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Final Report

Policies to Affect the Pace of Leasing And Revenues in the Gulf of Mexico Technical Report

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Part 2. Technical Report

by

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Final Report

Policies to Affect the Pace of Leasing and Revenues in the Gulf of Mexico

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Executive Summary

This study examines alternative leasing policies for Outer Continental Shelf (OCS) oil and gas resources in the Central and Western Gulf of Mexico (GOM). For each potential policy, we estimate the resulting levels on exploration, production, revenues and other impacts associated with OCS development. We also explore whether Areawide leasing for the OCS reduces the returns to leasing in the waters of coastal states, using Louisiana as an example.

Since 1983, offshore leasing has used an Areawide leasing policy, whereby nearly all blocks available for leasing in a region are offered for sale. The Areawide approach has been controversial, with some arguing that it has reduced competition and leasing revenues. Others have countered that Areawide leasing may not reduce overall revenues when one also considers the effects on royalties, area rentals, and federal corporate taxes.

An analysis of alternative leasing policies is well justified, given the significance of OCS oil and gas resources, dramatic changes in offshore technology, highly volatile oil prices, increasing national security concerns for added domestic sources of energy, and the potential for an increased role of coastal states in the leasing program under various ongoing Congressional Initiatives.

Organization of the Study

Our assessment focuses on tracts to be leased on the Central and Western Gulf of Mexico planning areas over the 50-year period from 2010 – 2060. The study is organized into three integrated tasks:

- Task 1 identifies alternative leasing systems, and outlines a set of Goals and Criteria for assessing alternative leasing systems
- Task 2 develops the modeling approach that quantifies the Criteria developed in Task 1, and
- Task 3 uses the output of Task 2 to assess each leasing policy alternative relative to the current Areawide leasing approach.

Some fifty potential leasing alternatives are identified, and then are reduced to a manageable "short list" of 12 policy alternatives for detailed analysis. The policies examined include two options for slowing the pace of leasing, three options for changing royalty rates, higher minimum bids, two options for profit shares, an increase in area rental payments, use of a multi-round bidding system, implementation of work commitments, and a reduction in the length of the primary lease period.

Novel aspects of the study are the use of a resource inventory approach, incorporation of OCS oil and gas technological advances, use of a probabilistic approach for forecasting the size of new discoveries, use of an economic experiment to assess multi-round bidding in OCS auctions, and the integration of all these study elements into a single, comprehensive framework.

Key Study Results and Conclusions

Despite the many uncertainties involved, the empirical results provide many useful insights into potential effects of the various policy alternatives. First and foremost, the results show that there are important tradeoffs across policy alternatives, so no single policy is best at achieving all Goals. Nor does any individual policy dominate the Status Quo policy. Rather, some policy alternatives perform better than the Status Quo in terms of some Goals, but not as well in terms of other Goals. So choice among policies depends upon value judgments regarding the relative importance of the various goals.

Our study also finds that comparisons across lease alternatives are complex, because there are multiple offsetting effects. In many cases the overall effect of a policy is greatly mitigated by these offsetting effects, so that differences across policies are often smaller that one might predict. Below we discuss each category of lease sale alternative, and highlight some of these effects.

Our Study finds that a *slower pace of leasing* significantly increases bidding revenues, but this increase is offset, in whole or in part, by reductions in the discounted value of royalty payments, area rentals and federal taxes. Although it is possible that overall Federal revenues may increase somewhat with a slower pace of leasing, large increases in revenues cannot be expected. At the same time, a slower pace of leasing adversely affects expeditious development of OCS resources and overall social value of OCS resources, while increasing the competition for tracts and reducing environmental risks of OCS development.

Our results show that use of a *higher royalty rate* can increase royalty payments, but these gains are offset by associated reductions in cash bonus bids, area rental fees, and federal corporate taxes. Higher royalty rates also adversely affect expeditious development of OCS resources, reduce competition for tracts, and reduce the overall social value of OCS resources. At the same time, higher royalties reduce regional planning costs and environmental risks. Coastal states may benefit from increased royalty rates through future revenue sharing under GOMESA, but these gains are offset by reduced onshore expenditures associated with lower levels of offshore activities.

Higher minimum bids are shown to increase cash bonus bids on some low-valued tracts, but also result in a reduction in the number of tracts sold. The tracts that go unsold will disproportionately be marginal tracts that would typically receive only a single bid, so that the average bid per tract sold is expected to increase. Increasing the minimum bid reduces OCS activities, thereby facilitating regional planning and reducing potential environmental risks, but adversely affecting the economies of coastal states by reducing onshore expenditures associated with offshore activity.

Our study finds that *profit shares* may increase government take through this source of revenue, but at the same time profit shares reduce the value of tracts to firms, and therefore reduce cash bonus bids, federal corporate tax payments and the number of tracts sold. Overall, we find a small decrease in OCS revenues when adding a profit share to the Status Quo policy, and a larger decrease in revenue when using profit share in lieu of royalties. More importantly, profit share may adversely affect the integrity of the leasing process because of the important practical problems attempting to validate profits reported by firms. Indeed, past experience has found considerable difficulties in reaching agreement on the proper profit share payments.

Increasing the area rental rate reduces the number of tracts sold, thereby reducing expeditious development of OCS resources. Higher area rental payments can be expected to be offset, in whole or in part, by decreases in cash bonus bids, royalty payments and federal taxes. Increased area rental payments increase the average number of bids per tract sold by reducing sales of marginal tracts that would otherwise typically be sold with only one bid.

Multi-Round Auctions result in more tracts sold, but otherwise adversely affect most Criteria for development of OCS resources, revenues and overall social value. This occurs because multi-round auctions lead to more tracts sold early in the time horizon, but fewer tracts sold later when prices are higher and technology improves. Multi-round auctions lead a smaller average number bids per tract as more marginal tracts are bid upon and sold, and these tracts typically receive only a single bid. Revenue sharing with coastal states and onshore expenditures both decrease with multi-round auctions, but this effect is offset by lower environmental and social costs.

Work Commitment increases exploratory activities on tracts sold, but the need to commit to higher exploration activity decreases tract values, and therefore reduces cash bonus bids and the number of tracts sold. The higher level of exploratory effort results in slightly more fields discovered, but many of those fields are small and only marginally productive. Work commitment decreases measures of obtaining fair market value and has offsetting effects on regional planning costs. But work commitment has an overall negative effect on the social value of OCS resources by decreasing all sources of revenues, while having a small, but insignificant, reduction in lost resources.

Shorter Lease Terms are found to adversely affect most measures of expediting development of OCS resources, and to reduce the overall social value of OCS resources. In effect, a shorter lease term reduces the effectiveness of tract exploration, such that fields go undiscovered during exploration, and the associated tracts are resold in the future. By the same token, a shorter lease period is forecast to increase area rental payments, but is otherwise expected to reduce revenues associated with OCS leasing. And a shorter lease period is expected to reduce the number of bids received, thereby decreasing competition for tracts. A shorter lease term slightly reduces revenue sharing with coastal states, significantly decreases state revenues associated with onshore expenditures, and reduces environmental and social costs. The model concludes that regional planning is facilitated by shorter lease terms, except that more tracts are sold due to re-sales of unsuccessful tracts, which might partially offset otherwise reduced planning costs.

Effects of Federal Leasing Policy on Revenues of Coastal States

Although we were unable to carry out a thorough study of the issue, we also explored the extent to which Areawide leasing could potentially harm coastal states by "flooding the market" with OCS leases, thereby reducing revenues from leasing in State waters. Our analysis uses Louisiana as a case study.

Louisiana is a mature oil and gas region, and its state waters have been well explored. Production from offshore Louisiana has been decreasing since 1970, well before the advent of Areawide leasing. Nearshore Federal waters also have been well explored. A large and increasing fraction of Federal OCS operations occur far offshore. The technologies and equipment used for deepwater operations differ enormously from those in State waters. Transferability of equipment, technology and skilled personnel between near shore and deepwater offshore areas is likely to be very limited. As a consequence, current and future operations in Federal waters and Louisiana state waters are, by and large, not likely to be close substitutes.

Data support this notion that OCS oil and gas and petroleum operations in Louisiana state waters are not close substitutes. A comparison of firms bidding in lease sales in Federal and State water shows relatively little overlap among participating bidders. And participants in federal lease sales show relatively low intensity in bidding for State of Louisiana tracts.

Final Report

Policies to Affect the Pace of Leasing and Revenues in the Gulf of Mexico

Part 2. Technical Report

I. Introduction

This Technical Report is Part 2 of a 2-Part Final Report on an extensive study designed to quantify the effects of alternative leasing policies for Outer Continental Shelf (OCS) oil and gas resources in the Central and Western Gulf of Mexico. Part 1 is a Summary Report that briefly describes the methods, and discusses the results and conclusions of the study (Opaluch, et al 2009). The present document is Part 2, the Technical Report, which describes in detail the methodologies employed, and discusses the results and conclusions. This Technical Report is designed to stand alone, and thus it subsumes all of the material from the Summary Report. As a consequence, this Report necessarily repeats the material from the Summary Report.

I.A. Background and Scope

This Final Report assesses the effects of alternative leasing policies on the pace of leasing, exploration, production, and revenues associated with Outer Continental Shelf (OCS) oil and gas resources in the Central and Western Gulf of Mexico. OCS hydrocarbon resources are a major source of domestic energy supplies, providing about 23% of domestic oil and 16% of natural gas in 2005. OCS lease sales are also an enormous source of national wealth, with cash bonus bids totaling over $65 billion dollars through 2006 (MMS, 2007), and the net economic value of leasable resources estimated at $145 billion just for the Central and Western Gulf of Mexico (U.S. MMS, 2006).

Leasing of OCS hydrocarbons is guided by the OCS Lands Act, as amended through PL106-580 (hereinafter, OCSLA). Most leases for oil and gas resources in federal waters are sold using a sealed cash bonus bids along with a fixed 16 2/3% royalty (and more recently, 18.75% royalty). Prior to 1983, lease sales followed a process of nominations by industry to identify tracts of interest. Following comments by other interested parties, such as coastal states and environmental interests, MMS determined the set of tracts that comprised the lease sale, which were typically on the order of a couple of hundred tracts. Since 1983, offshore leasing has been carried out under a process called Areawide leasing, whereby nearly all blocks available for leasing in a region are offered for sale. A single sale might contain over well over 3,000 tracts, while only small fraction might actually receive bids.

The Areawide process has been criticized for reducing competition for tracts, thereby lowering returns for the federal government, as well as for coastal states that hold their own lease sales (e.g., Stiglitz, 1984; GAO, 1985; Moody and Kravavant, 1990, Moody, 1994; Gelso, 2008). But others have argued that there is no evidence that the increased pace of leasing has reduced revenues from Offshore leasing (e.g., Farrow, 1987), especially when one considers the present value of all sources of revenues, including cash bonus bids, royalties, taxes, etc. (U.S., Department of Energy, 1995)

Furthermore, critics have charged that it has been over two decades since there has been experience in federal lease sales with approaches other cash bonus bids and fixed royalty rates, and that economic conditions that were used as the rationale for adopting an Areawide leasing policy are now seriously out of date.

It may be that the current leasing approach is, on balance, the best approach for achieving the Goals of the OCSLA. However, the OCSLA allows the MMS to use other leasing systems, and there is also considerable experience with many other leasing options at the state level, for federal onshore resources, in other countries and for other resources. Thus, it has been argued that it is time to consider alternatives to Areawide leasing.

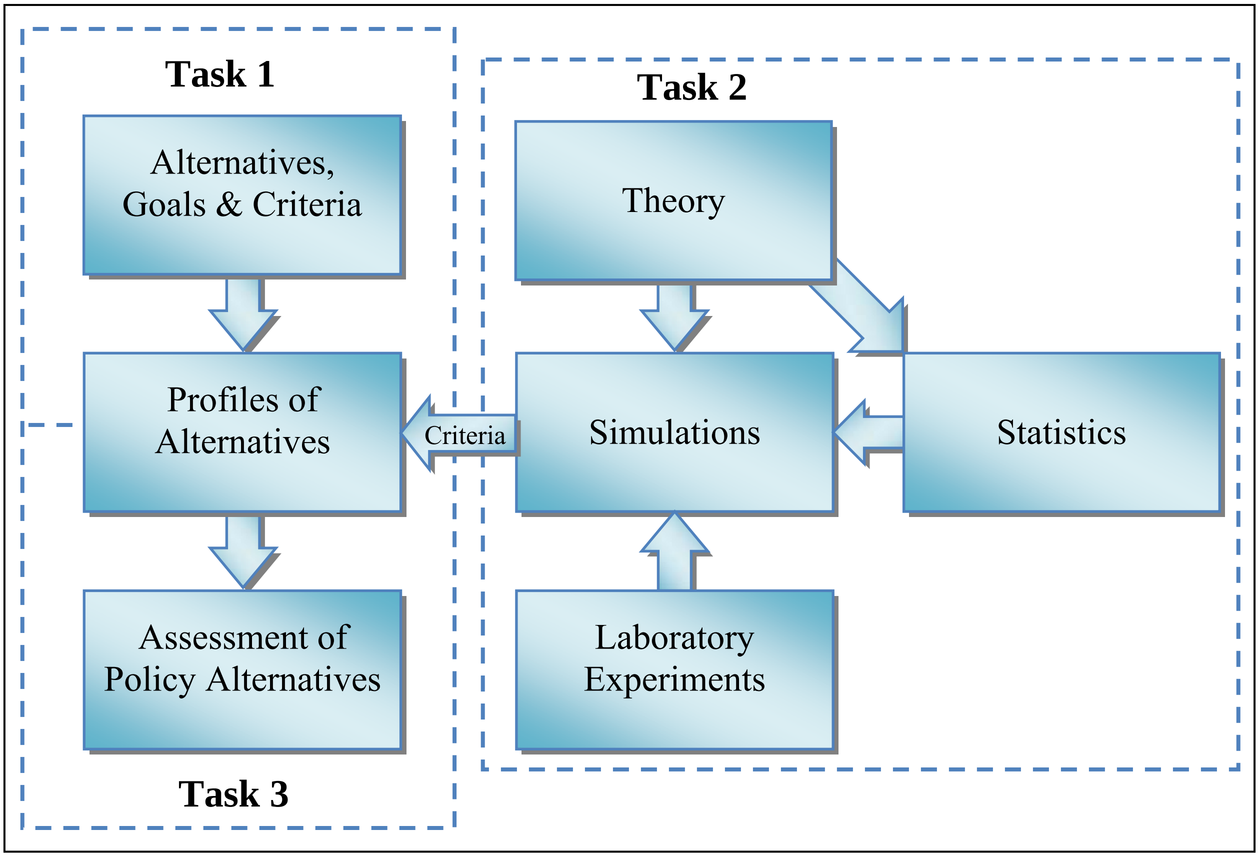
A comparative analysis of alternative leasing policies is well justified, given the significance of OCS oil and gas resources, and the absence of recent studies which systematically compare policies. Adding to the impetus for a major study of OCS leasing options are dramatic changes in offshore technology, which allow operations in deep (and now "ultra deep") waters; highly volatile oil prices, which exacerbate an uncertain and risky investment environment; increasing national security concerns for added domestic sources of energy in support of energy security; and complications caused by royalty relief for deep and ultra deep wells (e.g., Federal Register, May 18, 2007); and potential for an increased role of coastal states in the leasing program under various ongoing Congressional Initiatives.

I.B. Overview of the Study

This study was designed to compare alternative designs for the leasing system for OCS oil and gas resources in the Central and Western Gulf of Mexico. The study involves three integrated Tasks, as depicted in Figure I-1. In Task 1 we identify leasing alternatives that are specifically enumerated in the OCSLA, as well as other leasing systems that are in use elsewhere in the United States or in select other countries (e.g., Australia and Canada). We focus primarily on leasing systems that are enumerated in the OCSLA, and select other alternatives that are not specifically excluded by OCSLA. Task 1 also identifies a set of Goals for the OCS leasing process, and an associated set of Criteria for each Goal. Our selected Goals start with those specifically included in OCSLA, and we add a small number of other Goals that are also highly relevant, although not specifically mentioned in OCSLA. For each Goal, we develop a number of measureable Criteria that are intended to quantify the extent to which each lease alternative satisfies each of the Goals.

Task 2 encompasses a set of analyses that are designed to measure the Criteria developed in Task 1. The analyses in Task 2 are organized around a simulation model that is comprised of two major elements: a Field model and an Area model. The Field model is a detailed net present value model of managing individual fields. The output of the field model includes time series for wells drilled, production, as well as revenues, net present values, bids etc. for a represent set of fields of 16 size classes in each of 7 water depths. This information is passed onto the Area model. See Section III.A.1 for the details of the Field model.

Figure I-1. Project Overview



The Area model starts with scenarios for leasing and MMS statistics on undiscovered resources, and uses statistical analyses to forecast tracts sold. These are used to forecast exploration and successful discoveries for the same set of 16 size categories and 7 water depths over the 50 year time horizon 2010-2060.[1] The output of the field model is then linked with the Area model to forecast production, revenues and other key measures for all fields discovered from lease sales over the next 50 years. See Section III.A.2 for the details of the Area model.

Theoretical analyses are used to provide some key qualitative assessments of Criteria where adequate statistical data do not exist. The theoretical analysis is presented in Section II.B. The general game theoretic framework for OCS auction markets is presented, and some key results are derived.

Statistical analyses are used to quantify three key equations. First, we use data from past OCS lease sales from 1954-2008 to estimate the number of leases sold as a function of the number of leases offered for sale and net oil prices. This equation allows us to determine how leasing policy and economic conditions affect the number of tracts sold in each forecast year. The next key statistical equation determines the number of bidders on each tract as a function of the net present value of the tract and the total number of tracts offered in the year. The final statistical equation estimates the high bid as a function of net present value of the tract and the policy regarding the number of tracts offered. Together, these three equations can be used to forecast tracts sold, numbers of bidders and revenues from a host of different policies for size of lease sales, royalty rates, area rental fees, etc. See Section III.C for the details of statistical analyses.

Laboratory experiments are used to calibrate the empirical bid function in order to assess the potential for one novel lease alternative for which we have no historic data in OCS leasing—a multi-round bidding structure. We adopt a multi-round bidding process based on the approach used by the Federal Communications Commission in auctioning the right to use the electromagnetic spectrum for cell phone transmissions. Laboratory experiments are conducted using a leasing process that simulates the first price, sealed bid auction used in OCS leasing, and using a multi-round bidding process. The comparative results of these two treatments are used to calibrate the statistically estimated bid function to provide a perspective on the potential for multi-round bidding when applied to OCS leasing. We also carry out experiments in more competitive and less competitive environments to assess the relative performance of multi-round bidding under Areawide leasing with large numbers of tracts offered for sale, as compared to a lease environment where fewer tracts are offered, such as under nomination leasing.

In Task 3, we use the results from the Task 2 analyses, described above, to assess the leasing alternatives in terms of the Goals and Criteria developed in Task 1. Clearly, one would not expect any single lease alternative to dominate all other alternatives across all Goals, but rather tradeoffs are unavoidable. For example, one might find that one alternative is best at expediting development of oil and gas resources, while another lease alternative is preferred in terms of obtaining fair market value for resources leased. We make no attempt to make quantitative

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[1] Note that the model simulates subsequent production from tracts that are sold over the next 50 years; therefore, the full time horizon extends far beyond 50 years. For example, the model simulates field development, production, etc. over the full life span for tracts that are sold 49 years into the time horizon.

tradeoffs across the Goals, but rather note which options are most effective in achieving each of the Goals.

In addition to the Goals specifically enumerated in OCSLA, we include as a Goal the ability of an alternative to "maintain the integrity of the leasing process". Some leasing alternatives might be best at achieving the Goals of OCSLA, but might also facilitate collusion among auction participants, or might require subjective evaluation of bids that could be a challenge to present objectively, and therefore might be difficult to defend against charges of favoritism. Although these options could be good at achieving the Goals in theory, a leasing policy based on such an option could be extremely vulnerable to practical impediments that threaten the integrity of the entire process. We consider this to be a particularly important Criterion, and options could be excluded from consideration if they are judged to represent an extreme threat to the integrity of the process.

Finally, we apply the results of our models to carry out analyses of various lease alternatives. This element of the study is particularly important because some of the lease alternatives that we assess have never been used for OCS leasing in the United States, and other approaches have not been used for over twenty five years. Hence, for several of the approaches that are evaluated in this report, we have no field data, or no recent field data, to use to assess their likely affects.

The approach adopted for this study has several unique features, including the following:

(1) Use of a resource inventory approach for including field discovery and depletion, based on MMS estimates of presently undiscovered fields by field size and water depth,

(2) Incorporation of industry-specific technological advances in OCS exploration, development and production (Managi et al., 2004; 2005),

(3) Adoption of a probabilistic approach to forecasting the size of new discoveries that balances the numbers of undiscovered fields within different size classes and the relative difficulty of finding fields of a differing sizes,

(4) Use of an economic experiment to examine the potential adoption of multi-round bidding, an approach never used for OCS oil and gas leasing, but which has been used by the Federal Communications Commission to auction electromagnetic frequencies, and

(5) Integration of items (1) – (4) in a single OCS leasing policy model system which provides consistent estimates of OCS activities and a variety of associated effects, as noted above.

Throughout the report, we indicate where data is lacking or severely dated, and therefore the conclusions are preliminary. And we make recommendations for alternatives that could be field tested to provide more useful data. At the same time, we recognize that the reliability of data from field tests could also be subject to doubt, since bidders might have little experience or little recent experience with the lease option. So the results could easily change over time as experience is accumulated. Furthermore, companies might behave strategically if they know the results from a field test could be used to design leasing options to be used in the future. Therefore, one might expect that leasing results in stable, long term "equilibrium" might not be well represented from data that are collected from a one-shot field test, or even from a field test that is implemented over a few years. Nevertheless, judgment informed by theory, historic data, data from laboratory experiments and data from limited field tests provide the best available information on which to base leasing decisions.

Our analysis addresses many specific leasing policy alternatives. These include slowing the pace of OCS leasing, adopting different royalty rates, raising minimum bids, profit sharing, raising annual rental rates, shortening the lease term and other, more novel leasing approaches. The set of policy alternatives that we assess is discussed more fully in Section II below.

For each alternative leasing system, we evaluate its potential performance in achieving OCS policy Goals as compared with the current, Areawide system (the "Status Quo"). Generally, each potential leasing system is taken alone to assess how it performs in attaining identified Goals as compared with the Status Quo leasing approach.

Thus, our analysis below uses an alternative-by-alternative approach by assessing the extent to which a particular lease policy alternative achieves each of the Goals of OCS leasing. But the assessment can also be considered another way, by focusing on a particular Goal, and then identifying the policies options that appear most effective in attaining that Goal. For example, if energy independence or increasing government revenues from OCS development is identified as a Goal of special interest, then one use our results to identify the policy alternatives that best achieve that particular Goal.

We stress, however, that while each leasing option may support a desired Goal, it also carries with it unavoidable tradeoffs across Goals. A policy that is more effective at achieving one Goal, may be less effective at others. Thus, policy makers may want to consider different leasing systems or combination of systems, depending upon their policy priorities. Our methodology allows policy makers to assess the consequences of an individual policy, or a mix of policies, in light of their effectiveness in achieving leasing Goals. And this can be done in a manner that takes into account the unavoidable tradeoffs associated with each leasing system.

I.C. Organization of the Report

This report is organized around the three main Tasks of the Project. The next chapter describes the results of Task 1, which include identifying lease options and determining the Goals and Criteria for assessing the options. These Goals and Criteria set the stage for the remainder of the study.

Chapter III describes the analyses that together comprise Task 2 of the study. Section III.A describes the simulation model that serves to organize the information of the study and to quantify the Criteria. Section III.B outlines the key theoretical results that are used to provide qualitative assessments of a select set of key Criteria that cannot be quantified.

Then, Section III.C describes the statistical analyses that use historic data to estimate three key equations that quantify how different lease alternatives affect the Criteria. Section III.D describes laboratory experiments that were used to provide a perspective on a novel lease alternative—a multi-round auction.

Chapter IV presents the results of the assessments of the policy alternatives relative to current leasing policy. After that, we explore whether Areawide leasing results in conflicts with leasing in GOM state waters, using Louisiana as a case study. Finally, we present the recommendations and conclusions of the study, as well as important qualifications.

II. Task 1. Leasing Goals, Criteria and Alternatives

This section serves two purposes. First, the Goals of the Outer Continental Shelf (OCS) oil and gas leasing program are defined, as are specific Criteria to measure the attainment of these Goals. Second, we identify potential leasing alternatives to the current leasing system, which is based on Areawide leasing with sealed cash-bonus bids and a fixed royalty rate. Later in this report, the identified Goals and Criteria are used to assess the performance of alternative, potential OCS leasing systems.

To arrive at the specific Goals used for assessing the potential performance of alternative OCS oil and gas leasing programs, we draw heavily on the Outer Continental Shelf Lands Act (43 U.S.C. 1331-1356), as amended through PL106-580 (hereinafter referred to as the "OCSLA"). The selected Goals include, for example, receipt of fair market value, promoting competition, and balancing costs and benefits. For each Goal, specific Criteria serve as "metrics" to quantify (when possible) how alternative leasing systems compare with the approach now used in the GOM.

As we explain later, an inclusive process was used to identify an initial list of leasing system options. This resulted in a fairly large number of possibilities, which was then winnowed to a "short list" of alternatives. The narrowing process for this stage was a pragmatic exercise and is described later in more detail. Broadly speaking, however, the Criteria used to arrive at the short list of leasing alternatives included conformity with the OCSLA, consistency with well grounded economic theory, results of prior research, transactions costs, public acceptability, and maintenance of the integrity of the leasing process. Some overlap necessarily exists between the Criteria used to arrive at the short list and the Criteria used to compare OCS oil and gas leasing alternatives.

Specifically, this section

- Sets out the perceived Goals of OCS oil and gas leasing program, which provide the benchmarks used to assess the performance of prospective alternative OCS oil and gas leasing systems
- Provides Criteria or "metrics" for evaluating the performance of alternative leasing systems in achieving the identified Goals of the OCS leasing program, and
- Reviews alternative leasing systems in order to develop a short list of alternative OCS oil and gas leasing systems for the GOM for more detailed study,

Alternative leasing systems from our short list are compared with the Status Quo case, which is the currently used Areawide, cash-bonus bid system. The Status Quo leasing terms and conditions are those given for lease sale # 206 in the Central GOM and include, for example, a fixed 18 ¾% royalty, combined with an area rental fee, minimum bid and primary term which depend upon water depth. The Status Quo case is described in greater specificity in a later section.

We do not assign weights to reflect the relative importance of different leasing Goals and Criteria, nor do we recommend a particular leasing system. Instead, we assess how alternative systems might perform as compared with the current, or Status Quo leasing approach, in terms of the specific Criteria adopted for use in this study. We emphasize that this study considers a leasing period from 2010 – 2060.

Our assessment focuses on the Gulf of Mexico (GOM) and, in particular, on the Central (CGOM) and Western GOM (WGOM) planning areas. For convenience, however, these two areas are simply referred to in the text as the GOM, unless otherwise stated. We also note that while the analysis herein may have implications for other OCS areas, only the CGOM and the WGOM are explicitly considered in this report.

II.A. Goals and Criteria

II.A.1. Major Federal Acts

Our first step in assessing the prospective performance of alternative OCS oil and gas leasing options is to identify the Goals -- the objectives or the ultimate "ends" -- of the leasing process. We begin with the OCSLA.

Since 1978, the OCSLA has been the bedrock federal legislation for guiding the Minerals Management Service (MMS) in the management of oil and gas operations on or under federal offshore lands. The OCSLA (1) sets the terms under which individual tracts may be leased, (2) provides the requirements and process for the development of a Five-Year OCS Oil and Gas Leasing Schedule (Sec. 18), and addresses other issues, such as weighing environmental factors, balancing the regional gains and costs of leasing, and facilitating the involvement of coastal states.

Given the central role of this major federal Act in managing the nation's OCS oil and gas resources, we look to the OCSLA to discern the major Goals of the OCS leasing program. Broadly speaking, the OCSLA calls for the expeditious and orderly development of OCS oil and gas resources, the receipt of fair market value for leased resources, competition among firms in bidding, and the avoidance of wasting resources because of early shutdown of otherwise productive fields. Other OCS oil and gas leasing Goals concern the protection of coastal resources and the equitable sharing of costs and benefits of OCS development.

Clearly, the OCSLA reflects a multitude of significant resource management and related coastal issues and interests associated with OCS oil and gas activity. In view of the wide-ranging interests in the OCSLA, the leasing of federal oil and gas resources necessarily involves a balancing of multiple societal Goals.

Several other Acts, in addition to the OCSLA, influence OCS oil and gas policy. These include

- The National Environmental Policy Act of 1972 ("NEPA") (P.L. 91 - 190)
- The Oil Pollution Act of 1990 (P.L. 101-380) ("OPA '90"),
- The Energy and Policy Act of 2005 (P.L 109-58) ("EPACT"), and
- The Gulf of Mexico Energy Security and Independence Act of 2006 (P.L.109-432) ("GOMESIA 2006").

Briefly, NEPA requires that the MMS prepare an Environmental Impact Statement assessing the consequences for the affected environment of alternative leasing options, including no development and the alternatives to leasing. OPA '90 holds responsible parties liable for response, cleanup, economic losses, and restoration of resources injured because of oil spills. EPACT provides for royalty incentives for deep natural gas wells and also calls for a comprehensive inventory of OCS oil and gas, and GOMESA 2006 establishes policy for federal-state sharing of OCS oil and gas revenues. These Acts clearly are all germane to OCS leasing policy through such considerations as Environmental Impact Statements, royalty relief issues, more complete resource estimates, oil spill-related concerns, and the distribution of government take from leasing and production. However, the specialized issues raised by these Acts are outside the scope of this effort, and elements of these Acts are considered only insofar as they directly affect our comparative analysis of alternative leasing systems.

II.A.2. Goals Adopted for This Study

Seven specific Goals especially relevant to this study were identified early on in our work:

1. Expeditious and Orderly Development of OCS Resources
2. Obtain Fair Market Value for Leased Resources
3. Promote Competition
4. Equitable Sharing of Benefits and Risks of OCS Leasing
5. Facilitate Regional Planning and Minimize Environmental Risks to Coastal States
6. Maximize the Social Value
7. Maintain the Integrity of the Leasing Process

The above Goals capture the main policy aims of the OCSLA, and reflect the wide scope of this project. Clearly, the adopted Goals are much broader than typically used in studies of OCS oil and gas leasing[2]. Given the Goals of OCS oil and gas leasing, we next explain the development of Criteria to be used to assess the performance of alternative leasing systems in achieving the identified Goals.

II.A.3. Criteria for Assessing the Achievement of Leasing Goals

A core concern of this study is the extent to which alternative OCS leasing systems support or conflict with achievement of the Goals identified above. To this end, specific Criteria or "metrics" are developed for this purpose.

No single Criterion captures well the performance of alternative OCS oil and gas leasing systems in achieving a particular Goal. As a result, multiple Criteria are used, with each Criterion providing a summary assessment of the extent to which an alternative leasing system contributes to achieving each Goal. Consider, for example, the OCSLA requirement for MMS to pursue the Goal of "Expeditious and Orderly Development of OCS Resources" (Table II-1). Specific Criteria we use to evaluate the success of a leasing alternative in achieving this Goal include the annual number of OCS tracts sold, wells drilled, and the quantity of resources discovered (Table II-1).

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2 For example, studies by Kalter, Stevens, and Bloom (1975) and by Mead, et al. (1985) primarily use standard economic Criteria as opposed to the broad set of societal Goals given in the OCSLA and included in this report.

Table II-1. Goals and Criteria

1. Expeditious and Orderly Development of OCS Resources • Total Production • Discounted Production • Number of Exploration, Development, and Production Wells • Tracts Bid Upon • Number of Tracts Sold
2. Obtain Fair Market Value for Leased Resources • High Bids • Royalties • Area Rentals • Federal Taxes • Other Revenues (e.g., Profit Share)
3. Promote Competition • Number of Bids per Tract
4. Equitable Sharing of Benefits and Risks of OCS Leasing • Revenue Sharing with Coastal States • Economic Impacts on Coastal States • Environmental/Social Costs (5-Year Lease Schedule)
5. Facilitate Regional Planning and Minimize Environmental Risks • Environmental/Social Costs • Number of Tracts Offered • Number of Tracts Sold • Discounted Production • Number of Fields Discovered
6. Maximize the Social Value • Profit plus Federal Revenues • Avoid Wasting Resources from Early Shutdown • Discounted Production
7. Protecting the Integrity of the Leasing Process • Qualitative Considerations Only

Another OCSLA policy Goal is to "Obtain Fair Market Value for Leased Resources". For this Goal, our Criteria includes assessing the potential effect of alternative OCS oil and gas leasing systems on the bonus, royalty, rental, and tax revenues accruing to the federal government (Table II-1). Other Criteria used to assess the achievement of each of the leasing Goals are given in Table II-1.

Across all seven Goals, over 30 Criteria were identified. When possible, a quantitative assessment of each Criterion is made. To do this, we use the results of the Simulation Model (Chapter III) developed for this project. For example, our analysis might show that the use of an alternative leasing system results in an X% increase in the barrels of oil produced and Y% lower bonus bids as compared with the current system.

We also should also note that some results can be ambiguous. For example, employment of additional labor and resources to support more OCS development results in smaller gains to the area economy during periods of full employment because the resources employed have other opportunities. However, if the resources used would otherwise be idle, then part of the payment to resources suppliers in oil and gas development is an economic gain. Hence, additional OCS development is a plus for workers and other suppliers of input when unemployment is widespread (as is the case in 2009), but the gain is much smaller when full employment exists. In short, some Criteria are "case sensitive", that is, the impact will depend upon conditions in the area economy at the time of exploration, development, and production.

In sum, several Goals and Criteria are used to assess the likely performance of alternative OCS leasing systems over the period 2010 - 2060. For each Goal and Criteria, the alternative leasing systems are compared with the estimated performance of the Status Quo, Areawide approach over the same period. No single leasing system likely will outperform all alternatives across all Goals. Hence, when comparing alternatives, tradeoffs among Goals are to be expected.

Finally, it should be emphasized that it is beyond the purview of this report to assign policy priorities or weights to particular Goals or Criteria. This task belongs to policy makers who *ex ante* weigh the potential tradeoffs among Goals when selecting an appropriate OCS oil and gas leasing system to employ[3]. Instead, we provide concepts, an analytical framework, and empirical results which might be used by policy makers to assess how alternative leasing systems perform in meeting the Goals of the OCS oil and gas program using the Criteria set out in Table II-1.

II.B. Alternatives Leasing Systems

II.B.1. Introduction

This section explains the development of the "short list" of potential alternative leasing system. OCS oil and natural gas leasing systems have two basic policy dimensions (1) the terms and conditions applied to leasing individual OCS tracts, and (2) the pace of leasing -- the scale, timing, and location of lease sales. Leasing terms and conditions are described in some detail.

[3] In an interesting study, Farrow (1990) carried out a statistical analysis of actual OCS leasing decisions over time to estimate the implicit policy weights (government's "revealed preferences") used by the Secretary of Interior in setting the five year oil and gas leasing schedule.

We also consider several options concerning the pace of leasing for the CGOM and WGOM as a whole.

II.B.2. Potential Alternative Leasing Systems

Clearly, an enormous number of leasing policies could, in principle, be used to lease OCS hydrocarbon resources. Some alternatives, such as complete or partial nationalization or government control (for example, PEMEX in Mexico, Petrobas in Brazil, or STATOIL in Norway) are obvious nonstarters, far outside the set of feasible options. Other alternatives, such as the cash bonus and various royalty options, clearly should be part of a short list of leasing options. In many other cases, however, the decision as to whether or not to include a leasing option on the short list of alternatives for more detailed consideration is not always clear cut.

To identify leasing system options and then narrow the initial long list of alternatives to a feasible number for more detailed study, a two-step process was used. As a first step, we cast our net broadly and considered a host of approaches used in a variety of contexts, both within and, to a lesser extent, outside of the United States. Alternative candidate OCS oil and gas leasing systems were drawn from recent leasing practices, the published literature, agency reviews, insights provided from institutional experience, and prior empirical assessments of OCS oil and gas leasing.

Beyond oil and gas resources, bidding is used to allocate many natural resources, including hard minerals, timber, geothermal resources (steam), grazing rights, water, air wave spectra, and air pollution permits. Auctions also are employed to sell art, antiques, real estate, and stamps, to award contracts, and to buy blocks of electric power. A brief review of several alternatives can be found in, for example, Salant (2000). An extensive and rigorous review of the large auction theory literature underlying bidding for resources is beyond the scope of this study. But a brief literature review that focuses on the key elements most relevant to this study is given in Chapter III.B of this study.

Given the initial long list of over 50 possible systems, the second step was to reduce the number to a more manageable "short list" of leasing alternatives for detailed evaluation. To arrive at the short list, a pragmatic screening approach was adopted using several considerations, as noted earlier. They included consistency with the OCSLA, as amended; appeal on theoretical grounds; the likely transactions costs involved with administering a system; and practical considerations, including perceived social acceptability. Maintaining the integrity of the OCS oil and gas leasing process is a major consideration. For example, leasing alternatives that are easily manipulated by participants, or that cannot be enforced, are not desirable, even if they have many positive theoretical properties.

Consistency with the OCSLA is important because it puts reasonable bounds on the number of systems to be considered and it acknowledges the difficulty in substantially amending major legislation like the OCSLA. Economic theory is significant in that well-grounded theory can be used to assess how well a leasing alternative achieves particular Criteria Transactions costs for implementing alternative leasing systems matter if such costs are substantially higher under some systems than others. Social acceptability of the system is extremely important, because systems which may have appeal in theory may, in practice, be unacceptable if they have features which engender societal controversy. Finally, to have an orderly functioning leasing system, as is required by the OCSLA, the process must have integrity and public confidence. This means that in perception and in actuality the leasing system is regarded as open, fair, and consistently applied. The OCSLA, for example, requires the use of a single bid variable. Use of multiple bid variables may introduce subjectivity into the bidding-lease award process because tradeoffs have to be made. This could open the leasing decision to criticisms of favoritism, whether correct or not.

II.B.3. Leasing Terms and Conditions

II.B.3.a. The Current Areawide, Cash Bonus Approach

The MMS historically has relied upon sealed cash bonus bidding for leasing tracts to industry, with the exception of several rounds of experiments with alternative leasing systems carried out in the late 1970's and early 1980s. Beginning in April 1983, the Areawide approach was adopted. Under the Areawide approach, the MMS offers virtually all unsold, available tracts in a planning area. Participants in the lease sale submit a sealed cash bonus bid, and the winning bidder submits payment of 20% of the bid amount.

Leasing terms and conditions are specified for tracts to be offered for sale. The terms and conditions used are, fundamentally, policy instruments which the MMS can use to influence the timing of operations and the size and distribution of the potential economic rent associated with available tracts. Specific leasing terms and conditions may differ by water depth and area, and have changed over time. For example, the MMS currently is using escalating area rentals in Alaska planning areas, and in certain eligible cases in the Gulf of Mexico. Also, initial lease terms typically are longer for deep water tracts (up to 10 years) than for those in shallow water (usually, 5 years).

Companies interested in particular tracts can submit solo bids, or can form joint ventures with other firms. This allows smaller, more risk adverse companies the opportunity to share risks by lowering the variance of each firm's estimated returns and expertise and increases the number of bids (e.g., Meade, et al., 1985; Moody, 1994). The largest companies, however, are legally precluded from submitting joint bids.

Leasing terms and conditions include a minimum bonus bid (the reservation price) and a per acre annual rental fee. A primary (initial) lease term is set during which the winning company is required to begin exploration or surrender the tract. Initial lease terms, however, can be extended, for valid reasons, such as the unavailability of rigs or mechanical problems. Rental payments are made until either the operator surrenders a tract or until production starts. Once production occurs, the operator pays a fixed royalty rate on the value of production per period. Payment of a royalty in oil (Royalty in Kind) also occurs.

Table II-2 shows the leasing terms and conditions used in this study as the Status Quo case against which all alternatives are compared. Data in the table are from lease sale # 206 in the CGOM. As given in the table, the minimum bonus bid and annual rental fee are higher in deeper water than in shallower areas, Also, the length of the primary leasing terms increases from 5 years in shallow water to 10 years in deep water.

Table II-2. Status Quo Case for This Study: Lease Terms and Conditions for Sale #206 in the CGOM.

- Area-wide
- Minimum cash bonus per acre:
  - $25/acre for water depth < 400 meters
  - $37.50/acre for water depth ≥ 400 meters
- Royalty: 18 ¾% for all water depths[1]
- Rental:
  - $6.25/acre for water depth of < 200 meters
  - $9.50/acre for water depth of ≥ 200 meters
- Minimum Royalty[2]
  - $6.25/acre for water depth of < 200 meters
  - $9.50/acre for water depth of ≥ 200 meters
- Initial term of lease[3]
  - 5 years for water depth < 400 meters [4]
  - 8 years for water depth ≥ 400 meters to < 800 meters
  - 10 years for water depth ≥ 800 meters

Source: http://www.gomr.mms.gov/homepg/lsesale/206/fnos206.pdf

1 Ignores variations such as Royalty Relief for deep drilling in tracts in shallow water and for drilling on tracts in deep water. See source reference for details.

2 Applies when minimal production occurs on a tract.

3 Commencement of an exploratory well is required within the initial 5-year term in order to avoid cancellation.

4 An initial 5-year term can be extended to 8 years if the drilling depth to a target exceeds 25,000 or if mechanical or safety problems are encountered.

The royalty rate of 18.75% used in sale # 206 is somewhat higher than the 16.67% rate commonly used in the GOM and elsewhere until recently. Though higher than in the recent past, the royalty rate used by the MMS on the OCS tends to be lower than the rates recently used in the State of Louisiana or Texas, for example, for oil production in their offshore areas.

A unique feature of OCS oil and gas leasing is that if a tract receives fewer than three bids, the MMS carries out a formal fair market value evaluation (FMVE) before a high bid is accepted. This dimension of the MMS leasing process is designed to help ensure the receipt of the fair market value of tracts leased to industry. Tracts for which high bids are rejected by MMS, or tracts which receive no bids, typically are reoffered in subsequent sales when higher prices, technological advances, or additional information about resource potential may make them financially viable.

II.B.4. Alternatives to the Terms and Conditions in the Current Areawide Approach

II.B.4.a. Restrictions

We begin by noting several restrictions which apply in proposing leasing terms and options considered for the short list. One is that all of the alternatives considered use sealed bids and a single bid variable, as is required by the OCSLA. This rules out, for example, approaches which use oral auctions, such as some oil, geothermal, or timber auctions on Indian Trust lands by the Bureau of Land Management. It also excludes the use of multiple-bid variables, such as used by the State of Louisiana for leasing its offshore lands for oil and gas development.

Another limit is on the size of OCS tracts. Individual tracts on the US OCS cannot exceed 5,760 acres (9 square miles) and most GOM tracts in recent years are of that size. For some perspective, these are much smaller than those blocks of hundreds of square miles offered, for example, in offshore Canada or in the North Sea, but are larger than the tracts typically leased by, for example, Louisiana in its marine waters.

The relatively small geographic size of GOM tracts might cause higher investment costs per unit of oil discovered, as well as higher administrative and bureaucratic oversight costs per unit of oil discovered (Richardson, 2008). These factors may affect the value of development and hence bidding (Richardson, 2008). We are aware of only one domestic OCS economic bidding study which allowed for the influence of varying tract size. Mead, et al. (1985) found that tract size is positively related to high bids per acre. But to our knowledge, no in-depth study of how tract size affects bidding has been done in the U.S.

Another restriction is that we are unable to assess changes in the frequency of OCS lease sales. Currently, there are annual sales in the WGOM and CGOM; more frequent sales might somewhat expedite and increase the present value of revenues. For example, Louisiana has monthly sales, and Texas holds quarterly oil and gas lease sales. However, our modeling approach considers the number of OCS tracts offered per year and not individual lease sales per se. It is also worth mentioning that scheduling additional sales involves substantial costs for MMS because of many strict procedural requirements which must be met for OCS lease sales. Moreover, accelerated leasing would reduce the time available to firms to update their information and develop improved estimates of the value of the remaining available tracts.

While states like Louisiana and Texas hold much more frequent sales, as mentioned, these states offer a very limited number of tracts for sale, an Environmental Impact Statement is not required, and their lease sale process is less contentious and drawn out than is the case for OCS sales.

A further restriction on OCS leasing (though not relevant for this study) is that, under the 1976 Energy Policy and Conservation Act, the largest companies cannot form joint ventures to bid on OCS tracts. This contrasts with offshore Nova Scotia, Canada, for example, where firms of any size can participate in joint ventures. Lastly, our modeling does not have a detailed spatial dimension, except for water depth. Hence, we are unable to consider such possible leasing options as use of buffers or offering subsets of areas[4].

II.B.4.b. Identifying and Screening Alternative Leasing Terms and Conditions

As part of our efforts to create the long list of candidate leasing alternatives, an important source was a somewhat comprehensive internal policy review carried out by the MMS Alternative Leasing Policies Group ("ALPG") in 1993. The ALPG report examined the main features of some 35 leasing options and considered their perceived strengths and weaknesses. Also identified in the ALPG review are potential issues with implementing each option. For example, some alternatives face practical administrative difficulties, others might require revision of the OCSLA, and in yet other cases, political agreements with coastal states, for example, would be required before they could be used.

Several of the alternatives given in the 1993 APLG report now are somewhat outdated because of major advances in OCS oil and gas technology (e.g., Managi, et al., 2004, 2005), substantial development of deep water capability and development, market changes, and a now-long history of exploration and development in the GOM[5]. Nevertheless, this 1993 MMS internal leasing document remains a valuable reference for OCS oil and gas leasing policy. It reflects practical experience, expert judgment, and insights informally drawn from economic theory, especially natural resource economics and auction theory. Limited empirical information and no formal analysis of leasing options were used. The ALPG report is substantive and fairly lengthy, and as a result, each of the alternatives is described only briefly in an Appendix to this report.

Obvious candidates for bidding systems include the current cash bonus system and the alternative bidding systems listed in the OCSLA, as amended (43 USC 1336, Sec. 8)[6]:

1. Variable Royalty Bid, with either Fixed Work Commitment or Fixed Cash Bonus
2. Cash Bonus Bid, or Fixed Work Commitment Bid or Fixed Cash Bonus with Diminishing or Sliding Scale Royalty
3. Cash Bonus Bid with Fixed Share of Profit ≥ 30%
4. Fixed Cash Bonus with Net Profit Share as bid variable
5. Cash Bonus Bid with Fixed Royalty ≥ 12.5% and Fixed Profit Share ≥ 30%

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[4] The smallest area for which we have information from the MMS for the GOM is at the protraction-area level.

[5] For example, one option raised by the ALPP group is the drilling COST wells, as was done in the 1970s. These were drilled off structure to acquire basic information about the geological potential of OCS areas. COST wells are less useful today than two decades ago, especially for the mature GOM region.

