputable to the lessee's capital.

The lower cost of capital to larger, wealthier firms may be inferred from data in Appendix K. Larger firms make less use of their credit ratings than smaller firms do, even though the credit ratings are better. This is to say that the larger firms could, if they wished, borrow a good deal more at 7.5 or 8 percent but are choosing not to. This displays the presence of internal funds such that the internal cost of capital is no greater than 7.5 percent.

b. Front-end recovery

The proposal is to let the lessee recover his capital at the front end before the State gets anything. The lessee recovers his capital with maximum feasible speed. His stake is in and out so rapidly that it need earn little interest.

The advantages are the following:

1. The incentive is towards haste. The lessee will not dawdle just to have interest pile up. He avoids interest costs by minimizing the period of capital commitment rather than writing off interest at a given rate.

2. There is reduced temptation to pad the early, preproduction outlays, because no interest is allowed. Exploratory drilling is already largely expensible for federal tax, and further temptation by the State might be redundant.

3. There is minimum feasible risk imposed on the lessee except as before where there is wildcat acreage.

4. This system favors the leaner firms. It shifts payments into the future more than any other system. The lessee owes the State nothing until he has recovered almost everything -- everything that is his.

5. Lessees' capital is kept working in the industry, going in and out in a rapid reciprocating movement. A maximum of work is performed with a minimum of capital tied up.

Small firms, particularly, depend on high capital turnover.

6. There is no need to determine depreciable lives and depreciation paths.

7. There is no inflationary leakage because so little time passes between investment and recovery.

The negative points are the following:

1. The premium on early inception may be excessive and in some cases cause wasteful haste. Presumably this could be controlled.

2. There is no explicit provision for the lessee's receiving interest on his capital. He would, however, adjust for this by reducing his bid (for the bid variable, whatever that might be). The best arrangement probably is for the State not to try to capture 100 percent of the cash flow after capital is recovered but to set the rate at 80 percent or so, leaving the bid variable to soak up the remainder.

3. The nominal royalty rate will be extremely high. This will lend itself to exaggeration and misinterpretation by critics who might succeed in having the system changed after the lessees had already recovered their capital, resulting in severe losses to the State. There is no protection against this other than widespread understanding.

4. The problem remains of a bias against wildcat acreage and other long-shot acreage. If the system is attractive enough on other grounds, some means could probably be devised to compensate for this. It would have to be something other than simply letting large firms pool their entire accounts within the State, because this contains a built-in bias in favor of the larger firms just as the corporate income tax does.

5. The temptation to expense dubious capital outlays against any flush producer is overwhelming, posing a severe auditing problem. To be sure, the auditor must be shown that the

capital is to be productive on the same parcel, with its diminishing returns from a limited resource. So the possibilities of fraud are finite. In addition, this encourages intensive infilling and development as opposed to over-decentralization, probably a needed antidote to other biases. But this remains a drawback.

c. The *ad valorem* charge (AVC)

We touched on this method earlier in Section 3, the discussion of rentals, because it has some of the character of a rental, being an annual charge independent of production. We continue the discussion here because it also is a device for sharing rent. The *ad valorem* charge or AVC resembles a property tax. It consists of a base which is the current appraised value of the resource; and a percentage rate. The charge is the product of the base times the rate. The rate is high and common to all. The base varies from zero up to very high values for superior deposits.

The advantages of this leasing element are the following:

1. It cures the major fault of a high bonus by shifting payments into the future.

2. It cures the major fault of delay rentals by depending on *ex post* disclosures of what the ground contains rather than *ex ante* estimates made in the dark.

3. It cures the faults of a high royalty by not varying with production and by allowing for cost differences automatically in the evaluation procedure. That is, high-cost production carries a low AVC base. (In the extreme a marginal deposit has no value at all and hence there is no *ad valorem* charge.) As a counterpart, AVC minimizes the leakage of rents from low-cost resources out of the State treasury. They carry a high AVC base; and the common rate is high.

4. It cures the fault of profit sharing by allowing interest on the lessee's capital, again automatically in the valuation process. The "automaticity" depends on the appraiser's having

proper legislation to work with and upon the legislation's having competent appraisers to implement it, so it is only automatic on the assumption of careful preparation and continued vigilance. The present point is that an appraisal of the resource in situ is always made net of the full costs of developing it and one of these costs is interest on the capital required for the purpose.

5. This lease element cures the fault of other rent-sharing techniques by having no place for padding costs or gold plating. A lessee cannot reduce the assessed value of his property by overdeveloping it. The major risk indeed is the reverse. He might inadvertently get it increased that way, although this would constitute an error in administration rather than the intent of the system.

The intent is that the appraiser would calculate that schedule of production which maximizes discounted cash flow (DCF). He would value the deposit based on the assumption that that schedule was followed and that only those costs were incurred which were necessary to follow that schedule. Incurring additional costs would not lower the valuation, nor increase it either.

There should be no difficulty about recognizing this concept and procedure because it is what any buyer in the market place goes through when determining what to pay for bare land; and it is what any appraiser goes through when estimating what a market price would be, based on highest and best use.

6. AVC cures the fault of noncompetitive leasing, which is to overstimulate investment in exploration (which occurs whenever landlords fail to collect rent). A concern is that it might overcure the problem, leaving us with inadequate exploration. This is considered further on the negative side, and also in Section 11 on how to motivate exploration.

Overinvestment in exploration is just as much padding and gold plating as any other kind of overinvestment. It is insidious and seductive because it is invisible and hard to evaluate, and because there is in the "cultural subconscious" a proexploratory bias. There is also a federal tax bias for exploration to which the State need not add.

Nevertheless, one could go too far, and we must be careful to preserve enough motive to explore. There are several possible ways of doing this. One would be to let the lessee recover his postleasing costs of exploratory drilling before the *ad valorem* charge is imposed. Other options are discussed in Section 11.

7. Like options a. and b., this method of rent collection is progressive with respect to rentability -- the State gets a high share per barrel from rich deposits and little or nothing from marginal deposits. This option scores better on this count than the first two because of the absence of padding and gold plating (which would dissipate rent from richer deposits).

8. Because of advantage #7, this method permits the State to schedule the timing of lease sales in an optimal way, and to get more money from bid-variable-bonuses. Compare it with a high royalty rate. A high royalty rate means that at the time a deposit has risen to marginal status (owing to increased prices or any other cause) it is still worth less than nothing to a lessee after paying the royalty: yet it has a large positive value to the State, or would have if the State could induce a lessee to produce it. This gives the State an interest in selling leases at a time when lessees have little interest in buying them.

This in turn puts the State at a bargaining disadvantage at the time a lease is sold. When, on the other hand, the State's share is based merely on the net value of the resource, the State has an accurate criterion to follow in timing leases. Maximizing the DCF of the State is now socially optimal. This point is discussed in more detail in Section D below.

9. Where the AVC element is large, and appraisals are kept current (as they must be), the State assumes almost all the "passive" risks. Those are the risks imposed by price changes, cost changes, and changes of market interest rates. When prices rise, valuations rise and vice versa. This is appropriate since price basically affects the value of land which is the State's contribution. This also removes a good deal of risk from the lessee. It accomplishes for the lessee just what a perfect hedging market would accomplish.

As to interest rates, when market interest rates rise the capitalization or "cap rate" used in valuation should rise, too. This lowers the valuation and reduces the tax. Mathematically, it reduces the valuation exactly by that amount required to let the lessee continue to earn a market rate of interest at the new market rate. The mathematics is shown in Appendix H.

This is quite an important feature whose importance might not be as immediately obvious as the price hedging feature. It makes the investment less risky than investment in a government bond with a fixed coupon. When market interest rates rise, the value of fixed coupon bonds falls below par. Under the AVC system a rise in market interest rates does not reduce the valuation of mineral deposits by nearly the same amount -- the State's claim falls, protecting the holder from the same degree of price risk that he would experience with a government bond.

Both these features would be attractive to risk-averse investors. This probably would increase the number of bidders for State lands.

10. The valuations of reserves required to operate this system would constitute an inventory of proven reserves, an inventory much more accurate than what is available today and much more objective. This inventory information would be useful in planning community facilities, transportation, and allied infrastructure. The sum total of information known might be little greater than now, but it would all be of public record and centralized in one location and

accessible to all State planning agencies as well as to private individuals, -local governments, native corporations, and firms interested in exploration on comparable or adjacent lands. The benefits of better planning extend outside the State into consuming states and federal regulatory agencies which are concerned about supply adequacy when pipelines are authorized. This national interest in improved inventory would justify Alaska's requesting financial support for its program.

11. AVC is free from the fault of a royalty, that there is no early commitment. There is an immediate and growing commitment from the lessee to the lessor. This is accomplished without imposing such a heavy front-end load as the bonus does, but without deferring state revenues as much as front-end capital recovery would do. In this respect it is comparable to the Alaska tax on mineral reserves.

This time pattern may approach optimality in terms of the credit needs of all the parties involved, beginning from the assumption that it is desirable to encourage smaller firms as well as to prevent speculation and to protect State revenues. When we look at borrowing rates and credit, ratings we note that small firms can borrow for short periods of time at a small disadvantage compared with large firms. The greater disadvantage of small firms in capital markets is long-term borrowing. The present proposal calls for some short-term advance of capital by the lessee, but not very much in comparison with a high bonus payment.

A pure bonus bid would be derived by discounting future expectations over the next 30 or 40 years, including future gas production which may be way down the line. This means that the same 30 or 40 years will in general be required to recoup the investment. The unrecovered investment must be financed over that whole period. Access to long-term money is what gives larger multinational conglomerated firms their special edge in financial matters. The present

proposal cuts deeply into the prospects of future gain from leases and thereby minimizes the need for long-term financing to purchase leases initially.

12. A minor and uncertain potential advantage is that under price regulation by FEA and FPC, with their "cost plus" philosophy, an AVC might be construed as a current operating cost and rolled into the price, in contrast to historical bonuses which might be ignored.

13. AVC moves into one of the largest loopholes in federal tax law, the exemption of unrealized capital gains. After discovery, and before production, there is a large increase in the wealth of the lessee. The increase is bankable and bondable and therefore realizable in cash, but not taxable. AVC, like the Alaska reserves tax, taps this unpreempted source of revenue.

By taking early cash from lessees this might seem to hurt the leaner firms, but not so: they are not asked for cash until they have a bankable asset to raise cash on. At this point they are on the way from lean to fat.

On the negative side are the following drawbacks:

1. AVC is not in common use. We would start near the bottom of a learning curve when introducing a new system. In addition, there must be a lingering suspicion that there could be some reason why it is not in common use.

Tempering this, however, the components of the system are in common use and are acceptable business practices. In 1973 five of eight majors operating in Alberta voluntarily chose an AVC in preference to increased royalties. (Alberta did not follow through.) The concept of a variable payment based on an index determined by fallible human beings is not uncommon. The variable rate mortgage has been successfully introduced. Another acceptable practice is setting farm rents in midwestern counties by "county average yields." This allows for the effect of weather fluctuations. Property taxation everywhere, of course, depends on assessed variations.

Almost every investment everywhere in real estate is made subject to this hazard. While valuations vary in quality and complaining is constant, the system has lasted for 2,000 or 3,000 years and undoubtedly will continue. Mr. Paschall has explained how the system works in California and has emphasized that successful appraisal does not presuppose a 100 percent accurate estimate of ultimate reserves. Professor Adelman says "The development of known oil pools can be calculated with tolerable accuracy even on the basis of incomplete data" (Adelman, 1969:26), and in his research has demonstrated how one can draw inferences from limited data.

Oil companies buy and sell their reserves, and also each other, based on appraisal. A frequent practice is to hire two recognized appraisers and agree in advance to accept the average of-their two appraisals. In a recent case this resulted in a price increment of $6 million.[3] Loans and credit ratings are based on appraisals of property value and many outstanding contracts involve payments which are indexed or tied to the consumer price index or other price index.

The question is whether firms would have confidence that an objective assessment would be made by a State employee, and not whether such an objective assessment is possible or acceptable. It is up to the State, therefore, to set up procedures assuring objectivity. Judicial review is one of these and it might be desirable to create a court specializing in this kind of case, to be sure the judge understood the issues. This is the practice in Australian property taxation and is reported to work better than the use of general courts

2. AVC is a tax on successful exploration to the extent that exploration identifies the reserve whose value is the tax base. Large private landholders in the lower 48 have sometimes deferred exploration in order to avoid property taxation, at least by their own account. This fault is not peculiar to AVC: any system of tapping revenues from proven reserves is also a tax on

[3] The purchase of McAlester Fuel Co. by Alaska Interstate Co. for $45.8 million instead of $39.4 million originally announced (*Wall Street Journal*, January 6, 1977).

exploration. The problem is worse with AVC, however, by virtue of its greater efficiency in identifying and capturing the rent of proven reserves. Other systems, by their very inefficiency and inaccuracy, allow a considerable leakage of mineral rent out of the State treasury, which in turn serves as an incentive for more exploration.

Preleasing exploration is not the problem, so long as there is a lease sale with a bid variable. The lease sale would provide the same opportunity as it does now for firms to limit the size of their bids in light of the need to earn a rate of return high enough to recoup investment in preleasing exploration. The problem centers about post leasing exploratory drilling.

To keep this problem in perspective, this problem concerns one-tenth of all costs. The Joint Association Survey reported the following breakdown of expenditures from its respondents in 1974. These respondents were estimated to comprise about 76 percent of the revenues of the industry in the United States (Joint Association Survey, 1976).

	Billions of $	%
Exploratory wells	1.6	11
Acquiring undeveloped acreage	5.7	38
Geological and geophysical	0.6	4
Development wells	2.7	18
Lease equipment	0.8	5
Production expenditures and overhead	3.5	23
TOTAL	14.9	99[4]

Ad valorem taxes, that is property taxes resembling in their impact our AVC, were included among production expenses and overhead and were equal to $0.4 billion or almost two-

[4] Differences due to rounding.

thirds as much as was spent on preleasing exploration. Spending on exploratory wells is a substantial but not an overwhelming part of the total, being substantially less than the costs of development and production: While there is a problem to be solved yet, it is not as great a problem as it would be if exploratory drilling were a larger share of total costs.

A partial solution to the problem of motivating exploration adequately is simply to adopt a lower percentage rate for the charge.

Another mitigating factor is that deposits which are expensive to produce, and which therefore carry a low *ad valorem* base for the AVC, are on the whole the same ones that are expensive to find by virtue of being small, deep, remote and so on. AVC therefore does not • take a large bite out of the value of deposits that are expensive to discover but mainly out of those that are cheap to discover. In this respect it is less discouraging to exploration than would be a royalty which raised the same total revenue.

This problem is further explored in Section 11. In general there is a choice to be made between leaving some rent as bait for explorers or paying for exploration by direct contract before leases are signed.

3. As with other rent-collecting devices, the AVC rate is going to be high; so all judgments and decisions are more critical. In order to work properly the system must be more fine-tuned than a royalty for example. It is something like licensing surgeons to operate instead of giving aspirin. More careful training and control are called for, and personnel capable of more discriminating judgments. I would not overstate this point, because the judgments called for are primarily of one kind -- valuation -- and are subject to review according to preannounced objective criteria. Nor are they regulatory kinds of judgments which involve ordering lessees to

do or not to do specific acts. They are nonetheless judgments and the consequences of error may be severe, and this must be reckoned as a fault of this lease element.

Another disadvantage of high rates is the ease with which they may be misinterpreted. A high rate on a small base raises no more money than a low rate on a large base, but more easily evokes images of confiscation. This problem may be ameliorated by using a capitalization rate rather lower than the 18 percent currently in use in the Alaska reserves tax. Eight percent, a market rate of interest, seems more reasonable today. Inflated capitalization rates are the same as underassessment of the base. As indicated, the State is assuming a large share of the risk under this system so that a low, riskless capitalization rate is appropriate.

4. The first few annual payments are preproduction. As compared with some other systems, therefore, this one has a larger front-end load. This issue is discussed under advantage #13.

8. <u>Regulating field operations</u>

In issuing a lease, the State reserves the right to regulate field operations in the interest of preventing waste. This primarily involves control over rate of flow, unitization and spacing.

a. Rate of flow

Where many independently owned tracts overlie a common communicating pool, everyone recognizes that some regulation of flow is needed. This is true even where production is not rate-sensitive, in order to obviate the excess costs of hyperaccelerated withdrawals. Even where physical waste is caused by rapid recovery, it may be the lesser economic waste: capital sunk in excess capacity may be the greater one. The most frequently heard rationale, however, is to prevent physical waste, because of the traditional overemphasis on physical waste. Whichever we emphasize, all hands can agree that some control is needed over rate of flow. This may be

accomplished through total unitization, or through prorating allowable flows to individual wells and parcels based on an overall reservoir plan.

It would be most desirable to stipulate that the objective of such a plan, by whatever means administered, be to maximize discounted cash flow (DCF) rather than ultimate recovery. The latter is no criterion at all for reservoirs which are not "rate sensitive," and it is the wrong criterion for those that are.

In Appendix I we present discounted cash flow values derived from different production schedules for the reservoir at Prudhoe Bay as presented in the Van Poollen report. It is clear that the fastest option which they presented is the one that maximizes the gross DCF without deducting costs. Information on costs is not given in the report. In Appendix I, however, we show what to do with such cost information when it is available. Shifting from the 1.2 MBD schedule to the 1.8 MBD schedule increases gross DCF by $5.6 billion when a 10 percent discount rate is used. All we need to do now is match this gain against the cost of additional wells required to achieve it. The number of wells and the cost per well are figures that knowledgeable people could supply readily. It is quite likely that they would be less than the gain in DCF, and therefore be justified (in the absence of major considerations not listed here). Even as we complete this Report, the operators are announcing their intent to increase capacity in daily flow towards the upper figure.

Appendix I indicates that optimal flow is not very sensitive to the rate of interest. The gain in gross DCF from speeding up flow is calculated over a wide range of interest rates and is not much affected. To the extent it is affected, the effect is the opposite from what one normally expects in other kinds of investments: at a higher rate of interest more investment in drilling wells is justified rather than less. Most long-term investments, of course, look worse at higher

rates of interest. Investment in recovering minerals looks better, because we shift cash flow towards the present.

It might be thought that anticipated rising prices of petroleum products would reduce the optimal rate of flow. So they do but not by very much. The effect of well-head prices rising at 5 percent per year is the same as the effect of lowering the discount rate from 15 percent to 10 percent and Appendix I shows that this effect is not very great.

We must distinguish sharply, however, between anticipated rising prices and absolute high prices at a fixed level. While anticipated future increases tend slightly to reduce optimal flow, high prices today and continuing into the future (but not rising) increase the payoff from investment in additional wells and argue strongly in favor of speedier production. The existence of today's elevated price level, therefore, calls most urgently for review of traditional flow regulation based on MER or maximizing ultimate recovery. In the DCF analysis a slight loss of ultimate recovery is a minimal consideration. Even a substantial loss of ultimate recovery may be small relative to the interest costs of holding unproduced reserves longer than necessary. Tradition has elevated the minimal factor to a maximal and almost the sole criterion of rate determination.

Interest on assets which one owns is an "invisible" cost and all too easily relegated to the limbo of irrelevant, abstruse, philosophical speculation by those who don't actually have to pay it. Proper economy of valuable natural resources would be achieved if we regarded the managers as being saddled with a mortgage equal to the value of the resource, on which interest is due regularly, thus converting the invisible cost into a tangible, painful cash outflow.

A lessee, left to his own devices, will in his own interest act so as to maximize DCF. If the State prohibits this in advance of lease sale, it makes the lease that much less attractive. The

cost of this kind of regulation is thus borne by the State in lower bids. If the State imposes an uneconomical concept of regulating flow it has little gain to show for its cost. By the same reasoning, future leases can be sold at considerably advanced values if they are free from flow regulation based on the concept of MER.

Should the State decide to abandon MER, this also opens the possibility of renegotiating old leases. The State can calculate the present value to the lessee of being allowed to produce faster and offer to sell him that right for that price.

b. Unitization

Unitization may be partial or complete and it may be under the control of the operators exclusively or it may involve extensive State participation and surveillance.

There are advantages in keeping unitization partial. It is always tempting to view the potential gains from total rationalization of a large works project, consisting of many parts, but there is also the danger of losing individual initiative, enterprise and familiarity with the local scene; and there is the danger of doing too much at once. Not all producers are ready to move simultaneously, as we see today at Prudhoe Bay.

A two-tier approach is recommended, analogous to that used in irrigation areas for administration of aquifers overlain by many competing landowners, each with his own water pump. Landowners join in forming a water conservation district which is given the task of aquifer management, and certain powers over withdrawals by individuals. Water conservation districts generally have inadequate powers, but an analogous petroleum conservation district in Alaska, beginning *de novo*, need not suffer such limitations. The State might initiate such a district for each communicating pool and make membership compulsory among its lessees.

The argument for this two-tier approach is weaker with petroleum management than it is with aquifer management inasmuch as we cannot visualize a water agency taking over the minutiae of operating every farm, where the water input is relatively much less important than petroleum to an oil firm. Even so, the Joint Association Survey data cited earlier indicate that development and production costs in field management outweigh exploratory well drilling costs by a substantial amount, and it might be letting the tail wag the dog to let unitization become total. Partial unitization could involve trade-offs and adjustments among separate lessees. Where wells need to be divided unevenly among tracts, cash payments could be made to compensate the losers from the gains of the winners. The same can be done when one producer is ready to go and another wants to wait. Whether this is a feasible and superior arrangement in the circumstances would call for extended study, so in this Report we advance the suggestion without endorsing it.

It is desirable as a general principle to minimize the intervention of State officials in decisions which might be left to operators in the field who have a proprietary economic interest in the outcome. The arguments for this are numerous and traditional and need not be repeated here. A great advantage of abandoning the MER criterion and substituting the DCF criterion is that it eliminates the conflict of goals between the State and the lessees concerning flow regulation, thus making it possible to delegate fuller authority to the lessee operators themselves and minimize State intervention. The presumption today is that the State needs to prevent the operators doing something which is advantageous to them but somehow disadvantageous to the State. Things go better when we can presume that the operators are serving the public interest by attending to their private interests.

The State cannot impose unitization unilaterally where oil- bearing structures straddle the border with federal lands, to say nothing of subjecting federal structures to regulation by State

officials. On the other hand, if communicating pools were subject to regulation by an organization of the operators, using a two-tier system like that suggested, it should make it easier to achieve successful unified management in the field. The delegation of operating control and planning to local organizations should obviate the question of which central agency is in charge.

Much of the above presupposes that the State accept DCF in preference to MER as the criterion for regulating flow. Let us therefore recap how we justify spending more money to speed up flow even when that will result in physical waste. Can we accept real physical waste merely for the purpose of saving something as vulgar as money, in a form as profane as interest, and as imaginary as interest foregone on investments which we might have made?

Say it costs $100 to discover $50 worth of oil in the ground. The world is telling us something by the way it prices petroleum, as well as the resources required to develop it. It is telling us that the resources which we sacrifice to gain the petroleum are worth more than the petroleum. This is clear enough when the resource cost is materialistic in the form of steel and when it is personal in the form of labor. It is harder for some people to accept when the cost is entirely financial in the form of interest payments on a mortgage; but interest too is a real social cost.

Interest is the cost of getting your hands on wealth today which you do not own, in order to build something today which will yield you a much greater return in the future. Thus, if you put $100,000 into a building to be rented, you will get your $100,000 back in less than ten years, normally, in voluntary payments made by renters. After that everything is a surplus above the cost of production. Over a life of 50 years the unit will probably yield five or six times its initial cost in net cash flow to the owner. Thus, having wealth at your disposal today instead of years down the line is very productive, which is why interest is paid. The rate of interest is the rate of

exchange between wealth this year and wealth next year. It is determined in the same kinds of markets that determine conversion factors between apples and oranges.

Economists and businessmen are saying we are in greater danger of running out of capital to develop resources, than we are out of resources in the ground themselves. There is nothing vulgar or profane, therefore, about economizing on capital in a resource-short world. Nor is there anything sacred about economizing on physical resources when the cost is wasting capital.

Let us consider the feeling sometimes expressed that there would be something prodigal about producing rapidly from proven reserves at Prudhoe Bay. A purpose of faster production at Prudhoe Bay would be to fill the pipeline and thus delay the need for new lease sales. The pressure will be on, obviously, to increase production from some source until the pipeline is full. By producing slower at Prudhoe, we would not reduce the withdrawal of petroleum from Alaska; we would rather cause some to be withdrawn from other areas instead. Speeding the flow from Prudhoe means getting the same flow from fewer acres and from a lesser investment in exploration, drilling and equipping wells, and equipping leases.

This is not to argue against advance planning to keep the pipeline full. It is, rather, a matter of planning to do so at the least cost. Doing anything at the least cost involves a small risk of not accomplishing the goal, but that is acceptable. Keeping the pipeline full is not an absolute. It is a desirable thing, if at a reasonable cost. What is required is a careful cost-benefit analysis of the whole picture. It would be a mistake to let leasing policy be dominated by any absolute commitment to keep the pipeline full regardless of cost. When we look at the chaos at the marketing end of the pipeline it would be ludicrous to demand absolute certainty at the production end at the expense of the people of Alaska.

c. Well spacing

This is largely the same issue as rate of flow. Higher flow rates require more wells, more closely spaced. It is not very fitting that the State of Alaska should impose wide spacing requirements on its lessees. This may be a throwback to another situation in another state where surface subdivision caused excessive well density; which had to be countered by public regulation. In Alaska the State is the landlord collecting royalties. The interest of such a landlord is to maximize the capital invested by the lessee. The royalty reduces the operator's incentive to apply capital, and this needs to be countervailed.

Closer spacing in addition to increasing rates of flow may also have some effect in increasing ultimate recovery. In fractured reservoirs with noncommunicating pools, this is obviously true. In other reservoirs it may be true. Little is published on this. It may be desirable for the State to commission a study on this subject: what is the optimal well spacing, well diameter, and rate of flow to be adopted, assuming that the goal is to maximize discounted cash flow net of costs? Most past analysis is not on target because it is premised on the goals of minimizing physical waste, and prorating excess capacity to market demand. Alaska, 1977, is no time and place to be invoking "standards" and going by the book when the standards and the books were developed for other conditions in other places and times.

It sometimes happens that regulators, operating under what appear on the surface to be counterproductive criteria, modify them in practice and make regulation work out better. We have not reviewed actual procedures, and limit these comments to the criteria which appear to be followed as guidelines, whether by legislative mandate or professional tradition. No criticism is intended or implied of any individual or group.

9. <u>Acreage reservation (checkerboarding)</u>

The Alberta system of crown reservations has attracted considerable attention. Professor Andrew R. Thompson of the University of British Columbia Faculty of Law has been an exponent, although his enthusiasm is reported to be waning. Alberta, too, is modifying and backing away from the system. The concept as explained by Professor Thompson is for, "…free entry on unproven lands under an exploratory reservation or permit which carries the right to lease, but requires that at least half the acreage, or some other fraction, be relinquished to the State on a checkerboard or corridor pattern after the lapse of a sufficient period of time for completing exploratory work and evaluation. Thus, it is the oil company that…must decide when and what to lease…" (Thompson 1969:86-87). An attractive feature of this system is, as Thompson points out, that it relieves State officers of a "tremendous burden of decision."

On the negative side, this may also relieve the State of a large quantity of oil since the State (or the Alberta crown) gets the leftovers after the lessee has picked the eyes out of the land.

It does seem advantageous for the Commissioner of Natural Resources, in his discretion, to lease out some areas for exploratory drilling while holding back adjacent and interstitial tracts for later drainage sales to benefit from the spillover of exploration on the leased tracts. This is discussed further in Section D on the timing of lease sales.

It does not seem advantageous to let the lessee have the choice of lands to select. This is another 'blunt instrument" whose results may be capricious and arbitrary. Since finer instruments are available, we do not pursue this further at this time. Authorities who have studied this subject in some depth are Professor Michael Crommelin, Faculty of Law, University of Melbourne, Australia; Professor Andrew R. Thompson; Dr. Campbell Watkins, Petroleum Consultant in Calgary; and Professor Anthony Scott, Faculty of Economics, University of British Columbia.

For a fuller description of the Alberta system we are submitting along with this Report a copy of Crommelin, Scott, and Peter Pearse, "Management of Oil and Gas Resources in Alberta: An Economic Evaluation of Public Policy."

10. Sale of undivided interests

It has been proposed that communicating pools or even larger units should be sold as such, rather than as volumes of the earth's crust underneath tracts of land measured on the flat. There are certain advantages:

a. The "transactions costs" of negotiating among the several surface owners would be obviated. Unitization is inherent and automatic.

b. Small firms could take a small interest. The scheme allows for ownership to be divided into many units, let's say 100. Each bidder would indicate a price and also the number of units he wished to acquire at that price. These would then be ranked in order of price until they added up to 100 percent. The winning bidders would then automatically become an operating consortium.

c. There is a dramatic reduction in risk, since offsetting risks are pooled. There is much less need for preleasing survey, therefore. The structure itself can be confirmed before there is great concern about just where upon it to take a position.

On the negative side, here are some considerations:

a. Entire structures or geologic features would have to be marketed at one stroke. The possibility of the State's withholding acreage for later drainage sale at high price is precluded.

b. The degree of centralized administration may be unnecessary, and the loss of autonomous action by the smaller individual firms undesirable. The controlling operator

presumably would be the largest owner of shares and production would be presumably regulated more for his benefit than that of others. Smaller firms would tend to lose some freedom of action. There are alternative unitization methods available which do not impinge on freedom of action to the same degree (see Section 8 above).

c. Professor Rooney's analysis of the Long Beach case sheds some .light on problems inherent in undivided interests. The dominant interest there evidently gains considerably by integrating the Long Beach production into its vertically integrated operation. If the smaller interests represented other firms their interests would tend to be neglected.

On the whole this represents an interesting possibility for solving one of the many problems of petroleum leasing, but it is neither broad enough nor promising enough to warrant further discussion in this Report of limited scope.

11. Handling information: generation, control and disclosure

Preleasing investment in geological and geophysical investigation accounted for 4 percent of the expenditures recorded by the firms in the Joint Association Survey (JAS Survey, 1976). For a fairer picture of the importance of these expenses we should multiply by three or so, to account for the time difference. These expenditures take place many years before the others do and before their results show up on the positive side of the income statement. Remember that money doubles every seven years at 10 percent. Then we should multiply by another factor because preleasing work is bigger in Alaska than the lower 48.

The industry pays these costs on the first round but the State inevitably bears them in the form of lower bids. Alternative methods of financing preleasing exploration have therefore been suggested. We will consider the existing system and a couple of alternatives.

a. The present system: open access to State unleased lands; timing of leasing dependent on industry initiative through the nomination system

Some advantages are the following:

1. It is hard for the State to play the sleeping landlord. Enterprising private businessmen are free to call the attention of State officials to economic opportunities.

2. Judgmental decisions are in the hands of highly motivated private firms. Several of them are in competition so that many concepts are applied to the same land by people who are rewarded by being creative.

3. The State does not have to bear the cost of conducting its own survey.

4. The system is time-honored and familiar and acceptable to the industry.

On the minus side:

1. Preleasing investment is another front-end filter like a high bonus. It is a tighter screen as well for the leaner firms, at least per dollar involved, because of the long waiting period between investment and recovery and the uncertainty of recovery. A firm possessing no real estate but only intangible wealth in the form of information is not very creditworthy, especially for long-term loans, so that this activity is nearly unfinanceable and requires equity capital. The advantage then is to firms with accumulated wealth.

2. Preleasing exploration adds no value to any real asset owned by the firm and therefore has to find its reward in the firms' acquiring State lands at a low value. An extreme case, of course, is the 1965 sale of 90 percent of the oil in the Prudhoe Bay field for $6 million. Application by the State of a low "discovery royalty" rate to early finds aggravates this situation. The State gets a lot of wildcat acreage surveyed in this manner, but there is no guarantee that the cost to the State is less than the benefit. It is more likely to be the other way around. And the State does not get the information. (Nomination does not convey much information, because overnomination is the standard operating procedure.)

3. A counterpart to point #2 is that the firm with a large investment in preleasing exploration may neglect intensive infilling and development of acquired leases, and instead buy more, leases. This is implied by the common allegation that many firms do not look at investments that yield less than 20 percent, even though they can borrow at 7.5 or 8 percent. The excess of 20 percent over 8 percent presumably reflects, among other things, some allowance to cover the overhead of preleasing exploration. But if a firm spurns investment opportunities on leases which yield less than 20 percent, it will not apply adequate capital to develop them. This would lead to a pattern of decentralization of development in the State.

4. Duplication and prematurity. Since access is open, the competitive edge in exploration comes only in part from doing the job better. In large part it comes from doing it sooner. The result is "soonerism," somewhat akin to behavior in the Oklahoma land rush when the race went to the swift. In addition, there is a certain amount of costly duplication, some of which may be justified and some of which has been prevented by cooperative line-shooting, but not all of which has been or could be eliminated.

Even where the lines are shot jointly, costly interpretations are duplicated many times without there being any occasion to ask if the first exploratory well might not be a cheaper alternative. By the time many firms are interested in duplicating the same interpretation it is most likely that the existence of a structure is well known and the purpose of incurring this expense is primarily acquisitive and redistributive rather than productive: that is, it is a matter of jockeying for competitive advantage over other firms wishing to acquire the same resource rather than a matter of increasing the resource.

5. Each firm's information is held tightly secret. Secrecy is almost always counterproductive and expensive to maintain. Secrecy prevents any positive spillover value from

information in advance of disclosure. State planning agencies cannot use it and environmentalists cannot use it. Peg Tileston, spokesperson for Alaska Center for the Environment, advises me that industry secrecy about future plans for activities with large environmental impacts ranks at the top of environmentalists' concerns and that full disclosure would go far towards abating many of these concerns. Tina Stonorov, Executive Secretary, Alaska Conservation Society, writes "Thorough public discussion of lease proposals…should precede every such decision…If an area is so poorly known that…guidelines can't be written, lease sales are obviously premature" (Stonorov, 1976). These concerns are much aggravated by the fact that overnomination is routine on the part of many firms seeking to hide their real intentions.

6. The system is vertically integrated. The firms that explore and nominate a tract early have every advantage in bidding for it at the time, more or less of their choosing, when they nominate it and push for it to be auctioned. There are, to be sure, some firms which specialize in preleasing exploration and acquisition and then try to sell their acquisitions to production and marketing firms. Such sales are, however, subject to taxation at that time, which the vertically integrated firm is spared.

7. Larger deposits are generally easier to find than smaller ones. This system draws most exploratory effort into the search for big ones where it is least needed and away from the smaller ones. An elephant in the bush looks much better than several birds in the hand. This reinforces the propensity towards decentralization.

8. Preleasing exploration does not necessarily or even generally increase the value of State lands. It may reduce the value if the absence of petroleum is confirmed. This information is of value to potential buyers but not to the State and the State need not feel obligated to pay for it.

9. State officials, to recoup losses, may turn around and knowingly sell bad acreage

for high prices as in 1969. It should, I believe, be considered beneath the dignity of a sovereign state, equipped with the powers and immunities of sovereignty, to withhold information that would prevent a businessman from damaging himself by bidding high for defective real estate. The sovereign should be above this game, not part of it.

10. Independent exploratory firms which acquire leases for sale to majors may be exploited by the latter's superior bargaining power.

Because of these several criticisms, alternatives have been suggested which we now consider:

b. Exploration by contract

The State may employ firms specializing in exploration to perform geological and geophysical investigations on the understanding that the results would be made public. Contracts might be drawn in a variety of ways with or without substantial bonus incentives, based on results of investigations. Professor Rooney suggests one method (Appendix G). The State would also do its best to secure greater cooperation from the U.S. Geological Survey, NOAA, and the Department of Interior in order to use information derived from federal lands to learn more about adjacent State lands. Cooperation with native corporations would also be desirable. The advantages would be the following:

1. Preleasing investigations would be unitized, obviating the cost of duplication. The State would recoup its investment in the form of higher bids and it should recoup more than its investment because the bidding firms need not cover the overhead of their duplicative preleasing investments. Entry would be open to many more bidders, resulting in keener competition as well.

Once information has been gathered it costs little to disseminate it. It is a "public good" (a good which, once created, may be provided to any number of people at little extra cost). It

probably costs less to publish data than to keep it secret. Some analogous cases where government publicizes valuable information are: weather reporting, earthquake fault-mapping and prediction; navigation aids; road maps; public land survey; the Torrens system of land title registration used in Canada and Australia; farm market reports; farm extension services; public health information; and public education.

2. The State may control timing of lease sales better, reducing industry initiatives with demands for premature nomination. In order to time lease sales in an economic way, State officials need have some basis for predicting expected sale proceeds and this procedure supplies them some of that information. The State at the time of sale can set its own reservation price as well.

3. Contracting explorers would come from the same geo-data industry that presently exists in firms now doing contract work for the industry.

4. The State's exploratory function would not be preclusive. Any firm that can do the job better still has the option of doing so. Thus, while it may be true that the Postal Service is unenterprising, this criticism should be directed against the Post Office and not against the present proposal, which does not contain any prohibition on competition.

