

Effects of Royalty Incentives for Gulf of Mexico Oil and Gas Leases

Volume II: Technical Report



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Chapter 1

Introduction

Project Overview

The Deepwater Royalty Relief Act of 1995 (DWRRA) mandated royalty suspension in significant amounts for leases sold in the central and western Gulf of Mexico on all new deepwater oil and gas leases, meaning those sold from 1996 to 2000 in water depths of 200 meters or more, and for certain pre-Act leases upon application and approval. When this new lease provision expired, the U.S. Department of the Interior (DOI), Minerals Management Service (MMS), continued the program, with detailed changes to the incentives, on a sale-by-sale basis. Generally the changes mandated royalty relief on a lease-by-lease basis rather than on a field basis, and the suspension volumes were considerably lower. The shift from Congressional to administrative program created two important tasks for MMS's program office: (1) to assess the actual effects of the program thus far, and (2) to apply knowledge gleaned from item (1) toward designing royalty incentives for future sales.

The MMS has requested that Innovation & Information Consultants, Inc. (IIC, Inc.) perform an independent study and evaluation of the effect of the deepwater royalty relief program as it relates to leasing behavior and activity, exploration activity, and to the extent possible, exploration and development of oil and gas resources in the Gulf of Mexico (GoM). The project was divided into two tasks. The first task analyzed historical data on leasing and exploration activities in the Gulf of Mexico, and included testing statistically for the significance of royalty relief incentives. We analyzed the value and quantity of deepwater leases sold and the amount of exploration and discovery that has taken place. We have also examined the impacts of the program begun under the Deepwater Royalty Relief Act (DWRRA) in 1996-2000 as well as the MMS administrative program from 2001 to 2003. Due to lack of detailed data on exploration, development, and production trends on DWRRA leases, our analysis has focused on the impacts on leasing and exploration activity. The second task of the project involved developing projections of possible future impacts from several alternative programs. This simulation of future impacts begins in 2003, and due to modeling complexities, does not revisit what actually occurred between 1996 and 2002 in terms of royalty incentives even in the no incentive case.

The alternative future programs were provided to us by MMS and included the following:

1. A deepwater royalty relief program that resumes (in the first forecast year) the original provisions of the DWRRA, implemented with a field-based definition of suspension volume and new production requirement. (*DWRR – Field*)
2. A deepwater royalty relief program that resumes the provisions of the DWRRA, but is implemented with a lease-based definition of suspension volume and dropping the new production requirement. (*DWRR – Lease*)

3. A deepwater royalty relief program that continues the program like the current administrative program, with a lease-based definition of suspension volume specified for year 2003 sales. (*Current*)
4. No future royalty relief for deepwater leases beginning in the first model forecast year. (*No Relief*)

One difference between the DWRRA and the post-2000 program is that the former used a “field” definition of the relief volume suspension whereas the latter uses a “lease” definition. In general, a field is a set of pools that are geologically connected and are developed together, and a field can lie in more than one block (and less commonly, a block can cover more than one field). In contrast, a lease is associated with a single block. The DWRRA mandated a specific volume of relief (which varied by water depth), and MMS interpreted the language to mean that the leases in a field share a common suspension volume for that field. After 2000, MMS’s program stipulated volumes be applied to individual leases. These suspension volumes were significantly lower than under the original DWRRA.

This distinction became more important when lessees sued DOI, stating that the DWRRA ought to be interpreted using a lease definition of the suspension volume. On October 4, 2004, the 5th Circuit Court of Appeals upheld a United States District Court ruling in *Santa Fe-Snyder Corporations, et al. v. Norton, et al.* Under the court’s ruling, leases that were issued under the DWRRA (sales between 1996 and 2000) have lease-specific, rather than field-based, royalty suspension volume. In addition, the Court ruled that MMS’s denial of relief to deepwater leases in fields that had other leases with production prior to November 1995 was also invalid. Recent debate includes claims about what the 1996-2000 sales would have generated if, counterfactually, the lease definition had been in place.¹ MMS is interested in assessing whether the generally more generous, lease-based definition of royalty relief will accelerate exploration and subsequent activities and how to structure future leasing programs. In Task 2, IIC, Inc. has projected the effects of the four alternative cases including effects on drilling, discoveries, development, and production and impacts on bonus bids and rentals as well as royalty revenues.

Volume I presents a summary of the results of our study most relevant to policy analysis while this volume, Volume II, provides more technical details regarding the statistical modeling, and historical data analyses we performed.

Outline of Volume II

The first step in estimating the effects of deepwater royalty relief is lease sale analysis. The identity that gives overall structure to the lease sale analysis is:

$$\text{Bonus revenues in } t = (\text{Leases sold in } t) * (\text{High bid per lease in } t)$$

¹ *Santa Fe-Snyder Corporations, et al. v. Norton, et al.*, 385 F.3d 885 (5th Cir. 2004) and also see *Kerr McGee Oil and Gas Corp. v. MMS*, No. 03-CV-0060, which also relates to the lease versus field definition issue. The government is not appealing these rulings and will soon issue new regulations conforming to these decisions.

The impact of deepwater royalty relief on bonus revenues can be analyzed in terms of its impact on number of leases sold and its impact on the high bid per lease. More fully, this study analyzes the lease sale impacts of royalty relief as the difference between:

- Leases and revenues in actuality, where lease terms included royalty relief for a number of years, and,
- Leases and revenues in a hypothetical (or, counterfactual) case, the product of analysis, where it is assumed that there was never such a thing as deepwater royalty relief.