[6] The MMS has experimented with all of the alternatives given in the OCSLA, except for the work commitment and the bid deferral options.

6. Work Commitment Bid with Fixed Cash Bonus and Fixed Royalty ≥ 12.5%
7. Cash Bonus Bid with Royalty ≥ 12.5% with suspension for a period, volume or value determined by Secretary of DOI, where such suspension may vary based on the price of production from the lease.
8. Secretary may defer for up to 5 years any part of the lease Cash Bonus payment
9. Secretary may use any other approach, but must use only one bid variable

The current Areawide, cash bonus system with an annual rental and fixed royalty on production is the Status Quo. Alternative leasing approaches 1 – 7 above are considered for our short list. Alternatives 8 and 9 are not specific options and are not discussed further.

Within the alternative bidding approaches listed above (as well as with the current Areawide system), the Secretary of the Department of the Interior (DOI) has considerable flexibility in setting bidding terms and conditions. For example, royalties can be reduced or eliminated, if supported by economic, geological, and technological factors (including Royalty Relief"). Royalties can be based on value or paid in oil -- resources in kind (RIK). Annual per acre rentals, minimum bids, royalty rates, the length of the primary term, and other conditions can be and are varied over time and across lease sales because of variations in the difficulty in operating in different areas, challenges posed by deep water, and changes in market conditions. Innovative approaches that are not explicitly excluded also might be considered, such as "multi-round" bidding wherein tracts would be sold over several rounds of bidding, as described in more detail below.

As the preceding discussion makes clear, the Secretary has considerable latitude under the OCSLA in choosing leasing terms and conditions. At the same time, on many issues the Secretary's authority is limited by the requirements in the OCSLA that, for example, allow only a single bid variable, require the use of sealed bids, and limit blocks to a maximum of 5,760 acres.

In the section below, we identify selected, alternative terms and condition which might be used to lease OCS tracts. We outline their major features and indicate potential advantages and issues their use might pose. Then, in the following section, polices concerning the pace of leasing are addressed. .

II.B.4.c. Leasing Terms and Conditions: Options

Profit sharing

These approaches include leasing systems where profit share is the bid variable, and also use of fixed profit shares where a cash bonus might be the bid variable. A company's profits depend upon hydrocarbon production, the price of oil, and the cost of operations. Profit sharing systems have the virtue of sharing risks associated with the variability of price, quantity, and costs between companies and the government, which is better able to bear risks than companies. Risk can be substantial when energy markets are volatile and for relatively unexplored areas, although the latter may be a smaller factor in most of the CGOM and WGOM than for other, less well explored OCS planning areas.

An approach based more on profit sharing and less on upfront cash bonus bids is likely to be more attractive for smaller companies which are more risk-averse than larger firms (e.g., Smith, 1982). In addition to sharing risks, a profit-sharing system also improves cash flow, since firms' profit share payments are timed more closely with their receipt of revenues, compared to the up-front burden associated with cash bonus payments. Together, reduced risk and improvements in cash flow might make smaller companies more competitive in the leasing process, and perhaps promoting additional competition. And empirical results suggest small companies may reduce risk further by forming joint ventures with other small companies (Moody, 1994).

For the past 20 years, the State of Alaska has used a profit sharing system, with bids in the past of up to 92% of the profit. More recently, however, Alaska has used an administratively-set profit share of 30% or 40% of net income. California also has used profit sharing to lease tracts off the coast of Long Beach. The minimum profit share was 85.56% (reported in Mead, et al, 1985).

In theory, profit sharing does not distort incentives, and as a result operators produce the socially optimal output (Mead, et al, 1985). In principle, profit sharing allows maximum recovery of oil and economic rent toward the end of the life of a field. This occurs because, as the marginal cost of production rises, the profit share payment declines. However, a profit share approach will likely never achieve the theoretical ideal of completely avoiding distortions of incentives due to a host of practical problems. Indeed, profit share may not be an effective approach due to the difficulty in verifying profit calculations.

Experience shows that profit sharing can be complicated and contentious. Differences can arise about the interpretation and measurement of both revenues and costs, and questions can be raised about the appropriate formulae to use and their application. Potentially costly auditing is required to verify profits. Substantial information is required, and increasing care is needed as the profit share increases, the stakes get larger, and operators have an incentive to charge costs to profit share tracts rather than to other, non-profit share tracts. Further, government auditors face asymmetric information in that companies know their actual costs better than the government does. Additionally, companies may want to appeal the profit share rate they agreed to pay, in light of changing conditions. In Alaska, for example, BP has sought to renegotiate its profit share. MMS might also face challenges in administering such a system in the GOM.

Alaska has had to expand its auditing operations because of a substantial backlog of audits, some many months behind schedule.[7] Information can be interpreted in different ways, and constant disputes can be anticipated, as occurred in California with Long Beach profit share leases (as reported in Mead et al., 1985). Hence, the use of a profit share may result in significant transactions costs, delays, and uncertain outcomes.

An alternative to a detailed annual auditing of every OCS profit share tract could be the use of a standardized field simulation model in order to simplify the estimation of profits and the resulting share due to the government. Such an approach would be based on a combination of tract-specific information, such as water and drilling depths, and "averaged" information, such as

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[7] http://www.legfin.state.ak.us/BudgetReports/GetBackupDocuments.php?Year=2008&Type=proj&Number=48381&NumberType=LFD

cost per mile for transporting oil by pipeline. Accounting for changes in cost over time also would have to be part of the model. Such a model-based approach could be developed to carry out these calculations, and the model could be presumed correct if the model were embodied in official regulations. Nevertheless, such an approach would almost certainly require exceptions to take account of tract- and reservoir-specific conditions, and considerable transactions costs could result if firms commonly chose to appeal the model results. Also, developing the model and keeping it updated could be a costly.

Royalty Alternatives

High fixed rates. Leasing terms with high fixed royalties on the value of production per period (e.g., per quarter) would share quantity and price risks between the government and industry. With higher royalties, the value of the tracts to industry would be reduced due to greater royalty payments, and hence one would expect cash bonus bids would decline. With a lower upfront cash bonus bid, and a higher royalty based on the value of production, a greater emphasis on royalties would tend to transfer risk from companies to the federal government, and would also result in improved cash flow for companies. Thus, similar to profit sharing, increased royalties might improve the relative position of smaller firms, where risk and financing constraints may be more of a factor, thereby encouraging more small firms to participate. .

However, high fixed royalties raise operators' marginal and average costs. This will cause some otherwise profitable fields to become uneconomic, and premature shutdown of high-royalty fields can be anticipated, thereby wasting valuable oil and gas resources. (Royalty Relief, however, might be used to avoid waste from early shutdown.)

Royalty in kind. As an alternative to a royalty based on the monetary value of production, greater reliance could be placed on a royalty-in-kind (RIK). Under this option, firms would pay their royalty in oil (or natural gas) which could then be sold, or in the case of oil, perhaps used in the Strategic Petroleum Reserve. While the RIK is paid in product and not in dollars, oil field operators and the government recognize the value of oil. Hence, the effect of a RIK on their actions is the same as with a royalty based on the value of production.

There is, however, a potentially important benefit with a RIK approach. A RIK system avoids the serious, contentious, and vexing problem traditional royalty systems face with determining the correct price on which to figure the value of production on which to apply the royalty (Kumins, 2000)[8]. With a RIK, disagreements in pricing between the parties are a non-issue. Therefore, less auditing is needed, except for internal checks to ensure that in disposing of royalty hydrocarbons, MMS captures the fair market value of the oil or gas under its control. A RIK, however, would result in some additional costs for the MMS to market the oil received.

Sliding scale royalties (SSR). Here, the royalty rate varies with the value or volume of production. The effects of a SSR would depend upon the specific function linking production to the royalty rate, such as declining, increasing, or some other shape. Sliding scale royalties could be structured so as to decrease as fields become depleted, and thereby capturing rent in the early years, but also allowing but also encouraging recovery of resources in the latter stages of field

[8] http://digital.library.unt.edu/govdocs/crs/permalink/meta-crs-1167:1)

production when costs increases could lead to premature field shutdown and loss of resources. Use of historic production data in the GOM might provide a useful framework for developing a sliding scale formula. Alaska's Economic Limit Factor ("ELF") approach reduces royalties as production decreases. We note that the OCSLA allows MMS to reduce or eliminate royalties in order to avoid premature shutdown, and this is akin to a sliding scale royalty late in the life of a field. This form of royalty reduction, however, is administratively screened while ELF would primarily be applied by use of a formula.

Along this line, the State of Alaska uses an Economic Limit Factor ("ELF"). This approach is somewhat more complex than many royalty approaches but has the advantage of capturing the gains from higher prices and productive fields while reducing government take when field productivity declines or the market price of oil drops. It also encourages development of smaller and less productive fields.

Under this approach, Alaska sets an ELF rate as a (non-linear) function of well and field productivity (Alaska Oil and Gas Assoc. http://www.anchoragechamber.org/whats_new/aoga%20presentation.ppt). To determine government take, the ELF rate is multiplied by adjusted gross income and by a base tax rate which increases over time (12.25% for years 1-5, and 15% after 5 years).

We note that the OCSLA allows MMS to reduce or eliminate royalties in order to avoid premature shutdown, and this is akin to a sliding scale royalty late in the life of a field. This form of royalty reduction, however, is administratively screened while ELF, as noted, is applied by using a formula which automatically captures field and well productivity as well as gross revenue and a base tax rate.

Depending on the formula used, a SSR system might reduce bonus payments and by that, lower barriers to entry as compared to the Status Quo system. However, depending upon the structure of the SSR, it might provide incentives that encourage strategic behavior on the part of companies. For example, a structured sliding scale royalty that is based on the annual rate of production might induce a company to produce more slowly than optimal, thereby deferring production and reducing national security benefits and the social value of the field.

An alternative is an SSR which is a function of price. This approach captures more of the rent when oil prices increase and reduces the royalty rate for price decreases. Again, the specific results will depend upon the function used to relate the price and rate.

Variable royalty bids. Variable royalty bids would have the positive effect of sharing price and quantity risks between companies. However, marginal and average costs would be substantially higher. Thus, some otherwise profitable fields will be made uneconomic by this policy, while others will be prematurely shut down, by that unnecessarily wasting oil and gas by leaving it unproduced. Or, firms might request royalty relief. This creates a problem that could threaten the integrity of the leasing process. For example, a firm might submit a very high royalty bid, thereby winning the rights to a tract. Then if resources are discovered, the firm could correctly argue that the royalty bid is so high that the field is not profitable, and request a reduction in the royalty, as allowed under OCSLA §8(a)(3)(A). As a consequence, royalty bids might not be credible, thereby threatening the integrity of the auction process.

Work Commitment

Under OCSLA, work commitment is based on a dollar amount for exploration. However, more generally, work commitment is also sometimes defined in a plan to undertake specific exploratory activities. While the latter is not specifically mentioned in OCSLA, it is outlined here to highlight differences between work commitment alternatives.

It could be argued that work commitments are desirable in OCS areas where limited information exists on the resource potential. Early discoveries and production attributable to a work commitment could provide information externalities to other firms, thereby spurring additional exploration and expedited production relative to the use of a traditional cash bonus bid (Farrow and Rose, 1992; Lim, 2007). This appears to be a rationale for use of a work commitment in unexplored areas of offshore Eastern Canada. It could also be argued that reducing oil imports by expanding domestic OCS oil production has important non-market, natural security benefits which are not reflected in market prices. Hence, it could be socially beneficial to adopt policies in relatively unexplored areas which could accelerate exploration and production of domestic oil supplies beyond what would be occur under purely private incentives. A work commitment approach potentially could do this.

In general, a work commitment based on firms carrying out specific exploration activities would award OCS leases based on the perceived appeal of the bidders' submitted plans. The United Kingdom, for example, has awarded licenses based on companies' work commitment proposals and a commitment to use national businesses in day-to-day operations.

Potential issues with this type of work commitment include how a bid review team would distinguish, and make implicit tradeoffs, between competing bids. For example, the bid review team would need to compare work commitments with different numbers, locations, and timing of wells, and different combinations of activities (e.g., more and/or better seismic work vs. the number, location and timing of wells). As a result, a degree of subjectivity could be introduced in the lease-awarding process, which could erode confidence in the approach.

Also, considerable effort would be needed by MMS to assess plans by all bidders for what could be hundreds of tracts available per sale. The MMS also would need to ensure that winning companies met their work commitment; any post-lease changes of work plans could be time intensive and frequent *post-facto* changes may call into question the integrity of the process, even if the changes were prudent.

Additionally, work commitments might not make sense at some point. For example, would the government enforce a work commitment if absolutely no promising results were found early in the process? Consider the extreme example of a work commitment that includes production wells and transportation pipelines. Would the government require that these commitments be carried out if no resources whatsoever were found on the tract? Finally, the work commitment approach presumes that government knows better than industry what the optimal exploration plan should be for tract.

A dollar work commitment, but not an activity-based work commitment, is allowable under the OCSLA. We note that Canada uses a *dollar* work commitment in leasing its offshore Crown

Lands. A dollar work commitment encourages exploration, which is important in the vast relatively unexplored offshore areas of Canada where success creates an information externality which encourages others to enter the market. Also, the determination of the winning bidder based on a dollar work commitment bid is self evident as compared to an activity-based work commitment bid which, as noted, can become subjective. Indeed, OCSLA requires a single bid variable, and one could argue a work commitment of a single dimension might be the only form that is consistent with OCSLA. Dollar work commitment, however, leaves no room for assessing the relative merit of submitted exploration plans.

Finally, it must be recognized that encouraging exploration and production beyond what is privately optimal could have two, perhaps offsetting effects. One, it would reduce the value of tracts to industry and possibly government revenues for those tracts; but it might spur additional interest in nearby tracts, leading to earlier or additional revenues from other tracts.

Higher Annual Area Rental Payments

Firms awarded an OCS oil or gas lease are given an initial lease term during which they pay an area rental fee. Rental payments cease when production starts and royalty payments begin. For our Status Quo case, Sale #206 in the CGOM, the annual rental is $6.25 per acre for water depths up to 199 meters and $9.50 per acre for water depths of 200 meters or greater. For a 5,760 acre tract, the annual rental thus ranges from $36,000 to $54,720 per year, depending on water depth.

Increasing annual rental payments may provide an incentive for a firm to expedite exploration in order to determine whether development is financially justified and one element of that decision would be the cost savings from no longer needing to make the annual rental payment. It is not clear, however, that modest annual rental payments of $36,000 and $54,720 provide an adequate incentive to expedite exploration. On the other hand, higher area rental fees could make marginal tracts unprofitable, or could cause firms to prematurely cease exploration and relinquish tracts without discovery. At a lower area rental rate, exploration might continue for a longer period, perhaps resulting in some additional discoveries. Later in this study, we examine how higher fixed rental payment per acre might affect OCS exploration, development, and production.

Shorter Primary Lease Terms

Firms awarded an OCS oil or gas lease are given an initial or primary lease term during which they pay an area rental fee, as mentioned above. The primary terms typically varies by water depth. Companies which fail to initiate exploration during the primary period must surrender their lease, unless the delay was for good cause.

In the Status Quo case used in this study (OCS Lease Sale #206 in the CGOM), the initial lease term is 5 years for shallow waters (<400 meters), 8 years for intermediate depths (400 meters up to 799 meters) and 10 years for deep water (800 meters and deeper)(Table II-2). In our later analysis of alternative leasing systems, we consider the effects on performance of using shorter primary lease terms.

Additional Options

Four other approaches are mentioned. The first two, Vickery Second Bid Auctions and Dutch Auctions are novel in connection with OCS leasing, but may have appeal on theoretical grounds. The third approach, multi-round bidding, draws on the approach used by the Federal Communications to lease valuable broadband spectrum widths. Finally, a sequential leasing option is described. Below, each of these is taken up in turn.

Vickery second-price auctions. Use of a Vickery (1961) second-price auction would award the item being sold to the highest bidder who then, however, pays the amount of the *second–highest* bid. This type of auction has been commonly used to sell U.S. Treasury securities. Vickery auctions have the theoretical advantage of being "incentive compatible", in that firms have a dominant strategy of bidding their perceived value of the item being auctioned. In comparison, auction participants have an incentive to bid less than their true value under a first-price sealed bid auction. Thus, although the sales price in the Vickery auction equals the second highest bid, it is unclear whether price is higher under a second price versus first price sealed bid auction.

Vickery auctions can help to avoid the "winner's curse" since the winner pays the second-highest bid. However, a Vickery-type auction for OCS leasing might prove hard to support to the public, even though it might lead to the highest government take. The fact that the government does not actually collect the high bid and accepts instead a lower amount likely would engender public criticism and make use of a Vickery-type auction for leasing socially unacceptable. This would be particularly problematic in a case such as bidding for OCS leases, since many tracts have only one or a few bidders, and because there is a great deal of uncertainty, there is often considerable divergence in firms' estimated tract values. In such a case, the second highest bid is often far lower than the highest bid, and indeed there is only a single bid on many tracts. In such instances, many tracts—perhaps the majority of tracts—could sell for far less than the high bid, sometimes resulting in sales prices that are an order of magnitude or more below the highest bid. Even though theory suggests that firms bid higher in second price auctions, at least in part addressing this problem, it is unlikely that these subtleties would be recognized by the larger public. And the system could easily result in severe criticism—correct or incorrect—that tracts are essentially being "given away" for far lower prices than could be obtained. We fear this would lead to harsh criticism of the leasing system, and could threaten the integrity of the bidding process. For this reason, we do not consider further Vickery Second-Price auctions.

Dutch auctions. A so called Dutch (declining) Auction (Van Den Berg, et al, 2001) involves starting the bid process at a high level and then lowering the amount until someone accepts the given price. Dutch Auctions have been used, for example, to sell flowers and fish. The Dutch auction for a single item is strategically equivalent to a first price, sealed bid auction currently in place for OCS leasing. In a Dutch auction, the auctioneer starts with a price that exceeds the highest amount that any potential bidder might be willing to bid on the item. Then price declines until it reaches a point where someone chooses to purchase the item. Thus, participants in a Dutch auction need to determine the price at which they would purchase the item. If this same purchase price were written down, put in an envelope and delivered to the auctioneer, it is simply a first price sealed bid auction.

With multiple items, the Dutch auction most commonly proceeds sequentially, with items auctioned off one-by-one. In the context of OCS leasing, when tract number K is put up for auction, the auctions for tracts 1 through K-1 have already been completed. The sequential Dutch auction is again strategically equivalent to a sequential sealed bid auction, where sealed bids are made for tracts that are put up for sale in sequence, and bids for tract K are submitted only after the auction for tract K-1 is completed.

Hence, Dutch and first price sealed bids are strategically equivalent. But implementation of the Dutch auction is far more cumbersome than that for a sealed bid auction. First, the Dutch auction starting price for each tract needs to be placed higher than anyone would be willing to pay any tract. Since some tracts may be worth tens or hundreds of millions of dollars, and since there is great uncertainty with respect to estimates of tract values, each and every tract would need a starting point of perhaps several hundred million dollars. Then, the posted price would need to decline slowly enough that firms could choose to stop the auction for that tract by purchasing it at that posted price. And since typically only about 10% of all tracts received any bids whatsoever, the posted price would need to decrease to the minimum bid amount on most of the tracts that are offered without the tract ever being sold. Thus, process for each tract would be time consuming, especially for low valued tracts that are not bid upon or sold.

Hence, the Dutch auction offers no advantage over a first price sealed bid auction, but would be far more cumbersome and time consuming. Indeed, since the OCSLA requires that auctions be done by "sealed bid", the Dutch auction would need to be structured around a sealed bid, and could not be implemented as oral auction similar to most Dutch auctions, such as the flower auctions. So the most straightforward way to structure a Dutch auction to be consistent with OCSLA would be as a sealed bid, first price auction, which is the current auction system. Hence, we do not consider the Dutch auction as an alternative in our analysis.

Multi-round auctions. Multi-round auctions have been employed extensively by the Federal Communications Commission (FCC) to auction valuable broadband spectra. Such a system could be adapted to sell OCS leases.

The process would begin with a reservation price set by MMS for each tract. Companies then submit confidential electronic (sealed) bids for the available tracts. At the end of each successive round of bidding, the highest bid is announced for each tract, and bidding continues for the next round, where the bids on a tract in the next round must exceed the high bid on that tract from the previous round by a predetermined bid increment. Bidding continues until no further bidding occurs. Companies would know which other companies are participating in the overall sale, and the highest bid for each tract, but not who submitted bids for particular tracts. Anti-collusion rules are strictly enforced, as they are in FCC auctions.

The bidding process may include various options. For example, one option would allow bids to be withdrawn a limited number of times during a round, but those withdrawing a bid would pay a penalty to do so. If the winning bid is withdrawn, the company could be required to pay a penalty plus the difference between its bid and the next highest bid. .

Multi-round auctions have the virtue that bidders pick up information throughout the bidding process. Thus, companies can reassess their strategies as the sale proceeds. If companies are unsuccessful in bidding for some tracts, or note other substitute tracts are undervalued, they can switch their bids to other tracts. Hence, this approach allows for reallocation of bids during the sale, which might increase government take at no cost to efficient resource use.

A potential drawback is that multi-round bidding with many tracts offered would be much more complex and take more time than cash bonus sales, especially in the context of Areawide leasing where thousands of tracts might be offered in a single sale. Thus, the approach might be more practical with lease sales of smaller size.

Sequential auctions. This approach was suggested, in different forms, by Gilley and Karels (1981) and by McDonald (in Mead, et al, (1985)). Sequential auctions would begin with an initial cash bonus bid for offered tracts. After the initial, tentative closing of bidding in the sale, bids would be opened in the order of number of bids per tract. In McDonald's formulation, a drawing is used in the event of a tie. The winner is informed of their successful bid, but the winner's identity is not made public. Losing bidders are then free to bid on other unsold tracts before bids on these tracts are opened.

McDonald argues sequential auctions will increase the number of bidders and, as a result, allow government capture more of the economic rent of a tract. Such a leasing system would be cumbersome to implement with many tracts, but need not be applied to all tracts in a lease sale.

However, sequential bidding, as suggested by McDonald, is open to strategic behavior in the initial round of bidding. Submitting bids in the initial round could signal the firms' estimates of tract values. So, firms might behave strategically by not bidding on tracts of highest interest in the initial bidding, in an attempt to mislead others. In such as case, the first round of bidding would seem to be extraneous. One might just as well offer tracts in random order. In fact, Gilley and Karels (1981) suggest that groups of tracts, selected randomly, be offered in sequence. To avoid strategic behavior, it may be desirable to preclude firms which do not submit a bid on a tract in a particular round from submitting bids on that tract in subsequent rounds.

An alternative would be only to offer tracks for sale if they receive sufficient interest in the initial stage. This is similar to the use of "nomination points" (Opaluch, 2007) In effect, the first round becomes a nomination process.

This approach has the advantage that firms that lose bids on some tracts (or lose their interest in particular tracts) have the opportunity to reallocate the funds to other tracts, as in the sequential sale option, rather than delaying bids until a future lease sale. Also, the point system should be designed such that points have value to companies, such as by limiting the number of allowable points each auction participant is allowed to allocate. Otherwise, companies might want to nominate tracts of little or no interest to them but which could serve a strategic role of misinforming other potential bidders. Efforts to act strategically along these lines, however, would use up its allotment; and as a result, the firm might be unable to nominate other tracts of substantial interest to them. MMS might include some tracts which received few or conceivably no expressions of interest. For example, this might be done to fill in some nearby areas or as a strategic move to encourage bidding on tracts with little revealed interest.

II.B.5. Pace of OCS Leasing

This section addresses the second element of our assessment of alternative leasing systems, options which affect the pace of OCS leasing in the GOM. The pace of leasing in general encompasses the scale, timing, and location of OCS lease sales. As mentioned previously, however, our model considers the scale of annual leasing but not the timing of individual sales within a year. Also, our simulation model does not consider the location of tracts (other than for tract-specific water depth, which is included in the model).

MMS formally addresses the pace of OCS leasing under the Five Year OCS Oil and Gas Leasing Schedule, a requirement of the OCSLA. Development of the Five-Year OCS Oil and Gas Schedule occurs in a highly structured, legalistic setting, over an 18-month period. It involves rounds of public comments on various programmatic documents, including an Environmental Impact Statement and Draft Five-Year OCS Oil and Gas Leasing Schedule; government responses to those public comments, and revisions to programmatic documents to respond to such comments.

The current Five-Year OCS Oil and Gas Leasing Program covers the period 2007 – 2012 and provides for a total of 21 OCS oil and gas sales in the Gulf of Mexico. Of these, six sales are scheduled for the Central Gulf of Mexico and five will occur in the Western Gulf of Mexico[9].

By way of brief background, OCS oil and gas lease sales until April, 1983 were based on the nomination and selection approach. Following a call for nominations, oil companies indicated tracts of potential interest, and environmental and other interested parties designated areas of concern. After nomination, public review, comment, responses and adjustments, selected tracts were included in the lease sale. Under the nomination and selection approach, from 1955 – 1983 the number of tracts leased averaged 161 per year (MMS GOM Lease Data).

With adoption of the Areawide approach in April, 1983, virtually all unsold, available tracts in a planning area are offered for lease. The number of tracts leased annually increased from an average of 161 under nomination leasing, to an average of 805 tracts since the advent of Areawide leasing. Thus, with the advent of Areawide leasing, the number of tracts leased by a factor of 5 as compared with the nomination and selection approach.

The fact that the change in the basic approach to OCS leasing from tract nomination and selection to Areawide was done under the OCSLA, as amended, underscores the considerable flexibility the Secretary of the DOI has had in influencing the pace of OCS leasing. This flexibility has limits, however, and the Five-Year Program is subject to a formal and extensive outside review, as mentioned previously. Moratoria and buffer areas may be invoked, and coastal states can call for additional planning to assess and counter perceived harmful coastal impacts and to share in hydrocarbon resource benefits. In short, the Secretary's latitude in establishing the pace of leasing is considerable but by no means unlimited, and the many checks and balances in the process of developing the Five-Year OCS Oil and Gas Leasing Schedule limit the Secretary's options regarding the pace of leasing. These include moratoria in leasing certain

[9] OCS sale 224 in the Eastern Gulf of Mexico is a special case mandated by the GOMES2006 Act.

planning areas and restrictions on leasing certain sections of planning areas (e.g. limits on leasing within a certain distance from the coastline).

Looking forward over the 2010 – 2060 study leasing period, the focus of our study is how alternative leasing systems compare in achieving the Goals adopted for this study. One of the Goals identified is the requirement that government receive fair market value for tracts leased to industry. Studies by Mead, et al. (1985) and by Iledare and Kaiser (2007) found that the performance of the OCS oil and gas industry under the cash bonus system was competitive over the periods they studied. One way they assessed this issue was by estimating the after-tax rate of return earned by offshore oil operators in the GOM.

The consequences of the Areawide leasing policy, however, have been subject to much debate. A basic issue concerns the extent to which Areawide sales lowered high bids for OCS tracts or whether other factors were at work. Another issue is whether the low winning cash bonus bids observed since the introduction of Areawide leasing has reduced the government's take of economic rent, resulting in receipt of less than fair market value for sold tracts. A third issue is whether the observed lower OCS lease prices for tracts put coastal states selling offshore leases in state waters at a competitive disadvantage.

Next, we summarize this debate in order to help set the stage for out later analysis of alternative leasing systems for the 2010 – 2060 study leasing period. The introduction of the Areawide approach in April 1983 was followed by a dramatic increase in the number of leases offered for sale and, as noted, a five-fold the number sold. The number of bids per tract and high bids per tract fell sharply after the Areawide approach was implemented. An important issue in the debate is the extent to which the Areawide leasing system is responsible for lowered bids, and how much can be explained by other factors at work, such as lower oil prices, deeper water, limited resource potential, etc. A second important issue is whether Areawide leasing has resulted in a decrease in government take and, as a result, a of transfer economic rent to industry. A third critical issue in this debate is what effect the Areawide program has had on lease sales by GOM states in their coastal waters. Again, our main purpose is to review the various arguments with an eye toward contributing to our analysis of OCS leasing alternatives for 2010 – 2060 in a later section. A brief summary of major points follows.

Stiglitz (1984) provided a primarily conceptual analysis of how the change from tract nomination and selection to the Areawide approach increased the supply of leases, limited the information available to oil firms, increased firms' uncertainty, and reduced cash bonus receipts. Lietzinger (1984), in an accompanying affidavit, summarized resource, price and bid data from offshore Texas, which he argued showed that the Areawide approach was associated with declines in the number of bids and high bids in state waters.

The U.S. Government Accounting Office (1985) (GAO) carried out an early assessment of OCS leasing under the Areawide approach. Their statistical analysis led them to conclude that Areawide leasing reduced the number of bids and government revenues as measured by lower winning cash bonus bids.

The US Department of the Interior (1984) (DOI) pointed out that it is wrong to assess the consequences of Areawide leasing on government revenues by considering only the relation between Areawide leasing and cash bonus bids. DOI noted that cash bonus bids are just one of the financial mechanisms used to capture the economic rent from a lease tract. Other mechanisms are the area rental and royalty payments tracts pay. Since these receipts from annual rents and royalties are received over a long time period, they must be discounted to their present value. Accelerating receipt of rental and royalty payments, DOI argued, increases their present value relative to what would be realized with the tract nomination and selection approach.

An assessment by the U.S. Department of Energy (DOE) (1985) agreed with DOI's analysis and conclusions. The DOE report, however, noted that Areawide leasing also expedited receipt of federal tax payments, which had not been considered by MMS in its 1984 assessment of government take under the Areawide program. DOE estimated that, when all sources of government take were considered, the MMS receipts with Areawide leasing were at least as great as they were under the nomination and selection system.

Using a reduced form econometric model, Farrow (1987) subsequently annualized the determinants of tract high bids before and after the introduction of Areawide leasing. He argued that the declines in bidding per tract and high bids were due to falling oil prices in the mid-1980s and not the introduction of the Areawide program.

Moody and Kruvant (1990) and Moody (1994) estimated structural econometric models to explain both number of bidders and high bids. They concluded that the Areawide program reduced the number of bids and high bids and, as a result, transferred considerable amounts of OCS economic rent to industry. They did not, however, consider annual area rental payments, royalties, and taxes received by the government.

Our simulation model described in Section III estimates how different leasing systems would be expected to perform. Because our analysis is limited to federal OCS leasing, we do not use the model to carry out a full assessment of the effects in state waters. However, we provide a brief assessment of the various arguments.

The argument that OCS leasing harms leasing in state waters by "flooding the market" with leases and driving down lease prices assumes that the two are close substitutes (Stiglitz, 1984; Moody, 1994). While the oil or gas that is produced in state and federal waters certainly are substitutes, tracts in federal and federal waters are not necessarily close substitutes.

It is likely that OCS near shore leasing and nearby leasing in state waters are near-perfect substitutes. In this situation, water depths and distance from shore are much the same and are only divided by a boundary. However, the vast share of OCS leasing in the GOM is in deepwater. For example, 70% of the active leases now in the GOM OCS are in deep water, and it is likely that the percentage in deep water will increase for lands leased over the study period, 2010 – 2060. Nearshore OCS and state areas are mature, well explored areas as compared with deepwater areas. Deepwater areas are more attractive because the expected resource potential and drilling success rates are much higher than near shore areas (Iledare, et al., 2004). While we recognize offshore revenues remain important for the State of Louisiana, production in State waters has been in steady decline for nearly 40 years (http://dnr.louisiana.gov/sec/execdiv/techasmt/facts_figures/table04.htm).

Further, oil exploration, development, and production in deep water differ dramatically from operations in shallow, nearshore state waters. Obvious differences are that deepwater operations require specialized, costly equipment. Positioning and stabilizing rigs, drilling in thousands of feet of water, and installing subsea completion systems in deep water are all very specialized activities requiring sophisticated, high- technology equipment and highly trained operators. Also, operating conditions are more hazardous in distant, offshore water than in nearshore areas.

Nearshore exploration relies on barges and jackup rigs, while in deep water drill ships and semisubmersibles must be employed. In deepwater operations, accurate positioning and stabilization of the drilling equipment and operations is critical and extraordinarily difficult as compared with similar activities near shore. Also, in deepwater, directional drilling and subsea completions are common, whereas platforms complexes are typically used in shallow waters. Given the high level of technology, the training and personnel specialization is much greater for operations in deep water as compared with near shore.

Lastly, support for the notion that OCS oil and gas and petroleum operations in Louisiana state waters are weak substitutes is the fact that different companies are involved in each and OCS operators show relatively low intensity in bidding for State of Louisiana tracts. We explored the issue of substitutability and intensity of interest by reviewing oil and gas companies' overlapping bids. These are cases where companies that bid on OCS tracts also bid on State of Louisiana offshore tracts (in Louisiana, "parcels").

According to the Minerals Management Service, 531 companies bid on OCS tracts from 1980 to 2008 inclusive. (While this list covers all OCS planning areas, the CGO has been the dominant planning area for OCS leasing.) A list of these companies was obtained from MMS.

Turning to the State of Louisiana, our list of companies that participated in sales of offshore tracts came from State of Louisiana sales data. Louisiana holds monthly sales. We adopted a "convenience sample" for Louisiana whereby we considered all sales of parcels for every other monthly sale for the years 2003, 2005, 2007 and also for 2008, the last year for which data could be obtained. The sources we used and summary data are given in Table II-3.

On a company basis, of the 531 companies that bid on OCS tracts over the period 1980 – 2008, 35 (6.59%) also bid on the sample of Louisiana offshore parcels included in our convenience sample. The 35 companies which bid on both OCS and State of Louisiana offshore tracts are 13.83% of the 253 companies that bid on offshore State of Louisiana parcels. This suggests that firms which bid on OCS tracts have only a modest interest in State of Louisiana offshore tracts, while firms that bid on Louisiana offshore tracts have a greater – but still modest – interest in OCS tracts[10].

[10] It is possible that offshore companies have sub-divisions with different names which work onshore (or vice-versa), or that incorrect spelling of company names in electronic lists masks companies which operate in both offshore areas.

Table II-3. Bidding on Both OCS and State of Louisiana Offshore by Same Firms

Category	Federal OCS[1]	LA Offshore[2]
Number of Companies Submitting Bids	531	253
Number of Companies Bidding on Both Areas ("Overlapping")	35	
Percentage of Companies Bidding on Both Areas	6.59%	13.83%
Bids from Overlapping Companies on LA State Tracts		101
Number of Bids on State Tracts for LA Sample Sales		1,117
Percentage of Bids on State Tracts by Overlapping Companies		9.04%

Notes:

1 Federal OCS includes all companies submitting bids in sales from 1980 - 2008

2 LA Offshore includes firms submitting bids for offshore State of Louisiana lands for every other monthly sale in years 2003, 2005, 2007, and 2008

Source:

1 U.S. Dept. the of Interior, Management of Mineral Services, Outer Continental Shelf Tract Sales

2 Louisiana Department of Natural Resources, Office of Mineral Resources, Meeting Schedule and Lease Sales Results, Lease Sale Details, Offshore Bid Tract Sheet, the website accessed on May 29, 2009 (http://sonris.com/direct.asp?server=reports&path=/reports/rwservlet%3FSRMN9031B_p)

Looking instead at the number of bids, the 35 companies that bid on Louisiana offshore tracts and OCS tracts submitted a total of 101 bids on Louisiana offshore lands. These firms make up 13.83% of the firms bidding in Louisiana's offshore areas, as noted, but they submitted only 9.04% of the 1,117 bids in the sales included. This suggests that firms which bid in both areas were relatively unaggressive in bidding for tracts in Louisiana offshore areas.
In sum, taking all of the points given above collectively, petroleum development in Louisiana state waters and in the GOM OCS appears to be weak substitutes.[11] If this is the case, the pace of OCS leasing in federal waters will not have a large effect on lease prices in state waters.

II.B.5.a. Pace of Leasing: Options

Our Status Quo option is the current Areawide leasing system in the GOM, using the basic parameters set for CGOM lease sale # 206 (Table II – 2). This sale is used because it was held in the CGOM, the historically key area for OCS activity in the GOM, and the financial terms and conditions reflect recent OCS leasing policy. Other potential options for dealing with the pace of leasing are described next.

Limiting the Number of Tracts

Changing the number of tracts offered for sale annually will affect the amount and timing of oil and gas production. Other consequences have to do with the impacts on states and their ability to plan for OCS operations. Some approaches might better allow companies to achieve scale economies in their offshore operation.

Several approaches are available to limit the number of tracts leased. Two approaches are discussed here: limiting the number of tracts offered for sale and restricting the number sold. These options are outlined below and will be part of our more detailed assessment of the pace of leasing.

Limiting the Number of Tracts Offered. Here, MMS sets the maximum number of tracts it will offer for sale. This can be done in several ways. One approach would be to restrict sales to a specific area, such as deepwater; or limit sales to one or more protraction areas. The specific tracts to be offered might be determined purely on an administrative basis, or tract selection might be based on a process of nomination, such as was done prior to the advent of Areawide leasing.

Restricting development to an area allows the MMS and the states to better focus environmental studies. Concentrating activities also might help achieve scale economies in infrastructure, such as investment in collection and trunk pipeline systems, or provision of crew and supply transportation. This approach also might help companies better focus their exploration activities, by that avoiding what has been referred to as the diffusion of company effort under Areawide leasing (e.g., Moody, 1994). Also, offering fewer tracts means less development and less risk of environmental harm from development and production operations.

[11] In some respects, the differences in petroleum operating in state waters as compared with deepwater OCS can be viewed as akin to those associated with near shore versus offshore commercial fishing.

However, limiting the number of tracts offered for sale may also lower or defer production in the GOM, this would conflict with the Goals of the OCSLA to expedite exploration and development. In particular, since only about 10% of the tracts offered for sale receive bids, there is a concern that companies might have limited interest in the specific tracts offered for sale. This might be addressed by a process that solicits nominations to aid in the tract selection process.

Use of Nomination Points. Adoption of an auction mechanism capable of measuring *ex ante* firm-level expectations of tract value has considerable appeal and warrants more detailed study. For example, the information content of nominations might be extended by a procedure that provides firms with a fixed number of nomination points to be allocated among tracts. The MMS considers the number of nomination points for each tract in selecting the tracts to include in the lease sale. However, nomination points are kept strictly confidential, and are only used by MMS to decide which tracts to include in a sale. Furthermore, suppose that the MMS includes some tracts that receive no nomination points. Such a system provides firms with the incentive to place large numbers of points on tracts that they expect to be valuable. And the system minimizes opportunities to use nomination points strategically, since nomination points are not revealed to other firms, nor are they used by MMS to determine acceptable bids. The fact that the number of nomination points each firm has is limited, implies that they will be of value to firms as indicators of which tracts they wish to see included in the lease sale. And including tracts with no nomination points minimizes the opportunity for firms to infer the tracts that received nomination points from other companies. Thus, the system minimizes opportunities to use nomination points a strategically to mislead competitors (or the MMS).

Under such a system, the nomination points provide a quantitative index of each firm's *ex ante* expectations of the tracts value in a statistical analysis of bidding behavior in field tests. Nomination points can then be used as a conditioning variable, whereby different auction treatments are balanced across tracts with similar patterns of nomination points (e.g., total points, spread of points across firms, etc.), and/or nomination points can be used an explanatory variable in a statistical analysis of bidding behavior by individual firms.

A measure of this type addresses a serious shortcoming in the literature on bidding for offshore oil. Bids depend upon *ex ante* assessments of value, which are not observable and can vary dramatically across firms. Typically, the literature uses *ex post* indicators or the MMS measures of value, which is not highly correlated with a firm's *ex ante* estimates. A nomination process structured in this way provides a unique opportunity to obtain a reliable indicator of *ex ante* values estimates.

One shortcoming of this system of nomination points is that it is based only on firms' expectations prior to the nomination process, and firms might obtain additional information about the value of tracts after the time of nomination but prior to the lease sale. Nevertheless, nomination points still provide a means of improving statistical analyses in this complex and difficult estimation problem. And it may be possible to extend this process with a second round of nominations that occurs immediately prior to the sale. For example, prior to the sale, the MMS might ask for a second round of nominations, based on information obtained after the first round nomination process. Tracts that do not receive adequate nomination points in the second round or tracts whose nomination points drop by a specified amount might be excluded from the final sale. Again, nomination points would be kept strictly confidential to preclude firms from inferring information from their competitors, and hence to eliminate any incentives to use 2nd round nomination points as a strategic tool to mislead competitors. And it would be very useful to include tracts in the final sale that received no nomination points, so that tracts that are put up for sale are not good indicators of the nomination points awarded by a firm's competitors. Otherwise, there is a danger that nomination points might be used strategically to mislead competitors, which reduces (but does not completely eliminate) their value in a subsequent statistical analysis.

In an ideal case where firms do not behave strategically in the nomination process, tract nominations would be an indicator of firms' *ex-ante* estimates of tract value. However, any system based on nominations faces a danger that information content of nominations could be compromised by incentives for strategy behavior. For example, firms might nominate tracts in which they have no interest in order to avoid revealing their private information on tract values. Keeping nominations strictly confidential might help ensure that nominations are truthful indicators of value, and not being used strategically. Also, strategic behavior could be minimized by not using nominations for any purpose other than selecting tracts to be offered in a sale. For example, if firms believe that nominations will be used in as part of the bid acceptability process, firms might use nominations strategically to reduce minimum acceptable bids on tracts of interest. Indeed, firms might use a nomination process as a means to collude by coordinating bids. For example, a small subset of major actors might be complicit in agreeing to bid only on tracts that they themselves nominated, in order to reduce competition on tracts. Ultimately, the use of a nomination procedure, and the specific design of such a procedure represent a comprise between the possible information content and the provision of strategic incentives.

Restricting the Number of Tracts Sold. A limit could be put on the number of tracts sold. In this case, the MMS might offer a large number of tracts for sale, but indicate that it will lease no more than X tracts at a sale. The X tracts to be sold presumably would be selected from tracts receiving the highest bids.

This approach might be preferred to limiting the number of tracts offered since it would be more likely to result in the best tracts being explored and developed early. An obvious issue is that companies might object to going through the process of preparing a bid (which might exceed the MMS reservation price) and have it rejected because it was not among the highest X bids. Limiting the number of tracts sold might put less pressure on coastal areas for planning for possible impacts. But since coastal states could not anticipate which tracts are likely to sell, reducing the number of tracts sold does not facilitate planning by the coastal states at the time the lease sales is announced. In contrast, reducing lease offerings to a specific location within the planning area would be more effective in facilitating state planning. In summary, the "short list" of alternatives that we later assess in detail is given in Table II-4. In total, twelve alternative leasing systems are assessed.

Table II-4. Alternative OCS Leasing Systems for the GOM: Short List

Pace of Leasing

• Status Quo: 8,000 Tracts Offered in 2010
• Slower Pace of Leasing
  o Reduce Tracts Offered by 50%
  o Reduce Tracts Offered to Pre-Areawide Levels

Alternative Leasing Terms and Conditions

• Cash Bonus – Royalty Options
  o Base Case – 18 ¾%
  o Increase Royalty Rate 35 %
  o Decrease Royalty Rate 12.5%
  o Sliding Scale Royalty Rate Based on Production
• Minimum Bid per Tract
  o Increase Minimum Bid by Factor of 5
• Profit Share
  o 30% Profit Share Added to Status Quo
  o 30% Profit Share in Lieu of Royalty
• Area Rental
  o Increase Area Rental by Factor of 5
• Multi-Round Bidding
• Work Commitment
  o Double Exploration Effort
• Lease Term
  o Reduce Lease Term by 25%

APPENDIX II.A. Selected Experiences with Leasing

Appendix II.A.1. Introduction

This Appendix summarizes leasing policy and approaches to auctions in different contexts, focusing primarily on the United States. Also included is a description of the multi-round approach used by the Federal Communications Commission to allocate scarce and valuable leases for broadband spectra.

Many U.S. States lease hydrocarbons, and several produce oil and gas both onshore and offshore. Alaska, California, Louisiana, and Texas are the main offshore petroleum producing states, although California imposed a moratorium on leasing in 1979, and oil and gas production and revenues in Louisiana, Texas and Alaska waters has steadily declined (http://findarticles.com/p/articles/mi_qn4200/is_20020506/ai_n10172375)

Options were identified in the open literature for onshore oil and gas by the federal government (Bureau of Land Management) as well as by the states, including North Dakota, Oregon, and Wyoming. The state systems illustrate different approaches, elements of which might be transferable to U.S. OCS oil and gas leasing. Selected state approaches are briefly reviewed below, beginning with leasing practices by states in the Gulf of Mexico.

Appendix II.A.2. Leasing by the Gulf of Mexico Coastal States

Louisiana, Texas, Mississippi, and Alabama lease tracts for oil and gas development both offshore and onshore. Of these states, Louisiana is by far the largest offshore producer, followed by Texas. Mississippi, and Alabama have relatively modest offshore oil and gas activity. Information on leasing terms for each of the four GOM coastal states with offshore production is given in Table II-A-1

<u>Louisiana</u>

The State of Louisiana has leased oil and gas in state waters for over 50 years. Oil production in state waters peaked in 1984 at 27.1 million barrels and has declined since then, falling to 6.2 million barrels of oil in 2008. Louisiana offshore gas production reached a maximum of 4.6 MMMcf in 1979 but has declined to 88,857 MMcf in 2006 (http://tonto.eia.doe.gov/dnav/ng/hist/na1090_sla_2a.htm).

Louisiana's Office of Mineral Resources manages the state's minerals resources and advises the State Mineral Board on granting and managing minerals resources. The stated Goal is to: "optimiz[e] revenues to the state from bonuses, royalties, and rentals" (http://dnr.louisiana.gov/min/).

Table II-A-1. Requirements for Acquiring an Oil & Gas Lease on United States Offshore Gulf of Mexico State Lands, 2008

State	System	Primary Term	Minimum Bid	Annual Rental	Royalty	Comments
Texas	Tract nomination with $100 fee for each tract nominated	5 years, extendable for up to 390 days if drilling active and pay $3,000 or $6,000 fee/30 days	$100 to $300/ac, as specified in Sale Notice	$10/ac/yr until production and after primary term if temporary P&A producing well for up to 4 years	If sales start in yrs: ▪ 1 or 2, 20%; ▪ 3 or 4, 22.5%; ▪ 5, 25% ▪ 6 months grace for dry hole	Appear virtually the same as used for lease sales 5 years ago
Louisiana	Tract nomination with $400 fee for each tract nominated	5 years	Unspecified, but must include a leasing fee of 10% of cash bid plus $20/ac	½ of the cash bid per year, starting in 2nd year	At least 1/8, with part of bid being offer to pay higher fraction	May include additional consideratio ns e.g., agree to pay State's legal fee in title challenge
Alaska	Area wide	5, 7, or 10 years	$10/ac	$1/ac/yr increasing annually $0.50/ac to max of $3/ac	12.5% or 16.67%	Additional effective (State) production tax rate of 12%. [Oil & Gas Property Tax + Income Tax + Severance Tax]
Mississippi	Tract nomination or State initiated sale			At least $2/ac/yr	At least 3/16, with part of bid being offer to pay higher fraction	
Alabama*		5 years	$225/ac	$10/ac/yr	25%	

* From onshore lease sale in Dec 2007.

