Selling and Managing Offshore Oil Leases: A Real Options Analysis

Graham A. Davis  
Colorado School of Mines  
Golden, CO 80401

Radford Schantz  
US Department of the Interior  
Herndon, VA 22070

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Abstract

Real option valuation is applied to modeling and valuing oil and gas properties leased by the US government with focus on offshore areas. The properties owned by the government are modeled as compound American-type calls on oil and gas with an infinite term, and their exercise price is paid to nature. When the government leases these perpetual options to the private sector, it modifies their structure by imposing 5- to 10-year terms and other conditions. Diligence conditions in these leases are appropriate inasmuch as the decision of timing of exercise is made by the government when it leases out its options. However, current lease policy may result in exercise that is premature in respect of social economic efficiency. Total social loss of resource rent is estimated to be about 10% of the asset’s value. The principle policy implication is that if the finite lease terms are to be maintained, lease sales should be limited to oil options that are well in-the-money.

1 Earlier versions of this paper were presented at the 2000 American Economics Association meeting and the 2003 INFORMS meeting. We thank colleagues at these presentations for their helpful comments.
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Introduction

The application of real option valuation to modeling and valuing oil leases was one of the earliest uses of the technique (Paddock et al. 1988). However, that and subsequent applications assume the perspective of the lessee, that is, the person who rents the mineral rights by means of the lease. In contrast, no previous study yields advice or guidance to a government who plays the role of lessor. This paper begins to address this considerable omission.

There are large differences between the lessee's and the landowner's perspectives, affecting every aspect of the leasing transaction. Our focus will be on two principal aspects:

- The landowner possesses the mineral land as her property in perpetuity. Indeed, the mineral land is her property even during the term of the lease; she never gives it away. In contrast, the lessee has only specific rights granted by the lease for a limited term. The crucial implication in respect of real option analysis is that whereas the options of the lessee have a limited term, the options of the landowner are perpetual.

- The lease specifies what rights are (temporarily) granted to the lessee. In granting the specific rights, the landowner must be clear about her objectives; especially, she must be clear about what decisions she is delegating to the lessee and what decisions she reserves for herself. Typically, the lessee-operator has expertise in the oil business, so the landowner delegates to him decisions about exploration and production. The landowner, however, normally reserves for herself the important decision: when should the property be exploited? as this is a decision of managing her portfolio to promote her individual objectives. Typically, the devices she uses to keep that decision out of the operator's hands are the timing of the leases and "diligence" requirements in the lease that promote prompt work. If the landowner has decided that it is time to exploit the resource, she leases to someone and provides them with incentives to work promptly; otherwise, she simply does not lease out.

Our study focuses on the case where the landowner is a government. This is the case in the US for all of the offshore oil and gas land, as well as a significant portion of the onshore oil and gas land. The offshore land is divided between the States and the Federal government. As the Federal and State approaches to leasing are similar in their broadest features, there is little loss in generality when we emphasize the Federal offshore leasing policies and laws. The Federal program is specifically administered by a bureau of the Interior Department called the Minerals Management Service (MMS).

The real option framework provides some unique and valuable insights into the nature of the sale of leases under the MMS program. We are able to offer some recommendations for improvements to the program that would enhance social welfare...
through improving the decision process about when to lease the resources. In economic terminology, we could speak of enhancing the rent derived from the land, so long as it is understood that we are not suggesting monopolistic policies. Better timing of the government's leasing-out decision should generate increased lease-based revenues for the government and improve social welfare.

While our analysis is market-oriented, in one section we discuss environmental externalities. We do not, however, discuss geopolitical externalities. By geopolitical externalities, we refer to considerations of international competition and power. The importance of geopolitical externalities of resource exploitation is amply demonstrated by history. Today, US policy about competing in the international oil land market is incorporated in a somewhat complex package: Federal supply of oil land supports a domestic oil industry, and a domestic industry is supposed to provide some insurance against apparent risks of relying on oil imports. As real option theory suggests, competitive markets sometimes (but not necessarily) have a use-or-lose character that substantially modifies the nature of options (Trigeorgis 1996). E.g., if a market can absorb only one new project, then the option holder who exercises first pre-empts the other option holders, who are left with no value. Whether or not international competition modifies the US government's options is an interesting issue not addressed in this paper.²

The paper is organized as follows. In section I, we demonstrate the real option nature of oil leases, with focus on Federal offshore oil leases. In section II, we use real options analysis to investigate whether the current Federal leasing program might be socially inefficient. In section III, we consider whether existing authority and policy on leasing constrain the government’s decisions. In section IV, we suggest possible improvements to the leasing decision process.

I. The Real Option Characteristics of the Government’s Oil and Gas Property and Leases

In this section, we show that the government’s oil and gas resource property can be modeled as perpetual compound call options on spot oil (understood to mean gas, too), and its lease sales can be modeled as “loaning” or leasing those options, with modifications and restrictions added, for a fee.

The broad features of the MMS offshore leasing program are familiar to many readers. Briefly, and of relevance to this section, the oil land held by the government is mostly only minimally explored, and in all cases undeveloped. The MMS leases rights to exploit these assets by scheduled sales where private parties can purchase a lease with the option to explore for, develop, and extract the oil. Like so-called American calls in finance, the leased options terminate after a set period, 5 to 10 years. The lease reverts

² We also do not address auction design, which has been a main focus of research relating to the offshore oil lease program.
back to the government at that time if no production has taken place (i.e., the government has a “reversionary interest”). If the lessee does start production at the property, she may continue to lease until production ends, at which time the lease reverts to the government. The government also retains a royalty interest (normally 1/6 to 1/8) in production and a relatively small ($5/acre in shallow water and $7.50/acre in deep water) annual rent that begins when the lease is issued and ends when royalty production begins.

It is now common practice to conceptualize the development and extraction of unexplored underground oil as a compound American call option—an option on an option on an option—on oil (Bjerksund and Ekern 1991, Paddock et. al. 1988, Pickles and Smith 1993, Smit 1997). Such options, because the underlying asset is a real asset rather than a financial asset, are called real options. Within this framework the owner of underground oil has the right, but not the obligation, to invest irreversibly to explore the property, and the return to the investment is some amount, perhaps zero, of known but undeveloped reserves. Holding undeveloped reserves can, in turn, be viewed as a call on developed reserves, exercised by paying the development costs. Developed reserves, finally, entail a set of options to extract, that is, to lift the oil and pipe it to shore.3

The government’s possession of offshore oil resources can be seen as owning compound calls that are “perpetual,” in the sense that there is no time when the unexercised options expire; their terminal date is infinite. For ease of analysis, the ultimate underlying asset can be taken to be developed and producing reserves, and the exercise price is the combined exploration and development cost (Paddock et al. 1998).4 Bjerksund and Ekern (1991), Pindyck (1991), and Dixit and Pindyck (1994) provide closed-form solutions for perpetual American call options whose underlying asset value changes according to a geometric Brownian motion and where the exercise price is constant.5 If indeed changes in the value of the developed reserves follow a geometric Brownian motion, the government’s oil offshore oil property can be valued using this option pricing framework.6

Figure 1 provides an estimated schedule of the average per-barrel value of Gulf of Mexico oil property owned by the government using such a framework. We use the term, pure bonus value, to mean the cash value of the property, assuming optimal management (i.e., timing of development) and the absence of any taxes, royalties, or diligence requirements. To emphasize: the value shown in Figure 1 is not the value of a limited-