Principal issues about the analysis are:

- Number of leases sold is influenced, among other factors, by participants in the sale and their leasing objectives. Further, the number of participants is affected by royalty relief. The idea is that when the prices of items are lowered, it attracts more customers to the store and they buy more. Thus, the treatment of leases sold calls for regression using a two-equation model.
- At each lease, the bid amounts are co-determined with the numbers of bids. The theoretical bidding model shows how a bidder decides on the amount to bid after considering his estimate of the underlying block value (which is affected by royalty relief), the potential for competing bids, and the possibility that other bidders make different estimates of the block value. Thus, the treatment of high bid calls for a two-equation regression model for high bid and competition per tract.
- In this study, the analysis of leases sold is separate from the analysis of high bid per tract (i.e., the two variables are not part of an all-encompassing multiple-equation model). It is recognized that theory suggests that the two variables are linked, but problems prevent econometric analysis of the connection.

Following the lease sale analysis, Volume II turns to exploration and production effects of deepwater royalty relief. An exploration, development, and production (EDP) model can be used to make projections of oil and gas development and production based on assumptions of leases sold and other factors. Moreover, projections of future royalty revenues can be derived from production projections. Thus, the incremental effect of royalty relief on future production and royalty revenues can be derived using the EDP model. Bearing these issues in mind, the analysis proceeds by the following steps:

Chapter 1. Summarizing the main results from Volume II, this chapter gives the effect of royalty relief on total bonus revenues, inferred from effects on leases sold (Chapter 3) and average high bid (Chapter 5) as well as the results regarding exploration activity and the future projection of various policy scenarios using our EDP model.

Chapter 2. Literature Review

Chapter 3. The effect of deepwater royalty relief on leases sold and participants considered together.

Chapter 4. The effect of deepwater royalty relief on competition is considered by itself.

Chapter 5. The effect of deepwater royalty relief on high bids and competition is considered together

Chapter 6. The effect on exploration and discovery of new fields.

Chapter 7. The effect of alternative deepwater royalty relief policies on future oil and gas development, production, and royalties.

Deepwater Royalty Relief

The OCS Deep Water Royalty Relief Act (DWRRA) 43 U.S.C. §1337, enacted by Congress in November 1995, was designed to promote increased exploration and development and increased production on leases found in deepwater areas of the Gulf of Mexico. The legislation provided economic incentives for operators to develop new fields in water depths of 200 meters or more. These incentives included royalty relief (or “suspension” of royalties – “RSV”) for new leases issued between 1996 and 2000 on the initial barrels of oil equivalent (BoE) produced from a deepwater field² as detailed in Table 1-1 below. However, if a lease granted during the DWRRA period produces oil or gas from a field that had production prior to 1996, then that lease does not obtain royalty relief. Royalty relief can also be obtained on pre-DWRRA leases upon application and approval based on a showing that the field would not be economic to develop and produce without royalty relief. A price threshold of \$28.00 per barrel (1994 dollars), NYMEX annual average, for oil and \$3.50 per MMBtu gas, both to be inflated by the GDP implicit price deflator, was provided, meaning that royalties were to be paid when prices exceeded those annual average levels.

Table 1-1. Royalty Suspension Volumes (Field-Specific) Under DWRRA, by Water Depth.

<i>Lease Water Depth</i>	<i>RSV (MM BOE)</i>
0-200 m	None
200-400 m	17.5
400-800 m	52.5
800-plus m	87.5

Initially, the MMS interpreted the Act to mean that the RSV related to production from fields (which can encompass more than one lease block) instead of leases, and it also restricted relief in cases where there had been any production at a field prior to the Act. This study has not investigated whether the administrative policies affected bidding or other activities.

² As noted above, the determination of whether leases issued under DWRRA are entitled to relief on a field or a lease basis is the subject of pending litigation.

After the provisions of DWRRA expired, MMS included deepwater royalty relief in the terms of each sale, and these provisions form the post-DWRRA program. The terms for the years covered by this study as shown in Table 1-2 were:³

Table 1-2. Royalty Suspension Volumes (Lease-Specific) Under Post-DWRRA Program, by Sale and Water Depth.

<i>Sale</i>	<i>Year</i>	<i>Lease Water Depth</i>	<i>RSV (MM BOE)</i>
178	2001	800-1600 m	9
		1600-plus m	12
180	2001	800-1600 m	9
		1600-plus m	12
182	2002	400-800 m	5
		800-1600 m	9
		1600-plus m	12
184	2002	400-800 m	5
		800-1600 m	9
		1600-plus m	12
185	2003	400-800 m	5
		800-1600 m	9
		1600-plus m	12
187	2003	400-800 m	5
		800-1600 m	9
		1600-plus m	12
189	2003	1600-plus m	12

Note: Sale 189 related to the Eastern Gulf of Mexico

Summary of Lease Sale Analysis

The main results of the econometric lease sale analysis are presented in the following three tables. It is noted that the estimates shown here must be qualified by assumptions made and low statistical significance in some instances, as explained in later chapters. Table 1-3 gives the actual data for leases sold and high bids in deepwater (Central and Western regions) for royalty relief periods. The periods are DWRRA, 1996-2000, and post-DWRRA, 2001-2003 (the most recent year covered by the data). For instance, in 200-800 meters, the average number of leases sold per year over 1996-2000 was 97. (The number varied substantially year by year, as shown below.) The average of high bids accepted per tract (in other words, cash bonus bids) was \$0.94 million for the same set of tracts. Thus, total cash bonus averaged ($97 * 0.94 =$) \$91 million per year for this set of tracts.

³ Price thresholds were provided for these sales as well. Deep gas royalty relief was also instituted for shallow water leases during this period.

Table 1-3. Deepwater Lease Sales, Actual Results for Royalty Relief Policy Periods.