5. There is no built-in propensity towards underpricing or overpricing leases, as with the present system. All parties on the buying and selling sides have available all the information that there is.

6. A substantial barrier to entry would be eliminated. Many more firms could bid on any given lease. The State itself would also become an effective "bidder" in the sense that it could set an effective reservation price. Leaner firms have a greater need for foreknowledge and a lesser ability to finance it.

7. The State would assume the riskiest element in the petroleum business, a risk it is able to bear because of its diversification, and a risk which it should bear because the risk is inherent in the land which the State owns.

8. Contracting exploratory firms will be motivated by a desire to enhance their reputations and get future contracts. In addition, various bonus and incentive systems may be adopted which reward them with percentages of what they find.

9. The problem of secrecy is dispelled. Planners and environmentalists can know as much as anyone about what is planned and what is going on.

On the minus side, here are some weak points:

1. Firms in the geo-data industry are not used to allowing disclosure.

2. Incentives are less acute than when the firm is gambling its own money. In the extreme, we might visualize a group of long-haired geology professors out practicing art for art's sake, mindless of any payoff.

We might alleviate this problem by spelling out objectives clearly, keeping contracts short, and shifting away from poor performers. We could give performance bonuses based on findings, even though we know this is a function of what there is to find as well as the skill of the finder. At least we would not be giving it all away in order to get it found.

We could allow two or more contracting firms to explore the same ground, provided we had some rational reason based on evidence to think that might be worth the extra cost (as opposed to the present system of letting all comers in regardless of any evidence of productivity) and the door is always open to others if the government is botching the work. Experience would soon show if officials were capable of being productive. Competition and exposure would stir

them up, too -pride of performance is an important element in competition, regardless of remuneration. Most workers in competitive industry also work on fixed salaries.

A variation of the contract system is the Alberta practice. The province contracts with private firms to put up 30 percent of their costs in return for which it gets their information after a lapse of one year. The Province can, but normally does not, publish the information before a sale of the land in question. Canadians are great compromisers and this system appears to compromise between two or three different principles. The results, we may surmise, will be equally mixed.

Another variation is the incentive-bonus contract. Instead of paying the exploring firm a fixed fee or a cost-plus fee, we may reward it with a percentage (or other function) of the value of its findings. This is similar to the contract system except with greater performance bonuses built into the contract, and lesser cost-plus payments.

Either method has the advantage that the State breaks into a joint in the vertically integrated industry and creates a market at that joint. In this case it is a market for the "products" of exploration firms. It gets the job done cheaper and without giving away its right to dispose of the resource once its outlines have been discovered.

Incentive-bonus has the advantage of keying motivation more to results. It has the disadvantage that the value added by exploration depends on luck. No matter how skillfully you search and how hard you work you cannot find what isn't there; while a fool may stumble on an elephant in the dark. A good job of exploring barren land will reduce its value by confirming its barrenness. It is hard to find a system for rewarding the effort of exploration on small tracts on an incentive basis.

There is a federal tax problem, too. Cash rewards paid out become ordinary taxable income in contrast to capital gains, only 50 percent of which would be taxable, and in even greater contrast to unrealized capital gains enjoyed by vertically integrated corporations which are not taxable at all. The weight of bias in the federal tax system would work against this proposal. Simple contract exploration doesn't share this fault in the same degree, since the capital gains would be realized by the State which is not taxable. While we should in general be chary of exploiting the State's nontaxability, in this case it seems justified in order to offset the special tax privilege accorded to private firms which are vertically integrated.

Another approach which becomes feasible in the event that we announce our intention to recapture the lion's share of any findings (by any of the various methods described in earlier sections) is to abandon the distinction between preleasing and postleasing exploration. We could divide State lands into large tracts and lease them as wildcat acreage. In order to be sure that lessees were highly motivated we would subject them to a delay rental which rose annually at an increasing rate or a constant percentage rate of about 10 percent per year. This would assure that no one took out any such lease without exploring diligently.

Instead of the delay rental we might use the shrinking concession as Iran does. Iran progressively takes back a percentage of concession acreage after five, ten, and finally, twelve years, charging $3.00 per acre year in the meantime.

Another variation on this plan would be modeled on the proposal frequently made and sometimes implemented to base property tax assessments on self-assessment by the landowner. In this case the leaseholder would set his own delay rental, which would be considered an *Ad valorem* Charge at a specified percentage of a base value. To prevent his setting a low base value, the lease would contain a reservation stipulating that the State might repossess it for the

base value declared by the lessee. Another reservation would open the area to exploration by others who might acquire the lease from the sitting leaseholder by paying him his declared value plus 15 percent. The idea is to allow a reasonable security to the leaseholder but to keep everyone on his toes and avoid exploiting the State by underpayment.

There is little doubt that such a system could be made to work, even though it is novel and would require much explanation and discussion. Among its prominent advocates are Professor Arnold Harberger, University of Chicago, and Professor Daniel Holland, editor of the *National Tax Journal*. At this point we merely pose this as a beguiling alternative without lengthy discussion.

c. Postleasing incentives

All systems that take a bite of mineral rents based on *ex post* .disclosures have some tendency to discourage postleasing exploration, primarily exploratory drilling. This is no problem with the bonus system or with delay rentals. A high royalty rate still leaves an incentive to explore for large, rich deposits which still will yield a surplus but biases exploration away from possums in favor of elephants. Profit- sharing and rent-sharing schemes allow the deduction of exploratory outlays, solving the problem but creating another problem of padding.

The *Ad valorem* Charge, in most ways ideal, may leave inadequate incentive for exploratory drilling. We can now see several solutions to this problem. One is to allow a deduction for drilling costs, guarding as best we can against padding of costs. Second is the use of high and rising delay rentals. The level of such rentals might be the bid variable. This has the advantage over the first method of raising money instead of giving it away. Third is a time limit on leases. Fourth might be a reservation by the State, in its capacity as assessor, of the right to

enter the leasehold to investigate sections not being actively produced. It could also reserve a right to repossess them for the purpose of resale to others.

12. Sale of fixed volume

The State might contract with lessees to sell them a specified volume of oil, subject to the lessee's finding it at the lessee's expense. After the lessee had withdrawn the specified quantity, the lease would terminate and possession revert to the State for future resale, along with capital invested by the lessee. All-information generated by the lessee would belong to the State.

The purpose is to get the State's land explored at a reasonable cost without having to give away or sell below value those few extraordinarily valuable deposits.

The effect of the proposal would be similar to paying explorers a fixed finder's fee for any commercial deposit, regardless of its size. It has the advantage that there need be no dispute over whether a deposit is "commercial" or not. The lessee would search until he found one that he himself considered commercial.

The proposal seems potentially workable. It is, however, novel and untried and, insofar as we are aware, undiscussed. It contains several possible pitfalls to guard against, all of which would require further analysis. We omit further discussion here, leaving this for future study if there is interest.

13. State intervention

The State cannot achieve its goal of business-like management without knowing a great deal about the nuts and bolts of the industry with which it is dealing.

On the price side, almost all leasing schemes presuppose accurate knowledge about price. Internal transfer prices of vertically integrated corporations can rarely be taken at face value. In addition to the obvious kinds of fiddling which are possible and frequently discussed, there is the

question of volume discounts. There may be a spot market for petroleum at a considerably higher level than the price for firm wholesale supplies. There may be independent refineries that would pay a higher price than the major firms' internal transfer price. What, then, shall we consider the prevailing price?

In a perfectly competitive industry we would find a central market somewhere in which we could have some confidence. In an industry dominated by vertically integrated firms, where oil is frequently swapped for oil rather than for money, where certain markets are dominated by a small number of refineries and marketing networks, these questions assume great importance. The question of marketing is beyond our scope, but it seems obvious that the State would benefit by moving aggressively and definitively in this area to preclude its being exploited by underpricing. A very productive use of royalty oil might be to supply a state marketing agency to "test the waters" and find out what price might be fetched by independent oil offered outside of regular marketing channels.

The possibility should not be overlooked, particularly with natural gas, of dealing directly with governments of the consuming states. These governments, after all, regulate the distribution of gas within their boundaries. California has taken some halting steps in the direction of looking into securing its own supplies of gas reserves.

Here, however, arises another hazard. Consuming states would like nothing better than to capture oil and gas reserves in Alaska, subject to mandatory delivery at regulated low prices. A paramount consideration in leasing policy should always be to blunt the impact of regulation by the FPC and the FEA, agencies whose policies seem calculated to effect a large transfer of wealth from producers to consumers. There need be no sense of guilt about this. California has no more claim on the resources of Alaska than Alaska has on the resources of California; and if

California did have such a claim, underpricing gas and oil would be a most inefficient way to assert it. We are not suggesting that Alaska exploit consumers in a monopolistic way; we are, rather, suggesting that Alaska avoid being exploited by consumers in a monopsonistic way by consumers with the club of federal power at their command.

Dealing with vertically integrated concerns (with dedicated reserves designated for specific plants and consuming regions) lends itself to this kind of exploitation. Long-term leases dedicated to costly pipelines financed by consumers make the State vulnerable. The shorter the term of the lease, the later it is written, and the more the State depends on the free market, the stronger is its position. All these are complex and ramifying questions beyond our present scope. The present point is that they urgently require attention when a leasing policy is being formed.

Closer to home, access to any common carrier pipeline needs to be aggressively assured by exercise of the good offices of the State. Attorney John Lamont has indicated that equal access to common carrier pipelines is far from automatic (Lamont, 1974). In order to sell additional North slope leases the State clearly must guarantee potential buyers full and equal access to the pipeline. In the event that producing capacity may exceed transporting capacity, the formula for allocating capacity needs to be specified in advance. Second-class treatment for nonowners of the line will result in second-class bids for State leases.

14. **The choice of a bid variable**

There should be a bid variable. There should be an auction at some point in the leasing process. Otherwise we are back at a noncompetitive system with its propensity towards prematurity or "soonerism." We now ask which of the leasing elements makes the best bid variable.

An argument for choosing the royalty as the variable is that a sliding scale is needed to make high royalty rates tolerably workable, and one way of making the scale slide is to let the bidders decide what the rate is to be.

The trouble is, variable royalties will slide on *ex ante* expectations rather than *ex post* disclosures. If we do opt for sliding royalties, it would be more feasible in my opinion to base them on objective *ex post* conditions such as depth, location, size, pressure, bearing strength of surface, length of working season, and so on.

The same considerations, pro and con, apply to profit share bidding in somewhat lesser degree.

When we get to the rent share element there is no need for any sliding scale. Sliding scales are simply means to make royalty and profit share systems more nearly approximate rent share systems. The idea is to capture as close to 100 percent of the rent as the State can. There is no need to settle for less because rent is a surplus above necessary payments for costs and incentives. It is exactly the value -imputable to the natural resource which the State contributes to the production process.

The bonus makes a logical bid variable because it is hard to set in any other way. It is not a percentage of anything fixed or known. To be sure, it could be set equal to the State's appraisal, but this is based on imperfect knowledge *ex ante*. An additional advantage of the bonus as the bid variable is familiarity and custom.

The problem with the bonus bid variable is that whatever is variable may tend to increase over time in relative importance and we are trying to get away from heavy reliance on bonuses. We may solve this problem easily by tying the bonus and the rental together at a fixed

percentage, with the rental being a high percentage of the bonus. If the percentage were 50 percent the bonus bid would be converted to a rental bid with a double rental paid in year 1.

An annual rent has most of the good qualities of a bonus with few of its failings. We would recommend, therefore, that the rent-to-bonus ratio be set quite high. Indeed, the main reason for retaining the bonus element at all is its familiarity.

If we choose to let the *ad valorem* charge (AVC) be a large element in subsequent lease income, there is attractiveness in using the same rate for both the charge and the rent-to-bonus ratio, let's say 25 percent. Then there may be a smooth transition from the bonus bid as the basis of valuation to an assessment of reserves as the basis, maintaining the same 25 percent rate on each.[5]

If we choose a high delay rental and a system of production-based payments, we can probably improve on the present concept of letting the delay rental lapse when production is shown to be commercially feasible. This contains an arbitrary element, permitting token production or token shows of producibility to terminate the rental. It might be better to let the rental continue and be creditable against production payments. This will pose another arbitrary decision later on when pressure is dropping and production falling, but later arbitrary decisions are less harmful than earlier arbitrary decisions and in this case probably less consequential.

[5] Looking farther ahead, the State may wish to consider actually transferring land title, and go out of the leasing business. The Legislature could create a special class of property, to wit, oil and gas rights transferred to private hands after the date of legislation, subject to a 25 percent *ad valorem* property tax. The proposed system would lend itself to a smooth transition from public to private property, without there being any giveaway element.

D. Timing Lease Sales

Our position on this question has now been foreshadowed at several points. We will only summarize and recapitulate here.

Decisions about timing lease sales entail the following sequence:

1. Selecting the lease procedure

The State must determine which leasing procedure and method of repayment it will use before it is possible to determine rationally the optimal timing of lease sales.

2. Ranking by maturity

Potentially leasable lands should be ranked according to "ripeness" or maturity for lease sale. This ranking will be roughly in the order of value. Economists generally agree that it makes sense to use the best resources first, but value is not the only criterion nor is it unambiguous since it could mean value per acre, value per barrel, value per well or value per parcel. The correct criterion does not involve these ambiguities, because it is a percentage.

We are discussing the value of the State's share of the income from the lease and not the value of the leasehold interest. We mean the present value or discounted cash flow of the State's share. This reduces it to a unitary figure. It will be a substantial job to make these estimates and to attach appropriate degrees of certainty to them. This job is indeed impossible so long as preleasing exploration is a monopoly of the potential lessees and the information is not shared with the State. The State must buy or otherwise acquire more information. Professors Rooney and Norgaard both address this vital point (Appendixes G and E).

The next step is to arrive at a forecast of how rapidly we anticipate the present value of the State's share will be rising. This is not a mysterious concept. If we had a simple bonus

bidding system it would mean how fast we expected that bonus bids would be rising. If we have a State participation system it means that we calculate the present value or DCF of anticipated State revenues, first on the assumption that we begin the process this year, second on the assumption that we begin next year, third on the assumption that we begin the year after that, and so on.

This all might be done by hunch, but it would be much better to lay the whole process out explicitly on paper in a very systematic way with all the assumptions being stated. This will involve a substantial amount of work the first few times, but specialized personnel may quickly become familiar with the routines involved and devote most of their time to the few questions of judgment which have to be factored in.

3. Calculating the growth rate

The basic criterion for ripeness is now assessable. We calculate each year the anticipated percentage growth in the present value of the State's interest in the lease. So long as this figure is higher than the relevant interest rate the time is still unripe for selling.

This is a very difference criterion from a "high display of interest" by the industry. It is likely that the "sooner" interest will be high at a time when sooners anticipate future values to be rising at a very high percentage rate. They would like to get in on the fast part of the growth curve, but there is no advantage in this for the State.

In calculating the State's share, we must be sure to deduct all associated costs and figure only the net value of the State's share. The gross share will always be growing at a slower percentage rate than the net share, so if we focus on the gross we will sell too soon.

We should add State tax collections to the gross, but be sure to subtract associated public costs from the total to arrive at the net. Adding taxes without subtracting public costs will cause

us to sell too soon.

We should resist the blandishments of those whose incomes are our costs. Their interest will be to urge us to sell before the time that is optimal for the State.

We should not accept the argument to speed up selling so that development can occur before costs of development rise further. No cost of development is rising anywhere like as fast as the value of oil in the ground, a fact documented earlier. The wellhead price of Swanson River Oil in 1961 was $1.50 a barrel. If we produced that oil beginning today, fifteen years later, and had it classified as new oil and sold it for $12.00 a barrel -- that is an eightfold increase in fifteen years, which works out to 15 percent per annum compounded. The State can borrow money at a much lower rate than that.

We should not give in to the pressure applied by "sooners" who see the value of their map files depreciating with each passing year. The State owes them nothing.

We should not think that selling for top dollar will tend to screen out leaner firms. Lean, efficient firms can pay well for something they can sell quickly. It is long waiting periods that screen out lean firms: they work with impatient money. We can also reduce the price of entry by shrinking the size of the units we well, as the price per barrel goes up. The later we sell the more profit is to be made on each barrel and the fewer barrels it requires to make a viable operation.

We should remain constantly aware that the owners of the pipeline have much less interest than the State does in waiting for higher prices. Since they own the pipeline and the costs are mostly fixed, their value for oil is at Valdez while ours is at Prudhoe. The percentage increase in value at Prudhoe will always be greater than the percentage increase at Valdez because of the leverage effect.

In forecasting needs for production from new leases, the State should bear in mind the

finding from other areas that the major increment to new reserves each year does not come from new discoveries but from the revaluation of proven reserves on extant leases (Lovejoy and Homan, 1967).

4. The State's interest rate

The appropriate interest rate for the State to use should be no higher than its borrowing rate and might be lower if the State has surplus funds which it is being forced to invest in ventures of questionable marginal productivity merely in order to do something with the Permanent Fund. The State should add a "shadow cost" to its interest rate to account for its freedom from its own State and local taxes. It does not make sense for the State to invest capital or withhold assets earning 4 percent from its own citizens who might be earning 5 percent, where the extra 1 percent goes to pay State and local taxes. But as to the extra 3 or 4 percent required to pay federal taxes, that is another question. This is 99 percent leakage from the State and so, as a matter of State policy, should not be considered. Federal policy is something else, but that is not our present concern.

5. The time for exploration

Just as there is an optimal time to sell leases, so there is an optimal time to begin preleasing exploration. Where the State is contracting this out, the time to begin should be calculated essentially in the same way as the time of selling leases. This will necessarily be done on a much lesser base of information.

6. A reservation price

At the time of lease auctions the State should set a reservation price. The Public Land Law Review Commission found that where all bids were rejected, they were substantially higher

at the next auction. Professor Norgaard's analysis (Appendix E) pinpoints this as one of the most needed reforms.

7. Stability of sales

The State should give some concern to maintaining a steady flow of lease sales, but should not let that dominate policy. For one thing, it tends to follow automatically from the criteria suggested. That is, a bulge in lease sales will overload the industry and reduce present bids and create, therefore, an expectation of higher future bids.

An artificially contrived steady flow in the face of roller coaster world prices is not advisable. It is extremely costly in lost revenues and one of its major effects is to help the largest firms overcome their diseconomies of scale, that is, their large commitment of fixed capital. Smaller, more flexible firms are better able to move in and out and take advantage of unstable conditions.

Something along the line of the procedure sketched above has been attempted by Kalter, Tyner and Hughes in their "Alternative Energy Leasing Strategies and Schedules for the Outer Continental Shelf" (Kalter, et al., 1975). I do not vouch for everything in the Kalter report and I believe it leaves out some of the steps specified, yet I recommend it as a first step towards demonstrating how to apply these procedures.

8. Special factors

A particular problem in the context of current federal price controls is the need to watch federal regulators carefully with their tendency to discriminate against what they call "old oil." In many natural resource tenure questions there is a grandfatherhood principle of favoritism applied. This indeed is the basis of "soonerism." Federal price control of oil and gas has taken exactly the opposite tack, a reverse grandfatherhood principle, with new producers being allowed

better prices than old producers. So long as we may expect this regulatory philosophy to continue, the interest of the State obviously is to defer leasing commitments longer than otherwise. This consideration reinforces other arguments for deferral of leasing and argues strongly for withholding lands from lease. This would not be an antisocial gesture towards the lower 48, but a defensive posture forced on the State by a counterproductive, uneconomical, and irrational Federal policy to which the State has no choice but adapt as best it can.

The State should guard against losing control of its own priorities by being forced into drainage sales along the boundaries of federal and native lands. Some are born decisive, some achieve decisiveness, and some have decisions thrust upon them, often by others with other axes to grind. The State should push for early resolution of uncertain tenures: native over-claims and State selections. It should push for a drainage agreement with federal and native landowners. The more oil- and gas-prone lands it selects, the greater its decision-making role in the energy industry. Whether the recreation industry, one alternative, will be equally consequential in a future of higher energy and transportation costs is a question to which State officials should give much thought.

Another argument for deferring lease sales is the State's desire to extract more tax revenue from the windfalls at Prudhoe Bay. Heavy taxes on petroleum income received by private firms would be borne by the State in lower bids for new leases. If there is to be a period of high taxation of corporate income from petroleum, it would be well not to sell many new leases until this phase shall have ended.

E. Procedural Implications: Administrative Load and Staff Needs

We may now summarize and recapitulate our observations about staff needs.

Past policy has been dominated and limited by a traditional emphasis on economy of staff. Sales policy over a considerable period was dominated by the short-run cash needs of the State, a passive posture of non-management. These traditions are inappropriate now that the State's oil and gas assets have become so large and are ripening into even higher values.

Yet the Legislature is appropriately cautious about plunging ahead blindly, building a costly administrative empire without making careful, discriminating judgments as to what is most required. One need not look far for examples of valuable public resources whose administrations eat up much of the rents that might be returned to the Treasury.

Economists are aware of a serious perceptual bias, however, which makes most people more aware of padded payrolls than padded capital budgets, the latter being in general a worse problem. The capital- intensive and land-intensive bias of bureaucracies is easily explained: once capital is acquired and captured, its annual cost no longer appears in the budget. Payrolls, on the other hand, are a regular cash outflow, highly visible and much easier to jump on, fairly or not.

A recommendation, therefore, is to make a conscious effort compensate for this bias. An excellent way is to maintain a constant appraisal of the value of the assets disposed over by the bureaucracy and impose a "shadow mortgage" on the agency equal to the appraised value of its resources. If we discover that the annual value of the non-labor input, measured in this way, is much greater than the cost of the personnel we are using to administer it, it will give us a better perspective on the potential productivity of additional personnel.

Having said that we still want to economize on personnel. This does not mean underpaying them, which is one of the more expensive "economies" known to public

administration. It does mean adopting those leasing methods which involve the least lost motion. Lost motion results when the basic leasing concept fails to bind the lessee and the lessor in a community of interest. The cheapest leasing method to administer is the one which sets up the least conflict.

High royalties rate poorly on this score. The State shares in the gross income but not in the costs. The State is a landlord administering a share-cropping system. Historical experience with sharecropping shows that successful landlords always oversee many details of their tenants' operation. They have to require the tenant to apply minimum amounts of labor and capital per acre. Thus, a royalty system leads inevitably towards work commitments, with extensive State intervention into operating decisions, which in turn presupposes large staff requirements. Thus, the royalty system, which at first seems so simple, is not simple to administer successfully.

The next step beyond royalty is profit sharing. This in turn requires constant auditing of expenditures. Staff requirements here may be compared with Internal Revenue Service requirements in the kind and quantity of personnel. Some staff requirements could be obviated by borrowing information from the federal agency. However, the kind of information required for the net proceeds approach, presupposed with individual leases, might be difficult to obtain. In addition, federal tax returns are limited by the peculiar institutions of federal taxation of oil and gas, which we do not wish to emulate.

If we use a profit share system or a rent share system where the interest rate is guaranteed, we must solve complex problems about the useful lives and depreciation paths of capital assets. Many of these are treated as current expenses for federal purposes so that we cannot simply borrow the federal rules, even if we regard them as well conceived in the first place.

An advantage of the front-end recovery system is that we do not have to decide about depreciation lives and paths.

All cost sharing schemes, however, pose us a choice between two evils. We may submit to exploitation through cost padding or we may build up a large audit staff whose job is to trace down the endless and mind- bending maze of avoidance devices which may be and have been utilized to transfer profits to controlled companies elsewhere.

If we opt for the *ad valorem* charge approach, we need to staff up a large appraisal section. We need a staff of professional appraisers supported by additional reservoir engineers. On the other hand, we can dispense with the auditors and we need not be involved in imposing work commitments on lessees. Appraisal itself is a species of audit, and the *ad valorem* charge imposes its own kind of work commitment on the person who has to pay it. Where the administration of cost sharing may be compared with the Internal Revenue Service, the administration of the *ad valorem* charge may be compared with property tax assessment.

Whether we choose royalties or cost sharing or *ad valorem* charge, we cut into private motivation to explore the underground and will need to allocate some cash to acquire the information in other ways, either in-house, or by contracting out exploration, or by Rooney's Exploration Expenditure Bidding (Appendix G). Either way, the appropriations committee will see the cash outflow and have to use inference and analysis to be persuaded that the bids received for State property are higher as a result. We should guard against the resulting perceptual bias leading us to overestimate the costs relative to the gains.

The next step in eliminating administrative costs is to move back to an *ex ante* system with emphasis on the bid bonus and/or a corresponding delay rental. These systems appear to relieve us of some administrative burden.

Note well, however, that in order to time sales properly we need the services of an appraisal staff, even if we use a simple bonus system. We need to be able to set a reservation price in case the bids are all too low, and above all we need to know the rate at which probable sales prices are increasing, in order to know the optimal time to sell. We would obviate the simpler appraisal task of valuing resources *ex post* discovery and description, but make more critical the more difficult task of appraisal before disclosure of outcomes.

An appraisal staff is also needed to assess environmental impacts which may be measured as the difference in the value of property before and after the impact.

Our most unambiguous staffing recommendation is, therefore, the creation and staffing of an appraisal section. Appraisal gets right to the heart of the rent-collecting business which is to distinguish high-cost deposits from low-cost deposits. It gets right to the heart of timing leasing sales which is putting a value on the State's share and its rate of growth. It gets to the matter of environmental impacts as just mentioned. It supplies an inventory to be used in planning. It is a means of collecting and organizing information in the most generally useful way.

Whatever leasing method is selected, staff resources should be set aside for constant review and evaluation. There should be a postmortem on every sale. How did we do? What mistakes did we make? How can we avoid them next time? Few of us would welcome intensive scrutiny of all our past decisions and understand the reluctance of others to be similarly scrutinized. Yet we all recognize the potential value in such review when applied to others, like the surgeon who just took out our kid's tonsils. It would be desirable, therefore, to institutionalize the postmortem review procedure.

While these are all important matters an excessive concern with them would be premature at this time. The first priority is to legislate basic businesslike guidelines for managing

the State's extremely valuable resources. No administration can perform any better than its legislative mandate allows and an excessive concern with administrative questions at this time would interfere with putting full priority on the larger question of specifying the basic conceptual guidelines and criteria for businesslike management.

F. Leasing and Taxation

Comparisons of leasing alternatives and taxation alternatives have been made throughout this Report. We will not repeat, but bring out points not made elsewhere.

Various lease elements have their counterparts in various taxation elements, but a lease is a binding contract which cannot be unilaterally changed by future legislatures, unlike a tax. A lease can discriminate against interstate commerce unlike a tax (for example, by allowing deduction of in-State costs but not out-of-State costs). A lease is an interest in real estate from which the State can reserve all manner of powers to itself, which it can hardly do when imposing a tax.

A lease differs from most familiar taxes in that it is *in rem*, that is it is attached to a piece of real estate rather than being *in personam*, that is an obligation of individuals as such. While this differentiates it from most taxes, it makes it similar to the property tax which is also *in rem*.

Any attempt to use the corporate income tax in lieu of an adequate leasing policy meets with only limited success because the tax is *in personam*, and requires an audit of all the affairs of the corporation, and requires interstate sharing, and is subject to the interstate commerce clause. The alternative, "net proceeds" tax, has been criticized by Ziefman and Ainsworth. (Ziefman and Ainsworth, 1977).

The tax instrument that we see as most capable of substituting for leasing policy would be a special, classified property tax to be imposed either on leasehold interests in oil and gas, or on title to oil and gas after that had been passed from the State to a private buyer. This would closely resemble the proposed *ad valorem* charge, but would be subject to future changes of rates since the present legislature cannot bind future legislatures in tax matters.

G. Tentative Recommendations

Recommendations are offered tentatively by listing alternative leasing elements in what the consultant now believes to be their order of preference. This listing is not designed to persuade. On the contrary, it may serve to put readers on notice of the consultant's personal judgments which may have unconsciously affected his marshaling of the arguments. Nor is our position ready to be chiseled in stone. This is a complex new field; we have a lot to learn and the consultant reserves the right to change his mind subject to new information and new insights.

I would screen out the systems based on *ex ante* forecasts, and go with one of the *ex post* systems. This means primarily that I would not continue depending on a high front-end bonus. This is not because of any universal antipathy to bonuses. In the analogous matter of timber sales from federal forests, I prefer the bonus system as practiced by the ELM in preference to a stumpage rate based on scaled volume as practiced by the Forest Service. Standing timber may be cruised with tolerable accuracy before bids are made and accepted, and the period of time involved is or can be short.

Here on the other hand, we are dealing with resources much less well known in advance and whose extraction extends over two or three decades following the investment in the bonus. Even a five-year contract, as used in some forest sales, screens out many worthy operators without accumulated wealth and would much better be payable on the installment plan to avoid this problem. To require bidders to pay in advance for an unknown possibility of acquiring a 20- or 30-year supply is virtually to substitute wealth for productivity as the effective basis of allocation. The possession of great wealth suggests there may have been past productivity, although predation and privilege are also sources of wealth. It is no guarantee of present or future productivity.

Whatever system is chosen it needs to be accompanied by vigorous inquiry into the transfer prices being used as the basis of valuation. If costs are to be made deductible the same holds true in spades.

I would place greatest emphasis on that lease element I have called the *ad valorem* charge (AVC). As indicated earlier, use of this element detracts from the motivation for exploratory drilling and this needs to be compensated for. A high and rising delay rental is recommended.

If we wish to retain the form and terminology of the bonus system, we could describe this as a low signature bonus paid on the installment plan followed by a high production bonus or discovery bonus whose size depends on the flow of production.

To strengthen the State's hand in appraisal and minimize concealment of reserves it would be desirable to accompany this system with a program of State-financed contract exploration with publicity of findings. (Appendix E and Appendix G) This is not, however, absolutely necessary. We could have AVC postleasing, while continuing to rely on the present system of privately financed preleasing exploration.

An ad valorem charge (AVC) at a high rate obviates reservations of acreage for the purpose of getting top dollar at drainage sales. AVC assures that the State will collect these surpluses anyway.

My second choice would be profit sharing, without front-end recovery or recovery of interest at a guaranteed rate. This is a compromise among the pros and cons of different systems. Royalties, on the one hand, impose too much deadweight loss as the landlord shares revenues without sharing the costs. Sharing costs, on the other hand, in a high degree at a high rate is not administrable. There will be excessive padding.

Profit sharing is somewhat less paddable and hence, with severe policing, would be workable. Since costs may be written off against royalties, but without interest, its bias is mostly against costs which are incurred long before they result in increased production. We have noted that there is too much of that anyway, that several factors conspire to stretch out the period between investment and recovery of capital.

There is a substantial policing benefit to compensate for the social cost of not letting interest costs be deductible against production payments. Interest costs are invisible to most people, and somewhat mysterious, and not so easily perceived as padding. Most people perceive padding in terms of putting relatives on the payroll, featherbedding, girlfriends, and other labor-related offenses. These are highly visible and easily understood, hence likely to be overstressed relative to padding of interest payments. But capital can be lazy, too, and undoubtedly will be if interest payments are guaranteed. Profit sharing avoids this problem.

My third choice is a variable royalty with rates varying according to a variety of objective criteria which could be combined in a point system. Rates would be high where costs are low and vice versa. It would not do simply to assume that volume of flow is the only important factor affecting costs and to have a sliding or step scale increasing with flow. Several other cost factors, probably including several not even alluded to in our previous discussion, need to be entered into the formula. We could remove the future shift effect by limiting the term of the lease to about 25 years or less.

The advantage of this system over actual deduction of cash expenses is the absence of opportunities for padding. Royalty rates would be low where the characteristics of deposits indicated that a prudent operator of average capability would incur high costs. Individuals who performed better than this standard would reap the rewards of their own efficiency.

The system could be progressively amended and improved over the years as experience indicated that the cost of overcoming certain handicaps had been overestimated or underestimated.

In some ways this system resembles the AVC, being based on an outside objective appraisal of the differential value of different deposits. It is something like having the Legislature play the role of assessor when it sets up the point system. Whether this is practicable is partly a question of how many variables there are which affect costs of production. If there are only a few whose effects on costs can be accurately specified then this system might be workable.

My fourth choice would be front-end recovery. This is preferable to guaranteeing a rate of interest because fast recovery is so much more important to lean firms than to rich ones. This system is to be compared with the privilege of expensing capital investments for income tax purposes. The problem is that any capital expenditure could be written off immediately against a flush producer, opening the door to extensive goldplating and dissipation of rent. Auditing problems are not insurmountable: there is a limit to the credulity of any auditor as to what may legitimately be justified in expending to develop a specific mineral deposit, and auditors would be highly specialized in the oil and gas business.

If either the profit-share, variable royalty, or front-end recovery system is adopted it needs to be preceded by a substantial delay rental to commit the lessee to performance.

We would not recommend returning to the non-competitive or other claim-staking system. We would not recommend high front-end bonuses. We would not recommend exclusive reliance on annual rentals determined ex ante. We are mildly enthusiastic about unitization, but prefer a two- tier system coupling individual operation of tracts with overall reservoir management subject to control by lessees themselves, and encouraged by the State to maximize

discounted cash flow for the group. An effective two- tier system might permit parcels to be smaller than now, a subject we have not explored.

We would not object to putting an upper limit on the acreage controlled by any one lessee, but regard this as difficult to enforce, somewhat arbitrary, and probably unnecessary if other suggested changes are made. We would not object to leases' being subject to an antitrust impact evaluation by the Attorney-General, although we view this as legalistic, potentially arbitrary, and less desirable than generalized incentives designed to encourage competition.

We believe that liability for environmental damages downstream from a lease should be a lien on the leasehold interest (not on the State's interest) up to the full value of the leasehold interest, provided the damages occur in Alaska. It would be desirable for this lien to extend to all the leasehold investments held by the company committing the damages, introducing a progressive element into risk liability.

Leases should be transferable. All information generated on State-owned lands should be reserved to the State and made public immediately. The State should extend its good offices in the form of a guarantee to all leaseholders that they may have equal access to common carrier transportation. Differences among different leaseholders on the same structure as to desired rates of production are to be resolved by transfers from those preferring slower rates to those who prefer faster rates at a field price to be set by State authority, based on an appraisal of true market value.

Various lesser recommendations on a variety of points have been made from time to time as we proceeded.

We believe the measures recommended would constitute an effective response to the challenge of oil and gas leasing policy in Alaska.

Acknowledgments

I wish to thank many people who have given of their time and ideas to help make this Report a more useful product. The initiative of the Commissioner of Natural Resources, Guy Martin, his organizational input, and his continuing interest and support are particularly appreciated. In addition, there has been excellent support from the Assistant Commissioner, Jack Roderick, and the DNR staff: O. K. Gilbreth, Pedro Denton, Pat Dobey, and Hoyle Hamilton, particularly.

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I have benefited from an enormous volume of written words, only part of which are acknowledged in the text. Some particularly helpful works have been several articles by Gregg Erickson; Stephen McDonald's book on "Oil and Gas Conservation"; Lovejoy and Homan on "Estimating Mineral Reserves"; the Public Land Law Review Commission Report, quarterbacked by Duncan Harkin at the University of Wisconsin, dealing with Alaska; Stephen Cheung's book on "The Theory of Share Tenancy"; Gale Johnson's earlier seminal article on the same subject; the report of Professors Kalter, Tyner, and Hughes to the Department of the Interior on OCS leasing policy and scheduling; the California State Assessor's handbook, "Guide to Mineral Valuation"; the recent Library of Congress summary of alternative leasing methods by Useem and Lindahl; the report of the Jackson Committee; the Van Poollen report on the effect of different rates of extraction from the Sadlerochit Reservoir; the Tanzer report to the State Legislature; the Lipton statement; the work of Campbell Watkins on the economics of oil reservoir development; and Martin Stern's paper, "A Policy Impact Model for the Supply of Depletable Resources." All of these have proved to be fertile sources of information and ideas along with many other works too numerous to list, some of which no doubt should be listed on the same level with those already mentioned if memory only served and time were long enough.

Special mention is due to Professor Guy Phillips, University of California, Riverside, who researched recent changes and prospective changes in federal tax policy related to oil and gas.

Finally, I must thank my associates, Professor Michael Crommelin, Professor Richard Norgaard, and Professor Robert Rooney, whose work is in the Appendixes to this Report. In addition to this independent research, they improved my mind by frequent consultation. They added many ideas to the final Report and subtracted several bad ones. Final responsibility for the Report, however, rests with the author.

But it is possible to explore too much and - equally wasteful - too soon. I have discussed selecting a year of discovery when the present value (PV) of a mine net of discovery costs stopped growing faster than the rate of interest. Figure C.4 shows the relevant quantities.

The "Moving Present Values" (MPV) are present values computed as in Figure C.3 (p. 349). Each is the maximum PV (R-C) that could be achieved by beginning production in the current year. By waiting, this value rises if costs are falling or prices rising, as shown. This is what makes lease values rise, and makes owners hold them for the rise, for lease values represent the net value of a resource after all non-land costs*.