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3 The extraction options include the option to temporarily shut down or permanently abandon the well.
4 Collapsing of this compound explore/develop/produce option into a single explore and develop/produce option will cause the estimated value to be biased downwards (Paddock et al. 1998, Trigeorgis 1996).
5 Data produced by the Energy Information Administration (1999) indicates that over the long term advances in technology have reduced finding costs, offsetting increased drilling and development expenditures and making aggregate finding and development costs approximately constant over time.
6 There is some empirical evidence that spot oil prices are mean reverting (Schwartz 1997). Option pricing valuations could still be performed if oil is mean reverting using numerical methods. The resultant option prices could be higher or lower than those achieved here (see Schwartz 1997).
Addendum: calculations for Figure 1

The lease values in this figure are calculated using options pricing equation (7) in Pindyck (1991), which assumes that the change in value of developed and producing reserves follows a geometric Brownian motion, the exercise price is constant, and that the option to explore and develop is perpetual. The value of developed reserves is taken to be 1/3rd of wellhead price (Adelman et al. 1991, Paddock et al. 1988), implying that unit extraction costs are a constant proportion of price. Since the value of developed reserves is a market value, it includes the value from all options to temporarily suspend or permanently abandon the well once operating. The “1/3rd” rule also implies that the volatility (σ) and convenience yield of developed reserve value are the same as for wellhead crude (Davis 1998). Based on movements in average monthly Gulf of Mexico offshore wellhead crude prices from January 1997 to August 1999, σ = 30.21%. The average convenience yield on wellhead crude over the life of the option is taken to be 10% (Schwartz 1997), consistent with oil being in backwardation. The perpetual risk free rate is taken to be 6% (on December 22, 1999, the 30-year T-bond yield was 6.4%), and the constant finding cost (the exercise price) is $7.32/bbl., the average 1997 finding costs for offshore crude reported by the US Energy Information Administration (1999). We ignore the effects of any tax deductibility of the finding costs, and also ignore any potential value from enacting endogenous costly learning about reserve uncertainty (Martzoukos 2003). We assume that firms are risk-neutral to price and reserve uncertainty, probably a reasonable assumption since 1) the large firms that bid on these leases have been measured to be almost risk neutral, and 2) we are looking to measure pure rent destruction from the existing lease structure, and not from the risk-averse behavior of firms compared with the risk-neutral view of the government.

Some details about the model and calculations that created Figure 1 are given at the end of this subsection. We do wish to emphasize that, as one might expect, our
particular assumption about the stochastic process of prices is significant in determining the numerical results shown below.7

As shown in the figure, the average value of the property is about $1/bbl of reserves if the current wellhead price is $20. As undiscovered conventionally recoverable oil and gas resources in the Gulf of Mexico are estimated to be 26 billion barrels of oil equivalent (Lore et al. 1999), the total value of these options—of the offshore Gulf oil and gas property—is $26 billion at the $20/bbl wellhead price.

An important implication of the real option analysis is that the option will be optimally exercised only when the underlying asset price rises above a threshold or “barrier.” Based on the data used to calculate Figure 1, on average, the oil and gas fields in the Gulf will only be explored and developed, given that the option is perpetual, once the wellhead price exceeds $37.43/bbl.

Additional information about the value of the property generated from the real option analysis relates to its “Greeks.” For instance, the option’s Delta at $20/bbl. is 0.41, meaning that for each $0.10/bbl. movement in the price of spot oil, the value of the undeveloped resources changes by 0.10 x 1/3 x 0.41 = $0.014/bbl., or a total of $360 million over the entire reserve held by the government.

These calls, then, are part of the US government asset portfolio, being a natural asset rather than a financial asset. Instead of exercising the calls itself (i.e., exploring and developing the fields), the MMS “rents” the calls to potential developers by means of leases. As one might easily become confused about these concepts and definitions, let us emphasize that leasing is not the same as writing calls. MMS is not short the calls because it does not receive an exercise price if the calls are exercised. The calls are “written” by nature (the underlying asset is natural capital), and owned by the government, having been acquired by way of sovereignty of its territory. If the government were to exercise the calls itself, directly, it would spend the exploration or development costs itself and, in that sense, pay the exercise price to nature.

As it is, the calls are leased to operators, who must pay the exercise price (exploration or development costs) to nature themselves if they exercise the options. However, in the lease, some additional structure is added to the original, “natural” structure of the calls. Prominently, a 5-10 year time limit (termination date) is included

7 Applying the real option framework, we can draw on a standard technique called risk-free discounting. When an appropriate adjustment is made to the growth rate of oil and gas prices, we can use the risk-free rate for discounting future expected cash flows (assuming other conditions are met as well). The risk-free rate appropriate for long-range leasing decisions is the longest-term Treasury bond rate. When real option analysis is applied to private agent decisions, the risk-free discounting technique surprises people who are used to the traditional idea that risky projects should have a high discount rate. Amusingly, the T-bond rate is actually one of the traditional—that is, predating real option concepts—candidates for discounting some kinds of Federal government investments.
in the lease. Other terms are added as well. The royalty and pre-production rent, for instance, are features written into the lease by the government that are not part of the original, “natural” call. The rent is a maintenance cost for keeping the option alive, and the royalty is fundamentally a transfer payment from the operator to the government that lowers the value of the underlying asset, developed reserves. Both of these features affect the value of the option to the lessee.

Statistical overview of leasing and the timing of exercise by private operators

Much of the section II investigates conditions when a lease holder will wait until the end of term before exercising the option and would, presumably, wait longer if he could. In support of that discussion, we here offer some data about the timing of exercise of leases in the Gulf of Mexico.

Lease sales are held annually, one for the Central Gulf and one for the Western Gulf, plus infrequent sales held for the Eastern Gulf. The number of leases sold per sale since 1979 has averaged:

- For 5 year leases: 200
- For 8 year leases: 30
- For 10 year leases: 120

The average since 1995 for 10-year leases has been much higher than earlier.

Averaging overall Gulf sales for dates shown below, the shares of calls that were exercised by end of term by either producing or being incorporated in a larger producing unit are:

- for 5 year leases, '79-'93: 12%
- for 8 year leases, '85-90: 5%
- for 10 year leases, '82-88: 13%

So roughly, ratio of leases sold to leases producing was 8:1.

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8 The rule about lease terms is this. CFR Sec. 256.37 Lease term. (a)(1) All oil and gas leases shall be issued for an initial period of 5 years, or not to exceed 10 years where the authorized officer finds that such longer period is necessary to encourage exploration and development in areas because of unusually deep water or other unusually adverse conditions. (2) If your oil and gas lease is in water depths between 400 and 800 meters, it will have an initial lease term of 8 years unless MMS establishes a different lease term. (3) For leases issued with an initial term of 8 years, you must begin an exploratory well within the first 5 years of the term to avoid lease cancellation. (b) An oil and gas lease shall continue after such initial period for as long as oil or gas is produced from the lease in paying quantities, or drilling or well reworking operations as approved by the Secretary are conducted. The term of an oil and gas lease is subject to further extension as provided in Sec. 256.73.

9 Blocks are usually about 5760 acres, and if a field underlies more than one block, they can be combined as a production unit. In that case, all leases combined are held by production at any of the unitized blocks.
Leases relinquished, or given back to MMS before end of term (as distinct from leases reverting to MMS when the term “expires”), may be a rough proxy for leases drilled earlier than the last possible time and that were “dry” (there are other reasons to relinquish, as we shall discuss later). The ratio of relinquished to producing tracts and units is 2:1, averaged over the same dates. This rough indicator understates the proportion of leases where drilling failed because some leases were drilled, found dry, and simply left to expire.