Table II-A-1. Requirements for Acquiring an Oil & Gas Lease on United States Offshore Gulf of Mexico State Lands, 2008 (con't)

Sources:

List of State oil and gas agencies:
http://iogcc.state.ok.us/links

Texas oil and gas lease sale information:
http://www.glo.state.tx.us/energy/lease sales/oag/index.html
http://www.glo.state.tx.us/energy/lease sales/oag/2008-Jul-1/index.html

Louisiana oil and gas lease sale information:
http://dnr.louisiana.gov/INDBDS/MINBOARD/MINLEASE/082008/nop082008.ssi
http://dnr.louisiana.gov/MIN/PETLAN/Leasing/LeasingManual.pdf
http://dnr.louisiana.gov/MIN/forms.asp

Alaska oil and gas lease information
http://www.dog.dnr.state.ak.us/oil/products/publications/previous_sales.htm#ci08
http://www.dog.dnr.state.ak.us/oil/products/slideshows/2008%20presentations/og_activities1_22_08.pdf
http://www.tax.alaska.gov/programs/documentviewer/viewer.aspx?342

Mississippi oil and gas lease information:
http://www.deq.state.ms.us/MDEQ.nsf/pdf/Main_GEO-4/$File/GEO-4.pdf?OpenElement
http://www.mscode.com/free/statutes/29/007/0003.htm

Alabama oil and gas lease information:
http://www.outdooralabama.com/public-lands/stateLands/SLPublic-Notice/Oil_gas/Bibb_County_2007.pdf

The Petroleum Lands Division performs the leasing function on behalf of the Mineral Board. Lease sales for onshore and offshore areas are held monthly on the second Wednesday of the month. Interested parties must nominate lands of interest in order for the lands to be included in the next monthly sale. Prospective bidders pay a $400 nomination fee for each unit of land nominated.

In Louisiana, the time from nomination to sale is brief – 48 days -- as is illustrated in recent (Fall 2007) example below (Table II-A-2)

Sealed bids are used to auction off tracts. At the time of a sale, companies indicate the part of a nominated area to which their bid applies. By law, tracts can be no larger than 5,000 acres, but in practice the maximum area leased is 2,500 acres. Operators bid a dollar amount on all or a portion of a tract; and they can offer "other considerations" as well.

Operators must pay a one-time leasing fee (10% of the cash bid) and also make a $20 per acre payment. By law, the royalty is at least 1/8 of the value of production, although usually the fraction paid is higher. For a recent six-year period, the average royalty rate on offshore lands was 21.85%. This compares with the recent royalty rate on federal OCS land of 18.75% in CGOM lease sale #206, the Status Quo used in the present study.

Louisiana sets the primary term at 5 years for offshore tracts, as opposed to 3 years for inland tracts. During the primary lease term, operators pay an annual rental of ½ the cash bonus bid.

Louisiana's leasing program clearly differs from that used on the OCS in significant ways. One is that a nomination process is used. Another is that firms can and do bid on a fraction of an area nominated, although nominated lands do not always receive bids. Another notable difference with OCS oil and gas leasing is that Louisiana uses two bid variables in the leasing process. One is a cash bonus bid and the other is a royalty rate bid. As noted, "Other considerations" also may be offered at the option of bidders, and are taken into account when deciding which bidder is to be awarded the lease. Hence, in Louisiana effectively three bid variables can be in play at a lease sale. Other differences, noted above, are that Louisiana requires payment of a nomination fee, and the annual rental is tied to the amount bid.

<u>Texas</u>

Offshore production in Texas state waters peaked in at 1.689 million barrels in 1980 has dropped to 0.457 million barrels in 2006 (http://tonto.eia.doe.gov/dnav/pet/hist/m_epc0_fpf_txsf_1a.htm). Texas offshore natural gas peaked at 84,573 MMcf in 1994 and has declined to 29,299 MMcf in 2007, the latest year for which this data could be obtained.

Leasing of oil and gas in state waters is carried out by the Texas General Land Office, with leases sold by area. Five categories of areas are used, one of which is the "Gulf of Mexico", which is the only category considered to be offshore. (Oil from bayous with salt water influence is a different category and is not considered oil from the Gulf of Mexico).

Table II-A-2. Example Time Profile for Louisiana Oil and Gas Lease Sale

Activity	Date	Number of Days
Receipt of Application	Oct. 22, 2007	
Advertising Date	Nov. 29, 2007	38
Accepting Bids	Jan. 8, 2008 (noon)	9
Lease Sale	Jan. 9, 2008	1
Total		48

Texas holds quarterly lease sales in January, April, July, and October on first Tuesday of the month. Tracts are nominated no later than two weeks after a sale for inclusion in next sale. TX has sales in bays, lakes and bayous (tidally influenced) and in the Gulf of Mexico, which as mentioned, is referred to as "offshore". GOM tracts contain either 640 acres ("small tracts") or 5,760 acres ("large tracts").

In the bidding process, the operator specifies the area and size (in acres) of the land being bid on. They also indicate the cash bonus amount, which implies payment of an associated Sales Fee (1 ½% of the cash bonus). In recent years, the royalty rate has been 25%, but can be reduced over time. Texas has an escalating royalty whereby the rate if higher the longer the firm takes to initiate the production of oil.

One year after expiration of primary term, the lessee must pay a minimum royalty of $5 per acre, less the actual royalty payment made.

Appendix II.A.3. Leasing in Non-GOM States: *Alaska*[12]

Alaska offshore oil production dates from 1964. The State of Alaska now is the largest state producer of offshore oil and gas, producing some 97.7 million barrels of oil in 2006, down from the high of 108 million barrel in 2003. (http://tonto.eia.doe.gov/dnav/pet/hist/m_epc0_fpf_aksf_1a.htm).

Alaska's oil and gas leasing program mimics the federal approach in several ways. In 1998, Alaska dropped the system of tract nomination in favor of Areawide leasing in order to encourage rapid exploration and development. This approach is used by the state to lease both offshore and onshore oil and gas.

Most of the tracts leased (87.7%) in Alaska over the period 1964 to 2006 used the cash bonus approach with a fixed royalty. Royalty and profit share bidding systems were employed for 12.3% of the leased tracts (Nebesky, 2007). Alaska's profit sharing system in the past had bids up to 92% of the profit. More recently, however, Alaska has used an administratively-set profit share of 30% or 40% of net income.

Areawide leasing in Alaska has affected the extent of area leased, competition (number of bidders) per tract, and, according to Nebesky (2007), the structural aspects of competition for leases. Using the Areawide approach, Alaska has transferred more than twice the land to private operators than under the prior nominations approach (Nebesky, 2007). Use of the Areawide system also has led to more non-contested tracts. Under the pre-Areawide nomination approach, 67.3% of leases with bids had more than one bid; this contrasts with 12.8% under Areawide leasing.

Also, the mean bid per acre dropped from $1,191 per acre with nominations to $55 per acre with Areawide. However, the change is less for the median bid for nominated tracts (which removes the influence of outlier, high bids): $20 acre for nominated tracts as compared with $13 for tracts under Areawide leasing.

[12] This section draws heavily on Nebesky (2007).

Areawide leasing in Alaska appears to have made independents more important than under the nominations approach. Independent producers[13] won 27% of leases under area wide but held only 12% with nominations.

To spur exploration on state-owned offshore and onshore lands, Alaska offers Exploration Incentive Credits (EICs). Under this program, operators can claim a credit for up to 50% of the cost of footage drilled, geophysical assessment, depending upon the region in which the activity takes place. The credits earned can be charged against royalty or rental payments or other state taxes due the State.

Alaska offshore blocks are of irregular shape because of the allocation of lands to Native Americans and Eskimo tribes. Ascertaining the legal boundaries is time consuming and expensive, and is not done under Areawide leasing, unless a contested area receives a bid and a sale is contemplated.

Appendix II.A.4. Canada[14]

Canada has major oil and gas resources offshore and onshore, as well as enormous deposits in tar sands. Including estimated recoveries from tar sands, Canada's oil reserves are second only to those Saudi Arabia. However, Canada's offshore lands are vast and relatively unexplored. For example, the vast Canada-Nova Scotia area has had only 207 wells drilled to date.

The first offshore Canadian well was drilled in Beaufort Sea in 1966. http://www.geohelp.net/history.html. Offshore development currently occurs off the coasts of Newfoundland and Nova Scotia. Key legislation includes the Canadian Petroleum Resources Act, which provides for regulation of exploration and development and the Canadian Oil and Gas Act, under which production is regulated.

As happens in the U.S., disputes exist over resource ownership between the federal and "local" governments (Provinces in Canada). To avoid deadlock, the Canadian system relies on the use of Boards comprised of federal and provincial members and funded equally by the federal and provincial governments. Separate Boards exist for Newfoundland, Nova Scotia, and British Columbia, among others. These Boards carry out licensing and leasing, but not collection of royalties which is kept separate to avoid potential conflicts of interest.

The Canadian offshore leasing system is relatively flexible with respect to the timing of sales. Currently, Newfoundland has one sale per year, while Nova Scotia has two sales annually. British Columbia has a moratorium on lease sales because of environmental issues. Companies are asked to nominate lands, and the Board can as well. In fact, in a recent lease sale, NS07-1 the Board nominated the two tracts which were eventually sold.

Canada's law for leasing offshore oil and gas has parallels to that of the OCSLA in the United States in that leases are awarded to the highest bidder and only a single bid variable can be

[13] Independent producers are those operators who restrict their activities to oil extraction. They are not involved in refining.

[14] The author of this section benefited greatly from a telephone discussion with Ms. Christine Bonelle-Eisner of the Rights Administration Office of the Canada-Nova Scotia Offshore Petroleum Board.

considered. All other bids, however, are kept confidential, which differs from the U.S. approach which releases information on all bids by all companies after a sale.

In most other ways, however, Canadian policy differs considerably from that of the U.S. (http://laws.justice.gc.ca/en/C-8.5/index.html). Most notably, Canada relies exclusively on the use of a *dollar* work commitment as the one bid variable. An overview of the Canadian approach for leasing offshore areas follows. The Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) is in the process of revising its leasing approach in an effort to compete with offshore areas worldwide, which are viewed as substitutes for drilling in offshore Canada. As part of this effort, it has sought to make investment off Canada more attractive to smaller operators as well as to international firms, as explained next.

Leasing begins in offshore Crown (federal) lands with a Call for Nominations, which lasts from 30 – 90 days, followed by a Call for Bids, which is set at 120 days. As noted, the Board itself can and has nominated parcels. All lands designated in the Call for Bids have already been screened for environmental concerns. An interesting feature of the Canadian system is that, prior to a sale, the Board publishes its detailed estimate of resource potential for some Parcels

Unlike the U.S., Canada awards exclusive offshore exploration leases using bids based solely on their dollar work commitment, as mentioned. Cash bonus bids play no role in the Canadian OCS leasing system. A minimum bid is required and can be set as high as $1 million per parcel. Minimum bids are higher for parcels near developed areas and lower for deeper water parcels.

Calls for Bids on Crown Lands must be made at least 120 days prior to date of required submission (Canadian Petroleum Resources Act http://laws.justice.gc.ca/en/C-8.5/text.html). On the date of sale, bidders submit detailed seismic, exploratory drilling, and related plans for exploring the area. These plans play no role in lease allocation but can become part of the firm's (the "interest holder's") later development plan.

Most bids are joint ventures. Unlike the U.S., which since 1979 has prohibited joint bidding among the largest firms, in Canada any company can participate in joint bids.

Leases cover parcels, which are substantially larger than the maximum size of blocks in the U.S. (5,760 acres). The minimum bid allowable can be as high as $1 million per parcel. In the recent sale off Nova Scotia (NSO-7), however, the minimum bid required was reduced to $500,000. Two parcels were sold, one for CDN $103.1 million, the second for CDN $113.7 million.

An exclusive, non-renewable 9 year license to explore is granted to the operator submitting the highest dollar work commitment. Exploration is divided into two phases. Phase I is for 5 years, while Phase II is for the remaining 4 years. Except in deep waters, companies are expected to drill an exploratory well within the first five years and are assessed a fee if they have not initiated drilling but wish to retain their lease. (An additional year is allowed for deepwater parcels.) The fee increases each year that drilling does not occur[15]. However, firms must drill by the 9th year or surrender the submerged lands.

Three types of licenses are issued to operators. The company submitting the highest dollar work commitment is granted an exclusive Exploratory License. If a potential for sustained production is confirmed, a Declaration of a Significant Discovery (DSD) is made. (A DSD may cover many fields in an area.) Then, the operator is given an exclusive Development License and, subsequently, an exclusive Production License.

During the development phase, the government in principle has the authority to require the operator to drill a well in a specific location, for example. However, this authority has never been exercised. Production licenses are issued for 25 years, but may be extended, if production continues beyond this period.

Exploratory License (9 Years)
Phase I - 4 Years (spudding required to continue to Phase II)
Phase II - 5 Years

Financial Conditions of Leasing

Major financial conditions set for the October 2008 sale NS0 – 8 are:

- A lower minimum work expenditure bid, reduced from $1,000,000 to $500,000.
- By posting $50,000 upfront, work deposits can be submitted after three years, rather than in the first year.
- A 150% credit on allowable expenditures approved in the first three years.
- Deep water parcels allotted an extra year in Phase 1 to account for the challenges of exploring in deeper waters.

Royalties for Sable Island as compared with rates for future projects will follow the generic base case. The discussion below describes the generic royalty case used by Canadian Department of Energy (http://www.gov.ns.ca/energy/resources/RA/offshore/Offshore-Petroleum-Royalty-Regime.pdf.) Note, however, that Canada also uses lower royalty rates to encourage risk taking for the first project in a new area (a "high risk" project).

Should the successful bidder later seek a Significant Discovery License (SDL) for the lands, the SDL will be subject to refundable escalating rentals. At the time of the sale, the winning firm must submit to the government an amount equal to 25% of their bid. They can draw upon this amount to pay for their committed exploratory activities. However, companies forfeit the balance if they fail to meet their bid commitment.

When production begins, the interest holder pays a royalty set at 1% of the gross value of output. The rate increases by 1% every 18 months until it reaches a maximum of 5% on gross revenues

[15] Firms may receive an additional year without the extra delay fee if they can document that they have made efforts to drill but were unable to drill for extenuating circumstances, for example, were unable to rent a drillship because of excess demand for rigs worldwide.

beginning in the seventh year of production and continuing until payout[16] occurs (http://laws.justice.gc.ca/en/showdoc/cr/SOR-92-26/bo-ga:s_3//en#anchorbo-ga:s_3). For petroleum produced from project lands, the royalty is the greatest of (1) thirty percent of net revenue or (2) 5% of gross revenues (http://laws.justice.gc.ca/en/showdoc/cr/SOR-92-26///en?page=1). Hence, royalty alternative (1) is similar to profit sharing.

Companies also pay an annual escalating rental per acre. The rental begins in year 5 of the exploration period (year 6 for deepwater areas) and increases yearly. The current practice has the annual rent per acre increasing by $2.50.

Issues. Canadian offshore leasing has not expanded rapidly. Some recent sales off Nova Scotia involved only two parcels, with 20 the maximum number of parcels ever offered (in the late 1990s). Reasons for the slow pace may be the irregular scheduling of sales, competition with other petroleum areas worldwide, and, in a related vein, the manpower and associated costs required to lease more land in an orderly manner in Canada. To spur leasing, efforts have been made to set a clear schedule of future lease sales. Efforts are also being made to provide incentives for first project exploration of high risk areas, for drilling in deeper waters, and for smaller firms.

Other interesting approaches are those used onshore Canada by the Province of Alberta. Alberta has substantial conventional oil and gas as well as major tar sand resources. In Alberta, the royalty rate on conventional oil ranges from 5% increasing up to 40% for higher prices. For natural gas, the royalty rate ranges from a floor of 15% rising to 35%, again depending upon the price.

For both oil and gas, the royalty rate also varies with the production rate. For tar sands, the initial royalty rate is 1% of gross revenues until payout is achieved, after which the royalty increases to 25% of net revenue. With higher prices, there is an earlier payout and higher royalty payments—25% of net revenue. Hence, the royalty rate on tar sands is a form of profit sharing.

Appendix II.A.5. Federal Communication Commission Auctions

The Federal Communication Commission (FCC) has developed and used a multi-round auction (sealed bid) for the sale of the very valuable broad band spectrum. This approach might be applicable to OCS oil and gas sales and is outlined below. Briefly, in a multi-round auction, minimum bids are set for each item. Firms are not told before hand the names of other companies interested in particular spectra, although the names of firms which file to be eligible to participate in the overall auction are available to all. Strict confidentiality is legally required.

A novel feature of recent FCC auctions is that small firms are given a discount on their bonus bid. The sale begins with a reservation price or minimum bid set for each spectra offered. The minimum bid increases with the quality of the spectra and the size of the market served. At the end of a round, minimum bids are reset at higher levels. Firms then pick their bid from among the menu of the new posted bids. The increase in the posted bid for a license is higher for licenses receiving greater interest than for licenses for which less interest was shown in the prior

[16] Payout refers to the first month where the cumulative revenues of an interest holder equals or exceeds the cumulative costs. (http://laws.justice.gc.ca/en/showdoc/cr/SOR-92-26///en?page=1)

round. Joint bidding is allowed. Measures are taken to ensure a speedy auctioning process so that some firms do not systematically delay commitment and wait to bid at the last moment. A limited number of withdrawals, with a penalty, are allowed. Firms are informed of the high bids, the total dollar amount of bids, and the number of bidders at end of a round, but the identity of individual bidding firms is confidential.

A sale of a large number of tracts could pose problems for companies and may raise administrative issues, when such a new process is introduced. This suggests that the MMS might sponsor seminars and carry out experiments with companies to familiarize participants with the market. At an actual sale, the number of tracts might be limited to several hundred rather than several thousand. It also may be possible to drop tracts from a sale if they do not receive any bids within one or two rounds.

This approach provides more information to bidders than the current leasing system, and it updates this information within each round and between rounds. The multi-round nature of the process allows participants to increase their bid when faced with competition, and it allows firms to reallocate funds to other tracts while the auction is in process if they are outbid by others. However, multi-round auctions are more involved than the current OCS leasing approach, and hence transactions costs would be higher. To familiarize participants with the rules, the MMS would need to hold open seminars and "mock auctions" to provide participants with an opportunity to gain experience in such a market, an approach the FCC has taken.

APPENDIX II.B. Selected Alternative Leasing Approaches

OCSLA [43 USC 1336] Sec. 8

1. Cash Bonus Bid, with Fixed Royalty
2. Variable Royalty Bid, with either Fixed Work Commitment or Fixed Cash Bonus
3. Cash Bonus Bid, or Fixed Work Commitment Bid or Fixed Cash Bonus with or Diminishing or Sliding Scale Royalty
4. Cash Bonus Bid with Fixed Share of Profit ≥ 30%
5. Fixed Cash Bonus with Net Profit Share as bid variable
6. Cash Bonus Bid with Fixed Royalty ≥ 12.5% and Fixed Profit Share ≥ 30%
7. Work Commitment Bid with Fixed Cash Bonus and Fixed Royalty ≥ 12.5%
8. Cash Bonus Bid with Royalty ≥ 12.5% with suspension for a period, volume or value determined by Secretary of DOI, where such suspension may vary based on the price of production from the lease.
9. Secretary may defer for up to 5 years any part of the lease Cash Bonus payment
10. Secretary may use any other approach, but must use only one bid variable

MMS, DOI APL Group (November 1993)

1. *Cash Bonus Fixed Royalty by Depth*. The current system with a lower royalty rate for deeper water where costs are higher.
2. *Sliding Scale Royalty Leasing*. The royalty rate increases with the quarterly value of production. The cash bonus is the bid variable.
3. *Net Profit Share Leasing*, Lessee pays to the Government a share of its "net profits", which is defined as the revenue attributable to the lease once all exploration, development, and operating costs have been recovered.
4. *Royalty Rate Bid, Cash Bonus Fixed*. Prospective lessees submit royalty rate bid (the bid variable) for a lease which has a fixed cash bonus.
5. *Royalty Holiday*. Royalty holiday granted until bonus or exploration and/or development costs are recovered from a lease's gross revenue.

6. *Royalty Holiday Reward for Early Discovery*. A royalty would be granted to lessees who made discoveries within a timeframe specified by Government at the time of sale.

7. *Variable Work Commitment Bid, with Fixed Cash Bonus and Fixed Royalty Rate*. The lease would be awarded to the company which bids to spend the highest dollar amount of exploration of the lease. This system would be used exclusively in frontier areas.

8. *Licensing of Exploration, Development, and Production (frontier areas).* The license would be awarded in areas of high risk or costs to the company offering the best exploration plan or committing the largest amount to exploration.

9. *Minimum Bid Changes.* The minimum bid could be lowered to make a lease more attractive.

10. *Charge a Tract Nomination Fee.* To limit number of tracts, firms would pay a fee proportional to the number of tracts nominated, with reimbursement for tracts leased or not offered.

11. *Tract Nomination System (see options (p. 1.13).* To reimburse government for tract evaluation costs, *c*ompanies would nominate tracts to include in sale and pay in proportion to number of tracts nominated, perhaps with reimbursement for tracts not offered in sale.

12. *Variable Rentals.* The rental rate would increase annually until production begins.

13. *Deferred Bonus Payment.* Bidders submit 20% of bid at time of sale but are allowed to complete payment of bonus, with or without interest, on any schedule within 5 years of issue of lease.

14. *Revised Joint Bidding Ban Regulations.* Would eliminate the current ban on major companies submitting joint bids.

15. *Change Tax Code.*

16. *Increase Tract Size.* Larger tracts would be leased to allow companies to acquire entire prospects.

17. *Conditional Bidding.* Companies offer bids on a contiguous package of tracts thought to be a single structure and win only if all bids are accepted, i.e., are highest and exceed minimum for tracts concerned.

18. *Working Interest Bidding.* Qualified companies would bid on an undifferentiated number of acres within a large area comprising a structure and then would form unit to manage development and production.

19. *Long Term Leases.* Extend the current initial terms for a longer period, say 20 years, of for successive five-year periods, to give firms flexibility in timing exploration and production.

20. *Change Qualified Bidder Definition.* Allow any entity (for example, an environmental group) which can pay the bonus bid and the fixed area rental to bid on and hold the lease, even of development is precluded as long as the area rental is being paid.

21. *Issue Leases Explicitly Granting Four Unconditional 5-Year Suspensions.* Lessees would be given an unconditional delay for 5 years to accomplish exploration and development to take advantage of changed market conditions, for example.

22. *Issue Leases Explicitly Granting Suspensions of Operations at Lessee Request.* Lessee can suspend operations and production for, say two years, without giving a reason in order to take advantage of market conditions, with only payment of a rental or minimum royalty required.

23. *Issue 25-year Leases Applying the Diligence Requirement Only to Exploration*. Lessee obligated only to conduct exploratory drilling within 5 years, with no diligence requirement imposed on production but rental assessed for period of inactivity.

24. *Stagger Areas Offered for Lease in the Central and Western Gulf of Mexico (GOM) or Portions of These Areas.* Leases would alternate between Central and Western GOM, perhaps by water depth.

25. *Optional Sales Included in the 5-Year Program.* Allows for additional, optional sales, in response to market conditions.

26. *Place Limits on Number of Tracts Leased or Other Variables*. Limit number of tracts leased, number of exploratory rigs in operation, development platforms, or production volume.

27. *Limit Size of Leases in Frontier Areas.* Limit number of blocks offered in a sale based on environmental concerns and resource potential.

28. *Gas Only Leasing.* Gas only leasing would face reduced opposition from environmental groups because risks of oil spills are negligible and natural gas is a clean burning fuel.

29. *Two Stage Leasing.* Leases in frontier areas would be offered for exploration only, with results made public for successful discovery and share of production guaranteed to holder of original lease.

30. *Exploration Prior to Leasing.* Exploration (e.g. COST wells) would be conducted with the results used to determine is a sale should be held.

31. *Place a cap on number of leases to be issued.*

32. *Raise the minimum bid.*

33. *Split planning areas, offering at least a portion of each in alternate years.*

34. *Offer one or more large portions of each planning area, based on industry nominations*

35. *Offer one or more large portions of each planning area, based on industry nominations*

36. *Offer all available previously leased tracts in a planning area, but use nominations for never-leased tracts. Offer all shallow-water tracts but use traditional tract selection method for deepwater tracts*

III. Task 2. Analysis of Leasing Alternatives

This Chapter discusses the integrated components of Task II of our methodology (See Figure I-1 above). The goal of Task II is to development quantitative forecasts of the effects of alternative leasing policies on each of the goals and criteria that are identified in Task I. The quantitative output of Task II is used to assess alternatives in Task III.

The central component of the Task II analyses is a Simulation Model that forecasts tracts sold, exploration, discovery, production, revenues, etc under each of the alternative leasing policies. The Simulation model is made up of two major components: a Field model and an Area model. As the names suggest, the Field model simulates activity at the field level, while the Area model aggregates these activities across all fields in the Central and Western Gulf of Mexico.

As detailed below, the Field model simulates management of individual fields for a representative set of fields in 16 size classes, each in 7 distinct water depths, of 2 types (oil vs. gas) for a total of 224 representative fields. The Field model simulates the stages of exploration, development, production, and shutdown over the life of the field, and forecasts the associated wells drilled, platforms constructed, resources produced, revenues generated, etc. over the life of each of the 224 representative fields.

The Area model starts with the parameters of each policy scenario (e.g., number of tracts offered, economic conditions, etc.), and forecasts the total number of tracts sold. Next, the Area model simulates the numbers of fields discovered for each field size and water depth. The Field model outputs are then used to specify management for each field discovered. The Area model uses these outputs from the Field model, and aggregates across all fields over time periods within our time horizon. The Area model also keeps track over time of the number of remaining undiscovered fields and rate of technological change, thereby accounting for the offsetting effects of depletion and technological change over the time horizon.

Several of the key parameters of the Simulation model are based on the results of three sets of analyses: theory, statistical analysis and laboratory experiments. Theory provides a framework for all of the analyses, and theory is also used to derive some key qualitative results where empirical analyses of historic data are not feasible. Statistical analyses of historic data are used to estimate several key relationships employed in the Simulation model. The results of our statistical analyses are used to forecast the total number of tracts sold under various leasing policies, the number of bids received on each individual tract sold and the high bids received on each tract sold. Laboratory experiments are used to calibrate the bid function in order to assess the potential for one novel lease alternative not used to date in OCS leasing--multi-stage lease structure based on an approach used by the Federal Communications Commission in leasing the right to use the electromagnetic spectrum for cell phone transmissions.

This Chapter is organized as follows. First, we provide a detailed discussion of the Simulation model, including a brief description of all of the key equations in both the Field and Area models. Next, we briefly outline the theoretical framework for auctions within the context of OCS leasing. Then we describe our statistical analyses used to estimate three key relationships: the number of tracts sold for the area as a whole, the number of bids submitted on individual tracts and the high bids on individual tracts. Finally, we outline the laboratory experiments used to assess multi-stage auctions.

III.A. Simulation Model

This Section discusses the Simulation model used to forecast key values used to assess leasing alternatives. As indicate above, the Simulation model is comprised a Field model and an Area model. The Area model and its linkage to the Field model are depicted in Figure III-1. The tan boxes in Figure III-1 represent inputs into the Simulation model, while the blue ovals represent elements of the Simulation model.

The process starts with specification of a lease policy scenario, including tracts offered, economic conditions etc, which together determine the number of tracts sold. Then, the number of tracts sold, economic conditions (e.g., oil prices) and the remaining undiscovered fields determine the number of discoveries in each of 16 size classes and 7 water depths. The Field model simulates the management of representative fields within the size/depth categories, and the output of the field model include forecasts for wells drilled, production, net present value, royalty payments, etc for each of the representative fields. These outputs are passed to the Area model to develop forecasts of these variables for the Central and Western Gulf of Mexico as a whole.

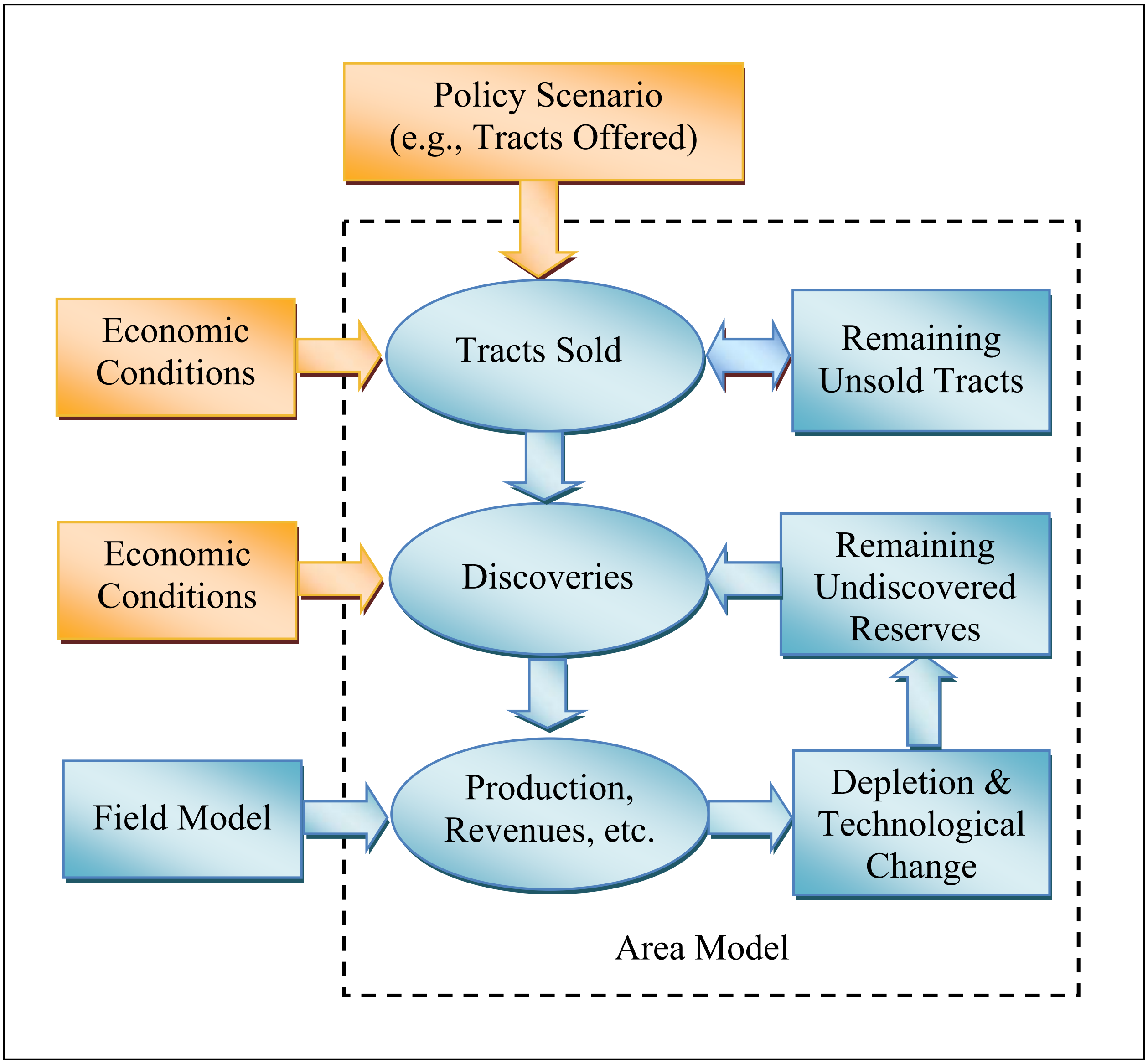
As the Area model "discovers" and develops new fields, these fields are subtracted from the remaining stock of undiscovered fields that are available in future time periods, therefore accounting for resource depletion. Simultaneously, the Area model also incorporates technological change which is comprised of two elements: output-biased technological change and input-biased technological change. The relative sizes of input- and output-biased technological change from Managi et al (2004) are used to assign improvements in technology to output-increasing versus cost-reducing elements of technological change. The output-increasing fraction simulates new technologies that increase potential hydrocarbon production, both through improving the ability to discover new fields and through extracting ever larger fractions of resources from a given field. For example, improvements in exploration technologies, computer processing power and 3-D seismology improves the ability of companies to discover new fields and/or to extract a larger fraction of hydrocarbon resources from a given field. The input-biased fraction of technological change is used to simulate cost-reducing technologies that reduce input requirements to extract resources from a given field. For example, directional drilling can reduce the number of wells and/or platforms needed to produce from given fields.

The following two sections describe in detail the mechanics and equations of the Field and Area models, respectively.

III.A.1. Field-Level Model

The Field model is described in this section. As discussed above, the Field model is a discounted cash flow model that simulates management of fields from exploration through field closure. First, we present the general framework, then we discuss the approach that simulates the stages of OCS exploration, development and production on a given field. Next, the optimization procedure is described, and then some model simulation results are reported.

Figure III-1. Depiction of the Area Model



III.A.1.a. The General Framework

The general logic of the Field model is illustrated in Figure III-2. The major input and output data for the Field model are summarized in Table III-1. The core of the model is the optimization element in which a firm maximizes after-tax-net present value, subject to exploration, development and production constraints. Sub-models simulate the exploration, development and production processes, and compute physical data, such as the number of wells, size and number of platforms, and production capacities. The sub-models also calculate unit and total costs associated with these physical data. The results are passed to the corresponding financial sub-models in which physical data and associated cost data are converted into financial data, such as tangible and intangible investments, depreciation, and indirect charges; then, annual cash flows are computed. Finally, all the necessary physical and financial information is sent to the central optimization model, and optimal controls for given states in given years are generated by a deterministic dynamic programming algorithm.

The entire computer program is written in Fortran. The main program named OCS is the central optimization model which is supported by ten subroutines. The functions of these subroutines are summarized in Table III-2.

III.A.1.b. The Simulation of OCS Exploration, Development and Production

The sub-models in the field model are described one by one in this section. The first version of the field model was developed in 1991. In the first version, most of the data, and engineering and financial assumptions were adopted from the study, *Replacement Costs of Domestic Crude Oil*, by Lewin and Associates, Inc. for U.S. Department of Energy (Lewin and Associates, Inc. 1985). The study by Lewin and Associates, Inc. integrated many data, assumptions, and statistical models from other studies by Attanasi and Haynes (1983 and 1984), and Energy Information Administration (1982). The cost data for drilling, equipping and operating were updated to 1989 dollars by using relevant indexes published by Energy Information Administration (Energy Information Administration 1985, 1990 and 1991).

In developing the current version of the field model, most exploration, development, and production parameters were recalculated and updated using recent MMS data. In addition, many cost functions were updated with new estimates from the study, *Modeling Exploration, Development and Production in the Gulf of Mexico,* by Innovation & Information Consultants, Inc (Ashton, et al. 2004). Relevant cost data were converted to 2003 dollars using PPI for crude oil extraction. Abbreviations used in this study are listed in Table III-3.

The Exploration Sub-model

The exploration sub-model simulates the exploration phase and performs the following computations:

Field Size

The size of an offshore oil and gas field is measured according to the MMS field size classification system which ranges from class 1 (0.0312 - 0.0625 MMBOE) to class 19 (8,192 - 16,384 MMBOE) as shown in Table III-4.

Figure III-2. Depiction of the Field Model

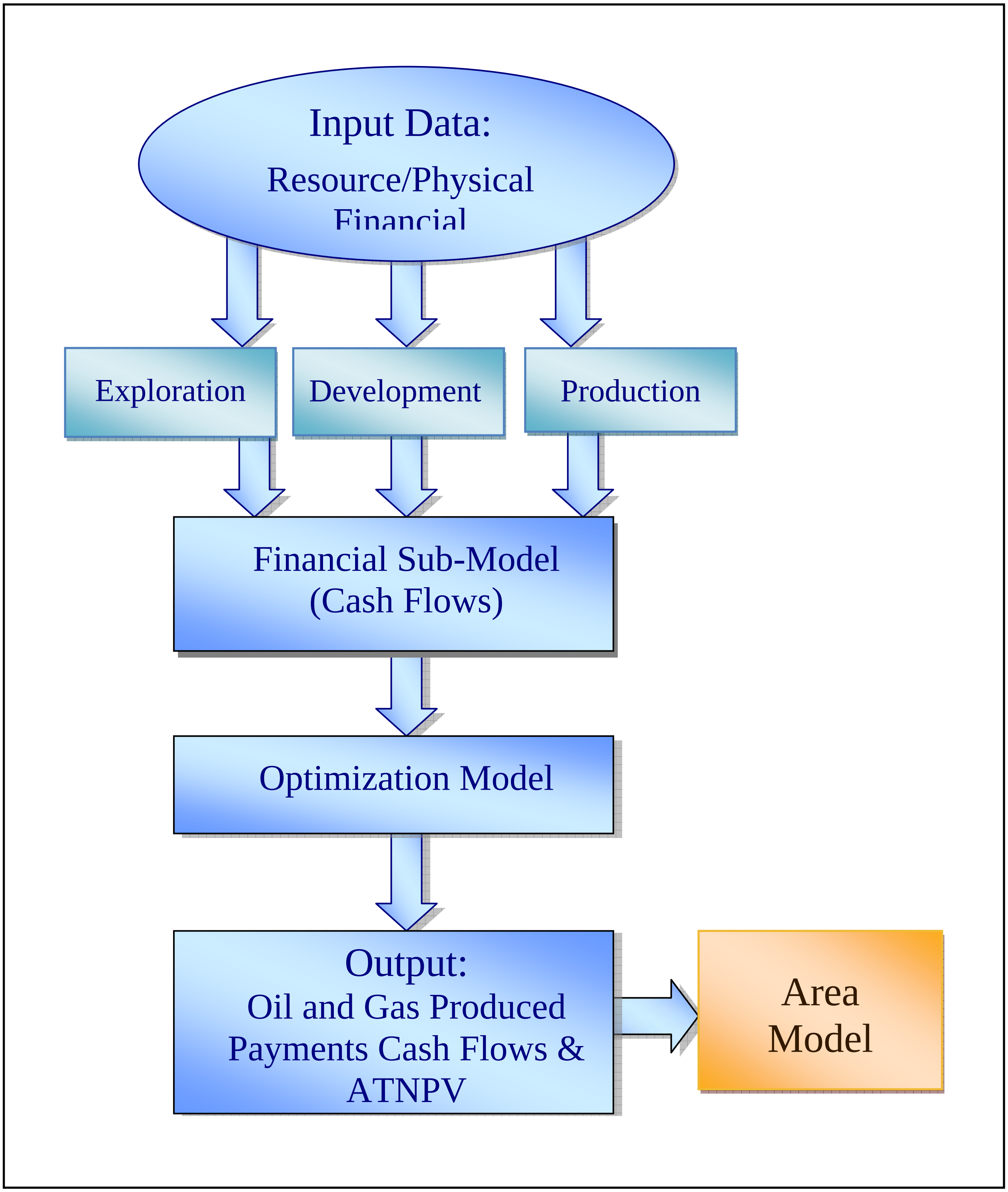


Table III-1. Summary of Major Input and Output Data of the Integrated Model

Input Data
Resource/Physical Input
Field size
Field type
Gas-oil ratio
Water depth
Drilled depth
Exploration and development dry hole rates
Etc.
Financial Input
Oil and gas prices
Discount rate
Royalty rate
Federal and state tax rates
Depreciation life
Bid factor
Etc.
Output Data
Oil and gas produced
Discounted oil and gas produced
Bonus payment
Royalty payment
Federal and state tax payments
Cash flows and ATNPV
Wells drilled
Platforms installed

Table III-2. Subroutines of OCS Model

Subroutine	Function
ZERO	Specify terminal conditions
SEXP	Simulate exploration phase
EXPCONT	Compute financial data for exploration phase
SDEV	Simulate development phase
DEVCONT	Compute financial data for development phase
SPRO	Simulate production phase
PROD	Compute annual oil and gas production
PROCONT	Compute financial data for production phase
SDPRE	Compute annual depreciation
ABAND	Compute financial data for field abandonment
CAFLOW	Compute annual cash flow
PATH	Compute the optimal exploration, development and production schedule

Table III-3. Abbreviations and Acronyms

bbl	barrel
Bcf	billion cubic feet
BOE	barrel of oil equivalent
Mcf	thousand cubic feet
Mbbl	thousand barrels
MMbbl	million barrels
MMBOE	million of BOE

Table III-4. MMS Field Size Classification System

Field Class Code	Field Size (MMBOE)		
1	0.0312	-	0.0625
2	0.0625	-	0.125
3	0.125	-	0.25
4	0.25	-	0.5
5	0.5	-	1
6	1	-	2
7	2	-	4
8	4	-	8
9	8	-	16
10	16	-	32
11	32	-	64
12	64	-	128
13	128	-	256
14	256	-	512
15	512	-	1,024
16	1,024	-	2,048
17	2,048	-	4,096
18	4,096	-	8,192
19	8,192	-	16,384

Source: MMS

Quantities of Oil and Gas

TOTBOE = OILREV + GASBOE

where TOTBOE is the total hydrocarbon in the field measured in BOE; OILREV is the quantity of oil that will ultimately produced from the field in MMbbl; and GASBOE is the quantity of gas measured in BOE, MMbbl. The quantity of associated/dissolved gas (ADGAS) in the field is

ADGAS = OILREV*GOR

where ADGAS is in Bcf; and GOR is gas-oil ratio, Mcf/bbl. The gas-oil ratio varies among different types and sizes as listed in Table III-5.

GASBOE = ADGAS/CONR

where CONR is conversion ratio, Mcf/bbl.

OILREV = TOTBOE/(1+(GOR/CONR))

Number of Exploration and Delineation Wells

The field is assumed to be discovered by one successful wildcat well.

ESR = 1 - EDHR

where ESR is exploration success rate; and EDHR is exploratory dry hole rate.

EDHR by protraction area in the Gulf of Mexico are presented in Table III-6 and Table III-7 provides the names of protraction areas (see also Figure III-3).

NWW = 1.00/ESR

where NWW is total wildcat wells.

NSWW = 1.00

where NSWW is the number of successful wildcats.

NDWW = NWW - NSWW

where NDWW is the number of dry wildcats. The number of delineation wells is computed as follows:

NPW = OILREV/WULT

where NPW is the number of production wells for the field; and WULT is per well ultimate recovery, MMbbl shown in Table III-8.

Table III-5. Solution Gas-Oil Ratio in the Gulf of Mexico

Field Type/Field Size	Gas-Oil Ratio (Mcf/bbl)
Oil Field Classes 1-9	4.82
Oil Field Classes 10-19	2.86
Gas Field Classes 1-9	135.73
Gas Field Classes 10-19	49.20

Source: Author's calculation.

Table III-6. Exploration and Development Drilling Dry Hole Rates

Area	Exploration Dry Hole Rate	Development Dry Hole Rate (oil field)	Development Dry Hole Rate (gas field)	Extension & Development Dry Hole Rate (oil field)	Extension & Development Dry Hole Rate (gas field)
AC	0.8921	0.9231	0.5000	0.9250	0.5714
AT	0.8073	0.1208	0.0563	0.3280	0.3732
BA	0.7488	0.0000	0.0000	0.7768	0.2675
BS	0.7552	0.3077	0.8333	0.4910	0.9064
CA	0.7581	0.1208	0.0000	0.3280	0.2086
DC	0.8073	0.1208	0.0563	0.3280	0.3732
DD	0.8073	0.1208	0.0563	0.3280	0.3732
EB	0.8202	0.3818	0.2078	0.4590	0.4883
EC	0.8032	0.0000	0.0000	0.1330	0.3507
EI	0.8278	0.0000	0.0000	0.1611	0.3176
EW	0.8397	0.0000	0.0563	0.3810	0.3732
GA	0.7871	0.0000	0.0000	0.1244	0.2378
GB	0.8337	0.1724	0.0000	0.5124	0.4813
GC	0.8938	0.0000	0.0000	0.3457	0.3276
GI	0.8344	0.3097	0.0000	0.3429	0.4295
HI	0.8180	0.0243	0.0000	0.1460	0.2939
KC	0.8073	0.1208	0.0563	0.3280	0.3732
LL	0.8073	0.1208	0.0563	0.3280	0.3732
MC	0.8682	0.3181	0.0000	0.4828	0.5359
MI	0.7934	0.1208	0.0000	0.3280	0.2502
MO	0.7598	0.1208	0.0000	0.3280	0.2931
MP	0.8273	0.0350	0.0000	0.1453	0.4843
MU	0.7955	0.1208	0.0000	0.3280	0.2526
PE	0.6939	0.1208	0.0563	0.3280	0.3732
PI	0.8073	0.1208	0.0563	0.3280	0.3732
PL	0.7256	0.0000	0.0000	0.1192	0.5271
PN	0.8166	0.1208	0.0000	0.3280	0.1784
PS	0.8073	0.1208	0.0563	0.3280	0.3732
SA	0.8198	0.0000	0.0000	0.3018	0.4636
SM	0.8185	0.0000	0.0000	0.1661	0.2748
SP	0.8798	0.1868	0.0384	0.2383	0.3198
SS	0.7900	0.0000	0.0000	0.1387	0.3013
ST	0.8045	0.0930	0.0000	0.1721	0.3603
SX	0.8258	0.1208	0.0526	0.3280	0.2648
VK	0.7972	0.1476	0.0000	0.2176	0.4522
VR	0.7874	0.0000	0.0000	0.2439	0.2916
WC	0.7860	0.0000	0.0000	0.7164	0.2682
WD	0.8240	0.0000	0.0000	0.1309	0.4251
WR	0.8073	0.1208	0.0563	0.3280	0.3732
Mean	0.8073	0.1208	0.0563	0.3280	0.3732

Source: Author's calculation.