	DWRRA 1996-2000		Post-DWRRA 2001-2003	
	200-800 m	800-plus m	200-800 m	800-plus m
Leases Sold Per Year	97	580	99	295
Cash Bonus (High Bid) Per Tract, \$MM	\$0.94	\$0.91	\$0.88	\$0.84
Total Cash Bonus Per Year, \$MM	\$91	\$529	\$87	\$249

Table 1-4 gives the inferred values for the same variables, based on the econometric analysis of the impacts of deepwater royalty relief. Specifically, the econometric model simulated the number of leases sold if the policy period variable were omitted from the model.⁴ Omitting the policy period variable removed from the simulation the influence of the royalty relief policy period; instead, only other factors like number of bidders, joint bidding behavior, etc., remained to determine the number of leases sold. For instance, without the influence of the royalty relief policy period, leases sold per year in 200-800 meters would have averaged 53 per year (instead of the actual 97).

Table 1-4. Inferred Results of Deepwater Lease Sales Assuming No Royalty Relief.

	DWRRA 1996-2000		Post-DWRRA 2001-2003	
	200-800 m	800-plus m	200-800 m	800-plus m
Leases Sold Per Year	53	367	79	221
Cash Bonus (High Bid) Per Tract, \$MM	\$0.72	\$0.58	\$0.92	\$0.73
Total Cash Bonus Per Year, \$MM	\$38	\$214	\$73	\$162

The difference between the actual and the inferred cases is a measure of the influence of the royalty relief period on leases sold, cash bonus per tract, and total cash bonus. The difference is shown in Table 1-5. For instance, it turns out that the DWRRA period added \$53 million per year to total sale revenues in 200-800 meters. From that number, one can calculate ($53 * 5 =$) \$265 million added revenues in that water depth for the entire DWRRA period (not shown in the table).

⁴ In this section, the phrase “policy period variable” and similar expressions allude to the model dummy variables that had the value 1 during policy period years and 0 otherwise. Statistically, dummy variables must be interpreted to represent both the policy and other factors changing at the same time not explicit in the model.

Table 1-5. Estimated Effects of Royalty Relief Periods on Deepwater Lease Sale Results.

	DWRRA 1996-2000		Post-DWRRA 2001-2003	
	200-800 m	800-plus m	200-800 m	800-plus m
Difference in Leases Sold Per Year	44	213	20	75
Difference in Cash Bonus (High Bid) Per Tract, \$MM	\$0.22	\$0.33	-\$0.04	\$0.11
Difference in Total Cash Bonus Per Year, \$MM	\$53	\$315	\$15	\$87

Two factors that made important contributions to lease sale results are the number of *participants* in sales and the level of *competition* among them. The number of participants was important because royalty relief, by increasing the expected profitability of investing in a lease, tended both to attract more buyers and to increase the lease purchases per buyer. Overall, the number of participants in lease sales has varied considerably from year to year.

In Table 1-6, the average number of participants per sale is presented by policy period, for deepwater. For instance, the number of participants, averaging over Central and Western sales from 1996-2000, was 28 in 200-800 meters. Table 1-6 also presents the portion of the actual participants that is attributed to royalty relief. For instance, 16 participants of the 28 (average for 200-800 meters in 1996-2000) were “added” by the policy period, although the study did not try to distinguish between participants who had bid in earlier sales and participants who were completely new to the Gulf of Mexico sales. In addition, a trend toward participation by non-major firms began during the DWRRA period. For example, in 800-plus meters, the average share by majors fell from 82 percent (1983-1995) to 51 percent (1996-2000) to 32 percent (2001-2003).

Table 1-6. Estimated Effects of Royalty Relief Periods on Participants.

	DWRRA 1996-2000		Post-DWRRA 2001-2003	
	200-800 m	800-plus m	200-800 m	800-plus m
Average Participants Per Sale	28	34	24	23
Participants Per Sale Attributed To Royalty Relief	16	12	9	9

We measured competition as the number of bids per tract (including tracts where lease was not awarded). As shown in Table 1-7, the average number of bids per tract in deepwater averaged between 1.28 and 1.48 for the royalty relief periods. It is estimated that the DWRRA period had a positive effect on competition (mainly 1996-1997), however, the post-DWRRA period was associated with a decline in competition, after accounting for other factors.

Table 1-7. Estimated Effects of Royalty Relief Periods on Competition.

	DWRRA 1996-2000		Post-DWRRA 2001-2003	
	200-800 m	800-plus m	200-800 m	800-plus m
Average Bids Per Tract By Period	1.48	1.46	1.38	1.27
Bids Per Tract Attributed To Royalty Relief	0.06	0.04	-0.07	-0.11

Derivation of Lease Sale Summary

The preceding section's summary is based on a combination of results from Chapters 3 through 5. This section presents the relevant results from Chapters 3 to 5 and demonstrates how they are combined to arrive at the summary. The demonstration proceeds step by step, presenting:

1. Data of leases sold and high bids in the actual case (where the policies are in effect)
2. Computation of actual total sale revenue
3. Policy effects on leases sold and high bids as estimated by regression analysis
4. Computation of hypothetical total sale revenue without policy

Historical Data: Leases and Acres Bid On Or Bid Accepted

Table 1-8 shows the count of tracts bid on and leases sold in the Central and Western Gulf of Mexico, as well as annual averages.⁵ For instance, the annual average of tracts bid on in 0-200 meters, for the 1983-1995 period equals (5993 / 13 =) 461. In this study, "leases sold" refers to tracts where high bid is accepted.⁶

The annual averages do not represent the year-by-year variation in tracts bid on or leased. In reality, the variation was substantial, as shown in the Figure 1-1. The onset of DWRRA, for instance, was associated with a three-year spike of leases sold. The key implication of the graph is that there are two phenomena that are not represented by the annual averages: (a) policy periods begin by lifting the series from previously low levels, and (b) the rise in the series does not endure for the entire policy periods.