Since this is a net value after all costs, including interest costs on non-land outlays, it is socially desirable to conserve the resource so long as its appreciation outpaces the relevant market interest rate. The time to begin discovery and development is when the lease appreciation slows down to the interest rate or less.

That is the year in which the non-moving PV of the lease is a maximum (A). On Figure C.4 this stationary PV is based on the origin, 1966, but any other year would do as well.

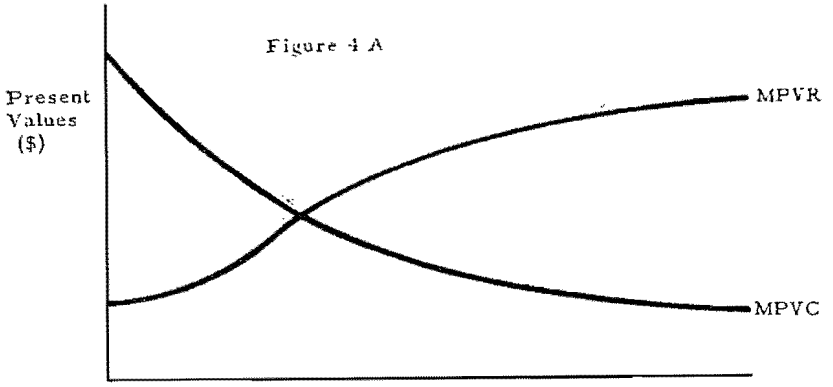
It would not make sense to hold the lease until its MPV was a maximum. That might be never; and in any case it would deprive us of interest on the net value of the resource in situ.

It would not make sense to develop the lease as soon as it assumed any spot liquidation value (C), for it is then of negligible current net value, but appreciating much faster than money in the bank.

It would make even less sense to develop the lease at the time D (not shown in Fig. C.4) when it first developed a perceptible market value. D would come before C.D would be the year in which the remote future possiblity of rent-yielding mineral development was first faintly suspected. For a future net value, once foreseen, always has some present value, however small.

A tax that takes a fixed percentage of the rent will lower the absolute but not the percentage growth of MPV (R-C) and so leave unchanged the date of A, the time to begin exploration and development.

*In a perfect market, however, lease values will not rise as fast as MPV(R-C). Rather, they would grow exactly at the rate of interest, along the compound interest curve in Figure C.4B. The expectation of future value assumes a present value some years before the optimal date to begin liquidation, as shown. The conditions under which leases are written, however, probably do not allow full expression of those foreshadowed values in the market for leases. Rather, they show up in inflated prices for range land, reservations of mineral rights, etc.



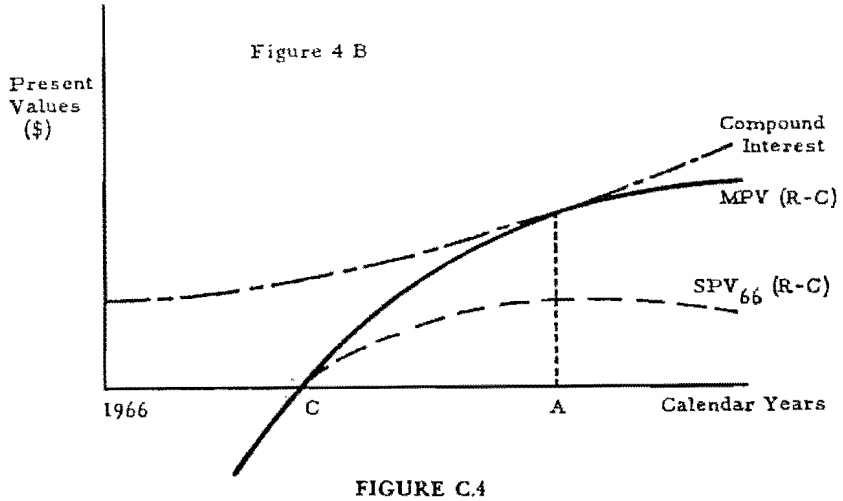


FIGURE C.4

Moving Present Values (MPV) of Revenues and Costs of Mineral Discovery and Development; and Stationary Present Value (SPV) of Revenues Minus Costs (R-C) Referred to a Base Year, 1966

Appendix B

Changing reserve-output ration (R:O) is slow, especially when it is long to begin with.

Another distinctive feature of the staggered model is the lag it implies in adjustment to new conditions. If interest rates fall, prescribing longer lives and higher R:O, the miner's primary adjustment is building less capacity and longer life into new mines. The life of old ones is largely determined by the original capacity, which not reviewable until the new replaces the old. It takes mining longer to respond to new economic stimuli, therefore, than it takes the new stimuli to be replaced by still newer ones, so the industry is chronically maladjusted, lagging its times by many years.

It is not really staggering as such, but time-indivisibility, that causes the lag. If we had 40 even-aged mines of 20-year life we could not adjust any mine at all, except one year in 20 when we could change every one. Staggering merely spreads this problem evenly so that each year we can make some change.

Staggered or not, a longer life of mines means a longer lag in adjusting to changed parameters. Oil reserves queued up behind shafts of low capacity are by no means on tap to meet emergency needs, either for minerals in particular or capital in general. Today interest rates stand double what they were fifteen and twenty years ago. Many mines and wells producing today are geared to that slower pace. The owners cannot benefit from earlier recovery of their money, and needy borrowers cannot benefit from the additional funds thus released.

The comforting thought that long reserves give us great flexibility to meet contingencies we must partly abandon, therefore. There is some short-run flexibility in each given mine, but it is not increased by having longer reserves behind each mine. Most of the adjustment occurs in the new mine opened yearly.

This adjustment is in fact slowed by longer reserves. With 40-year life of the representative staggered mine, and one mine turnover yearly, we retire and replace 1/40 of our output yearly and complete the changeover in 40 years, by which time, no doubt, new adjustments will be long overdue. With 20-year life it takes 20 years, and so on. With the shorter life, and still 40 mines, we must now retire two yearly; or we could get along on fewer mines (and somewhat larger jolts to our going concern). But no matter; in either case a shorter initial life means faster turnover and faster response to new economic stimuli.

The adjustment from longer to shorter reserves may be rapid if we drop the assumption that each producing mine finish out its pre-ordained life cycle before replacement. An owner with very long reserves behind his mines in effect has completely idle, uncommitted reserves which he can bring to life quickly. An 80-year reserve behind one mine, for example, is more like one 40-year reserve and one idle deposit, and this owner can double output by throwing the uncommitted 40-year units into the breach. Forty years is long enough to exhaust most economies of longevity in mine capital. He simply needs to duplicate existing capital and double output.

Thus a firm of high R:O can break the pattern of perfect staggering and by an energetic wrench increase output promptly. Anaconda Copper, which has 40 percent of world copper reserves compared to less than 14 per cent of the output, is currently investing heavily in new mine improvements to raise output by 50 percent from existing reserves (35)--simple enough when your R:O is more than four times the rest of the industry's. But that is better conceived as putting idle reserves to use than as shortening a systematic pattern of staggering. In the absence of idle reserves, a faster turnover clearly accelerates change, and thus substitutes for holding sterile reserves. A high turnover firm or industry achieves its adaptability by subjecting a high percentage of its production to redesign each year, a procedure which achieves the end without the high social cost of idle reserves.

The adaptable firm also needs to be able to reduce output quickly in response to lower prices. A firm needs no advance reserves to do that; but the shorter reserves it has, the higher percentage of its capacity it retires each year. Furthermore, mines of few years of future life (YFL) can economically be turned on and off in response to changing relations of present to future prices. A small price advantage is enough to warrant substituting near-future production for present production. With longevous mines, on the other hand, sacrifice of present production adds nothing to near-future production, but only to remote future production whose present value is too low to be worth much present sacrifice.

The adaptable firm also needs to guard against obsolescence. Here again a short life of mine and a high replacement factor each year is the best policy.

Appendix C

Table C-1

Ranking of Oil Companies by Noncompetitive Total Acreage

		Individual	Cumulative	
Texaco	119,513.19	16.2%	16.2%	
Union	117,328.52	15.8	32.0	
Cities Service	70,006.91	9.5	39.5	
Amoco Production	53,851.94	7.3	46.8	
Atlantic Richfield	51,277.40	6.9	53.8	10%
Alaska North America	32,606.49	4.4	58.2	
Pan Ocean	32,081.00	4.3	62.5	
Beard	29,765.19	4.0	66.0	
Mobil	29,564.14	4.0	70.0	
Marathon	22,085.37	2.9	72.9	20%
Standard Oil of California	21,107.14	2.8	75.7	
Exxon	18,362.00	2.5	78.2	
Placid	14,769.00	2.0	80.2	
Brinkeroff	14,271.90	1.9	82.1	
Alaska Offshore	12,249.00	1.6	83.7	
Skelley	9,562.00	1.3	85.0	
Farmland	8,878.00	1.2	86.2	
Home Petroleum	8,862.00	1.2	87.4	
Amarillo	7,065.00	1.0	88.4	
Sun	5,000.00	1.7	89.1	
Tidelands	4,693.00	.6	89.7	
Inlet	4,130.00	.6	90.3	
Apco	4,130.00	.6	90.9	
Shell	4,034.00	.5	91.4	
Texas International	3,713.34	.5	91.9	
Clark	3,716.00	.5	92.4	
Ashland	3,101.62	.4	92.8	
Newmont	2,940.00	.4	93.2	
Columbia Gas	2,560.00	.4	93.6	
Dixie Gulf	2,560.00	.4	94.0	
Dome Petroleum	2,560.00	.4	94.4	
South States	2,560.00	.4	94.8	
BP Alaska	2,560.00	.4	95.2	
Ozark Refineries	2,487.00	.4	95.6	
Alaska Kenai	2,463.15	.4	96.0	
Burton Hawkins	1,920.00	.3	96.3	
Alaska International	1,760.00	.2	96.5	
Ampco American	1,640.00	.2	96.7	
Little Bear	1,440.00	.2	96.9	
Continental	1,343.15	.2	97.1	

(To be continued)

Table C-1 (continued)

		Individual	Cumulative
American Petrofina	1,280.00	.2%	97.3%
Anschutz Corporation	877.76	.1	97.4
Cache	640.00	.1	97.5
Derby Refineries	639.82	.1	97.6
Simasko	461.25	.1	97.8
Belco	70.52	Nil	
Salcha	37.75	Nil	
	738,524.55		

47 members so deciles will be rounded to every five members

Source of raw data: Pedro Denton, D.N.R.

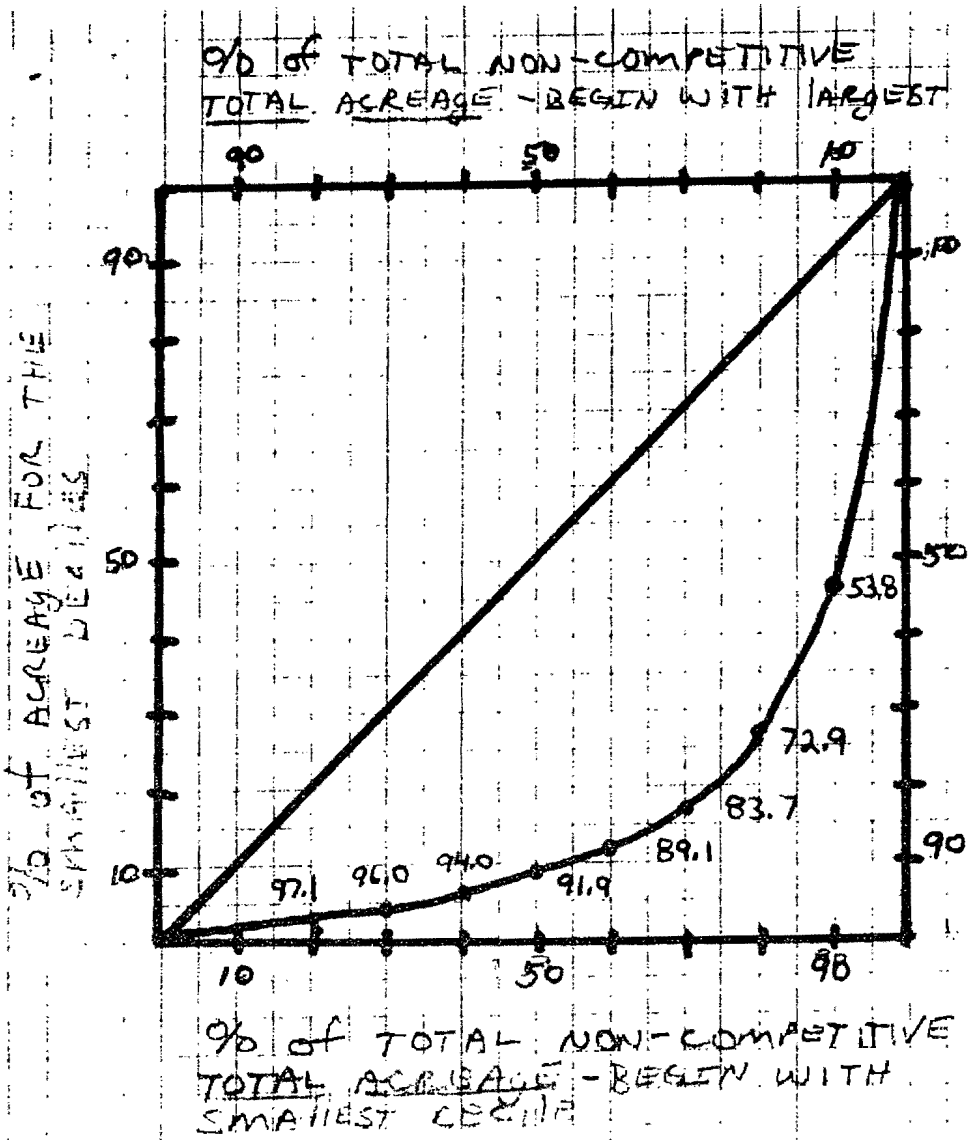

% of TOTAL NON-COMPETITIVE TOTAL ACREAGE - BEGIN WITH LARGEST DECILE
% of ACREAGE FOR THE SMALLEST DECILES
90
50
10
97.1
96.0
94.0
91.9
89.1
83.7
72.9
53.8
% of TOTAL NON-COMPETITIVE TOTAL ACREAGE - BEGIN WITH SMALLEST DECILE
% of ACREAGE FOR THE LARGEST DECILES
NON-COMPETITIVE TOTAL ACREAGE

Table C-2

Ranking of Oil Companies by Noncompetitive Net Acreage

		Individual	Cumulative	
Texaco	113,238.64	18.1%	18.3%	
Union	109,809.97	17.5	35.6	
Cities Service	70,006.91	11.2	46.8	
Amoco	42,944.51	6.8	53.6	
Atlantic Richfield	33,402.30	5.3	58.9	10%
Alaska North America	32,666.49	5.2	64.1	
Pan Ocean	32,041.00	5.1	69.2	
Beard Oil	29,765.19	4.8	74.0	
Mobil	17,280.50	2.8	76.8	
Marathon	16,594.04	2.7	79.5	20%
Placid	14,769.00	2.4	81.9	
Brinkeroff	13,491.90	2.2	84.1	
Standard Oil of California	13,336.35	2.1	86.2	
Alaskan Offshore	12,249.00	1.9	88.1	
Exxon	10,102.00	1.6	89.7	
Skelly	9,562.00	1.6	91.3	
Farmland	8,872.00	1.4	92.7	
Amarillo	7,065.00	1.1	93.8	
Home Petroleum	6,515.25	1.1	94.9	
Tidelands	4,693.00	1.0	95.9	
Texas International	3,713.34	.6	96.5	
Clark	2,920.00	.5	97.0	
Dome Petroleum	2,560.00	.5	97.5	
South States Oil	2,560.00	.5	98.0	
Ozark Refineries	2,487.00	.3	98.3	
Burton Hawks	1,920.00	.3	98.6	
Phillips Petroleum	1,858.00	.3	98.9	
Alaska International	1,760.00	.2	99.2	
Ampco American Mineral	1,640.00	.2	99.4	
American Petrofina	1,280.00	.2	99.6	
Alaska Kenai	1,262.38	Nil		
Sun	1,249.51	Nil		
Shell	1,173.70	Nil		
Little Bear	1,140.00	Nil		
Apco	1,072.56	Nil		
Inlet	1,032.50	Nil		
Anschutz	877.76	Nil		
Ashland	811.75	Nil		
Newmont	730.29	Nil		
Continental	671.57	Nil		
Cache Investment	640.00	Nil		

(To be continued)

Table C-2 (continued)

		Individual	Cumulative
BP Alaska	544.00	Nil	
Simasko	461.25	Nil	
Columbia Gas Company	368.12	Nil	
Derby	255.93	Nil	
Dixie Gulf	200.00	Nil	
Belco	70.52	Nil	
Salcha	37.75	Nil	
	624,703.25		

48 members so deciles will be rounded to every five members

Source of raw data: Pedro Denton, D.N.R.

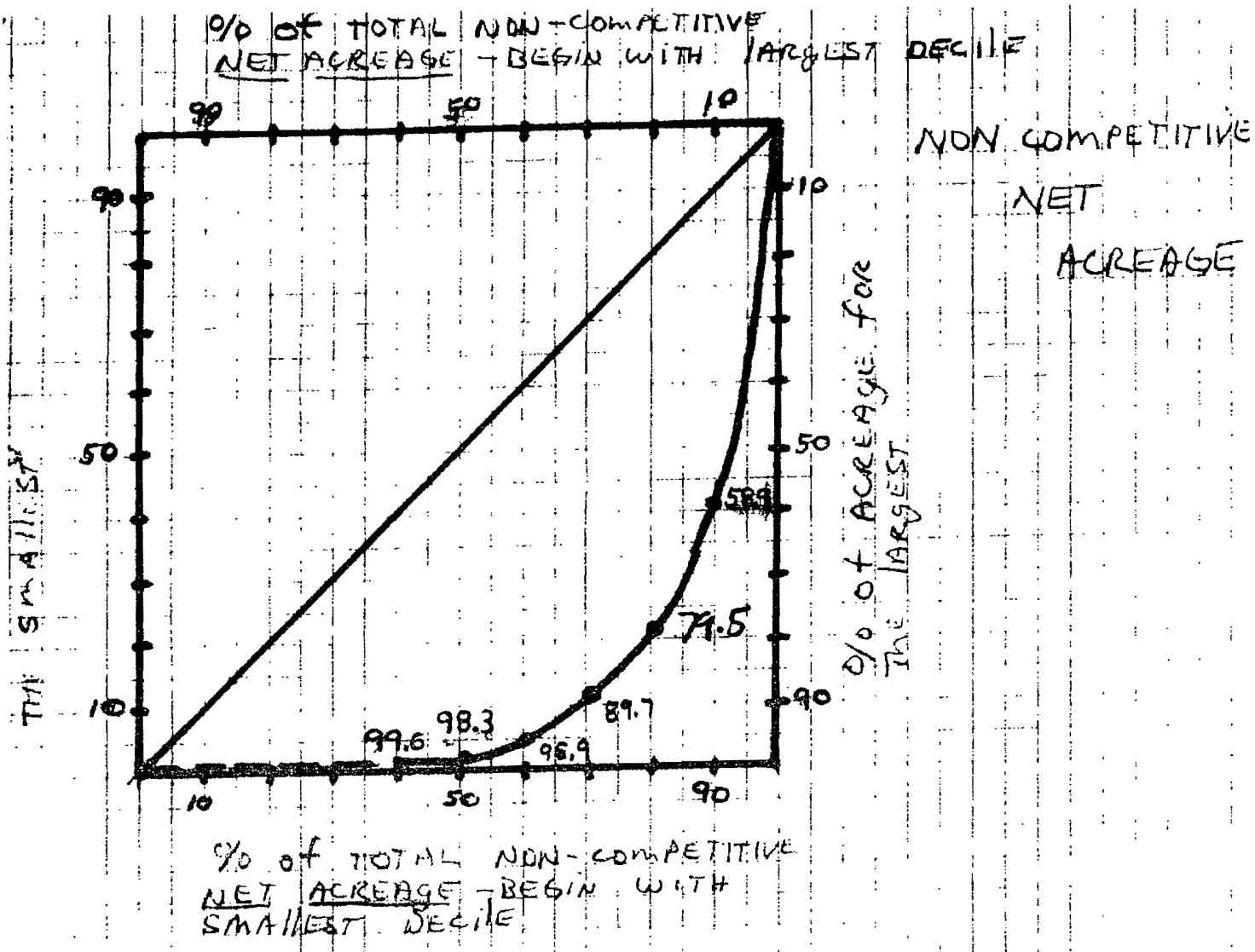

% of TOTAL NON-COMPETITIVE NET ACREAGE - BEGIN WITH LARGEST DECILE
NON COMPETITIVE NET ACREAGE
% of ACREAGE for THE LARGEST
THE SMALLEST
99
50
10
10
50
90
58.9
79.5
89.7
98.3
99.6
96.9
% of TOTAL NON-COMPETITIVE NET ACREAGE - BEGIN WITH SMALLEST DECILE

Table C-3

Ranking of Oil Companies by Competitive Total Acreage

		Individual	Cumulative	
Atlantic Richfield	937,724.22	17.8%	17.8%	
Sohio	447,674.00	8.5	26.3	
Phillips Petroleum	413,546.00	7.9	34.2	
Union	381,893.67	7.3	41.5	
BP Alaska	351,151.00	6.7	48.2	
Exxon	291,884.00	5.5	53.7	
Standard Oil of California	248,271.89	4.7	58.4	
Amoco	274,134.05	5.2	63.5	10%
Mobil	218,685.44	4.2	67.8	
Cities Service	139,284.93	2.7	70.5	
Continental	121,459.73	2.3	72.8	
Texaco	84,218.47	1.6	74.4	
Louisiana	80,161.36	1.5	75.9	
Shell	71,554.28	1.4	77.3	
Pennzoil	64,997.36	1.2	78.5	
Placid	60,669.36	1.2	79.7	20%
Marathon	60,529.20	1.2	80.9	
Amerada Hess	58,495.00	1.1	82.0	
Getty	58,454.00	1.1	83.1	
Newmont	45,828.71	.9	84.0	
Maruzen	43,297.44	.8	84.8	
Beard	40,855.00	.8	85.6	
Skelly	40,449.00	.7	86.3	
Gulf	38,994.71	.7	87.0	
Hunt Industries	38,129.00	.7	87.7	
Halbouty	29,291.35	.6	88.3	
Texas International	27,422.45	.5	88.8	
Simasko	26,956.16	.5	89.3	
Derby	23,753.00	.4	89.7	
Yates Petroleum	21,168.29	.4	90.1	
Hamilton Bros. N.S. Venture #I	20,464.00	.4	90.5	
Hamilton Bros. N.S. Venture #III	20,464.00	.4	90.9	
Carl Brewing	20,453.00	.4	91.3	
Oil Resources	20,453.00	.4	91.7	
Sunlite Nevada	20,453.00	.4	92.1	
Superior	19,163.00	.3	92.4	
Ulster	18,873.00	.3	92.7	
Westcoast	18,873.00	.3	92.7	
Ashland	18,691.08	.3	93.0	
Gas Supply	17,990.00	.3	93.3	

(To be continued)

Table C-3 (continued)

		Individual	Cumulative
Hamilton Bros. Oil and Gas Co.	17,334.00	.3%	93.6%
Amarex	16,412.00	.3	93.9
Coastal State	15,360.00	.3	94.2
Pacific Lighting	15,322.00	.3	94.7
Trans Ocean	14,729.00	.3	95.0
Hunt Oil	14,779.00	.3	95.3
Hunt Petroleum Corporation	14,779.00	.3	95.6
Inexco	12,149.00	.2	95.8
Cabot	11,105.79	.2	96.0
Champlin	10,284.00	.2	96.2
Home Petroleum	10,240.00	.2	96.4
Tenneco	10,183.00	.2	96.6
Acoma	9,033.00	.2	96.8
Mitchell Energy	8,880.00	.2	97.0
Sundance	8,880.00	.2	97.2
Clark	8,830.00	.2	97.4
Oil Development Company	8,320.00	.2	97.6
Brinkeroff	8,078.56	.2	97.8
Alaska Kenai	8,078.50	.2	98.0
Apexco	7,680.00	.2	98.2
Highland Research	7,680.00	.2	98.4
Anadarko	7,670.00	.2	98.6
Alaska Energy	7,571.56	.2	98.8
America Petrofina	7,407.00	.2	99.0
Tesoro	5,705.00	.1	99.1
AGIP	5,120.00	Nil	
Buttes	5,120.00	Nil	
Oxy Petroleum	5,120.00	Nil	
Aztec	5,120.96	Nil	
Aminoil	5,120.00	Nil	
Alaska Exploration	5,001.00	Nil	
Inlet	4,735.00	Nil	
Beel and Beel	4,735.00	Nil	
Cable Petroleum	4,335.00	Nil	
1409 Corporation	2,560.00	Nil	
Geopol	2,560.00	Nil	
Hamilton Bros. Petroleum	2,555.00	Nil	
Canus	2,501.00	Nil	
Panocean	2,501.00	Nil	
Alaska Energy	2,168.00		
	5,282,451.52		

80 members so deciles are in groups of eight

Source of raw data: Pedro Denton, D.N.R.

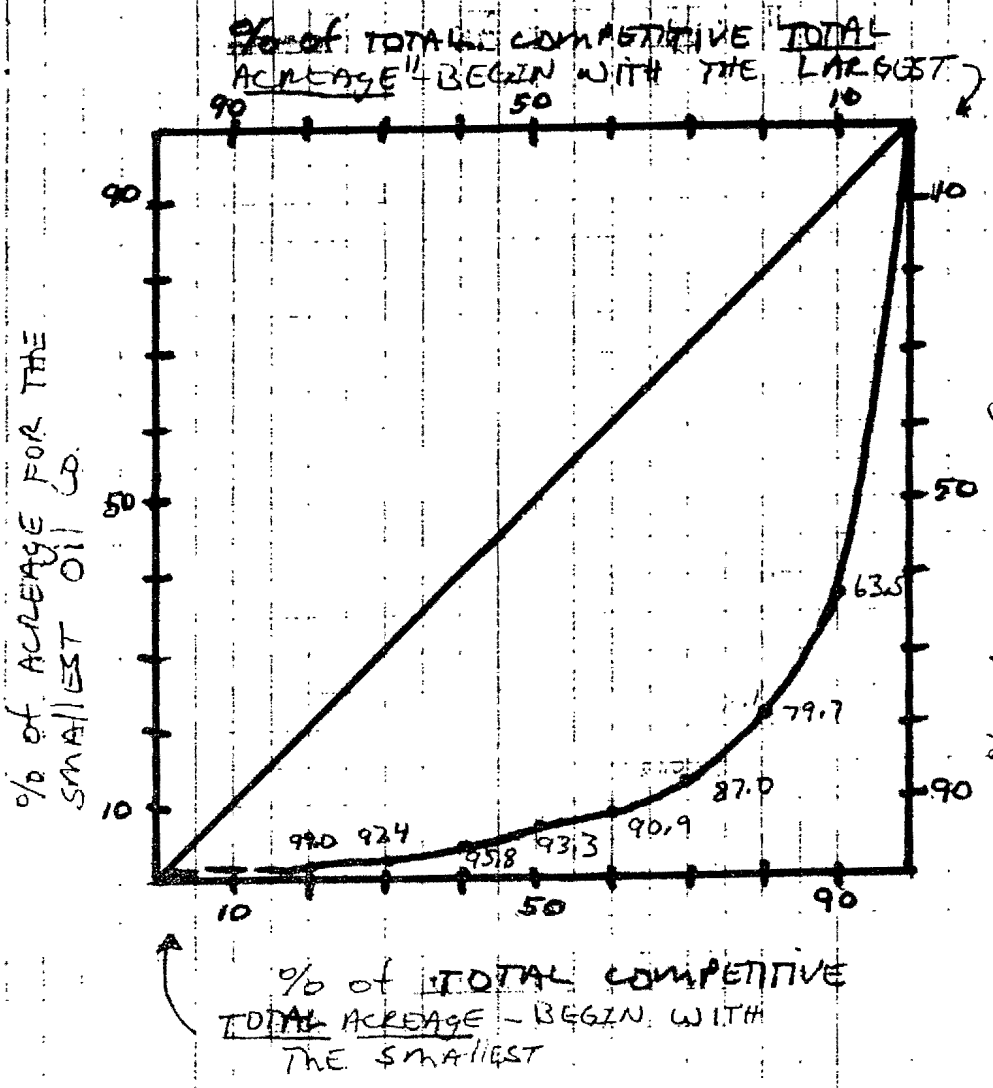

% of TOTAL COMPETITIVE TOTAL ACREAGE - BEGIN WITH THE LARGEST
90
50
10
% of ACREAGE FOR THE SMALLEST OIL CO.
% of ACREAGE FOR THE LARGEST
COMPETITIVE TOTAL ACREAGE
99.0
92.4
95.8
93.3
90.9
87.0
79.7
63.3
% of TOTAL COMPETITIVE TOTAL ACREAGE - BEGIN WITH THE SMALLEST

Table C-4

Ranking of Oil Companies by Competitive Net Acreage

		Individual	Cumulative	
Atlantic Richfield	401,400.02	16.8%	16.8%	
Phillips Petroleum	270,826.50	11.3	28.1	
Union	172,792.05	7.2	35.3	
Standard Oil of California	162,323.78	6.8	42.1	
Exxon	147,205.23	6.2	48.3	
Sohio	138,875.88	5.8	54.1	
Mobil	120,203.04	5.0	59.1	
Cities Service	117,681.20	4.9	64.0	10%
BP Alaska	102,674.99	4.3	68.3	
Amoco Production	97,532.62	4.1	72.4	
Texaco	63,708.10	2.7	75.1	
Continental	49,145.82	2.1	77.2	
Beard Oil	40,855.00	1.7	78.9	
Shell	37,578.64	1.3	80.2	
Marathon	31,917.69	1.1	81.3	
Texas International	26,413.05	1.1	82.4	20%
Simaski	26,356.66	1.0	83.4	
Gulf	24,546.61	1.0	84.0	
Louisiana	24,451.34	.9	84.9	
Pennzoil	22,658.00	.9	85.8	
Yates	21,168.29	.9	86.7	
Halbounty	20,508.43	.9	87.6	
Ame ada Hess	19,262.97	.8	88.4	
Newmont	13,993.39	.6	89.0	
Getty	13,778.12	.6	89.6	
Inexco	12,149.00	.5	90.1	
Cabot	11,105.79	.5	90.6	
Placid	10,737.99	.4	91.0	
Skelly	10,577.00	.4	91.4	
Gas Supply Corporation	10,531.00	.4	91.8	
Superior	9,520.05	.4	92.2	
Westcoast	9,436.50	.4	92.6	
Ulster	9,436.50	.4	93.0	
Oil Development	8,320.00	.3	93.3	
Home	8,320.00	.3	93.6	
Amarex	8,206.00	.3	93.9	
Alaska Energy Corporation	7,571.56	.3	94.2	
Anadarko Production	7,670.00	.3	94.5	
Sundance	6,786.54	.3	94.8	
Tesoro	5,705.00	.2	95.0	

(To be continued)

Table C-4 (continued)

		Individual	Cumulative
Aztec Oil	5,122.96	.2%	95.2%
Alaska Kenai	5,049.10	.2	95.4
Derby Refineries	4,787.98	.2	95.6
Apexco	4,736.00	.2	95.8
Al-Aquitaine Exploration	4,670.84	.2	96.0
Maruzen	4,329.84	.2	96.2
Ashland	3,913.36	.2	96.4
Tenneco	3,817.51	.2	96.6
Pacific Lighting	3,629.50	.2	96.8
Clark	3,031.49	.1	96.9
Inlet	2,959.20	.1	97.0
Oxy Petroleum	2,816.00	.1	97.1
Geopol	2,560.00	.1	97.2
Alaskan Exploration	2,503.50	.1	97.1
Hunt Oil	2,216.85	.1	97.4
Hamilton	2,143.88	.1	97.5
Brinkeroff Drilling	2,019.64	.1	97.6
American Petrofina	1,851.75	.1	97.7
Alaska Energy	1,734.40	.1	97.8
Ampco American	1,640.00	.1	97.9
Hunt Industries	1,589.60	.1	98.0
Transocean	1,477.90	Nil	
Champlin	1,476.00	Nil	
Acoma	1,470.60	Nil	
Hamilton Bros. III	1,429.25	Nil	
Hamilton	1,376.28	Nil	
Buttes Gas	1,280.00	Nil	
Calderwood	1,199.48	Nil	
Hunt Petroleum Corporation	1,182.32	Nil	
Mitchell	1,110.01	Nil	
AGIP	1,024.00	Nil	
Pan Ocean	937.88	Nil	
Coastal State	662.63	Nil	
Canus	625.25	Nil	
Carl Brewing	540.80	Nil	
Aminol	531.97	Nil	
Cable Investment	334.15	Nil	
1409 Corporation	256.00	Nil	
Sunlite	214.42	Nil	
Hartog	194.67	Nil	
Husky	149.61	Nil	
Arnold	105.76	Nil	

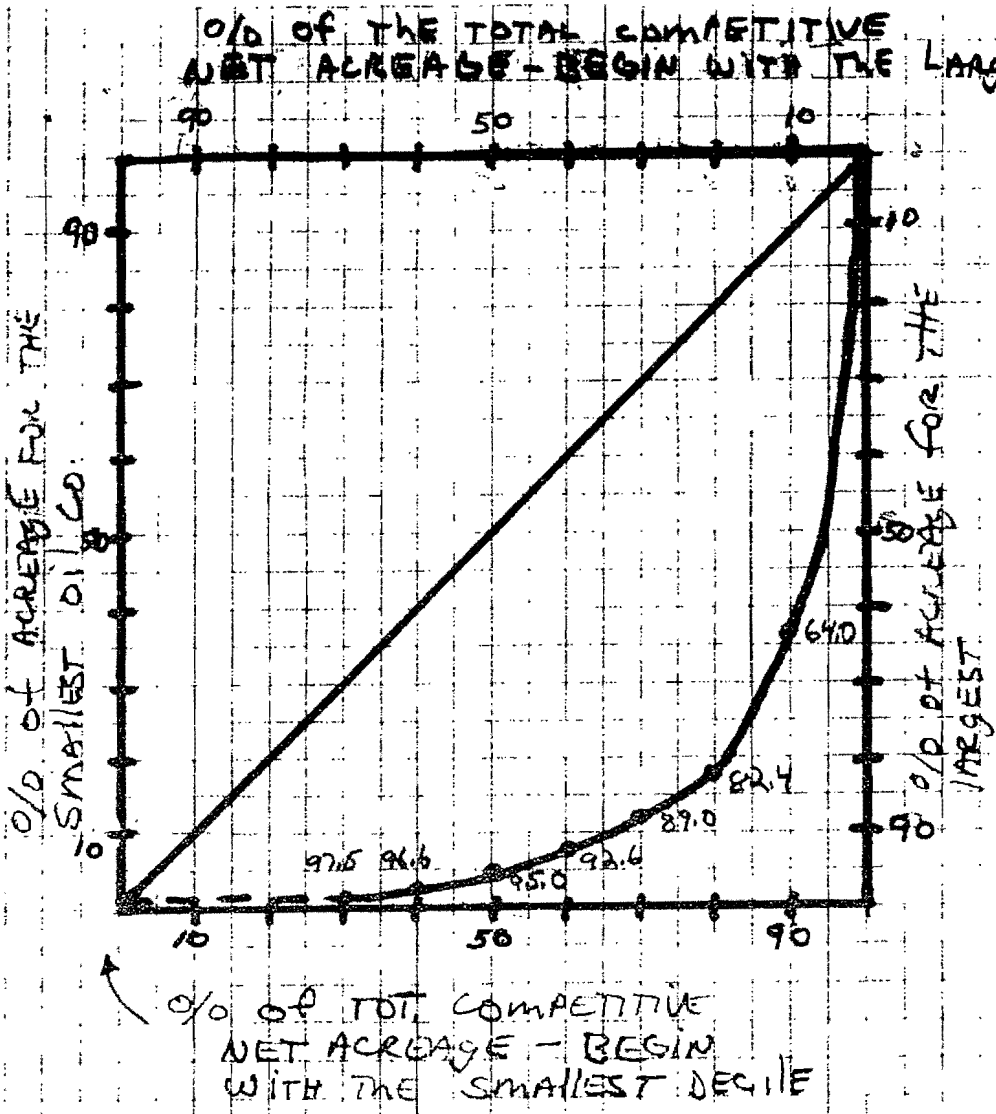
(To be continued)

Table C-4 (continued)

		Individual	Cumulative
Beel and Beel	94.70	Nil	
Belco	70.52	Nil	
Highland Resources	45.51	Nil	
Oil Resources	21.47	Nil	
	2,389,758.33		

86 members so deciles will be in groups of eight since so many have such small percentages

Source of raw data: Pedro Denton, D.N.R.