Table III-7. Protraction Areas in the Gulf of Mexico

Area	Area Name	Area	Area Name
AC	MINOS CANYON 60.	LP	LIGHTHOUSE POINT (THIS IS A FIELD) 17.
AM	AMERY TERRACE.	LS	LUND SOUTH.
AP	APALACHICOLA 60.	LU	LUND * 60.
AT	ATWATER * 60.	MA	MIAMI 60.
BA	BRAZOS AREA 42.	MC	MISSISSIPPI CANYON 60.
BM	BAY MARCHAND AREA 17.	MI	MATAGORDA ISLAND AREA 42.
BS	BRETON SOUND AREA 17.	MO	MOBILE 60.
CA	CHANDELEUR AREA 17.	MP	MAIN PASS AREA 17.
CC	CORPUS CHRISTI 60.	MQ	MARQESAS 09.
CE	CAMPECHE ESCARPMENT.	MU	MUSTANG ISLAND AREA 42.
CH	CHARLOTTE HARBOR 60.	PB	ST PETERSBURG 60.
CP	COON POINT (THIS IS A FIELD) 17.	PE	PENSACOLA 60.
CS	CHANDELEUR SOUND 17.	PI	PORT ISABEL 60.
DC	DESOTO CANYON 60.	PL	SOUTH PELTO AREA 17.
DD	DESTIN DOME 60.	PN	NORTH PADRE ISLAND AREA 42.
DT	DRY TORTUGAS 60.	PR	PULLEY RIDGE 60.
EB	EAST BREAKS 60.	PS	SOUTH PADRE ISLAND AREA 42.
EC	EAST CAMERON AREA 17.	RK	RANKIN 60.
EI	EUGENE ISLAND AREA 17.	SA	SABINE PASS (LOUISIANA) 17.
EL	THE ELBOW 60.	SE	SIGSBEE ESCARPMENT.
EW	EWING BANK 60.	SM	SOUTH MARSH ISLAND AREA 17.
FM	FLORIDA MIDDLE GROUND 60.	SP	SOUTH PASS AREA 17.
FP	FLORIDA PLAIN.	SS	SHIP SHOAL AREA 17.
GA	GALVESTON AREA 42.	ST	SOUTH TIMBALIER AREA 17.
GB	GARDEN BANKS 60.	SX	SABINE PASS (TEXAS) 42.
GC	GREEN CANYON 60.	TP	TARPON SPRINGS 60.
GI	GRAND ISLE AREA 17.	TS	TIGER SHOAL (THIS IS A FIELD) 17.
GV	GAINESVILLE 60.	TV	TORTUGAS VALLEY.
HC	HUDSON CANYON.	VK	VIOSCA KNOLL 60.
HE	HENDERSON 60.	VN	VERNON * 60.
HH	HOWELL HOOK 60.	VR	VERMILION AREA 17.
HI	HIGH ISLAND AREA 42.	WC	WEST CAMERON AREA 17.
KC	KEATHLEY CANYON 60.	WD	WEST DELTA AREA 17.
KW	KEY WEST 60.	WR	WALKER RIDGE 60.
LL	LLOYD 60.		

Figure III-3. OCS Protraction Areas in the Gulf of Mexico

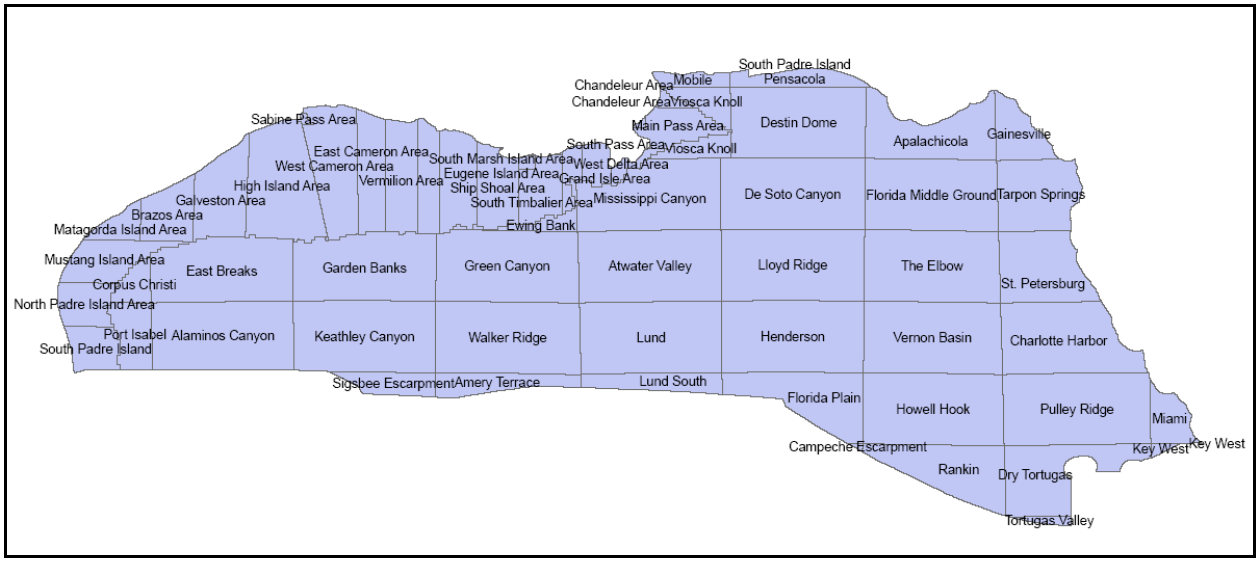


Table III-8. Relation between Field Size and per Well Ultimate Recovery in the Gulf of Mexico

Field Class	Mean Resources (MMbbl)	Per Well Ultimate Recovery	
		oil field (MMbbl)	gas field (MMbbl)
1	0.05	0.0200	0.0030
2	0.09	0.0400	0.0040
3	0.19	0.0600	0.0050
4	0.38	0.0900	0.0055
5	0.71	0.1225	0.0088
6	1.49	0.2171	0.0127
7	2.93	0.3424	0.0252
8	5.87	0.4805	0.0502
9	11.68	0.6242	0.0835
10	23.03	0.7666	0.1219
11	44.70	0.9007	0.1899
12	89.86	1.0194	0.2236
13	177.85	1.1157	0.2722
14	345.64	1.1828	0.3164
15	716.57	1.3010	0.3582
16	1,355.13	1.4311	0.3960
17	2,666.52	1.5743	0.4356
18	5,093.81	1.7317	0.4792
19	9,906.20	1.9049	0.5271

Note: Average field size is the geometric mean.

Source: MMS and Author's calculation.

$$DSR = 1 - DDHR$$

where DSR is developmental success rate; and DDHR is developmental dry hole rate, summarized in Table III-6, above.

$$NDW = NPW/DSR$$

where NDW is total number of development wells.

$$EDSR = 1 - EDDHR$$

where EDSR is extension and development success rate; and EDDHR is extension and development dry hole rate, also in Table III-6, above.

$$NEDW = NPW/EDSR$$

where NEDW is total number of extension and development wells.

$$NDEL = NEDW - NDW$$

where NDEL is the number of delineation wells.

Costs of Exploration and Delineation Wells

Exploratory and delineation wells are drilled from a mobile rig. The equation for the cost of one of these wells is from the IIC EDP Model (Ashton, et al. 2004). For water depth less than 656 feet (200 meters), jack-ups are used:

$$CEXP = 1000000 + 600*WD + (0.03*WD + 0.05*DD - 500)*DD + (0.0000000015*WD + 0.0000032)*(DD^3)$$

for water depth between 656 feet and 2953 feet (900 meters), semi-submersibles are used:

$$CEXP = 2000000 + 1825*WD + (0.01*WD + 0.045*DD - 415)*DD$$

for water depth great then 2953, drillships are used:

$$CEXP = 8000000 + 175*WD + (0.0525*DD - 600)*DD$$

where CEXP is the cost of one exploratory or delineation well, dollars; WD is water depth, feet; and DD is drilled depth, feet. Typical water and drilled depths are listed in Table III-9.

Thus, the total costs of exploratory wells (WCEXP) and delineation wells (DCEXP) are calculated as:

$$WCEXP = NWW*CEXP$$

$$DCEXP = NDEL*CEXP$$

Table III-9. Water Depth, Total Drilled Depth and Coefficients for Estimating Injection Wells (NIWR)

Area	Water Depth (feet)	Drilled Depth (feet)	NIWR (oil field)	NIWR (gas field)
AC	6,935	14,124	0.1241	0.1176
AT	5,117	18,883	0.1241	0.1176
BA	105	10,265	0.1241	0.1176
BS	23	11,973	0.1241	0.1176
CA	71	6,140	0.1241	0.0769
DC	7,944	11,955	0.1241	0.1176
DD	234	18,715	0.1241	0.1176
EB	2,460	10,413	0.1304	0.1176
EC	145	10,423	0.0737	0.1154
EI	136	11,800	0.0725	0.0419
EW	976	12,472	0.2500	0.1176
GA	101	9,137	0.1241	0.1176
GB	1,677	13,588	0.1241	0.1176
GC	2,638	14,209	0.2284	0.1176
GI	152	11,244	0.0434	0.1304
HI	154	9,341	0.1526	0.0573
KC	5,866	11,955	0.1241	0.1176
LL	8,773	18,060	0.1241	0.1176
MC	3,445	14,084	0.1904	0.1176
MI	99	10,718	0.1241	0.4545
MO	63	12,252	0.1241	0.1000
MP	151	8,959	0.1167	0.1176
MU	171	10,779	0.1241	0.1176
PE	57	11,955	0.1241	0.1176
PI	3,450	11,955	0.1241	0.1176
PL	40	14,567	0.1241	0.1176
PN	185	8,029	0.1241	0.1176
PS	114	11,955	0.1241	0.1176
SA	36	12,728	0.1241	0.1176
SM	139	10,816	0.1085	0.0209
SP	263	10,607	0.1455	0.1176
SS	129	11,151	0.2001	0.0615
ST	164	12,217	0.0569	0.0058
SX	39	13,077	0.1241	0.1176
VK	824	10,226	0.0660	0.4000
VR	141	10,712	0.0906	0.0651
WC	123	10,400	0.1241	0.0607
WD	177	12,399	0.0601	0.0556
WR	7,557	11,955	0.1241	0.1176
		Mean	0.1241	0.1176

Source: Author's calculation.

The total drilling costs in the exploration phase is:

TCEXP = (NWW+NDEL)*CEXP

Costs of the Pre-bid Geological and Geophysical Activities

The costs of pre-bid activities (CPBID) are estimated at 15 percent of the cost of drilling exploration and delineation wells:

CPBID = 0.15*TCEXP

Financial Part of the Exploration Sub-model

The costs of pre-bid activities (CPBID) and all drilling costs in the exploration phase (WCEXP, DCEXP and TCEXP) are treated as intangible investment, i.e., they are deductible for tax purposes as incurred. The bonus payment is tangible investment, i.e., it is subject to depreciation. General and Administrative expenses are assumed ten percent of the investment costs:

GNA = RIC*(TANG + INTANG)

where GNA is the general and administrative costs; TANG is tangible cost; INTANG is intangible cost; and RIC is the rate of indirect charges

The Development Sub-model

The development sub-model simulates the development phase and performs the following computations:

Number of Production and Injection Wells

The number of production wells (NPW) is computed using the equation discussed in the exploration sub-model:

NPW = OILREV/WULT

The number of development dry holes is calculated as follow:

DSR = 1 - DDHR

NDW = NPW/DSR

NDH = NDW - NPW

where NDW is total number of development wells; and NDH is the number of developmental dry holes. Oil and associated gas are produced using both primary and secondary recovery techniques. Secondary recovery (waterflooding) is an option for increasing total recovery from the field, if economic conditions are suitable. The number of injection wells (NIW) is proportional to the number of production wells:

$$NIW = NIWR*NPW$$

where NIWR is a coefficient from Table III-9.

Number of Platforms

$$NPLAT = NPWSR*NPW/SLT$$

where NPLAT is the number of platforms in the field; NPWSR is the slot to production well ratio from Table III-10; and SLT is the number of slots on a platform.

The minimum and maximum slot numbers for various water depths are in Table III-11. The number of slots per platform (SLT) is determined as follows:

if NPWSR*NPW is smaller than or equal to minimum slots (SLOTMIN), then

$$SLT = SLOTMIN$$

if NPWSR*NPW is greater than or equal to the maximum slots (SLOTMAX), then

$$SLT = SLOTMAX$$

if NPWSR*NPW is between SLOTMIN and SLOTMAX, then

$$SLT = NPWSR*NPW$$

When a fractional platform is required, the next larger integer is chosen.

Time Required for Platform Construction

If the water depth exceeds 300 feet, the platform must be constructed in sections that are assembled on-site. For example, a platform in 900 foot water required three sections and was completed in three years. Thus, for water depth less than 1,300 feet, the time required for platform construction is estimated as:

$$TPLAT = WD/300$$

where TPLAT is the time for platform construction, in years; WD is water depth, feet. For water depth between 1,300 feet and 2,000 feet,

$$TPLAT = WD/400$$

For water depth great than 2,000 feet, TPLAT = 5.

Table III-10. Slot to Production Well Ratio

Field Type/Field Size	Slot to Production Well Ratio
Oil Field Classes 1-12	1.00
Oil Field Classes 13+	0.50
Gas Field Classes 1-8	0.88
Gas Field Classes 9-11	0.46
Gas Field Classes 12+	0.18

Source: Author’s calculation.

Table III-11. Platform Size as a Function of Water Depth and Number of Slots

Water Depth Range (feet)			Minimum Slots	Maximum Slots
0	-	200	3	18
201	-	300	3	36
301	-	400	9	48
401	-	500	13	48
501	-	800	19	48
801	-	900	19	62
901	-	1,000	37	62
1,001	-	1,300	49	62
1,301	-	2,000	21	58
2,001	-	5,000	4	32
5,001	-	6,000	6	20
6,001	-	12,000	3	60

Note: A slot is the deck area required for a production well and all equipment required to operate it, including injection wells.

Sources: Lewin and Associates, Inc., 1985, adopted from DOE/EIA-0372/2, p50; Author's Calculation.

Time Required for Drilling Development Wells

The yearly maximum number of production wells drilled per platform (YMNW) is summarized in Table III-12. On platforms with more than 24 slots, it is assumed that there is room for two drilling rigs. Thus, twice the number of wells may be drilled per year per platform. The time required for development drilling (TDRIL) is computed as follows:

if SLT is smaller and equal to 24, then

TDRIL = NDW/(NPLAT*YMNW)

if SLT is greater than 24, then

TDRIL = NDW/(2*NPLAT*YMNW)

TDRIL is in years, and if the result includes a fraction, the next larger integer is chosen. The maximum value for TDRIL is 4 years.

Maximum Daily Production per Well

DPR = 0.01*PCT0*WULT*10^6/365

where DPR is the maximum daily production, bbl/day/well; and PCT0 is the initial production level as a percent of per well ultimate recovery.

Distance from Shore

The profile of typical continental shelf generally allows the distance from shore to be approximated by the linear relationship:

SHRDIS = 0.2*WD

where SHRDIS is the distance between the offshore oil and gas field and the shoreline, in miles. The factor of 0.2 is estimated from the Gulf of Mexico shelf. The maximum value for SHRDIS is 120 miles.

Costs of Production and Injection Wells

Production and injection wells are drilled from platforms. The equation for the cost of one producing well is from the IIC EDP Model (Ashton, et al. 2004):

for water depth less than 2,953 feet (900 meters),

CPRO = 1500000+(1500+0.04*DD)*WD+(0.035*DD-300)*DD

Table III-12. Rate of Development Drilling as a Function of Total Well Depth and Platform Size

Total Depth Range (feet)			Yearly Maximum Number of Production Wells Drilled (per platform)
0	-	5,000	16
5,001	-	7,000	14
7,001	-	9,000	12
9,001	-	11,000	10
11,001	-	13,000	8
13,001	-	20,000	6
20,001	-	27,000	5

Note: On platform with more than 24 slots, it is assumed that there is room for two drilling rigs. Thus, twice the numbers of wells may be drilled per year per platform.

Sources: Lewin and Associates, Inc., 1985, adopted from DOE/EIA-0372/2, p51; Author's calculation.

for water depth greater than 2,953 feet (900 meters),

$$CPRO = 5500000+(150+0.004*DD)*WD+(0.035*DD-250)*DD$$

where CPRO is the cost of one production well, dollars; WD is water depth, feet; and DD is drilled depth, feet.

The cost of one dry hole drilled during the development phase (CDRY) is assumed at 80 percent of the cost of one producing well:

$$CDRY = 0.8*CPRO$$

Similarly, the cost of one injection well (CINJ) is assumed at 80 percent of the cost of one producing well:

$$CINJ = 0.8*CPRO$$

The total costs of producing wells (TCPRO), developmental dry holes (TCDRY), and injection wells (TCINJ) are estimated as:

$$TCPRO = NPW*CPRO$$

$$TCDRY = NDH*CDRY$$

$$TCINJ = NIW*CINJ$$

Costs of Production and Injection Equipment

The cost of the equipment required to produce oil and associated gas from each well in dollars (CEQUP) is estimated by the equation from the Replacement Costs Model (Lewin and Associates, Inc. 1985):

$$CEQUP = 83{,}200*DPR^{0.29}*0.991*1.473$$

The cost of injection equipment (CEQUI) is assumed at 80 percent of the production well equipment:

$$CEQUI = 0.8*CEQUP$$

The total costs of production equipment (TCEQUP), and injection equipment (TCEQUI) are computed as:

$$TCEQUP = NPW*CEQUP$$

$$TCEQUI = NIW*CEQUI$$

Costs of Platforms

The cost of one platform in dollars (CPLAT) is from the IIC EDP Model (Ashton, et al. 2004):

for water depth (WD) less than 1,300 feet, fixed platforms are used:

CPLAT = 2000000+9000*SLT+1500*WD*SLT+40*WD**2

for water depth (WD) between 1,300 feet and 2,000 feet, compliant towers are used:

CPLAT = (SLT+30)*(1500000 +2000*(WD-1000))

for water depth (WD) between 2,000 feet and 5,000 feet, tension leg platforms are used:

CPLAT = (SLT+30)*(3000000 + 750*(WD-1000))

for water depth (WD) greater than 5,000 feet, SPAR platforms are used:

CPLAT = (SLT+20)*(5000000 + 500*(WD-1000))

The total cost of platforms (TCPLAT) is calculated as:

TCPLAT = NPLAT*CPLAT

Costs of Pipelines

The pipeline costs (CPIP) is a function of pipeline length in miles (L), the diameter of the pipeline in inches (D), and the average water depth of the pipeline in feet (H). The equation is from the OCS Oil and Gas Supply Model (Energy Information Administration 1982):

CPIP(L, D, H) = Exp(9.1470 + 0.8243*Ln(L) + 1.3555*Ln(D) +

0.0890*Ln(H))*2.0*0.991*1.473

Thus, for the main trunk pipeline:

CPIPMT = CPIP (SHRDIS, DMT, AWD)

where CPIPMT is the cost of main trunk pipeline, dollars; DMT is the diameter of main trunk pipeline; and AWD is the average depth of main trunk pipeline (= WD/2). For each individual gathering line:

CPIPGL = CPIP (LGL, DGL, WD)

where CPIPGL is the cost of each gathering line, dollars and; DGL is the diameter of gathering line.

The number of gathering lines (NGL) is the number of platforms (NPLAT) minus one:

NGL = NPLAT – 1

The total cost of pipelines (TCPIP) is:

TCPIP = CPIPMT + CPIPGL*NGL

Abandonment Costs

Abandonment costs in dollars (CABD) is computed as 50% of the platform costs:

CABD = 0.5*TCPLAT

Financial Part of the Development Sub-model

For the development phase, tangible and intangible costs are estimated based on data computed above. Among platform costs (TCPLAT), 90 percent are tangible and 10 percent are intangible. For platform-based drilling costs, costs of production and injection wells (TCPRO and TCINJ) are 28 percent tangible and 72 percent intangible. Costs of developmental dry holes (TCDRY) and costs of abandonment (CABD) are intangible.

Other tangible investments include costs of production and injection equipment (TCEQUP and TCEQUI), and pipeline cost (TCPIP). General and Administrative expenses is assumed 10 percent of the investment costs:

GNA = RIC*(TANG + INTANG)

where GNA is the general and administrative costs; TANG is tangible cost; and INTANG is intangible cost. RIC is the rate of indirect charges

The Production Sub-model

The production sub-model simulates the production phase and performs the following computations:

Cost of Primary Production

The primary operating cost of one platform in dollars (COPEP) is estimated by the equation from USGS Professional Paper 1294 (Attanasi and Haynes, 1983):

$$COPEP = (1,265,821 + 13,554.933*SLT + 0.058798*SLT*WD^2)*1.011*1.016*1.473$$

The primary operating costs are function of slots, which is a proxy for output. The total costs of primary operation (TCOPEP) are:

TCOPEP = NPLAT*COPEP

Cost of Secondary Production

The fixed cost component of secondary recovery (COPESF) is an input variable in dollars per well per year. The total fixed cost of secondary recovery is:

TCOPESF = NPW*COPESF

The variable cost component of secondary recovery is related to the amount of water injected. The total volume of water in barrels (TWATV) is assumed to be four times the recoverable oil in the reservoir (OILREV in million barrels):

$$TWATV = 4*OILREV*10^6$$

Then, the annual injection volume (WATV) can be computed as:

$$WATV = TWATV/LS$$

where LS is the life of secondary recovery, years. Thus, the variable cost of secondary recovery in dollars per year (COPESV) is:

$$COPESV = CWAT*WATV$$

where CWAT is the waterflood cost, $/bbl.

Oil and Gas Production Schedule

Yearly primary and secondary oil recoveries are estimated using the generic curves as shown in Tables III-13 for small fields and III-14 for large fields. The recovery curves for small and large fields are plotted in Figures III-4 and III-5. The generic curves represent the percentages of ultimate recovery from a typical well as shown in Table III-8, above. For primary production only:

$$QOP = OILREV*PCTP*0.01$$

where QOP is the quantity of oil recovered by primary production, MMbbl/year; and PCTP is the yearly primary oil production as a percentage of ultimate oil recovery. As PCTP is not a decimal number, it is multiplied by 0.01.

$$QGP = OILREV*PCTP*PGOR*0.01$$

where QGP is the quantity of gas recovered by primary production, Bcf/year; and PGOR is the producing gas-oil ratio, Mcf/bbl, from Table III-15. For primary and secondary productions:

$$QOPS = OILREV*(PCTP + PCTS)*0.01$$

where QOPS is the quantity of oil recovered by primary and secondary production, MMbbl/year; and PCTS is the yearly secondary oil production as a percentage of ultimate oil recovery.

When the pressure in the reservoir is above the bubble point, the gas solution is constant. The gas produced is the oil produced times the producing gas-oil ratio (Campbell 1973):

$$QGPS = OILREV*(PCTP + PCTS)*PGOR*0.01$$

where QGPS is the quantity of gas recovered by primary and secondary production, Bcf/year.

Table III-13. Generic Curves Used to Estimate Yearly Recoveryfor Small Field (Class 9 or below)

Year of Production	Primary Recovery	Secondary Recovery	Total
1	7.68%		7.68%
2	7.68%		7.68%
3	7.68%		7.68%
4	7.68%		7.68%
5	7.68%		7.68%
6	6.92%		6.92%
7	6.17%		6.17%
8	5.41%		5.41%
9	4.65%		4.65%
10	3.89%	0.00%	3.89%
11	3.13%	0.43%	3.56%
12	2.38%	0.85%	3.23%
13	1.62%	1.28%	2.90%
14	0.86%	1.71%	2.57%
15	0.72%	1.73%	2.45%
16	0.57%	1.75%	2.32%
17	0.43%	1.77%	2.20%
18	0.29%	1.79%	2.08%
19	0.14%	1.81%	1.96%
20	0.00%	1.84%	1.84%
21		1.68%	1.68%
22		1.53%	1.53%
23		1.37%	1.37%
24		1.22%	1.22%
25		1.07%	1.07%
26		0.91%	0.91%
27		0.76%	0.76%
28		0.61%	0.61%
29		0.45%	0.45%
30		0.30%	0.30%
Total	75.59%	24.87%	100.46%

Source: Author's calculation.

Table III-14. Generic Curves Used to Estimate Yearly Recovery for Large Field

(Class 10 or above)

Year of Production	Primary Recovery	Secondary Recovery	Total
1	4.07%		4.07%
2	4.07%		4.07%
3	4.07%		4.07%
4	4.07%		4.07%
5	4.07%		4.07%
6	4.07%		4.07%
7	4.07%		4.07%
8	4.07%		4.07%
9	4.07%		4.07%
10	4.07%		4.07%
11	3.72%		3.72%
12	3.38%	0.00%	3.38%
13	3.00%	0.15%	3.15%
14	2.62%	0.29%	2.91%
15	2.24%	0.44%	2.68%
16	1.86%	0.59%	2.44%
17	1.47%	0.74%	2.21%
18	1.39%	0.75%	2.13%
19	1.30%	0.76%	2.06%
20	1.21%	0.76%	1.98%
21	1.13%	0.77%	1.90%
22	1.04%	0.78%	1.82%
23	0.95%	0.79%	1.75%
24	0.87%	0.80%	1.67%
25	0.78%	0.81%	1.59%
26	0.69%	0.82%	1.51%
27	0.61%	0.83%	1.44%
28	0.52%	0.84%	1.36%
29	0.43%	0.85%	1.28%
30	0.35%	0.94%	1.28%
31	0.26%	1.02%	1.28%
32	0.17%	1.11%	1.28%
33	0.09%	1.20%	1.28%
34	0.00%	1.28%	1.28%
35		1.22%	1.22%
36		1.16%	1.16%

Table III-14. Generic Curves Used to Estimate Yearly Recovery for Large Field (con't)

Year of Production	Primary Recovery	Secondary Recovery	Total
37		1.10%	1.10%
38		1.04%	1.04%
39		0.98%	0.98%
40		0.91%	0.91%
41		0.85%	0.85%
42		0.79%	0.79%
43		0.73%	0.73%
44		0.67%	0.67%
45		0.61%	0.61%
46		0.55%	0.55%
47		0.48%	0.48%
48		0.42%	0.42%
49		0.36%	0.36%
50		0.30%	0.30%
Total	70.74%	29.51%	100.25%

Source: Author's calculation.

Figure III-4. Oil Recovery Generic Curves: Small Fields

(Class 9 or below)

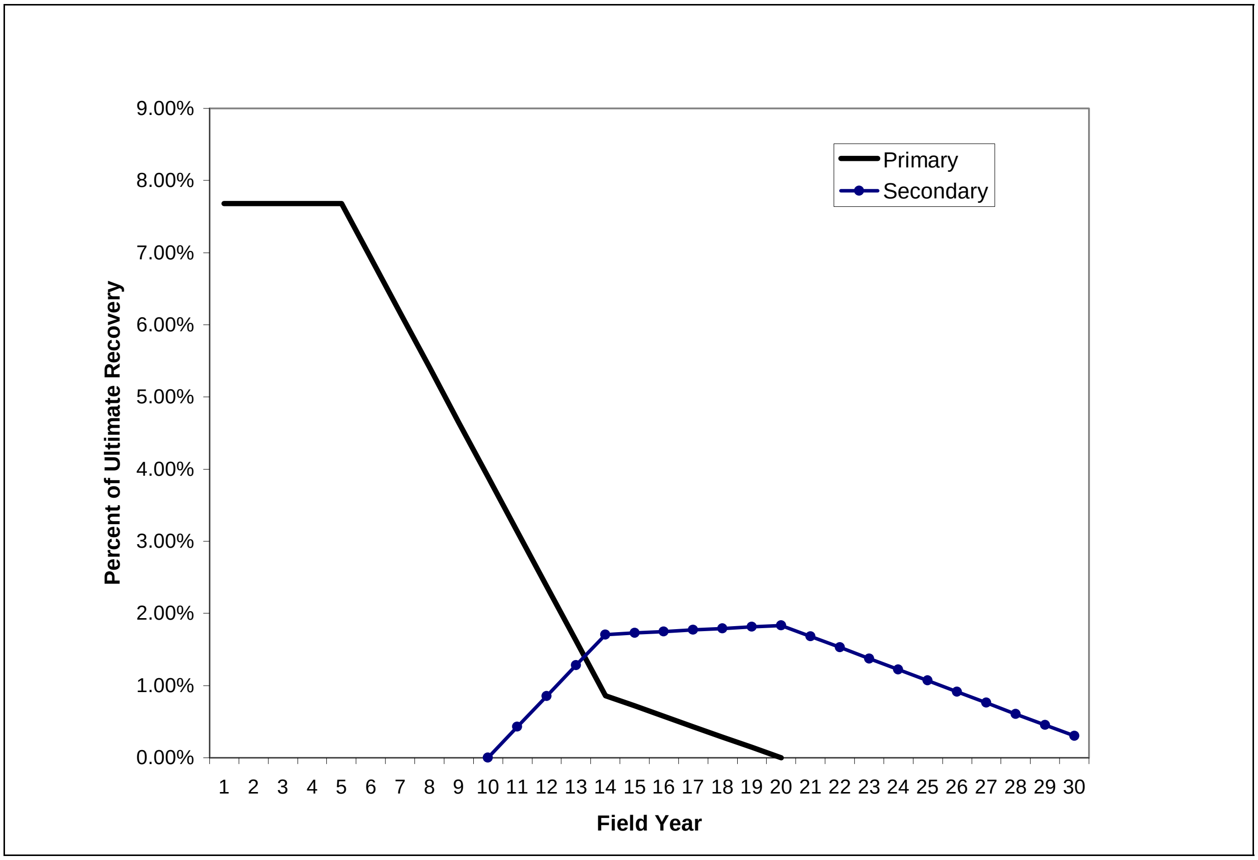


Figure III-5. Oil Recovery Generic Curves: Large Fields

(Class 10 or above)

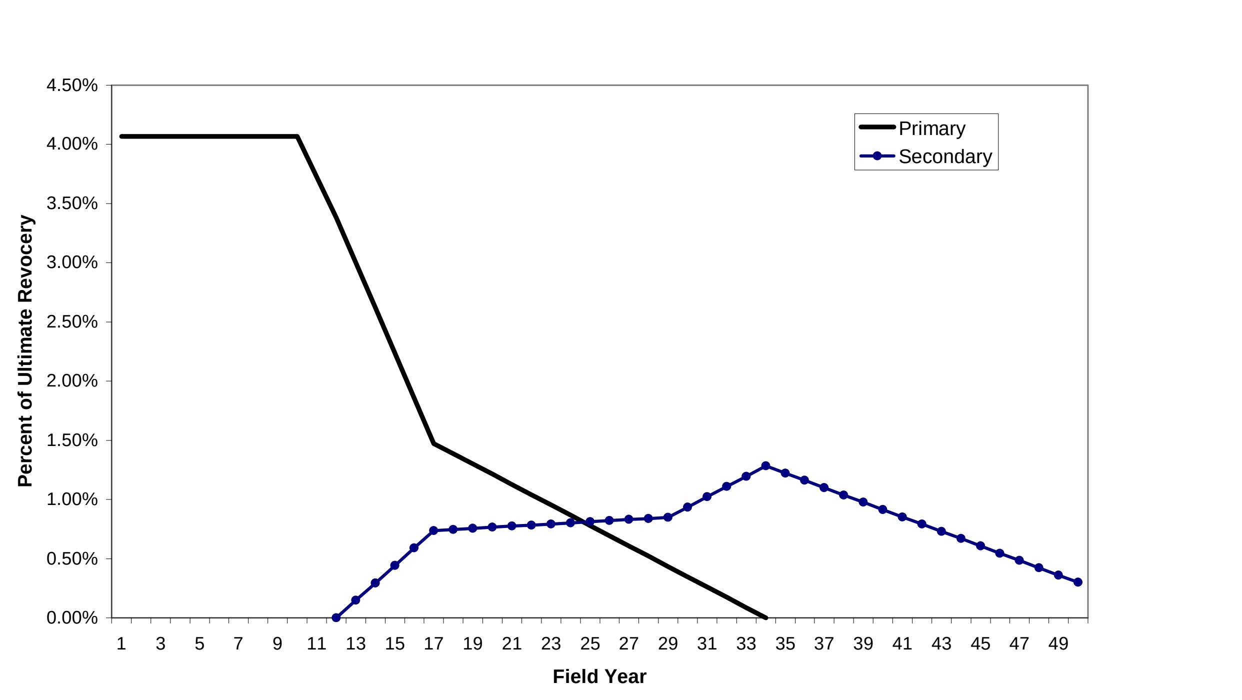


Table III-15. Production Gas-Oil Ratio in the Gulf of Mexico

Field Type/Field Size	Production Gas-Oil Ratio (Mcf/bbl)
Oil Field Classes 1-9	3.354
Oil Field Classes 10-19	2.670
Gas Field Classes 1-9	87.072
Gas Field Classes 10-19	43.043

Source: Author's calculation.

When the pressure in the reservoir drops below the bubble point, a free gas phase is created, and gas recovery dramatically increases:

$$QGPS = (ADGAS - SQG)/(LP - TB + 1)$$

where ADGAS is total associated/dissolved gas in the field, Bcf; SQG is the cumulative gas produced before bubble point is reached; LP is the life of the field, year, from Table III-16; and TB is the year when bubble point reached.

Costs of Pipeline Operation

Pipeline operating costs are calculated as:

$$YCTRAP = QOP*CTRA*10^6$$

$$YCTRAPS = QOPS*CTRA*10^6$$

where YCTRAP is the yearly pipeline operating cost in the case of primary production only, \$/year; YCTRAPS is the yearly pipeline operating cost in the case of primary and secondary productions, \$/year; and CTRA is the pipeline transportation cost, \$/bbl.

Financial Part of the Production Sub-model

In the production phase, the annual oil and gas production (QO and QG) and the production operation cost (COPE) are calculated as follows. For primary production only:

$$QO = QOP$$

$$QG = QGP$$

$$COPE = TCOPEP + YCTRAP$$

For primary and secondary production:

$$QO = QOPS$$

$$QG = QGPS$$

$$COPE = TCOPEP + TCOPESF + COPESV + YCTRAPS$$

General and Administrative expenses is assumed 20 percent of the operating costs:

$$GNA = RICO*COPE$$

where GNA is the general and administrative costs; and RICO is the rate of indirect charges for production operations.

Table III-16. Parameters for the Recovery Curves

Variable Name	Description	Unit	Small Field	Large Field
LP	Total production life	year	30	50
LS	Life of secondary recovery	year	17	33
PCT0	Initial production rate	percent	7.68	4.07
PCTSP	Peak production rate of secondary recovery	percent	1.84	1.28
PCTSE	Final production rate of secondary recovery	percent	0.3	0.3
TD	Deliverability life	year	5	10
TB	Time when bubble point reached	year	27	45
TE	Time when primary production reaches zero and secondary production at peak	year	20	34

Source: Author's calculation.

Field Abandonment

The platform abandonment cost is incorporated in the model in such a way that the firm will abandon the field whenever production is terminated. That is the abandonment can happen at any time during production phase.

Depreciation

The depreciations of tangible investments is calculated as follows. The unit of production depreciation allowed in a year (UNPR) for the bonus payment is:

UNPR = BONUS*(QO + QG/CONR)/TOTBOE

where CONR is conversion ratio in Mcf/bbl. The depreciation of tangible investment (DEPRD) for given depreciation life (LDEP) after the investment is:

DEPRD = TANG/LDEP

Thus, the total depreciation in a year (DEPR) is:

DEPR = DEPRD + UNPR

The Annual Cash-flow Sub-model

The cash-flow sub-model uses the outputs of the financial sub-models associated with the exploration, development and production sub-models as inputs to compute the annual cash-flow:

NWIR = 10^6*(OPRICE*QO + GPRICE*QG)*(1 - ROYL)

where NWIR is the net working interest revenue, $/year; OPRICE is the price of oil, $/bbl; GPRICE is the price of gas, $/Mcf; and ROYL is the royalty rate.

It is assumed that there is a fixed relationship between oil and gas prices:

GPRICE = 0.7632+0.0792*OPRICE

As QO and QG are in MMbbl and Bcf, respectively, the results are multiplied by 10^6. Before tax income is:

BTI = NWIR - DEPR - COPE - GNA - INTANG

where BTI is before tax income, $/year; DEPR is total depreciation in the year, $/year; and INTANG is intangible cost.

STAX = BTI*STAXR

where STAX is state income tax, $/year; and STAXR is the state income tax rate.

FTAX = BTI*(1 - STAXR)*FTAXR

where FTAX is Federal income tax, \$/year; and FTAXR is the Federal income tax rate. Thus, the after-tax cash flow in dollar per year (ATI) is calculated as:

$$ATI = BTI - STAX - FTAX - TANG + DEPR$$

Note that the sum of discounted ATIs is the key economic performance parameter, ATNPV. The model assumes that the firm has other income that can benefit from the "sheltering" impact of negative income in any year. Thus, no carryover of losses is modeled.

III.A.1.c. The Optimization Model

The optimization model is the center of the integrated model. In this model, the firm maximizes after tax net present value, subject to all the exploration, development, and production constraints. The deterministic dynamic programming algorithm is discussed in Jin (1991). In the model developed below, only one field is considered. Thus, the model computation follows the exploration, development, and production sequence. The state and control variables are denoted by X, Y and Z, and Q, R and S, respectively. They are indexed according to different steps and corresponding actions for each phase in OCS development. The possible X, Y and Z combinations are shown in Table III-17.

Variables X, Y and Z are defined as steps in the exploration, development and production phases, respectively. For all cases, it is assumed that the exploration takes three years. Thus, XMAX is three. YMAX is determined by the following equation,

$$YMAX = TPLAT + TDRIL$$

where TPLAT is the number of years required for platform construction, and TDRIL is the number of years required for development drilling. ZMAX is 30 years for small fields (class 9 and below) and 50 years for large fields (class 10 and above). To illustrate the relationship between state and control variables, an example is summarized in Table III-18. In the example, it is assumed that platform construction and development drilling each takes two years. Within this framework, Q and R can be either zero or one; and S has the third alternative, two. The constraints are:

$$X_{t+1} = X_t + Q_t$$

$$Y_{t+1} = Y_t + R_t$$

$$Z_{t+1} = Z_t + S_t \text{ (for S = 0 and 1)}$$

$$Z_{t+1} = Z_t + 1 \quad \text{(for S = 2)} \qquad t = 1,2,...,T$$

Although in the production period, the control can be no production, or primary recovery only, or primary and secondary production, the choice is not free from certain constraints. As the secondary recovery curves in Figures III-4 and III-5 are realized through a given water injection plan, if the firm does not start water injection on time, or the injection stops early, it will be unable to follow that secondary recovery path in later years.

Table III-17. The Possible Combinations of State Variables

Exploration	Development	Production
X = 0 - XMAX	Y = 0	Z = 0
X = XMAX	Y = 0 - YMAX	Z = 0
X = XMAX	Y = YMAX	Z = 0 - ZMAX

Table III-18. States and Corresponding Controls

State	Control
Exploration Phase	
X = 0: on exploration	Q = 0 or 1: no action or start pre-bid activity
X = 1: pre-bid activity completed	Q = 0 or 1: no action or bonus paid
X = 2: lease bonus paid	Q = 0 or 1: no action or drill exploration and delineation wells
Development Phase	
X = 3, Y = 0: exploration and delineation wells drilled	R = 0 or 1: no action or half of the platforms built
Y = 1: half of the platforms built	R = 0 or 1: no action or rest of the platforms built
Y = 2: all platforms built	R = 0 or 1: no action or half of the development wells drilled and equipped
Y = 3: half of the development wells drilled and equipped	R = 0 or 1: no action or rest of the development wells drilled and equipped, and pipelines completed
Production Phase	
Y = 4, Z = 0: all development wells drilled and equipped, pipelines competed	S = 0 or 1: no action or primary recovery
Z = 1 - TD = t: after t year production	S = 0 or 1: no action or primary recovery
Z = TD - TE = t: after t year production	S = 0 or 1 or 2: no action or primary recovery or primary and secondary recovery
Z = TE - (ZMAX-1) = t: after t year production	S = 0 or 1: no action or secondary recovery
Z = ZMAX: all oil and gas recovered	field abandonment

In early years, the benefits from water injection are small. Thus, per barrel production costs with investment in secondary recovery is higher than the without case. Yet, the benefits from added production will grow in following years. Therefore, there is a trade-off between current cost increase and future benefits. These constraints are built into the model by specifying separate benefit functions for primary and secondary recovery. Finally, it is assumed that there is no capital constraint on borrowing, since this is a field level model. Other fixed input parameters for the field model are summarized in Table III-19.

III.A.1.d. Field Model Simulation Results

This subsection reports simulation results. All dollar values are in 2003 dollars. The integrated model is designed to focus on the following results: (1) oil and gas production, (2) royalty payment, (3) Federal tax payment, and (4) cash flows and the after-tax-net present value (ATNPV). The results will be presented for combinations of several physical and financial variables. The physical variables include: water depth and field size. The financial variables are: oil price and royalty rate.

The Input Data

In addition to the fixed parameters in Table III-19, Gulf of Mexico regional average values in Tables III-6 and III-9 above were used in the simulations. Drilled depth (DD) was fixed at 11,955 feet; discount rate (DR) at 7%; and oil price at constant level (PR = 0). Unless described otherwise, the simulations used a royalty rate of 18.75%, oil price of $90/bbl, water depth of 1,000 feet, and field size of class 14.

Annual Production and Cash-Flow Profile of an Example Field

The simulation results of a class 14 field in the Gulf of Mexico are shown in Figures III-6 and III-7. In this example, the water depth is 1,000 feet; and oil price is $90/bbl. The annual oil and gas production is plotted in Figure III-6, and the annual after-tax cash flows are depicted in Figure III-7. For this field, the first three years are the exploration phase. Pre-bid activity, bonus payment, and exploratory drilling occur in these years respectively. Years four and seven are for platform construction. Development drilling are in years eight through 11, and pipelines are completed in year 11. Oil and gas are produced from year 12 to year 61. Around year 40, the result of secondary recovery can be seen. After year 56 the pressure in the reservoir is below the bubble point and gas recovery increases. In the 62nd year the field is abandoned.

The After-Tax-Net Present Value for Different Fields

The total oil and gas production, payments and after-tax-net present value of a field is examined for fields under different physical and financial conditions.

Water Depth

The change in payments and ATNPV of a class 14 field in the Gulf of Mexico with respect to different water depth is shown in Figure III-8. The oil price is assumed $90/bbl. The production decision is made for each year. The production will continue as long as the cash flow in that year is positive, even though cash flow will decline as water depth increases. Thus, in this example, the total oil and gas outputs are constant from water depth of 100 to 3,100 feet.