⁵ Data for the Eastern Gulf of Mexico were omitted from most analyses for this study, as explained in Chapter 3.

⁶ The distinctions between tracts bid on, bids accepted, and leases awarded can be confusing. If the high bid for a tract is not less than the MMS value for the tract, then the high bid is accepted, however, for purposes of this study, bid acceptance is strictly indicated by an element of the MMS database that reports "accepted" or "rejected." (Between 1983 and 2002, there were 16,371 "accepted" bid instances in the Central and Western Gulf, whereas there were 16,185 leases where the high bid was not less than the MMS value.) Lease award normally follows upon bid acceptance, but there are rare instances where legal or other problems prevent award.

Table 1-8. Tracts Bid On Or Leases Sold (Central And Western).

0-200	Tracts Bid On		Leases Sold	
	Count	Annual Average	Count	Annual Average
Pre-Policy 1983-1995	5993	461	5586	430
DWRRA 1996-2000	1974	395	1910	382
Post_DW 2001-2003	1379	460	1347	449
All	9346	445	8843	421
200-800	Tracts Bid On		Leases Sold	
	Count	Annual Average	Count	Annual Average
Pre-Policy 1983-1995	1216	94	1180	91
DWRRA 1996-2000	513	103	485	97
Post_DW 2001-2003	315	105	297	99
All	2044	97	1962	93
800+	Tracts Bid On		Leases Sold	
	Count	Annual Average	Count	Annual Average
Pre-Policy 1983-1995	1778	137	1780	137
DWRRA 1996-2000	3009	602	2900	580
Post_DW 2001-2003	897	299	886	295
All	5684	271	5566	265

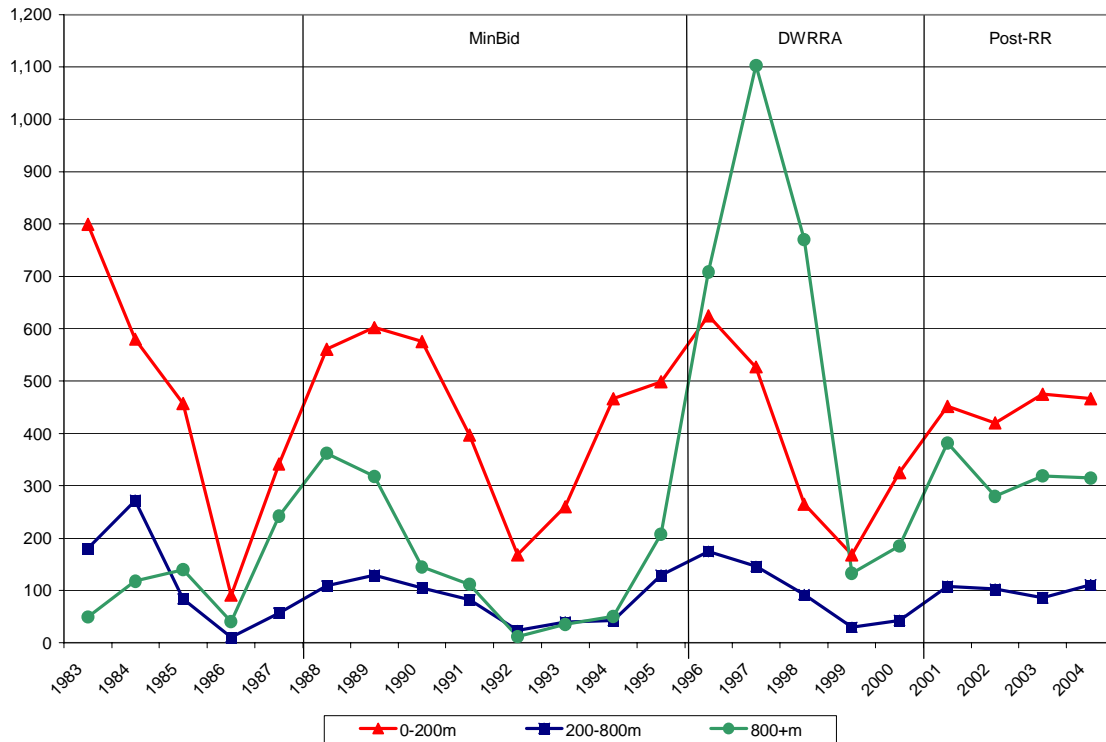


Figure 1-1. Leases Sold, By Water Depth.

The changes between the pre-policy and the royalty relief period of leases sold are given in Table 1-9. These numbers are provided to contrast with the impact estimates of the regression analysis later in the chapter. As can be clearly seen, in deepwater the average number of leases sold increased significantly during the policy period.

Table 1-9. Leases Sold, Difference of 1983-1995 and Royalty Relief Periods.

	Leases Sold, Annual Average		
	0-200	200-800	800+
DWRRA 1996-2000	-48	6	443
Post_DW 2001-2003	19	8	158

Historical Data: High Bids and High Bids Per Acre

Bonus revenue is computed in this study on the basis of total of high bids accepted (that is, at leases sold). The historical data are given in the following tables. Table 1-10 gives the high bids placed or accepted over the periods indicated, and it also provides the annual average. Table 1-11 displays the high bids per tract and per acre. This table includes acres-per-tract factors, which are computed as the high bids per tract divided by the high bids per acre. Although acres-per-tract might appear to be a small detail, the fact is that average tract size varies among different sets of tracts, and it is accounted for explicitly in these tables.⁷

⁷ A “full sized” tract size is 5,760 acres, but since some tracts are not full-sized, average tract size is generally smaller.

Table 1-10. Total High Bids Placed and Accepted.