COMPETITIVE NET ACREAGE

Appendix D

NON-COMPETITIVE ALLOCATION SYSTEMS: A CRITIQUE

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Paper prepared for Dr. Mason Gaffney

27 January 1977

1. Introduction

The United States represents the exception rather than the rule in its adoption of competitive mechanisms for allocating oil and gas rights on public lands.[1] The United Kingdom, Norway, Canada, Australia and the Middle East oil producers have all preferred non-competitive systems. These systems may be classified into two categories: filing (or "free entry") procedures and discretionary (or negotiated) systems.

2. Filing Systems

The distinguishing feature of these systems is the opportunity presented to each private operator to obtain exclusive exploration and/or production rights for oil and gas on public lands simply by lodging an application, at nominal cost. Additional obligations may also be imposed, such as location of a claim, survey of the area in question, and registration of the claim, but these are generally insignificant. What is important is that the initiative in obtaining rights rests solely with the private operator. The government has no active role in the allocation process. Examples of filing systems for oil and gas rights may be found in Canada, in the northern and offshore regions under the jurisdiction of the federal government[2], and in Alberta (until 1 July 1976).[3] Many more instances occur in the field of hard rock mining.

Problems encountered with filing systems are numerous while advantages are few. The major difficulties include (a) inefficiency (b) loss of potential government revenue, and (c) lack of control over location of oil and gas operations.

(a) Inefficiency. Filing systems promote inefficiency by providing an incentive for exploration before it is required. Each operator is aware of the fact that, in order to obtain rights over prospective acreage, he must be the

first to make an application. He is therefore encouraged to apply earlier than he would in the absence of this "competitive" element. This factor in itself need not lead to inefficiency if the cost of obtaining the rights is negligible. However, a common characteristic of filing systems is the obligation imposed upon private operators to spend fixed amounts in approved exploratory work each year in order to maintain the rights in force. This requirement causes premature expenditure on exploration.

It is sometimes suggested that exploration should take place at the earliest possible date, in order to provide information about the resource. While it is true that information is useful, it must be recognized that information is obtained at a cost. A dollar spent on exploration today amounts to more than a dollar spent next year. Accordingly, premature exploration reduces the ultimate value of the resource in production.

Another argument made in favour of filing systems proceeds on the ground that the cost of any inefficiency is borne by the private operator rather than the government. Since the major companies explore in many jurisdictions other than Alaska, it is claimed that encouragement of premature exploration merely attracts dollars from other places to be spent in Alaska (with consequent benefits to the local economy). The difficulty with this approach is that it too overlooks the fact that exploration expenditures are taken into account in assessing the value of the resource. And it is that value which provides the opportunity for government revenue. In the end result, it is the government which suffers the cost of premature exploration.

Another problem with filing systems is that they do not ensure that rights are awarded to the most efficient operator. The company which is first to recognize the potential of an area need not be the one to develop it at least cost. If rights are transferable among operators without restriction (a

feature usually absent from filing systems because of opposition to "speculative" gains) the most efficient operator may ultimately acquire the acreage by purchase. But this may well be a costly process which again leads to inefficiency and waste.

(b) Loss of Government Revenue. Under a filing system, a private operator has an incentive to apply for oil and gas rights in respect of an area as soon as that area takes on a positive value, however small. Thereafter, any increase in value of the area flows to the private operator rather than the government.

The discovery process for oil and gas causes frequent reappraisals of the value of areas, often upwards. A successful well drilled on one block upgrades the potential of adjoining areas. A government which allocates blocks on a restricted basis, retaining nearby areas until their potential is better known, is in a position to benefit from these information "spillovers". In contrast, a filing system allows private operators to reap these unearned rewards. An illustration is provided by the different allocation systems in force in Alaska and the Canadian north at the time of the Prudhoe Bay discovery. Alaska was in a position to sell adjoining acreage at considerable benefit to government revenue. In Canada the filing system allowed private operators to acquire prospective acreage on a first-come, first-served basis. The area under permit more than doubled (from 190 to 440 million acres) between 1968 and 1970.[4] There can be no doubt that the filing system precluded the Canadian government from vast revenues.[5]

It is not surprising that the Canadian filing system was suspended in 1970, with a view to widespread revision. However, in 1977 that process has still not been completed.[6] This illustrates another feature of filing systems: they allow private operators to acquire rights long before development may be contemplated. A change in external circumstances (such as occurred with the enormous increases in world oil prices during 1973 and 1974) may destroy the

underlying assumptions upon which the rights were issued. Nevertheless, the government finds itself in a position where many of its options are foreclosed. It may be driven to new forms of taxation by an inability (or unwillingness) to revise the rights structure.

(c) Lack of Control Over Location. Since a filing system places the initiative regarding allocation of oil and gas rights squarely upon the private operator, the government has little opportunity to control the siting of exploration and production. Oil and gas operations are thereby afforded priority in situations of land use conflict. This situation is plainly inconsistent with government responsibility to take account of a wide range of social, economic and political factors, such as impact on local communities and protection of the natural environment.

The principal advantage claimed for filing systems is that the minimal role of government implies correspondingly small administrative cost. This is so, but the argument proceeds upon a highly restrictive view of cost. If account is taken of the losses of potential government revenue flowing from the above inefficiencies and inequities, it appears beyond doubt that filing systems are very expensive to the public.

Finally, it may be noted that the original proponents of filing systems, the Canadian and Albertan governments, have recently abandoned them. The proposal for changes in oil and gas rights in the Canadian northern and offshore regions adopts competitive bidding as the allocation mechanism, as does the new Alberta regime which took effect on July 1, 1976.

3. Discretionary Systems

Characteristic of discretionary or negotiated systems is the fact that the administrator is placed in a position of choosing among applicants for oil and gas rights in specified areas. The government retains a very high measure of

control over private operators: it nominates the areas available for acquisition, determines the time at which such areas become available, selects the operator for each area, and (usually) lays down the terms and conditions upon which rights are acquired. In the result, there are often considerable variations in rights among operators in different areas. Examples of discretionary systems are found in Norway[7], the United Kingdom[8], Australia[9], and most OPEC countries.

Disadvantages inherent in these systems are (a) the potential for graft, (b) inefficiency, (c) administrative difficulties and (d) loss of government revenue.

(a) Graft. It is unnecessary to say much about the opportunity for graft and corruption presented by a system which vests wide descretion in a public official to deal with resources of considerable value. It is not suggested that this has been a failure of the Norwegian, United Kingdom or Australian systems. However, the potential must be recognized and, if such a system is adopted, an appropriate review mechanism included to take account of this factor.

(b) Inefficiency. The inefficiency arising under discretionary systems is derived from the fact that the private operator selected for each area is not necessarily the least cost operator. Of course, this result is to a degree intentional: it simply represents the price paid for the opportunity to implement government policy. The difficulty lies in quantifying that price. In the absence of a bidding procedure, the government is unable to ascertain how much potential revenue it is forgoing in order to promote its chosen policies.

(c) Administrative Difficulties. This factor is closely related to the previous one. The administrator is placed in a position where he must choose among applicants. On what basis should the choice be made? Undoubtedly the legislature may specify guidelines or criteria. Inevitably, though, the administrator will require considerable information regarding the geology of

the area, exploration and production costs, marketing and pricing factors (to name but a few) in order to apply those guidelines. The difficulty is compounded by the fact that the only source of such information is likely to be the companies themselves. Perhaps it is not surprising, therefore, that some countries which rely upon discretionary allocation have opted for creation of a government corporation to participate in all phases of exploration, development and production, not just as a means of obtaining revenue but also to provide the information necessary to administer the system. The United Kingdom and Norway illustrate this trend.

(d) Loss of Government Revenue. Unless the government is confident that it can design a production tax which is entirely successful in taking account of differing geological, cost and location factors among fields (all of which influence the ultimate value of production), discretionary systems involve a loss in government revenue. This loss may indeed be large. In 1971 the United Kingdom experimented with bonus bidding for 15 blocks in the North Sea. The revenue obtained, more than 37 million pounds, became a source of government embarassment as people were not slow to calculate how much potential revenue may have been lost on the 848 blocks previously issued "free" by the discretionary method.[10]

Advantages claimed for discretionary systems flow from the control retained by government. The allocation process may be manipulated to achieve policy objectives, such as preference for domestic operators (apparent in the U.K. system) and priority for small rather than large corporations. The only response to be made to this claim is to inquire, at what cost?

Supporters of discretionary allocation also point out that it avoids "front-end load" - the commitment of substantial capital sums by private operators long before production (and cash flow) begins. However, it is not the only

method for dealing with this problem. A competitive allocation system may be designed where cash bonuses are intentionally small because the system also employs production-based taxes or charges designed to collect the greater part of government revenue.

Finally, there is no doubt that discretionary allocation, if combined with negotiated work commitments, may provide a means of subsidising exploration. The problem lies in deciding whether, accepting that a subsidy has been judged to be desirable, this method represents the most efficient form of subsidy. This is unlikely to be the case. The cost to government revenue is unascertained, so that the success of the programme is difficult to evaluate. Moreover, it has been shown that if a government is prepared to give up cash bonuses in order to stimulate exploration, work commitment bidding will generate greater exploration expenditure.[11]

4. Conclusion

In summary, it is suggested that competitive allocation of oil and gas rights over public lands has considerable advantages over non-competitive mechanisms, on both efficiency and equity grounds. Competitive allocation need not be inconsistent with other government objectives, such as avoidance of front-end load. Part of the strength of a competitive system is derived from the fact that it places reliance upon private operators to evaluate different areas (although government should not be precluded from calculating reserve bids, which implies that government obtain the information necessary for this task). Moreover, competitive allocation may be the only way (short of ex post assessment) of taking account of all factors which determine the value of areas. When used in combination with other taxes and charges, bidding provides a measure of the effectiveness of the entire revenue system. When the level of bids uniformly rises, the government receives a signal that revision of future taxation

arrangements may be necessary (the converse also holds). Lastly, and perhaps most significantly, competitive allocation adds a measure of political acceptability (and thereby stability) to a system designed for public resources.

Footnotes

1. Competitive mechanisms are not exclusively employed in the U.S., of course; the Mineral Leasing Act of 1920 provides for non-competitive allocation outside a "known geologic structure of a producing oil or gas field."

2. Canada Oil and Gas Land Regulations, Statutory Orders and Regulations 61 - 252 (as amended). A detailed description (and critique) of this system is to be found in Michael Crommelin, "Offshore Oil and Gas Rights: A Comparative Study", 14 Natural Resources Journal 457 - 500 (1974).

3. For a review of the Alberta allocation process as it operated until July 1, 1976, see Michael Crommelin, "Government Management of Oil and Gas in Alberta", 13 Alberta Law Review 146 - 211 (1975).

4. Canada, Department of Indian Affairs and Northern Development, Activities 1970: Oil and Gas North of 60 (Ottawa, 1971).

5. See Crommelin, "Offshore Oil and Gas Rights", 474.

6. In May 1976 the federal government issued a Statement of Policy giving details of the proposed new leasing system. The legislation to implement the widespread changes has not yet appeared. (January 1977)

7. For an account of the Norwegian system, see Kenneth Dam, "The Evolution of North Sea Licensing Policy in Britain and Norway", 17 Journal of Law and Economics 213 - 263 (1974).

8. See Dam, "North Sea Licensing Policy", and Crommelin, "Offshore Oil and Gas Rights".

9. See Crommelin, "Offshore Oil and Gas Rights".

10. Crommelin, "Offshore Oil and Gas Rights", 470.

11. Gregg K. Erickson, "Work Commitment Bidding", in Crommelin and Thompson (eds.), Mineral Leasing as an Instrument of Public Policy (Vancouver: University of British Columbia Press, 1977 forthcoming).

Appendix E

UNCERTAINTY, COMPETITION, AND LEASING POLICY

by

Richard B. Norgaard

UNCERTAINTY, COMPETITION, AND LEASING POLICY

by

Richard B. Norgaard*

In a world of certainty and competition--of known resources, known production costs, known future prices, and many competing firms--the optimal resource transfer policy would be to sell development rights everywhere simultaneously on a simple lump-sum basis to the highest bidders. On the other hand, when there is considerable uncertainty, all at once, fee-simple sales will be suboptimal. Farmland, for example, is almost always sold on a lump-sum basis for the quantity and quality of the land can be readily assessed, the costs of farming are quite well known, futures markets are available to stabilize income received by farmers, and there are many buyers and sellers of farmland. Book publication rights are an example of the opposite extreme; the demand for a book is difficult to predict, average production costs decrease substantially with volume, and most authors are quite fortunate to have more than one seriously interested publisher. Due to the uncertainty at the time the sale must occur, most publication rights are transferred in exchange for a royalty--a share of the gross revenues.

Petroleum development rights are currently transferred using a mixed strategy, a combination of lump-sum (bonus bid) payments and royalties. This paper investigates how uncertainty and competition theoretically relate to optimal leasing policy in section I; reviews game theoretic bidding models in section II; analyzes leasing performance for offshore Cook Inlet, Alaska, in section III; and

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*Associate Professor of Agricultural and Resource Economics and a member of Energy and Resources Group, University of California, Berkeley.

presents general conclusions in section IV. Overall, this paper is concerned with whether the current mixed strategy is mixed appropriately.

I. Uncertainty and Leasing Policy[1/]

In this section we will assume that the assumptions of the competitive economic model hold, particularly with respect to the number of buyers and sellers, except that uncertainty will be introduced. To begin, however, it is appropriate to review why the competitive model under conditions of certainty leads to the conclusion that the optimal petroleum leasing policy is to lease all tracts strictly on a lump-sum (bonus) bidding basis. Under these conditions, the most efficient firms--the ones with the lowest production costs--would win the lease since they will be able to bid the most. The state would collect all the rent since competition between firms would eliminate excess profits. Lastly, theoretical studies indicate that, under conditions of uncertainty, competitive industry will optimally exploit a finite resource over time.[2/]

A royalty would be an undesirable means for the state to collect rent since it decreases revenues on the margin and thereby reduces the incentive to explore, drill wells, and bear extraction costs. These distortions lead to lower production levels and lower government revenues. Thus, under certainty, the optimal policy is to lease all tracts to the highest bonus bidder, with no other forms of payments required.

1/ Discussion similar to this section but applied to federal OCS leasing can be found in Hayne E. Leland and Richard B. Norgaard with Scott R. Pearson, "An Economic Analysis of Alternative Outer Continental Shelf Petroleum Leasing Policies," Prepared for the Office of Energy R&D Policy, National Science Foundation, September, 1974.

2/ Robert M. Solow, "The Economics of Resources or the Resources of Economics," American Economic Review, Vol. LXIV, No. 2 (May, 1974), pp. 1-14. The theoretical model assumes that the rate of interest is appropriately determined in perfect capital markets. To the extent that this is not true, the conclusions reached in these analyses will be incorrect.

But petroleum development is not risk free, especially in frontier areas such as Alaska. There is uncertainty about the amount of petroleum that will be found. Section III of this report indicates that this risk has been substantial. The costs of exploration, production, and transport to market vary greatly in Alaska and are largely unknown to potential lessees at the time of a sale. And future petroleum prices are highly uncertain due to OPEC's instability and changes in the pace of resource discovery and technological breakthroughs. For a variety of reasons—changing social values, increased awareness of environmental complexity, and skepticism of new technology—these uncertainties seem to be greater than they have been in the past.

Relative to the risk-free optimal leasing policy, uncertainty introduces exploration, sale sequencing, and risk sharing into leasing strategy. To the extent that petroleum firms, or at least many firms, operating in or potentially operating in Alaska are more risk averse or less able to diversify risk than Alaskans as a whole, the firms tend to discount future net revenues too much. Excessive discounting leads to suboptimal exploration and development, lower levels of production, and consequently to lower bonus bids. Further, uncertainty makes it difficult for firms to raise capital. Small firms with fewer opportunities to spread risk may be at a disadvantage to larger firms. Unequal competition is less competition which further reduces the likelihood that the government will collect its fair share.

Exploration, especially with the drill bit, reduces uncertainty. More exploration prior to lease sales could substantially increase government revenues. Of course, for those areas for which additional early exploration results in a lowering of expectations of petroleum potential, bonus bid revenues would decrease sharply. Indeed, with additional exploration prior to sales, more areas would logically remain unleased than with the current timing of exploration.

On the other hand, where earlier exploration results in increased expectations of petroleum, bonus bid revenues would increase. To the extent that many firms are more risk averse and/or less able to diversify risk than Alaskans as a whole and/or to the extent that the current approach to exploration is inefficient due to information externalities, bonus bid revenues to the state will increase on the average. The analysis developed in section III indicates that, if exploration with the drill bit increased the effectiveness of the bonus bid from 16 percent to 80 percent as a means of collecting rent on offshore Cook Inlet sales through 1968, then lease bonus bids would have increased overall by a factor of five. The increased revenues to the state would have been equivalent to nearly $300 million (in 1975 dollars) received in 1961.[1/] Since most if not all state-initiated exploration with the drill bit prior to lease sales would have been undertaken by industry eventually anyway, the $300 million represents a net gain. Many will argue that government-initiated exploration is inefficient. Perhaps so, but from the point of view of revenues to the state, it appears that considerable inefficiency would be tolerable.

RECOMMENDATION I.A. <u>The Department of Natural Resources should initiate the drilling of some of the more uncertain structures, especially in new areas, and publicly disseminate the information collected prior to lease sales.</u>

The state would be better able to plan petroleum lease sales over time if it had better information on resource potential in the various petroleum areas.

1/ Using a 10 percent discount rate, the 1961 present value in 1975 dollars of bonus bids received from offshore Cook Inlet tracts was $73.8 million. The 16 percent effectiveness rate is derived in section III. Raising the effectiveness rate to 80 percent would increase the revenues by an additional factor of 4, or an additional $295.2 million. This estimate is subject to all of the assumptions specified in section III but nevertheless is an appropriate illustration of how earlier exploration could increase revenues.

The wellhead value of Alaskan oil may be fairly sensitive to the level of production due to limited pipeline capacities within the state, limited demand on the West Coast, and limited pipeline capacities to the Midwest. Unless Alaskan oil can be exported to Japan, there will be significant advantages to coordinating petroleum development with transportation development and demand. With better information, lease sale revenues to the state could be better predicted or sales better scheduled to meet state revenue needs. The timing of lease sales with different expected petroleum potential is the best mechanism for scheduling production and revenues. Production prorationing, such as occurred extensively in Texas, Oklahoma, and Louisiana during the late 1950's, is a poor mechanism since capital (each well) is used inefficiently. Such inefficiencies in the long run reduce the rent collected by the state. Currently, however, the state is not systematically collecting information on the resource potential of petroleum provinces for the purpose of scheduling lease sales.

RECOMMENDATION I.B. The Department of Natural Resources should share with industry the expense of collecting geological and geophysical information and develop its own capability or contract for the interpretation of seismic and other data in order to better assess petroleum potential for the purpose of improving the scheduling of lease sales.

Petroleum development risks can be shared between government and industry in many ways--royalties, oil pledges, annual rental payments, and profit sharing are the more commonly considered means. Because risk is shared in these approaches, the negative effects stemming from risk aversion--excessive discounting of future revenues and lower levels of competition--are abated. Since annual revenues are related to production (or cumulative acreage or estimated value of

acreage under lease), the revenues are more evenly distributed over time than when more reliance is placed on the bonus bid. This is advantageous if the state perceives a lower rate of discount as appropriate and/or is reluctant to rely on capital markets to even out the flow of bonus bid revenues. Differences in the various schemes for sharing risk are developed fully in the main text of this report and, hence, further elaboration is unnecessary here.

II. Game Theory and Leasing Policy

The market economy model is the predominant framework used in western societies for thinking through issues involving resources (property), production, and exchange. With or without a formal course in economics, most people currently understand and accept the concept of competitively determined market prices. The theory of supply and demand, barely two centuries since its infancy, is deeply embedded in the slogans of businessmen, the logic of newspaper editorialists, and the rhetoric of legislators. Because the basically simple, yet expandable and adaptable, market model is widely accepted, both debate over economic issues and public decision making are vastly simplified.

However, there are other models or frameworks for devising individual strategies and for analyzing economic behavior. Game theory is such a model with special importance to leasing policy. In the competitive model, certainty and competition are assumed. Game theory, on the other hand, assumes uncertainty and a limited number of competitors. The objective of this section is to describe the differences between the models and their implications for leasing policy. Alaska will not collect its fair share of the rent if it presumes the competitive market model is operational while industry plays a different game.

With respect to petroleum development right bidding, the two models differ as follows. In the competitive model the petroleum potential is known, and there are many bidders. Each bidder realizes that he will only be able to win the lease and thereafter cover all costs if he is the most efficient operator. Since efficiency of operation is the only variable the entrepreneur can affect, all entrepreneurial talents are directed at efficiency. Competitive bidding with reasonable certainty does take place in some areas of construction and light manufacturing, and in these industries efficiency indeed makes the critical difference between success and failure.

Efficiency never hurts a firm which faces limited competition in an uncertain situation. But under these circumstances, there are additional or alternative outlets for entrepreneurial talent. The objective is still profit maximization, but now the bidder logically asks: "What is the tradeoff between reducing the bid and reducing the probability of winning; what is the optimum reduction from the tract's expected value for profit maximization?" Game theoretic models provide an analytical framework for answering this question. The petroleum industry managers have undoubtedly asked and pursued the question intuitively since the industry's beginnings. Formal models have been employed, at least experimentally, since at least 1962.[1/]

The model by Capen et al. is fairly representative and is presented here to illustrate the factors formally considered.

Let

$f_i(x)$ = the probability density function for the ith opponents' bid;

and let

$F_i(X)$ = the probability that the ith opponent bids a value less than x.

With n opponents,

$\prod_{i=1}^{n} F_i(X)$ = the probability that n independent opponents all bid a value less than x.

Now let

$g(x)$ = the probability density function for our bid.

1/ E. C. Capen, R. V. Clapp, and W. M. Campbell, "Competitive Bidding in High-Risk Situations," Journal of Petroleum Technology (June, 1971), pp. 641-653.

Define

$$h(x) = K_n\left[\prod_{i=1}^{n} F(X)\right] \quad g(x) = \text{the probability density function for our winning bid where } K_n \text{ is a constant to make the integral of that density equal 1.}$$

Then the expected value of our winning bid, $E(X_w)$ is:

$$E(X_w) = \int_{-\infty}^{\infty} xh(x)\,dx$$

$$= \int_{-\infty}^{\infty} xK_n\left[\prod_{i=1}^{n} F_i(X)\right] g(x)\,dx.$$

The objective then is to maximize this expected value. The bidding strategist clearly becomes concerned with two phenomena--the number of opponents, n, and the probability density function of the opponents' bids. Capen et al. assume that the opponents' bids are independent and their probability density functions (quality of information about tract value) are the same. Alternative assumptions about the underlying density functions have been utilized; log normal is frequently rationalized.[1/] Except in the simplest examples, solutions are derived through simulation techniques rather than analytically.

Other researchers have simulated optimal strategies when all bidders are pursuing optimal strategies and investigated strategies where the bidder expects he has superior or inferior information relative to his competition.[2/] It is

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1/ Paul B. Crawford, "Texas Offshore Bidding Patterns," Journal of Petroleum Technology, March, 1970, pp. 283-289. Also, Chester Pelto, "The Statistical Structure of Bidding for Oil and Mineral Rights," Journal of the American Statistical Association, Vol. 66, No. 33 (September, 1971), pp. 456-460. Capen et al. also provide a simple argument for the log-normal distribution.

2/ C. D. Zinn, W. G. Lesso, and G. R. Givens, "OILSIM--A Simulation Model for Evaluation of Alternative Bidding Procedures," Paper presented at the 96th Winter Annual Meeting, American Society of Mechanical Engineers, November 30-December 5, 1975, Houston, Texas; and E. L. Dougherty and M. Nozaki, "Determining Optimum Bid Fraction," Journal of Petroleum Technology, March, 1975, pp. 319-356.

interesting to note that, while a significant portion of the growing literature on bidding for petroleum rights on public lands has been contributed by university researchers, almost none of the papers take a public perspective.[1/] A forthcoming Ph.D. dissertation by Douglas K. Reece incorporates a superior game theoretic model and specifically simulates what happens to the government's share of the rent as the number of bidders increases and the quality of information improves under lease bonus, royalty, and profit share bidding schemes. Completion of this dissertation is expected by June, 1977.[2/]

In summary, under conditions of certainty and a large number of bidders, the state of Alaska could expect to receive all of the rent from the petroleum resource. Game theory indicates bidding strategies whereby firms can maximize the rent they receive from the petroleum resource when there is uncertainty and few bidders. Game theoretic models indicate that the magnitude of the winning bid and, hence, the share of the rent received by the government increases with increasing certainty and more bidders. These general conclusions support the argument for more publicly initiated exploration and for the state of Alaska to establish bid-rejection criteria which, at least, have the effect of increasing competition and perhaps are established to counter game theory derived industry-bidding strategies.

RECOMMENDATION II.A. The Department of Natural Resources should establish bid rejection criteria based on the expected value of

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1/ Leading universities are Southern Methodist University, University of Southern California, and the University of Texas. An article by David Hughart of the University of Michigan is an exception to the above generalization. See David Hughart, "Informational Asymmetry, Bidding Strategies, and the Market of Offshore Petroleum Leases," Journal of Political Economy, Vol. 83, No. 5 (1975), pp. 969-985.

2/ Douglas K. Reece, "Leasing Offshore Oil: An Analysis of Alternative Bidding Systems." Applied Economics Division, Graduate School of Business Administration, University of California, Berkeley, June, 1977.

petroleum in order to effectively increase the level of competition by one bidder.

RECOMMENDATION II.B. The Department of Natural Resources should employ an expert in game theory as a part of its permanent staff to explore the implications of alternative game theory models, levels of information, and leasing strategies from the state's perspective and to assist in the development of bid rejection criteria for particular lease sales. Given the theoretical nature of this staff position, a joint appointment with the University of Alaska, Anchorage, may prove attractive.

III. Analysis of Offshore Cook Inlet Lease Sales

The lease sales of offshore Cook Inlet tracts are analyzed in this section in the context of the problems raised by uncertainty and game theoretic bidding strategies developed earlier. This area was selected because there have been a fairly large number of sales and tracts leased, there is a history of production, and per barrel production costs are probably more representative of other Alaskan petroleum provinces than, for example, Prudhoe Bay. The level of competition, bidding patterns, and lease ownership are considered in Part A. An estimate of the share of the rent captured by the state, the effectiveness of the lease bonus bid in capturing rent, and possible explanations of this effectiveness are developed in Part B.

The analysis draws upon leasing data kept by the Division of Lands, production data kept by the Division of Oil and Gas, and production decline rates estimated by John Miller of the Division of Oil and Gas. John Baxandall of the Division of Oil and Gas supervised the data processing and derivations of key statistics. The initial data came from diverse sources which had never been brought together in a single analysis before. Each of the initial data sets had some errors, and additional small errors have undoubtedly been made in the process of combining the sets. Time has been insufficient during the period of this study to correct all of the possible small errors. No errors or combination of errors have been come upon to date, however, which would change the general conclusions of the analysis.

RECOMMENDATION III.A.1. The Department of Natural Resources should allocate more resources to data management and to processing capability to improve the accessibility and reliability of information needed for ongoing management decisions and occasional in-depth analyses.

A. Competition, Bidding Patterns, and Lease Ownership

The level of competition and average lease bonus bids for offshore Cook Inlet sales through 1968 are presented in Table 1. The average number of bidders per tract in these sales ranges from one to four, with the vast majority of the sales averaging between two and three bidders per tract. These averages are not impressively high. The average number of bidders, for example, for federal OCS sales in the Gulf of Mexico in the early 1960's ranged between three and four, nearly 50 percent higher.1/ Column 8 of Table 1 indicates the percentage of tracts leased, with only one bidder. For the sales with a significant number of tracts, this ranges from 11 percent to 36 percent, with an overall average of 25 percent. For the federal sales cited above, 37 percent of the tracts leased received only one bid. Column 9 of Table 1 indicates the percentage of tracts with four or more bidders. For the larger Cook Inlet sales, this ranges between 26 percent and 51 percent, with an overall average of 33 percent. For the federal sales cited above, 41 percent of the tracts leased had four or more bidders. These two columns in Table 1 together illustrate the wide range in the interest in bidding on individual tracts in each lease sale and across lease sales.

Merely looking at the number of bidders, however, is insufficient. In the Cook Inlet sales, at least one of the bids on a significant number of the tracts has been placed by an individual or group of individuals. These bidders have poorer access to geologic and seismic data and, when a tract is won, are unlikely to be able to acquire sufficient capital or expertise to explore for and develop

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1/ The lease sales dated February 24, 1960, and March 13 and 15, 1962, are used for comparison because a bidding and production analysis similar to that developed in this report is available: John Lohrenz and Hillary A Oden, "Bidding and Production Relationships for Federal OCS Leases: Statistical Studies of Wildcat Leases, Gulf of Mexico, 1962, and Prior Sales," Paper prepared for the 48th Annual Fall Meeting of the Society of Petroleum Engineers of AIME, September 30-October 3, 1973, Las Vegas, Nevada, Paper Number SPE 4498.

TABLE 1

Lease sale number	Date	Acreage leased	Number of tracts	Total bonus bid received	Bonus bid per acre	Average number of bidders on each tract	Percent of tracts with only one bidder	Percent of tracts with four or more bidders
1	2	3	4	5	6	7	8	9
				1975 dollars			percent	
1	December, 1959	25,621	11	5,491,775	214.35	2.4	36	27
2	July, 1960	8,435	5	126,702	15.03	1.6	60	0
3	December, 1960	1,852	1	18,464	9.96	1.0	100	0
7	December, 1961	146,126	33	26,687,220	183.10	2.5	36	30
9	July, 1962	264,437	74	28,830,474	109.00	2.8	23	28
10	May, 1963	75,669	35	1,960,480	25.93	3.0	11	29
12	December, 1963	184,248	135	4,858,631	26.37	2.8	22	27
13	December, 1964	149,089	86	1,951,697	13.09	2.8	27	26
15	September, 1965	287,383	187	8,299,350	28.88	2.9	33	34
16	July, 1966	76,394	65	2,174,137	28.46	4.0	22	51
19	March, 1967	2,560	1	4,521	1.77	1.0	100	0
20	July, 1967	175,836	85	31,685,321	180.19	4.0	14	47
22	October, 1968	895	1	10,266	11.47	2.0	0	0

petroleum. They typically bid a small fixed amount per acre--$1.00, $1.01, and $1.10 have proven popular--on a large number of tracts. These "fishing bids" significantly increase the apparent average number of bids per tract but provide little competition to the more knowledgeable industry bidders on tracts more likely to be valuable. For example, in lease sale 9 there were a total of 207 bids submitted on 74 tracts leased, an average of 2.8 per tract. But 101 bids of $2.25 per acre or less were submitted, and 25 tracts were leased with these low bids. If we subtract both the low bids and the less valuable tracts won with low bids from the total, then 106 serious bids were submitted on 49 tracts. The average number of bidders per tract falls from 2.8 overall to 2.2 serious bidders on the more likely tracts.

The sum of the lease bonus bids on the 25 tracts in lease sale 9 won with fishing bids came to $100,000 or only 0.6 percent of the total in bonus bids received in this sale. Only one tract won with a fishing bid (Pan American Oil, ADL tract #17579) has ever produced a significant amount of oil. This tract's share of the total discounted value of oil produced and expected to be produced from tracts ever in production to date come to a mere 1.5 percent. The higher level of apparent industry interest in the federal sales cited above has typically been attributed to the remoteness of and special technologies needed in Alaska. It appears, however, that a large portion of the difference may also be due to more intense screening of industry nominations of tracts to be leased or better selection by the U. S. Geological Survey of sites with petroleum potential. In the federal sales cited above, between 15 percent and 30 percent of the tracts became productive, whereas only 2 percent of the offshore Cook Inlet tracts leased through 1968 have thus far produced a significant amount of oil.

RECOMMENDATION III.A.2. The Department of Natural Resources should initiate an analysis of the tract nomination and selection process; the role of nonindustry bidders and low dollar bids on the level of competition; and the administrative, environmental, and resource development delay costs of leasing petroleum development rights on highly unlikely tracts and/or to bidders incapable of undertaking exploration and development.

The average bonus bid per acre for each lease sale is presented in column 6 of Table 1. The average bonus bid per acre in 1975 dollars ranges between $13 and $214 for the significant lease sales. This compares with an average of $786 for the Gulf of Mexico sales in the early 1960's. The difference between Gulf of Mexico and Cook Inlet bids is usually attributed to the differences in development and transportation costs. More significant, perhaps, is the difference in the tract selection criteria used by the federal and state administrations.

Pan American, Richfield (now combined with Atlantic and called ARCO) and Union have had the greatest influence on offshore Cook Inlet sales. Lease sales 7 and 9 transferred the only tracts that are currently producing or have historically produced oil. In these two sales, these three companies--the latter two bidding jointly with six other large oil companies--acquired 58 of the 107 tracts leased and spent almost $28 million of the $30 million collected in bonus bids (Table 2). These three consortia acquired 13 of the 17 tracts which later proved productive. Atlantic acquired three of the remaining four productive tracts but has since joined with Richfield.

The distribution of lease holdings among companies on the federal OCS in the Gulf of Mexico is comparable. There, 10 companies held 62 percent of the acreage in 1972.[1/] But in Alaska, 9 of the 10 companies formed 3 consortia,

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1/ U. S. Senate Committee on the Judiciary, Subcommittee on Antitrust and Monopoly, Testimony of Dr. John W. Wilson, Chief, Division of Economic Studies, Federal Power Commission, Washington, D. C., June 27, 1973.

TABLE 2

	Lease sale No. 7		Lease sale No. 9		Lease sales Nos. 7 and 9	
	Number of tracts won	Bonus bid paid	Number of tracts won	Bonus bid paid	Number of tracts won	Bonus bid paid
		thousand dollars		thousand dollars		thousand dollars
Richfield bidding with Socal, Shell, Sinclair, or Phillips	8	5,671	13	7,715	21	13,386
Pan American	13	7,296	13	3,338	26	10,634
Union bidding with Ohio or Socony Mobil	3	165	8	3,624	11	3,789
Total for three groups	24	13,132	34	14,677	58	27,809
Total for sale(s)	33	14,411	74	15,626	107	30,037

whereas in the Gulf of Mexico, almost all of the companies joint bid with each other at sometime or another. An analysis of bidding in these sales does show competition between the consortia on those tracts which were most attractive, some of which later became productive. Nevertheless, if one is not aware of the consortia, there appears to have been more companies competing and more participation in presale exploration and bid formulation than there, in fact, was. The consortia specified in Table 2 broke up somewhat in later offshore Cook Inlet sales. Independent bids appear to have been submitted by Shell and Socal, for example. And new names, notably Texaco and Marathon, appear among the more aggressive bidders in the later sales.

In the economist's model of perfect competition, there are many well-informed participants bidding prices up or withholding goods from sale until an equilibrium market price is reached. Doubt has thus far been cast on the assumption that there have, in fact, been many bidders. Lack of knowledge is also apparent from an analysis of bidding patterns. Column 10 of Table 3 presents the ratio of the difference between the first two bids divided by the sum of the first two bids. With competition and perfect information, this ratio should be very close to zero, while the greatest it could even possibly be is one. The ratio when a large number of randomly drawn numbers are compared tends toward an average of 0.5. This ratio for Lease Sales 7 and 9 averages 0.32.