Table III-19. Fixed Input Parameters for the Field Model

Variable Name	Description	Unit	Sample Value
YEAR	Planning period	year	65
FTAXR	Federal tax rate		0.35
STAXR	State tax rate		0
LDEP	Depreciation life	year	10
B	Bid factor		0
RIC	Rate of indirect charge for investment		0.1
RICO	Rate of indirect charge for production operation		0.2
COPESF	Fixed cost component of secondary recovery	$/well/year	252,920
CWAT	Water cost	$/bbl	0.3
CTRA	Pipeline transportation cost	$/bbl	0.15
CONR	conversion ratio	Mcf/bbl	6
DMT	Diameter of main trunk pipeline	inch	20
DGL	Diameter of gathering line	inch	4
LGL	Length of gathering line	mile	10

Figure III-6. Oil and Gas Production by Year

Class 14, $90/bbl, 1,000 Feet Water Depth

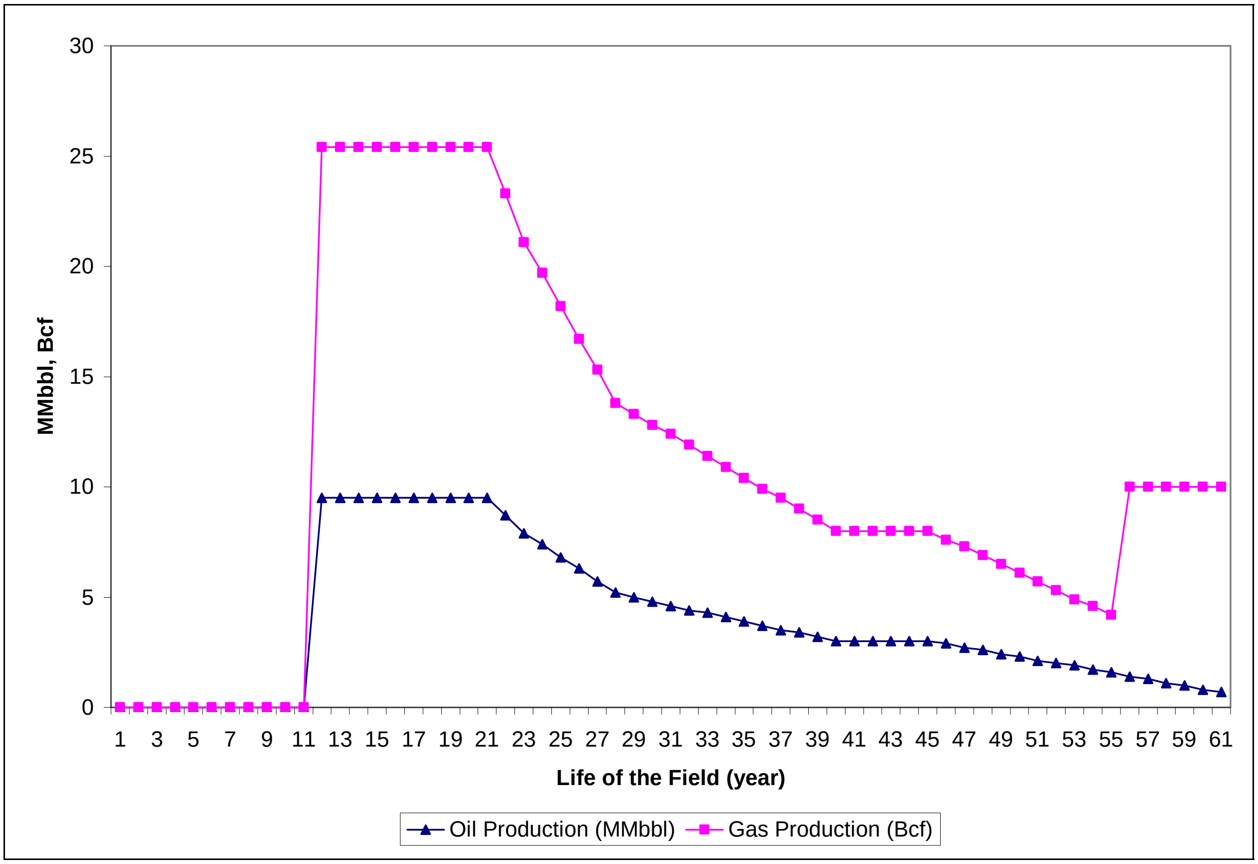


Figure III-7. After-Tax Cash Flows for a Oil Field

Class 14, $90/bbl, 1,000 Feet Water Depth

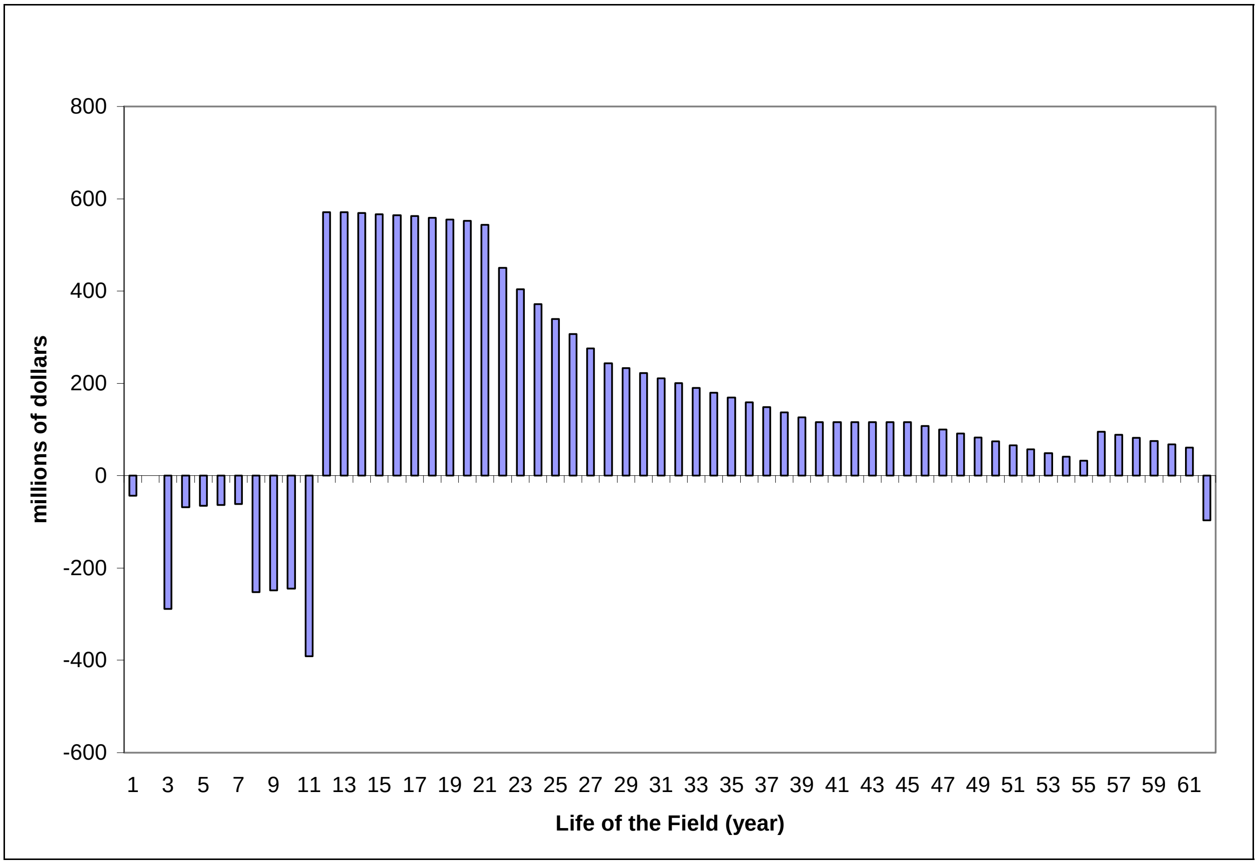
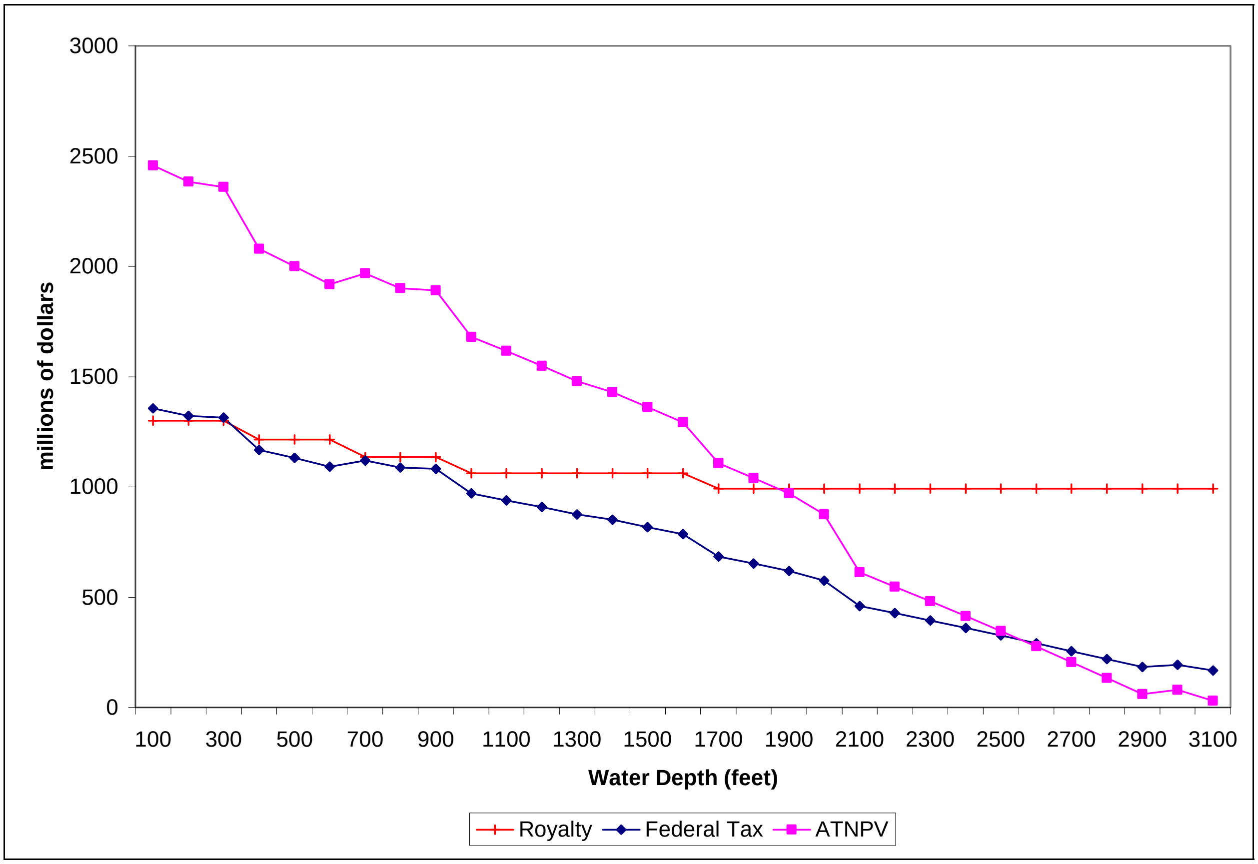


Figure III-8. Payments and ATNPV by Water Depth

Class 14, $90/bbl



As the field moves to deeper water, the present values of royalty and tax payment and ATNPV decrease. The net present value of total royalty drops slowly. This is due to constant oil and gas outputs. Yet, deeper water depth means longer development phase and later production. The decline in royalty payments is only induced by the discounting factor. For oil price of $90/bbl, the firm will not develop the field if it is located in a water depth deeper than 3,100 feet. The internal rate of return for class 14 fields in different water depths are plotted in Figure III-9.

Field Size

The results for various payments from fields of different size classes are in Figure III-10. These fields are in the Gulf of Mexico, water depth is 200 feet; oil price is $90/bbl. With these input values, there will be no development for fields less than class 9. As field size increases from class 9 to class 16, payments and ATNPV rise. For example, the royalty payment (in current value) is 61 million dollars for a class 9 field and 5 billion dollars for a class 16 field. Figure III-11 shows how ATNPV would alter as oil price changes. When oil price is $40/bbl, the minimum field size is class 13. In contrast, class 8 would generate positive ATNPV when oil price is $140/bbl.

Royalty Rate

Payments and ATNPV of a class 14 field in 1,000 foot water were estimated for oil price at $90/bbl. The results in Figure III-12 indicate that ATNPV is positive for all royalty rates up to 60%.

III.A.2. Area model

This Section describes the Area model that specifies all key output variables for the Central and Western Gulf of Mexico over the 50 year time horizon. As indicate above, the field model forecasts key field inputs and outputs for 16 field size classes at 7 water depths, for a total of 112 representative fields. The Area model uses the output of the field model, along with MMS data on undiscovered fields by size class and water depth, to estimate total tracts sold, wells drilled, field discoveries by size and water depth, production, depletion, technological change, net present value, cash bonus bids, royalties, area rentals, etc.

We consider oil and gas fields (type = 1 and 2) that range in size from Class 1 to Class 16 in seven sub-areas by water depth (wd = 1, 2, …, 7; see Table III-20). The Area model requires 11 input values listed in Table III-21. Below we detail the equations used to forecast the various model outputs.

III.A.2.a. OCS Leasing Policy

The number of tracts leased (LEASE) at t is modeled as a function of oil price and tracts offered. Under areawide leasing:

$$LEASE(t) = \exp(2.7275+ 0.2705*\ln(OPRICE(t)) + 0.323* \ln(TRACT(t))$$

Figure III-9. Internal Rate of Return by Water Depth

Class 14, $90/bbl

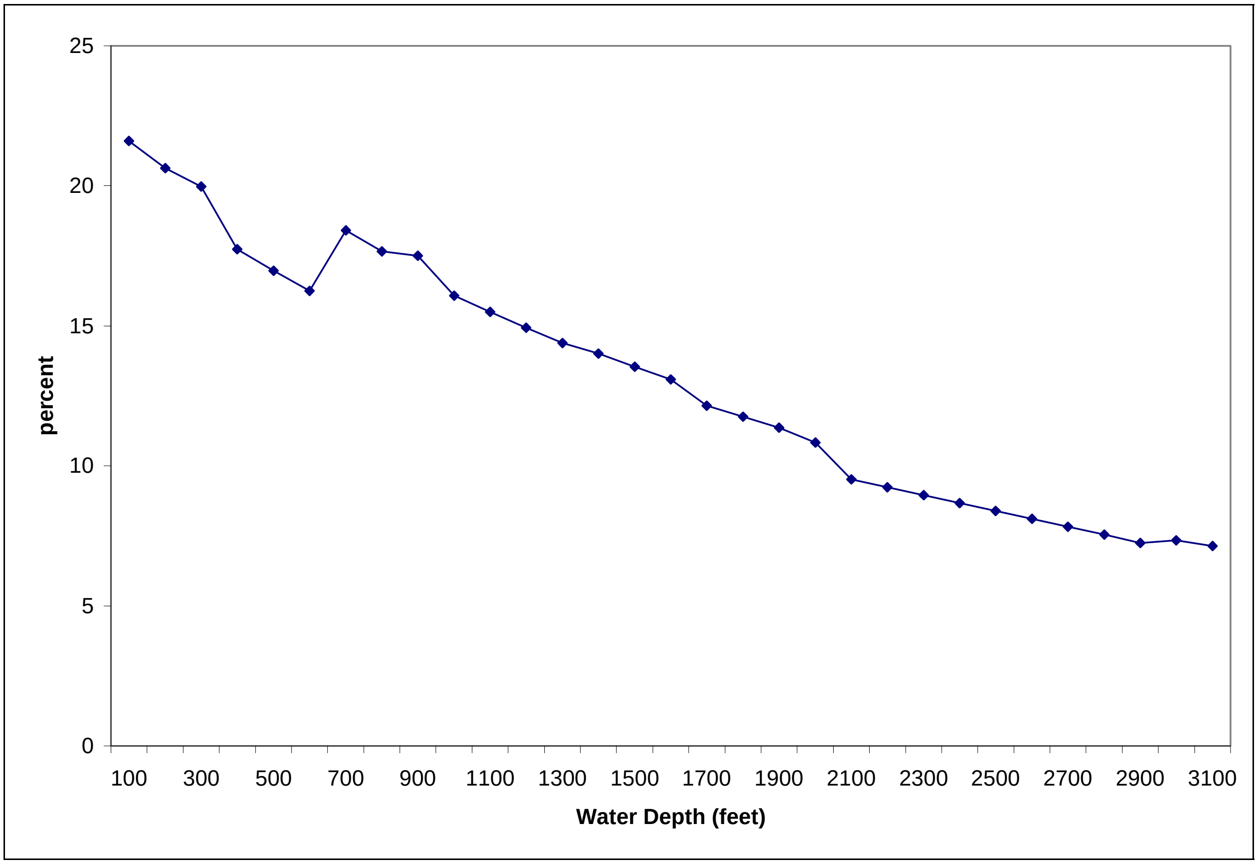


Figure III-10. Payments and ATNPV by Field Size

$90/bbl, 200 Feet Water Depth

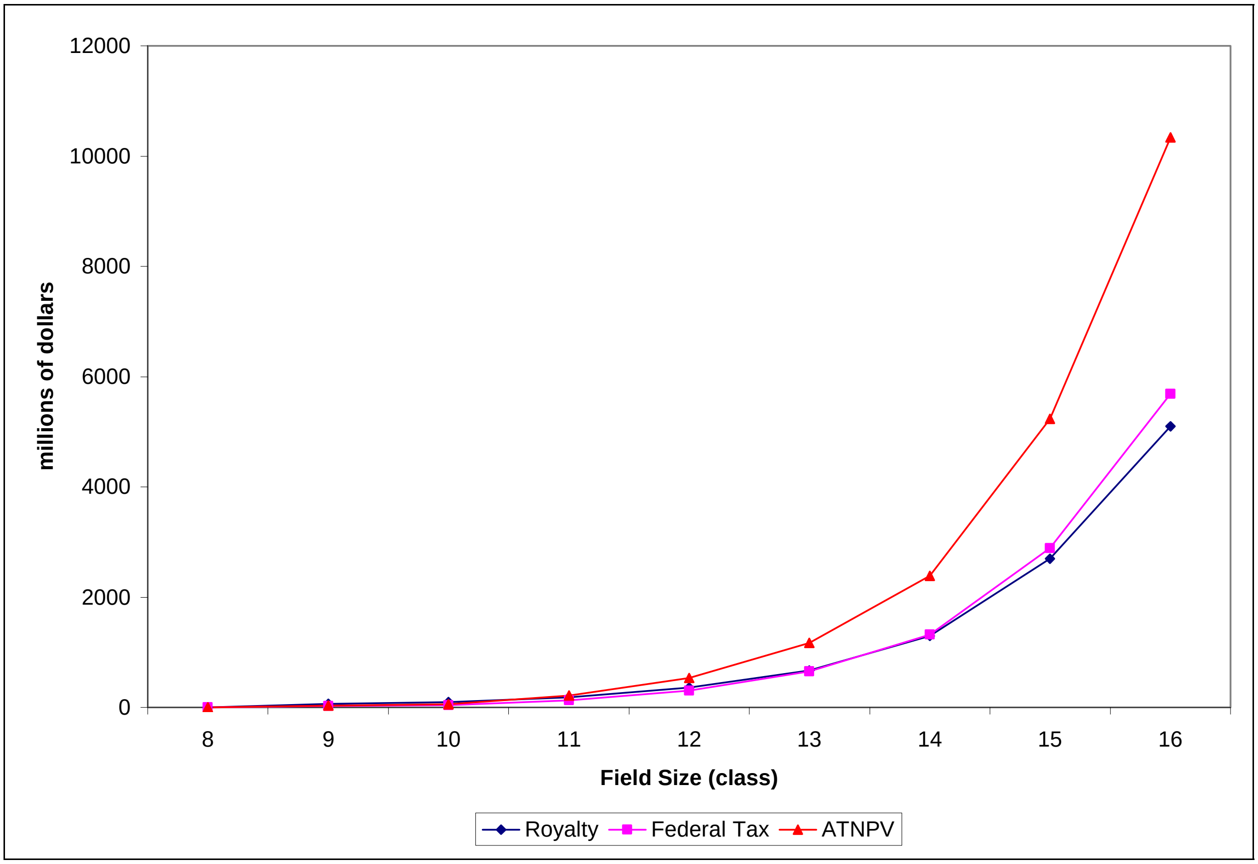


Figure III-11. ATNPV by Field Size and Price

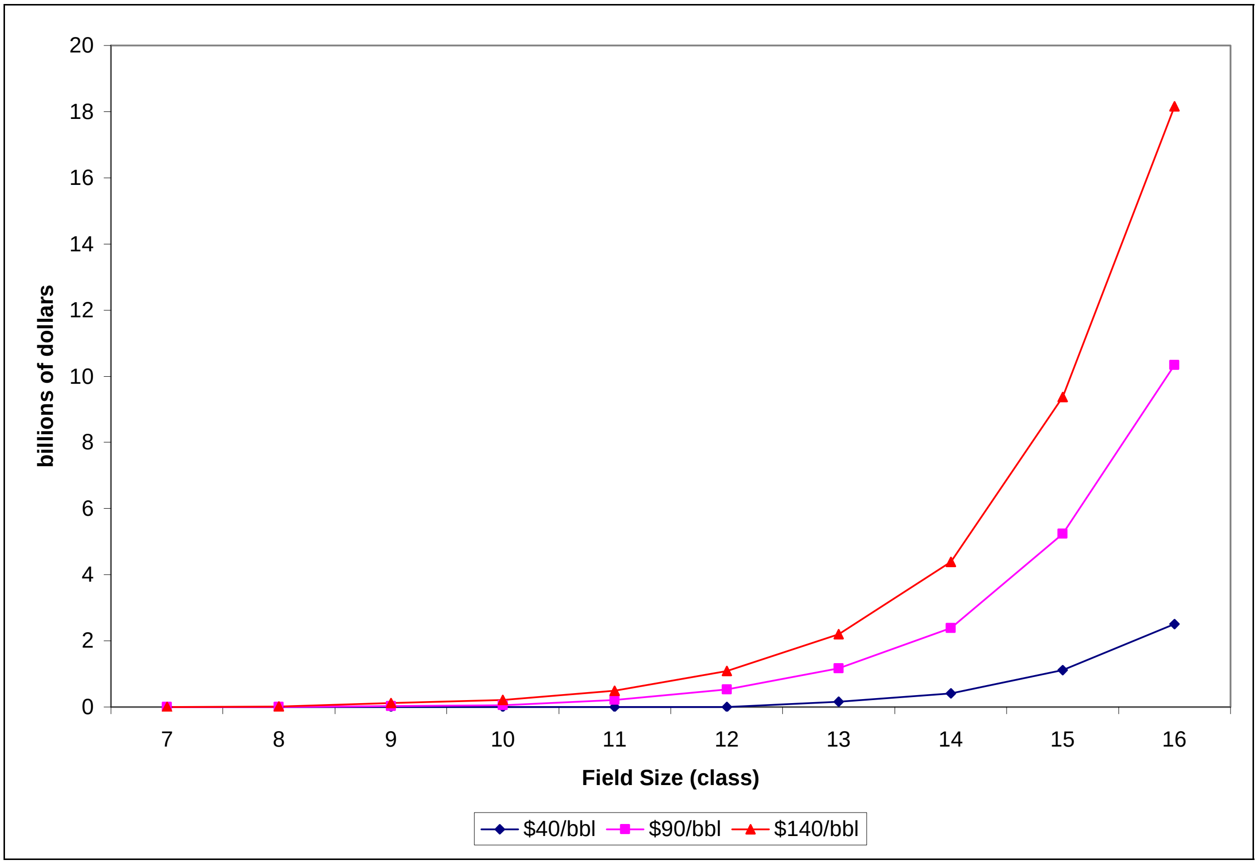


Figure III-12. Payments and After Tax Net Present Value for Different Royalty Rates

Class 14, $90/bbl, 1,000 Feet Water Depth

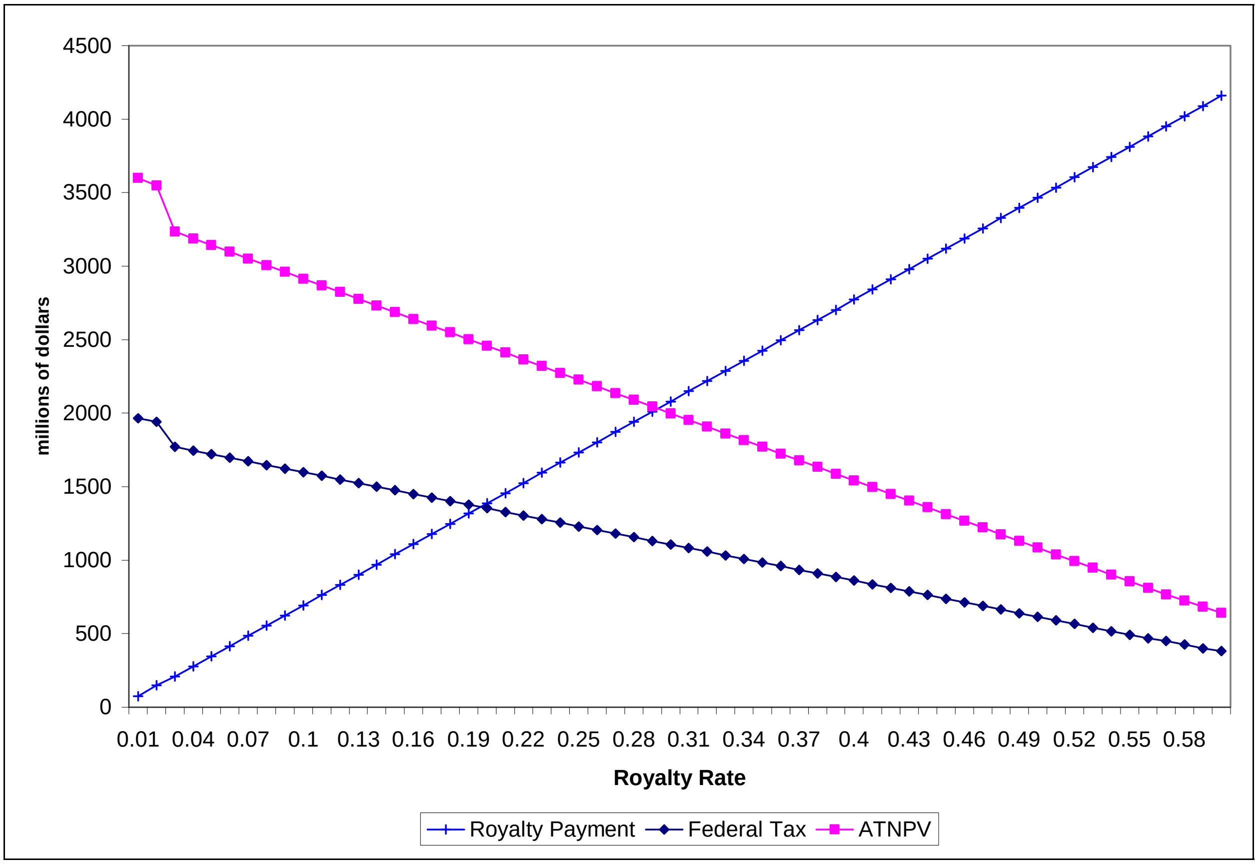


Table III-20. Water Depth and Drilled Depth

	Water Depth Range				Average		Drilled Depth
	Meters			Feet	Meters	Feet	Feet
WD1	0	-	60	197	30	98	10,887
WD2	60	-	200	656	130	427	9,566
WD3	200	-	400	1,312	300	984	11,687
WD4	400	-	800	2,625	600	1,969	13,020
WD5	800	-	1,600	5,249	1,200	3,937	16,281
WD6	1,600	-	2,400	7,874	2,000	6,562	16,449
WD7	2,400	-	3,658	12,000	3,029	9,938	17,901

Source: Author's calculation.

Table III-21. Model Inputs

TRACT	Number of tracts offered
OPRICE	Oil price at t =1
PR	Annual rate of price increase
AREAWIDE	Dummy for areawide lease
ROYAL	Royalty rate
RENTALS	Rental for water depth < 200 meters
RENTALD	Rental for water depth ≥ 200 meters
DR	Discount rate
EDHR	Exploration dry hole rate
TCE	Annual rate of technological change in exploration
TC	Annual rate of technological change in inputs

And under nomination leasing:

LEASE(t) = exp(0.1231+ 0.2426*ln(OPRICE(t)) + 0.7197* ln(TRACT(t))

where OPRICE is oil price; and TRACT is the number of tracts offered. To avoid possible difficulties that might arise when extrapolation beyond the range of the data, we use the following constraint to ensure that tracts sold never exceed the number of tracts offered for sale:

If LEASE(t) > TRACT(t), then LEASE(t) = TRACT(t).

III.A.2.b. Drilling Activities

The number of wells drilled (WELLDRILL) at t is calculated as:

WELLDRILL(t)=exp(4.7415+0.1017*ln(OPRICE(t))+0.1597*ln(LEASE(t)))

The total number of wells drilled is allocated across 7 water depth categories (wd):

WELL(t, wd) = WELLDRILL(t)*WDSHARE(t, wd)

where WDSHARE(t, wd) is the share of wells drilled at t in wd (Table III-22).

III.A.2.c. Field Discovery

The number of fields discovered (NN) by water depth at t is

$$NN(t, wd) = (1+TCE)^{t}*ESR*WELL(t, wd)$$

where TCE is the annual rate of technological change in exploration; and ESR is the exploration success rate. ESR = 1 – EDHR (exploratory dry hole rate). The expected number of fields discovered by field size class is

NN(t, class, wd) = (NU(t, wd)/NU(1, wd))*NN(t, wd)*Prob(t, class, wd)

where NU(1, wd) is the number of undiscovered fields at t = 1 (initial period) at wd; and Prob(t, class, wd) is the conditional probability for a specific class at wd. We calculate a depletion effect of fields using the index of remaining fields:

NU(t, wd)/NU(1, wd)

Finally, the number of field discovered (NN) is partitioned into oil and gas fields with the share of oil fields (OSHARE) in each class and water depth calculated as:

OSHARE(class) = 0.008*CLASS**2- 0.0891*CLASS + 0.2915

We now have NN(t, class, wd, type), the number of fields discovered by size class, water depth, and field type at t.

Table III-22. Shares of Exploration Wells Drilled by Water Depth

Year	WD1	WD2	WD3	WD4	WD5	WD6	WD7	Total
2009	29.59%	10.42%	4.06%	7.77%	23.53%	19.04%	5.60%	100.00%
2010	28.87%	10.16%	4.06%	7.77%	23.78%	19.46%	5.90%	100.00%
2011	28.17%	9.92%	4.06%	7.77%	24.01%	19.88%	6.20%	100.00%
2012	27.49%	9.68%	4.06%	7.77%	24.22%	20.28%	6.50%	100.00%
2013	26.83%	9.45%	4.06%	7.77%	24.41%	20.68%	6.81%	100.00%
2014	26.18%	9.22%	4.06%	7.77%	24.58%	21.07%	7.13%	100.00%
2015	25.54%	8.99%	4.06%	7.77%	24.74%	21.45%	7.44%	100.00%
2016	24.93%	8.78%	4.06%	7.77%	24.88%	21.83%	7.76%	100.00%
2017	24.32%	8.56%	4.06%	7.77%	25.00%	22.20%	8.09%	100.00%
2018	23.74%	8.36%	4.06%	7.77%	25.10%	22.56%	8.41%	100.00%
2019	23.16%	8.15%	4.06%	7.77%	25.19%	22.92%	8.74%	100.00%
2020	22.60%	7.96%	4.06%	7.77%	25.27%	23.27%	9.08%	100.00%
2021	22.05%	7.77%	4.06%	7.77%	25.33%	23.61%	9.41%	100.00%
2022	21.52%	7.58%	4.06%	7.77%	25.38%	23.95%	9.75%	100.00%
2023	21.00%	7.39%	4.06%	7.77%	25.41%	24.28%	10.09%	100.00%
2024	20.49%	7.22%	4.06%	7.77%	25.43%	24.61%	10.43%	100.00%
2025	20.00%	7.04%	4.06%	7.77%	25.43%	24.93%	10.78%	100.00%
2026	19.51%	6.87%	4.06%	7.77%	25.42%	25.24%	11.12%	100.00%
2027	19.04%	6.70%	4.06%	7.77%	25.40%	25.55%	11.47%	100.00%
2028	18.58%	6.54%	4.06%	7.77%	25.37%	25.86%	11.82%	100.00%
2029	18.13%	6.38%	4.06%	7.77%	25.33%	26.15%	12.18%	100.00%
2030	17.69%	6.23%	4.06%	7.77%	25.27%	26.45%	12.53%	100.00%
2031	17.27%	6.08%	4.06%	7.77%	25.21%	26.74%	12.89%	100.00%
2032	16.85%	5.93%	4.06%	7.77%	25.13%	27.02%	13.24%	100.00%
2033	16.44%	5.79%	4.06%	7.77%	25.04%	27.30%	13.60%	100.00%
2034	16.04%	5.65%	4.06%	7.77%	24.95%	27.57%	13.96%	100.00%
2035	15.65%	5.51%	4.06%	7.77%	24.84%	27.84%	14.32%	100.00%
2036	15.28%	5.38%	4.06%	7.77%	24.73%	28.11%	14.69%	100.00%
2037	14.91%	5.25%	4.06%	7.77%	24.60%	28.37%	15.05%	100.00%
2038	14.55%	5.12%	4.06%	7.77%	24.47%	28.62%	15.41%	100.00%
2039	14.19%	5.00%	4.06%	7.77%	24.33%	28.88%	15.78%	100.00%
2040	13.85%	4.88%	4.06%	7.77%	24.17%	29.12%	16.15%	100.00%
2041	13.52%	4.76%	4.06%	7.77%	24.02%	29.37%	16.51%	100.00%
2042	13.19%	4.64%	4.06%	7.77%	23.85%	29.61%	16.88%	100.00%
2043	12.87%	4.53%	4.06%	7.77%	23.68%	29.84%	17.25%	100.00%
2044	12.56%	4.42%	4.06%	7.77%	23.49%	30.08%	17.62%	100.00%
2045	12.26%	4.31%	4.06%	7.77%	23.31%	30.31%	17.99%	100.00%
2046	11.96%	4.21%	4.06%	7.77%	23.11%	30.53%	18.36%	100.00%

Table III-22. Shares of Exploration Wells Drilled by Water Depth (con't)

Year	WD1	WD2	WD3	WD4	WD5	WD6	WD7	Total
2047	11.67%	4.11%	4.06%	7.77%	22.91%	30.75%	18.73%	100.00%
2048	11.39%	4.01%	4.06%	7.77%	22.70%	30.97%	19.10%	100.00%
2049	11.11%	3.91%	4.06%	7.77%	22.49%	31.19%	19.48%	100.00%
2050	10.84%	3.82%	4.06%	7.77%	22.26%	31.40%	19.85%	100.00%
2051	10.58%	3.73%	4.06%	7.77%	22.04%	31.61%	20.22%	100.00%
2052	10.33%	3.64%	4.06%	7.77%	21.80%	31.81%	20.59%	100.00%
2053	10.08%	3.55%	4.06%	7.77%	21.57%	32.02%	20.97%	100.00%
2054	9.83%	3.46%	4.06%	7.77%	21.32%	32.22%	21.34%	100.00%
2055	9.59%	3.38%	4.06%	7.77%	21.07%	32.41%	21.71%	100.00%
2056	9.36%	3.30%	4.06%	7.77%	20.82%	32.61%	22.09%	100.00%
2057	9.14%	3.22%	4.06%	7.77%	20.56%	32.80%	22.46%	100.00%
2058	8.91%	3.14%	4.06%	7.77%	20.30%	32.99%	22.84%	100.00%

Source: Author's calculation

III.A.2.d. Field Distribution and Resource Depletion

The number of undiscovered fields (NU) by size class, water depth, and field type at t is

$$NU(t, class, wd, type) = NE(t, class, wd, type) - ND(t-1, class, wd, type)$$

where NE is the endowment field distribution; and ND is the cumulative number of fields discovered up to t -1. The data for ND(t = 1; year = 2003) are shown in Table III-23. Data for NE are in the same format. At each t, the number of newly discovered fields (NN) is smaller than or equal to NU:

$$NN(t, class, wd, type) \leq NU(t, class, wd, type)$$

The newly discovered fields are added to the cumulative count of discovered fields at each t:

$$ND(t, class, wd, type) = ND(t-1, class, wd, type) + NN(t, class, wd, type)$$

III.A.2.e. Probability Distribution on Field Size

This analysis uses a discrete probability distribution for 16 field classes, with each class defined by upper and lower bounds on reserves. While each class is defined by a range on field size, we ultimately work with an "average" field within each size class. Bayes rule is used to model this problem as follows:

$$P(s,d) = P(s/d)P(d) = P(d/s)P(s).$$

where s is field size (class) and d is discovery (0 or 1). P(s,d) is the joint probability of discovering a field of class s, P(s/d) is the conditional probability that a newly discovered field is of size s, p(d) is the probability of making a discovery, P(d/s) is the probability of discovering a field given it is of size s and P(s) is the probability of a randomly selected field being of size s.

Our model needs to specify the probability that a newly discovered field is of size s, so we need to calculate the conditional probability, P(s/d). We use Bayes rule to write this as:

$$P(s/d) = \{P(d/s)/P(d)\} * P(s)$$

P(s) is the proportion of fields falling within class s, and it is calculated starting with the MMS estimates of the numbers of undiscovered fields of each size class. This will be adjusted over time to account for depletion (and technological change). Note again, all fields within size class s are represented as an "average" field within the size class.

P(d/s) is assumed to be proportional to the amount of reserves within a field in that size category. This is based on the notion that a given large field is easier to discover than a given small field because the larger geological structure makes it easier to detect. So the first factor on the right hand side of this equation is proportional to q(s), the reserves in a field of class s. That is, the term P(d/s) can be written as:

Table III-23. Discovered Fields in 2003

Class	Oil Fields WD1	Oil Fields WD2	Oil Fields WD3	Oil Fields WD4	Oil Fields WD5	Oil Fields WD6	Oil Fields WD7	Gas Fields WD1	Gas Fields WD2	Gas Fields WD3	Gas Fields WD4	Gas Fields WD5	Gas Fields WD6	Gas Fields WD7	Total
1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	1
2	2	2	0	0	0	0	0	5	1	0	0	0	0	0	10
3	0	1	0	0	0	0	0	10	0	0	0	0	0	0	11
4	0	0	0	1	0	0	0	23	3	0	0	0	0	0	27
5	3	0	0	0	0	0	0	50	16	1	0	0	0	0	70
6	1	3	1	1	0	0	0	80	17	1	1	0	0	0	105
7	2	5	3	1	1	0	0	79	28	5	0	0	0	0	124
8	8	4	0	1	1	0	0	105	26	7	2	1	0	0	155
9	9	5	3	4	2	0	0	82	24	2	0	5	1	0	137
10	6	14	1	3	4	0	0	79	24	4	1	4	2	0	142
11	7	12	2	5	5	2	0	80	33	4	2	2	3	0	157
12	16	9	2	2	6	1	0	42	7	3	2	1	0	0	91
13	13	8	2	4	3	1	0	20	13	0	0	1	1	0	66
14	8	3	1	0	3	1	0	11	3	0	0	0	0	0	30
15	4	1	0	0	0	2	0	2	0	0	0	0	0	0	9
16	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1

Source: MMS

$$P(d/s) = q(s)*x$$

where x is an unknown proportionality factor. This allows us to write P(d/s) as:

$$P(s/d) = q(s)\ x * P(s).$$

Since P(s/d) must sum to one over field classes, we know:

$$\Sigma s\ P(s/d) = \Sigma s\ q(s)\ x * P(s) = 1$$

or

$$x = \frac{1}{\sum_s q(s)P(s)}$$

Therefore:

$$P(s/d) = \frac{q(s)}{\sum_s q(s)P(s)} P(s)$$

The denominator in this expression is constant overall all tracts within a time period, and is determined by the initial conditions on P(s), which obtained from MMS. The numerator of the first factor (q(s)) indicates that larger fields are more likely to be discovered in relation to their proportion of the population of tracts. The second factor (P(s)) indicates that larger fields are less common, and therefore less likely to be found. Calculating these probabilities is straightforward. We start with definitions for our size classes and associated reserves, q(s). Next we estimate the proportion of fields within each size class, P(s), which starts with the MMS distribution on field size.

III.A.2.f. Field Model

The field model is used to assess the profitability of each discovered field at t. Inputs to the field model include: field size (CLASS), water depth (WD), drilled depth (DD), field type (FTYPE), oil price (OPRICE), annual rate of price increase (PR), cost index (INDEX), exploratory dry hole rate (EDHR), discount rate (DR), royalty rate (ROYL), rental for water depth < 200 meters (RENTALS), rental for water depth ≥ 200 meters (RENTALD), annual rate of technological change in exploration (TCE), and annual rate of technological change in inputs (TC). The cost index is used to incorporate the effects of cost-saving technological change.

$$INDEX = (1-TC)^t$$

where TC is the annual rate of technological change in inputs

As part of the Area model, the field model is modified as follows. First, the net present value (ATNPV) is adjusted by the rental payment for the field. It is assumed that each field occupies one tract. The rental payment for the field is simply the payment for a 9 square mile (5,760 acre) tract. The total discounted sum of rental payment is calculated from the first year after the bonus payment to the year right before production (and royalty payment) starts. We subtract the rental payment from the ATNPV so that the adjusted ATNPV is lowered to reflect the effects of rental payment on the field's profitability.

In addition, the field model is modified to simulate sliding scale royalty rate. The fixed royalty rate, a scalar variable, is converted into a vector so that the royalty rate vector is a function of field production year (i.e., the number of years in production). Since we have fixed production paths the field model, the above specification is the same as a varying royalty rate with respect to cumulative production (or remaining resource reserves). With the modification, the Area model can simulate different sliding scale royalty rate for fields of different sizes and at different water depths.

The field model generates 14 outputs as shown in Table III-24. If a discovered field is not profitable (ATNPV ≤ 0), the field is not developed. All 14 output variables are set to zero.

III.A.2.g. Bidding Function and Bonus Payment

In the field-model calculation, the bonus payment is set to zero. Thus, a field's ATNPV does not include the effects of bonus payment. Bonus payments are calculated in the Area model separately. Again, assuming that each field occupies one tract, a firm's bid on a tract is

$$BID = \exp(3.516111 + 0.8049071*\ln(ATNPV) - 0.183409*\ln(TRACT) - 1.144289*AREAWIDE)$$

where BID is the bid in millions of dollars; ATNPV is the value of the field in millions of dollars; TRACT is the number of tracts offered; and AREAWIDE is the dummy for areawide leasing. The estimated BID is used in the Area model as VAR5 (BONUS) to calculate the areawide bid payment.

The number of bidders per tract (BIDDER) is estimated using the result from the statistical analyses, as discussed in Section III.C. The number of bidders on a tract is estimated as:

$$BIDDER = \exp(.9751+.0186*(ATNPV) -.0543 *(TRACT)),$$

where BIDDER is the number of bidders and TRACT is the total number of tracts in thousands offered for sale that year in the Central and Western Gulf of Mexico. Thus, we expect more bidders on higher valued tracts and fewer bidders per tract when more tracts are offered for sale. In order to ensure that the forecasts for number of bidders is reasonable for any scenario, we impose a constraint that $1 \leq BIDDER \leq 16$. We select 16 as a maximum number of bidders since this is largest number of bidders on any tract in our data set. Without such a constraint, it is conceivable that extreme scenarios could result in an unrealistic estimate for the number of bidders on individual tracts.

III.A.2.h. Rental Payment

At the regional level, we know that the number of tracts leased at each t, the total acreage subject to rental payment is calculated as the sum of total number of tracts lease over the last 5 years (using a lease term of 5 years), from t-5 to t-1.

Table III-24. Field Model Outputs

VAR1	TQO	Total quantity of oil produced
VAR2	TQG	Total quantity of gas produced
VAR3	TDQO	Total discounted quantity of oil
VAR4	TDQG	Total discounted quantity of gas
VAR5	BONUS	Bonus payment = 0
VAR6	ROTALTY	Royalty payment
VAR7	FTAX	Federal tax payment
VAR8	ATNPV	After-tax net present value
VAR9	NWW	Number of wildcat wells
VAR10	NDEL	Number of delineation wells
VAR11	NPW	Number of production wells
VAR12	NDH	Number of dry holes
VAR13	NIW	Number of injection wells
VAR14	PLAT	Number of platforms

The number of tracts leased by water depth is calculated as

$$\text{LEASEWD(t, wd) = LEASE(t)*WDSHARE(t, wd)}$$

For the lease term of 5 years, the total acreage subject to rental payment by water depth at t is

$$\mathrm{ACRE}(t, wd) = 5760 \sum_{t=t-5}^{t-1} \mathrm{LEASEWD}(t, wd)$$

Note that LEASEWD is in number of tracts. Typically, one tract is 9 square miles (= 5,760 acres). The rental payment (RENT) at t is

$$\mathrm{RENT}(t) = \mathrm{RENTALS} \sum_{wd=1}^{2} \mathrm{ACRE}(t, wd) + \mathrm{RENTALD} \sum_{wd=3}^{7} \mathrm{ACRE}(t, wd)$$

where RENTALS is the rental in \$/acre for water depth < 200 meters and RENTALD is the rental in \$/acre for water depth ≥ 200 meters.

III.A.2.i. Regional Effects of Leasing Policies

At regional level, the outputs from the field model (Table III-24) are summed across all newly discovered fields. The total value of each of the 14 output variables ($i = 1, 2, \ldots, 14$) at t is:

$$\mathrm{TVAR}_i(t, class, wd, type) = \mathrm{NN}(t, class, wd, type) * \mathrm{VAR}_i(t, class, wd, type)$$

The sum of each of the output variables over the planning horizon is:

$$\mathrm{ATVAR}_i = \sum_{t=1}^{50} \sum_{class=1}^{16} \sum_{wd=1}^{7} \sum_{type=1}^{2} \mathrm{TVAR}_i(t, class, wd, type) \qquad i = 1, 2, 9.$$

$$\mathrm{ATVAR}_i = \sum_{t=1}^{50} \sum_{class=1}^{16} \sum_{wd=1}^{7} \sum_{type=1}^{2} \frac{\mathrm{TVAR}_i(t, class, wd, type)}{(1+\mathrm{DR})^t} \qquad i = 3, 4, \ldots, 8.$$

$$\mathrm{ATVAR}_i = \sum_{t=1}^{50} \sum_{class=1}^{16} \sum_{wd=1}^{7} \sum_{type=1}^{2} \mathrm{TVAR}_i(t, class, wd, type)(1-\mathrm{TC})^t \qquad i = 10, 11, \ldots, 14.$$

The discounted total rental payment is

$$\mathrm{ARENT} \sum_{t=1}^{50} \frac{\mathrm{RENT}(t)}{(1+\mathrm{DR})^t}$$

In summary, our model generates 15 outputs as shown in Table III-25. ATAVR1 through ATVAR14 plus ARENT are used to assess the effects of different leasing policies.

Table III-25. Area Model Outputs

ATVAR1	TQO	Total quantity of oil produced
ATVAR2	TQG	Total quantity of gas produced
ATVAR3	TDQO	Total discounted quantity of oil
ATVAR4	TDQG	Total discounted quantity of gas
ATVAR5	BONUS	Bonus payment
ATVAR6	ROTALTY	Royalty payment
ATVAR7	FTAX	Federal tax payment
ATVAR8	ATNPV	After-tax net present value
ATVAR9	NWW	Number of wildcat wells
ATVAR10	NDEL	Number of delineation wells
ATVAR11	NPW	Number of production wells
ATVAR12	NDH	Number of dry holes
ATVAR13	NIW	Number of injection wells
ATVAR14	PLAT	Number of platforms
	ARENT	Rental payment

III.B. Auction Theory and Mechanism Design

This section briefly summarizes economic theory relevant to OCS auctions and presents some key results of theory as they relate to design of auction markets for OCS oil and gas leasing. As indicated above, the objective of this study is to assess various lease alternatives in terms of the goals of OCSLA and other considerations, using the criteria defined in Task 1. Where feasible, we quantify these criteria using the results from our analyses discussed below. However, in some instances the data are not adequate to allow us to quantify key criteria. In these cases we use qualitative results based on theory and judgment. This section describes auction and mechanism design theory which provides a basis for some qualitative judgments on advantages of different auction designs.

III.B.1. Background

The design of an auction mechanism can have important consequences for the market performance and the distribution of gains from trade. There is a well established body of economic theory that provides many important insights regarding market performance of various auction designs (e.g., Hurwitz, 1960; Wilson, 1977; Milgrom and Weber, 1982; McAfee and McMillan, 1987; Milgron, 1989; Krishna, 2001; Milgrom, 2004). This section draws upon the established results of game theory and mechanism design as applied to auctions. Game theory is used to analyze behavior in situations of strategic interaction among decision makers, and auctions are one of many situations where game theory has been extensively and profitably applied. Auction rules define a non-cooperative game, and mechanism design is a "meta-game" approach that studies how alternative sets of auction rules affect market performance. The mechanism design approach assesses alternative auction rules in terms of the desirability of the solutions that result from the games defined by those rules. Solutions can be compared to each other and/or relative to a theoretical optimum.

One important result of auction theory is the Revenue Equivalence Theorem (e.g., Milgrom, 2004), which states that, under a certain set of assumptions, the seller of an object can expect to obtain the same revenues from each of the standard auction designs: the ascending oral auctions (English), descending auctions (Dutch), first price sealed bid auctions, and 2nd price sealed bid auctions. Essentially, the revenue equivalence theorem states that under a set of strong assumptions, the auction design does not matter, since the same outcome occurs for any of the standard designs. However, the set of assumptions required for revenue equivalence are not satisfied in the case of OCS oil leasing. In particular, revenue equivalence requires (1) a single auction item, (2) independent private values, (3) risk neutrality by all bidders, (4) the number of bidders is exogenous, and (5) all prospective buyers are identical except for different private values held for the item being auctioned. None of these assumptions are likely to hold for OCS lease sales, and therefore theory states that auction design *does* matter in determining the outcome of the auction. Furthermore, OCS auctions are more complex than simple purchase of an item for a stated price. For example, the auction design includes factors such as area rental payments, royalty rates, etc, in addition to a cash bonus bid. Thus, for example, the revenue equivalence theorem does not apply to comparing auctions with different royalty rates, or with royalty bidding versus cash bonus bidding. In short, theory tells us that we should expect auction design will matter in both the efficiency and distributional aspects of OCS auctions, and therefore it may be highly productive to carefully analyze leasing alternatives.

OCSLA dictates a sealed bid auction (43 USC 1336, Sec. 8(a)1). Consequently, OCS bidding is a static game of incomplete information, termed a Bayesian game (e.g., Gibbons, 1992). Sealed bid auctions are static games, because when each auction participant selects their strategy, they do not observe the strategies adopted by the other participants. Therefore, the process can be viewed as though all bids occur simultaneously, which makes the game static. Auctions are games of incomplete information because players do not know the ultimate payoffs that result if they win the auction, nor do players know assessments held by other players, due to the many uncertainties affecting the present value of the tract at the time of the auction.

The solution to a static game of incomplete information is termed the Bayes-Nash equilibrium. This solution concept requires that each player select a strategy that is "rational"—a best response to the strategies of others, conditioned on the beliefs held by the player. In the context of a sealed bid auction, the strategy of a player is the bid submitted. Furthermore, the beliefs held by players are also required to be "rational" (e.g., Gibbons, 1992). In the auction context, beliefs held by players are their expectations of strategies selected by other players (bids), and their expectations of payoffs that would be received by the winning bidder.

In the mechanism design literature, a mechanism is a game that is defined in terms of (1) an environment, (2) a set of participants and (3) an institution. The environment defines the domain within which the game takes place. For example, in OCS oil and gas leasing, the environment includes elements such as the status of remaining offshore resources to be leased, the degree of uncertainty faced by participants, external supply/demand conditions, and the many other factors that define the context within which the auction process occurs. The participants are a set of oil companies that bid on the rights to explore for and extract offshore resources, and the U.S. Minerals Management Service, which serves as the principal in this game. The institution is the set of rules that govern how the auction market operates, such as the bid variable, the minimum bid, the structure of royalties, the time allowed for exploration prior to lease termination, etc. Below we discuss each of these elements of the game in the case of OCS leasing.