0-200	High Bids Placed \$MM		High Bids Accepted \$MM	
	Total	Annual Average	Total	Annual Average
Pre-Policy	\$9,070.23	\$697.71	\$8,503.54	\$654.12
DWRRA	\$1,172.53	\$234.51	\$1,154.38	\$230.88
Post-DWRRA	\$614.77	\$204.92	\$602.49	\$200.83
All	\$10,857.54	\$517.03	\$10,260.41	\$488.59
200-800	High Bids Placed \$MM		High Bids Accepted \$MM	
	Total	Annual Average	Total	Annual Average
Pre-Policy	\$2,536.86	\$195.14	\$2,506.28	\$192.79
DWRRA	\$478.10	\$95.62	\$464.53	\$92.91
Post-DWRRA	\$277.80	\$92.60	\$267.29	\$89.10
All	\$3,292.76	\$156.80	\$3,238.10	\$154.20
800+	High Bids Placed \$MM		High Bids Accepted \$MM	
	Total	Annual Average	Total	Annual Average
Pre-Policy	\$1,166.46	\$89.73	\$1,164.64	\$89.59
DWRRA	\$2,745.25	\$549.05	\$2,655.36	\$531.07
Post-DWRRA	\$756.93	\$252.31	\$740.58	\$246.86
All	\$4,668.63	\$222.32	\$4,560.58	\$217.17

Table 1-11. High Bids per Tract and Per Acre.

0-200 m	Mean High Bids Placed			Mean High Bids Accepted		
	Per Tract	Per Acre	Acres Per Tract	Per Tract	Per Acre	Acres Per Tract
Pre-Policy	\$1,508,186	\$327.30	4608	\$1,522,295	\$330.09	4612
DWRRA	\$594,590	\$126.98	4683	\$604,389	\$129.08	4682
Post-DWRRA	\$446,135	\$96.51	4623	\$447,613	\$96.85	4622
All	\$1,159,498	\$251.15	4617	\$1,160,417	\$251.16	4620
200-800 m	Mean High Bids Placed			Mean High Bids Accepted		
	Per Tract	Per Acre	Acres Per Tract	Per Tract	Per Acre	Acres Per Tract
Pre-Policy	\$2,089,667	\$380.08	5498	\$2,123,967	\$386.13	5501
DWRRA	\$933,796	\$169.40	5512	\$957,794	\$173.97	5506
Post-DWRRA	\$881,920	\$154.42	5711	\$912,250	\$159.71	5712
All	\$1,613,309	\$292.40	5517	\$1,653,780	\$299.69	5518
800-plus m	Mean High Bids Placed			Mean High Bids Accepted		
	Per Tract	Per Acre	Acres Per Tract	Per Tract	Per Acre	Acres Per Tract
Pre-Policy	\$653,477	\$114.59	5703	\$654,290	\$114.73	5703
DWRRA	\$911,437	\$160.51	5678	\$915,643	\$161.33	5676
Post-DWRRA	\$842,905	\$146.64	5748	\$835,873	\$145.43	5748
All	\$819,778	\$143.93	5696	\$819,365	\$143.90	5694

A summary of the change in high bids accepted, computed as the policy period minus the 1983-1995 “pre-policy” period, is shown in Table 1-12. The change is computed in this way in order to contrast it with the policy effects estimated by means of regression models with dummy variables. The mean high bids per acre fell from the 1983-1995 “pre-policy” period to lower means in the royalty relief periods, except for the 800-plus meter water depth class. In 800-plus meter, the change from 1983-1995 “pre-policy” mean was positive for the DWRRA period and

positive by a smaller amount for the post-DWRRA period. In interpreting this table, it is important to bear in mind that the period averages do not reveal how the variables changed over the periods. For instance, the 1983-1995 averages are lifted by the relatively higher bids placed in the first portion of that period. A different picture would emerge from showing a sub-period preceding the policy periods. These details are examined in Chapter 5.

Table 1-12. High Bids, Difference of 1983-1995 Pre-Policy and Royalty Relief Periods.

0-200 m	High Bids Accepted Per Tract	High Bids Accepted Per Acre \$/a	Difference in High Bids Per Tract	Difference in High Bids Per Acre \$/a
	Mean	Mean	Policy-Pre-Policy	Policy-Pre-Policy
Pre-Policy	\$1,522,295	\$330.09	NA	NA
DWRRA	\$604,389	\$129.08	-\$917,906	-\$201.02
Post-DWRRA	\$447,613	\$96.85	-\$1,074,682	-\$233.24
200-800 m	High Bids Accepted Per Tract	High Bids Accepted Per Acre \$/a	Difference in High Bids Per Tract	Difference in High Bids Per Acre \$/a
	Mean	Mean	Policy-Pre-Policy	Policy-Pre-Policy
Pre-Policy	\$2,123,967	\$386.13	NA	NA
DWRRA	\$957,794	\$173.97	-\$1,166,174	-\$212.16
Post-DWRRA	\$912,250	\$159.71	-\$1,211,717	-\$226.42
800-plus m	High Bids Accepted Per Tract	High Bids Accepted Per Acre \$/a	Difference in High Bids Per Tract	Difference in High Bids Per Acre \$/a
	Mean	Mean	Policy-Pre-Policy	Policy-Pre-Policy
Pre-Policy	\$654,290	\$114.73	NA	NA
DWRRA	\$915,643	\$161.33	\$261,353	\$46.60
Post-DWRRA	\$835,873	\$145.43	\$181,583	\$30.69

Lease Sale Effects of Royalty Relief

The study performed various statistical analyses of tracts bid on or leased and high bids, including: univariate analysis; correlation analysis of leasing and bidding variables and a variety of other variables; and single and multiple equation regression analysis and simulation. Chapters 3 through 5 provide details of the lease sale analyses. An important limitation of the analysis is that it does not examine whether leases sold attributed to policy periods might represent, to some extent, some acceleration in leasing. For instance, it is possible that the 1996-1999 boom in deepwater leasing included the leasing of some blocks that “might” have been leased a few years later even in absence of royalty relief. The comparative static framework of this study cannot investigate that dimension of the policy effects.