Typically, a producing well must be drilled on a lease by the end of the primary term, or the lease expires and reverts to the MMS. There are exceptions, so a few cases of first wells being drilled after the primary term appear in the data below.

Five-year primary terms

These leases are in “shallow” water. We observe a U-pattern: most of these leases that are drilled at all are drilled either in the first 2 years or the last year. In an option framework, this indicates that the options to develop are either far enough “in-the-money” at the sale date that it is optimal to exercise, or else are exercised, if at all, at the option’s expiry.

Figure 2. Timing of First Drilling, 5-year Leases Sold Between 1979 and 1994
It helps in interpreting these data to bear in mind the distinctive aspects of Gulf shallow water leasing:

- Jack-up rigs used in shallow water are not in short supply, generally, so it is feasible to arrange for drilling in the first lease year.

- Many of the 5-year leases are bought by small operators. The small operators don’t hold working inventories of leases. Instead, they tend to buy for prompt development to generate cash flow promptly. In an option pricing framework, this means they target leases that are in-the-money given their financial constraints and the high opportunity cost of waiting. They also tend to target areas of known potential, and hence there is less advantage to waiting for new area-wide reserve information before drilling.

- Related to that point, many of these are gas leases, which tend to be quicker to complete and produce than oil prospects.

8-year term

8-year leases are offered in water depths between 400 and 800 m. There are comparatively few leases in this class. At least one well must be drilled within 5 years, but it need not be producing to hold the lease for 3 more years. By the end of the 8th year, a producing well must be drilled, or the lease expires.

The graph of 1st wells shows a peak at the end of the exploration term, years 4-5, again consistent with the option framework of exercising at the option’s first expiry date.

![Graph of First wells drilled at 8-year leases, Gulf, '85-'91](image)

Figure 3. Time of First Development, 8-year Leases Sold Between 1985 and 1991
Below, total wells are graphed for the 8-year leases, and we see a peak at year 8. Presumably, there is a flurry of drilling for productive wells in this year at leases where the 1st well was drilled by year 5, but unproductive. The picture suggests that there is some tendency to wait on drilling a 2nd well until the end of the 8 years (the ultimate expiry of the option).

![Wells spudded in 8-yr term leases](image)

**Figure 4. Total Wells Drilled for 8-year Leases Sold Between 1985 and 1991**

**10-year term**

The graph below shows the pattern of first wells at 10-year leases. These are offered in deeper water, over 400 m. These leases tend to be held by majors who hold working inventory of leases, sometimes numbering hundreds of leases at a time.

The graph shows a small peak at the outset and a large peak at the end of the primary term. Deepwater drilling rigs can be scarce; in deeper water, it is not generally feasible to arrange for deepwater rigs on short notice; hence the amount of drilling in the first years is dampened and spread out over years 1-3.

The tendency to wait to end of term to drill is evidently strongest in the class of deepwater, 10-year leases. Presumably, the advantage of waiting for new information and new technology is greatest in deepwater. The majors holding portfolios of deepwater leases can, of course, afford to wait, since their effective opportunity costs of waiting are lower.
Overall, a pattern of drilling activity is consistent with lessees optimally managing their finite options to produce. The majority of leases are drilled, if at all, only at expiry, and the early exercise feature is usually not used by the lessee unless they are a small operator with a high opportunity cost of waiting and a need to generate cash.

II. Economic Efficiency

Three elements of the US government’s offshore leasing program are considered here as potentially affecting the leasing program’s economic efficiency, in the sense that social net benefits related to the exploitation of the oil and gas options might be diminished by those elements. These elements are finite lease terms, pre-production rents, and production royalties. These elements of the program have been criticized on several fronts—principally in the academic forum—as inefficient, or resource-rent destroying (e.g., Bradley and Mead 1998, Muraoka and Mead 1987).

Let us begin by stating the criticisms:

- First, there is the concern that the finite lease term suboptimally advances the timing of oil extraction and lowers the resource rent attributable to the asset. However, this has never been validated or quantified using a model of economic value. Viewing the government’s holdings as perpetual American call options not only aids us in valuing
the holdings, but allows important insights into these inefficiency aspects of the lease program.

- Second, the pre-production rental payments are thought to distort the timing of extraction by moving it forward. Below, we quantify these resource rent losses.

- Third, the royalty payments are alleged to delay production—perhaps countering the effects of the first two items—and to lead to a greater amount of oil to be left in the ground. We again quantify the efficiency effects below.

To avoid confusion, however, let us state here that we do not advocate longer lease terms nor omission of diligence requirements. To the contrary, relatively short terms and other restrictions are appropriate elements of government-issued leases. Our policy position will become clearer after we have analyzed the effects of lease terms and requirements.

**Effect of finite lease terms**

We first analyze the loss of resource rent on an average lease due to selling leases with finite terms. Assume that the leases are sold on a pure bonus basis. By “pure bonus” basis, we mean paying for the lease with a single, up-front cash payment, with no royalty or rental terms attached. As is well known, the lease program has three revenue components: bonus payments (i.e., winning bids in an auction), pre-production rental income, and royalties. (Additionally, the government taxes net income, if any, but the business income tax is considered a different program.) The pre-production rental and royalty structure adjusts the structure of the payments for the lease from a single cash bonus payment to a combination of bonus payment and deferred taxes. If the payment structure were non-distortionary, the present value of receipts from all sources on any one lease could potentially be equivalent to the revenue that would be raised were the leases made on a pure bonus format.

A lease of something like a machine for a fixed term has been modeled as a portfolio that is long in the underlying asset and short a European call option on the same underlying asset. The idea is that the lessee is obligated to return the machine at the end of the lease term, and this is modeled as a call held by the lessor. The lessor’s call has an exercise price of zero and expiration date set to the termination date of the lease (Grenadier 1995). The short call, in this case, is a liability of the lessee that lowers the value of his portfolio below that of outright ownership of the underlying asset. One implication of this model is that such a lease only partially monetizes the asset that is being leased by the lessor, as the shortfall, the value of the short position in the European call, is simply the value of the reversionary interest of the lessor.

In the case of the government’s oil leases, the lease is of a significantly different nature, in that what is being leased is an option rather than a service flow. The American-type call may expire unexercised and revert to the government, or it may be exercised by the lease holder. As with all leases, the finite lease period reduces the value
of the call to the lessee. But in this case, the finite lease period might also destroy resource rent by forcing suboptimally early exercise. While the option owned by the government is a perpetual American call, the lessee must, by the term of the lease, treat it as a finite-life American call option, and will manage the asset according to this paradigm. The result might be suboptimal from the government’s (and society’s) point of view.

Grade A. When the option is well in-the-money

Consider first options that are well in-the-money, as would be the case in Figure 1 if spot wellhead prices were greater than $37.43/bbl. Such options are valued at or slightly below their intrinsic value and are exercised immediately, more or less.\(^{10}\) Both the MMS and the lease holder will manage the option identically; were the MMS to “lend” such options to the market, the lessee would, in a competitive market, pay the MMS the option’s intrinsic value and exercise the option immediately. There is in this case no suboptimality in the lease program. This is an important point to which we later return.