III.B.2. Environment and Participants

One of the principal conceptual elements defining the environment is the manner in which the value of the item being sold varies over auction participants, and the associated information held by participants. The polar cases in the economics literature are the independent private value environment and the pure common value environment. In an independent private value auction, each participant has their own value for the commodity being auctioned. It is generally assumed that participants know their own value with certainty, but values are unknown by other participants except for the statistical distribution from which the value is drawn. Examples of independent private value auctions are art or wine auctions, assuming that no resale market exists. One auction participants might love a particular piece of art or bottle of wine, while another might hate it. The polar case of the independent private value auction is an illustration of the adage "there's no accounting for taste".

The opposite polar case is the pure common value auction, where all prospective buyers have precisely the same value for the item being auctioned, but the value is assumed not known with certainty by any of the auction participants. However, each participant is assumed to have an estimate of value, which is termed a “signal”. In the polar case of the common value auction, signals are assumed to be independently drawn from an identical distribution.

The OCS oil and gas auction is often used as an example of a common value auction, since the value depends upon the resources contained in the tract and the costs of exploring for and extracting oil, which in turn depend upon the geological properties of the field (e.g., water depth, drilling depth, porosity, etc). These characteristics are the same for all participants, so the common value environment is often assumed to hold.

However, in practice, OCS auctions do not precisely fit the pure common value paradigm, nor do they fit the pure private value paradigm. In the case of OCS oil, values might differ across auction participants since some participants might have better access to advanced technologies for use in deeper water, while others might specialize in producing from fields in shallower water. Some companies might be more risk averse, and therefore have a relative preference for less risky prospects, while others might be less risk averse. At the time of a particular lease sale, some companies might be interested in increasing the share of offshore prospects in their portfolio of investments, while others might not. Thus, while OCS leasing might be thought of as a common value auction to a first approximation, there are also likely private value elements.

There is also an established body of economic theory for environments that have both private value and common value elements. In the common value auction, values across respondents are perfectly correlated—i.e., the “true” value of the item is exactly the same to all participants. In the independent private value auction, participants’ values are statistically independent. The affiliated value auction is the general case, where the correlation among values can be anywhere between 0 and 1 (e.g., Milgrom and Weber, 1982). Affiliated value auctions are appropriate for OCS leasing because, although tract values are generally highly correlated across participants, values are not exactly the same for all participants, as discussed above. Affiliated value auctions are the most complex type, and unfortunately less can be said about the results of an affiliated value auction than private value or common value auctions. Below we will use the general affiliated value paradigm, but we will make several reasonable, but perhaps somewhat limiting, assumptions that will allow us derive some key results for our study.

Another category of auction environment that has been studied is the “almost common value” auction (e.g., Klemperer, 1998), where all participants have the same value, except for one participant who has a higher value for the commodity. The almost common value auction might apply to OCS leasing when one participant owns a tract that is adjacent to the one being auctioned. In this case, the owner of the adjacent tract might have a cost advantage since there may be lower costs of joint development. For example, if a firm owns two adjacent tracts, it might coordinate drilling and servicing operations on the two tracts, and geological information obtained during exploratory drilling on one tract might provide information about the geologic structures in the adjacent tract.

Participants

The participants in the OCS leasing process are the U.S. Minerals Management Service, which administers leasing of the rights to explore for and develop OCS tracts, and the companies that bid for tracts. Participants of a larger game might also include coastal states, environmental and other interests, who may object to the sale of one or more tracts. But our formulations of participants will only include the seller and prospective buyers in the auction market.

In this Section we assume that prospective buyers of OCS leases maximize the expected utility of profit. To keep the problem manageable, this section simplifies the analysis by assessing strategies on a tract-by-tract basis, rather than employing a more complex model that develops a simultaneous bidding strategy for all tracts being auctioned in a lease sale. Thus, this Section primarily focuses on development of bid strategies in a single item auction, and we later briefly discuss the implications of the multi-item auctions. We also assume equilibrium bidding strategies that are strictly monotonic functions of value. That is, if the value (expected utility) of an item increases for a bidder, we assume the bid by that player will also increase. It has been proven that under fairly general conditions there exist equilibria where bid functions are monotonic in value (e.g., Krishna, 2001). At the same time, to the knowledge of the authors, the converse has not been proven: that there are no equilibria where bid functions are not monotonic functions of value.

For simplicity of exposition, we adopt a mean-variance approach, whereby expected utility of profit depends upon the expected value of profit and the variance of profit obtained from owning the rights to explore, develop and extract resources from the tract.

In most simple mechanism design formulations, participants are assumed to be identical. However, there are several ways that participants vary in the OCS leasing process that could be important for our analysis. First, companies differ by size, degree of risk aversion, and access to financing, which may have important implications for bidding due to concerns regarding cash flow and risk aversion. Larger companies may have more readily available access to cash, thereby facilitating the financing of upfront costs, and may be better able to spread risk across a larger number of investments. These factors could have important implications for companies that might want to finance large cash bonus bids, drill expensive wells on ultra-deep tracts, or make tradeoffs between up-front cash bonus bids versus royalties which accrue with production. Auction designs that imply higher upfront costs might be relatively more disadvantageous to companies with less ready access to capital and to companies that are more risk averse, and thus may affect the degree of competition in the auction market.

MMS designs the rules under which OCS auctions occur, subject to limitations set forth by the OCSLA. Thus, the auction market can be thought of as a principal-agent game, whereby MMS plays the role as principal to design a mechanism to achieve the objectives defined by OCSLA. As discussed above, the primary goal of this study is to identify the extent to which different auction designs achieve the various OCSLA objectives, as measured by the set of Goals and Criteria outlined in Task 1 (Chapter II). No single auction mechanism can be expected to be best at achieving of all goals, so tradeoffs must be made. Our analysis makes no attempt to balance or to weigh the different goals, but rather views the goals as a series of indicators of desirability of alternative auction mechanisms. For example, one auction design might be expected to result is more timely development of OCS resources, while another might be better suited to obtain fair market value for the resources leased. Still another design might better balance the costs and benefits of OCS development to the coastal states. These are viewed as separate indicators, and no attempt is made in this analysis to aggregate these into a single measure of auction market performance.

Institutions

Mechanism design theory studies how market performance is affected by the form of the institution — that is, the specific set of rules governing transactions. For purposes of the present study, the design of the institution is the set of rules that govern auctions for OCS leasing. Alternative auction rules include such elements as the bid variable (e.g., cash bonus bid versus royalty bid), minimum allowable bid, royalty (percentage of a fixed royalty, or a sliding scale royalty), length of the initial lease period, etc. As indicated above, mechanism design theory is key to our analyses, since our goal is to assess alternative designs for leasing systems, which is precisely the goal of mechanism design theory.

The auction design parameters we evaluate include (1) reducing the number of tracts offered for sale each year, (2) increasing or decreasing the fixed royalty rate, (3) a sliding scale royalty, (4) profit share, (5) increasing the area rental rate, (6) work commitment, (7) shortening the lease term, (8) increasing the minimum bid, and (9) a multi-round auction structure. In general, it is not possible to "solve" for optimal strategies and the associated Bayes-Nash equilibrium for a complex auction design that defines a complete set of rules governing all auction parameters especially within the context of the complex affiliated value auctions. However, it is possible to do some limited comparative static results. For example, theory can be used to derive the well known result that increasing the royalty rate reduces resources extracted from a given field, since higher royalties decrease the marginal profitability of extracting oil, thus hastening the time at which fields are no longer economically viable. At a low royalty rate, it might be profitable for a firm to use secondary recovery techniques on a particular field, while at a higher royalty rate it might not be profitable.

Thus, while we cannot use theory to compare the outcomes of complex combinations of sets of rules, theory can provide some guidance on the implications of varying a single rule (e.g., increasing the royalty rate) on a particular Criteria (e.g., resources extracted). This section focuses on these qualitative and comparative results of varying one element of the auction design. Quantitative assessments of simultaneously changing multiple rules are done with our simulation model, and are described in Chapter IV below. It is also not generally possible to identify a single auction design that weakly dominates all others in terms of the full set of goals defined by OCSLA. For example, one mechanism might lead to the most expeditious development of OCS oil and gas resources, but might not be most effective in obtaining "fair market value" for extraction of publicly owned resources. Thus, we necessarily face tradeoffs among goals. As indicated above, this study will make no attempt to balance the different goals, but rather will simply report the extent to which alternative designs are fulfill the various goals.

For the most part, theory can be relied upon for qualitative, not quantitative, assessments of the metrics. For example, theory might conclude that increasing the minimum bid might reduce the number of tracts bid upon, the number of bids per tract and the number of tracts sold, while simultaneously increasing revenue per tract sold. Theory might also be used to conclude that a high royalty rate could have a distortionary effect on time of field closure. But theory cannot be used to quantify these effects. Rather, our econometric methods and simulation model, described below, will be relied upon to carry out these tasks. A second role of economic theory is to provide guidance on the appropriate specification of econometric models, such as the appropriate form and variables to include in the so-called bid function.

The efficient design of an auction mechanism for leasing offshore oil must consider both *ex ante* incentives for acquisition of information prior to the lease sale through exploration, as well as the *ex post* allocation of tracts among auction participants. A key result of the mechanism design literature is that it is not feasible to design an auction which provides both efficient incentives to acquire an efficient amount of information *ex ante*, and an efficient allocation of auctioned items conditioned on private information *ex post*. (Bergemann and Valimaki, 2002).

The literature differentiates between optimal and efficient auction designs (e.g., Krishna and Perry, 1997). An auction design is said to be "optimal" if it maximizes expected payment by the auction participants, thereby maximizing expected revenues to the seller. An auction design is said to be "efficient" if it maximizes total expected returns to the seller and buyers.

Payoffs

This section discusses the payoffs to players in the game, as formulated above. We assume that firms bidding for OCS oil attempt to maximize expected utility of profit, and we use a mean-variance formulation for expected utility. Bidders are assumed to be risk averse, which implies a negative coefficient on the variance of profit. But the degree of risk aversion is allowed to vary across bidders. For simplicity of exposition, we assume that only resources contained in the tract, R, are uncertain at the time of the bid, but this model generalizes to a case where R is a vector of uncertain variables. Payoffs are defined in terms of the expected utility of profit, which can be expressed as:

$$\mathrm{EU}(\pi) = \int_0^{\bar{\mathrm{R}}} \mathrm{U}(\pi(\mathrm{R}))\,\mathrm{P}(\mathrm{R})\,d\mathrm{R}$$

where $\pi(R)$ is the present value of profits conditioned on the true size of the resources contained in a tract and P(R) is probability density function of resources in a given tract and $\bar{R}$ is upper limit on possible resources in the tract.

The present value of profits conditioned on the level of reserves is:

$$\pi(\mathrm{R}) = \int_0^{\mathrm{T}} \left[(1-\theta)\mathrm{p(t)} * \mathrm{e(t)} - \mathrm{c(t)}\right] e^{-\mathrm{rt}} d\mathrm{t} - \mathrm{CB}$$

where T is the time when economic resources are depleted and extraction ceases, θ is the royalty rate, p(t) is the price of resource at time t, e(t) is the extracted resources at time t, c(t) is the cost at time t, including exploration, development and production costs and CB is the cash bonus bid. This expression can be rewritten as:

$$= (1-\theta)\mathrm{Rev} - \mathrm{Cost} - \mathrm{CB}$$

where Rev is the present value of revenues, Cost is the present value of cost and CB is the cash bonus bid. Viewed *ex ante*, at the time of the bid, the future time paths for both prices and extraction rates are uncertain, and hence the present value of revenue is uncertain. Costs are also uncertain, but the cash bonus bid is known.

From this equation, it immediately follows that increasing the royalty rate reduces the expected value of the tract, so that the royalty, in effect, becomes capitalized into the value of the tract. Under the monotonicity assumption above, this decrease in the value of a tract to the bidders results in a downward shift in the bidding strategy for each auction participant.

Thus, our first result of theory is that there is a tradeoff between royalty rates and cash bonus bids: higher royalty rates reduce tract values, and under a monotonic bidding strategy this will reduce cash bonus bids. Thus, while the Revenue Equivalence Theorem does not apply to OCS auctions, there is a tendency for revenues to become equalized. Increasing one fee (e.g., royalty rate or area rental) will tend to reduce the net present value of tracts, thereby making the auction items less attractive to bidders, and potentially reducing cash bonus bids. Conversely, reducing fees will increase the value of tracts, thereby making auction items more attractive to bidders, potentially increasing bids. This effect will tend to moderate differences in expected revenues across different policies, although there is no reason to believe it will lead to identical revenues. Below we discuss some theoretical reasons to believe that, although moderated, differences in expected revenues are likely to persist across different lease policies.

III.B.3. Some Key Results

Next we apply the mean-variance approach, where expected utility of profit depends upon the mean and variance of the present value of profits. For purposes of this discussion, we assume that the production, revenues and costs associated with each tract do not change under varying royalty rates. We address this issue below in our discussion of field closure.

In the case with a royalty and no cash bonus bid, expected utility of profit is:

$$EU(\pi) = \alpha E(\pi) + \beta \text{ Var } (\pi) = E\{(1\text{-}\theta)\text{Rev-Cost}\} + \beta \text{ Var}\{(1\text{-}\theta)\text{Rev} - \text{Cost}\}$$

$$= E(\text{Rev-Cost}) - \theta\ (E(\text{Rev})) + \beta\ (1\text{-}\theta)^2 \text{ Var (Rev)} + \text{Var (Cost)} - 2(1\text{-}\theta)\text{Cov(Rev, Cost)}$$

In the case with a cash bonus bid, and no royalty, expected utility of profit is:

$$EU(\pi) = \alpha E(\pi) + \beta \text{ Var } (\pi) = E\{\text{Rev-Cost}\} + \beta \text{ Var}\{\text{Rev} - \text{Cost}\}$$

$$= E(\text{Rev-Cost}) + \beta \text{ Var (Rev)} + \text{Var (Cost)} - 2\text{Cov(Rev-Cost)} - \text{CB}$$

where CB is the cash bonus bid. Next, we equate expected utility of profits in these two cases to define an indifference surface between royalty payments and cash bonus bids.

$$E(\text{Rev-Cost}) - \theta\ (E(\text{Rev})) + \beta\ (1\text{-}\ \theta)^2 \text{ Var (Rev)} + \text{Var (Cost)} - 2(1\text{-}\ \theta)\text{Cov(Rev-Cost)} =$$

$$= E(\text{Rev-Cost}) + \beta \text{ Var (Rev)} + \text{Var (Cost)} - 2\text{Cov(Rev,Cost)} - \text{CB}$$

Solving for the difference between expected royalty payment and the cash bonus bid:

$$\theta(E(\text{Rev}))\ - \text{CB} = -\ \beta\ (1\text{-}\theta)^2 \text{ Var(Rev)} + \theta \text{ Cov(Rev, Cost)}$$

The left hand side of this expression is the difference in the expected revenue and cash bonus bid, when the firm is indifferent between the two. This expression is positive because β is negative for risk averse firms and the covariance between revenue and cost is positive, since firms will spend more to develop valuable tracts. Therefore, this expression shows that a firm would be indifferent between a cash bonus bid and a royalty whose expected value is great than the cash bonus bid by an amount depending upon the variance of revenue and the covariance between costs and revenues. That is, a risk averse firm ($\beta<0$) will prefer to make an equal expected payment through a royalty than a cash bonus bid. The more risk averse the firm, the greater the "discount" it would apply if it were to pay through an *ex ante* cash bonus bid rather than an *ex post* royalty. This result is consistent with prior expectations, because the cash bonus bid is paid irrespective of whether, or how much, resource is ultimately extracted. In comparison, the royalty payment is only made if profitable resources are extracted, and the size of the royalty payment is dependent on the value of the resources that are ultimately extracted. Thus, cash bonus bids embody more risk than royalties, and a risk averse firm will prefer to make a given payment through a royalty rather than make a payment of the same expected discounted value through a cash bonus bid.

The second result of theory is that, given payments of a given expected value, risk averse firms will prefer that payments are based on royalties, rather than cash bonus bids. This is related to the notion of risk sharing under cash bonus bids versus royalties. Under a system of cash bonus bids, payments are made irrespective of the ultimate profitability of a tract. Given the considerable uncertainties regarding tract values, this implies a significant risk borne by the firm. In contrast, under a system of royalties, payments are proportional to revenues received, so that the degree of payment made depends upon the value of the resources extracted. Thus, under a cash bonus bid system, the bidders bear more of the risk, while the government bears more risk under a system of royalty payments.

This also has important implications for the number of participants in an auction for a particular tract, and therefore the number of tracts that would receive positive bids. Under a system with identical expected payment but where risk averse firms bear less risk, bids could be higher and more firms would be willing to submit bids for a tract. Thus, theory suggests that a lease policy that depends more on royalty rates and less on cash bonus bids would attract more auction participants, and therefore promote competition.

Profit Share

The above analysis can be applied to profit share. In this case, present value of profits can be expressed as:

$$\pi(\mathrm{R}) = \int_0^T \left[(1-\varphi)(\mathrm{p(t)} * \mathrm{e(t)} - \mathrm{c(t)})\right] e^{-rt} dt - \mathrm{CB}$$

where φ is the profit share. Next we compare expected utility of profits under a pure profit share approach, as compared to a cash bonus bid by equating expected utility of profits, again applying the mean variance approach:

$$\mathrm{EU}(\pi^{PS}) = \mathrm{E}\{(1-\varphi)(\mathrm{Rev}-\mathrm{Cost})\} + \beta\ \mathrm{Var}\{(1-\varphi)(\mathrm{Rev}-\mathrm{Cost})\}$$

$$= E(Rev\text{-}Cost) - \varphi\,(E(Rev\text{-}Cost)) + \beta\,(1-\varphi)^2\,Var\,(Rev\text{-}Cost) =$$

$$E(Rev\text{-}Cost) + \beta\,Var\,(Rev\text{-}Cost) - CB = EU\,(\pi^{CB})$$

This can be rewritten as:

$$\varphi\,(E(Rev\text{-}Cost)) - CB = -\beta\,\varphi(1-\varphi)\,Var\,(Rev\text{-}Cost)$$

The left hand side is the difference between the expected profit share minus the cash bonus bid that gives the identical expected utility of profits. The right hand side is a measure of the risk premium, which is positive. This implies that the expected value of the profit share is greater than the cash bonus that results in the same expected utility. Thus, since the firm faces a higher risk with up front payment of the cash bonus bid, relative to a profit share of the same expected value, a risk averse firm would prefer to the profit share approach.

Again invoking our monotonicity assumption, one might again expect an auction market that depends purely on a profit share to result in higher expected revenue than an auction market than one that depends on a cash bonus approach. Risk averse firms can obtain an identical expected utility of profit by paying a profit share with a higher expected value than the cash bonus bid, and therefore we find a qualitatively similar result as was discussed above for royalties.

Field Closure

We can also define the discounted value of revenues and cost starting at some point in time, t, until shutdown time. A company will choose to close down a field when the present value of future costs (including decommissioning costs) exceeds the present value of future profits. With a royalty based approach, the present value of future revenues is reduced by the royalty payment. However, the cash bonus bid is a sunk cost that does not affect the present value of future revenues. Thus, the royalty may lead to early shutdown of fields, while the cash bonus will be viewed as a sunk cost, and will not lead to early shutdown. This means that for tracts that would sell both under a cash bonus and royalty approach, greater production can be expected from an auction mechanism that depends more on cash bonus bids and less on royalties.

However, a cash bonus system with a minimum bid will lead to profitable tracts not being bid upon. In addition, the risk associated with cash bonus bids implies that a tract will look more unprofitable for the firm than would happen under a royalty based system with an equal expected payment. For example, suppose firms compare the case of a cash bonus system with a minimum bid of CB_{min}, and a royalty that results in the identical expected discounted revenue. In this case, the expected utility of profit under the royalty system is greater than expected utility of profit from the cash bonus system. The cash bonus is *not* a sunk cost *ex ante*, prior to bidding, and for some set of marginal tracts, firm will hold a positive expected utility of profit the tract under the royalty system, but a negative expected utility of profits from the cash bonus system. Thus, the royalty system will lead to some tracts being developed that would not otherwise be, but will also lead to early shutdown of fields, while the cash bonus will not. However, this may not be an important issue in practice, since MMS has the right to reduce or eliminate royalties in cases where they would lead to premature field closure (43 USC 1336, Sec. 8(a)(3)(A)). This also increases the expected value of the tract (while reducing expected government revenues) under the royalty-base approach, since the firm will anticipate that royalties will be excused once the tract would otherwise become unprofitable.

The profit share has the best theoretical properties among the options mentioned above. In an idealized situation, profit shares do not cause an otherwise profitable field to become unprofitable, thereby avoiding distortionary effects. Profit share reduces the variance of returns, thus encouraging participation by risk averse firms and increasing competition. However, there may be important practical problems with the profit share approach, since it is difficult for the government agency to measure and verify profits by the firm. Profits should also be calculated after taking into account the opportunity cost of capital, which is the potential return received by using that capital elsewhere. Therefore, it can be difficult or impossible for the government to confirm the claim regarding payments. In the mechanism design literature, these problems are referred to as imperfect monitoring.

Sliding scale royalty.

Above we discuss effects of a fixed royalty rate, and we identify two potential problems. First, potentially profitable fields might be unprofitable due the royalty payments. In particular, small fields or moderately sized fields in very deep waters could become economically infeasible due to royalty payments. Second, royalty payments might make secondary recovery unprofitable, so that firms might choose to shut down fields early while socially profitable resources remain. Thus, royalties might have an advantage of making highly risk averse firms more competitive by reducing risk compared to large upfront cash bonus payments,. At the same time, royalties will distort incentives thereby reducing production, and potentially reducing overall social returns. Here we briefly outline the potential for a sliding scale royalty to address some of these issues.

A sliding scale royalty could be used to reduce risk and obtain a larger share of returns from highly profitable finds, while reducing the distortionary effects of a fixed royalty rate. Such a royalty might start at a low level, increase as production increases and then decrease as depletion becomes a factor. Low early royalties could be used to provide an opportunity for firms to recover investment pre-production costs such as cash bonus bids, and costs associated with exploration and development. Thus, starting royalty payments at a low level has the advantage of reducing the tendency for royalties to cause smaller fields to be unprofitable to develop. Increasing royalties with production has the advantage of capturing rents from larger fields that are profitable even with royalty payments. Reducing royalties as field depletion becomes a factor reduces incentives for early field closure.

Thus, in theory, a sliding scale royalty payment can be designed to minimize distortionary effects, while capturing excess profits. However, designing an ideal sliding scale royalty requires a large amount of information about the costs of developing each individual field. Furthermore, the ideal sliding scale royalty needs to be designed specifically for the characteristics of each individual field, which is simply not practical. Thus, one can attempt to design one, or a small number of sliding scale royalties that depend upon critical characteristics of the field (e.g., water depth). Such a sliding scale royalty may be appropriate for a subset of fields, but may have little or no advantage over fixed royalties for other fields. Indeed, a "one-size-fits-all" sliding scale royalty will have disadvantages compared to a fixed royalty for at least some fields. Thus, while a sliding scale royalty could ideally have very good properties, in practice the advantages of a sliding scale royalty are likely to be of much less significance.

There are alternative approaches to correcting the adverse effects of fixed royalty rates. For example, the distortionary effect of royalties on early field closure could be address using the Secretary of Interior's discretion to reduce or eliminate royalties in order to preclude early shutdown (OCSLA § 8(a)(3)(A)).

III.B.4. Summary

This Section briefly summarizes some key elements of the very extensive theoretical literature on auctions, and summarizes some key results. One of the key results of the auction literature is the Revenue Equivalence Theorem, which roughly says that under a restrictive set of conditions, all "standard" auction designs results in identical outcomes. When the Revenue Equivalence Theorem is applicable, the selection among different "standard" auction designs is irrelevant. However, the Revenue Equivalence Theorem is not relevant for OCS auctions, since the highly restrictive conditions for Revenue Equivalence do not apply.

While the Revenue Equivalence Theorem does not strictly hold for the various OCS leasing policies, we find that there is a tendency for revenue differences to be moderated across different leasing policies. For example, theory suggests that changes in various fees, in effect, becomes capitalized into the value of tracts, and thereby affects the amount that firms are willing to bid for those tracts. Theory suggests that increasing the royalty rate or the area rental fee will decrease the expected value of tracts to bidders, thereby potentially reducing cash bonus bids. Conversely, decreasing various fees will tend to increase bids. As a result, differences in revenues across different leasing policies are likely to be smaller than one might initially expect.

While the above effect will moderate differences across policies, one might not expect revenues to be identical across different policies. For example, cash bonus bids are paid upfront, irrespective of the ultimate value of the tract. In comparison, royalties or profit share are only paid if a tract results in a successful find, and associated production. Therefore, the policies have potentially important implications for risk sharing. Firms bear more risk under a policy based on a pure cash bonus bid, while the government bears more risk when payments are based on royalties or profit shares. It is generally assumed that the US government is less risk averse than private firms, since the government can spread risk over a broader portfolio of activities. If this is the case, policies that reduce risk faced by firms may provide higher expected payments, and could result in firms that are more risk averse becoming more competitive in the OCS leasing process. Thus, one might expect higher revenues and more competition when leasing policies are used that result in firms bearing less risk.

At the same time, some policies such as royalty payments create distortionary effects by making socially valuable fields unprofitable, and by creating incentives for early closure of fields, for example, by making secondary recovery unprofitable. In theory, sliding scale royalty rates can be designed to moderate these effects. But an effective sliding scale royalty must be customized to the properties of each field, which is not practical. As an alternative, more *ad hoc* approaches can be implemented to reduce adverse incentives, such as the capacity provided by OCSLA for the Secretary of Interior to "reduce or eliminate" royalties in order to promote increased production.

III.C. Statistical Estimation

Statistical analysis is used to estimate four key equations for the simulation model: the rate of change in tracts offered for sale in the Central and Western Gulf of Mexico, the aggregate annual number of tracts sold in the two areas, the number of bids received on individual tracts and the high bids received on tracts.

These four equations allow us to forecast future numbers of tracts sold, number of bidders on tracts and bids received under different lease alternatives. The number of tracts sold is then used in the Simulation model to simulate exploration, new field discoveries, values of fields etc. This output is linked back to the statistical relationships to forecast number of bids received and the high bid on each tract.

Because our primary goal is forecasting, two key requirements of the statistical models are to generate predicted values that are consistent with historic observations, and to generate forecasts are reasonable for a wide range of policy variables (e.g., number of tracts offered for sale) and market factors (e.g., oil prices). And these forecasts must be reasonable even for scenarios extrapolate beyond historic ranges for the input variables (e.g., for oil prices that are higher than historic levels). Even the most advanced and rigorous theoretical model results would be of little use for our analyses if the resultant forecasts were not credible when applied to a wide range of values for the policy variables and other key parameters (e.g., oil prices, etc.).

Our exploratory statistical analyses found that simpler, reduced form models provided the most stable and reasonable forecasts, especially when applied to a wide range of input values. Thus, we adopt simpler, reduced form models. Below we discuss the four key equations estimated with our statistical models.

III.C.1. Tracts Offered

Our model is used for forecast lease sale scenarios extending over a fifty year time horizon. We adopt an assumption that the number of tracts offered for sale will decline over the 50 year time horizon in order to ensure that selected scenarios are reasonable. For example, since the advent of Areawide leasing, an average of roughly 12 thousand tracts have been offered for sale per year (e.g., MMS, 2009). The average annual number of tracts offered for sale in the Central and Western Gulf of Mexico has declined from just under 11 thousand tracts per year over the period 1983-1989, to under 10 thousand tracts in 1990-1999 to fewer than 8,500 tracts per year in 2000-2008.

We use this data to specify a forecast for the number of tracts offered for sale that is consistent with this historic decline rate. We regress the log of tracts offered for sale on a constant terma and a time trend to estimate the percentage rate of change in historic lease offerings. In this regression, we adopt data on total lease offerings since the advent of Areawide leasing, from 1983 to 2008, and regress the log of tracts offered on a time trend variable and a constant term. The results are presented in Table III-26.

Table III-26. Regression for Time Trend on Number of Tracts Offered

Dependent Variable: Log Tracts Offered (1983 – 2007)

Independent Variables	Coefficient Estimate	Standard Error	t-Statistic
Time	-0.0156	.00244	-6.39
Constant	40.34	4.873	8.28

R^2= 0.62

As can be seen, the regression coefficient on the time trend is 0.0156, which implies an annual decrease of in the number of tracts offered of about 1.56% per year. For example, when applied to our base scenario of 8,000 tracts per year offered for sale at the beginning of our time horizon, the simulated number of tracts offered per year will decline to about 3,700 tracts offered at the end of the 50 year time horizon, and an average annual number of tracts offered of 5,598. In order to make the result more comparable, we adopt this same percentage decline in tracts offered for sale in the alternative policies that slow the pace of leasing.

III.C.2. Tracts Sold

We model the number of tracts sold each year in the GOM as a function of the number of tracts offered for sale, and state economic conditions, represented by the oil price, net of the royalty rate paid. We use MMS summary data from all lease sales data over the history of the Gulf of Mexico (MMS, 2009). We extract data for all lease sales in the Central and Western Gulf of Mexico, and aggregate to the annual level. Thus, we work with the annual number of leases offered for sale in the Central and Western Gulf of Mexico, the annual number of tracts sold, etc.

We then carry out a statistical analysis that uses a double log model to regress the log of the annual number tracts sold on the log of the number of tracts that are offered for sale, the log of real net price of oil and a dummy variable indicating whether the sale occurred prior to, or following 1983, the year when Areawide leasing policy was adopted. The pre-1983 dummy is especially important since, not only did leasing policy change in 1983, but also the method of analysis changed. Prior to 1983, MMS carried out value assessments for all tracts. However, since 1983, value assessments were only carried out for tracts that received at least one bid, which complicates interpretation of the coefficient on the pre-1983 dummy variable.

Net price refers to the price net of the royalty payments, so net price = (1-royalty rate)*price. One would expect more tracts to be sold when more tracts are offered for sale, and with higher oil prices, net of royalty payment. Thus, we expect positive coefficients on both number of tracts offered and net price.

The regression results are shown in Table III-27 below. As can be seen in the table, the number of tracks offered and the pre-1983 dummy variable are positive and statistically significant at a high level of confidence. Net price of oil is also positive, and is statistically significant at about the 11% confidence level.

III.C.3. Bids per Tract

The number of bids on a tract is modeled as a function of the value of the tract, the number of tracts offered for sale and whether sale offering occurred prior to or after 1983. Higher valued tracts would be expected to attract more bids than lower valued tracts. When more tracts are offered, one would expect fewer bids per tract since bids will be allocated across a large number of tracts.

Table III-27. Regression Results for Number of Tracts Sold in Central and Western Gulf of Mexico

Dependent Variable: Log Tracts Sold (1954 – 2008)

Independent Variables	Coefficient Estimate	Standard Error	t-Statistic
Log Tracts Offered	0.706	.108	6.54
Log Net Oil Price	0.273	.168	1.63
Pre-1983	0.903	.428	-2.11
Constant	0.158	.660	0.24

$R^2 = 0.82$

Two key econometric issues arise in this equation. First, the number of bids on a particular tract is an integer, therefore a count data model is required. Secondly, since 1983 MMS has not carried out tract assessments for tracts that receive no bids, so we only have data on estimated tract values for tracts where at least one bid is submitted. Therefore, we need use a method that accounts for this data censoring problem.

For these reasons, we applied the zero-truncated Poisson regression model (see, for example, Greene, 2007). The results are shown in Table III-28. As can be seen in the Table, the coefficients are all of the expected sign. The coefficients are also statistically significant at a high level of confidence, except for the coefficient on number of tracts offered, which is significant at the 12% confidence level.

It is interesting to note that the R^2 in this equation is fairly low, and much lower than the R^2 for the other three equations discussed in this Section. This indicates that it is difficult for these models to explain differences in the numbers of bids received on tracts, so that forecast of numbers of bids will not differ very much, as compared to actual numbers of bids. This simply implies that it is difficult to predict the number of bids received on tracts, due to the uncertainties involved.

The expected value in the Poisson regression model is simply a linear function of the variables. Therefore the marginal effect of the change in a variable is simply the coefficient on that variable. So the estimated coefficient provides an estimate of the predicted change in the number of bidders that would result if a policy resulted in a change in a variable of one unit. In our context, if the royalty rate changed such that the value of a tract changed by $1 million, the resultant change in the expected number of bidders would be 0.02. Similarly, if the number of tracts offered for sale were to increase by 1,000, the predicted change in the number of bidders is -.018. These small marginal effects reflect the small R^2 for this equation. That is, it is simply difficult to predict the number of bidders on particular tracts.

III.C.4. High Bid

The final regression equation is used to forecast the high bids on tracts as a function of the lease alternatives. We regress the log of the high bid on the log of tract value, the number of tracts offered for sale, and a dummy variable indicating whether the lease sale occurs before or after 1983. The regression results are shown in Table III-29. As can be seen, the coefficients are of the expected sign and statistically significant better than a 2.5% confidence level.

In summary, the four estimated equations discussed above are used to specify key relationships in the Simulation model. Given a lease policy scenario, these equations determine: the timeline for the number of tracts offered for sale, the number of tracts sold, the number of bids on each tract and the high bid. The policy scenarios (e.g., the pace of leasing) and the results of the simulation model determine the values of explanatory variables for these equations. For example, a leasing policy that slows the pace of leasing reduces the number of tracts offered, thereby reducing the number of tracts sold through the second key equation discussed above. A policy that increases royalty rates will reduce the net price (price net of royalty) and the values of tracts, and the estimated equations above determine the resultant affect on the number of tracts sold, the number bidders on tracts and the high bids on tracts.

Table III-28. Zero-Truncated Poisson Regression Results for Number of Bids on Individual Tracts

Dependent Variable: Number of Bids (1978 - 2008)

Independent Variables	**Coefficient Estimate**	**Standard Error**	**t-Statistic**
Tract Value	.020	.0011	18.18
Number of Tracts Offered (000)	-.018	.0116	-1.55
Pre-1983	.882	.123	7.17
Constant	.914	.023	39.74

$R^2 = 0.13$

Table III-29. Regression Results for High Bids on Individual Tracts

Dependent Variable: Log High Bid

Independent Variables	Coefficient Estimate	Standard Error	t-Statistic
Log Tract Value	.805	.0077	104.55
Log Number of Tracts Offered	-.183	.0808	-2.26
Pre-1983	1.144	.2831	4.04
Constant	3.516	.4715	7.46

$R^2 = 0.514$

III.D. Laboratory Experiments

While theory and statistical estimation provide important guidance on bidding behavior and the properties of simple auction institutions, they are not sufficient tools for the design of sophisticated auctions for specific applications. We augment economic theory and desk analyses with the use of controlled laboratory experiments of bidding behavior. Our primary focus in the experiments is assessment of an ascending simultaneous multi-round (MR) auction institution that has been used to sell electromagnetic spectrum rights in the United States and around the world, but has not been used in oil lease sales. This auction is evaluated in a high competitiveness and a low competitiveness environment, which can also provide insight into the merits of Areawide versus more limited sales (through administration or nomination).

III.D.1. The Role of Experiments

This project draws on a number of sources to make inferences and predictions about the likely effect of alternative processes for leasing access to public oil resources. First, we draw on economic (game) theory to provide guidance about the effects of possible institutions. However, theory yields only predictions—hypotheses to be tested—and experience suggests that there are significant theoretical predictions that are not behaviorally accurate. Perhaps the best-known example is the failure of the revenue equivalence theorem among first price and Dutch auctions, and among second price and English auctions. While theory indicates they should yield the same selling price, in fact English first price sealed bid auctions raise significantly more than other institutions (e.g., Cox, Smith and Walker 1985; Coppinger, Smith and Titus 1988). Second, integrating all of the features of the OCS into a single theory is intractable at the present state-of¬-the-art. Third, economic theory is by its nature extremely reductive, and often-important, practical details of the auction are not discovered during even the most careful theoretical exercise.

Similarly, results from statistical estimation in complex auction environments provide information that is essential to the design of effective auction markets. However, estimating structural equations using auction data is extremely difficult due to factors such as (1) the endogenous nature of many of the key variables (e.g., Laffont and Vuong, 1996; Porter, 1995), (2) incentives for auction participants to use strategic behavior to mislead competitors, (3) the thick tailed and skewed distributions of resources and bids (e.g., Uhler and Bradley, 1970; Smiley, 1979; Opaluch and Grigalunas, 1984), (4) the many key variables that are unobservable, such as ex ante expectations of tract value (e.g., Porter, 1995) and (5) an absence of recent experience—or in some cases, any experience—with many of the leasing alternatives that might be considered. Together, these complications imply that, while valuable lessons can be gleaned from econometric data, it is not possible to use historic auction data to estimate the full suite of effects of the various auction structures that need to be considered.

To address these shortcomings, we use human subjects to play the role of OCS bidders, facing the set of incentives and constraints based on those faced by actual bidders, bidding within alternative auction institutions. This technique was recognized when Vernon Smith was awarded the 2002 Nobel Prize in Economics "for having established laboratory experiments as a tool in empirical economic analysis, especially in the study of alternative market mechanisms." Laboratory experiments have been used in a number of closely-related, high-profile, high-value applications, including the auction NASA uses to determine space shuttle payload priorities (Ledyard, Porter and Wessen, 2000) and the auction the FCC has used to raise more than ten billion dollars selling licenses to bandwidth used by cellular telephones (Banks et al. 2003; Salant 2000; Plott 1997). Policy-oriented experiments have focused on developing and refining markets and auctions, including comparing auctions for fishing rights (Anderson and Holland 2006), and refining water allowance trading (e.g., Murphy et al. 2000; Murphy et al. 2003; Cummings, Holt and Laury 2004), tradable pollution permits (Franciosi et al. 1993) and fishing access (Anderson 2004; Anderson and Sutinen 2005, 2006) (see Shogren and Hurley 1999 for a survey). Specific cases include the market mechanism for trading sulfur dioxide and nitrous oxide in southern California (Ishikida et al. 2000; Carlson et. al. 1993) and that used by the Environmental Protection Agency (EPA) to trade pollution permits for sulfur dioxide under the Clean Air Act (Cason 1995; Cason and Plott 1996). In the latter case, the EPA implemented a discriminative auction for trading permits in which buyers and sellers each submit sealed bids and low-asking sellers are matched with high-bidding buyers; buyers pay their bid price to their matched sellers. Experiments demonstrated that this institution's incentives led sellers to underreport the true costs of emissions control in hopes of being matched with lower-bidding buyers, leading to inefficient trades. These experimental results led to a change in the auction design; investing in laboratory testbed research before implementing an allowance-trading system can improve initial outcomes. Cox, Isaac and Smith (1983) argue experiments should be used to evaluate OCS auction rules, but perhaps because the rules have not been reconsidered since then, no OCS-specific experiments have been published.

Economic experiments are effective because they are distinguished from other laboratory social science by incentives that depend on the participants' performance (Smith 1976; Davis and Holt 1993). Participants are told how to earn money, and those who make better decisions are paid more, in cash at the end of the simulation, for their participation. This feature is crucial to the external validity of the experiments. It is axiomatic in economics that people make decisions that maximize their utility, and since money earned in the laboratory can be used to increase utility outside the lab, participants will make decisions during the simulation that earn them the most money. If the incentives of the economic environment being simulated have been properly represented in the experiment, then subjects acting to maximize their laboratory earnings will make the same decisions as agents trying to maximize their utilities in the natural environment.

While experimentalists do their best to capture the key incentives of naturally occurring situations, laboratory experiments provide only imperfect information on expected results of actual auctions in the field, and thus have limitations in projecting outcomes of field auctions. But all data on OCS leasing markets have important shortcomings, and the ability to apply strict controls allows laboratory experiments to perfectly complement uncontrolled and incomplete data from historic auctions. We combine all information sources to provide the best possible analysis of leasing alternatives, prior to recommending options for field testing.

III.D.2. Experimental Evaluation of Auctions for OCS Leasing

Our experiments focus on exploring the use of a simultaneous multi-round (MR) auction for application in OCS leasing. In multi-round auctions, bids are submitted through a series of rounds, at the end of which the highest bid on each object is revealed as a provisional winner. In subsequent rounds, bidders may submit bids to capture objects on which they previously bid but were not the provisional winner, or to bid on additional objects. In purest form, the auction ends when no bidder wants to raise the provisional winning bid on any object, and thus no new bids are submitted in a round.

Multi-round auctions have been used to great success in electromagnetic spectrum auctions by the FCC in the United States, and by similar government agencies around the world (e.g., Milgrom, 1996). These auctions are characterized by a relatively small number of bidders competing over a small number, generally complementary, licenses that have both common and private value components. However, they have never been used on OCS leasing, so we have no data to compare multi-round auctions to the first price, sealed bid auctions that have been used historically.

The OCS application has several features that distinguish it from applications for which the MR auction has been studied. The MR auction was developed primarily to leverage synergies among sets of multiple objects. Synergies are not the focus of our exploration. Rather, we are interested in the potential advantage of multi-round auctions to reveal private information in a common value environment. Even the baseline common value environment suggested by the OCS application has not been evaluated experimentally, as Cox et al. (2001) is the only study of endogenous entry in common value auctions, but they do so with only one object being auctioned at a time. Thus, a new dimension of this work is the opportunity to assess behavior in simultaneous auctions of a large number of common value items, and to do so in an MR environment that progressively reveals private information. Finally, most common value auction experiments (e.g., Kagel and Levin, 1986) have focused on bidders' learning about the winner's curse. Since we are interested in predicting the behavior of experienced professional bidders, we will want to explore methods for actively training subjects to avoid the winner's curse, and then test the auction institutions in an environment where all subjects share that understanding.

We view our assessment of multi-round auctions as a first attempt to assess how multi-round auctions might affect bids relative to the historically used institutions. We use laboratory experiments to compare bidding under first price sealed bid and multi-round auctions. Ultimately, we use the results of the experiments to calibrate the bid function estimated from historic data to provide a general sense of what might be expected if MR auctions were to be adopted in a field test.

The next two sections describe the auctions institutions evaluated in the experiments.

III.D.2.a. First Price Sealed Bid Auction

The first price sealed bid (FP) auction reflects current practice in OCS leasing. In this auction, bidders examine their value signals for all objects for sale, then decide on which ones to submit bids, and the amount of those bids. Bids are sealed and submitted to the auctioneer, who awards each object to the bidder who submitted the highest bid on that object, at the price bid. This is a simple, well-studied environment.

III.D.2.b. Simultaneous Multi-Round Auction

In the simultaneous multi-round auction (MR), bids are submitted through a series of rounds, at the end of which the highest bid on each object is revealed as a provisional winner, although the identity of the bidder is not revealed. In subsequent rounds, bidders may submit bids to capture objects on which they previously bid but were not the provisional winner, or to bid on additional objects. In purest form, the auction ends when no bidder wants to raise the provisional winning bid on any object, and thus no new bids are submitted in a round.

Such MR auctions can be problematic because they present incentives to raise bids very slowly. There are two reasons for this. First, bidders do not want to bid any more than necessary to prevail over competing bidders, and thus have a tendency to increase bids above the provisional winner no more than required. Second, in common value auctions, bids reveal private information that can provide guidance to other bidders on their bidding strategies (this could be especially true if the private information were expensive). This provides an incentive for bidders to wait to see what information others will reveal before placing their own bids.

Two measures are used to counteract these incentives: minimum bidding increments and activity rules. Minimum bidding increments limit the number of rounds by forcing bidders to raise their bids a minimum amount over the posted provisional winner. The drawback of minimum bidding increments is that, if increments are too large, bidders may have reservation bids above the current provisional bid, but below the new minimum bid, thus a higher-value bidder has no legal bid she is willing to submit, and the seller forgoes the increase in revenue. We address this drawback with sliding minimum bid increments that are responsive to the round of the auction, as well as the amount of interest in each object. Our rules require a 10% increase in the first five rounds of the auction. Following that, bids for an object had to be 5% above the provisional winner if three or more bidders bid on it in the previous round, 2% if one or two or more bidders bid on it, and only 1% if no bids were submitted.

Activity rules have been the focus of study in multi-round auctions, because they must balance bidders' desire to avoid revealing information or submitting bids on objects they have already won, with ensuring that bidders are not driven out of the auction too early, only to find that they are later outbid by active bidders on objects of which they were the provisional winner when they stopped bidding. This could be bad for the seller if a bidder with a high value leaves the auction while the provisional winner of an object, and later finds herself outbid, but for a price she would be willing to top. The simplicity of our auction technology demanded that our activity rules be very simple. Thus, each bidder started the first round of each MR auction with three "bids" of eligibility, the number of bids they were able to submit in each round of the auction. They were then not permitted to submit more bids in any round than they had submitted in the previous round. Thus, if a bidder decided to submit only two bids in round five, in following rounds, she could submit no more than two. The auction closure rule of stopping after the first round in which only one bid was submitted ensured that subjects were running a risk by dropping their eligibility to only one bid.

III.D.3. Experimental Design

While identifying the exact institutions and rules to be evaluated is part of the research contract, we anticipate designing an environment where a moderate number of subjects (10-20) will act is bidders in a simulated auction. Our subject pool will be comprised of graduate students in business, economics and finance, who are capable of the sophisticated analyses of complex concepts needed to simulate behavior of experienced auction participants. We will provide these subjects with training and experience with auctions, using professional literature from OCS leasing.

Following Kagel and Levin's (1986) common value environment, bidders will be provided with (heterogeneous, noisy) information on the resources in each tract within an area, and then will bid on them. The distribution of tract values will be benchmarked to actively auctioned regions of the Gulf of Mexico and historical data. The bidding process used—including a possible nomination phase, number of tracts available, reserve price policies, form of bids, available public information, market clearing rules—will vary according to the candidate processes under consideration.

Because the intention of the experiments is to provide insight into likely behavior of professional bidders, we recruited unusually selectively, and required subjects to attend—and do well in—a training session in order to participate in the data collection sessions. Our selective recruiting targeted graduate students in technical fields, who were comfortable with "basic math and probability," but unable to attract a sufficient pool with that restriction, we invited top earners in previous (unrelated) experimental projects, many of whom were undergraduates, to participate. Subjects were recruited to attend training sessions of approximately two hours, for which they would receive a fixed payment of $25. In addition, they were told that they may earn additional money during the training session, and that those performing well may be invited to data collection sessions where they would collect the additional money earned during the training session, and earn considerably more money. Training sessions were conducted with between five and 10 subjects.

III.D.3.a. Training Sessions

The training sessions had three parts: a candy auction, a section explaining the winner's curse, and practice first price sealed bid auctions, mirroring those in the experiments. At the beginning of the candy auction, each subject was endowed with 50 M&Ms candies, with which to bid in five auctions of cups full of additional M&Ms. In each auction, a small cardboard box was filled with some unknown amount of M&Ms. It was passed around among subjects, who could feel and shake the box to form a guess at the number of M&Ms inside. There was then a first price sealed bid auction of the box wherein subjects would write a bid, denominated in M&Ms, on a bid slip and hand it to the auctioneer. The person who bid the most M&Ms for the box was the winner, and got to keep the difference between the number of M&Ms actually in the box and their bid; if the winning bid exceeded the number of M&Ms in the box, the cursed winner would pay our of his or her initial endowment.