The effects given below are based on multivariate regression models that incorporated period dummy variables. When interpreting estimates of policy period dummies, there are two important considerations:

- The dummy variables reflect both the change in royalty relief policy from pre-relief to DWRRA or to the post-DWRRA program, as well as other factors not accounted for by other regressors. The implicit factors include a possible decline in the geologic potential or prospectiveness of tracts offered as the “best were sold

first.” In its effect on high bid levels, a decline in geologic potential from pre-relief to royalty relief periods would oppose the positive effect of royalty relief on profitability. *Thus the expected signs of the policy period dummies are indeterminate.*

- Regressors present in the models provide insight into changes taking place besides policy. For instance, there is a significant trend for tracts offered to be re-offerings; that is, more and more frequently tracts offered have been either leased (or at least bid on) previously. Generally, a re-offered tract is associated with greater information, which tends to raise the level of bids if any are received. That tendency reduces any increase of high bids attributable to policy period dummies.

Further, estimates of some model parameters are statistically insignificant, and results are sensitive to detailed assumptions made for two-stage least-squares regression, as explained in later chapters.

Effects on Leases Sold and High Bids

Table 1-13 presents the regression model results for the number of leases sold. The table repeats, for convenience, actual leases sold, and then gives leases sold that the regression analysis attributes to the policy period dummy variable. For example, in 800-plus meters, the DWRRA dummy accounts for 213 out of 580 leases sold. Thus, in the hypothetical (counterfactual) case of no policy, it is estimated that 367 leases would have been sold, on average per year.

Table 1-13. Policy Period Effects on Leases Sold.

0-200	Annual Actual Leases Sold	Annual Leases Attributed to Policy	Annual Hypothetical Leases Sold (No Policy)
Pre-Policy 1983-1995	430	0	430
DWRRA 1996-2000	382	-6	388
Post_DW 2001-2003	449	44	405
200-800	Annual Actual Leases Sold	Annual Leases Attributed to Policy	Annual Hypothetical Leases Sold (No Policy)
Pre-Policy 1983-1995	91	0	91
DWRRA 1996-2000	97	44	53
Post_DW 2001-2003	99	20	79
800+	Annual Actual Leases Sold	Annual Leases Attributed to Policy	Annual Hypothetical Leases Sold (No Policy)
Pre-Policy 1983-1995	137	0	137
DWRRA 1996-2000	580	213	367
Post_DW 2001-2003	295	75	221

Similarly, Table 1-14 presents the effects of royalty relief on high bids per acre. In this table, it is striking that, while the DWRRA program has estimated effects that are positive (as

expected), the post-DWRRA period has counterintuitive negative effects in 200-800 meters. Why is that? First, *competition* is an important determinant of average high bids, according to the regression model. Competition for a tract was reduced by the policy period in this category. Second, factors such as declining geologic potential of tracts offered and other trends, as mentioned before, cancel the effect of royalty relief per se, and these can give the policy period dummies a negative effect.

Table 1-14. Policy Period Effects on High Bid Per Acre.

0-200	Annual Actual High Bid Accepted Per Acre	Annual High Bid Per Acre Attributed to Policy Variable	Annual Hypothetical High Bid Per Acre (No Policy)
Pre-Policy	\$330.09	\$0.00	\$330.09
DWRRA	\$129.08	\$13.76	\$115.32
Post-DWRRA	\$96.85	-\$16.52	\$113.37
200-800 m	Annual Actual High Bid Accepted Per Acre	Annual High Bid Per Acre Attributed to Policy Variable	Annual Hypothetical High Bid Per Acre (No Policy)
Pre-Policy	\$386.13	\$0.00	\$386.13
DWRRA	\$173.97	\$39.69	\$134.28
Post-DWRRA	\$159.71	-\$7.02	\$166.73
800-plus m	Annual Actual High Bid Accepted Per Acre	Annual High Bid Per Acre Attributed to Policy Variable	Annual Hypothetical High Bid Per Acre (No Policy)
Pre-Policy	\$114.73	\$0.00	\$114.73
DWRRA	\$161.33	\$57.85	\$103.48
Post-DWRRA	\$145.43	\$19.26	\$126.16

Combined Effect on Total High Bids

Table 1-15 shows the actual total high bids (or cash bonus revenues). For instance, in 0-200 meters for the “pre-policy” period, 1983-1995:

1. \$330.09 high bid per acre times 4,612 acres per tract equals \$1,522,295 high bid per tract, annual average for the period
2. 430 leases sold times \$1,522,295 equals \$654,118,520 total high bids (cash bonus revenue), annual average for the period
3. \$654,118,520 total per year times 13 years in period equals \$8.5 billion high bids (cash bonus revenues) for the entire period

Table 1-16 presents the hypothetical (counterfactual) total high bids (or cash bonus revenues) as inferred from regression analysis. The computation is the same as for actual high bids. Finally, Table 1-17 shows the effects of policy on period total high bids (cash bonus

revenues), computed as the difference of actual (with relief) and hypothetical (without relief) cash bonus revenues. In the end, the combined effect of royalty relief policy on high bid revenues is positive for all deepwater depth classes and royalty relief periods.

Table 1-15. Actual Total High Bids (Cash Bonus Revenue) at Leases Sold.