Grade B. When the option is not well in-the-money

Options in this grade have some “hold” value in addition to their intrinsic value. That is, the options are worth more alive (unexercised) than dead (exercised), and it is optimal to wait for higher wellhead prices before exercising. The option is loaned to a lessee for a consideration. During the interior of the lease period there is some probability that the option will remain unexercised. If the grade B option is still unexercised at expiration, the lessee exercises then if the option is in-the-money (if the value of reserves is greater than the finding costs, a straight net present value calculation). This exercise is suboptimally early from society’s point of view, as the expiry of the option is artificially forced by the terms of the lease. That is, were the government to retain ownership of and optimally time the exercise of the option, its exercise would be delayed beyond the time at which the lessee is forced to exercise. Evidence in Section I pointed to many of the options sold by the government being exercised at the end of the finite lease. The structure of the lease therefore results in lost resource rent, with premature extraction of the oil. The effect is much like any “use it or lose it” clause on property development; it lowers the value of the asset and induces premature development by the owner of the asset.\(^{11}\)

Figures 6-8 show the approximate loss in resource rent per barrel of oil in an average lease as a result of the 5 and 10 year lease terms imposed on options that may have some holding value. The loss is plotted as a function of current wellhead price when the lease is issued. To estimate the losses, we first calculated total payments for the lease, assuming that the lease-holders will manage the leases as finite and that the government

\(^{10}\) As mentioned elsewhere, rig scheduling can suboptimally delay exercise.

\(^{11}\) This aspect of the government leasing program has been recognized by Bradley and Mead (1998), among others.
Figure 6. Dollar per Barrel Loss in Resource Rent from the Finite Lease Term, Shown with the Pure Bonus Lease Value

Figure 7. Detail from Figure 6, Dollar per Barrel Loss from the Finite Lease Term
will immediately re-lease the same property should it revert to the government unexercised at the expiry of the lease period. These payments are contrasted with the “pure bonus” value of a perpetual and optimally managed lease (cf. Fig. 1). Under our assumptions about finding costs, etc., at wellhead prices greater than $37.43/bbl, immediate exercise is optimal, and so there is no holding value sacrificed by the finite term —this is grade A. At intermediate price ranges—which relate to grade B—losses are up to $0.10/bbl for the 5-year leases, and, all else being equal, somewhat less for the 10 year leases.\textsuperscript{12} The numerical approach used to calculate the option values, a binomial lattice, introduces some error into the calculations, which is reflected in the non-smooth appearance of the curves.\textsuperscript{13} From Figure 8, the losses are greatest, at around 10% to 15% of asset value, when the spot price is low, since under these circumstances it is more likely that a lease will be exercised “prematurely” by the lessee at the expiration of the lease.

\textit{Effect of pre-production rent}

Next, given the finite term of the leases, we assess the incremental impact on the average lease of the second diligence requirement, the annual per-acre rental fee that is

\textsuperscript{12} As noted earlier, the 5-year leases are in shallow water, while the 10-year leases are in deep water. Thus, the exercise price for the 10-year leases will tend to be higher than for the 5-year leases, although we have assumed that they are equal.

\textsuperscript{13} We assume that if, after 30 years, the lease is unexercised, the government receives the perpetual value for the lease. This overestimates the value of the asset, and by this underestimates the inefficiency losses of the finite lease periods. The bias is small, though, being less than $0.006/bbl. for at-the-money options (calculated by assuming, on the contrary, that no money is received for any leases that are not explored after 30 years of being on the market).
paid to the government while the operator waits to produce. The pre-production rental alters the lessee’s payments from an up-front bonus to a combination bonus/rental stream. In our option framework, the call option on reserves decreases in value when there is a cost to keeping the option alive, but prima facie one might expect the option value to decrease by the expected present value of the rent payments, leaving the total receipts constant in terms of expected present value. However, adding a fixed “maintenance” cost to the lease structure destroys value by lowering the wellhead price at which the option will be exercised by the lessee, thereby increasing the suboptimal speeding up of exploration and development already invoked by the finite lease terms.

A second effect of the pre-production rental is that it creates, in effect, a minimum auction bid on out-of-the-money options. Under the rental fee, out-of-the-money options can become worth less than the expected present value of the pre-production rental fees, and they are, as a result, not leased for their small option value. The effect reduces resource rents because should prices rise to above $37.43/bbl. while the lease is dormant (waiting for the next lease round), exercise would be optimal, and yet since the lease is not in operators’ hands, it will not be exercised. While there might be sound reasons to set a minimum bid when selling leases, it seems inefficient to implement a minimum bid requirement in the way of a pre-production rental devise.

Focusing on the 5-year leases, Figures 9-10 show the decrease in rent due to the suboptimally early exercise induced by the finite lease structure, and then the additional decrease in resource rent due to the rent-destroying feature of the pre-production rental fees. Values for the rental fee case are only plotted for spot wellhead prices greater than $12/bbl., as below that the options will not be leased since their value is negative (the present value of the expected pre-production rental payments outweighs the option value). At low wellhead prices the additional loss due to the pre-production rental is

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14 There is also a third effect, the possibility of early relinquishment of the lease should prices fall to the point where the option value becomes less than the present value of the continued rental payments. We ignore this aspect of the rentals since we know of very few instances where lessees walked away from unexercised options— that is to say, relinquished unworked leases— prematurely (which suggests some substantial “psychic” cost associated with relinquishment).

15 The bonus-value equivalent is the expected bonus plus the expected present value of pre-production rental receipts, defined to be consistent with the “pure bonus” value given in Figure 1.
Effect of royalty

The third element of the lease that is thought by some to distort the exercise decision is the royalty payment, usually 1/6th to 1/8th of gross production. (Often the royalty is calculated from sales value of the oil or gas, priced at the wellhead, but it sometimes is paid in-kind.) This payment arrangement again is, prima facie, simply a substitution of deferred income for bonus income. However, within an option pricing framework, the royalty on production lowers the lessee’s value of the underlying asset, in this case developed and producing reserves, by about 19%.  

\[ PV(\text{Royalties}) = \int_0^\infty 0.125P(t)q(t)e^{-r_f t} dt = \int_0^\infty 0.125P(0)e^{(r_f-\delta)t}q(0)e^{-\gamma t} e^{-r_f t} dt, \]

where \( P \) is the wellhead price, \( q \) is the rate of production, \( r_f \) is the risk-adjusted discount rate, \( \delta \) is the constant convenience yield or rate-of-return shortfall on wellhead oil and \( \gamma \) is the rate of exponential decline of production. Solving, \( PV(\text{Royalties}) = \)

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16 The expected present value of royalties over the life of the reserve, once producing, is \( PV(\text{Royalties}) = \int_0^\infty 0.125P(t)q(t)e^{-r_f t} dt = \int_0^\infty 0.125P(0)e^{(r_f-\delta)t}q(0)e^{-\gamma t} e^{-r_f t} dt, \) where \( P \) is the wellhead price, \( q \) is the rate of production, \( r_f \) is the risk-adjusted discount rate, \( \delta \) is the constant convenience yield or rate-of-return shortfall on wellhead oil and \( \gamma \) is the rate of exponential decline of production. Solving, \( PV(\text{Royalties}) = \)
Addendum: calculations for Figures 9 and 10