With perfect information and many bidders, the winning bid should equal the discounted value of the oil less production costs and royalties. Given that royalties are proportional to value and production costs stay within a fairly well-defined range for Cook Inlet, one would expect if information prior to the lease sale was "pretty good" that the ratio of the discounted value of

TABLE 3

ADL tract number	Name of highest bidder	Name of second highest bidder	Total number of bidders	Bonus bid	Bonus bid per acre	Discounted value of:			$\frac{B_1 - B_2}{B_1 + B_2}$
						Oil production	Oil production per acre	Oil/bonus bid	
1	2	3	4	5	6	7	8	9	10
				thousand 1975 dollars	1975 dollars	thousand 1975 dollars	1975 dollars		
17579	Pan American	None	1	20	4	18,340	3,582	904.7	1.00
17586	Pan American	British American	5	1,422	463	14,510	4,746	10.3	0.78
17587	Pan American	Gulf	3	1,202	464	3,813	1,471	3.2	0.90
17594	Union and Ohio	Pan American	2	237	46	24,398	4,769	102.9	0.42
17595	Pan American	Richfield, Shell, and Socal	5	4,730	926	42,507	8,325	9.0	0.40
17597	Superior	Union and Ohio	4	721	141	22,292	4,354	30.9	0.20
	Lease sale No. 7—other		2.3	18,355	153	0	0	0	0.31
	Lease sale No. 7—total		2.5	26,687	183	125,920	864	4.7	0.36
18729	Union and Ohio	Lloyd Powers	2	142	46	221,812	71,906	1,566.6	0.91
18730	Union and Ohio	Atlantic	5	96	25	315,264	82,140	3,297.5	0.43
18731	Union and Ohio	Atlantic	5	4,062	1,058	117,888	30,733	29.1	0.70
18742	Pan American	Socony Mobil, British American	3	971	192	74,888	14,788	77.1	0.12
18746	Pan American	None	1	62	20	43,296	13,527	694.4	1.00
18754	Richfield, Shell, and Socal	Pan American	5	5,566	1,486	75,242	20,086	13.5	0.07
18756	Richfield, Shell, and Socal	Pan American	4	953	186	110,387	21,558	115.8	0.00
18761	Union and Socony Mobil	Richfield, Shell, and Socal	4	1,122	220	84,019	16,508	74.9	0.77
18772	Atlantic	Pan American	4	110	29	48,768	12,704	445.1	0.21
18776	Atlantic	Union and Ohio	5	244	190	12,753	9,963	52.4	0.89
18777	Atlantic	Union and Ohio	4	90	48	75,909	39,908	839.7	0.36
	Lease sale No. 9—other		2.6	15,413	69	0	0	0	0.32
	Lease sale No. 9—total		2.8	28,830	109	1,180,226	4,464	41.0	0.30

Note: Column 7 presents an estimate of the discounted value of oil production at the time of the lease sale expressed in 1975 dollars. This estimate was derived as follows. The quantity of oil produced from the tract each year to 1975 was valued at the average wellhead price for that year and converted to 1975 dollars using the wholesale price index. Production in 1976 and later years was estimated from 1975 production and decline rates derived for each tract by John Miller of the Division of Oil and Gas. For 1976 and later years, real prices were forecast to rise at 5 percent per year. The estimated historic and projected future values of oil production were discounted back to the lease sale year using a 10 percent discount rate and then aggregated.

the oil to bonus paid on a tract would be positive and reasonably constant. Column 9 of Table 3 illustrates that this ratio varies from 0 on the numerous unproductive tracts to 3,298 in the case of ADL tract #18730 leased in Sale 9. Seismic exploration obviously produces very imperfect information. No one questions that there is uncertainty. The point of these two paragraphs is to show how tremendously large the uncertainty really is.

As suggested in the previous paragraph, one would expect there to be a strong positive correlation between the discounted value of the oil and the bonus bid offered under conditions of certainty or perfect information. Using the respective values for these variables from Lease Sales 7 and 9, shown in Table 3, the sample correlation between the discounted value of the oil and the bonus bid is slightly negative, -0.065. Other researchers have shown a strong correlation between the number of bidders and the bonus bid. For Lease Sales 7 and 9, the simple correlation between these two variables is indeed large and positive, 0.563.

Given both the low level of competition and the uncertainty, bidding games are played. There are numerous examples of an individual or company establishing a simple bidding pattern, for example, $1.00 per acre or perhaps $2,500 per tract, and another individual or company learning this pattern from previous sales and bidding $1.01 per acre or $2,501 per tract and winning the lease. Close bids hardly indicate competition when the numbers used are so obviously unrelated to an expected quantity of oil in place. On one tract, ADL #18729, Union 76 bid $76,760 and won. Table 3, column 7, indicates that the estimated discounted value of the oil on this tract in 1975 dollars, at the time of the lease sale, was $222 million.

A model was hypothesized to describe the relationship between bonus bid (B) and two "explanatory" variables, the discounted value of the oil (DVO) and number of bidders (N) as follows:

$$B = \alpha DVO^{\beta_1} N^{\beta_2}.$$

The value of α was expected to be a small fraction. The value of β_1 was expected to be between 0.5 and 0.8. β_2 was expected to be positive, but it was unclear whether to expect it to be greater or less than one. Lease Sales 7 and 9 data were fitted to this relationship by linear regression analysis after taking the logarithms of both sides of the equation. The estimated relationship is:

$$B = 0.043\ DVO^{0.58}\ N^{1.96}.$$

The R^2 (multiple correlation coefficient) is 0.72 and β_1 and β_2 are significantly different from zero at the 95 percent, or better, confidence level. The statistical significance of α is much less certain which further emphasizes the underlying high uncertainty in seismic exploration information.

The estimated relationship indicates that, even when account is taken of the value of the oil discovered after the fact, the bonus bid is highly sensitive to the number of bidders. The analysis indicates, for example, that, when the number of bidders increases from three to four, the bonus bid increases by approximately 16/9 or by an additional 78 percent. This undoubtedly overstates the sensitivity of the bid to the number of bidders since the actual oil produced is used in the estimation of the relationship rather than the industry's prior expectation of oil at the time bids must be formulated.

The parameter α is understandably small since the firm must reduce its bid from the value it would be if oil was there (as was the case for the productive

tracts used to estimate the relationship) by the probability that oil, in fact, will be found. It is curious, however, that β_1 is considerably less than rather than equal to one. This suggests that potential large fields are discounted more than potential smaller fields. Perhaps, risk aversity and/or capital constraints prevent firms from bidding the price of the few potentially highly valuable tracts up to their full market value. This possible relationship is consistent with the author's research on federal OCS leases where it appears that those companies which place a few large bids on the most likely tracts generally earn higher returns than those companies which place more but smaller bids on less likely tracts.

In summary, the data illustrate the tremendous variations between bonuses bid and subsequent petroleum production. The simple correlation coefficient between these two variables even turned out to be negative. There is also substantial variation between the winning and next highest bid, variation closer to randomness than to order. These phenomena are undoubtedly due to a combination of high uncertainty, risk-averse behavior, capital constraints, and bidding games. Regardless of which of these explanations or combinations of explanations is most important, the bonus bid appears to be an ineffective method, or at least highly erratic method for the state to collect petroleum rents. This will be considered in further detail in Part B.

B. Bonus Bids and Rent Collected by the State

It is now well known to Alaskans that approximately 90 percent of the Prudhoe Bay field was acquired by ARCO and British Petroleum in mid-1960's sales which, along with considerable other Arctic Slope acreage, brought $10,500,000 in bonus bids. After oil was discovered, the small amount of remaining Prudhoe Bay acreage brought $900 million in bonus bids. Clearly, had the state known

about the Prudhoe Bay field in advance, between $5 billion and $10 billion more would have been collected in bonus bids. Several years after the sale, petroleum prices tripled. Presuming that industry had not predicted this increase at the time of the sale, then the state probably "lost out" on perhaps an additional $15 billion to $30 billion. Prudhoe Bay is clearly a "tough luck" story for the state, and industry is quick to point out that at other times and places they have bid large bonuses and lost. Offshore Cook Inlet is undoubtedly more representative than Prudhoe Bay due to the larger number of sales and smaller size of fields discovered.

The discounted value of oil produced and estimated to be produced from Lease Sales 7 and 9 is $1.3 billion (Table 3, column 7). Ideally, we would like to determine what portions of this value have gone to cover production costs, what portion has been collected in royalties and similar per barrel taxes, and what portions of the remaining amount were paid in lease bonuses and retained by the industry. The following discussion will be complicated by (1) imprecise measures of the value of future natural gas production; (2) imprecise estimates of production costs; (3) uncertain shares of rent collected or to be collected by royalties, severance taxes, and other taxes; (4) the value of oil and gas in fields which are under lease but have not yet produced; and (5) the number of lease sales to be included in the analysis. The effect of alternative assumptions for items 1 through 5 could be incorporated in a computer-modeled sensitivity analysis. For the purposes of this report, assumptions will be made which are biased in favor of the effectiveness of the bonus bid as an instrument for collecting rent. If the bonus bid appears to be ineffective under these favorable assumptions, then we can be reasonably confident that it, in fact, has been ineffective.

Natural gas sales from Cook Inlet fields are now approximately 11 percent of the value of oil sales. This percentage, however, has been increasing historically and is expected to continue to increase significantly in the future. Nevertheless, the discounted value of oil will only be increased by 13 percent to $1.5 billion to account for gas sales. Production costs (exclusive of interest charges since petroleum flows have been discounted to the present) in 1975 dollars are assumed to be $1.25 per barrel, which may be somewhat low, or $2.50 per barrel which is definitely high. The average wellhead price of crude oil in 1975 dollars reached a high in 1965 of $5.66 a barrel, declined to $4.26 in 1973, rose dramatically to $5.38 in 1974, and is likely to increase gradually in the future. Nevertheless, for this analysis, we assume a constant price of $5.00 per barrel. The state collects a 12.5 percent royalty, a severance tax of 3 percent to 8 percent depending on the rate of production, and has occasionally levied other smaller production taxes as well as occasionally granted discovery credits. For the purposes of this analysis, we assume these payments average 20 percent of the value of petroleum produced which is undoubtedly somewhat higher than actually the case. Lastly, we assume that all the oil and gas fields that will ever be produced up to Lease Sale 16 are now producing, and we assume that these 11 sales constitute a meaningfully large sample.

Given the above assumptions, production costs plus royalties and related payments come to 0.45 to 0.70 of the discounted value of the petroleum. The 0.30 to 0.55 remaining share has a discounted value of $450 million to $825 million. What proportion of this amount was collected in lease bonus payments? The value of the lease bonus payments discounted to 1961, roughly the year of the sales for the tracts in which oil was discovered, equals $74 million. Thus, assuming the high production cost estimate, bonus bids transferred 16 percent

of the remaining rent, after royalties, etc., to the state. With the low production cost estimate, this percentage diminishes to 9 percent. Even given the favorable assumptions, the effectiveness of the bonus bid as a method for transferring rent to the state appears to be very low.

RECOMMENDATION III.B.1. The Department of Natural Resources should conduct a more sophisticated analysis along the above lines, with attention given to the sensitivity of the conclusions to alternative assumptions.

One might still argue that offshore Cook Inlet is another bad-luck example for the state of Alaska but that, with a large number of sales, the state will earn a fair return over the long run. This may be true in theory. But given the tremendous variations around the mean which are possible due to the great uncertainties involved, the state should (1) consider whether it has enough petroleum lands to lease to be reasonably certain that the law of large numbers is relevant and (2) whether it has sufficient planning expertise and access to capital to cope with the variations in bonus bid flows over time.

RECOMMENDATION III.B.2. The Department of Natural Resources should employ a statistician to assess alternative confidence limits about the mean for bonus bid revenues in 2-year, 5-year, and 10-year intervals given the projected pace of acreage to be leased in the future.

IV. Conclusions

The lease bonus bid appears to have been between 5 and 20 percent effective as a means of collecting rent over and above that collected through royalties. Its historic ineffectiveness may be due to extensive risk discounting on the part of industry, low levels of competition and the use of game theory by industry in determining bids, simply bad luck, or a combination of all of these. Regardless of the reason, both the theory and evidence brought out in this report suggest the state of Alaska should seriously consider alternative leasing systems, initiating or participating in presale exploration, acquiring the expertise to establish competitive bid rejection values for each tract, or a combination of all three of these.

This portion of the overall study does not address alternative lease terms or procedures for determining lease winners. If the state retains the lease bonus bid approach, especially with current royalty levels, its effectiveness can be increased in two interrelated ways. First, the state could contract or provide incentives for limited exploratory drilling with public dissemination of information prior to lease sales. This information could reduce uncertainty substantially and thereby increase the level of competition. Second, the state could, itself, behave as a bidder by establishing competitive bid rejection criteria for each tract. Such an approach at least would increase the level of competition substantially, for example, from 2.2 to 3.2 serious bidders on likely tracts in Lease Sale 9. But more importantly, the state's bid could reduce the effectiveness of game theoretic strategies significantly, thereby having a bigger impact than merely increasing the number of bidders. Each of these approaches can be developed over time with increasing intensity or sophistication. There effectiveness and cost can be monitored and optimal levels roughly

determined. These proposals cannot be rejected on the grounds that staffing and expenditures comparable to Exxon's exploration division would be required.

Even if the lease bonus bid approach is abandoned, some changes along the above lines would probably be desirable. First, there is no known perfect set of lease terms or procedures of determining lease winners under conditions of uncertainty and limited competition. While other leasing strategies may be better, there will probably still be advantages to reducing uncertainty and increasing competition. Second, the state could better plan sales over time and predict revenue flows if it had information on areas to be leased. Again, such information might be gathered by initiating or providing incentives to industry to drill. Or it may be sufficient for the state to participate in industry-initiated seismic exploration and to employ several seismologists or contract for the analysis of seismic data.

In summary, the Department of Natural Resources should seriously consider increasing its level of expertise and role in exploration, incrementally over time but substantially during the next 5 to 10 years.

Appendix F

ROYALTIES ON PETROLEUM PRODUCTION: RECOMMENDATIONS ON FOUR POLICY CONSIDERATIONS

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Four basic policy objectives are considered in this paper with respect to determining the optimal royalty rate on State of Alaska oil and gas leases. These policy objectives are

1. Maximizing the lease bonus and the present value of the royalties received by the state.
2. Maximizing the economically feasible production of oil and gas from each lease.
3. Maintaining, and enhancing where economically feasible, employment and economic activity levels in the state and the affected local communities.
4. Increasing the number of bidders at lease sales.

The basic conclusion of this paper is that an increase in the average royalty rate probably would increase substantially the lease bonus and the present value of the royalties received by the State of Alaska. If the increase in the average royalty rate is obtained by means of a multipart royalty schedule, all four of the above policy objectives can be attained simultaneously. Increasing the flat rate royalty above the customary one-sixth of gross revenues will attain policy objectives one and four; however, it would almost certainly fail to attain policy objectives two and three.

As is indicated at a number of points throughout this paper, additional research should be performed to firm up these conclusions. The simulation model which was used to estimate the impact of higher royalty rates or multipart royalty schedules on the State revenues and on the total amount of oil and gas produced from the lease needs to be supplied with data more typical of Alaskan operating conditions (it was based on Gulf of Mexico offshore operations). The model also should be modified to permit consideration of the impact of higher royalty rates on (1) the appropriate interest

rates for computing the present values of the lessee and the State's cash flow streams and (2) the level of the lessee's investments in exploring, developing and producing the lease.

This paper is divided into three sections. In the first section, the basic economic functions of royalties are discussed relative to the policy objective of maximizing the State's lease bonus revenues and the present value of its royalty receipts. The second section is concerned with the two principal economic critiques of higher royalty rates, again primarily in the context of the first policy objective. The other three policy objectives are treated in the third section of the paper and its principal conclusions with respect to all four policy objectives are discussed.

CHAPTER 1

ECONOMIC FUNCTIONS OF ROYALTY PAYMENTS

Determination of the optimal terms under which to lease a parcel of land for mineral extraction involves consideration of the relationship between changes in the royalty rate and the change in the landowner's wealth from leasing the land. In this regard, royalty payments serve two primary functions. One function is to transfer all or a portion of the economic rents inherent in the property from the firm extracting the minerals to the landowner. The second function of royalties is to permit the landowner to bear some portion of the risks inherent in the process of finding, developing and extracting minerals from the property.

Where the landowner is a government agency, other public policy considerations may enter into determination of the optimal royalty rate. These policy considerations include (1) maximizing the reserves[1] of the mineral, (2) maintaining or enhancing employment levels and economic progress within the community, and (3) increasing the number of bidders for the lease. The relationship between these policy considerations and the level of the royalty rate are discussed in chapter three.

The definition of wealth used throughout this paper is that used by the industry in assessing whether it is profitable to make a specified investment or to take some other action. That is, the contribution to the landowner's wealth resulting from leasing a tract of land is the present value of the cash flows paid by the lessee. For government owned lands, these cash flows primarily are the lease bonus, the royalty and/or land rental, severance and/or property taxes, and the income taxes paid by the lessee. Secondary governmental

cash flows generated by the increased investment, employment and economic activity levels resulting from the exploration, development and production activities of the lessee may also be included in the economic evaluation of the optimal royalty rate for a given lease or set of leases. When these secondary governmental revenues are considered, it is also appropriate to consider (1) the additional public services expenditures to be incurred by the government as a result of the decision to lease the land and (2) the environmental impacts and externalities generated by the exploration, development and production of the lease. Although these secondary effects can be very important--especially where small, basically rural, communities are involved--the study upon which this paper is based did not include consideration of secondary economic impacts generated by the decision to lease government lands. A full economic and environmental impact assessment would include an evaluation of these secondary effects.

There are three principal dimensions calculating the present value (PV) of the alternative leasing policies: the level of the cash flow, its timing, and the interest rate. The general formula is

$$PV = \sum_{t=0}^{n} \frac{F_t}{(1+i)^t}$$

Where F_t is the level of the cash flow received at time t, "i" is the appropriate rate of interest, and "n" is the time when the lease is to be terminated. Royalty rate policies can affect the level of the landowner's cash flow, the appropriate rate of interest, and--in some cases--the timing of the cash flows. The first two factors are discussed in the remainder of this chapter. The third factor is treated briefly in chapter two.

The cash flows from a given tract of land depend upon several economic and technological factors, in addition to the lease bonus and royalty rate

policies adopted by the landowner. They include:

1. The delivered price of oil from other sources in the market or markets to which the oil from the lease would be shipped.
2. The cost of transporting the oil from the lease to the markets in which it is to be sold.[2]
3. The costs of exploring, developing, and operating the lease. These costs depend upon the physical nature of the reservoir (including such factors as its depth; the gravity, sulfur content, and other properties of the oil; its permeability, porosity, energy source, etc.), the nature of the climate, terrain, and ecological conditions where the lease is located, and the technologies available to the industry, the costs of labor and materials delivered to the lease, and the general administrative costs allocated to operating the lease.
4. The income, severance, property, franchise and other taxes imposed on the lessee.
5. The costs of the debt and equity capital invested in evaluating and acquiring the lease, and in exploring, developing and producing the lease.

Increases in taxes, the cost of capital or the costs of funding, developing, producing, or transporting the oil reduce the lessee's cash flow and, thus, the economic rents inherent in the tract to be leased. Reductions in the delivered prices of competing oils similarly reduce the economic rents. All of these factors must be taken into consideration by the landowner in determining the wealth maximizing lease terms for specific tracts of land. These factors, and possibly other factors as well, are analyzed by petroleum engineers in their economic evaluations of leases. For the purposes of this paper, these factors are taken as givens and varied parametrically in the evaluation of the relationship between changes in lease terms and the landowner's wealth.

1.1 Royalties As a Means of Transferring the Economic Rents Inherent in the Lease to the Landowner

The economic rent inherent in a tract of land is the increase in the lessee's wealth in excess of that increase which is just sufficient to get the lessee to explore, develop and produce the minerals in the land. As applied to the leasing of mineral lands, the term "ex. ante. economic rents" applies to the situation at the time the lease contract is awarded. That is, a wealth-maximizing landowner would want to lease the lands under the set of terms that reduces the present value of the lease, from the lessee's point of view, to as near to zero as is feasible.[3] So long as the expected present value of the lease is positive, the potential lessee will be willing to invest in acquiring the lease and its development.

The term "ex. post. economic rents" is applied to the actual results of exploring, developing and producing the lease after the lease contract is signed. In general, unless there are specific provisions for renegotiating the lease terms, the private landowner cannot capture all or part of any increase in the ex. post. economic rents over the ex. ante. rents, nor can the lessee obtain a return of a portion of the contractual bonus and royalty payments if the ex. ante. economic rents exceed the ex. post. rents. Governmental landowners may, however, obtain all or a portion of any difference between the ex. ante. and the ex. post. economic rents by changing general tax rates or imposing new taxes.

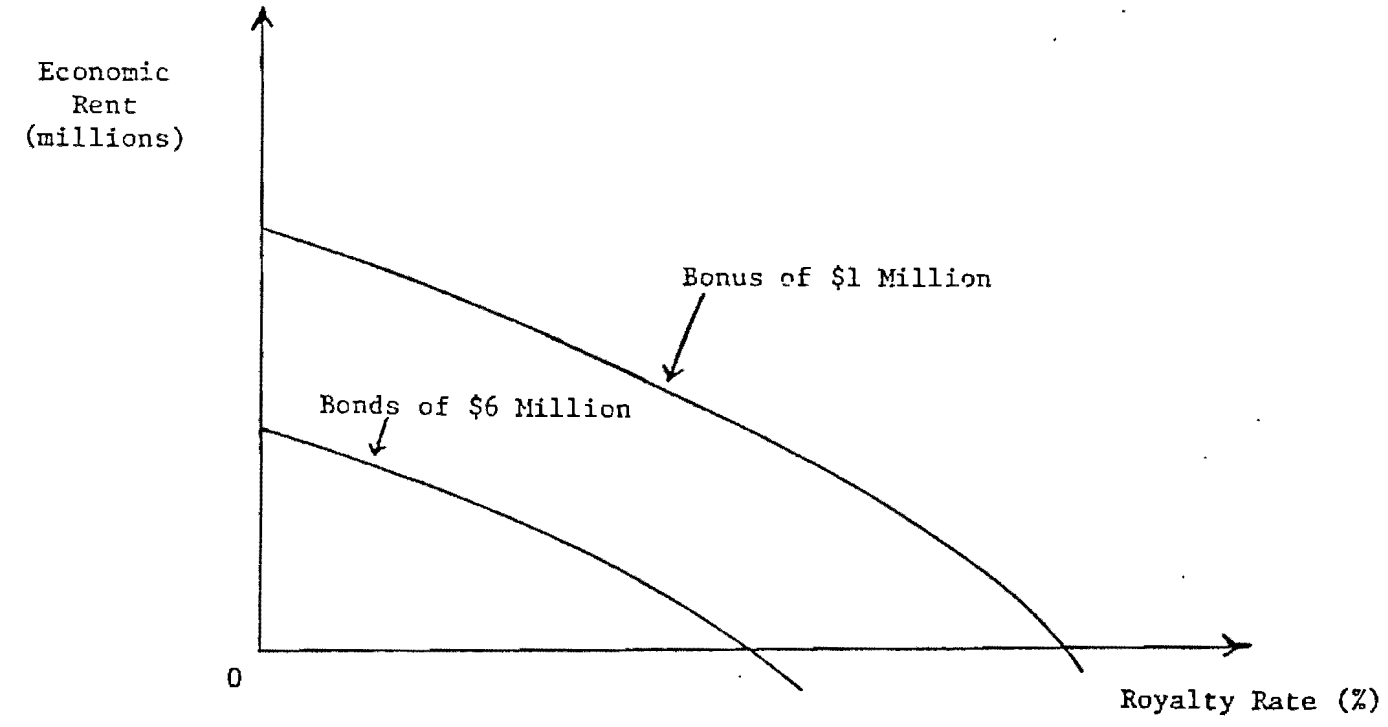
For those mineral properties which are expected to be sufficiently productive to give rise to potential economic rents for the lessee, the private landowner generally has two methods for transferring the expected rents to himself. In addition to these two methods, governmental landowners can obtain a portion of the economic rents inherent in the lease through

various taxes. One method is to require the lessee to pay as a royalty a percentage of the gross revenues from the sale of minerals produced from the tract of land.[4] The second method is to require the lessee to pay a bonus to the landowner at the time the lease is signed. In general both methods are used for reasons discussed in section 1.2. In principle, by setting either the royalty rate or the lease bonus at a sufficiently high level, the ex. ante. economic rents inherent in the tract of land can be transferred from the lessee to the landowner.

An increase in the royalty rate will reduce the economic rent inherent in the tract, as will an increase in the lease bonus. Moreover, for any specified level of the lease bonus less than the level of economic rent inherent in the tract, there exists a royalty rate that will reduce the economic rent from the lessee's point of view to zero. This relationship is illustrated in Figure 1 for two hypothetical lease bonus amounts,

Figure 1

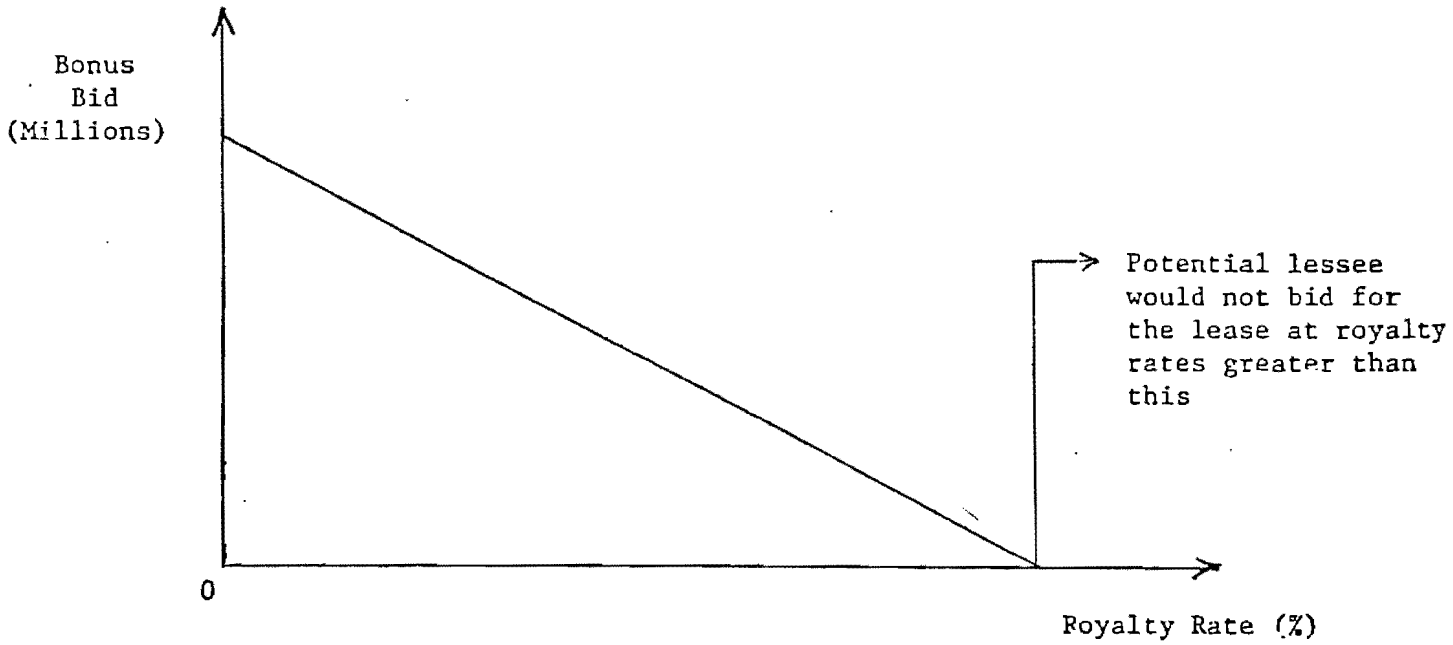
Relationship Between the Royalty Rate, the Lease Bonus and the Level of Economic Rent



When competitive bonus bidding is used to select the firm to receive the lease, the landowner generally expects the competitive bidding process to reduce to zero the ex. ante. economic rents inherent in the tract from the lessee's point of view.[5] Since the royalty rate (usually one-sixth of gross revenues) is specified in the lease terms, the level of economic rents inherent in the tract of land from the point of view of the lessee, and thus the maximum lease bonus the lessee would be willing to pay, depends upon the level of the royalty rate. If the rate of interest for computing the present value of the lessee's cash flow is held constant (a simplifying assumption--see section 1.2), an increase in the royalty rate will result in a reduction in the economic rents inherent in the tract of land and, thus, the lease bonus. This general relationship is illustrated in Figure 2.[6]

Figure 2

Relationship Between Bonus Bid and Royalty Rate



From the private landowner's point of view, the total economic rent which he obtains is the sum of the lease bonus and the present value of the royalty

payments. Although competitive bonus bidding with the customary one-sixth royalty rate can, in principle at least, result in transferring most or all of the economic rents inherent in the tract from the lessee to the landowner, does the customary one-sixth royalty maximize the total economic rent to be obtained from the lease. In general, the answer to this question is "No!". If the interest rates for calculating the present value of the lessee's after-tax cash flow and the landowner's royalty payments are held constant with changes in the royalty rate, increasing the royalty rate up to at least four- or five-sixths increases the present value of the landowner's royalty receipts by substantially more than it decreases the maximum lease bonus that the landowner would be willing to pay. Table 1 presents the results of calculations of the maximum lease bonus and the present value of royalty receipts for a simulated exploratory lease. The general relationship between the present value of total landowner receipts and the royalty rate is graphed in Figure 3.

In general, increasing the royalty rate increases the present value of the landowner's total receipts from lease bonus and royalty payments for royalty rates up to five-sixths of total revenues. The increases in total receipts are at a decreasing rate as the royalty rate increases. In the example in Table 1, at a royalty rate only slightly greater than five-sixths, the maximum bonus bid would become negative--which means that the potential lessee would not bid on the lease because it would be unprofitable to do so. Thus, based on this one example, increasing the royalty rate to five-sixths and awarding the lease to the firm making the highest bonus bid would result in a greater ex. ante. economic rent to be captured by the landowner than the customary one-sixth royalty rate and competitive bonus bidding.

The author has made many similar simulation studies and found the same general conclusion--that increasing the royalty rate to three-sixths or more

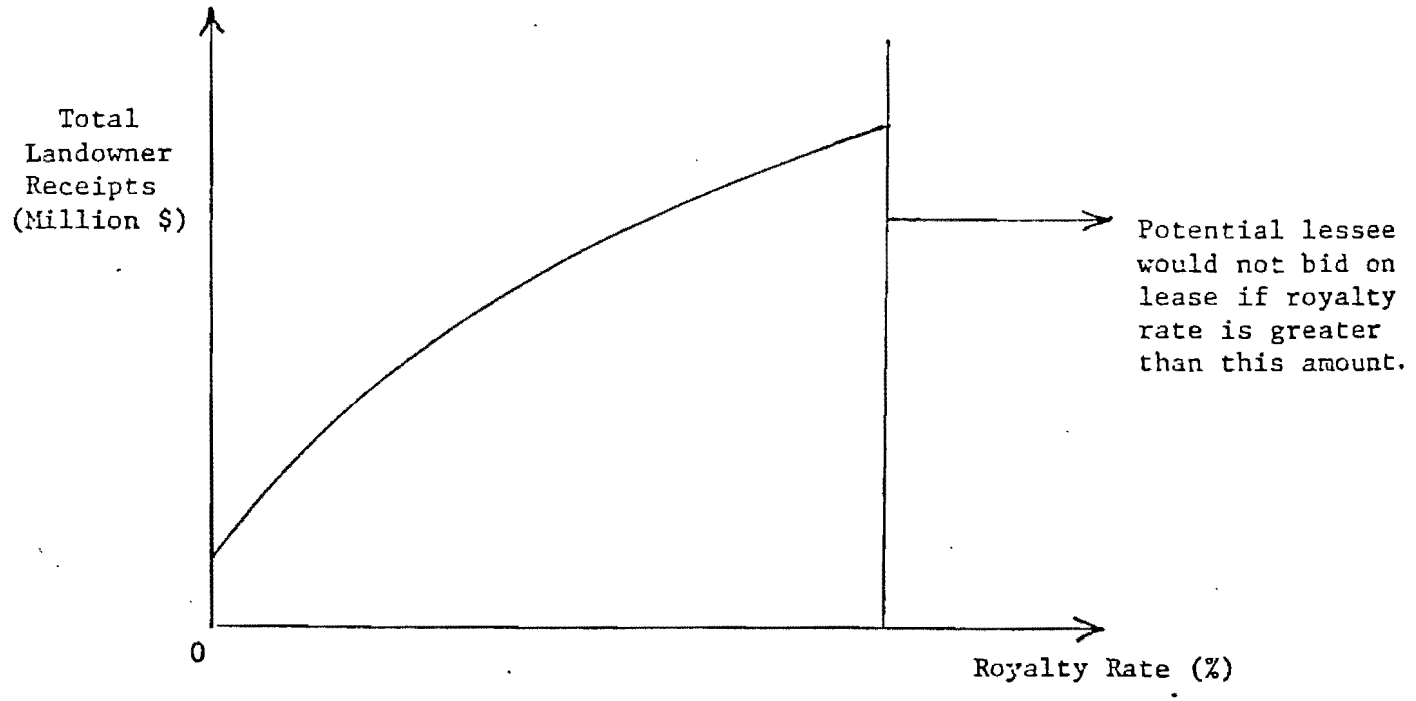
Table 1

Example of Relationship Between the Royalty Rate and Landowner Receipts
(Millions)

Royalty Rate	Maximum Bonus Bid	Present Value of Royalties	Landowner Receipts	
			Total	Change
0	$17.5	$ 0.0	$17.5	Base
1/6	14.0	19.9	33.9	$+16.4
2/6	10.5	39.5	50.0	+16.1
3/6	7.0	59.0	66.0	+16.0
4/6	3.6	77.2	80.8	+14.8
5/6	0.2	88.9	91.0	+10.2

Figure 3

Relationship Between Royalty Rate and Landowner Receipts



increases the present value of the landowner's receipts from the lease. These studies included cases where the well-head price of the oil was $7 per barrel and finding, developing and producing costs were double the estimated 1976 costs for offshore Gulf of Mexico leases. Runs were not made using estimates of Alaskan North Slope well productivities, well-head prices, and costs.

This general conclusion, however, is subject to two major reservations. The first is that as the royalty rate increases, and the lease bonus paid by the lessee decreases, the landowner is assuming a greater proportion of the risk that the lease may be unproductive or less productive than was assumed by the lessee at the time he bid for the lease. Similarly, the lessee is bearing a smaller proportion of these risks. Since the interest rate for calculating the present values depends upon the proportion of the risks inherent in exploration and development of the lease assumed by the party receiving the cash flow stream, the interest rate for the lessee should fall with a rising interest rate and the interest rate for the landowner should rise. This reservation is discussed in the section 1.2 of this paper.

The second reservation has to do with the impact of the higher royalty rate on the percentage of the total mineral resources that will be recovered by the lessee--that is on the oil reserves created by exploration and development of the lease. Although the present value of the total receipts of the landowner can be maximized by increasing the royalty rate, the reserves created by the lease will decline. This decline in reserves is a direct result of adopting a higher royalty rate to transfer economic rents to the landowner. This reservation with respect to increasing the royalty rate over the customary one-sixth rate, and the use of multipart royalty schedules to mitigate this effect, are discussed in sections 2.2 and 3.1.

If the landowner is a governmental entity, such as the federal government or a state, the optimal royalty rate policy must consider the impact of changes

in the royalty rate on its tax revenues, and the tax revenues of its political subdivisions where severance taxes or property taxes on oil reserves are important sources of revenues.[7] In the case of the federal government, its relatively high coprorate income tax rate makes its income tax receipts sensitive to the royalty rate since royalties are deductible as a normal business expense. An example of this relationship, which is based on the same simulation study as was used to generate Table 1, is in Table 2.

For all royalty rates up to five-sixths of gross revenues, the increase in the federal government's royalties exceeded the decrease in the federal government's income tax revenues. Thus, based on this sample simulation study, there is a net increase in the present value of the federal government's revenues from the lease if the royalty rate is increased. Since state income tax rates are substantially lower than federal income tax rates, the reduction in state income tax revenues resulting from an increase in the royalty rate would be substantially less than the amounts indicated in Table 2.

The impact of changes in the royalty rate on the severance tax revenues of the political subdivisions of the state results from the reduction in reserves that accompanies increases in the royalty rate (see section 2.1). Since this reduction occurs in the final years of the well's life and since it can be eliminated entirely by adopting a multipart royalty schedule (see section 3.1), the impact of a higher royalty rate on the severance tax revenues of the state's political subdivisions is either minimal or easily compensated for by transfer payments to the political subdivisions financed out of the state's increased royalty receipts. Moreover, since both royalties paid to a state and severance taxes paid to a state or one of its political subdivisions are deductions for the purpose of computing the lessee's federal income tax liabilities, much of the burden of increases in royalties or state and local taxes is borne by the federal government rather than by the state or lessee.

Table 2

Example of the Relationship Between Changes in the Royalty Rate and Federal Income Tax Revenues
(Million $)

Royalty Rate	Present Value of Royalty Receipts		Present Value of Income Taxes	
	Amount	Change	Amount	Change
zero	-0-	Base	$47.0	Base
one-sixth	$19.9	$+19.9	37.1	$ -9.0
two-sixths	39.5	+19.6	27.1	-10.0
three-sixths	59.0	+19.5	17.2	-9.9
four-sixths	77.2	+18.2	7.3	-9.9
five-sixths	88.9	+11.7	-2.5*	-9.8

*Negative value indicates tax losses which can be written-off against other income earned by the lessee.

1.2 Royalties As a Means of Sharing the Risks Inherent in Exploring, Developing, and Producing the Property

Mineral exploration in general and petroleum exploration in particular are subject to a relatively high level of uncertainty with respect to both the functional form and parameters of the probability distributions associated with the several geological characteristics of a tract of land and the appropriate technologies for extracting any minerals that may be present. In addition, even when the relevant probability distributions and their parameters are determined to a degree acceptable to the decision maker, the variances of the probability distributions generally are felt to be relatively greater than those faced by most investments of capital in the American economy, which is why petroleum exploration and development is generally felt to be a relatively risky business.