0-200	Annual Actual Leases Sold	Actual High Bid Accepted Per Acre	Acres Per Tract	Actual High Bid Accepted Per Tract	Annual High Bids At Leases Sold	Years In Period	Period Total High Bids At Leases Sold
Pre-Policy	430	\$330.09	4612	\$1,522,295	\$654,118,520	13	\$8,503,540,761
DWRRA	382	\$129.08	4682	\$604,389	\$230,876,580	5	\$1,154,382,901
Post-DWRRA	449	\$96.85	4622	\$447,613	\$200,978,336	3	\$602,935,009
200-800 m	Annual Actual Leases Sold	Actual High Bid Accepted Per Acre	Acres Per Tract	Actual High Bid Accepted Per Tract	Annual High Bids At Leases Sold	Years In Period	Period Total High Bids At Leases Sold
Pre-Policy	91	\$386.13	5501	\$2,123,967	\$192,790,858	13	\$2,506,281,156
DWRRA	97	\$173.97	5506	\$957,794	\$92,905,972	5	\$464,529,862
Post-DWRRA	99	\$159.71	5712	\$912,250	\$90,312,764	3	\$270,938,293
800-plus m	Annual Actual Leases Sold	Actual High Bid Accepted Per Acre	Acres Per Tract	Actual High Bid Accepted Per Tract	Annual High Bids At Leases Sold	Years In Period	Period Total High Bids At Leases Sold
Pre-Policy	137	\$114.73	5703	\$654,290	\$89,587,403	13	\$1,164,636,241
DWRRA	580	\$161.33	5676	\$915,643	\$531,072,948	5	\$2,655,364,738
Post-DWRRA	295	\$145.43	5748	\$835,873	\$246,861,120	3	\$740,583,361

Table 1-16. Hypothetical (No Policy) High Bids (Cash Bonus Revenues).

0-200	Annual Hypothetical (No Policy) Leases Sold	Annual Hypothetical (No Policy) High Bid Per Acre	Acres Per Tract	Annual Hypothetical High Bid Per Tract	Annual Hypothetical (No Policy) High Bids	Years In Period	Period Hypothetical (No Policy) High Bids
Pre-Policy	430	\$330.09	4612	\$1,522,295	\$654,118,520	13	\$8,503,540,761
DWRRA	388	\$115.32	4682	\$539,978	\$209,614,910	5	\$1,048,074,552
Post-DWRRA	405	\$113.37	4622	\$523,962	\$212,316,074	3	\$636,948,222
200-800 m	Annual Hypothetical (No Policy) Leases Sold	Annual Hypothetical (No Policy) High Bid Per Acre	Acres Per Tract	Annual Hypothetical High Bid Per Tract	Annual Hypothetical (No Policy) High Bids	Years In Period	Period Hypothetical (No Policy) High Bids
Pre-Policy	91	\$386.13	5501	\$2,123,967	\$192,790,858	13	\$2,506,281,156
DWRRA	53	\$134.28	5506	\$739,292	\$39,000,524	5	\$195,002,620
Post-DWRRA	79	\$166.73	5712	\$952,369	\$75,067,163	3	\$225,201,490
800-plus m	Annual Hypothetical (No Policy) Leases Sold	Annual Hypothetical (No Policy) High Bid Per Acre	Acres Per Tract	Annual Hypothetical High Bid Per Tract	Annual Hypothetical (No Policy) High Bids	Years In Period	Period Hypothetical (No Policy) High Bids
Pre-Policy	137	\$114.73	5703	\$654,290	\$89,587,403	13	\$1,164,636,241
DWRRA	367	\$103.48	5676	\$587,329	\$215,423,506	5	\$1,077,117,530
Post-DWRRA	221	\$126.16	5748	\$725,159	\$159,957,125	3	\$479,871,376

Table 1-17. Effect of Policy on Total Cash Bonus Revenues.

0-200	Period Total High Bids at Leases Sold	Period Hypothetical (No Policy) High Bids	Total High Bid Attributed to Policy Variable
Pre-Policy	\$8,503,540,761	\$8,503,540,761	\$0
DWRRA	\$1,154,382,901	\$1,048,074,552	\$106,308,349
Post-DWRRA	\$602,935,009	\$636,948,222	(\$34,013,213)
200-800 m	Period Total High Bids at Leases Sold	Period Hypothetical (No Policy) High Bids	Total High Bid Attributed to Policy Variable
Pre-Policy	\$2,506,281,156	\$2,506,281,156	\$0
DWRRA	\$464,529,862	\$195,002,620	\$269,527,242
Post-DWRRA	\$270,938,293	\$225,201,490	\$45,736,803
800-plus m	Period Total High Bids at Leases Sold	Period Hypothetical (No Policy) High Bids	Total High Bid Attributed to Policy Variable
Pre-Policy	\$1,164,636,241	\$1,164,636,241	\$0
DWRRA	\$2,655,364,738	\$1,077,117,530	\$1,578,247,208
Post-DWRRA	\$740,583,361	\$479,871,376	\$260,711,985

Overview of Exploration Impacts

Royalty relief influences not only the leasing process, but also subsequent activity related to exploration, development, and production of oil and gas resources. For example, royalty relief may create incentives to drill sooner in certain areas or to explore deepwater areas more intensively. Greater emphasis on exploration may lead to accelerated rates of discoveries and subsequent production. Such impacts are important to understand as they have implications for future policy direction. Unfortunately, limited information exists on the effects of royalty relief on exploration and discovery for leases that were sold during the DWRRA period. New drilling activity and new discoveries are continually emerging and exploration activity in the Gulf is constantly changing. Furthermore, leases sold in water depths greater than 800 meters have a ten-year lease term, and therefore, even leases sold in the first year of the DWRRA (1996) have not yet expired and thus limited information exists about impacts for leases sold in these water depths. Leases sold in the 200-400 meter range have five-year terms and therefore some exploration and discovery information is known about these leases, at least for the 1996-1998 period. Finally, leases in the 400-800 meter range have eight-year terms and thus only a limited amount of information is known about these leases that were sold during DWRRA.