Since the winner of the auction was usually the person who was most optimistic about the number of M&Ms in the box, the winning bid was often in excess of the actual number of M&Ms. Observing this was the starting off point for the explanation of the winner's curse, in which it was explained that if guesses are right on average, then the highest guess is likely an overestimate of the number of M&Ms in the box. Since higher bids are usually based on higher guesses, if the winner's guess was an overestimate and her bid was close to her guess, she likely wound up paying more than the received, thus losing M&Ms. It was then suggested to subjects to "reduce your bid to reflect the fact that if you win the auction, it is likely because your guess is more optimistic than average and most likely an overestimate." Questions were solicited and answered at several stages.

Once subjects understood the cause of the winner's curse, they were introduced to the information environment used in the experiment, where the range of value signals is induced, rather than arising from different individual assessments of a physical object. Our experiments are based on the common value environment in Kagel and Levin (1986) and Cox et al. (2001), but with much higher signal variance relative to the support of the true values, reflecting uncertainty in geologic analysis associated with OCS leasing (e.g., Quirk and Ruthrauff (2008) Table 6). Subjects were told objects would have true values vj drawn from $U[0,1000]$, and that they would each receive a private signal $s$ij drawn from $U[v\text{j} -200, v\text{j} +200]$. The explanation of the winner's curse was reviewed in this context by showing everyone an example vj and corresponding set of six $s$ij draws.

The final phase of the training session is a set of five first price sealed bid auctions, each selling 20 tracts simultaneously[17]. Each subject could win any number of tracts, but could only receive value from three; additional tracts had to be paid for, but yielded zero value. With the exception of having a number of bidders, the auction procedures followed those in the actual experiment, explained below. After the five practice auctions, each subject totaled their earnings. Those with positive earnings were informed they would be invited to data collection sessions, and would be paid their earnings there; those with zero or negative earnings were not invited to data collection sessions, though they were allowed to return to one training session to attempt to requalify[18].

III.D.3.b. Data Collection Sessions

A total of 50 subjects participated in training sessions, yielding a field of 37 subjects trained to participate in data collection sessions; 34 individuals eventually participated in at least one session. Subjects were permitted to participate in more than one data collection session, but were rotated so that no session had more than two subjects who had been in a previous session together before, in order to limit collusion possibilities.

Each data collection session had exactly six subjects and consisted on three first price auctions, followed by two multi-round auctions (three in later experiments), followed by three more first price auctions[19]. This design controls for the additional experience in the environment accrued during the multi-round auctions that might otherwise confound a behavioral difference between the FP and MR auctions.

Each session was in either a competitive or open treatment, in which each auction made 20 or 42 objects available for sale. Each subject was limited to receiving value from three objects, reflecting limitations on exploration or development resources. If more than three objects were

[17] In training sessions with 5-6 participants, only 15 were made available.

[18] One pilot combined training and data collection without the intermediate phase of dismissing subjects who did not demonstrate an understanding of how to respond to the winner's curse. The result was one subject bidding to signal on too many objects, sending incorrect information to other subjects, widespread losses, and very frustrated subjects. We view this dismissal as key to nearly eliminating overpayment from the data collection sessions.

[19] The first experiment had only two first price auctions following the multi-round auction because we did not anticipate time to conduct eight full auctions, based on pilot pacing.

won, the subject would choose which three from which she would receive value, still paying for the additional objects but receiving zero value. Each object had a minimum bid value of 100, so on average 10% of objects would not be worth the minimum bid. Thus, the competitive treatment had an expected number of potentially profitable tracts equal to total demand, while the open treatment had over twice the number of potentially profitable tracts as were demanded. Neither of these is as competitive as most previous auction experiments, where most subjects would have unsatisfied demand, or as uncompetitive as the actual OCS auctions, where only about 10% of tracts receive bids, but together they demonstrate the differential effect of the auction mechanisms as the competitiveness of the environment changes.

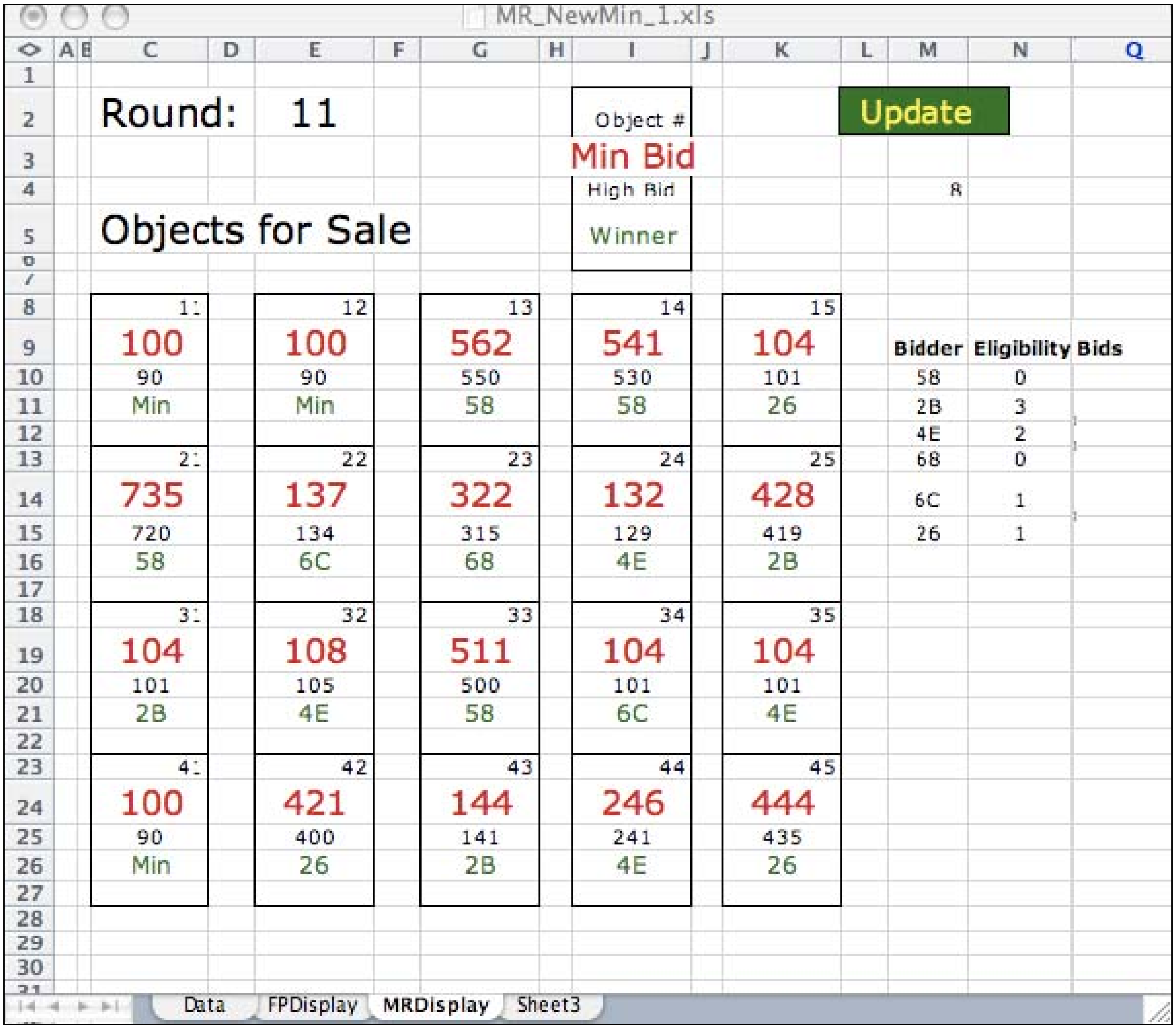
The mechanics of the auction were carried out using a radio frequency "clicker" system to submit bids to a single computer that processed the bids using an Excel VisualBasic macro. During the auction, the current status of the auction was projected onto a screen at the front of the room. A sample for a competitive treatment (20 unit) auction is shown in Figure III-13. The display shows an auction in Round 11, revealing the provisional winners after Round 10. The grid displays key information on the 20 objects for sale, including the object number (in the upper right hand corner) and the current minimum bid in large letters (e.g., the current minimum bid on object 23 is 322. Below that is the current winning bid, 316, submitted by bidder 68. On the right is the list of eligibility, the number of bids each subject may legally submit in each round.

Each subject was provided with a clicker (TurningPoint ResponseCard XR), a personal keypad into which they would type their bid code. The bid code is a five-digit number that concatenated the object number on which they were bidding with the amount they wished to bid on that tract. When they hit a button on their clicker, the bid would be submitted to the experimenter's computer, along with the serial number of the clicker, which was used as a subject identifier.

The clicker interface required subjects to submit bids one at a time; all subjects submit a first bid, then all subjects submit a second bid, etc. In the MR auction, three bids were solicited from each subject (fewer if no subject was eligible to submit three bids) before the macro was run to determine provisional winners and update the display for the round. The auction ended after a round in which only one valid bid was submitted. In the FP auction, the experimenter solicited bids until no subject wanted to submit more bids, and then the macro was run once to determine winners.

At the beginning of each auction, private signal sheets were distributed for each subject. The signal sheet showed the signal, minimum possible true value given the signal, maximum possible true value given the signal, and a Bayesian "best guess" at the true value, which is the signal except when the signal is within 200 of 0 or 1000. Subjects were given time to study the signal sheets, and then the auction was conducted. Following the auction, subjects noted the objects they'd won, selected the three from which they would receive value, and were told the true value of the three objects they'd chosen. They then computed their profits, which were included in their total earnings for the experiment.

Figure III-13. Example Auction Display



Earnings were calibrated to be relatively high in this experiment, and averaged over $50 for sessions lasting between two and three hours. The exchange rates were adjusted a couple times as we learned more about earning patterns in this complex environment, but were about twice as high for the open sessions.

III.D.4. Experimental Results

Ten data collection sessions yielded bids in 29 FP open auctions, 30 FP competitive auctions, 12 MR open auctions and 11 MR competitive auctions.

Figures III-14 and III-15 present an overview of the data. To make visual patterns more apparent, true values were grouped into ten-unit bins, and corresponding observed high bids were averaged within each bin.

The most readily apparent pattern is the bids are noticeably higher, especially at high true values, in the competitive environment; making available additional units does reduce competition therefore bid levels. Within each environment, however, there are not strong differences between the MR and FP auction mechanisms.

A ready visual test of the presence of the winner's curse, and thus the success of our training regimen at approximating the behavior of professional bidders, is that very few of observations are above the dashed line that indicates where the high bid equals the true value. Most instances were true values below the minimum bid. Some instances are lost in averaging in the figure, but overall there were only 16 cases in which the bidder paid more than an object was worth. These instances were distributed across all four treatments.

The following sections explain these patterns in more detail.

III.D.4.a. Bids as a Proportion of Value

While it does not appear that one institution dominates the other at all true values, several subtleties emerge as one considers that many objects at all points in the value range are available at once, and differences within relatively small regions of the value range are interesting. Note that in both figures the MR auction yields higher bids for true values over 950; the difference is considerable in the open environment. For values between 850 and 950, the relationship switches, with FP being higher than MR. Such behavior at the high end of the value range is likely of particular interest in the OCS auctions, where actual values are lognormally distributed, so an auction that extracts a slightly larger percentage of the value of the highest value tract would yield considerably more revenue, even if it extracted a smaller percentage of the value of less valuable tracts.

This bidding pattern is likely revealing a key difference in the strategies between the two auctions. In the MR auction, bidders can pursue a particularly high value object, and then switch to a lower value parcel when it's price gets too high. In the FP auction, however, bidders must make a guess about how many others will be bidding on each object, and thus what portion of their best guess to bid in order to be competitive. In this multi-object environment, high value objects are likely to be focal, and bidders likely to think high value objects will attract more other bidders.

Figure III-14. Observed High Bids Plotted Against True Value in the Competitive Environment

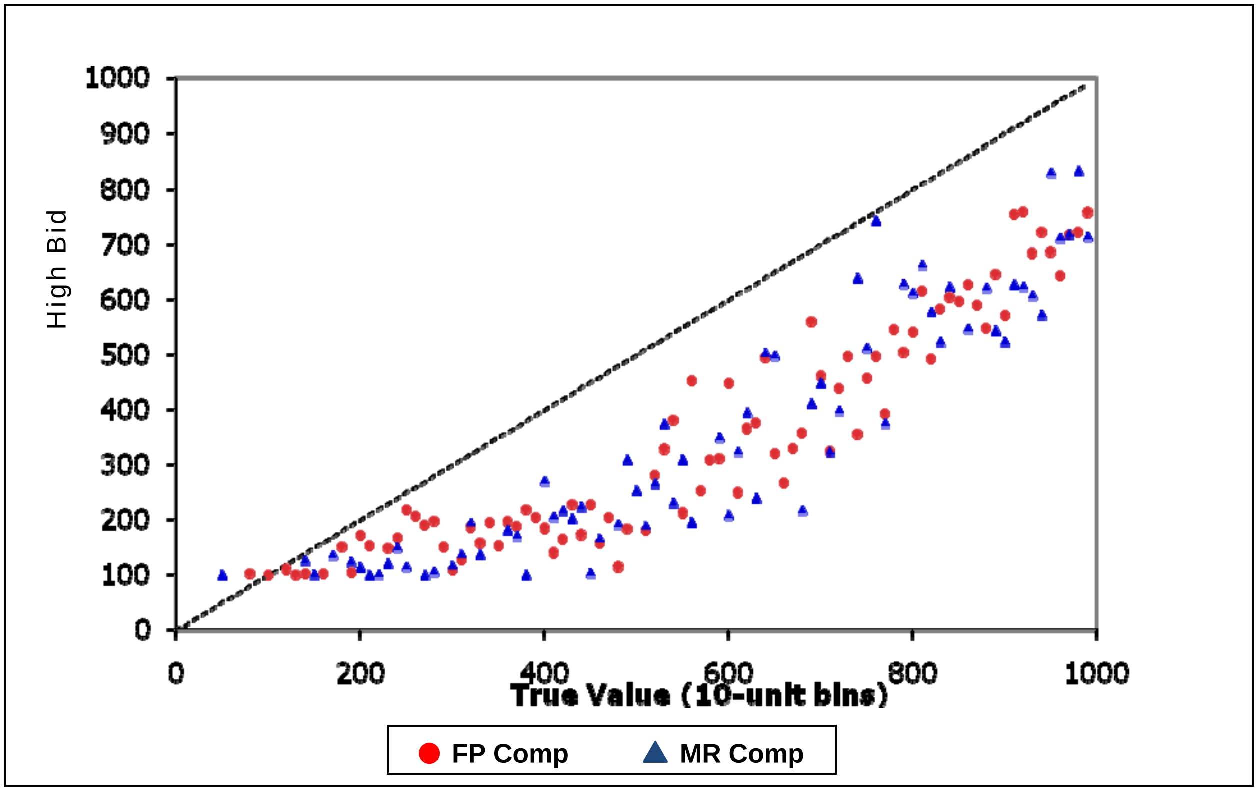
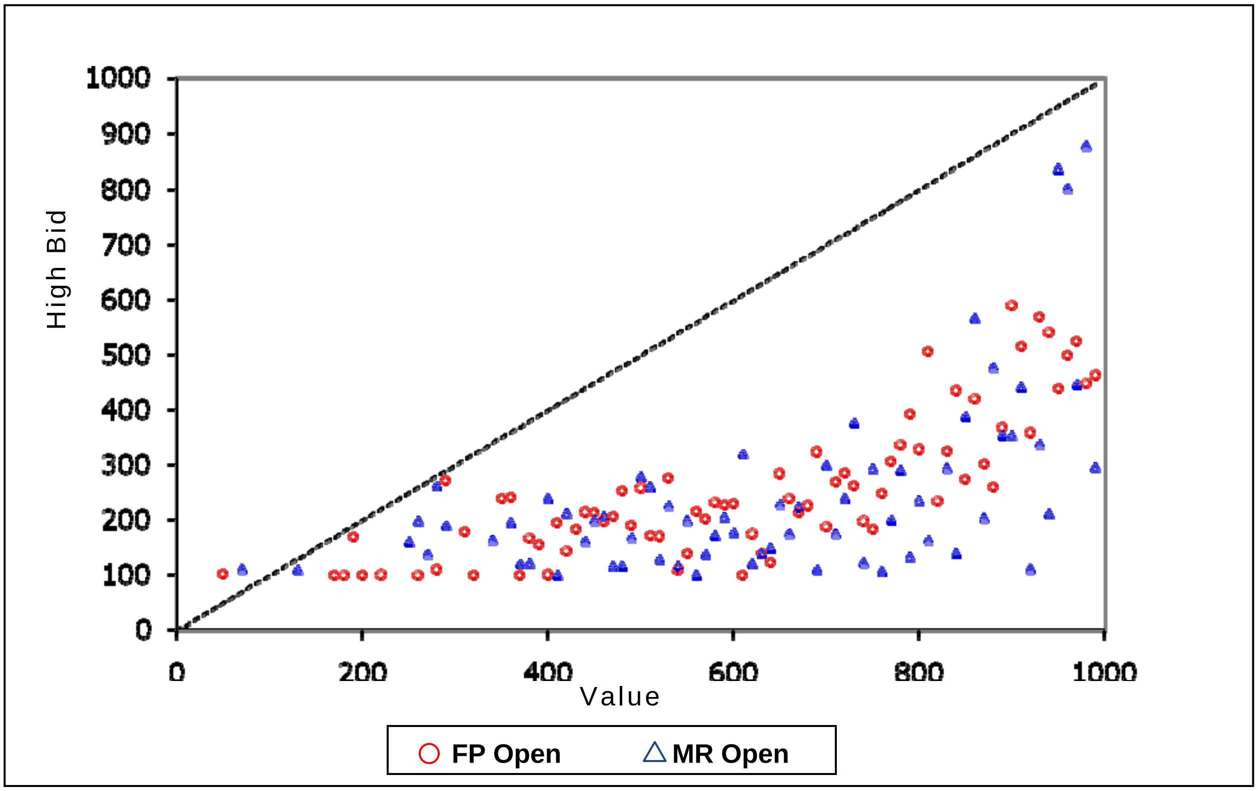


Figure III-15. Observed High Bids Plotted Against True Value in the Open Environment



In the FP auction, this exposes a bidder to two risks. First, she must bid higher, exposing them to a larger winner's curse. Second there is a simultaneous auction risk wherein, with more bidders, she may not win the object, thus either falling short of the three objects from which she can derive value, or she may decide to bid on an additional object in anticipation of losing, but end up paying for a fourth object from which she cannot derive value. A reasonable response to these two risks might be to bid on less focal, lower-valued objects, in hopes there will be fewer bidders.

Note that the MR auction addresses both of these risks, the former by revealing information held by others in subsequent rounds, and the latter by allowing subjects to switch bidding activity to another object once the bidder's reservation value is exceeded. The lower prices observed in the MR for values just below the highest range may arise when the provisional winners holding those objects relinquish their eligibility in the middle rounds, not fully anticipating that bidders pursuing the highest value objects will switch to those slightly lower-valued objects once they drop from the competition for the objects of highest value. Modifying the activity rules to something more sophisticated, or additional training, may help the seller capture more of the value from these tracts in the MR auction.

III.D.4.b. Number of Bidders

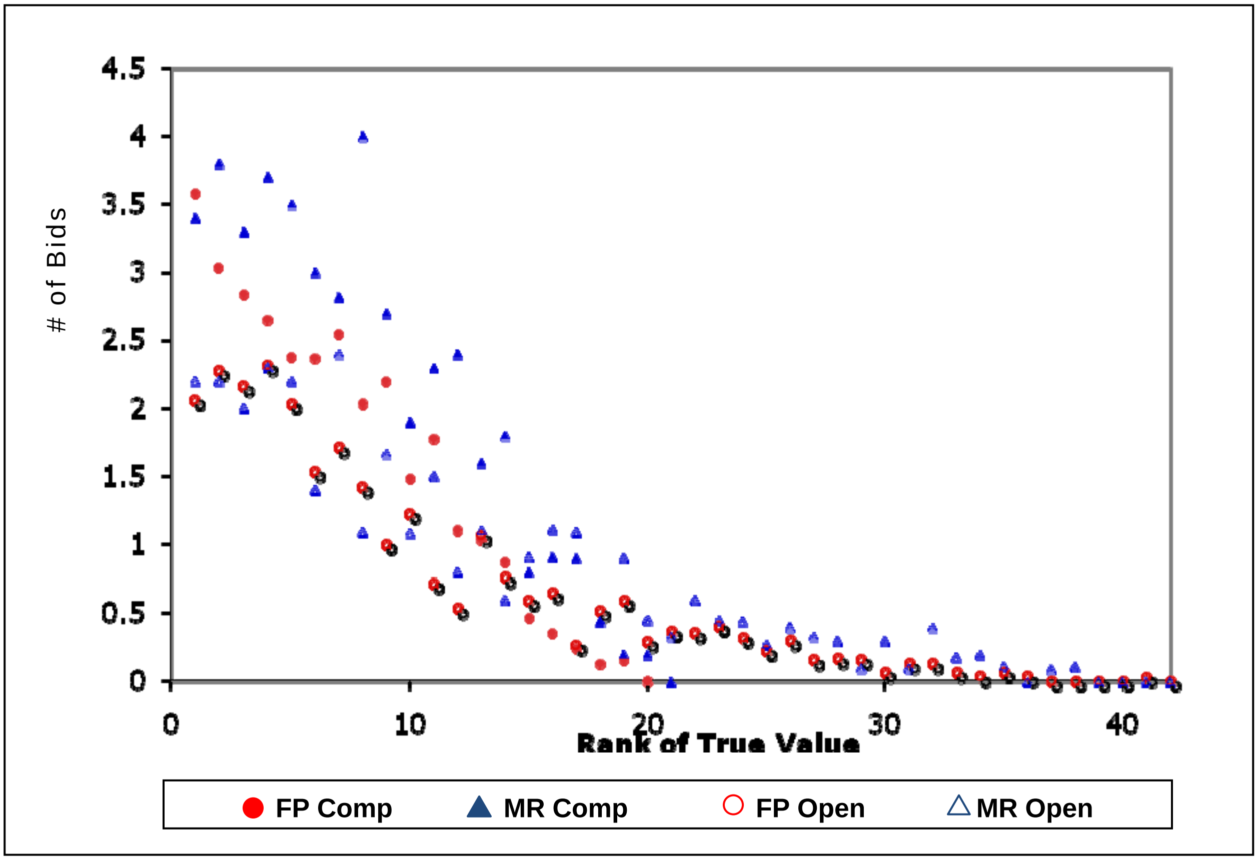
One of the major determinants of bid levels in the OCS auction data is the number of bidders per tract. Figure III-16 shows the number of bidders submitting bids on each object, arranged by the rank of the true value on each object, i.e., the leftmost observation is the average number of bidders bidding on the highest-valued object within each treatment.

Comparing the open and competitive environments, the competitive environment has a steeper curve than the open environment. That is, in the competitive environment there is a higher number of bidders on the highest value tracts, and a lower number of bidders on the lower value tracts. This is apparent even though the actual values of ranks 15-20 are much higher in the open environment than the competitive environment. This reflects the fact that in the open environment, bidders spread their bidding effort out across tracts in an attempt to find tracts with fewer other bidders, and on which there will be less competition.

Comparing the MR and FP auctions on this measure is unfair in some ways, since the MR allows subjects to submit so many bids, and bids on more objects as rounds elapse. However, from an information standpoint, the comparison is useful. The more bidders that participate on each object, the more private information is introduced into the market. In a common value environment this can reduce the risks associated with the winner's curse, the level of bid reduction, and perhaps yield higher revenue.

In the competitive environment, the MR has more bidders per object, as much has half a bidder more on the highest value objects. This difference shrinks as rank rises and the overall desirability of the objects falls.

Figure III-16. Number of Bidders Submitting Bids on Items of Different Values



In the open environment, the FP and MR are much more closely tracked with one-another on the highest value objects, which is puzzling. The MR is attracting consistently more bidders at ranks higher than ten, probably reflecting initial bidding patterns motivated by the same strategic desire to bid on objects no one else does as in the FP, but then a later opportunity to return competitive bidding to those objects as higher-value objects are settled.

III.D.4.c. Revenue Capture and Efficiency

Simultaneous auctions present bidders with the opportunity to bid higher on the most valuable objects, or to bid less aggressively on lower valued objects, where there will perhaps be fewer bidders. Hence, the revenue effects of an auction can only be evaluated by looking at the auction as a whole, not individual bids.

Overall, the MR auction raises more revenue, but sells a larger number of more valuable objects to do so. The average total revenue from the competitive MR was $9195 compared with $8589 in the competitive FP (Wilcoxon sign-rank p=0.133), and $14,002 in the open MR compared with $11,353 in the open FP ($p$<0.001), indicated the MR yields more revenue per auction.

However, the MR also sells more objects per auction, an average of 15.73 compared to 13.33 in the competitive environment (p<0.001), and an average of 19.50 compared to 15.38 (p=0.001) in the open environment. Thus the higher revenue comes at a cost of selling more resource, which cannot be sold in subsequent auctions. If this is considered, the efficiency conclusion may actually be reversed, as the total revenue is a smaller proportion of sold object value under the MR. In the competitive environment, the MR captures 59.4% of the true value of its sold objects, not statistically significantly less than the 63.1% of the FP (p=0.659), but in the open environment, the MR's 37.8% capture is significantly less than the FP's 45.2% (p=0.048).

The auction revenue averaged 56.4% of the total true value of the top 18 objects in the competitive MR, slightly more than the 55.1% for the competitive FP. The MR captured 37.3% of value in the open environment, again slightly more than the 36.1% for the FP. The across-auction differences are not significant by a Wilcoxon rank-sum test (p=0.617 and p=0.841 for the competitive and open environments, respectively), but the environment differences are highly so (p<0.001 and p=0.003 for the FP and MR, respectively).

III.D.4.d. Estimated Bid Function

In order to more completely understand the effects of the MR auction institution, and to translate its results for use in the simulation model, it is necessary to develop a high bid prediction model. This model relates the observed high bid to the true value of each object, capturing variation associated with treatment.

The high bid data presents a number of serious econometric challenges. First, the bids are censored below at the minimum bid of 100. Second, the data are highly heteroskedastic, as the variance increases with value. Third, there is evidence of two disparate bidding strategies: bidding low on lots of tracts and winning only a few, and aggressively bidding on a few tracts. As a result, there is a cluster of high bids very close the minimum bid (less than 120) at all value levels, meaning the density of errors is not only censored, but also non-normal. Finally, it is panel data, in which subjects are making multiple decisions.

Tackling all of these issues within a parametric model would be challenging; instead, nonparametric quantile regression is applied to model the median behavior and test for basic treatment effects[20]. Table III-30 shows the results of a quantile regression to test for primary treatment effects. All coefficients are significant at p=0.001 or better.

The base treatment is FP auction in the competitive environment. In this case, the median bid is 89.8% of value, but shaded down by a constant of -159. In the MR treatment, the effective median bid percentage drops to 71.3% of true value, but the constant level of bid shading also falls to 78.4. This means that in the competitive MR treatment, bids are higher on true values below 438.

Comparing the base treatment to the open FP treatment, the median bid is only 38.0% of true value, but additionally shaded by only 21.3. This means open treatment bids are higher for values below 267, but otherwise the open treatment leads to lower median bids.

[20] Differences in underlying bidding strategies will need to be explicitly addressed in later analysis

Table III-30. Bid Function Estimated by Quantile Regression

Variable	**Coefficient**	**Std Err**
TrueValue	0.898	0.032
TrueValue × MR	-0.185	0.060
TrueValue × Open	-0.518	0.081
Constant	-159.580	21.676
MR	81.103	31.528
Open	138.291	38.887
N=1249	Pseudo-R2 = 0.298	

IV. Task 3. Assessment of Leasing Alternatives

This Section discusses the results of Task 3, in which we apply the analyses from the Task 2 analyses (described in Section III. above) to assess the leasing alternatives in terms of the Goals and Criteria developed in Task 1. First, we discuss the details of our specification of the policy alternatives, and the measures of the various Criteria. Then, we present the results of the analysis of the policy alternatives.

IV.A. Specification of Policy Alternatives

Table IV-1 shows the values that we use for several key parameters in our empirical analyses, and the leasing terms and conditions under the Status Quo leasing policy are shown in Table IV-2. The policy alternatives we consider for the pace of leasing and the tract leasing terms and conditions are shown in Table IV-3. We consider two policy alternatives that modify the pace of leasing relative to the Status Quo, where 8,000 tracts offered in 2010. Our first alternative scenario reduces the pace of leasing by 50%, with 4,000 tracts offered per year in 2010. Next, we consider a scenario that reduces the pace of leasing to 400 tracts offered in 2010, which is intended to represent a return to the pre-Areawide leasing program. All of our scenarios for the pace of leasing assume that the number of tracts offered for sale declines over time at that same rate of 1.56% per year that has been observed historically.

Next we consider alternatives to the Status Quo royalty rate of 18.75%. We consider an alternative that reduces the royalty rate to 12.5%, the minimum allowable under OCSLAS, and an alternative that increases the royalty rate to 35%. We also considered is a sliding scale royalty rate that starts at 35% and decreases in linearly with production, until it reaches 12.5% for the final 25% of production from each field. The rationale for this sliding scale royalty is to capture revenues by starting with a high royalty rate, while at the same time attempting to avoid overly distorting incentives for early shutdown by reducing the royalty rate as the field is depleted.

Then, two scenarios for profit sharing are considered. The first scenario involves adding a 30% profit share to the base case leasing conditions. The second scenario involves using a 30% profit share in lieu of royalty payments—that is 30% profit share with a 0% royalty rate. We also consider an alternative that increases the minimum acceptable bid by a factor of 5 relative to the Status Quo policy, where the minimum bid rate is $25 per acre in water less than 400 meters deep, and $37.50 per acre in water greater than 400 meters.

The next policy increases the area rental rate by a factor of 5. Under the Status Quo, area rentals are $6.25 per acre for shallower tracts and $9.50 per acre for deeper tracts. Under the alternative policy, area rentals are increased to $31.25 for shallower tracts and $47.50 for deeper tracts. Then, we examine a policy that imposes a work commitment on exploration, which we implement by requiring double the exploration effort as would occur without a work commitment.

Finally we consider a multi-round bidding system which represents a more significant departure from the Status Quo auction rules than the options mentioned immediately above. The multi-round approach we examine is similar in many respects to the approach used by the Federal Communications Commission for leasing rights to the electromagnetic spectrum.

Table IV-1. Summary of Key Parameters Used in the Analyses

- Oil Price: $90 per barrel, increasing at a 2% real rate per year
  - Sensitivity Analyses: $50 per Barrel and $120 per Barrel, both increasing at 2%
  - Sensitivity Analysis: $90 per Barrel, No Price Increase Over Time
- All Monetary Values Expressed in 2003 Dollars
- Discount Rate: 7% Real Rate
- Technological Progress:
  - Input Oriented: Input Requirements Decrease at 0.72% per Year
  - Output Oriented: Production Increases at 0.48% per Year
  - Sensitivity Analysis: No Technological Change
- Tracts offered for Sale: 8,000 Tracts Offered, Declining at 1.56% per Year
  - Policy Options: 4,000 Tracts Offered and 400 Tracts Offered, both decreasing at 1.56%
- Exploration Well Dry Hole Rate: 80.73%
- Field Size Classifications:

Size Class	Range of Resources (Millions of BOE)	Mean Resources
1	0.0312 – 0.0625	0.05
2	0.0625 – 0.125	0.09
3	0.125 – 0.25	0.19
4	0.25 – 0.5	0.38
5	0.5 – 1	0.71
6	1 – 2	1.49
7	2 – 4	2.93
8	4 – 8	5.87
9	8 – 16	11.68
10	16 – 32	23.03
11	32 – 64	44.70
12	64 – 128	89.86
13	128 – 256	177.85
14	256 – 512	345.64
15	512 – 1,024	716.57
16	1,024 – 16,384[21]	1,355.13

[21] Note: We aggregate field classes 16-19 into a single category due to the small numbers of predicted fields greater in size than class 16.

Table IV-1. Summary of Key Parameters Used in the Analyses (Con't)

- Water Depth Classifications

Water Depth Range	Mean Depth Meters	Feet
0- 60m	30m	98ft
60- 200m	130m	427ft
200- 400m	300m	984ft
400- 800m	600m	1,969ft
800-1600m	1,200m	3,937ft
1600-2400m	2,000m	6,562ft
2400-3658m	3,029m	9,938ft

Table IV-2. Status Quo Lease Policy for This Study: Lease Terms and Conditions for Sale #206 in the CGOM.

- Area-wide
- Minimum cash bonus per acre:
  - $25/acre for water depth $<$ 400 meters
  - $37.50/acre for water depth $\geq$ 400 meters
- Royalty: 18 ¾% for all water depths[1]
- Rental:
  - $6.25/acre for water depth of $<$ 200 meters
  - $9.50/acre for water depth of $\geq$ 200 meters
- Minimum Royalty[2]
  - $6.25/acre for water depth of $<$ 200 meters
  - $9.50/acre for water depth of $\geq$ 200 meters
- Initial term of lease[3]
  - 5 years for water depth $<$ 400 meters [4]
  - 8 years for water depth $\geq$ 400 meters to $<$ 800 meters
  - 10 years for water depth $\geq$ 800 meters

Source: http://www.gomr.mms.gov/homepg/lsesale/206/fnos206.pdf

1 Ignores variations such as Royalty Relief for deep drilling in tracts in shallow water and for drilling on tracts in deep water. See source reference for details.

2 Applies when minimal production occurs on a tract

3 Commencement of an exploratory well is required within the initial 5-year term in order to avoid cancellation.

4 An initial 5-year term can be extended to 8 years if the drilling depth to a target exceeds 25,000 or if mechanical or safety problems are encountered.

Table IV-3. List of Lease Sale Policy Alternatives

Pace of Leasing

• Status Quo: 8,000 Tracts Offered in 2010
• Slower Pace of Leasing
  o Reduce Tracts Offered by 50% (4,000 Tracts)
  o Reduce Tracts Offered to Pre-Areawide Levels (400 Tracts)

Alternative Leasing Terms and Conditions

• Cash Bonus – Royalty Options
  o Base Case – 18 ¾%
  o Increase Royalty Rate 35 %
  o Decrease Royalty Rate 12.5%
  o Sliding Scale Royalty Rate Based on Production
• Minimum Bid per Tract
  o Increase Minimum Bid by Factor of 5
• Profit Share
  o 30% Profit Share Added to Status Quo
  o 30% Profit Share in Lieu of Royalty
• Area Rental
  o Increase Area Rental by Factor of 5
• Multi-Round Bidding
• Work Commitment
  o Double Exploration Effort
• Lease Term
  o Reduce Lease Term by 25%

Under multi-round bidding, tracts are sold by sealed bids, but bidding continues for multiple rounds, with the provisional winning bids on each tract being announced at the end of each round. Trading continues as long as new, higher bids are received. The multi-round bidding system is discussed in more detail in Section IV of the Technical Report.

IV.B. Assessment of Policy Alternatives

Each of the leasing policies discussed above is evaluated relative to the Status Quo leasing policy using the Goals and Criteria described in Section II. Each of the Criteria is listed in Table IV-4, along with a brief explanation of how the criteria are implemented. While some interested parties may place greater emphasis on some Goals than others, we simply emphasize how effective the various options are in achieving each of the Goals.

Prior to discussing the results in detail, the reader should be reminded that many of the policies considered below are well outside the range of OCS experience within the past 25 years. Indeed, we have no experience in OCS leasing whatsoever with some of the policies that we assess below. And many of the results discussed below reflect numerous offsetting effects. Thus, while the results given here are quantitative, the reader is cautioned to interpret the results with care, given the long time horizon and the extensive uncertainties involved at virtually every stage.

Given these uncertainties, we believe the results are best viewed as indicators of likely incremental effects of policies, and not as precise quantitative predictions of actual policy outcomes. Thus, we prefer to utilize the results to identify strengths and weaknesses of policies, including whether one might expect differences across policies to be "substantial", "modest" or "small". In cases where we find differences across policy alternatives that are small in percentage terms, the results should not be interpreted to suggest one option is demonstrated to be clearly superior to the other. Rather small differences should be taken as an indicator that major differences should not be expected across the two alternatives.

In a similar vein, a reader might also be tempted to ask questions such as whether the effect of a particular policy (e.g., increasing royalty payments) is larger or smaller in percentage terms when combined with some other policy (e.g., slowing the pace of leasing). This type of question relates to interaction effects among policies, which might be termed "second order" effects. While certainly the model can be run to quantify these sorts of interaction effects, we have resisted considering such scenarios in this report due to a concern that the large size of the inherent uncertainties and the long time horizon imply that data are not sufficient to support such a demanding and precise interpretation of the results. Thus, we prefer to interpret the results as qualitative "first order" indictors of the size and direction of incremental effects of a particular policy. If one were interested in combining policies, we view our results simply as cumulative. For example, if one policy reduces revenues and another policy also reduces revenues, then we would conclude that revenues are reduced by "more" if the policies are combined, without attempting to quantify how much more. That is, we make no attempt to assess whether the incremental effect of some particular policy is larger or smaller when some other policy is also in place.

Table VI-4. Description of Criteria Used to Assess Policy Alternatives

Total Production - Total production of oil and gas resources over the time horizon measured as billion barrels of oil equivalent
Discounted Production - Total physical production of oil and gas resources over the time horizon, but physical production each year is discounted to 2010 at a 7% discount rate. Discounting physical production provides insights into the extent to which an option expedites production of OCS oil and gas resources. For example, if two options have identical total production, but one has higher discounted production, then that option has more production earlier in the time horizon, and less production later in the time horizon
Fields Discovered - Total number of fields profitably discovered over the entire time horizon
Exploration, Development and Production Wells - The total number of the relevant wells drilled over the time horizon
Average Annual Number of Tracts Offered for Sale - The average number tracts offered for sale under the relevant lease alternative. Recall that tracts offered for sale are assumed to decline at a rate of 1.56% per year. So, for example, under the Status Quo pace of leasing, 8,000 tracts are offered in 2010, and tract offerings decline each year until approximately 3,746 tracts are offered for sale in 2060. The average number of tracts offered for sale is 5,598 under the Status Quo pace of leasing
Average Annual Tracts Sold - The average number of tracts sold per year under the lease alternative
Discounted High Bids - The forecast total discounted value of high bids over the time horizon
Discounted Royalties - The forecast total discounted value of royalties collected over the time horizon
Discounted Area Rental Payments - The forecast total discounted value of area rental payments over the time horizon
Profit Share - The forecast total discounted value of profit share over the time horizon. Note that this is zero for all alternatives, except for the two alternatives with profit share.
Discounted Federal Taxes - The forecast total discounted value of federal tax payments over the time horizon

Table IV-4. Description of Criteria Used to Assess Policy Alternatives (Con't)

Discounted OCS Revenues - The sum of discounted high bids, plus royalties, plus area rental payment, plus profit shares, when applicable
Bids per Tract - The forecast average number of bids per tract over the time horizon
Environmental/Social Costs - The forecast total discounted value of environmental and social costs. This calculation is based on Tables 5 and 6 from MMS (2009), which present the production and environmental/social costs for the upcoming 5 years of leasing. We divide the social and environmental costs in Table 6 by BOE from Table 5 to get an average cost per BOE of \$68.67 million per BOE. We then multiply by discounted production to get a discounted value of social and environmental costs
Revenue Sharing with Coastal States - Discounted value of revenues shared with coastal states, based on the assumption of a 37.5% sharing of all cash bonus bids, royalties, area rentals and profit share starting in 2017 under the Gulf of Mexico Energy Security Act (GOMESA). The amounts reported assume OCS revenue sharing available to states is not subject to the \$500 million per year limitation specified in section 105(f) of GOMESA.
Onshore Economic Impacts - This is calculated using the results of Dismukes et al, 2003 for exploration, development and production wells. We use the direct, indirect and induced expenditures associated with the "Output" Impact Type, then sum over all three regions in Dismukes et al, Tables 4.4., 4.5. This amounts to approximately \$2.9 million per exploration well, \$2.5 million per development well and \$143 thousand per production well. These values are adjusted to 2009 dollars, and discounted over the time horizon. We assume expenditures associated with exploration and development wells occur within the year of drilling of the associated well, while expenditures associated with production wells continue for the life of production
Lost Discounted Resources - Reduction in discounted physical resources developed due to early shutdown of fields, and or reduced number of fields developed. This is calculated by subtracting total discounted production under the Alternative in question from the total discounted resources that would be produced under the Status Quo option, except with a zero royalty rate

With those caveats in mind, the empirical results provide many useful insights into potential effects of the various policy alternatives (see Table IV-5). To simply compare with the Status Quo, we present results for the policy alternatives in terms of percentage differences with the Status Quo results. The absolute values for all lease policy alternative are given in Table IV-A-1 in Appendix IV.A.

First and foremost, the results show that there are important tradeoffs across policy alternatives, so no single policy is best at achieving all Goals. Nor does any individual policy dominate the Status Quo policy. Rather, some policy alternatives perform better than the Status Quo in terms of some Goals, but not as well in terms of other Goals. So choice among policies depends upon value judgments regarding the relative importance of the various Goals.

Slower Pace of Leasing

In general, slowing the pace of leasing is detrimental to Goal 1. Expeditious Development of OCS Resources.[22] In terms of Goal 2, Obtain Fair Market Value, the model forecasts that slowing the pace of leasing results in significantly larger cash bonus bids. However, other sources of revenue decline under a slower pace of leasing, including royalties, area rental payments, and federal corporate taxes. Thus, the effect on overall revenues is a complex interplay of several factors. Our model forecasts that overall federal revenues increase slightly (4.1%) with a return to the pace of leasing used prior to the advent of Areawide leasing. The reader should be cautioned, however, that this empirical result is dependent on extrapolating the number of tracts offered for sale far outside of the range of experience within the past 25 years. Given all of the many uncertainties, such small changes in forecasted revenues should be taken as an indication that offsetting effects are significant, and one should not expect a large overall change in revenues from slowing the pace of leasing.

We also find that a slower pace of leasing results in more competition for tracts (Goal 3), and the resultant reduction in OCS activity facilitates regional planning (Goal 5). But a slower place of leasing has offsetting effects on equitable sharing of costs and benefits (Goal 4) and is likely to adversely affect the maximization of overall social value associated with offshore production (Goal 6).

Changing Royalty Rates

Increasing royalty rates adversely affects the expeditious development of OCS resources (Goal 1), and has offsetting effects on OCS revenues (Goal 2). Our model forecasts that increasing the royalty rate has a very small, but positive overall effect of OCS revenues (2.4%), which results from multiple offsetting factors. Again, given the many uncertainties involved, this small a change in forecast revenues should be taken as an indicator that one cannot expect large changes in revenues from increasing the royalty rate.

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[22] It is interesting to note that the slowest pace of leasing, 400 tracts offered, results in fewer field discoveries, but more production. This occurs because slowing the pace of leasing delays development to future periods when prices are higher and technology improves, thereby reducing input requirements and increasing output. Together, this makes more fields profitable, and increasing production from fields through improved profitability of secondary recovery. The delay in leasing is clearly shown in the reduction in discounted resources.