Because of the relatively high degree of risk associated with these investments, the landowner may find it to be wealth maximizing to bear a greater portion of the risks and uncertainties associated with the exploration and development of his lands by increasing the royalty rate. By assuming a greater portion of the inherent risks, the landowner may be able to reduce the interest rate used by potential lessees in calculating the maximum bonus bid they would be willing to pay to acquire the lease, which would increase the bonus bids. The cost of this rise in the bonus bid is an increase in the interest rate which the landowner uses to calculate the present value of his royalty receipts, which tends to reduce their present value. These general relationships between the royalty rate and the appropriate interest rate to use in calculating present values are illustrated in Figures 4 and 5.

Figure 4

General Relationship Between the Royalty Rate and the Interest Rate for Discounting the Lessee's Cash Flows

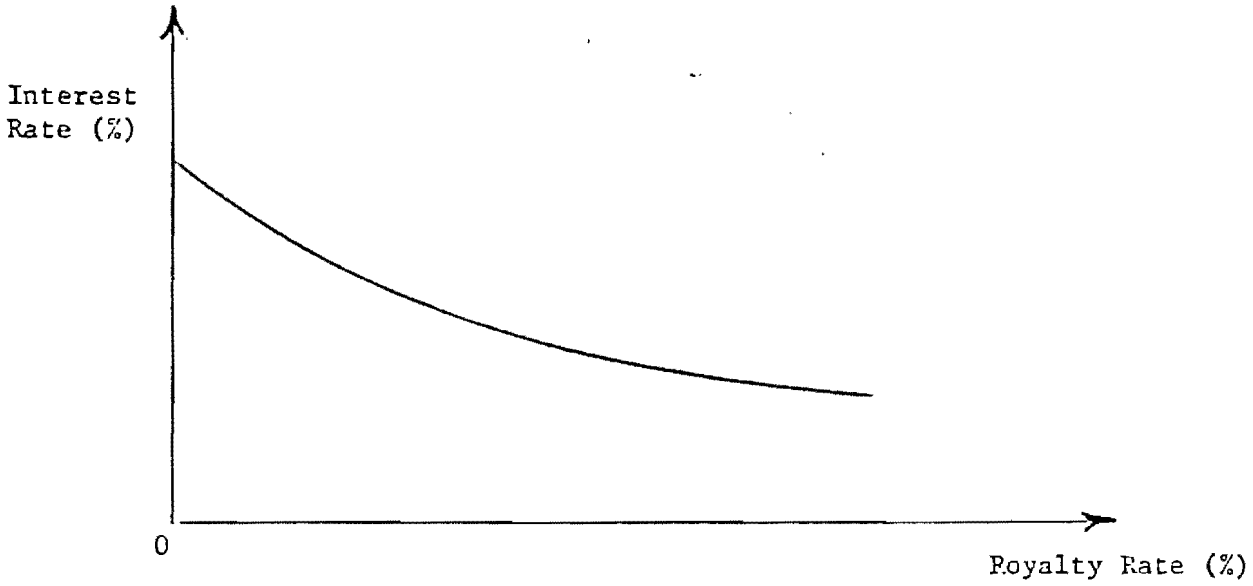
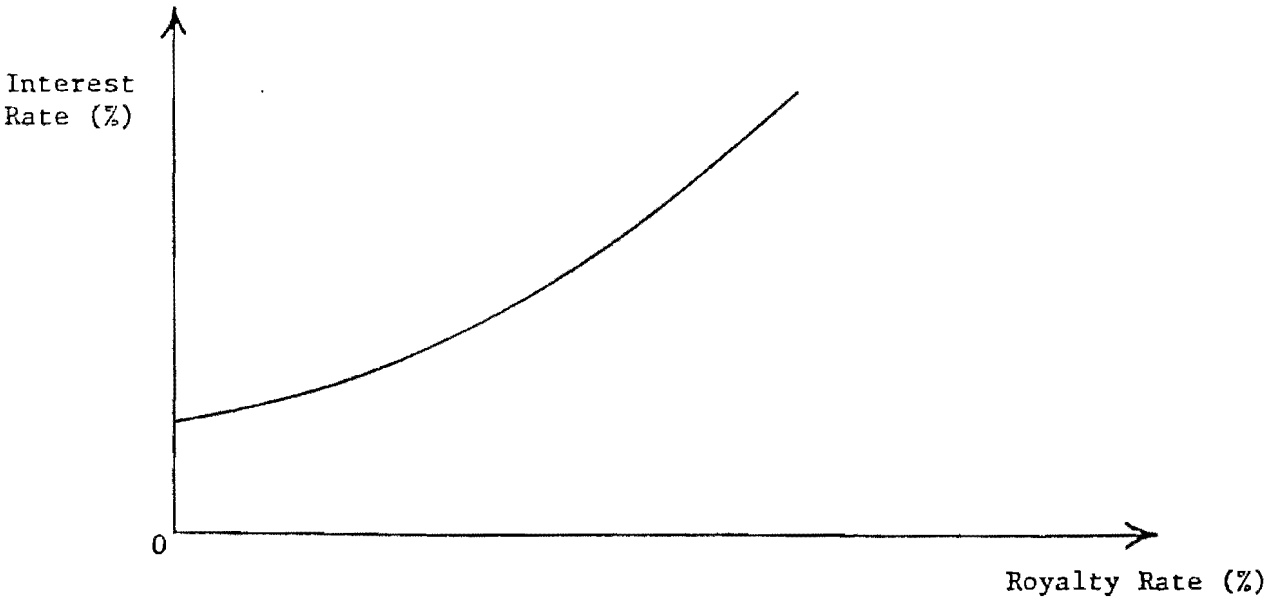


Figure 5

General Relationship Between the Royalty Rate and the Interest Rate for Discounting the Landowner's Cash Flows



The potential impact of these interest rate changes on the landowner's wealth is illustrated in Table 3, which was obtained from the simulation study used to generate Table 1. Note that both the maximum lease bonus and the present value of the landowner's royalties are relatively sensitive to the interest rate. Unfortunately, the simulation study on which Table 3 is based did not consider higher interest rates for the landowner or lower interest rates for the lessee. Had such a study been made, it is very likely that a numerical example could be constructed showing that an increase in the royalty could so change the two interest rates that the present value of the landowner's total receipts (lease bonus plus royalties) would fall.

The general relationships in Figures 4 and 5 are based on the conventional premise that investors in future income streams are risk-aversive. That is, when given a choice between two options with the same internal rate of return, the risk-aversive investor would choose the less risky option. There is both theoretical and empirical evidence that investors in oil and gas exploration and development (i.e., the oil companies) are not risk-aversive, but rather are risk-seekers. If this is the case, the interest rate which the potential lessees would use to calculate the maximum lease bonus they would be willing to pay to the landowner would fall with an increase in the portion of the risk inherent in the lease that they must bear. That is, the general relationship in Figure 4 would become that in Figure 6.

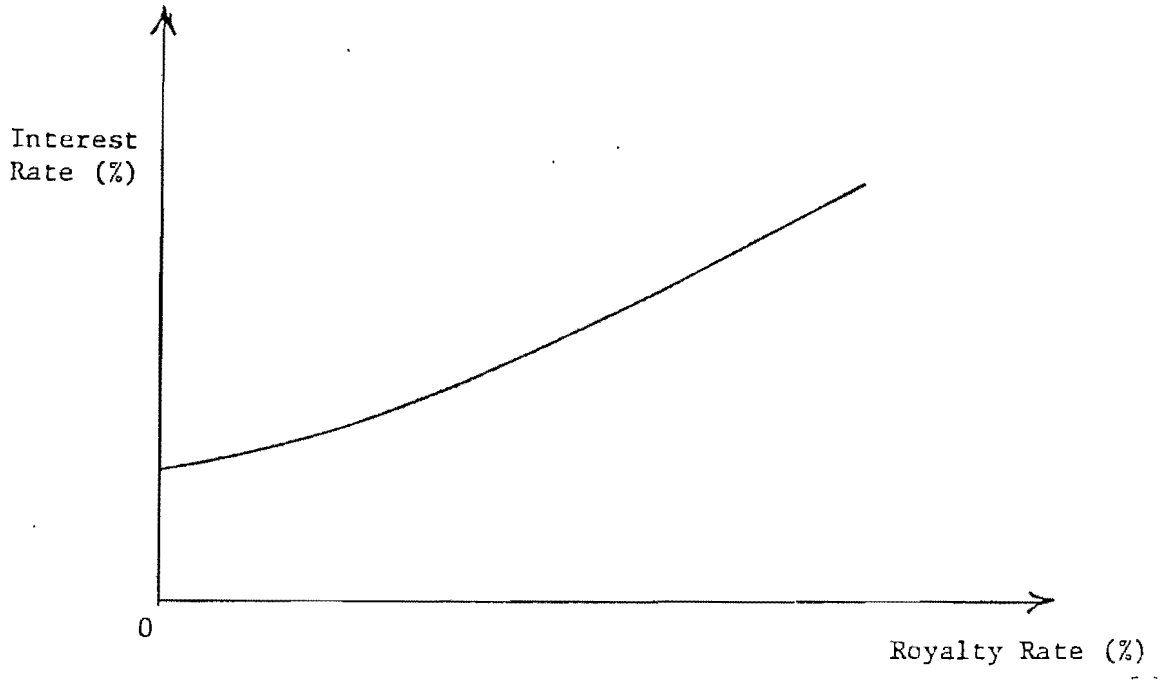
Table 3

Example of the Relationship Between Changes in the Royalty and Interest Rate and the Maximum Lease Bonus and Present Value of Royalties (Millions of $)

Royalty Rate	Lessee		Landowner	
	Interest Rate	Lease Bonus	Interest Rate	PV of Royalties
zero	20%	$17.5	6%	-0-
	25	12.7	9	-0-
	30	9.4	12	-0-
one-sixth	20%	$14.0	6%	$19.9
	25	10.1	9	15.2
	30	7.4	12	12.0
three-sixths	20%	$ 7.0	6%	$59.0
	25	4.8	9	45.5
	30	3.3	12	36.0
five-sixths	20%	$ 0.2	6	$88.9
	25	(0.3)	9	70.6
	30	(0.6)	12	56.9

Figure 6

General Relationship Between the Royalty Rate and the Interest Rate for Discounting a Risk-Seeking Lessee's Cash Flow



If the relationship between the lessee's interest rate and the royalty rate is that implied by Figure 6, rather than by Figure 4, the wealth maximizing leasing policy for the landowner probably would be to set a relatively low royalty rate.

There is still another school-of-thought that argues where the government is the landowner, the appropriate interest rate should be the default-risk-free rate of interest on long-term U.S. government bonds. (This interest rate is not entirely risk-free since the owner of long-term U.S. government bonds must bear the risks of unanticipated changes in the rate of inflation.) Furthermore, this school-of-thought argues that the government should be risk-neutral in its decisions, which implies that the same interest rate would be used to calculate the present value of royalties regardless of the level of the royalty rate. Thus, the potential lessee's interest rate would fall with increases in the royalty rate. This implies that the governmental landowner

would almost certainly benefit from increases in the royalty rate.

In the author's opinion, the relationship between royalty rates and the interest rates appropriate for computing the present values of both the lessee's and the landowner's cash flows requires further research before optimal royalty rate policies can be determined. This research would involve two separate issues:

1. A study of the relationship between the level of the royalty rate and the proportion of the risk inherent in the tract of land borne by the lessee and the landowner.
2. A study of the relationship between the portion of the inherent risk borne by each party and the appropriate interest rates for computing the present value of their cash flows.

Based on his search of the available literature, the author does not know of any studies which specifically address either of these issues in the context of determining the optimal royalty rate for a specific tract of land. In the absence of such studies, it is the author's opinion that increases in the royalty rate beyond three-sixths (50%) of gross revenue from the lease should be approached with considerable caution. However, based on the author's simulation studies, it appears likely that increasing the royalty rate to three-sixths would substantially increase the landowner's wealth under present market conditions. A significant reduction in the new-oil[8] price below current levels would likely imply a lower royalty rate than three-sixths.

CHAPTER 2

ECONOMIC CRITIQUES OF ROYALTY PAYMENTS

Although increases in the royalty rate applied to the gross revenues of an oil lease above the customary one-sixth royalty are likely to increase the total lease bonus and royalty receipts of the landowner, net of reductions in income tax revenues in the case of governmental landowners, there are two major economic critiques of the use of higher royalty rates to transfer economic rents from the lessee to the landowner. One of these critiques is that an increase in royalty rates will result in a reduction in the total production of petroleum from the lease relative to the rate of production that would result if some other means of transferring economic rents were used. This critique is discussed in section 2.1. The second critique, which is the more serious one, is that higher royalty rates will result in a reduction in the intensity of the lessee's exploration and development efforts and in his incentives to engage in pressure maintenance and secondary recovery projects. This critique is discussed in section 2.2 of this paper.

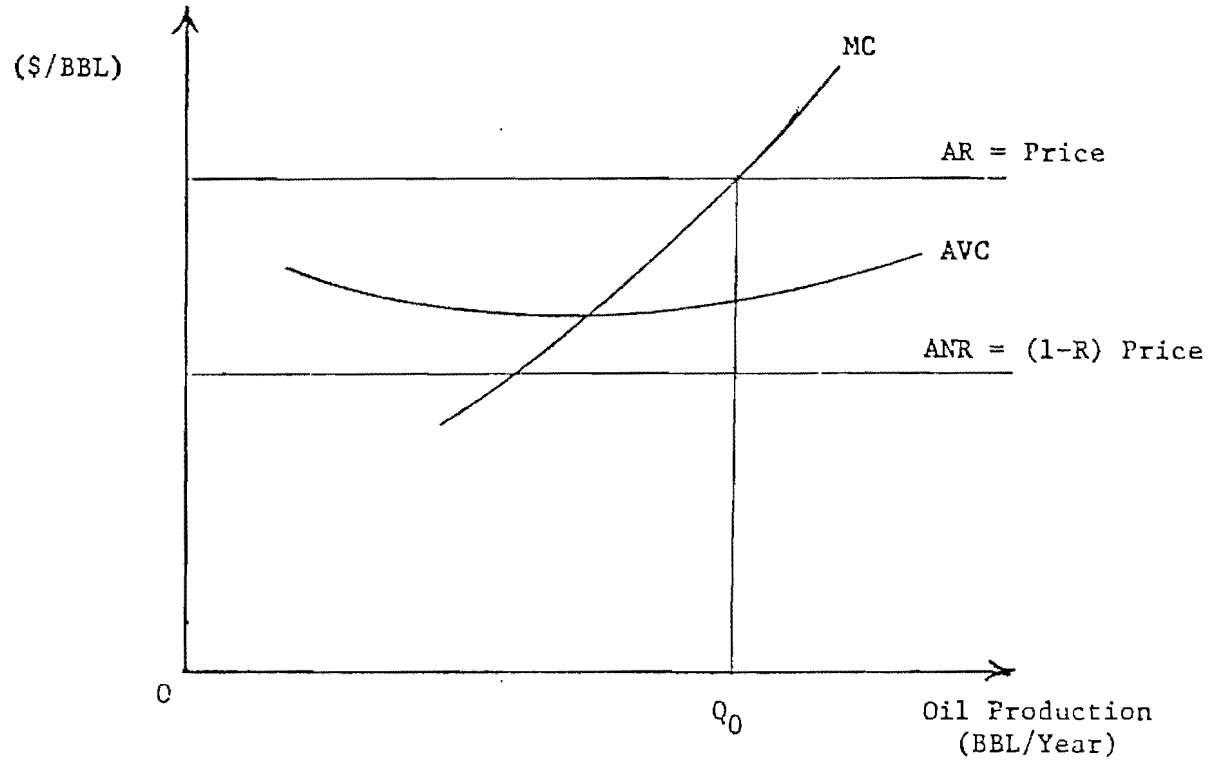
2.1 Loss in Reserves Due to a Higher Royalty Rate

The traditional argument against royalties based on gross revenues as a means of transferring economic rents from the lessee to the landowner is based on the observation that positive royalty rates will result in earlier abandonment of the well or field than would be the case if the royalty rate were zero. According to the traditional argument, since the lessee views the royalty payment as a production cost, the lessee will abandon the well or field when his average variable cost of production exceeds his average revenue net of the royalty, In Figure 7, the lessee would continue producing oil from the lease if the royalty rate were zero; however, given the royalty rate, R, his average net revenue (ANR) would be less than his average variable costs of production (AVC) for all rates of oil production. Hence, the lessee would abandon the lease and all the oil that would have been produced if the royalty rate were zero would be lost to society since it generally only pays to reopen an abandoned well when there is an exceptionally large unexpected increase in the price of oil.[9] A corollary to this argument is that the higher the royalty rate, the sooner the well or field will be abandoned and the greater the unnecessary loss in oil reserves. Given the national objectives with respect to increasing the nation's energy selfsufficiency and the impact of oil field abandonments on the economies of states and, especially, localities, this critique can assume considerable importance in governmental leasing policy decisions.

Figure 8 provides another way to look at the resource misallocations resulting from the use of a royalty to transfer a portion of the economic rents from the lessee to the landowner. The royalty payment does not bring

Figure 7

Oil Production Costs and Revenues



forth any additional production of petroleum for the economy. Since capital, labor and natural resources have already been allocated to developing and producing the lease, petroleum should be extracted from the lease so long as its market value exceeds the current costs of producing it. If the royalty rate were zero, the well or field would be abandoned at time T_0; whereas, with royalty rate R, the revenues to the producer, PQ, would be reduced to (1-R)PQ and the well or field would be abandoned at time T_1. All of the oil that would have been produced between time T_1 and T_0 (see Figure 9) is lost to the economy because the royalty rate was set at R instead of zero. Thus, the positive royalty rate results in an increase in the amount of capital, labor and natural resources that must be allocated to producing a given amount of oil.

There are, however, significant counterarguments to this position. One counterargument with particular application to oil fields and some types of mining operations is that it is not the inexorable increase in the cost of operating an oil field, per barrel of oil produced, that generally leads to the abandonment of a well or field. In general, it is a mechanical problem with the well or the producing equipment of the field which requires a substantial new investment on the part of the operator that leads to the abandonment decision. That is, given the well or field's low productivity due to its depletion, the present value of the operator's future cash flow simply is not great enough to cover the cost of reworking the well or the new equipment for the field. In many cases, this counterargument contends, the cost of reworking the well or the new equipment is so great relative to the productivity of the well or field that even a zero royalty rate would lead to abandonment. Hence, the abandonment decision generally is independent of the royalty rate, although this counterargument is likely to lose much of its

Figure 8

Early Abandonment of a Well or Field
Induced by a Positive Royalty Rate

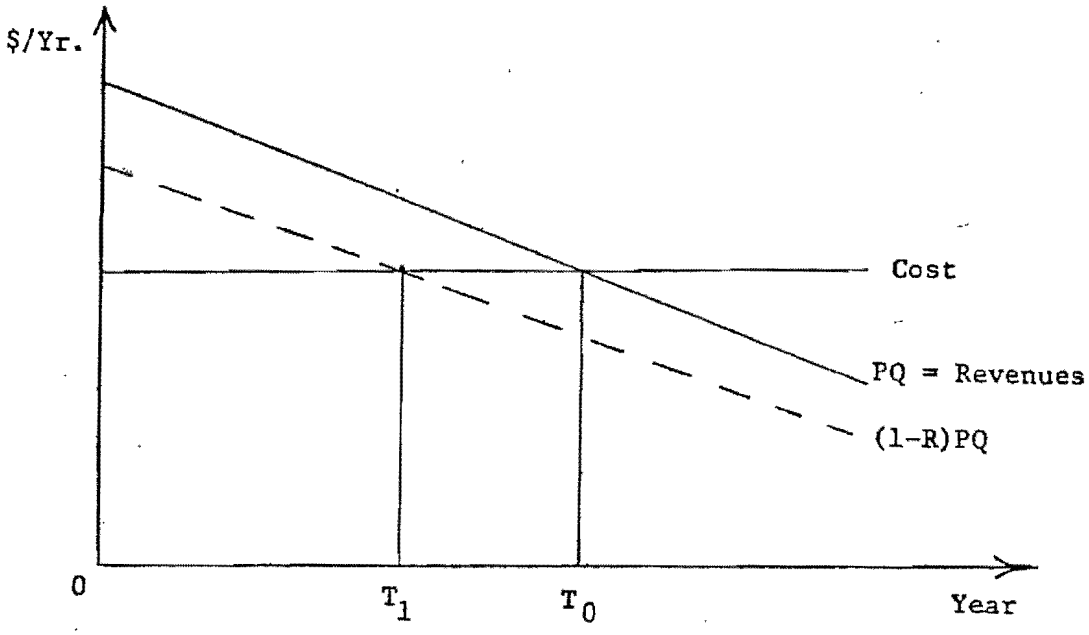
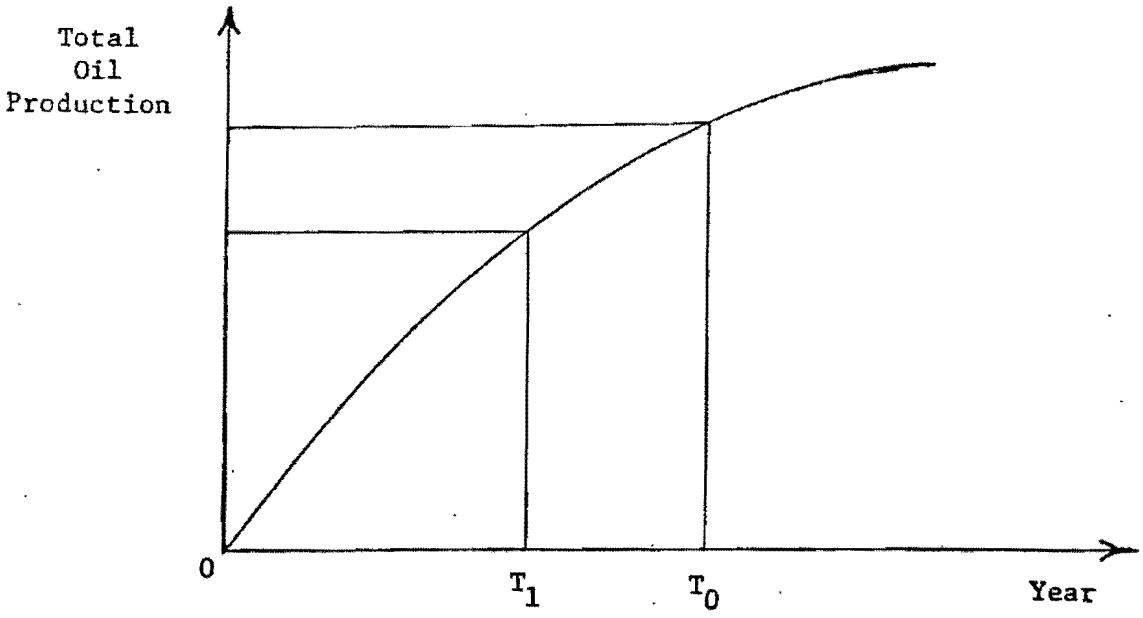


Figure 9

Total Oil Production Over the Life of
a Well or Field
(Barrels)



reasonableness when the royalty rate substantially exceeds the customary one-sixth rate.

This counterargument is based on the author's experience in the industry and on his conversations over the past fifteen years with a number of industry people responsible for the operations of oil fields, principally in California. The author is aware of no empirical studies that would either support or reject this counterargument. Such a study very likely could be performed for California using the records of the Division of Oil and Gas, although some degree of industry cooperation likely would also be required.

The second counterargument is provided by the author's simulation studies. As is indicated by the data in Table 4, which is from the same study as the previous three tables, the loss in reserves due to an increase in the royalty rate from zero or one-sixth to three-sixths is not exceptionally large. In the case of the simulated field for Table 4, increasing the royalty rate from zero to three-sixths resulted in a 3.55% reduction in reserves. Using the customary one-sixth as the base, this percentage reduction in reserves becomes 3.10%. The corresponding percentage increase from the one-sixth royalty rate in royalty receipts is 196.5%. Moreover, if the increase in the present value of royalties ($59.0 - $19.9 = $39.1 million) is divided by the reduction in reserves (0.67 million barrels), the loss in royalties per barrel of reserves exceeds $58 per barrel.[10] This means that the landowner could buy 0.67 million barrels of foreign crude oil at current market prices and store it at a cost that would be substantially lower than the per barrel royalty receipts that would be foregone if the customary one-sixth royalty was incorporated in the lease terms rather than a three-sixths royalty.

These calculations of the relationship between increases in the royalty rate and the resulting reductions in oil reserves are based on a simulated

Table 4

Example of the Reduction in Oil Reserves Due to An Increase in the Royalty Rate
(Million Barrels)

Royalty Rate	Oil Reserves	Change in Reserves*	
		Amount	Percentage
zero	21.69	Base	Base
one-sixth	21.59	(0.10)	(0.46)%
two-sixths	21.23	(0.46)	(2.12)
three-sixths	20.92	(0.77)	(3.55)
four-sixths	19.85	(1.84)	(8.48)
five-sixths	17.00	(4.69)	(21.62)

*Measured from reserves when the royalty rate is zero.

oil field that may not be typical of all oil fields in the continental United States or Alaska. However, the same basic result was obtained in virtually all of the simulation studies performed by the author. These studies covered a wide range of well and field productivities, development and operating costs and posted prices for the field. In the author's opinion, it is very unlikely that this general relationship between the increase in royalty receipts and the reduction in oil reserves will not be observed for most new fields in the United States, with the possible exceptions of marginally productive fields and of remote fields in Alaska where the posted price is substantially below current new-oil delivered prices due to high transportation costs.

In conclusion, it does not appear that the traditional economic argument against royalties has much relevance for leasing policy where the goal is maximizing the present value of the landowner's receipts. None-the-less, before royalties greater than, say, three-sixths (50%) are included in the terms of a lease to be put up for bid, a study of the potential impact of the higher royalty rate on reserves and the present value of the revenues generated by the lease would generally be appropriate where adequate data on which to base the study are available. Where the higher royalty rate may have a significant impact on the present value of the revenues generated by the lease, the mitigating measures discussed in section 3.1 should be investigated before adopting a lower royalty rate.

2.2 Impact of a Higher Royalty Rate on Investments in Exploring, Developing and Producing the Lease

The lessee of oil or mineral lands includes the royalty paid to the landowner as a cost of production in determining the amount of capital that he will commit to exploring, developing, and producing the lease. Like an increase in any other cost of production, a higher royalty rate reduces the profitability of incremental capital investments in the lease. The result is that the exploration, development and production of the lease will be less intensive than if the royalty rate were zero. The same basic point applies, of course, to income and other taxes that reduce the profitability of investing an additional dollar of capital in an enterprise.

Requiring that a bonus be paid to the landowner at the time the lease contract is signed also reduces the amount of capital that will be invested in the lease;[11] however, the lease bonus has a different effect on the investment of capital in exploring, developing and producing the lease than royalties or income taxes based on the future productivity of the lease. Although the amount of the lease bonus depends upon the royalty (and income tax) rates applicable to the future revenues from the lease, once the bonus is paid, it becomes a sunk cost that does not influence future investment decision. Future investment decisions depend upon the incremental cash flows that are generated as a result of making the new investments. Past investments are only relevant in the new investment decision process to the extent that they provide depreciation allowances that reduce future income taxes or that they provide assets which can be sold to others.

The sunk cost attribute of the lease bonus means that the lessee will invest more capital in exploring, developing and producing the lease if the

royalty rate is reduced below the wealth maximizing level as calculated in section 1.1 or even eliminated. Moreover, with a zero royalty rate, the capital invested in the lease will earn the same ex. ante. rate of return, in terms of the goods and services produced, in exporting the lease as in other sectors of the economy--where the rates of return are adjusted for differences in the inherent risks and uncertainties associated with the cash flow streams. This is, of course, the basic condition for an efficient allocation of capital when the fundamental social goal is to maximize the value of the economy's capital, labor and natural resources.

As was discussed in section 1.2, relying entirely on the lease bonus to transfer the economic rents inherent in the tract of land to the landowner increases the interest rate for computing the present value of the lessee's cash flows. Thus, the total economic rents inherent in the lease--from the landowner's point of view--may be lower at a zero royalty rate than if some combination of lease bonus and royalty payment is used. However, the greater the amount of capital invested in the lease, the greater the expected future cash flows, and hence economic rents, because:

1. More capital will be invested in exploring the lease, thus increasing the probability that the petroleum deposits beneath the lease, if there are any, will be discovered and that their full extent will be determined.
2. More capital will be invested in development wells, which will result in greater reserves being created since portions of the reservoirs that would not be profitable to drill with a positive royalty rate would be drilled and produced. A somewhat greater density of development wells will likely also be profitable, which will generally add somewhat to reserves and to the rate at which the reserves are produced.
3. More capital will generally be invested in production facilities, in part to handle the higher rate of production from the field; in part

to enhance oil recovery from the reservoirs through expanded pressure maintenance and possibly additional multiple completions; and in part from more efficient, capital intensive, technologies.

4. Secondary recovery techniques, where outside energy is provided to the reservoir to increase the percentage of the original oil in place recovered, that are marginal where the royalty rate is one-sixth or greater could become attractive investments for the lessee--thus increasing reserves and the life of the field.

The simulation studies upon which the conclusions of the previous sections were based assumed that a fixed number of wells would be drilled regardless of the royalty rate and that the level of exploration and producing expenditures is independent of the level of the royalty rate. In addition, no consideration was given to the impact of the royalty rate on the prospects for secondary recovery projects. There are two reasons why the simulation model was designed in this manner:

1. The model was developed to use readily available Bureau of Mines and Industry data on on- and offshore exploration costs.
2. The model was principally constructed to study multiple part royalty schedules, rather than the flat rate royalties which were discussed in sections 1 and 2 of this paper. It was felt that multipart royalty schedules would significantly reduce the impact of higher royalties on investments in exploring, developing and producing the lease.

Whether the impact of high royalties on investments in the lease would be significant basically is an empirical question. Where the lease is expected to be relatively productive, American oil companies have entered into contracts with foreign governments (e.g., Indonesia) under terms that closely approximate flat rate royalties in excess of 50%; hence, it is unlikely that higher royalty

rates will sharply reduce investment in those prospective areas where geological conditions are indicative of some possibility of large reservoirs or fields. Investments in prospects that are likely to yield small fields or reservoirs, or fields where well productivities are low, or fields where operating and transportation costs are likely to reduce the margin between the well-head price and costs to relatively low levels are more likely to be influenced by higher royalty rates, as are all secondary recovery projects. The computer program for the similation model can be modified to permit analysis of the available empirical data relevant to determining whether the impact of higher royalty rates on investment in exploring, developing, and producing the lease.

CHAPTER 3

POLICY CONSIDERATIONS OTHER THAN WEALTH MAXIMIZATION

The preceeding two sections have primarily been based on the assumption that the landowner's objective is to maximize the increase in his wealth from the lease. Where the landowner is a private party, rather than a government agency, this objective probably dominates all others. However, governments generally have other goals that their oil lands leasing policies may be required to reflect. Although there may well be others, for the purposes of this paper, two policy constraints on the level of royalty rates are discussed in this section:

1. Maximize the total amount of oil and gas produced from each reservoir consistent with the market price of the oil and the capital, labor and materials costs of producing it. This policy is consistent with long-standing resource conservation policies of the state and federal governments and with the basic goals of Project Independence.
2. Maintain, and enhance where possible, the employment and economic activity levels of those communities involved in the production, processing and transporting of oil and gas.

A third constraint on the level of the royalty rate, which is applicable to both private and governmental landowners, would be a policy of attempting to increase the number of bidders for leases, and thus the competitiveness of the lease sale. This constraint is briefly discussed in section 3.3.

Although these policies are treated as constraints on the level of the royalty rate, they can also be treated as independent policy goals and trade-offs between these two goals and the wealth maximization goal evaluated. This

approach, however, requires that the key policy-makers specify their views on the nature of the trade-offs that are acceptable to them and that some means of resolving differences of opinion with respect to the trade-offs be developed. Since these matters are a normal part of the political decision process, they are not considered here. Formulation of the problem in terms of constraints permits consideration of the trade-offs among the three goals should that be desired.[12]

3.1 Maximizing Oil and Gas Production from the Lease

As was shown in section 1.1, increasing the flat rate royalty to high levels--even as high as four- or five-sixths of gross revenue--substantially increases the landowner's wealth above that with the customary one-sixth royalty. However, one of the critiques of this conclusion was that high royalty rates will lead to premature abandonment of the well or field. Using the same simulation study as was used in the preceeding tables, the reserves losses in Table 4 rose to 8.5% and 21.6% when the flat rate royalty rose to four- and five-sixths, respectively. At a three-sixths flat rate royalty, the loss in reserves was 3,55%. Given the reservations with respect to the possible impact of sharply higher royalty rates on the level of investment in the lease expressed in section 2.2, the loss in reserves could be somewhat greater than the amounts in Table 4.

Given the conservation goal of maximizing the amount of oil and gas produced from each reservoir, such losses in reserves would be unacceptable. For the purposes of this paper, assume that the conservation policy is specified in terms of the following constraint: Royalty rate policies which are expected to reduce oil and gas reserves below the levels that are expected with a one-sixth flat rate royalty are unacceptable.

Given this policy constraint, flat rate royalties in excess of one-sixth of gross revenue would be politically unacceptable. It is, however, possible to increase the average royalty rate above one-sixth and still meet the above conservation policy constraint. This is done by adopting a two or more part royalty schedule similar to that in Table 5. The average royalty rates implied by this royalty schedule in Table 5 are in Table 6.

Table 5

Sample Two-Part Royalty Schedule
For Each Well on the Lease

Annual Oil Production*	Royalty Rate
0 to 10,000 bbl.	12.5%
Over 10,000 bbl.	66.7%

*10,000 bbl/yr is 27.4 bbl/day.

Table 6

Average Royalty Rate for Selected
Annual Production Rates*

Annual Oil Production	Average Royalty Rate
10,000 bbl.	12.5%
12,000	21.5
15,000	30.5
20,000	39.6
30,000	48.6
50,000	55.9
100,000	61.3
150,000	63.1
200,000	64.0

*Based on royalty schedule in Table 5.

The royalty rate on the first 10,000 barrels of oil produced in a year is 12.5% of gross revenue, with a 66.7% royalty rate being changed on 10,001st barrel and all subsequent production in the year. Thus, when production exceeds 10,000 barrels per year the average royalty rate rises--relatively rapidly at first and then gradually approaching 66.7% as production rises above 100,000 barrels per year (274 barrels per day). When oil production falls below 10,000 barrels per year, the low royalty rate makes it economic for the lessee to continue operating a well that would have to be abandoned if there were a flat rate royalty of, say, three-sixths. In general, when oil production is greater than 10,000 barrels per year for a given well, the lessee's marginal operating costs of producing each barrel of oil over 10,000 barrels are virtually zero; hence, a substantially higher royalty rate on production over 10,000 barrels in a year will not result in abandonment of the well.

The 10,000 barrels per year breaking point in the royalty schedule was only an example of a production rate that might be used for the breaking point. The actual rate of production to be used as the breaking point would depend upon the expected operating conditions and productivity of the lease, and the expected well-head price. Where expected costs are high, and/or well productivities and well-head prices low, a higher breaking point may be appropriate as might be another step in the schedule. For example, the royalty schedule could be that in Table 7, which implies the average royalty rates in Table 8. The rate of increase in the average royalty rate is substantially slower under this three-part schedule than under the two-part schedule in Table 5.

It is important to note that the higher royalty rates are applied to incremental rates of production and not to all production from the well. If the higher royalty rate applies to all production from the well when, say,

Table 7

Sample Three-Part Royalty Schedule
For Each Well on the Lease

Annual Oil Production	Royalty Rate
0 to 10,000 bbl.	12.5%
10,001 to 30,000 bbl.	25.0%
over 30,000 bbl.	75.0%

Table 8

Average Royalty Rate for Selected
Annual Production Rates*

Annual Oil Production	Average Royalty Rate
10,000 bbl.	12.5%
12,000	14.6
15,000	16.7
20,000	18.8
30,000	20.8
50,000	42.5
100,000	58.8
150,000	64.2
200,000	66.9

*Based on the royalty schedule in Table 7.

production is above 10,000 barrels in a year, the royalty schedule would provide an incentive for the lessee to hold production below 10,000 in a year when the well's productivity is somewhat, but not greatly, above 10,000 barrels in the year. By holding production below 10,000 barrels in the year, the lessee could avoid the higher royalty rate. It is strongly recommended that multipart royalty schedules be based on incremental production rates carrying the higher royalty rates, not all of the production from the well.

The author has computed the reserves and landowner lease bonus and royalty receipts for the lease used in Tables 1 through 4 using the two-part royalty schedule in Table 5. The oil reserves for the lease were calculated to be 21.59 million barrels and the lease bonus plus the present value of royalties was calculated to be $73.85 million. If a flat rate royalty of one-sixth had been specified in the lease contract, instead of the two-part royalty schedule, oil reserves would have been 21.59 million barrels (see Table 4) and the lease bonus plus the present value of royalties would have been $33.9 million (see Table 1). Thus, the sample two-part royalty schedule meets the conservation policy constraint while more than doubling the landowner's receipts by increasing them from $33.9 to $73.85 million.