The bonus-equivalent lease values given a rental fee are calculated assuming a rental fee of $7.50/acre [although the fee for 5-year leases is currently $5] and the parameters listed in Figure 1. Drawing on data for recent Gulf lease sales, if we take the average lease sale to convey roughly 0.80 billion BOE and to sell 677 leases of 5,760 acres each, the rental fee equates to $0.00457/BOE. We ignore income-tax deductibility of the rental payments. The bonus-equivalent is the present value of all expected bonus payments, including the additional bonuses after repeated offerings of unexercised leases for up to 30 years, plus, if applicable, the present value of all expected rental payments for a typical lease as we follow its possible lives over an infinite period. When calculating the impacts of the fixed rental fees, we assume that if the present value of the expected rental payments exceeds the option value at any lease sale, the lease receives no bids at that time. This happens at all wellhead prices below $12/bbl. When the option value of the leases during any lease sale is greater than the expected rental fee obligations, we assume that the lease is successful and that rental payments are made until the expiration of the lease, or development, whichever comes first (that is, there is no relinquishment option if this should prove optimal). If the lease remains unexercised after 6 consecutive leases, we assume that the subsequent lease sale will receive the maximum of the perpetual lease value less the present value of a perpetual stream of rental payments—on an expectations basis, with oil prices in backwardation and the market price of risk of oil being zero (Schwartz 1997), the lease will never be exercised (Riddiough 1997, 66)—or zero.

\[ 0.125 P_0 \delta_0/(\delta + \gamma), \]  

or, on a per barrel basis, \( PV(\text{Royalties})/Q_0 = 0.125 P_0 \gamma/(\delta + \gamma) \) where \( Q_0 \) is initial reserves and \( q_0 = \gamma Q_0 \). Assuming \( \delta = \gamma = 0.10 \), \( PV(\text{Royalties}) = (0.125/2)P_0 \). Using the 1/3rd rule, this is equivalent to a tax of 18.75% on the value of developed and producing reserves.
This tends to delay exercise by artificially increasing the oil price at which exercise is warranted. Our calculations show that the immediate exercise threshold rises from around $33/bbl. for a 5-year lease (with pre-production rental) to $40.50/bbl., above the optimal (undistorted) immediate exercise threshold of $37.43/bbl. Thus, when oil prices are between $33/bbl. and $37.43/bbl. the royalty component not only offsets the early exercise suboptimality induced by the finite lease terms and pre-production rentals, but it now causes the resource to be developed too late. For spot prices between $37.43/bbl. and $40/bbl., the royalty suboptimally delays immediate exercise and destroys lease value where there was no destruction before. The royalty has no impact above $40.50/bbl., as leases that would have been immediately exercised are still immediately exercised.

At the same time, the royalty payments increase the oil price at which an operating oil well is shut-in.\textsuperscript{17} We cannot say whether more or less oil will be left in the ground, though, as the first effect, delayed exercise, makes it less likely that abandonment prices will be reached during the life of the well, and this partially or fully counters the risk that oil at an operating well will more readily be abandoned should prices fall.

The net result of all three lease requirements on bonus-equivalent value, which now includes the present value of all future bonuses, pre-production rental, and royalties, is shown for the 5-year leases in Figure 11. When the royalty is included the bonus-value of the options becomes negative at wellhead prices below $15.00/bbl., and so the leases will not be sold in that case. At wellhead prices above $15.00/bbl. the royalty scheme is shown to offset some of the loss in rent due the rental fees and finite lease term. This is because at these wellhead prices the royalty slightly dissuades premature exercise, offsetting some of the efficiency losses. At higher wellhead prices (greater than $33/bbl.), though, the exercise becomes too tardy, inducing economic losses that are greater than they would be without the royalty.

The royalty of course reduces the bonus that the government receives when the leases are sold. Figure 11 also shows the bonus payment expected to be received per barrel of oil equivalent eased, as a function of current wellhead price. At a wellhead price of $18/bbl., the bonus is $0.17/bbl., with the present value of expected future bonuses if the lease expires unworked, expected pre-production rents, and expected royalties adding $0.64/bbl. to give a bonus-equivalent value of $0.81/bbl. In the August 1999 Central Gulf lease sale, during which the wellhead price was $18/bbl., the bonuses paid were between $0.14/bbl. and $0.41/bbl. depending on the amount of oil and gas ultimately recovered, and our estimate, applicable to the “average” lease, falls within this range.\textsuperscript{18} Of course, there are no accurate, \textit{ex post}, estimates of resources conveyed by the leases until many years later, when production is completed. Also, we note that until

\textsuperscript{17} In option pricing terminology, the royalty increases both the investment \textit{and} abandonment trigger prices.

\textsuperscript{18} We included data for Central Gulf sales held in August of 1997, 1998, and 1999. MMS’s \textit{ex ante} estimate of reserves conveyed in these sales is 0.42-1.22 BBOE of oil and gas. The number of leases sold averaged 677 for an average $600 million in high bids.
In 1999, recent oil and gas prices were higher than $18/bbl, and if we look only at sales results for

![Graph showing bonus-equivalent lease value with finite lease term, pre-production rental, and royalty, shown with pure bonus value and actual bonus paid, 5 Year Leases](image)

**Figure 11:** Bonus-equivalent Lease Value With Finite Lease Term, Pre-production Rental, and Royalty, Shown with Pure Bonus Value and Actual Bonus Paid, 5 Year Leases

**Addendum: calculations for Figure 11**

In this figure we add the impacts of a 12.5% gross royalty on production. The bonus-equivalent here is the present value of all expected bonus payments including the additional bonuses after repeated offerings of unexercised leasings, plus, if applicable, the present value of all expected rental payments and royalty payments. We ignore any tax deductibility of the royalty payments, and assume away any investment distortions created by the royalty (see Ramoo 1995, Manzano 1999).

In 1999, bonuses averaged an estimated roughly one-half dollar per barrel. In addition to the crudeness of our calculations with actual sales data, the neglect of income-tax considerations in our analysis might cause an under-estimate of theoretical bonus bids.

In sum, the three diligence requirements, when considered together, have a remarkably minor impact on the efficiency of resource development and extraction in the Gulf of Mexico, resulting in at worst a 10% loss in economic rent derived from extraction and ultimately paid to the government. This is in part because the royalty effects mitigate the effects of the finite lease term and rental payments. Another impact of the diligence requirements is that the leases are made uneconomic to the lessee at low oil prices, and they will not, as a result, be taken up in a lease sale. We have not estimated the lost value for these leases, as they tend not to be offered by the government anyway. We have also not analyzed the impacts for leases of varying cost, and have used an average finding cost.
of $7.32/bbl. in all calculations. It may well be that the impacts are greater for higher or lower cost tracts, something that we will investigate in the future.

Preliminary policy implications: lease terms and timing of sales

Under the assumptions of our real options analysis, unlimited sales of finite term leases with royalties and diligence requirements tend to result in private management of the resource that is suboptimal from the government’s point of view. To this extent, our conclusions are consistent with the conclusions of a number of other, mostly academic, discussions of the leasing program, although our results show that the degree of rent destruction is not likely to be large. Even so, the question arises, what change to policy might be recommended to eliminate this rent destruction? Here we differ from some who have written on this subject.

Consider first the 5- to10-year lease terms. It has been suggested that lease terms should be longer in order to allow the lessee more flexibility in deciding the optimal exercise time and to avoid forcing her “prematurely” to exercise within a short term. (e.g., Muraoka and Mead 1987). This suggestion is confused. The answer to the question, what should the lease term be, is: the shortest term that allows the lessee reasonable flexibility in performing his business expeditiously, namely, the business of exploration and development. For instance, an exploration term of 1 year is too short, because it may be that oil prices are temporarily low or rig rates are temporarily high; and also, orderly planning of exploration takes time. It is reasonable to allow the lessee a few years to ride out the temporary, profit-reducing bumps in the road and to allow a few years for orderly planning and deployment. And 5 to 10 years is, most people believe, sufficient— even ample— flexibility.