Table IV-5 Assessment of Criteria Under Alternative Lease Sale Scenarios

(Critera for Policy Alternatives are Expressed as Percentage Differences from the Status Quo)

Goal 1. Expeditious and Orderly Development of OCS Resources

Alternatives 1-6

Critera	Status Quo	Alternative 1	Alt. 2	Alt 3	Alt. 4	Alt 5.	Alt. 6
	Current Leasing System	Fewer Tracts Offered (4,000)	Fewer Tracts Offered (400)	Decrease Royalty to 12.5%	Increase Royalty to 35%	Sliding Scale Royalty (35% to 12.5%)	Higher Minimum Bid
Total Production (MMBOE)	22,113	-0.5%	10.6%	16.0%	-22.0%	-13.5%	-0.6%
Discounted Production (MMBOE)	3,733	-4.4%	-11.7%	18.3%	-22.1%	-14.3%	-5.2%
Fields Discovered	954	-5.6%	-25.5%	0.6%	-1.9%	-0.2%	-6.7%
Exploration Wells	10,931	-13.3%	-47.5%	1.6%	-4.8%	-0.6%	-15.7%
Development Wells	5,267	-2.4%	-0.3%	12.9%	-19.9%	-11.9%	-2.8%
Production Wells	11,467	-2.3%	1.4%	14.8%	-17.3%	-10.3%	-2.7%
Ave. Annual Number of Tracts Offered	5,598	-50.0%	-95.0%	0.0%	0.0%	0.0%	0.0%
Average Annual Tracts Sold	119	-29.0%	-78.0%	0.3%	-1.0%	-0.1%	-33.5%

Alternatives 7-12

Critera	Status Quo	Alt. 7	Alt. 8	Alt. 9	Alt.10	Alt. 11	Alt. 12
	Current Leasing System	Profit Share (30%) Royalty 18.75%	Profit Share (30%) No Royalty	Higher Area Rental Fee	Multi-Round Bidding	Work Commit-ment	Shorter Lease Term
Total Production (MMBOE)	22,113	0.0%	46.8%	-3.1%	-0.5%	-4.6%	-0.5%
Discounted Production (MMBOE)	3,733	0.0%	50.3%	-7.1%	-3.5%	0.0%	-6.4%
Fields Discovered	954	0.0%	1.7%	-5.7%	-4.4%	7.2%	-8.3%
Exploration Wells	10,931	0.0%	4.6%	-13.5%	-10.7%	60.7%	-19.0%
Development Wells	5,267	0.0%	39.6%	-4.3%	-1.9%	-1.4%	-3.3%
Production Wells	11,467	0.0%	42.0%	-4.0%	-1.9%	-0.8%	-3.2%
Ave. Annual Number of Tracts Offered	5,598	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Average Annual Tracts Sold	119	0.0%	0.8%	-29.4%	42.6%	-34.6%	13.0%

Table IV-5 Assessment of Criteria Under Alternative Lease Sale Scenarios (Con't)

(Critera for Policy Alternatives are Expressed as Percentage Differences from the Status Quo)

Goal 2. Obtain Fair Market Value for Leased Resources

Alternatives 1-6

Critera	Status Quo	Alternative 1	Alt. 2	Alt 3	Alt. 4	Alt 5.	Alt. 6
	Current Leasing System	Fewer Tracts Offered (4,000)	Fewer Tracts Offered (400)	Decrease Royalty to 12.5%	Increase Royalty to 35%	Sliding Scale Royalty (35% to 12.5%)	Higher Minimum Bid
Discounted High Bids	$ 31,464	12.0%	52.3%	19.1%	-38.7%	-16.7%	-0.2%
Discounted Royalties	$ 44,290	-3.8%	-6.7%	-20.2%	53.1%	19.8%	-1.7%
Discounted Area Rental Payments	$ 5,579	-47.7%	-94.0%	0.3%	-0.8%	-0.1%	-25.1%
Discounted Profit Share							
Total Discounted OCS Revenues	$ 81,333	-0.7%	10.2%	-3.6%	13.9%	4.3%	-2.7%
Discounted Federal Taxes	$ 35,269	-0.6%	-15.9%	20.5%	-35.8%	-16.6%	14.7%
Total Discounted Revenues	$ 116,602	-0.6%	4.1%	2.0%	2.4%	-0.5%	1.3%

Alternatives 7-12

Critera	Status Quo	Alt. 7	Alt. 8	Alt. 9	Alt.10	Alt. 11	Alt. 12
	Current Leasing System	Profit Share (30%) Royalty 18.75%	Profit Share (30%) No Royalty	Higher Area Rental Fee	Multi-Round Bidding	Work Commit-ment	Shorter Lease Term
Discounted High Bids	$ 31,464	-28.0%	19.2%	-6.6%	-21.8%	-2.3%	-5.5%
Discounted Royalties	$ 44,290	0.0%	-100.0%	-5.8%	-3.0%	0.3%	-5.3%
Discounted Area Rental Payments	$ 5,579	0.0%	0.7%	158.4%	76.0%	-58.7%	13.6%
Profit Share	$ -	100.0%	100.0%				
Total Discounted OCS Revenues	$ 81,333	-0.1%	-22.1%	5.1%	-4.9%	-4.7%	-4.1%
Discounted Federal Taxes	$ 35,269	-30.6%	16.6%	-9.2%	4.7%	-18.3%	2.5%
Total Discounted Revenues	$ 116,602	-7.2%	-13.2%	1.8%	-2.7%	-7.9%	-2.6%

Dollar Values are Millions of 2003 Dollars

Table IV-5 Assessment of Criteria Under Alternative Lease Sale Scenarios (Con't)

(Critera for Policy Alternatives are Expressed as Percentage Differences from the Status Quo)

Goal 3. Promote Competition

Alternatives 1-6

Critera	Status Quo	Alternative 1	Alt. 2	Alt 3	Alt. 4	Alt 5.	Alt. 6
	Current Leasing System	Fewer Tracts Offered (4,000)	Fewer Tracts Offered (400)	Decrease Royalty to 12.5%	Increase Royalty to 35%	Sliding Scale Royalty (35% to 12.5%)	Higher Minimum Bid
Bids per Tract	1.26	7.9%	61.9%	2.4%	-4.8%	-1.6%	3.2%

Alternatives 7-12

Critera	Status Quo	Alt. 7	Alt. 8	Alt. 9	Alt.10	Alt. 11	Alt. 12
	Current Leasing System	Profit Share (30%) Royalty 18.75%	Profit Share (30%) No Royalty	Higher Area Rental Fee	Multi-Round Bidding	Work Commit-ment	Shorter Lease Term
Bids per Tract	1.26	-2.4%	3.2%	7.9%	-6.3%	11.1%	-3.2%

Table IV-5 Assessment of Criteria Under Alternative Lease Sale Scenarios (Con't)

Goal 4. Equitable Sharing of Costs and Benefits of Offshore Leasing

(Critera for Policy Alternatives are Expressed as Percentage Differences from the Status Quo)

Alternatives 1-6

Critera	Status Quo	Alternative 1	Alt. 2	Alt 3	Alt. 4	Alt 5.	Alt. 6
	Current Leasing System	Fewer Tracts Offered (4,000)	Fewer Tracts Offered (400)	Decrease Royalty to 12.5%	Increase Royalty to 35%	Sliding Scale Royalty (35% to 12.5%)	Higher Minimum Bid
Revenue Sharing with Coastal States*	$ 20,556	-2.8%	4.7%	-14.7%	38.7%	14.3%	-5.2%
Onshore Economic Impacts	$ 27,925	-14.0%	-40.8%	7.1%	-11.4%	-3.5%	-14.8%
Discounted Environmental/Social Costs	$ 256	-4.4%	-11.7%	18.3%	-22.1%	-14.3%	-5.2%

Alternatives 7-12

Critera	Status Quo	Alt. 7	Alt. 8	Alt. 9	Alt.10	Alt. 11	Alt. 12
	Current Leasing System	Profit Share (30%) Royalty 18.75%	Profit Share (30%) No Royalty	Higher Area Rental Fee	Multi-Round Bidding	Work Commit-ment	Shorter Lease Term
Revenue Sharing with Coastal States*	$ 20,556	27.6%	-74.2%	5.4%	-0.9%	-5.0%	-2.9%
Onshore Economic Impacts	$ 27,925	0.0%	20.6%	-13.5%	-10.1%	43.6%	-17.8%
Discounted Environmental/Social Costs	$ 256	0.0%	50.3%	-7.1%	-3.5%	0.0%	-6.4%

*Revenue Sharing Calculations Do Not Consider $500M Annual Limit Under Section 105(f) of GOMESA

Dollar Values are Millions of 2003 Dollars

Table IV-5 Assessment of Criteria Under Alternative Lease Sale Scenarios (Con't)

(Critera for Policy Alternatives are Expressed as Percentage Differences from the Status Quo)

Alternatives 1-6

Goal 5. Facilitate Regional Planning and Minimize Env. Risks

Critera	Status Quo		Alternative 1	Alt. 2	Alt 3	Alt. 4	Alt 5.	Alt. 6
	Current Leasing System		Fewer Tracts Offered (4,000)	Fewer Tracts Offered (400)	Decrease Royalty to 12.5%	Increase Royalty to 35%	Sliding Scale Royalty (35% to 12.5%)	Higher Minimum Bid
Discounted Environmental/Social Costs	$	256	-4.4%	-11.7%	18.3%	-22.1%	-14.3%	-5.2%
Number of Tracts Offered	$	5,598	-50.0%	-95.0%	0.0%	0.0%	0.0%	0.0%
Number of Tracts Sold	$	119	-29.0%	-78.0%	0.3%	-1.0%	-0.1%	-33.5%
Total Discounted Production	$	3,733	-4.4%	-11.7%	18.3%	-22.1%	-14.3%	-5.2%
Number of Field Discovered	$	954	-5.6%	-25.5%	0.6%	-1.9%	-0.2%	-6.7%

Alternatives 7-12

Critera	Status Quo		Alt. 7	Alt. 8	Alt. 9	Alt.10	Alt. 11	Alt. 12
	Current Leasing System		Profit Share (30%) Royalty 18.75%	Profit Share (30%) No Royalty	Higher Area Rental Fee	Multi-Round Bidding	Work Commit-ment	Shorter Lease Term
Discounted Environmental/Social Costs	$	256	0.0%	50.3%	-7.1%	-3.5%	0.0%	-6.4%
Number of Tracts Offered	$	5,598	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Number of Tracts Sold	$	119	0.0%	0.8%	-29.4%	42.6%	-34.6%	13.0%
Total Discounted Production	$	3,733	0.0%	50.3%	-7.1%	-3.5%	0.0%	-6.4%
Number of Field Discovered	$	954	0.0%	1.7%	-5.7%	-4.4%	7.2%	-8.3%

Dollar Values are Millions of 2003 Dollars

Table IV-5 Assessment of Criteria Under Alternative Lease Sale Scenarios (Con't)

(Critera for Policy Alternatives are Expressed as Percentage Differences from the Status Quo)

Goal 6. Maximize Social Value

Alternatives 1-6

Critera	Status Quo: Current Leasing System	Alternative 1: Fewer Tracts Offered (4,000)	Alt. 2: Fewer Tracts Offered (400)	Alt 3: Decrease Royalty to 12.5%	Alt. 4: Increase Royalty to 35%	Alt 5.: Sliding Scale Royalty (35% to 12.5%)	Alt. 6: Higher Minimum Bid
Discounted Leasing Revenues	$ 81,333	-0.7%	10.2%	-3.6%	13.9%	4.3%	-2.7%
Discounted Federal Taxes	$ 24,541	-0.6%	-15.9%	20.5%	-35.8%	-16.6%	14.7%
Discounted Profit	$ 29,000	3.7%	-21.6%	17.3%	-34.6%	-17.1%	8.8%
Total Discounted Revenues	$ 134,874	0.3%	-1.4%	5.3%	-5.6%	-4.1%	2.9%
Discounted Lost Resources	1,876	8.8%	23.2%	-36.3%	44.0%	28.4%	10.4%
Discounted Environmental/Social Costs	$ 256	-4.4%	-11.7%	18.3%	-22.1%	-14.3%	-5.2%

Critera	Status Quo: Current Leasing System	Alt. 7: Profit Share (30%) Royalty 18.75%	Alt. 8: Profit Share (30%) No Royalty	Alt. 9: Higher Area Rental Fee	Alt.10: Multi-Round Bidding	Alt. 11: Work Commit-ment	Alt. 12: Shorter Lease Term
Discounted Leasing Revenues	$ 81,333	-0.1%	-22.1%	5.1%	-4.9%	-4.7%	-4.1%
Discounted Federal Taxes	$ 24,541	-30.6%	16.6%	-9.2%	4.7%	-18.3%	2.5%
Discounted Profit	$ 29,000	0.4%	41.8%	-16.4%	-1.3%	-45.2%	13.4%
Total Discounted Revenues	$ 134,874	-5.6%	-1.4%	-2.1%	-2.4%	-15.9%	0.9%
Discounted Lost Resources	1,876	0.0%	-100.0%	14.0%	7.0%	-0.1%	12.7%
Discounted Environmental/Social Costs	$ 256	0.0%	50.3%	-7.1%	-3.5%	0.0%	-6.4%

Dollar Values are Millions of 2003 Dollars

A higher royalty rate decreases competition (Goal 3), as it reduces the number of bids per tract. Increased royalty rates have offsetting effects on equitable sharing (Goal 4), as higher royalty rates are forecast to significantly increase shared revenues with coastal states and reduce environmental and social costs. But these effects are offset by a decrease in onshore expenditures associated with reduced OCS activity. At the same time, this reduction in activity reduces regional planning costs and environmental risks (Goal 5). We find an increased royalty rate will likely have a net negative effect on the overall social value of offshore development (Goal 6), because higher royalties distort incentives by making otherwise socially valuable resources unprofitable to extract. This lowers production because there are fewer profitable fields and because high royalties cause early closure of fields which are profitable despite the higher royalty.

Higher Minimum Bid

A higher minimum bid is forecast to reduce expeditious development of OCS resources (Goal 1) and to decrease OCS revenues (Goal 2). Higher minimum bids reduce the number of tracts sold, although the resultant tracts that go unsold are disproportionately lower-valued tracts. At the same time, a higher minimum bid will increase federal revenues from tracts that sell at the higher minimum bid, and would otherwise have sold at a lower bid.

Rather surprisingly, our model predicts that increasing the minimum bid slightly increases profits and associated federal corporate tax payments. This counterintuitive result likely occurs because tracts not leased due to the increased minimum bid are, on average, forecast by the model to be unprofitable. This suggests that either firms are overly optimistic about marginal tracts, or the model underestimates the potential of tracts that appear to be marginal tracts at the time of the lease sale. This remains an open question.

A higher minimum bid results in more bids per tract sold (Goal 3). However, this occurs because increasing the minimum bid results in some marginal tracts going unsold. These marginal tracts would otherwise be sold typically with only a single bid, at or near the minimum. Thus, while the average number of bids per tract sold increases with a higher minimum bid, this does not imply increased competition for the remaining tracts that sell at a price above the minimum bid.

Increasing minimum bids reduces OCS activities, thereby facilitating regional planning and reducing potential environmental risks (Goal 5), and is forecast to have mixed effects on social values (Goal 6). Again this conclusion either suggests that firms make errors in assessing marginal tracts, or the model underestimates the potential of tracts that appear marginal at the bidding stage.

Profit Share

Due to a total absence of experience with profit share in the past 25 years, and the modest experience in prior years, the model uses a theoretical implementation of profit shares, rather than an empirically-based approach. Theory suggests that profit shares do not distort incentives, since whatever action maximizes profit with no profit share, also maximizes net profit, after paying the share. Thus, adding a profit shares to the Status Quo policy with 18.75% royalty rate does not change OCS activity levels (Goal 1), royalties, or area rental payments. Using a 30% profit share in lieu royalty payments results in higher levels of OCS activity (Goal 1), since removing royalty payments eliminates the associated distortions in incentives for production.

Profit shares reduce the value of tracts to firms, and therefore reduce both cash bonus bids and federal corporate tax payments. Overall, we find a small decrease in OCS revenues (Goal 2) when adding a profit share to the Status Quo policy, and a larger decrease in revenue when using profit share in lieu of royalties, due to the elimination of all royalty payments. Overall, our model finds that federal take is lower under both profit share approaches than under the Status Quo. Adding profit share to the 18.75% royalty slightly reduces the number of bids per tract (Goal 3), since in some cases bids on marginal tracts fall below the minimum bid. Using a profit share in lieu of a royalty payment increases competition by increasing the number of bids per tract.

Adding profit share to the 18.75% Status Quo royalty has an overall positive effect on Equitable Sharing of Costs and Benefits (Goal 4). But using a 30% profit revenue share in lieu of royalty payments has offsetting effects, reducing revenue sharing and increasing environmental and social costs, while increasing onshore expenditures associated with increased OCS activity. Both profit share options are forecast to slightly reduce total discounted revenues (Goal 5).

Profit share approaches also have an important adverse effect on the Integrity of the Leasing Process (Goal 7). There are important practical problems attempting to implement a profit share approach, since it is difficult for the government agency to monitor profits by the firm. Profit share payments depend on accounting profits, and there is considerable flexibility for firms to allocate costs and revenues such that it can be difficult or impossible for the government to verify claims regarding the appropriate profit share payment. Indeed, past experience with profit shares has found considerable difficulties coming to agreement on profit share payments. In the mechanism design literature, these problems are referred to as imperfect monitoring.

Higher Rental Rates

Increasing area rental payments reduce the number of tracts sold, thereby reducing expeditious development of OCS resources (Goal 1). Increasing area rentals have mixed effects on federal revenues (Goal 2), decreasing bids and royalty payments, while increasing area rental payments. Overall, higher area rental rates are forecast to result in a small increase (1.8%) in federal revenues. This is not likely significant, given all of the uncertainties involved.

Increased area rental payments increase the number of bids per tract sold (Goal 3). However, similar to increasing minimum bids, increasing area rental payments reduces the marginal tracts that would otherwise be sold with only one bid, and thus increases the average number of bids per tract. However, this does not lead to any real increase in the competition for the remaining tracts. Increased area rentals has offsetting effects on equitable sharing of costs and benefits (Goal 4). This is because, increased area rentals increase revenues shared with coastal states and reduce environmental/social costs due to reduced activity. But at the same time, higher rental rates decrease onshore expenditures associated with offshore activity. Higher rental rates facilitate regional planning (Goal 5) due to the associated reduction in OCS activity.

Multi-Round Auctions

Multi-Round Auctions decrease most criteria associated with expeditious and orderly development (Goal 1), except for the average annual number of tracts sold. Multi-round auctions lead to more overall tracts sold, and more tracts sold early, but fewer tracts sold later when prices are higher and technology improves. Multi-Round auctions also reduce overall revenues slightly (Goal 2). Area rental payments increase significantly due to increased numbers of tracts sold, but otherwise discounted OCS revenues decline. Federal tax revenues increase, primarily because of lower cash bonus bids under multi-round auctions, which are otherwise written off for tax purposes.

Multi-round auctions lead to fewer bids per tract (Goal 3) as more marginal tracts are bid upon and sold, and these tracts receive few bids. Thus, while there are more bids overall, there are more tracts sold, and as a consequence fewer bids per tract sold. Revenue sharing with coastal states and onshore expenditures both decrease with multi-round auctions, but this is offset by environmental and social costs, which also decrease slightly (Goal 4).

Multi-round auctions considerably increase the number of tracts sold, thereby contributing to increased regional planning costs, but reduce other measures of planning costs and environmental risks (Goal 5). Multi-round auctions lead to an overall decrease in social value (Goal 6).

Work Commitment

Work commitment has offsetting effects on expeditious and orderly development of OCS resources (Goal 1). Work commitment increases exploratory activities on each tract sold, but the commitment to higher exploration activity decreases the number of tracts that appear profitable, and therefore reduces the number of tracts sold. The number of exploration wells increases significantly, and a small number of additional fields are discovered, but many of those fields are small fields that would not be found with a smaller level of effort, and are only marginally productive. Possible information externalities may occur whereby successful additional drilling encouraged by a work commitment spurs other firms to explore and develop other nearby tracts. However, our simulation model cannot capture such effects.

Work commitment decreases measures of obtaining fair market value (Goal 2), as cash bonus bids are reduced slightly, royalty payments increase, but area rental payments decline considerably due to fewer tracts sold. Overall, our model forecasts that revenues decline by about 8% with a work commitment policy. Bids per tract sold increase, but again this occurs because marginal tracts go unsold that would otherwise receive only one bid. This does not result in a real increase in competition for tracts that continue to be sold despite the work commitment.

Work commitment has offsetting effects on regional planning (Goal 5) by significantly decreasing the number tracts sold, while increasing the number of fields discovered and having only very small effects on other criteria. But work commitment has a negative effect on maximizing social value (Goal 6) by decreasing all sources of revenues, while having a small positive, but insignificant, overall effect on lost resources.

Shorter Lease Term

Shorter lease terms have negative effects on most measures of expediting development of OCS resources (Goal 1). The model forecasts that more tracts are sold, but this occurs because fewer fields are found due to the shorter lease period, and therefore there is less resource depletion. In effect, shorter lease terms reduce the effectiveness of exploration of tracts, such fields go undiscovered during exploration, and the associated tracts are resold in the future. By the same token, a shorter lease period is forecast to increase area rental payments, but is otherwise forecast to reduce revenues associated with OCS leasing (Goal 2) and reduce competition for tracts (Goal 3). Shorter lease terms slightly reduce revenue sharing, and significantly reduce state revenues associate with onshore expenditures, but reduce environmental and social costs (Goal 4). The model concludes that by most measures, regional planning (Goal 5) is facilitated by shorter lease terms, except that more tracts are sold, which might partially offset what would otherwise be reduced planning costs. Shorter lease periods are forecast to reduce most measures of overall social welfare (Goal 6).

Sensitivity Analyses

We also run several sensitivity analyses, whose results are reported in Table IV-A-2 in Appendix IV.A. The sensitivity analyses include scenarios for a lower oil price of $50 per barrel, a higher oil price of $120 per barrel, and a $90 per barrel oil price that is constant over time (i.e., no 2% real rate of increase as in the Status Quo scenario). We also run a sensitivity analysis that includes no technological change, and a sensitivity analysis that include no technological change and a constant $90 per barrel oil price.

Finally, we run two different sensitivity analysis that are based assumptions that new, unexpected oil discoveries occur that expand economically recoverable resources beyond the current MMS estimates of undiscovered fields. These sensitivity analyses are intended to represent unanticipated discoveries that bring about new ideas of where to search for additional reservoirs, as well as new advances in technology that allow discovery of fields in areas that are not currently feasible to find and/or develop, and therefore are not included in MMS undiscovered resource estimates.

The first scenario for new discoveries is based on the estimated number of undiscovered fields increasing at 0.48% per year, which is the result found for "output-biased" technological change by Managi et al, (2004). The second scenario for new discoveries is a more optimistic level of 1.5% per year, which is roughly based on the historic increases in MMS estimates of undiscovered resources estimates in the GOM. As indicated above, the results for the sensitivity analyses are reported in Table IV-A-2 in Appendix IV.A.

IV.C. Areawide OCS Leasing and Leasing in State Waters

We also explore the extent to which Areawide leasing in the federal waters of the GOM could potentially harm coastal states by reducing industry interest in, and revenues from, sales in state offshore waters by "flooding the market" with leases. Carrying out a thorough analysis of this issue would require an extensive study in its own right, and is beyond the scope of the present effort. Rather, we briefly review some readily available data to provide a perspective on the issue.

The effect that Areawide leasing in Federal waters has on State leasing revenues is dependent upon the extent to which tracts in State waters are close substitutes for tracts in Federal waters. While the products are the same – oil and gas – available evidence suggests that leases in federal waters may not be close substitutes for leases in state waters. Our discussion uses Louisiana as an example. Section II above provides additional details.

Louisiana State waters are mature oil and gas areas, which have been well explored and developed over many decades. The mature stage of production in offshore Louisiana is reflected by the steady decline in the production in state waters since reaching its peak in 1970 (http://dnr.louisiana.gov/sec/execdiv/techasmt/facts_figures/table04.htm). By 1983, offshore production in State of Louisiana offshore waters declined to about 1/3 of peak production, and by 2008 production declined to about 8% of peak production. Since discoveries of new resources considerably lead production, the peak in new discoveries in state waters must have started its decline even earlier, although we have not identified nor analyzed detailed data as part of this study. While we recognize offshore revenues remain important for the State of Louisiana, production in State waters has been in steady decline for nearly 40 years. Thus, production from offshore LA began to decline well before Areawide leasing was introduced.

Similarly, the shallow areas in Federal waters also have been well explored, with the vast share of OCS activity now occurring in deep water, far from shore (Iledare, et al., 2004). And this trend is virtually certain to continue into the future. Deep water oil and gas operations are highly sophisticated and rely on drill ships and semi-submersibles and accurate positioning, subsea completions, and operating in deep and risky waters far from shore. In short, technologies and equipment used for deepwater operations differ enormously from those in state waters. Transferability of equipment, technology and skilled personnel between nearshore and deepwater offshore areas is likely to be very limited.

Lastly, support for the notion that OCS oil and gas and petroleum operations in Louisiana state waters are not close substitutes is the fact that different companies are involved in each area and OCS operators show relatively low intensity in bidding for State of Louisiana tracts. We explored the issue of substitutability and intensity of interest by reviewing oil and gas companies' overlapping bids. These are cases where companies that bid on OCS tracts also bid on State of Louisiana offshore tracts (in Louisiana, "parcels").

We obtained from Minerals Management Service a list of companies that bid in federal offshore lease sales. According to the data obtained from MMS, 531 companies bid on OCS tracts from 1980 to 2008 inclusive. Turning to the State of Louisiana, our list of companies that participated in sales of offshore tracts came from sales data. Louisiana holds monthly oil and gas lease sales. We adopted a "convenience sample" for Louisiana whereby we considered all sales of parcels for every other monthly sale for the years 2003, 2005, 2007 and 2008, the last year for which data could be obtained. The sources we used and summary data are given in Table II-3, above.

On a company basis, of the 531 companies that bid on OCS tracts over the period 1980 – 2008, 35 (6.59%) also bid on the sample of Louisiana offshore parcels included in our convenience sample. The 35 companies that bid on both OCS and State of Louisiana offshore tracts are 13.83% of the 253 companies that bid on offshore State of Louisiana parcels. Firms that bid on OCS tracts apparently have only a modest interest in State of Louisiana offshore tracts, while firms that bid on Louisiana offshore tracts have a greater – but still relatively modest – interest in OCS tracts.

Looking instead at the number of bids, the 35 companies which bid on Louisiana offshore parcels and OCS tracts submitted 101 bids on Louisiana offshore lands. This is about 9% of the 1,117 bids in the State of Louisiana lease sales included in our convenience sample. This suggests that firms which bid in both Federal and State waters were relatively unaggressive in bidding for tracts in Louisiana offshore areas.

In summary, while we have not been able to carry out a thorough study of the issue, available evidence suggests that Federal and State offshore tracts are not close substitutes for each other. So one would expect that leasing policies in Federal waters would likely have relatively modest effects on leasing revenues in State offshore waters. The likely modest size of impacts on State revenues is to be reinforced by the fact that offshore production in State of Louisiana waters has been in decline for nearly 40 years, so that one might not expect substantial revenues from future lease sales. Furthermore, any adverse effect of Areawide on state leasing revenues would likely be offset, in whole or in part, by the associated increase in onshore expenditures that support offshore activities in the Federal waters (e.g., Dismukes et al, 2003). Together, this suggests that one would not expect that a policy of Areawide leasing in Federal OCS waters to have a large adverse effect on future revenues in Louisiana.

IV.D. Summary and Conclusions

This Technical Report describes an extensive study to assess alternative policies for leasing OCS oil and gas resources in the Central and Western Gulf of Mexico. The study employs a simulation model to forecast the pace of leasing, and associated OCS activities, revenues and other impact over a 50-year time horizon for lease sales. Alternative policies are compared to the Status Quo policy of Areawide leasing. The comparison is formulated in terms of the extent to which each policy can fulfill a set of policy Goals for OCS development.

This analysis finds that no single leasing policy alternative promises to outperform all other policies in terms of every Criteria. In particular, no policy outperforms the Status Quo policy of Areawide leasing in terms of all Goals. Rather, a policy that performs better at some policy Goals, is less effective at others. Hence, the choice among policy alternatives necessarily involves making tradeoffs across the various Goals of the OCS leasing process.

Furthermore, even considering an alternative that is more effective at achieving a particular Goal, there tends to be offsetting effects such that differences across alternatives are moderated, and are smaller than one might initially expect. For example, our model finds that greatly slowing the pace of leasing is expected to significantly increase cash bonus bids. But this is likely to be offset, in whole or in part, by subsequent delays and reductions in other payments such as royalties, area rentals and federal corporate taxes. A slower pace of leasing also adversely affects our ability to achieve some policy Goals (e.g., expeditious development of OCS resources), while benefiting others (e.g., facilitating regional planning).

Similarly, our analysis finds that higher royalty rates can increase royalty payments, but at the cost of lower cash bonus bids, area rental payments, and federal corporate tax payments. The analysis finds that financial gains from changes in royalty payments may be possible, but it is unlikely that large increases in overall revenues will result because of these various offsetting effects. Given the many uncertainties involved, and the absence of recent experience with higher royalty rates, one cannot conclude with confidence whether overall federal take will increase or decrease with higher royalty rates. But the model suggests that substantial gains seem unlikely. And increasing royalty rates also come at a cost of less expedited resource development and losses in social welfare due to the distortions which created in the incentive to leave in the ground extract otherwise profitable resources.

One larger lesson of this analysis is that, while the "Revenue Equivalence Theorem"[23] does not strictly apply to OCS leasing, there is a tendency towards equalization of revenues of the different policies that we consider. For example, increasing one or more of the fees will adversely affect tract values, so that the increase in the fees, in effect, becomes capitalized into the values of tracts. So increases in one fee will tend to be offset, in whole or in part, by reductions in cash bonus bids.

Tradeoffs are inevitable when comparing policy alternatives, and a thoughtful analysis of the full effects of various policies suggests that we need to have realistic expectations of possible gains from a particular option. This does not imply that no potential gains are possible from changing policies, but rather that offsetting effects imply that in many cases differences across alternatives are likely to be more modest than one might expect, and differences across policies will be difficult to forecast with confidence given the long time horizons involved and the many uncertainties.

Although our approach has examined incremental effects of individual policy changes on Goals, the results can also provide insight into combinations of policies that are most effective in attaining specific Goals, while recognizing the inevitable tradeoffs that result. For example, achieving the Expeditious and Orderly Development of OCS Resources (Goal 1) could be enhanced by combining policies, such as a lower royalty rate and a fast pace of leasing. Or if one wanted to Facilitate Regional Planning and Reduce Environmental Risk (Goal 5), this goal could be better achieved by reducing the pace of leasing while increasing the royalty rate. As noted earlier, the policies are not likely to be simply additive, and interaction effects are likely too difficult to ascertain with confidence given the many uncertainties and the long time horizon involved. But at the same time, policies are likely to have cumulative effects, so that if both policies are used together, there would likely be a larger effect than if either policy is used alone.

[23] The Revenue Equivalence Theorem is a well known result from auction theory, that roughly speaking says that under certain highly restrictive conditions, one can expect identical revenues from all "standard" auction designs (see, for example, Milgrom, 2004). Therefore, under these conditions, the specific form of the auction has no effect on the outcome. This Theorem is discussed in more detail in the Section III.B.

APPENDIX IV.A. Simulation Model Results for Policy Alternatives and Sensitivity Analyses

Table IV-A-1 Assessment of Criteria Under Alternative Lease Sale Scenarios

Goal 1. Expeditious and Orderly Development of OCS Resources

Alternatives 1-6

Critera	Status Quo Current Leasing System	Alternative 1 Fewer Tracts Offered (4,000)	Alt. 2 Fewer Tracts Offered (400)	Alt 3 Decrease Royalty to 12.5%	Alt. 4 Increase Royalty to 35%	Alt 5. Sliding Scale Royalty (35% to 12.5%)	Alt. 6 Higher Minimum Bid
Total Production (MMBOE)	22,113	21,997	24,468	25,657	17,251	19,131	21,991
Discounted Production (MMBOE)	3,733	3,567	3,297	4,415	2,907	3,199	3,537
Fields Discovered	954	901	711	960	936	952	891
Exploration Wells	10,931	9,478	5,740	11,108	10,412	10,866	9,219
Development Wells	5,267	5,140	5,251	5,948	4,219	4,638	5,119
Production Wells	11,467	11,200	11,633	13,160	9,487	10,288	11,156
Ave. Annual Number of Tracts Offered	5,598	2,799	280	5,598	5,598	5,598	5,598
Average Annual Tracts Sold	119	85	26	119	118	119	79

Alternatives 7-12

Critera	Status Quo Current Leasing System	Alt. 7 Profit Share (30%) Royalty 18.75%	Alt. 8 Profit Share (30%) No Royalty	Alt. 9 Higher Area Rental Fee	Alt.10 Multi-Round Bidding	Alt. 11 Work Commit-ment	Alt. 12 Shorter Lease Term
Total Production (MMBOE)	22,113	22,113	32,453	21,437	22,013	21,090	22,000
Discounted Production (MMBOE)	3,733	3,733	5,609	3,469	3,601	3,734	3,495
Fields Discovered	954	954	971	900	912	1,023	876
Exploration Wells	10,931	10,931	11,432	9,452	9,765	17,567	8,855
Development Wells	5,267	5,267	7,354	5,041	5,165	5,195	5,091
Production Wells	11,467	11,467	16,288	11,014	11,253	11,371	11,100
Ave. Annual Number of Tracts Offered	5,598	5,598	5,598	5,598	5,598	5,598	5,598
Average Annual Tracts Sold	119	119	120	84	170	78	135

Table IV-A-1 Assessment of Criteria Under Alternative Lease Sale Scenarios (Con't)

Goal 2. Obtain Fair Market Value for Leased Resources

Alternatives 1-6

Critera	Status Quo	Alternative 1	Alt. 2	Alt 3	Alt. 4	Alt 5.	Alt. 6
	Current Leasing System	Fewer Tracts Offered (4,000)	Fewer Tracts Offered (400)	Decrease Royalty to 12.5%	Increase Royalty to 35%	Sliding Scale Royalty (35% to 12.5%)	Higher Minimum Bid
Discounted High Bids	$ 31,464	$ 35,239	$ 47,923	$ 37,458	$ 19,278	$ 26,211	$ 31,386
Discounted Royalties	$ 44,290	$ 42,626	$ 41,336	$ 35,326	$ 67,804	$ 53,079	$ 43,543
Discounted Area Rental Payments	$ 5,579	$ 2,919	$ 337	$ 5,593	$ 5,537	$ 5,574	$ 4,178
Discounted Profit Share							
Total Discounted OCS Revenues	$ 81,333	$ 80,784	$ 89,595	$ 78,377	$ 92,619	$ 84,863	$ 79,106
Discounted Federal Taxes	$ 24,541	$ 24,403	$ 20,632	$ 29,580	$ 15,756	$ 20,465	$ 28,136
Total Discounted Revenues	$ 105,874	$ 105,187	$ 110,227	$ 107,957	$ 108,374	$ 105,328	$ 107,243

Alternatives 7-12

Critera	Status Quo	Alt. 7	Alt. 8	Alt. 9	Alt.10	Alt. 11	Alt. 12
	Current Leasing System	Profit Share (30%) Royalty 18.75%	Profit Share (30%) No Royalty	Higher Area Rental Fee	Multi-Round Bidding	Work Commit-ment	Shorter Lease Term
Discounted High Bids	$ 31,464	$ 22,659	$ 37,499	$ 29,395	$ 24,601	$ 30,735	$ 29,743
Discounted Royalties	$ 44,290	$ 44,290	$ -	$ 41,710	$ 42,963	$ 44,444	$ 41,922
Discounted Area Rental Payments	$ 5,579	$ 5,579	$ 5,618	$ 14,416	$ 9,819	$ 2,304	$ 6,340
Discounted Profit Share		$ 8,700	$ 20,204				
Total Discounted OCS Revenues	$ 81,333	$ 81,228	$ 63,320	$ 85,521	$ 77,382	$ 77,483	$ 78,005
Discounted Federal Taxes	$ 24,541	$ 17,042	$ 28,616	$ 22,281	$ 25,685	$ 20,054	$ 25,152
Total Discounted Revenues	$ 105,874	$ 98,270	$ 91,936	$ 107,801	$ 103,068	$ 97,537	$ 103,157

Dollar Values are Expressed in Millions of 2003 Dollars

Table IV-A-1 Assessment of Criteria Under Alternative Lease Sale Scenarios (Con't)

Goal 3. Promote Competition

Alternatives 1-6

Critera	Status Quo	Alternative 1	Alt. 2	Alt 3	Alt. 4	Alt 5.	Alt. 6
	Current Leasing System	Fewer Tracts Offered (4,000)	Fewer Tracts Offered (400)	Decrease Royalty to 12.5%	Increase Royalty to 35%	Sliding Scale Royalty (35% to 12.5%)	Higher Minimum Bid
Bids per Tract	1.26	1.36	2.04	1.29	1.20	1.24	1.30

Alternatives 7-12

Critera	Status Quo	Alt. 7	Alt. 8	Alt. 9	Alt.10	Alt. 11	Alt. 12
	Current Leasing System	Profit Share (30%) Royalty 18.75%	Profit Share (30%) No Royalty	Higher Area Rental Fee	Multi-Round Bidding	Work Commit-ment	Shorter Lease Term
Bids per Tract	1.26	1.23	1.30	1.36	1.18	1.40	1.22

Table IV-A-1 Assessment of Criteria Under Alternative Lease Sale Scenarios (Con't)

Goal 4. Equitable Sharing of Costs and Benefits of Offshore Leasing

Alternatives 1-6

Critera	Status Quo	Alternative 1	Alt. 2	Alt 3	Alt. 4	Alt 5.	Alt. 6
	Current Leasing System	Fewer Tracts Offered (4,000)	Fewer Tracts Offered (400)	Decrease Royalty to 12.5%	Increase Royalty to 35%	Sliding Scale Royalty (35% to 12.5%)	Higher Minimum Bid
Revenue Sharing with Coastal States*	$ 20,556	$ 19,982	$ 21,522	$ 17,530	$ 28,511	$ 23,494	$ 19,493
Onshore Economic Impacts	$ 27,925	$ 24,012	$ 16,524	$ 29,911	$ 24,731	$ 26,953	$ 23,805
Discounted Environmental/Social Costs	$ 256	$ 245	$ 226	$ 303	$ 200	$ 220	$ 243

Alternatives 7-12

Critera	Status Quo	Alt. 7	Alt. 8	Alt. 9	Alt.10	Alt. 11	Alt. 12
	Current Leasing System	Profit Share (30%) Royalty 18.75%	Profit Share (30%) No Royalty	Higher Area Rental Fee	Multi-Round Bidding	Work Commit-ment	Shorter Lease Term
Revenue Sharing with Coastal States*	$ 20,556	$ 26,225	$ 5,295	$ 21,660	$ 20,379	$ 19,526	$ 19,961
Onshore Economic Impacts	$ 27,925	$ 27,925	$ 33,680	$ 24,165	$ 25,101	$ 40,111	$ 22,953
Discounted Environmental/Social Costs	$ 256	$ 256	$ 385	$ 238	$ 247	$ 256	$ 240

*Revenue Sharing Calculations Do Not Consider $500M Annual Limit Under Section 105(f) of GOMESA

Dollar Values are Expressed in Millions of 2003 Dollars

Table IV-A-1 Assessment of Criteria Under Alternative Lease Sale Scenarios (Con't)

Goal 5. Facilitate Regional Planning and Minimize Env. Risks

Alternatives 1-6

Critera	Status Quo	Alternative 1	Alt. 2	Alt 3	Alt. 4	Alt 5.	Alt. 6
	Current Leasing System	Fewer Tracts Offered (4,000)	Fewer Tracts Offered (400)	Decrease Royalty to 12.5%	Increase Royalty to 35%	Sliding Scale Royalty (35% to 12.5%)	Higher Minimum Bid
Discounted Environmental/Social Costs	$ 256	$ 245	$ 226	$ 303	$ 200	$ 220	$ 243
Number of Tracts Offered	5,598	2,799	280	5,598	5,598	5,598	5,598
Number of Tracts Sold	119	85	26	119	118	119	79
Total Discounted Production	3,733	3,567	3,297	4,415	2,907	3,199	3,537
Number of Field Discovered	954	901	711	960	936	952	891

Alternatives 7-12

Critera	Status Quo	Alt. 7	Alt. 8	Alt. 9	Alt.10	Alt. 11	Alt. 12
	Current Leasing System	Profit Share (30%) Royalty 18.75%	Profit Share (30%) No Royalty	Higher Area Rental Fee	Multi-Round Bidding	Work Commit-ment	Shorter Lease Term
Discounted Environmental/Social Costs	$ 256	$ 256	$ 385	$ 238	$ 247	$ 256	$ 240
Number of Tracts Offered	5,598	5,598	5,598	5,598	5,598	5,598	5,598
Number of Tracts Sold	119	119	120	84	170	78	135
Total Discounted Production	3,733	3,733	5,609	3,469	3,601	3,734	3,495
Number of Field Discovered	954	954	971	900	912	1,023	876

Dollar Values are Expressed in Millions of 2003 Dollars

Table IV-A-1 Assessment of Criteria Under Alternative Lease Sale Scenarios (Con't)

Goal 6. Maximize Social Value

Alternatives 1-6

Critera	Status Quo	Alternative 1	Alt. 2	Alt 3	Alt. 4	Alt 5.	Alt. 6
	Current Leasing System	Fewer Tracts Offered (4,000)	Fewer Tracts Offered (400)	Decrease Royalty to 12.5%	Increase Royalty to 35%	Sliding Scale Royalty (35% to 12.5%)	Higher Minimum Bid
Discounted Leasing Revenues	$ 81,333	$ 80,784	$ 89,595	$ 78,377	$ 92,619	$ 84,863	$ 79,106
Discounted Federal Taxes	$ 24,541	$ 24,403	$ 20,632	$ 29,580	$ 15,756	$ 20,465	$ 28,136
Discounted Profit	$ 29,000	$ 30,061	$ 22,739	$ 34,010	$ 18,980	$ 24,040	$ 31,559
Total Discounted Revenues	$ 134,874	$ 135,248	$ 132,966	$ 141,967	$ 127,355	$ 129,368	$ 138,801
Discounted Lost Resources	1,876	2,041	2,311	1,194	2,701	2,409	2,071
Total Discounted Production	3,733	3,567	3,297	4,415	2,907	3,199	3,537

Alternatives 7-12

Critera	Status Quo	Alt. 7	Alt. 8	Alt. 9	Alt.10	Alt. 11	Alt. 12
	Current Leasing System	Profit Share (30%) Royalty 18.75%	Profit Share (30%) No Royalty	Higher Area Rental Fee	Multi-Round Bidding	Work Commit-ment	Shorter Lease Term
Discounted Leasing Revenues	$ 81,333	$ 81,228	$ 63,320	$ 85,521	$ 77,382	$ 77,483	$ 78,005
Discounted Federal Taxes	$ 24,541	$ 17,042	$ 28,616	$ 22,281	$ 25,685	$ 20,054	$ 25,152
Discounted Profit	$ 29,000	$ 29,105	$ 41,108	$ 24,254	$ 28,626	$ 15,900	$ 32,876
Total Discounted Revenues	$ 134,874	$ 127,376	$ 133,044	$ 132,055	$ 131,694	$ 113,437	$ 136,033
Discounted Lost Resources	1,876	1,876	-	2,139	2,007	1,875	2,113
Total Discounted Production	3,733	3,733	5,609	3,469	3,601	3,734	3,495

Dollar Values are Expressed in Millions of 2003 Dollars

Table IV-A-2. Sensitivity Analyses

Goal 1. Expeditious and Orderly Development of OCS Resources

Critera	Status Quo Current Leasing System	Sensitivy 1 Lower Oil Price ($50)	Sensitivy 2 Higher Oil Price ($120)	Sensitivity 3 Constant Real Oil Price ($90)	Sensitivity 4 No Technolog y Change	Sensitivity 5 Constant Real Price, No Tech Change	Sensitivy 6 Increase New Fields (0.48%/Yr)	Sensivity 7 Increase New Fields (1.5%/Yr)
Total Production (MMBOE)	22,113	13,372	35,351	20,534	20,320	19,341	48,421	133,644
Discounted Production (MMBOE)	3,733	2,299	6,100	3,580	3,550	3,480	4,868	7,988
Fields Discovered	954	906	977	919	905	870	1,252	2,230
Exploration Wells	10,931	9,605	11,631	9,800	10,864	9,731	13,260	17,434
Development Wells	5,267	3,307	7,973	4,896	5,034	4,725	9,909	24,757
Production Wells	11,467	7,474	17,835	10,745	11,016	10,411	22,320	22,320
Ave. Annual Number of Tracts Offered	5,598	5,598	5,598	5,598	5,598	5,598	5,598	5,598
Average Annual Tracts Sold	119	116	121	115	118	114	157	258

Goal 2. Obtain Fair Market Value for Leased Resources

Critera	Status Quo Current Leasing System	Sensitivy 1 Lower Oil Price ($50)	Sensitivy 2 Higher Oil Price ($120)	Sensitivity 3 Constant Real Oil Price ($90)	Sensitivity 4 No Technolog y Change	Sensitivity 5 Constant Real Price, No Tech Change	Sensitivy 6 Increase New Fields (0.48%/Yr)	Sensity 7 Increase New Fields (1.5%/Yr)
Discounted High Bids	$ 31,464	$ 7,357	$ 59,888	$ 27,061	$ 28,950	$ 25,113	$ 47,740	$ 95,172
Discounted Royalties	$ 44,290	$ 16,564	$ 96,432	$ 40,422	$ 42,126	$ 39,365	$ 63,759	$ 119,593
Discounted Area Rental Payments	$ 5,579	$ 5,465	$ 5,633	$ 5,547	$ 5,810	$ 5,775	$ 6,211	$ 7,417
Discounted Profit Share								
Total Discounted OCS Revenues	$ 81,333	$ 29,385	$ 161,953	$ 73,029	$ 76,886	$ 70,254	$ 117,710	$ 222,181
Discounted Federal Taxes	$ 24,541	$ (28)	$ 59,172	$ 20,820	$ 22,059	$ 19,049	$ 42,565	$ 95,517
Total Discounted Revenues	$ 105,874	$ 29,357	$ 221,125	$ 93,848	$ 98,945	$ 89,303	$ 160,275	$ 317,699

Dollar Values are Expressed in Millions of 2003 Dollars

Table IV-A-2. Sensitivity Analyses (Con't)

Goal 3. Promote Competition

Critera	Status Quo Current Leasing System	Sensitivy 1 Lower Oil Price ($50)	Sensitivity 2 Higher Oil Price ($120)	Sensitivity 3 Constant Real Oil Price ($90)	Sensitivity 4 No Technolog y Change	Sensitivity 5 Constant Real Price, No Tech Change	Sensitivy 6 Increase New Fields (0.48%/Yr)	Sensivity 7 Increase New Fields (1.5%/Yr)
Bids per Tract	1.26	1.12	1.36	1.19	1.22	1.17	1.34	1.49

Goal 4. Equitable Sharing of Costs and Benefits of Offshore Leasing

Critera	Status Quo Current Leasing System	Sensitivy 1 Lower Oil Price ($50)	Sensitivity 2 Higher Oil Price ($120)	Sensitivity 3 Constant Real Oil Price ($90)	Sensitivity 4 No Technolog y Change	Sensitivity 5 Constant Real Price, No Tech Change	Sensitivy 6 Increase New Fields (0.48%/Yr)	Sensivity 7 Increase New Fields (1.5%/Yr)
Revenue Sharing with Coastal States*	$ 20,556	$ 11,020	$ 60,732	$ 27,386	$ 28,832	$26,345	$ 44,141	$83,318
Onshore Economic Impacts	$ 27,925	$ 21,238	$ 31,999	$ 25,909	$ 27,864	$25,780	$ 33,084	$45,020
Discounted Environmental/Social Costs	$ 256	$ 158	$ 419	$ 246	$ 244	$239	$ 334	$549

*Revenue Sharing Calculations Do Not Consider $500M Annual Limit Under Section 105(f) of GOMESA

Dollar Values are Expressed in Millions of 2003 Dollars

Table IV-A-2. Sensitivity Analyses (Con't)

Goal 5. Facilitate Regional Planning and Minimize Env. Risks

Critera	Status Quo	Sensitivy 1	Sensitivity 2	Sensitivity 3	Sensitivity 4	Sensitivity 5	Sensitivy 6	Sensivity 7
	Current Leasing System	Lower Oil Price ($50)	Higher Oil Price ($120)	Constant Real Oil Price ($90)	No Technology Change	Constant Real Price, No Tech Change	Increase New Fields (0.48%/Yr)	Increase New Fields (1.5%/Yr)
Discounted Environmental/Social Costs	$ 256	$ 158	$ 419	$ 246	$ 244	$ 239	$ 334	$ 549
Number of Tracts Offered	5,598	5,598	5,598	5,598	5,598	5,598	5,598	5,598
Number of Tracts Sold	119	116	121	115	118	114	157	258
Total Discounted Production	3,733	2,299	6,100	3,580	3,550	3,480	4,868	7,988
Number of Field Discovered	954	906	977	919	905	870	1,252	2,230

Goal 6. Maximize Social Value

Critera	Status Quo	Sensitivy 1	Sensitivity 2	Sensitivity 3	Sensitivity 4	Sensitivity 5	Sensitivy 6	Sensivity 7
	Current Leasing System	Lower Oil Price ($50)	Higher Oil Price ($120)	Constant Real Oil Price ($90)	No Technology Change	Constant Real Price, No Tech Change	Increase New Fields (0.48%/Yr)	Increase New Fields (1.5%/Yr)
Discounted Leasing Revenues	$ 81,333	$ 29,385	$ 161,953	$ 73,029	$ 76,886	$ 70,254	$ 117,710	$ 222,181
Discounted Federal Taxes	$ 24,541	$ (28)	$ 59,172	$ 20,820	$ 22,059	$ 19,049	$ 42,565	$ 95,517
Discounted Profit	$ 29,000	$ (12,475)	$ 85,006	$ 22,870	$ 24,265	$ 19,253	$ 59,934	$ 151,610
Total Discounted Revenues	$ 134,874	$ 16,882	$ 132,966	$ 141,967	$ 127,355	$ 129,368	$ 131,694	$ 127,376
Discounted Lost Resources	1,876	2,041	2,311	1,194	2,701	2,409	2,007	1,876
Total Discounted Production	3,733	3,567	3,297	4,415	2,907	3,199	3,601	3,733

Dollar Values are Expressed in Millions of 2003 Dollars

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