The two-part royalty schedule in Table 5 is, of course, only an example. It is possible to construct reasonably optimal two or more part royalty schedules for any given set of leases depending upon the expected geological and operating conditions and well-head price of the oil. It is strongly recommended that any increase in the average royalty rate be accomplished by means of a multipart royalty schedule rather than by raising the flat rate royalty above the customary one-sixth of gross revenues.

3.2 Maintain, or Enhance, Employment and Economic Activity Levels

As was discussed in section 2, increasing the flat rate royalty substantially above the customary one-sixth of gross revenues will result in earlier abandonment of the field and a reduction in the total oil and gas production of the field. For example, with a four-sixths flat rate royalty, the lease in Tables 1 through 4 would be abandoned 26 years after the lease contract was signed, rather than 36 years later if the one-sixth flat rate royalty was used. Although the annual production rate in the 26th year is 308,000 bbl. (844 bbl/day) and the annual production rate in the 36th year is only 113,000 bbl. (310 bbl/day), it is none-the-less economic to operate the lease for an additional ten years at the customary one-sixth royalty rate. This means that the lease will continue to provide employment at about the same rate as in the 26th year and contribute accordingly to the local economic activity.

At the lower royalty rate, it is more likely that secondary recovery, pressure maintenance, in-fill drilling, and salvage perforation operations will be commenced or engaged in during the latter years of the field's life. These investment activities all contribute to maintaining, or even enhancing, employment and economic activity levels in the local community and the state. Property, sales and other tax revenues of the local community will be maintained for a longer period of time, and the relatively long-lived public service, utility and housing facilities of the community will be used for a longer period of time more closely approximating their useful economic lives (30 to 50 years for most buildings and utility systems).

Where maintaining the employment and economic activity levels of the local community is a fundamental policy constraint on the lease terms, it generally is imperative that flat rate royalties above the customary one-sixth of gross

revenue be avoided. However, it is possible--as with respect to the previous policy constraint--to construct a multipart royalty schedule that will attain this policy objective while, at the same time, increasing substantially the landowner's lease bonus and royalty receipts. An example of such a royalty schedule is the two part royalty schedule in Table 5.

If there is a reasonable prospect that secondary recovery projects might be initiated by the lessee at some time during the life of the lease, this policy objective implies that the landowner may wish to provide in the lease terms a separate royalty schedule for secondary recovery projects. The royalty schedule applying to secondary recovery projects would provide for lower average and marginal royalty rates, especially for relatively low rates of production. Providing this secondary recovery royalty schedule would increase the probability that secondary recovery projects would be initiated--thus enhancing employment and economic activity levels in the community--and eliminate the uncertainties and costs associated with lease provisions that permit renegotiation of royalty rates. It is the author's understanding that the costs of renegotiating royalty and override rates have led to abandonment of potentially promising secondary recovery projects before they could be initiated.

3.3 Increasing the Number of Bidders for Leases

One criticism of the competitive bonus bidding procedure used by the federal government and most state government to determine which potential lessee is to receive a given lease is that it favors large firms with ready access to large, internally generated, cash flows and to the capital markets over smaller firms. Since a higher average royalty, in general, implies a lower bonus bid for the lease (see Table 1), increasing the average royalty rate by using a multipart royalty schedule may make the bidding process more competitive. It may also make it possible for relatively small, locally based, oil companies formed by residents of the state or community to bid for leases in competition with larger firms from other areas or nations. Reducing the amount of the bonus bid may also be desirable in periods of capital stringency.

Both a higher flat rate royalty and a multipart royalty schedule can attain this objective of reducing the amount of the bonus bid. Since a higher flat rate royalty fails to meet the constraints on royalties discussed in the preceeding two sections, it is recommended that multipart royalty schedules be used to increase average royalty rates and thus reduce the maximum bonus bid that a potential lessee would be willing to pay.

FOOTNOTES

1. The definitions of reserves and original-oil-in-place used by the American Petroleum Institute are used through this paper.

2. The difference between the delivered price and the cost of transporting the oil is the principal determinant of the well-head price for the oil where competitive refiners buy the oil at the well-head.

3. Other public policies may imply that the present value of the lease be held to some positive value--for example, to obtain as quickly as possible specified employment levels.

4. The lease contract also generally requires that the lessee pay a per-acre rental on the land under lease, with the royalties replacing the rental when the former is larger. In most cases, the rentals are at nominal levels compared to the potential value of the land.

5. Whether competitive bonus bidding with the usual number of bidders for an oil lease actually accomplishes this objective is not discussed in this paper.

6. The relationship between the bonus bid and the royalty rate is almost linear because of the nearly proportionate reduction in the lessee's revenues with a higher royalty. Strict proportionality does not hold because a higher royalty rate generally implies an earlier abandonment of the lease. See section 2.1 for more on this point.

7. An example would be the State of Texas where ad. valorum severance taxes on petroleum make up as much as half, or more, of the tax revenues of many of its political subdivisions.

8. The Federal Energy Administration's definition of the term "new-oil" is implied here.

9. This has occured since 1973 in several of the oldest producing areas of the continental United States since oil from long abandoned wells receives the FEA's new-oil price.

10. It exceeds $58 per barrel because the royalties are discounted (i.e., Table 1 contains the present value of the royalties) and the reserves are not discounted.

11. This is especially the case in periods where capital is relatively scarce and expensive.

12. By changing the policy constraints and recalculating the impacts of the leasing policy on the landowner's wealth, oil reserves, and employment and economic activity levels, the effects of alternative policy combinations can be determined. The political decision makers can then rank the policy combinations and resolve the differences in their ranking through the normal democratic political process.

Appendix G

EXPLORATION EXPENDITURE BIDDING FOR EXPLORATORY LEASES ON LANDS OWNED BY THE STATE OF ALASKA

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January 1977

Although reserves of several billion barrels of oil and several trillion cubic feet of natural gas have been discovered and proven on the North Slope, a substantial field located in the Umiat area, and large reserves produced for almost two decades in the Cook Inlet area, very large areas of the State of Alaska are believed to have geological conditions that are suitable for the occurance of commercially exploitable deposits of petroleum. Virtually all of these attractive exploratory areas are untested by exploratory drilling. These prospective areas are both offshore and onshore, and include remote inland areas of the State. They present some of the most difficult and technologically challenging operating conditions in the world for petroleum exploration and for the development of commercial fields should any be discovered. Furthermore, many of these areas have fragile ecological systems that recover relatively slowly from the effects of environmental stress. Yet, these areas in Alaska provide one of the few remaining areas of the United States where oil and gas discoveries of significant magnitude are reasonably likely. Because of the exceptionally great uncertainties with respect to the geological, technological, environmental and economic conditions associated with exploring and producing these tracts, it is recommended in this paper that the State of Alaska investigate the competitive exploration expenditure bidding procedure for leasing these lands.

The competitive exploration expenditure bidding procedure for leasing government lands for petroleum exploration is based on selecting the winning bidder for each exploration lease on the basis of the amount of money the firm or joint venture is willing to spend on exploring the lease. Each exploration lease would normally consist of several tracts of land that are believed to be geologically related. Accompanying each exploration expenditures

bid would also be a description of the nature of the exploration activities the firm proposes to undertake with the funds in its bid. These exploration activities would include both exploration of the leased area for petroleum and assembly of the necessary data for an environmental impact assessment of development of the lease should it prove to be productive. The initial exploration plan would be subject to mutually acceptable modifications should exploration of the lease indicate that a change would be in the best interests of both parties to the lease. Upon completion of the exploration program, if one or more of the tracts proves to be productive, the lessee would be permitted to select one of the tracts for a development and production lease to be awarded upon completion of the environmental impact assessment process. The State can offer for competitive bidding some or all of the remaining tracts of land in the exploration lease. All the geological and other data developed by the exploration lessee would be provided to the potential bidders for these leases. If the first exploration lease on the tracts fails to identify commercially attractive oil or gas reserves, one or more additional competitive exploration expenditure lease sales can be held if firms in the industry are still interested in bidding for the lease.

The basic objectives of this exploration expenditure bidding program are:

1. The data provided by the exploration lessee should reduce substantially the levels of risk and uncertainty regarding the geological, technological, environmental and marketing conditions of the tracts to be offered for development and production leases. This data should, on the average, substantially increase the bids on the tracts offered for development and production leases where the initial exploration has either proven the existence of commercially exploitable petroleum deposits or indicated that there is a reasonable probability of their occurance.

2. The data provided the exploration lessee should permit the State to better determine
   a. the timing and extent of its future lease sales, so that the leases offered will more closely approximate the ability of the industry to explore, develop and profitably produce additional reserves, and
   b. the optimal lease terms for the development and production leases with respect to royalty rates, conservation and environmental protection regulations, etc.
3. The data provided by the lessee would permit the State to prepare an environmental impact assessment of the proposed development and production leases and would enhance the development of mitigating technologies and procedures based on far more data than would be available if the exploratory lease had not preceeded the offering of development and production leases.
4. The very nature of the exploratory lease's terms and the program of exploration activities which the lessee has agreed to undertake would prevent the speculative holding of leases by private firms in hopes that the exploratory activities of others will increase their value.
5. The industry's capital requirements are reduced and their expenditures on exploration and research increased since none of the industry's expenditures are diverted, by means of a lease bonus, from exploring the tracts contained in the exploration lease.
6. The data provided by the lessee would facilitate inclusion of specific terms in development and production leases with respect to unitized operation of tracts covering the same reservoir. These unitization terms could be included in the lease contract at the time the tracts are offered for development and production leases.

The principal disadvantage of the exploration expenditure lease bidding procedure, which may be an advantage given the projected crude oil surplus in District V for the next decade, is that it may lengthen the time between the decision to lease an area and its development by one or more years since development and production leases are not awarded until after all of the contracted exploration is completed. This procedure is intended to avoid the necessity of almost immediately offering the tracts adjacent to a discovery at a "drainage" sale. Another disadvantage of this procedure is that tracts on which the industry may have been willing to make multimillion dollar bonus bids before an exploration lease was issued may become worthless to the State if the exploration shows them very unlikely to contain commercially attractive oil and gas reserves. Whether this loss in lease bonus revenues is more than offset by higher lease bonus and royalty revenues on the tracts of land which the exploration lease has identified as likely to contain commercially attractive reserves is an empirical matter; however, the author believes that on balance the State would benefit substantially from using the exploration expenditure lease bidding procedure and bearing the risks associated with unexpectedly unproductive leases.

Central to the exploration expenditures lease bidding procedure is determination of the number and location of the tracts to be offered as an exploration unit. Three principal considerations enter into determination of the number of tracts in the exploration lease:

1. The tracts in the exploration lease should be geologically related so that intensive exploration, including the drilling of exploratory wells (some in locations specified in the lease and some in locations to be mutually agreed upon by the lessee and the State after drilling of the specified wells), will develop the kind and amount of data necessary

to reduce substantially the uncertainty about the potential petroleum resources of all or most of the tracts in the unit. For example, the tracts making up an exploration lease may be all of the tracts over and immediately adjacent to a suspected geological feature. If the suspected structure is relatively large, two or more exploration leases may be established. In addition, the number of tracts to be included in an exploration lease should not be so small as to result in the winning bid's being sufficiently large to reduce the expected marginal benefits from the last dollar spent on exploration to less than one dollar. To avoid this situation and situations where the initial exploration results indicate little likelihood of discoveries from more exploration, the lessee can be required to pay directly to the government any exploration funds which cannot--in the opinion of the lessee and the State--be economically spent on exploration or research.

2. The economic constraint on the number of tracts to be included in an exploration lease is based on the State's estimate of the ex. ante. economic rents inherent in the tract with the greatest ex. ante. economic rents, since the lessee is permitted to select only one of the tracts for a development and production lease upon completion of the exploration program. Thus, determining the number and configuration of the tracts to be included in an exploration lease requires that the State obtain some geological and economic data on the tracts prior to the lease sale. The best way to obtain this data appears to be to request all firms in the industry to make a preliminary nomination of the groups of tracts that they believe should form the exploration leases. Prior to the lease sale, the interested companies--singly or in groups--would be given permits to perform geological and geophysical

studies of the proposed exploration leases. These studies would provide the information necessary for each company or joint venture to determine the amount of exploration expenditures they will bid on each lease and the nature of their proposed exploration program. By then requesting each company or joint venture to nominate formally the tracts to make up each exploration lease and to provide a confidential report indicating the geological and economic reasons why it grouped a specific set of tracts into one exploration unit, the State's geologists, petroleum engineers, and economists would likely obtain sufficient information to specify the tracts to be included in each exploration lease. If necessary, the State could contract with service companies for additional information.

3. It is recommended that the lessee be required to prepare a preliminary environmental impact assessment for the development of those tracts which exploration has shown to be productive, or likely to be productive, of petroleum; or a full environmental impact statement where it is appropriate. To reduce the costs of the environmental impact assessment--which must be paid for from the lessee's evaluation of the ex. ante. rents inherent in the best tract in the exploration lease--wherever geologically feasible, the area covered by the exploration lease could be restricted to one, or a few, environmental and ecological settings. To further hold down these costs, the State may wish to require all of the winning bidders for exploratory leases to finance joint studies of those environmental and ecological factors that are common to two or more exploration leases.

Where the prospects for discovering commercial quantities of petroleum in one of the tracts of a given exploration lease are relatively minimal or exceptionally uncertain, or where a substantial technological advance will

be required to profitably operate the lease, transport the oil or provide the required degree of environmental protection, it may be necessary to permit the winning bidder to select two or more tracts from the exploration lease for development and production leases. Under these conditions, the ex. ante. economic rents inherent in the best tract may not be adequate to bring forth adequate exploration or research to meet the objectives of the leasing program. Identifying which exploration leases will require permitting the lessee to select two or more of the tracts for development and production leases requires the State to acquire a geological, economic and environmental data base adequate to estimate the ex. ante. economic rents inherent in the best tracts in the area of the exploration lease, and the costs of exploring it and preparing the required environmental impact assessment.

The competitive research expenditure bidding procedure determines the winning bidder for a given exploration lease by awarding the lease to the firm, or joint venture, contractually agreeing to spend the greatest amount on geological and geophysical exploration; exploratory well drilling; research and development relating to environmental protection, production and transportation facilities for the productive tracts; and other research activities the State and the lessee may agree are appropriate to increase the economic value of the lease or to preserve its environmental and ecological values. Each bid should be accompanied by the lessee's formal acceptance of the State's specifications for the environmental impact assessment for development of the productive tracts and for future exploration of those tracts for which the State believes additional exploration or research is appropriate. It should also include the lessee's agreement to release in a timely fashion and in a manner specified by the State all information generated as a result of the agreed upon exploration and research expenditures.

The lease bid should include a preliminary description of the geological and other exploration and research work that the bidder will perform if its bid is accepted. Where one or more bids are within, say, five or ten percent of the highest bid, the bidding procedure could specify--if the enabling legislation or regulations were to permit it--that the State could negotiate with all these bidders with respect to the exploration program and award the lease to the bidder proposing the "best" exploration program. The criteria for determining the "best" exploration program should be made public prior to the exploration lease sale. In any event, the winning bidder would be required to finalize the description of its exploration program and obtain the State's approval before the lease would be formally awarded.

The description of the work to be performed would include at least the following major points:

1. The geological and geophysical program for the tracts, including a description of the geophysical work already performed. Geological and geophysical expenditures made prior to the lease sale should not be included in the amount of exploration expenditures in the bid.
2. The initial exploratory drilling program if geophysical work prior to the lease sale was adequate to specify such a drilling program. The description of the drilling program would include the preliminary timing, location, and formation objectives of each well; an explanation of why this drilling program will provide adequate information to evaluate the most prospective tracts; and a description of the lessee's environmental protection program for its exploratory drilling program.
3. The general specifications of the anticipated follow-up geophysical and drilling program, if any.

4. A description of the lessee's research and development program with respect to exploration, production and transportation technologies (including specific design criteria where applicable) and to environmental protection facilities and procedures applicable to the exploration lease or to future development and production leases.
5. Descriptions of other activities which the bidder believes to be appropriate for research relating to these tracts.

The State could specify a range of terms, say three to five years, for the exploration lease at the time the lease sale is announced. The winning bidder would then be permitted to specify the length of time for the exploration lease. The lessee, however, should not be permitted to terminate the lease prior to its expiration (i.e., upon making a discovery on one tract) without permission of the State. Expenditure of the amount bid and completion of the contractually agreed upon elements of the exploration program would, naturally, terminate the lessee's work under the exploration lease and the lease could then be terminated by mutual consent even if the entire term has not yet elapsed. Should the lessee fail to complete the contractually agreed upon exploration program prior to the end of the term of the lease, as might occur due to unexpectedly bad weather or unanticipated equipment breakdowns, the State should have the option of terminating the lease upon receipt of any unexpended funds or it could extend the term of the lease to permit the lessee to complete the exploration program. If the lessee were to be unable to complete the contractually agreed upon exploratory program within the exploration expenditure bid amount, the lessee should be required to fund its completion or to forfeit its right to select one or more tracts for a development and production lease. Upon completion of the agreed upon exploration program to the satisfaction of the State and termination of the exploration lease, the

lessee would be able to select the tract, or tracts, upon which it is to receive a development and production lease, with the awarding of this lease to be subject to acceptance of the lessee's environmental impact assessment by the appropriate agencies.

The above descriptions provide only a general outline of the nature of an exploration expenditures bidding program intended to provide the State of Alaska with the benefits which it can obtain from the resulting reductions in the uncertainties regarding (1) the economic value of the tracts in the exploration lease and (2) the environmental and ecological impacts of developing those tracts which are shown to be productive of petroleum. Formulation of a practical competitive exploration expenditures bidding program would require far more detailed and specific legal, geological, engineering, environmental, economic and administrative analyses and review by the State, industry trade associations, and individual companies than has been provided in this paper.

Appendix H

Computing the Ad Valorem Charge (AVC)

Table H-1 shows how the ad valorem charge is figured. It begins with a forecast of daily flows. In this case they are taken from the Van Poollen report, "Prediction of Reservoir Fluid Recovery, Sadlerochit Formation, Prudhoe Bay Field," January, 1976. These figures do not apply to separate leaseholds and, of course, would have to be broken down in application.

Table H-1 assumes that the ad valorem charge is at a rate of 20 percent, levied on the base of the discounted cash flow (DCF).

This whole process is quite mysterious to many people and so we are laying it out step by step.

Note first that a 20 percent rate is not as high as it seems at first, because it is "capitalized." That means that the expectation that the charge will be levied over the next 25 years reduces the present value of the DCF. It reduces it in exactly the same way that increasing the basic discount rate from 8 to 28 percent would reduce it. The interest rate is basically a toll for moving through time, and that is exactly what the ad valorem charge is as well.

Comparing columns 4 and 5 of Table H-1, the effect of capitalizing the ad valorem charge is that the discounted cash flow is only about three times as high as the current year's cash flow in the early years. In the later years the two values come even closer together.

A high rate does not take more income than there is because if it did there would be no base, and if there were no base there would be no

charge. This dog-chasing-tail process balances out at a point where the high percentage rate and the low DCF base combine to produce a middling sort of figure. Table H-1 shows exactly how the base is reduced and the charge arrived at.

A high percentage rate does not cause early shutdown because the base drops over time. Table H-1 shows that it drops from $16.1 billion down to $.1 billion, the second figure being six-tenths of 1 percent of the initial one.

The DCF base is arrived at by discounting future cash flows at 28 percent per annum compounded. For anyone not conversant with this process, the last figures in columns 4 and 5 are the easiest place to begin. A cash flow of $.14 billion is due on December 31 of the year. The value of that on the preceding January 1 is the sum which will grow at .28 percent interest to equal $.14 billion. That sum is $.109 billion, because

$$.140 \div 1.28 = .109$$

The last two columns, 11 and 12, indicate something about the orderliness of this process. The lessee always gets 8 percent of the current year's DCF and the lessor always gets 20 percent of it. The split between them, then, is always 2½ to 1, that is, 20 ÷ 8.

The 8 percent figure is known as the capitalization rate. The split between the lessor and the lessee always depends basically on the relationship between the AVC rate and the capitalization rate. The effect of the 20 percent AVC rate would be considerably offset by the adoption of an equally high capitalization rate. Alaska uses an 18 percent rate in

computing the Alaska reserves tax, a figure which we believe is too high. Just for illustration, if the AVC rate were 20 percent and the cap rate were 20 percent, then the split would be 1 to 1, or 50-50.

The implicit assumption is that the lessee has paid $16.1 billion to buy the lease on January 1 of year 1. He is earning 8 percent on that investment under conditions of very low risk over a 25-year period. He is not earning 8 percent on all of it for 25 years because he recovers some of it each year. He is earning 8 percent on the unrecovered balance each year. The unrecovered balance is the amount shown in column 5, that is, the discounted cash flow as of each current year.

The last barrel lifted is charged 25 times at a rate of 20 percent before being lifted. This might seem like an awful lot but it turns out to be much less, because what is taxed in year 1 is not the value of the barrel in year 25 but the discounted cash value of the barrel, discounted back 25 years at 28 percent per year. A barrel of oil to be sold for $8 at the end of 25 years has a present value of 1.7¢; and 20 percent of 1.7¢ is .3400 of a cent. Therefore, the fact that the barrel is charged 25 times at 20 percent does not mean that the sum of the charges will amount to a great deal.

There will be an incentive to accelerate production but that would require more capital, lasting over the full life production and only used part of the time during the early flush years. To estimate the effect we have to look at the whole process over 25 years and not just at one barrel. Appendix I does this and the finding is that production is not very sensitive to large increases in the interest rate or the ad valorem charge.

All this assumes that the existence of the last barrel is known over 25 years. In fact it may not be. The greatest weakness in this proposal, in my opinion, is its inadequate collection of revenue from deposits whose presence is concealed or unknown until shortly before they are produced.

Lacking from Table H-1 is a statement of what would happen in the years preceding year 1, which is here treated as the year when cash flow begins. In practice, there is a substantial number of years when DCF is positive and quite large before there is any production. AVC would be raising revenue all during this period. From the lessee's point of view this would be tolerable since all the signs in column 8 would be plus: that is, the value of the leasehold interest would be rising each year as we move nearer to production.

Table H-1

An Ad Valorem Charge of 20%, Showing Capitalization of Charge into DCF

(1) Year n	(2) Daily Flow MM B/D	(3) Yearly Flow (2) x 365 MM B/Y	(4) Cash Flow @ $8/B MMM $/Y	(5) DCF MMM $	(6) AVC .20xDCF .20 (5) MMM $	(7) Cash to Lessee CF-AVC (4)-(6) MMM $	(8) True Depletion or Change in DCF MMM $	(9) State's Share of Cash Flow AVC/CF (6)/(4) %	(10) Income to Lessee CF-AVC Less True Depletion (7)+(8)	(11) Return on Lessee Investment (10)/(5) %	(12) ~~Avg.~~ avc. Income to Lessee (6)/(10)
1.	1.40	511	4.1	16.1	3.21	.88	+ .41	79	1.28	.08	2.5
2.	1.80	657	5.3	16.5	3.30	1.96	- .61	63	1.34	.08	2.5
3.	1.80	657	5.3	15.9	3.18	2.07	- .82	61	1.26	.08	2.5
4.	1.80	657	5.3	15.1	3.01	2.25	-1.02	57	1.23	.08	2.5
5.	1.80	657	5.3	14.1	2.82	2.42	-1.31	54	1.11	.08	2.5
6.	1.80	657	5.3	12.8	2.55	2.72	-1.69	48	1.02	.08	2.5
7.	1.80	657	5.3	11.1	2.21	3.04	-2.16	42	.876	.08	2.5
8.	1.31	478	3.8	8.9	1.78	2.04	-1.31	47	.730	.08	2.5
9.	1.10	401	3.2	7.6	1.52	1.69	-1.11	47	.584	.08	2.5
10.	.91	332	2.7	6.5	1.30	1.37	- .818	49	.555	.08	2.5
11.	.89	325	2.6	5.7	1.13	1.46	-1.02	44	.438	.08	2.5
12.	.87	318	2.5	4.6	.929	1.61	-1.26	37	.350	.08	2.5
13.	.58	212	1.7	3.4	.677	1.02	- .730	40	.292	.08	2.5
14.	.48	175	1.4	2.66	.531	.876	- .660	38	.216	.08	2.5
15.	.35	128	1.0	2.00	.400	.613	- .450	39	.163	.08	2.5
16.	.24	88	.70	1.54	.310	.380	- .263	44	.117	.08	2.5
17.	.17	62	.50	1.27	.254	.234	- .140	51	.094	.08	2.5
18.	.16	58	.46	1.13	.228	.234	- .146	48	.088	.08	2.5
19.	.15	55	.44	.984	.196	.234	- .163	45	.071	.08	2.5
20.	.13	47	.38	.821	.163	.220	- .146	43	.068	.08	2.5

(To be continued)

Table H-1 (continued)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year n	Daily Flow	Yearly Flow (2) x 365	Cash Flow @ $8/B	DCF	AVC .20xDCF .20 (5)	Cash to Lessee CF-AVC (4)-(6)	True Depletion or Change in DCF	State's Share of Cash Flow AVC/CF (6)/(4)	Income to Lessee CF-AVC Less True Depletion (7)+(8)	Return on Lessee Investment (10)/(5)	Income to Lessee (6)/(10)
	MM B/D	MM B/Y	MMM $/Y	MMM $	MMM $	MMM $	MMM $	%		%	
21.	.12	44	.35	.672	.134	.216	- .164	38	.052	.08	2.5
22.	.10	36	.29	.508	.102	.188	- .149	35	.039	.08	2.5
23.	.08	29	.23	.359	.073	.146	- .117	31	.029	.08	2.5
24.	.06	22	.18	.225	.044	.135	- .117	26	.018	.08	2.5
25.	.05	18	.14	.109	.022	.118	- .109	16	.009	.08	2.5

Technical Notes by Column

(2) Daily flows in barrels from Run #18 in "Prediction of Reservoir Fluid Recovery, Sadlerochit Formation, Prudhoe Bay Field," January, 1976, Table XIX. Gas recovery not included. Rounded to two places. The rounding results in minor discrepancies in the body of the table.

(3) We convert barrels per day to barrels per year. We make no adjustment for shutdowns or other factors.

(4) We multiply the number of barrels by $8 each. This is purely to show a method, and the price is assumed constant over 25 years without implying that that is an accurate forecast. We also assume that current operating expenses are deducted.

(5) The figure at the top of this column, 16.1, is arrived at by first discounting each year's cash flow in column 4 by the number of years that it follows January 1 of year 1 and then cumulating them. That is, we discount 4.1 over one year, assuming that the 4.1 is received on December 31. Then we discount 5.3 over two years and add that to the cumulative total. Then we discount the next 5.3 over three years and so on. We finally get down to .14 received at the end of year 25, discount that over 25 years and add that to the total, bringing us to 16.1.

The second figure, 16.5, is arrived at by the same process, except that now we omit the initial 4.1 and then we discount the first 5.3 over one year instead of two and so on down to .14 at the end of year 25, which we now discount over 24 years instead of the initial 25.

When we finally get to the bottom of column 5, the last figure, .109, is arrived at simply by discounting .14 over one year.

As we run down column 5, DCF changes as a result of two things. First, we chop off a year; but second, all the later years move one year closer to the present and therefore rise in present value by 28 percent. The net result is normally a decline in DCF, but not in the first year. Note that if we went back to the years before 1, DCF would always be rising at 28 percent per year, of which 20 percent would go to the State and 8 percent to the lessee.

(6) AVC is always 20 percent of DCF.

(7) This is what the lessee gets after paying the charge.

(8) This is the change in DCF from year to year. It is what economists call "true depletion," that is, the decline in the value of the asset. Note that it is much less in the early years than the cash flow (column 4). This is because production today does not reduce

production next year but, rather, reduces production many years in the future.

Again note that this column might be extended upwards into years before number 1 and all the figures would be positive.

(9) This is the State's share of the cash flow. It is less than the State's share of income because income is lower than cash flow, as we see next.

(10) The lessee's income is the cash he receives minus the decline in his wealth.

(11) The lessee's income is always 8 percent of the DCF. DCF is also the unrecovered balance of his initial investment of $16.1 billion on January 1 of year 1. The lessee always gets 8 percent of that figure and the lessor gets 20 percent, so that:

(12) The lessor always gets 2½ times the lessee's income.

Appendix I

Sensitivity of Discounted Cash Flow (DCF) to Production Rates and Interest Rates, Sadlerochit Formation

Table I-1 shows two alternative schedules of the flow of production from the Sadlerochit Formation. These are taken from the Van Poollen report, "Prediction of Reservoir Fluid Recovery, Sadlerochit Formation, Prudhoe Bay Field," Tables XVII and XIX. Both runs result in almost exactly the same ultimate recovery. The difference is that Run 18 starts faster and ends slower than Run 16. Run 18 would require a greater investment in lessee's capital to allow the faster starting rate of production to occur. This is compensated by the higher present value. Table I-2 shows the increase in present value or DCF at different rates of discount. Several points stand out.

DCF is sensitive to production rates. The gain in DCF from choosing Run 18 over Run 16 is a present value increment of $5.4 billion at a 10 percent rate of discount. This is the maximum gain: it declines in both directions from 10 percent. However, it does not decline very sharply and is surprisingly insensitive to the rate of interest.

DCF is sensitive to the discount rate. For Run 18 it declines from $47.8 billion down to $16.1 billion as we go from a 3 percent to a 28 percent discount rate.

Run 16 is more sensitive to the discount rate than is Run 18. This is because Run 16 is slower and therefore more weighted towards the future, where discount factors are more sensitive to the choice of a discount rate.

The third row, which is Run 18 minus Run 16, is not very sensitive to the discount rate. This last point is quite significant. The amount of capital we can justify investing to speed up the flow of production is limited by the gain in DCF that results. Normally, with other kinds of investments, a higher rate of discount means a lesser gain from any investment that increases future production. In this case it means a greater gain, at least until the discount rate reaches 10 percent, after which the gain tapers off again.

Note how this bears on the concern that a higher ad valorem charge (AVC) would cause the last barrel of oil to be extracted too rapidly. When the discount rate rises above 10 percent, the addition of an ad valorem charge will slow down rather than speed up production by limiting the number of wells that may be drilled.

There appear to be two countervailing forces at work here. As we raise the discount rate both series of DCF's become smaller, which tends to bring them closer together, but Run 16 is more sensitive to the discount rate, which tends to pull them farther apart. Between 3 and 10 percent, the second force overpowers the first, and above 10 percent vice versa.

We leave further investigation of this interesting phenomenon to future study. The present point is that the application of an ad valorem charge would not contain much net bias either in the direction of speeding up or slowing down production.

Another important implication is that we may live in a world of uncertainty about future interest rates, but that does not prevent our

scheduling flows with some assurance that our scheduling will be optimal in case future interest rates change. Because future interest rates may change a good deal without changing the optimal application of capital.

Table I-1

Runs 16 and 18 from the Van Poollen Report

Year	Run 16 MMB/D	Run 18 MMB/D
1	1.4	1.40
2	1.2	1.80
3	1.2	1.80
4	1.2	1.80
5	1.2	1.80
6	1.2	1.80
7	1.2	1.80
8	1.2	1.31
9	1.2	1.10
10	1.2	.91
11	1.2	.89
12	1.2	.87
13	.99	.58
14	.75	.48
15	.56	.35
16	.47	.24
17	.35	.17
18	.27	.16
19	.22	.15
20	.17	.13
21	.13	.12
22	.11	.10
23	.10	.08
24	.08	.06
25	.07	.05
26	.05	--

Table I-2

Present Values at Different Rates of Discount,

Runs 16 and 18, Van Poollen Report

Discount Rate	.03	.05	.08	.10	.15	.20	.28
Run 18	47.8	42.3	35.6	32.7	25.6	21.0	16.1
Run 16	43.5	37.5	30.7	27.3	21.0	16.8	12.6
Run 18-Run 16	4.3	4.8	4.9	5.4	4.6	4.2	3.5
Run 18/Run 16	1.098	1.127	1.160	1.196	1.22	1.25	1.28

Appendix J

The Future Shift Effect

The object here is to use simple mathematical models of some generality, to show the general point. For a total treatment we need one model of complete generality (which is attached at the end, but not recommended for light reading). We would also need several specific models based on actual decline paths. We have not undertaken the second, but our second model is tolerably near the actual runs predicted for the Sadlerochit Formation.

Model One

Model One assumes constant ultimate recovery = \$A, recovered at an even flow of $\frac{A}{n}$ over n years. We may reduce n by investing more capital. \$B is a (hypothetical) sum that it would take to build capacity to recover A in one year; so actual capital is $\frac{B}{n}$.

$$DCF = \frac{A}{n} \frac{1-e^{-in}}{i} - \frac{B}{n} \qquad (J\text{-}1)$$

Now we impose a royalty at the rate r. The new DCF is reduced. We label this new DCF after royalty as σ (sigma).

$$\sigma = \frac{A}{n} (1-r) \frac{1-e^{-in}}{i} - \frac{B}{n} \qquad (J\text{-}2)$$

Now we divide σ by DCF. If the royalty is neutral it will reduce the DCF of all schedules by the same percentage, so the best schedule before royalty is the same as the best one after royalty.

$$\frac{\sigma}{DCF} = \frac{A(1-r)(1-e^{-in}) - Bi}{A(1-e^{-in}) - Bi} \qquad (J-3)$$

J-3 can easily be shown to be an increasing function of n. This means that σ as a percentage of DCF is higher for the slower schedules of production. This has to shift the optimal production plan to a longer, slower schedule.

Cost recovery alleviates but does not eliminate the bias. Let's assume the lessee can recover his capital, $(\frac{B}{n})$, by straight line depreciation (this is actually faster than true depreciation, and moves a little in the direction of accelerated write-off).

Let π = DCF after royalty with capital recovery.

$$\pi = \frac{A}{n}\frac{1-e^{-in}}{i}(1-r) - \frac{B}{n}\left[1-r\,\frac{1-e^{-in}}{i}\right] \qquad (J-4)$$

$$\frac{\pi}{DCF} = \frac{A(1-e^{-in})(1-r) - B(i-r(1-e^{-in}))}{A(1-e^{-in}) - Bi} \qquad (J-5)$$

J-5 can also easily be shown to be an increasing function of n, although less so than J-3.

Model Two

Model Two addresses the same question as Model One, but in an incremental instead of a total way. We want to know the value of adding a well to a given number already planned or existing. The last well adds to flow for 12 years, and then reduces it for 12 years by the same amount. It simply advances its production 12 years. This resembles the

matter of going from Run 16 to Run 18 in the Van Poollen report (our Appendix I).

Let F be yearly well capacity, in dollars.

$$\text{Gross gain} = F\left(\frac{1-e^{-12i}}{i}\right) \tag{J-6}$$

$$\text{Loss} = F\left(\frac{e^{-12i} - e^{-24i}}{i}\right) \tag{J-7}$$

$$\text{Net gain} = F\left(\frac{1-2e^{-12i} + e^{-24i}}{i}\right) \equiv F\theta \tag{J-8}$$

We label the expression in brackets as $\underline{\theta}$.

The value of $\underline{\theta}$ depends on $\underline{i}$, the rate of interest. Some values are given here:

i:	.06	.10	.13	.16
θ:	4.167	4.640	4.546	4.325

The value of θ is not very sensitive to the rate of interest. The net gain is about 4½ times the yearly cash flow over a wide range of interest rates. This is the net gain from investing in a new well. Cf. Appendix I, where DCF is not very sensitive to interest rates.

It is clear that if we take a cut of F by a royalty, the gain of the new well is correspondingly reduced to:

$$\text{Net gain less royalty} = F\theta(1-r) \tag{J-9}$$

If we let cost be recovered, there is still a decline in the net gain:

Net gain less royalty plus cost recovery =

$$F\theta - r\left[F\theta - \frac{C}{12}\,\frac{1-e^{-12i}}{i}\right] \tag{J-10}$$

The expression in brackets is positive, because

$$C < F\theta \text{ and } \frac{C}{12}\,\frac{1-e^{-12i}}{i} < C$$

$\therefore$ (J-10) $< F\theta$

$\therefore$ the charge reduces investment and slows recovery.

There are several other routes to the same conclusion, which we omit. But specifically, if we have the lessee maximize his internal rate of return, the effect of royalties and profit sharing is the same, and the math is easier.

Another reason for deferring production is expected higher field prices, and/or expected lower real costs. Royalties exaggerate this motive. Compare J-1 and J-2, as the value of A rises while B remains the same. It is obvious by inspection that the royalty in J-2 gives more leverage to the constant $\frac{B}{n}$, so that

$$\frac{\frac{d\sigma}{dA}}{\sigma} > \frac{d(DCF)}{DCF} \tag{J-11}$$

This is most obvious when $\sigma = 0$ and DCF > 0. It can be shown to be true for all higher values of σ as well.