Let us, now, smooth out the bumps in the road and consider more broadly, should exploration or development in a certain area occur now, or 50 years from now, or 100 years from now? So long as the land is government property, the decision about exploiting the land over this time horizon is the government’s decision. The private oil industry has no inherent insight into the government’s objectives in managing its natural capital assets. There is no reason to allow longer lease terms, delegating to the operator the decision whether to exploit now or later over the long term. Thus:

- On one hand, if the government decides to exploit now, then it holds a lease sale. Its purpose in holding the sale is to put land in the hands of people who will act with reasonable promptness -- hence, short lease terms.

- On the other hand, if it decides to wait, then it simply does nothing. Later, if it decides to exploit the land, then it holds a lease sale.

The real option analysis suggests a policy of selling only leases that are well in-the-money, the grade A above, where both lessee and government are in agreement that prompt exercise is optimal. In that policy, short lease terms are useful in order to ensure
that the lessee either acts promptly, as the government desires, or gives up the lease for resale. The burden is on the government to somehow sell only leases where prompt exercise is deemed desirable.

Broadly speaking, there are two ways to limit lease sales to only leases that are well in-the-money:

1. Limit the selection of leases offered for sale to those that the government deems are well in-the-money. This is a quantity limitation.

2. Have reservation prices that are high enough that only well in-the-money leases will be bought. This is a price limitation.

These two implementations are discussed further below.

In theory, an alternative policy is that the government could eliminate the inefficiencies induced by the finite lease terms by offering finite leases on a pure bonus basis and buying back the option from the lease holder for its hold value if it remains unexercised just prior to the end of the lease period. This is somewhat similar to a cash rebate on a barrier option. Since, to the MMS, the “hold” value of the perpetual option at the lease’s expiry will be worth at least the finite option’s value to the lessee, the lessee will gladly sell the option rather than exercise. In essence, this buy-back scheme, by inducing the lease holder to behave as if they were holding a perpetual option on the oil, will eliminate the suboptimally early exercise currently imposed by the lease terms at many leases. However, a program that involves large-scale refunds by the government is probably not realistic.

Other policy implications: pre-production rental and royalty

Suppose that, as recommended in the preceding subsection, the government only sells leases at optimal times. Is there any justification for either pre-production rentals or for royalties?

So far as our analysis indicates, pre-production rentals remain a source of inefficiency. Since the government has sound reasons to write leases with a certain degree of flexibility, it appears to be self-contradictory for it to penalize lessees who take advantage of that flexibility and wait the full term.

One possible justification for pre-production rental is that it generates some revenue for the government at leases which do not produce at all. In this respect, the pre-production rental is redundant of, and tends to reduce, the bonus bid, insofar as both payments would be made at non-producing leases. At the same time, as we mentioned earlier, the pre-production rental has an effect similar to a minimum bonus bid requirement. In practical policy, the government finds it useful to have redundant policy instruments, and in this case, the government might desire to have both the direct
minimum bid requirement and the indirect minimum bid represented by the pre-
production rental.

As for the royalty, royalties have been much discussed in the literature on
resource taxation. While theoreticians tend to agree that a gross production royalty
distorts the lessee’s decisions to some degree, policy must also take account of the
administrative aspect of taxes. We showed earlier that the distortion due to the royalty
tends to counteract the inefficiencies due to the finite term (for leases where prompt
exercise is suboptimal); but if the timing problem is resolved, then the royalty would be a
remaining source of inefficiency.

The law provides for reducing royalties in certain instances. A major policy to
reduce royalties was the 1995 Deepwater Royalty Relief Act, which eliminated, up to a
point, royalties on deepwater leases purchased in the following five years. Our analysis
suggests that eliminating royalties without resolving the exercise timing problem means
that the remaining lease elements all promote inefficiently early exercise. Congress
originally established royalties that roughly tended to counter the tendencies for
premature exploitation of the resource; the 1995 Act, however, removed that brake. (Of
course, arguments based on international competition and deepwater technology may be
offered in support of the 1995 Act.)

The remainder of this paper addresses the issue of optimal timing of lease sales,
assuming that the government continues to write its leases with 5- to 10-year terms.
Whether the government is authorized to limit sales to well in-the-money leases is
addressed in the next section. In the last section, we consider the possible roles for real
option analysis in a decision process for optimal leasing.

III. Authority to Sell Leases

Viewed from the perspective of real options, a decision by the government to write and to
sell certain leases should reflect a prior decision by the government to arrange for the
prompt exercise of those particular options on natural capital. As we shall see, under
current policy, the government appears, under the assumptions of our analysis, to be
relatively aggressive in promoting the exploitation of its natural capital. With some
significant qualifications – such as not leasing in areas having environmental risk -- it
leases any of its oil and gas perpetual options that buyers deem to be currently in-the-
money, even when socially optimal management would direct the government to wait.

In fact, the government sells also leases that appear to be currently out-of-the-
money but which are bid on seemingly for the sake of the limited option value created by
the 5 to 10 year term. One of the contributions of earlier real option analyses of oil leases
was to demonstrate that even leases that are out-of-the-money, up to a point, have option
value that may be the explanation for their being bid on. As mentioned earlier, in
accordance with the real options literature, a 5 to 10 year term allows for a degree of
flexibility which results in some option value; and a lease with a “slightly” negative
intrinsic value may still attract a bid due to its limited option value. (However, its bid would not reflect the full value of the perpetual option.) As such, the government, under current policy, may lease it, so long as the bid is deemed representative of fair market value for a 5 to 10 year oil lease.

Our argument in preceding sections leads to a suggestion that the government consider a different policy, namely, a policy of limiting the sale of leases to the leases that are well in-the-money. These leases are the “grade A,” as we said above, class of perpetual options. For the grade A options, it is socially efficient to exercise relatively promptly, and selling leases with relatively short terms, perhaps the 5- to 10-year terms currently written, is an appropriate way to arrange for the exercise. In contrast, the “grade B” of perpetual options are not optimally exercised in the 5 to 10 year time frame, even if they are “somewhat” in-the-money. Our analysis indicates that grade B options should not be exercised promptly and should not, therefore, be leased.

In this section, we investigate mainly whether a policy of limiting the sale of leases to well in-the-money, “grade A” options makes sense within the context of the government’s existing authority. Specifically, we consider:

- The legislative authority for programs that may be loosely termed “land disposal”
- How the current program carries out that authority
- Whether or not a leasing program limiting sales to well in-the-money leases would be consistent with existing authority

Throughout this section, we employ the real option model to illuminate the government’s management of leasing. The government is a landowner in possession of perpetual options that have a certain structure – that is, they are American-type calls on natural assets, and so on – and the question of leasing policy becomes the question, how can it best manage its portfolio?