Appendix II

By William Vickrey and Michele Consigny*

Proof that an income tax using true depreciation is intertemporally neutral

Let A(x) be a (continuous) cash or service stream bought for C(0), 0 being the time of purchase and x the time of payment, m being the date of maturity or final payment. Let P(x) be the present value at time 0 of a payment of $1 at time x. The instantaneous short term rate of interest at time x is then $h(x) = -\frac{1}{P}\frac{dP}{dx}$. (The annual rate of interest is $i = e^h - 1$.) C(y), the value at time y of the remaining payments from y to m, is then given by $P(y)\cdot C(y) = \int_y^m P(x)\cdot A(x)\,dx$. (1)

The depreciation in capital value at time y is then obtained from (1) by differentiating with respect to y:

$P\frac{dC}{dy} + C\frac{dP}{dy} = -P(y)\cdot A(y)$, and by solving for the depreciation, $\frac{dC}{dy}$ we get $D(y) = -\frac{dC}{dy} = A(y) + \frac{C}{P}\frac{dp}{dy} = A - hC$ (2)

Now let a tax be imposed at a rate t(y) on the net income after depreciation Y = A - D, so that the tax is $t(y)\,[A(y) - D(y)]$ and the net receipts after tax are then $N = A - t(A-D) = A - thC$. Then there exists a private (2a) discount function R(y), such that for any asset with a stream of payments A(y), the current value of the asset can be obtained equally from discounting the gross payments A with the public discount function P, or the net proceeds N

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* Again, credit is hard to allocate precisely. Miss Consigny first formulated the problem and proved the theorem. Professor Vickrey greatly shortened and generalized the proof and brought it to its present form. A third proof by Matthew P. Gaffney, Jr., might equally well have been presented.

with the private discount function R: $\int_0^\infty PA\,dy = \int_0^\infty RN\,dy$.

The private discount function R will be related to P and t by the equation

$$-\frac{1}{R}\frac{dR}{dy} = r = h(1-t) = -(1-t)\frac{1}{P}\frac{dP}{dy} \tag{3}$$

where P, R, t, and h are all functions of y, h being the public rate of discount and r being the private rate of discount. $P(0) = R(0) = 1$.

We have $\int_0^\infty R(y)\,N(y)\,dy$

$$= \int_0^\infty R(y)\,[A(y) - t(y)\,h(y)\,C(y)]\,dy \text{ [using (2a)]} \tag{4}$$

$$= \int_0^\infty R(y)\,[A(y) - t(y)\,h(y)\int_y^\infty \frac{P(x)}{P(y)}A(x)\,dx]\,dy, \tag{5}$$

[using (1)]

$$= \int_0^\infty R(y)\,A(y)\,dy - \int_{y=0}^\infty \int_{x=y}^\infty \frac{t(y)\,h(y)\,R(y)}{P(y)}$$

$$P(x)\,A(x)\,dx\,dy \tag{6}$$

which becomes, by inverting the order of integration

$$= \int_0^\infty R(y)\,A(y)\,dy - \int_{x=0}^\infty \int_{y=0}^x \frac{t(y)\,h(y)\,R(y)}{P(y)}$$

$$dy\,P(x)\,A(x)\,dx. \tag{7}$$

From (3), we have $ht = \frac{1}{R}\frac{dR}{dy} + h = \frac{1}{R}\frac{dR}{dy} - \frac{1}{P}\frac{dP}{dy}$ (8)

so that $\frac{t(y)\,h(y)\,R(y)}{P(y)}\,dy = \frac{1}{P}\,dR - \frac{R}{P^2}\,dP = d(\frac{R}{P})$, so (9)

that (7) becomes

$$\int_0^\infty R(y)\,A(y)\,dy - \int_0^\infty [\frac{R(y)}{P(y)}]\Big|_{y=0}^{x} P(x)\,A(x)\,dx \tag{10}$$

$$= \int_0^\infty R(x)\,A(x)\,dx - \int_0^\infty [\frac{R(x)}{P(x)} - 1]\,P(x)\,A(x)\,dx$$

$$= \int_0^\infty [R(x)\,A(x) - R(x)\,A(x) + P(x)\,A(x)]\,dx$$

$$= \int_0^\infty P(x)\,A(x)\,dx = C(0).$$

Q.E.D.

APPENDIX K

FINANCIAL CHARACTERISTICS OF ENERGY FIRMS OPERATING IN ALASKA

1. The low labor intensity of large energy firms.

   A. Relative to smaller energy firms.
   There were 36 energy firms in Fortune 500 for 1975. Here we rank them by net worth per employee. The document trend is evident in the right column.

K-1: Top Energy Firms Listed by Net Worth Per Employee

Firm	Net Worth	Net Worth /Assets	No. of Employees	Net Worth /Employee
	Billion $	Ratio	Thousands	Thousand $
Socal	6.500	0.50	39	166.7
Arco	3.700	0.50	28	132.1
Exxon	17.000	0.52	137	124.1
Shell	3.900	0.56	32	121.9
S.O. lud.	5.600	0.57	47	119.1
Texaco	8.600	0.50	75	114.7
Sun	2.500	0.54	28	89.3
Mobil	6.200	0.45	71	87.3
Phillips	2.400	0.53	31	77.4
Gulf	3.500	0.52	52	67.3
Marathon	1.010	0.50	20	50.5
Continental	2.130	0.42	44	48.4
Occidental	1.200	0.34	36	33.3
Tenneco	2.400	0.36	78	30.8
Ashland	0.720	0.37	27	26.7
Sohio	1.460	0.35	73	20.0
Pittston	0.500	0.56	27	18.5
Cities S.	1.630	0.51	96	17.0
Union	1.920	0.51	128	15.0
Getty	1.900	0.59	158	12.0
Ken McGee	0.810	0.58	81	10.0
Pennz.	0.570	0.28	60	9.5
Ameraga	1.040	0.44	174	6.0
Clark	0.100	0.33	20	5.0
Texas Gulf	0.630	0.54	128	4.9
Murphy	0.340	0.29	85	4.0
Tesoro	0.223	0.38	56	4.0
Superior	0.540	0.61	181	3.0
Am. Petrofl.	0.360	0.60	121	3.0
Commonwealth	0.179	0.31	66	2.7
Charter	0.141	0.26	53	2.7
Mapco	0.163	0.38	81	2.0
United Ref.	0.044	0.37	23	1.9
Belco	0.173	0.43	108	1.6
Oil Shale	0.029	0.17	21	1.4
Crown	0.071	0.35	72	1.0
Total/Mean	80.183		2557	31.4

The top eight are all above the mean in net worth per employee. The bottom six are all below the mean

B. Relative to smaller general firms

Smaller general industrial firms are more labor-intensive than the oil firms, large and small. We have here the smallest ten firms (by net worth) from Fortune's 500.

FIRM	NET WORTH (000,000,000)	EMPLOYEES (000)	NET WORTH PER EMPLOYEE (000)
Seaboard All. Min.	27.5	583	47.2
Ward Foods	20.9	871	24.0
Col. Pic. Lud.	19.8	2288	7.1
Idlewild Foods	19.5	975	20.0
Mattel	16.9	12,071	1.4
Flavorland	16.9	754	22.1
Rath Packing	14.6	3,842	3.8
Spencer Foods	13.5	1,753	7.7
Sucrest	9.9	1,295	7.7
Am. Beef Packers	(10.4)	370	(28.0)
Mean	14.9	2,531	5.9

C. Relative to large general firms

Two factors are to be observed in these comparisons. Energy firms are less labor intensive than general industrial firms; and large firms are less labor intensive than small ones. To show the first point, we show data for the largest non-energy firms, 1975, ranked by Net Worth.

FIRM	NET WORTH (000,000,000)	EMPLOYEES (000)	NET WORTH PER EMPLOYEE (000)
GM	13.1	682	19.2
IBM	11.4	289	39.4
Ford	6.3	412	15.3
USS	4.9	171	28.5
DuPont	3.8	131	29.1
East Kodak	3.7	127	29.1
Union Carbide	2.7	104	25.9
Beth. Steel	2.6	112	23.2
Dow Chem.	2.5	55	45.3
Mean	5.4	223	24.2

The largest ten non-energy firms had $24,200 of net worth per employee, compared to $93,200 for the 36 energy firms, and $119,000 for the largest ten energy firms.

D. Relative to 1963

The labor-intensity of energy firms has dropped since 1963. Here are some data on firms active in Alaska. 1975 sales are 4.1 times 1963. 1975 Net Worth is 1.9 times 1963. 1975 Assets are 2.8 times 1963. But 1975 employment is only 1.1 times 1963. Of course wage rates have risen, so these comparisons overstate the trend a good deal.

	SALES (000,000,000)			NET WORTH (000,000,000)			ASSETS (000,000,000)			EMPLOYEES (000)		
Co.	'63	'75	'75/'63	'63	'75	'75/'63	'63	'75	'75/'63	'63	'75	'75/'63
Arco	.9	7.36	8.1	.9	3.66	4.1	1.4	7.4	5.3	18	28.1	1.6
Sohio	.5	2.5	5.0	.4	1.46	3.7	.47	4.2	8.9	10.5	20.6	2.0
Exxon	10.31	44.9	4.3	8.0	17.02	2.1	12.0	32.8	2.7	147	137.0	.9
Mobil	4.5	20.6	4.6	3.2	6.8	2.1	4.8	15.1	3.1	79	71.3	.9
Socal	2.2	16.8	7.6	2.9	6.5	2.2	3.5	12.9	3.7	44	38.8	.9
Texaco	3.4	24.5	7.2	3.5	8.7	2.5	4.5	17.3	3.8	55	75.3	1.4
Phillips	1.3	5.1	3.9	1.2	2.4	2.0	1.8	4.5	2.5	25	30.5	1.2
Cities Serv.	1.2	3.1	2.6	.9	1.6	1.8	1.6	3.2	2.0	23	17.1	.7
Union	.5	5.1	10.2	.6	1.9	3.2	.9	3.8	4.2	7	15.7	2.2
Mean	1.4	5.8	4.1	1.2	2.3	1.9	1.7	4.7	2.8	22.9	24.9	1.1

Note #1: Atl and Richfield are totaled for the 1963 figure.

2: Conversion of Prudhoe into cash.
Note in the table just above how much faster the assets of Arco and Sohio have risen than the other firms: 5.3 and 8.9 as compared with 2.8 for the whole group (which includes them).

Then note how much faster the assets of Arco and Sohio have risen than their net worth has risen: 5.3 vs. 4.1, and 8.9 vs. 3.7. This an index to how they have raised cash on the gain to their wealth caused by Prudhoe. They have taken tax-free cash by bonding the value of their leaseholds. They have done so at prime interest rates. This is the source of ability to pay rents, add valorem charges and taxes in advance of production.

Note #3: The under used credit base of larger firms
The smaller, leaner firms tend to use their credit more. We compare the ratios of net worth to total assets for the top ten, the middle ten, and the bottom ten of Fortune's 500, (be Net Worth), 1975.

	TOP TEN	NET WORTH/TOTAL ASSETS
1.	Exxon	.52
2.	GM	.60
3.	IBM	.73
4.	Texaco	.50
5.	Mobil	.45
6.	Socal	.50
7.	Gulf	.52
8.	Ford	.46
9.	S.O. Iud.	.57
10.	U.S.S.	.60

	MIDDLE TEN	NET WORTH/TOTAL ASSETS
246	Sherwin Wins.	.53
247	Potlatch	.62
248	Champ. Spark.	.73
249	Crown Cork	.54
250	Hamua	.76
251	SCM	.41
252	Becton, Dick.	.64
253	Farmland	.31
254	East. Gar.	.42
255	Cherekr.-Pouds	.59

	BOTTOM TEN	NET WORTH/TOTAL ASSETS
491	Seaboard All. Min.	.27
492	Ward Foods	.14
493	Col. Pic. Indust.	.06
494	Idlewild Foods	.44
495	Mattel	.09
496	Flavorland	.29
497	Rath Pkg.	.28
498	Spencer Foods	.25
499	Su Crest	.09
500	Am. Beef	-(.19)

The bottom ten clearly are heavily in debt compared with the top ten. This is same index to the lower cost of capital to the larger firms.

Refer back to the first set of data, under heading #1, App. K, showing Net Worth/Assets for 36 energy firms. The smaller ones are using their credit harder than the larger ones. 9 of the last 10 firms are under .40. 9 of the top 10 are over .50.

Note #4: Credit ratings and long term financing
The following table shows how the effect of a low credit rating is felt more strongly for long term than short-term borrowing. Figures are from July, 1976, taken from Moody's.

Bonds Mature	Aaa	Aa	A	Baa	Ba	B
1976-80	7.2	3.7	7.6	8.3		
	6.9	6.9	7.0	8.8		
	6.5					
	3.7					
1981-85	7.9	7.9	8.5	10.0		
	8.0	8.2	8.6	10.0		
	7.9	8.3	10.0			
	5.3	8.1	9.0			
	5.5		8.3			
	8.0		8.5			
			8.9			
1986-90	11.4		6.3	8.7		14.0
			8.2	6.9		
				10.0		
1991-95	8.9		9.3	11.0	16.0	11.0
	6.8		9.1	7.4		14.4
	8.5		9.1	8.9		
	7.4		7.7			
	7.3					
1996-2000	7.6	7.6	9.8	12.0		
	7.9	8.3	8.7	9.7		
	7.9	8.9	8.8	12.0		
	7.8	8.7	7.2			
	7.7	8.5				
	7.6	7.8				
		8.7				
		7.3				
		8.7				

The specific bond issues arrayed above are identified in the following table.

Note how the Aaa bonds of Exxon, Socal, and Texaco, and the Aa bonds of Arco, yield only 7.6% to 7.9% even when they are long term.

The Baa rating of Penzoil and Tenneco pushes them up only to 8.3% and 8.8% for near instanties. But on long maturation we see a real spread between the Aaa and the Ba of Grolier (16.0% and the B of White Motor (14.4%).

While these are only fragments, they do make the point that firms with accumulated wealth have a comparative advantage in financing for the longer term.

Bonds maturing between 1976 and 1980 - Moody's Ratings				Current yield July 1976
Aaa	Ford 7¼%	1977	note	7.2
	6¼%	1979	note	6.9
	GE 6¼s	1979	deb.	6.5
	GM 3¼s	1970	deb.	3.7
Aa	Altantic Refining 3¼s	1979		3.7
	Atlantic Richfield 7.0%	note	1976	6.9
A	AMAX 7½%	note	1978	7.6
	Cities Service 7.0%	note	1978	7.0
Baa	Pennzoil 8 3/8s	deb.	1976	8.3
	Tenneco 10¼s	deb.	1978	8.8

Mature between 1981 and 1985				
Aaa	DuPont 8.0%	note	1981	7.9
	GM 8.05%	note	1985	8.0
	Merck 7 7/8%	note	1985	7.9
	St. Oil-Ca. 4 3/8s	deb.	1983	5.3
	St. Oil-Ind. 4¼s	deb.	1983	5.5
	Warner Lambert 8.3%	note	1985	8.0
Aa	Monsanto 8.0%	note	1985	7.9
	Union 8 3/8s	deb.	1982	8.2
	8 3/8s	deb.	1985	8.3
	Xerox 8.2%	note	1982	8.1
A	AMAX 8½%	note	1984	8.5
	Hercules 8 3/4	note	1983	8.6
	ITT 11%	note	1982	10.0
	9 1/8%	note	1983	9.0
	Pepsi 8¼%	note	1985	8.5
	Phelps Dodge 4¼s	deb	1982	8.5

	Sybron 9 1/8% note 1985	8.9
Baa	Occidental Petro. 11.0% note 1982	10.0
	Pennzoil 10 5/83 deb 1983	10.0
	Maturing between 1986 and 1990	
Aaa	DuPont 8% note 1986	10.4
	Aa	
A	Beth. Steel 4½s sub. deb. 1990	6.3
	Reynolds Tob, 7s sub. deb. 1989	8.2
Baa	Amax 8s deb 1986	8.7
	Internat. Harvester. 7 3/8s convert. sub. deb. 1988	6.9
	SCM 9½s deb. 1990	10.0
B	United Brands 6 3/4 1988	14.0
	Maturing between 1991 and 1995	
Aaa	Ford 9¼s deb 1994	8.9
	Gt 5.35 deb. 1992	6.8
	Gulf 8½s deb 1995	8.5
	St. Oil-Ca 5 3/4s 1992	7.4
	-Ind 6s deb 1991	7.3
	Aa	
A	Chemetron 9s deb 1994	9.3
	Intern. Harvester 8 5/8s deb 1995	9.1
	ITT 8.9s deb 1995	9.1
	Sherwin Williams 5.45s deb 1992	7.7
Baa	Chrysler 8 7/8s deb 1995	11.0
	Intern. Harvester 4.8s sub. deb. 1991	7.4
	Tenneco 7s deb. 1993	8.9
Ba	Grolier 9½s deb 1991	16.0

B	Evans 6½s convert. sub. deb. 1994	11.0
	White Motor 6 3/4s deb 1993	14.4

Maturing between 1996 and 2000

Aaa	Exxon 6s deb. 1997	7.6
	6½s deb 1998	7.9
	GE 7½s deb 1996	7.9
	St. Oil-Ca. 7s deb 1996	7.8
	-Ind 6s deb 1998	7.7
	Texaco 5 3/4s deb 1997	7.6
Aa	Atlantic Richfield 5 5/8s deb 1997	7.6
	Bet. Steel 6 7/8s deb 1999	8.5
	9s deb 2000	8.9
	Cat. Tractor 8 3/4s deb 1999	8.7
	8.6s deb 1999	8.5
	Dow Chem 7.6s deb 1998	7.8
	8.78s deb 2000	8.7
	Union Carbide 5.3s deb 1997	7.3
	Xerox 8 5/8s deb 1999	8.7
A	ITT 10s deb 2000	9.8
	St. Oil-Oh 7.6s deb 1999	8.7
	8½s deb 2000	8.8
	US Steel 4 5/8s deb 1996	7.2
Baa	Chrysler 8s deb 1998	13.3
	Pennzoil 8 3/8s deb 1996	9.7
	US Industries 7 3/4s deb 1997	12.0

Appendix L

PROFIT SHARE BIDDING FOR PETROLEUM LEASES

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Competitive profit share bidding, where potential lessees bid the percentage of total profits from the lease that they will pay to the State, is an alternative to the traditional competitive bonus bidding procedure for allocating an oil and gas lease to one among several potential lessees. This approach was used by the State of California and the City of Long Beach in the 1965 sale of leasehold interests in the East Wilmington unit located in the Long Beach Harbor tidelands. A variant of this procedure is for the lessor to specify the percentage of profits that the lessee pays to the lessor and then to allocate the lease to the highest bonus bidder. To be most effective at preventing premature abandonment of the lease, profit share leases should not contain a royalty provision.

Profit share bidding has three particularly attractive features relative to bonus bidding and most other alternative bidding procedures. One is that profit share bidding permits the lessor to share in unexpectedly large future price increases that would not be built into bonus bids or into the royalty schedule included in the lease contract. Given the price trends of recent years and the future outlook for still higher petroleum prices, this advantage appears to be particularly important. However, an offset to this is that the lessor bears a higher proportion of the risks that the market price may go down in the future than with bonus bidding. The supporters of profit share bidding are arguing, in effect, that the probability of unexpectedly higher prices is greater than that of unexpectedly lower prices; hence, on balance, the State would gain from profit share bidding.

The second principal argument for profit share bidding is that it permits the State to capture more of the inherent economic rent in the lease when discoveries are unexpectedly (from the industry's point of view) large and

profitable. On the other hand, the lessor bears more of the risk that the lease is unexpectedly unproductive or only marginally productive than if bonus bidding is used. If the industry shows a bias towards predicting smaller discoveries than actually occur on the average, profit share bidding would indeed provide advantages for the lessor. The author is aware of no evidence that supports the hypothesis that the industry, on the average, expects smaller discoveries than actually occur. In the author's opinion, the opposite is the more likely hypothesis--the industry probably expects a greater probability of finding commercial reserves and larger and more profitable reserves than actually occur, in which case profit share bidding would not be in the lessor's best interests.

Both of these arguments for profit share bidding presume that the State cannot or will not impose additional taxes, such as a severance tax or an ad valorem property tax when industry profits become so large, due to unexpected price rises or unexpectedly great productivity, as to be politically unacceptable. Since it is doubtful that any lease contract should be so written as to cover every possible outcome or eventuality, these arguments for profit share bidding do not appear, to the author, to be very strong because of the safety valve provided by the State's general taxing powers--which are implicitly accepted by each lessee when he decides to operate within the State's boundaries.

The third advantage of profit share bidding is that it can avoid the related problems of disincentives for development of the marginal portions of the reservoirs under the lease and premature abandonment of the lease that are present where the lease contract includes a royalty. This advantage obtains if all capital and operating costs (including interest on the lessee's borrowed and equity capital) are deducted from gross revenues. Where the costs of debt and equity capital are not deductible against gross revenues, the percentage of

total profit going to the lessee--from which he must recover the costs of his debt and equity capital--is the determinant of whether he will make investments at the margin in pressure maintenance, development drilling, secondary recovery, etc. At the very high profit shares going to the lessor in the case of the East Wilmington unit, and given the relatively low "general contractor's" fee, the lessee's incentives to develop marginal portions of the lease are likely to be minimal. In the author's opinion, profit share bidding lease contracts should permit deductions of interest and a reasonable return on the lessee's equity capital from gross revenues when computing profits for the lease. The deduction for the cost of equity capital must be carefully set so that it will not be greater than the lessee's cost of equity capital, thus resulting in over-investment of equity capital in the lease.

Although competitive profit share bidding appears, on the surface at least, to be an attractive procedure, it is subject to several major problems with respect to its ability to maximize the landowner's wealth. The five principal problems which appear to limit the applicability of profit-sharing bidding are:

1. How can "profit" be defined so that the lessee will act in the best interests of the lessor.
2. How can "gold-plating" of physical facilities be avoided,
3. How should the oil be valued for the purpose of computing profits.
4. How can reciprocity between the lessee and its suppliers be prevented.
5. How can the portion of the inherent risk in the lease that the lessor bears be controlled by the lessor.

1. The Definition of Profit

As is readily apparent from any elementary course in accounting, there is no single, widely applicable, method for computing the annual profits from a

business enterprise. This is especially the case if the objective is to compute the annual profits of one operating entity of a business firm that has other operating entities. The problems with these calculations fall into three major categories: (1) the distribution of costs (particularly the costs of capital goods subject to physical depreciation or obsolesence) over more than one annual accounting period, (2) the allocation of joint costs (particularly general administrative expenses) among the firm's several operating entities, and (3) determination of the value set on the output of one entity that becomes an input for another entity of the same firm (the "transfer price" problem). The third problem is sufficiently important in the petroleum industry that section 3 of this paper is devoted to its discussion.

The basic objective of any business firm, whether it is an oil company operating leases on government land or engaged in some line of business, is to earn as high a return as possible on its equity capital--the capital which its shareholders have invested in the business either through purchasing its stock or through decisions of the board of directors to retain earnings in the firm. Regardless of how "profits" are defined for the purposes of the Securities and Exchange Commission, the Internal Revenue Service, or for computing payments to the lessor of oil and gas lands, the business firm will "adjust" these measures of profit for the purpose of making its management decisions so that it will maximize the return on its equity capital. Thus, from the point of view of the lessor, one fundamental objective is to design the definition of profit within the lease so that the lessee, in the process of maximizing the return on its capital, will act in the best interests of the lessor.

The author has no expertise in the fine points of accounting and can little more than recommend that before profit share bidding is seriously considered by the State of Alaska, a competent accountant should make a careful study of

the detailed procedures used by the State of California and the City of Long Beach with respect to the East Wilmington leases. The author also has been informed that a study of procedures for defining profit in profit share bidding leases is either being contemplated or is under way by the U.S. Department of the Interior as part of an overall evaluation of federal government oil and gas leasing policy.

2. Prevention of "Gold-Plating"

When a lessee agrees to share the profits from an oil and gas lease with the lessor, the effect is to permit the lessee to deduct all operating and capital costs (with the general exception of the "cost" of the lessee's equity capital) before computing profit. If the profit share going to the lessor is very high (it ranges between 96 and 100% for the East Wilmington unit leasehold interests), the lessee's incentives to control costs, especially those costs which can yield some benefit to the lessee which the lessor cannot capture, is substantially reduced or even eliminated. This is particularly the case where the lessee receives a "general contractor's" fee based on the cost of plant and equipment installed on the lease (this fee is 4% in the case of the East Wilmington leases).

Prevention of gold-plating is difficult and requires the creation of a skilled staff of field auditors and engineers employed by (or retained by) the State. Moreover, these state officials will likely have to be given considerable discretion with respect to what constitutes the appropriate level of capital investment and operating expenditures for the lease. This task is difficult enough for the executive managements of profit seeking business firms; however, given the nature of the political atmosphere within which state officials must make decisions, the task of eliminating or sharply curtailing gold-plating may be insurmountable. Two examples will illustrate this point.

The first example is concerned with reducting the probability of environmental damage through an oil spill or other accident. Given the growing concern for protecting the environment and the great interest of the news media in industrial accidents where environmental damage has or may occur, the government officials responsible for protecting the state's interest in the lease are under considerable pressure to prevent the occurance of oil spills that would result in political outcries by vocal environmentalists and political pressures on elected officials to "do something." What is likely, of course, is that the officials responsible for protecting the state's interests in the lease will be fired or transferred to a "deadend" position. To avoid such political risks, the responsible state officials, and even the elected officials, have strong incentives to permit gold-plating with respect to environmental protection. The East Wilmington unit provides substantial examples of such gold-plating.

Furthermore, since the political outcries resulting from an oil spill or other real or fancied environmental damage may lead to strong political pressures to shut-down the lease (as happened in the 1969 Santa Barbara Channel oil spill), the lessee also has strong incentives to gold-plate his lease with respect to environmental protection devices and to operating procedures which are exceptionally costly but reduce the probability of oil spills to acceptable levels. These incentives can operate even when the profit share going to the state is considerably less than that of the East Wilmington leases. These incentives are also present when other procedures, including bonus and royalty bidding, are used to determine the lessee; however, the ability of the lessee to deduct all costs in determining the payment to the lessor makes profit-share bidding particularly vulnerable to this kind of gold-plating.

The second example has to do with operating costs. In remote areas of Alaska subject to climatic extremes, the operators of oil production and transportation facilities provide living quarters and some level of the amenities

of life to their employees. Where a very large percentage of the profits from the lease go to the lessor, the lessee has little incentive to control these costs, especially where they contribute to labor peace and minimal labor-related disruptions in the flow of oil to be marketed by the lessee. Furthermore, since labor troubles can result in considerable political pressures on elected officials for meeting the workers' demands--especially where major labor unions are involved--the officials responsible for protecting the state's interests in the lease have definite incentives to permit gold-plating with respect to worker amenities to reduce the probability of losing their jobs because of labor unrest.

It should be noted, none-the-less, that environmental gold-plating and the provision of worker amenities are not viewed as being serious problems by some interest groups--most notably environmentalists and labor union leaders. However, the issue is not whether environmental protection and the provision of worker amenities are good or bad. The basic issue here is whether a profit sharing leasing procedure will, through its incentives for gold-plating, provide the politically acceptable level of environmental protection and worker protection from the point of view of all citizens of the State and their elected officials. In general, it appears to the author that the lease contract should promote maximizing the wealth of the lessor and that the State's elected officials should make explicit political decisions with respect to the levels of environmental protection and worker amenities that should be incorporated into the lease contract as constraints on the lessee's behavior.

3. Valuation of the Oil and Gas for the Purpose of Computing Profit

If none of the State's profit sharing lessees were integrated oil companies or if all of the oil marketed by the lessee were sold on the free market to non-affiliated refiners and carried in non-affiliated transportation facilities, the market price of the oil would provide an objective standard for determining the value of the oil to be used in computing profits. In this case, the lessee

could not capture a portion of the economic rent inherent in the lease through increased refining or transportation profits--except possibly through secret rebates, reciprocity or oil exchange deals. The problem of policing one of these sources of "extra" profits--reciprocity--is discussed in the next section of this paper.

Where the lessee is an integrated firm and some of the oil is sold on the free market (and the rest processed in the lessee's refinery), the free market price of the oil provides an apparently objective basis for determining the value of all oil produced by the lessee. However, there is an inherent problem with using this approach that has been a major concern of California officials responsible for the East Wilmington unit. Oil prices (including the base price and API gravity price differentials) depend upon the value of the oil, relative to alternative crude oils that could be used by refiners and the refiners' product slates, to the marginal refiner of that oil. Each refinery has its particular mix of crude oil distillation units and downstream processing units (e.g., cracking facilities), of varying ages and technologies. Some refineries are able to process more profitably a given crude oil than others. Where a refiner has on a long-term basis an assured supply of a given crude oil, he can design his refinery (and orient his marketing efforts) so that he can most profitably process that crude oil--thus, increasing its value (sometimes substantially) relative to the value of that same crude oil at the typical refinery which could profitably use that crude oil. This is, of course, the primary economic reason for vertically integrated oil companies.

By acquiring leases on lands producing a large volume of a given crude oil, the integrated refiner may be able to capture a portion of the economic rents inherent in the lease by selling some of the oil on the free market, to establish its value for the purpose of calculating the profits from producing the lease, and then building the necessary refinery units to increase the value of the

crude oil above this "market price." The integrated refiner records the added profit, assuming that there is any, as a higher rate of return on his refinery investment than the rate of return just necessary to get him to invest in the refinery facilities. The "economic rent" thus captured by the integrated refiner/producer is generally called "quasi-rent" by economists because it results from the lower price necessary to sell all of the oil, by selling the excess over the refinery's requirements to a refiner who places a lower economic value on the crude oil because of his particular technology, crude oil and product mix.

A similar situation may arise where the producer owns a portion of the transportation facilities moving the oil from the field to his refinery. By tailoring his transportation facilities to the lease, he can reduce the transprotation costs to his refinery relative to the cost of transporting the oil to the marginal refinery. This further increases the "quasi-rents" which the integrated firm can capture from the lease.

Where competitive bonus bidding is used to select the lessee, it is likely that those potential lessees who are integrated refiners, transporters and producers of oil would include in their bid at least a portion of the increased value of any crude oil they find on the lease at their refinery since this would increase the probability of their winning the lease. This would particularly be the case if the reserves under the lease are possibly large enough to make it profitable for the potential lessee to contemplate substantial modernization of his refinery in the process of adapting it to the potential oil under the lease. It is also more likely to be the case at drainage sales where the properties of the oil and its potential volume can be reasonably well estimated from previous discoveries. The ability of the lessor to capture at least a portion of the refinery profit over all costs through the bonus bid supports continuing to permit integrated refiners to bid for leases on government lands.

It is difficult for the lessor to capture all or a portion of these "quasi-rents" through provisions in the lease contract. The lessor would need to have access to the lessee's refinery simulation models, which contain the necessary cost and technological information to determine the value of the oil to the lessee. This information is normally treated as being highly confidential by refiners, on par with the explorationist's geological and geophysical information. Provisions in the lease contract giving the State access to this refinery information may be difficult to enforce and would require considerable expertise on the part of the responsible state officials to interpret.

The above discussion was with respect to oil, and by inference natural gas liquids, because valuation problems do not arise with respect to sales of natural gas to regulated interstate pipeline companies owned by others. It is unlikely that natural gas would be used by the lessee for other than oil field uses. A possible exception might be with respect to sales of natural gas to be liquified and/or transported to markets in facilities owned by the lessee. By having the liquification plant pay less than the value of the gas or by having its transportation affiliate charge more than its total costs for shipping the LNG, the lessee could reduce the profits of the lease and capture a portion of the economic rents inherent in the lease. Preventing this kind of undervaluation of the natural gas produced on the lease would involve the State in widespread investigations of the lessee's LNG operations.

In the case of either oil or gas, the nature of the profit share bidding procedure provides greater incentives for the lessee to undervalue production from the lease than bidding systems based on bonuses, rentals and/or royalties. With a royalty, the State can always take its share of production and market it itself if it believes the price paid by the lessee is too low. With profit shares, the State loses this important protection against undervaluation of the production from its lease.

4. Reciprocity Between the Lessee and Materials Suppliers

Although the Federal Trade Commission and Justice Department have long been concerned about the market-foreclosing aspects of reciprocity arrangements where a firm's supplier must buy products from that firm, reciprocity has special implications where profit sharing arrangements are included in oil leases. If the lessee can shift most or virtually all of a higher price for plant and equipment or materials and supplies to the lessor, and can thus receive lower prices or better services on goods purchased elsewhere from the supplier, the lessee has an incentive to pay more than is necessary for those goods where reciporcity is possible. Similar incentives arise where the lessee is involved in constructing transportation facilities whose tariffs are based on traditional cost-of-service regulation. This problem is more likely to occur where the lessee is a large firm with geographically diverse operations.

Short of having an "inside" informant, this type of reciprocity arrangement is almost impossible to police by state officials. There is no practical way that the State can audit the books of a widely diversified corporation to detect such arrangements. Competitive bonus bidding, however, does not present this problem since the prospects for reciprocity arrangements--if there are any--would likely be reflected in the bonus bids since that would increase the probability of the bidder's winning the lease.

This reciprocity problem potentially arose with the East Wilmington unit when the operators wanted to restrict bidding for tubular steel goods to American steel companies, rather than to permit the greater price competition that existed with foreign (principally Japanese) firms entering bids. The arguments by the lessees and the government officials managing the leases favoring restricting the bidding to American firms related primarily to the alleged higher quality of American-made products (which is related too to the "gold-plating" issue discussed above in section 2); however, since all tubular

goods used on the lease had to meet the same strict specifications regardless of source, the quality argument was not particularly persuasive. The author in his study of this situation for the California State Lands Commission concluded that reciprocity must be the major economic reason for the lessee's wishing to restrict the bidding to American firms.

5. Risk-Sharing Attributes of Profit Share Leasing

Since petroleum exploration, development and production is an inherently risky business, one of the important aspects of each alternative leasing procedure is the way in which the geological and technological risks inherent in the tract of land and the market risks inherent in the oil business generally are to be shared by the lessee and lessor. For example, with bonus bidding and no royalty the lessee bears all of the risks inherent in the lease. With profit share bidding and a very high percentage of the profits going to the lessor, the lessor bears a large portion of the risks resulting from operations after the exploration and initial development phases. The proportion of risk borne by each party to the lease is a major determinant of the present value of each party's cash flow since bearing a higher portion of the risk generally increases the applicable discount rate, thus reducing the present value of future cash flows.

Given the objective of maximizing the present value of the cash flow going to the State, the State may wish to bear more or less of the inherent risks than would be implied by a profit sharing arrangment. One of the criticisms of the use of profit share bidding in the case of the East Wilmington unit was that since the area had already been explored prior to the lease sale and the oil reserves and appropriate technologies for extracting the oil had been identified, the geological and technological risks inherent in the lease were exceptionally low. The remaining risks were primarily market-oriented in nature.

Under the circumstances, the critics of the profit share bidding procedure argued that the State should have used a leasing procedure where the lessee bears virtually all of the geological and technological risks. In either event, the lessor would have to bear the same basic market risks whether profit share or bonus bidding was used. This argument implies bonus bidding; however, given the identified reserves of the lands to be leased (in the neighborhood of one billion barrels) and their location in a crude oil short refinery center, the bonus bids would have been huge by 1965 standards and could have severely constrained the industry's capital raising abilities.

The critics of the use of profit share bidding in the East Wilmington case believe that profit share bidding is most applicable to rank-wildcat prospects where the inherent geological and technological risks are greatest. In their opinion, having the lessee bear virtually all of the risks in this case likely reduces the present value of the lessor's expected cash flow from the lease relative to the situation where the lessor bears a higher proportion of the risks.

Determining the proportion of the inherent risks that the State wishes to bear is, of course, a political decision that is best made explicitly by elected officials at the time they determine their leasing policies.

The portion of the inherent geological, technological, and market risks that the lessor wishes to bear can be controlled to some extent by specifying the profit share in the lease contract and then select the lessee using the bonus bidding procedure. The smaller the profit share going to the lessor, the greater the bonus bids and the greater the proportion of the total risks inherent in the lease borne by the lessee. It is possible that the bonus bid would shift some or all of the benefits of the higher value of the oil at the lessee's refinery and even reciprocity arrangements to the lessor since under truly competitive bidding the bidder would have incentives to include such

profits in his bid. The problems of defining profits so that the lessee will act in the lessor's best interests and of "gold-plating" are still present when the bonus bid is used to allocate the profit sharing lease, although they can be reduced by reducing the profit share. To the author's knowledge, such a system of awarding leases has not been used in the United States.

6. Conclusions

Although some of the above problems with profit share bidding are more-or-less common with other leasing procedures, the author believes that a careful analysis of all the alternative leasing procedures will result in a relatively low ranking being assigned to profit share bidding on economic grounds. Whether the political attractiveness of profit share bidding or a profit sharing lease contract allocated by bonus bidding is sufficient to overcome its apparent weakness with respect to its inherent administrative problems is another matter for others to decide.