When the question is posed in this innovative way, it implies some new directions for analysis, such as the possibility of a government-wide portfolio management analysis. In the course of our investigation, we pursued these implications. As it turns out, the existing structure of US government tends to separate the management of natural capital from other fiscal operations, rendering the notion of a grand government portfolio void. With reluctance, then, we abandoned the imaginative project of a government-wide portfolio analysis, and here we focus on the portfolio of oil land only.
Legislated authority

The authority for leasing (offshore) is explicitly stated in the Outer Continental Shelf Leasing Act (OCSLA). Below is the most relevant section of the act (43USC1331) (bolds added):

(a) Schedule of proposed oil and gas lease sales
The Secretary [of the Interior] … shall prepare and periodically revise, and maintain an oil and gas leasing program …. The leasing program shall consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which he determines will best meet national energy needs for the five-year period following its approval or reapproval. Such leasing program shall be prepared and maintained in a manner consistent with the following principles:

• (1) Management of the outer Continental Shelf shall be conducted in a manner which considers economic, social, and environmental values of the renewable and nonrenewable resources contained in the outer Continental Shelf. …
• (2) Timing and location of exploration, development, and production of oil and gas among the oil- and gas-bearing physiographic regions of the outer Continental Shelf shall be based on a consideration of -
  • (A) existing information concerning the geographical, geological, and ecological characteristics of such regions;
  • (B) an equitable sharing of developmental benefits and environmental risks among the various regions;
  • (C) the location of such regions with respect to, and the relative needs of, regional and national energy markets;
  • (D) the location of such regions with respect to other uses of the sea and seabed, including fisheries, navigation, existing or proposed sealanes, potential sites of deepwater ports, and other anticipated uses of the resources and space of the outer Continental Shelf;
  • (E) the interest of potential oil and gas producers in the development of oil and gas resources as indicated by exploration or nomination;
  • (F) laws, goals, and policies of affected States which have been specifically identified by the Governors of such States as relevant matters for the Secretary's consideration;
  • (G) the relative environmental sensitivity and marine productivity of different areas of the outer Continental Shelf; and
  • (H) relevant environmental and predictive information for different areas of the outer Continental Shelf.
• (3) The Secretary shall select the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone.
• (4) Leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government.
Our bold text emphasizes that the statutory requirements for the program are fewer than might first appear. Many of the decision criteria expressed in the Act are “considerations.” The only statutory requirements for the leasing program are, besides following an appropriate process of “considering” things, the requirement in (3) to balance environmental risk and discovery potential and a requirement in (4) for MMS in all of its leasing activities – including the planning of where and when to offer leases -- to try to obtain fair market value for leases.

Current policy about selling leases

The 5-year schedule

The required schedule of leasing is implemented by recurring 5-year plans, and when speaking of the existing program, we can speak of lease scheduling and 5-year planning interchangeably. Note, however, that scheduling a sale does not guarantee that it will be held. The lease schedule is followed by sale-specific environmental studies and other decisions that determine whether each individual sale is held or not.

With slight oversimplification, we summarize the salient decision criteria for scheduling sales as follows. Leasing in an area can be included in the schedule when:

1. There is sufficient industry interest in the area. Interest in an area for purposes of the 5-year plan is signaled mainly by industry response to an initial “call for information” and by industry comments on MMS’ Federal Register notices and the successive versions of the plan. It is possible, and it has occasionally happened, that a scheduled sale is held but no one, or very few, people bid on leases.

2. Coastal state and local governments, etc., concur with the schedule. These governments too comment on the plan when it is being prepared.

3. Interested and affected parties agree that consideration of leasing in the area is reasonable in the 5-year time frame. At a minimum, the agreement or lack of it becomes apparent through the NEPA process. It is not required to obtain consensus or even to propose a plan that, so to speak, runs down the middle of interest groups. In the past, there have been plans that were “aggressive” in planning large or frequent lease offerings; however, those aggressive 5-year plans were sometimes scaled back as individual sales were subsequently canceled. The current Administration emphasizes “consensus” decision making. Evidence of this style of decision making is a special “stakeholders task force” in Alaska, where sales are controversial.

In general, at areas other than the Central and Western Gulf of Mexico, there is substantial “political risk” to both the 5-year schedule and to individual sales when they are held. The practice, so to speak, of trying to stop a sale from taking place is naturally
highly political. A way that was successful in the past was to convince Congress declare a moratorium on leasing in specific areas. Recently, the Administration preempted these annual congressional moratoria by declaring a long-term moratorium on lease sales everywhere outside of areas where significant leasing has occurred in the past (namely, Alaska, most of the Gulf of Mexico, and small areas of the California Outer Continental Shelf (OCS)).

What about the “national” goals of the act?

So far, we have described influences on lease planning that are more or less local in scope: the opposition or support from local communities, regional governments, and industry active in the region. But further, the OCS Leasing Act refers to national energy needs, a national cost-benefit balance, and a national-level consideration of the how the costs and benefits are allocated to regions. In current practice, MMS “considers” the national needs by undertaking quantitative analyses of national consumer surplus, forecasts of energy needs, import substitution, etc.

What about government revenue?

Economists might wonder why we have not mentioned obtaining, or perhaps maximizing, government revenue as a goal. The fact is that the OCSLA rarely mentions government revenue, and certainly it is not something to be maximized. A suggestion that revenue should be maximized would possibly arouse fear of monopolistic behavior by the government in areas such as offshore where it is the dominant landowner.

Revenue is related to “fair market value.” “Fair market value” is a statutory requirement for the leasing program, but one must not infer that obtaining FMV implies maximizing revenue. The usual definition of FMV is that it is the price that the lease would receive if it were sold and bought by knowledgeable parties in a competitive context. MMS, as part of its over-all program, makes an effort to be a knowledgeable seller and to create some degree of competition in the lease auction. But FMV seems to have, at most, indirect influence on sale scheduling. FMV is reflected in the goal of industry interest; that is, a region of very low bidder interest might be omitted from the schedule partly because of MMS assumes bids would be depressed in contrast to a future time when the number of bids might be higher.

Tradition of public land disposal policy

The seeming indifference to government revenue is in the tradition of public land disposal policy, and a few, informal words about that tradition might be illuminating.

As is well known, traditional land disposal policy was a way of placing the once-huge (and still large) government lands in the service of national growth through private enterprise. The US government would simply hold public land until it could be put it to productive use. At the same time, traditionally, there was little, if any, weight placed on holding value in the option-theoretic sense. (Environmentalism promotes preservation as
a valid land use, but that is a different issue.) Public land is traditionally held only when no one offers to take it for productive use. The government is not waiting on optimal exploitation or “speculating” when it holds the land; it is merely holding land that no one wants until someone wants it.

Also, the traditional policy was averse to allowing “speculators” to obtain public resources, as land speculation was not viewed as “productive.” The traditional policies generally included, in various ways, diligence requirements that were supposed to ensure that the person taking the resource put it to productive use promptly. As we have remarked, one diligence feature of oil and gas leases is that they revert to the government if not put into production within a certain interval. It is true that the lease term is long enough to allow the lessee some discretion about when to exercise the “option” within the limit of the term; but the government’s main purpose in granting the 5- to 10-year interval is to allow operators to hold leases in a working inventory and to arrange timely rig scheduling. A small scope for short-term speculation is created as an unavoidable side-effect.

The real options model as we employ it here leads away from the tradition. It shows that the government holds infinite-term call options on natural assets; to carry out its authority, it ought to manage those options optimally.

Would limiting sales to well in-the-money leases be consistent with existing authority?

There are two authorities in the OCSLA that might support a policy of limiting sales to well in-the-money leases.

1. Meeting national energy needs

The OCSLA requires the Secretary of the Interior to prepare “a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which he determines will best meet national energy needs for the five-year period following its approval.” We suggest that this does not necessarily mean that MMS considers only national energy for a few years or even a few decades, letting the more distant future fend for itself. The scope of analysis can be 50 or 100 or more years if there is reason for it, as we think there is.

If we assume that energy needs are reflected in price (and it may not be, if one believes that price is a monopoly outcome), then it is socially optimal to exercise the government’s perpetual calls only when the oil or gas price rises above some critical value. In section II above we computed a critical value of $37/bbl. for an average finding cost. Managing the calls as the perpetual options that they are will lead to orderly and optimal flow of oil into the market, with less oil being developed when prices are low (cheaper to import) whereas when price rise oil will be developed in terms of least-cost (lowest exercise price) first.
2. Fair market value

MMS is required to assure receipt by the government of fair market value for the leases. FMV is not defined in the title of OCSLA that is quoted above. The going interpretation of FMV as applied to leases is:

The amount in cash, or on terms reasonably equivalent to cash, for which in all probability the property would be sold by a knowledgeable owner willing to sell to a knowledgeable buyer who desired but is not obligated to buy (US Dept. of the Interior 1983).

This definition is applied to the FMV of the 5- to 10-year leases as burdened with other government-written conditions, royalties, and so on. Since the perpetual calls, unburdened by those conditions, are never offered for sale by the government, there is never an occasion to estimate their FMV. If there were, hypothetically, a market in the properties themselves, then FMV relative to that market would more likely capture the full value of the options.

Our analysis implies that the government should anticipate that exercise of in-the-money leases at lease term expiry will pre-empt later exercise that might be preferable from society’s perspective. That is, in broad terms, the FMV of a lease should incorporate a shadow cost of pre-empting future, possible superior, exercise. The existing “market” in primary Federal leases, namely, the auction of 5 to 10 year leases, fails to account for an externality on future generations.19 So the requirement to assure FMV, applied now to leases understood as real, perpetual calls, seems to require a reservation price that promotes, not prompt exercise, but optimal exercise. In section IV below we present a range of reservation prices that our analysis suggests would accomplish this.

To answer the question heading this subsection, then, yes, the existing leasing authority would support limiting sales to well in-the-money leases; indeed, the two parts of law just mentioned appear to require it.

IV. Suggestions for Implementation of Real Option Analysis in Selling Leases

One of the main differences between traditional net present value (NPV) analysis and real option analysis is the timing of investment. NPV analysis suggests that, if the investment opportunity is “now or never,” invest now if NPV is positive. But most investments are not now or never, and this is true of oil development on Federal lands, for which the option to develop is perpetual. In these cases an NPV greater than zero is

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19 Note that private land owners can buy and sell their mineral lands, and the market in those properties ideally would account for optimal exercise and would internalize the effect on future generations. Of course, the degree to which private persons account for future generations is a controversial subject.
not sufficient for immediate investment: option pricing theory tells us that, for the typical Gulf lease, immediate investment is not optimal unless wellhead prices are higher than $37.43/bbl., or equivalently, if the per barrel intrinsic value is greater than $5.16.  

As we noted in Section II, if the government wishes to lease only oil that will be developed immediately, it must only lease tracts that are well in-the-money, or whose NPV is significantly greater than zero. Table 1 below shows how high the per barrel NPV values must be, given the option parameter values listed in Figure 1, for immediate development of the oil in the Gulf to be optimal. Any oil with a lower NPV should not be immediately developed, and it will not be immediately developed upon sale in the absence of development incentives such as a finite lease term and a pre-production rent.

Importantly, Table 1 also suggests the minimum lease bid the government should set, in the absence of rental and royalty requirements, to ensure that any leases sold will be developed immediately. Any leases that should not be developed immediately will not receive the minimum bid (their values are lower than those listed in the table), and will remain, correctly, in the hands of the government and undeveloped.

<table>
<thead>
<tr>
<th>Finding Cost ($/bbl.)</th>
<th>Minimum NPV ($/bbl.) at Which it is Optimal to Develop the Lease Immediately</th>
<th>Minimum Bid** ($millions)</th>
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<tbody>
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<td>4.2</td>
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<td>4.23</td>
<td>5.0</td>
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<td>7.32*</td>
<td>5.16</td>
<td>6.1</td>
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<tr>
<td>10.00</td>
<td>7.05</td>
<td>8.3</td>
</tr>
</tbody>
</table>

* Current average finding cost
** Based on a typical ex ante expected reserves of 1,181,684 BOE per lease

Table 1: Minimum NPV Values and Minimum Bid Values For Which Immediate Lease Development is Optimal

As mentioned earlier, there are two ways to limit lease sales to only leases that are well in-the-money:

\[\text{Finding Cost} \times \frac{1}{3} - \text{Current Average Finding Cost} = \text{Minimum Bid}\]

\[\text{Current Average Finding Cost} = \frac{\text{Value of Developed Reserves}}{\text{Reserve Life}} - \text{Development Cost}\]

\[\text{Value of Developed Reserves} = \text{Wellhead Price} \times \text{Reserve Life} \times \text{Recovery Factor}\]

\[\text{Development Cost} = \text{Finding Cost} \times \text{Recovery Factor}\]

20 When it is optimal to exercise an option, its value is the same as the asset’s NPV, which in this case is the value of developed reserves less the development cost: $37.43 \times \frac{1}{3} - 7.32 = 5.16.$
1. Limit the selection of leases offered for sale to those that the government deems are well in-the-money. To implement this approach, the government calculates the optimal timing directly and selects leases to sell (with diligence required) or does not sell them as indicated.

2. Have reservation prices that are high enough that only well in-the-money leases will be bought. All available leases can be offered at all times (subject naturally to restrictions designed to mitigate externalities). But the minimum bid schedule is set according to the above-mentioned calculation, and the minimum bids are high enough that only leases that are well in-the-money will be bought by knowledgeable buyers.

Implementation of both schemes is hampered by information asymmetries. It is quite possible that the government could withhold what it thinks is a high cost tract while waiting for oil prices to rise, and yet, were it leased immediately, the market would know it is a low cost tract and would (optimally) develop immediately. In this sense, it is possible that value destruction from suboptimally withholding low cost leases under information asymmetries would destroy more value than the current leasing scheme. In addition, the conversion of thinking from the traditional NPV paradigm of leasing whenever NPV is positive to leasing (and promptly developing) only when the NPV is very positive is a difficult one. It requires a conversion in the seller’s mind, so to speak, to thinking in terms of real options, which is not easy. In this sense, a leasing scheme that does not destroy more than 10% of asset value may be good enough.

An alternative version of the optimal timing calculations might be easier for some decision-makers to adopt. In this version, we can get to optimal development timing by staying with the NPV framework and using an adjusted discount rate that will invoke the same optimal leasing (and development) timing behavior (Davis 1995). In essence, we want to adjust the discount rate upwards, and by calculating NPV with that rate, we obtain what might be termed the “Adjusted NPV” of the lease. Development is only indicated where this Adjusted NPV is positive. Note that this Adjusted NPV and its corresponding rule—leases will be developed immediately when their Adjusted NPV value is greater than zero—is only useful for the development timing decision; asset valuation still requires ordinary option pricing techniques. In this respect specifically, the usual practice in government to use low discount rates, such as the T-bond rate, moves the timing decision in the wrong direction.

The important point here is that suboptimal leasing decisions will be made using the traditional NPV framework, since having an NPV of greater than zero is not sufficient indication that it is optimal for a tract to be developed. Instead, the exercise threshold price for a correctly defined option value provides an indication of the correct lease and development timing.
References