Table 1-18 presents three measures of exploration activity broken out by time period and water depth: the average number of leases drilled, the average number of leases filing exploration plans, and the average number of leases either having drilled and/or filed an exploration plan. As expected, in the more recent time periods, and in deeper water, there is less overall exploration activity, particular in 800-plus meter, where only 10 percent of DWRRA leases and 4 percent of post-DWRRA leases have either drilled or filed an exploration plan with

MMS. This is largely attributable to the lag between the purchase of a lease and the commencement of exploration activity on the lease.

Table 1-18. Mean Number of Leases Drilled and/or Filing Exploration Plans, By Period and Depth.

	Mean Leases Sold	Mean Leases Drilled	Percent of Leases Drilled	Mean Leases Filing E-Plans	Percent of Leases Filing E-Plans	Mean Leases Drilled OR Filed E-Plan	Percent of Leases Drilled OR Filed E-Plan
0-200 m							
Pre-Policy 1983-1995	430	181	42%	170	40%	227	53%
DWRRRA 1996-2000	382	109	28%	113	31%	144	38%
Post-RR 2001-2003	449	75	17%	56	14%	97	22%
200-800 m							
Pre-Policy 1983-1995	91	25	27%	19	22%	31	34%
DWRRRA 1996-2000	97	16	17%	22	24%	25	26%
Post-RR 2001-2003	99	9	9%	6	6%	11	11%
800-plus m							
Pre-Policy 1983-1995	137	19	14%	22	17%	27	20%
DWRRRA 1996-2000	580	32	5%	45	8%	58	10%
Post-RR 2001-2003	295	10	3%	7	3%	13	4%

Data on leases drilled is current as of August 2004

Statistical Analysis of Exploration Activity

The model results for leases sold in all water depths and each planning area indicated that tract type had the strongest influence on the likelihood that a lease would be drilled. Table 1-19 presents the results of the probit model for 800-plus meters where the dependent variable takes on the value of 1 if the lease has been drilled. Other variables were positive and significant including competition, high bid, lagged oil price, and whether the lease was on a block in which prior leases had been sold. Water depth, sale date, and majors were significant and had negative coefficients, indicating that these factors made it less likely a lease would be drilled.

Table 1-19. Probit Parameter Estimates for Leases Drilled, 800-plus meter.

McFadden R-squared	0.2072	Obs with Dep=0	4061
Dependent Mean	0.0957	Obs with Dep=1	430
Root MSE	0.2668	Total obs	4491
Variable	Parameter Estimate	Chi-Square	Pr > ChiSq
Intercept	0.0128	0.0055	0.9407
High Bid by Major Bidder	-0.3399	25.2570	0.0000
High Bid	0.0000	149.8046	0.0000
Oil Price	-0.0226	11.7325	0.0006
Repeat Block	0.5995	65.7068	0.0000
Water Depth	-0.0003	26.7248	0.0000
WGM	-0.3530	29.5221	0.0000
DWRRRA	-0.5946	56.6366	0.0000

The sign on the coefficient for the DWRRRA dummy variable was negative in the model in which wells drilled was the dependent variable, but positive and significant when exploration plans was the dependent variable. While the data are limited, the fact that exploration plans are

filed before drilling takes place provides some indication that over time the sign on the DWRRA dummy may change in the well-drilled regression, but at this point it appears that the data are too limited to conclude much about the impact of royalty relief on exploration activity. This idea is substantiated when looking at simulation results of the hypothetical situation had no policy existed as presented in Table 1-20. In all cases, the models, which are based on regression results performed by water depth, estimate that the probability of a lease drilling would actually *increase* had the policy not existed. For example, in 800-plus meters, the model predicts that 13 percent of leases would have drilled had no policy existed, compared to the actual probability of only 5 percent.

Table 1-20. Simulation Results of Probability of Lease Drilling Without Policy.

0-200	Annual Actual Probability of Lease Drilling	Annual Probability of Lease Drilling Attributed to Policy Variable	Annual Hypothetical Probability of Lease Drilling (No Policy)
Pre-Policy	42%	0%	42%
DWRRA	28%	-7%	35%
200-800	Annual Actual Probability of Lease Drilling	Annual Probability of Lease Drilling Attributed to Policy Variable	Annual Hypothetical Probability of Lease Drilling (No Policy)
Pre-Policy	27%	0%	27%
DWRRA	17%	-10%	27%
800+	Annual Actual Probability of Lease Drilling	Annual Probability of Lease Drilling Attributed to Policy Variable	Annual Hypothetical Probability of Lease Drilling (No Policy)
Pre-Policy	14%	0%	14%
DWRRA	5%	-8%	13%

The second stage of the model provided even less meaningful results. We modeled discoveries as a probability distribution over the leases for which drilling had taken place, i.e., the subset of drilled leases. In all cases the royalty relief dummy variable was not significant, and the explanatory power of the regression was low. Given the strong likelihood that we would be unable to produce a model in which the royalty relief variable would attain any significance, we did not attempt to develop this model any further.

Overview of Projected Future Impacts of Alternative Program Designs

Turning to Task 2, Table 1-21 summarizes the net fiscal effects per barrel of oil equivalent discovered that one can expect from implementing each of the four royalty alternatives.⁸ Net fiscal effects include the sum of royalty, lease, and bonus revenue collected between 2003 and 2042, discounted to a 2003 present value using a 12 percent discount rate. In particular, we focus on the amount of foregone royalties necessary to discover each incremental

⁸ Task 2 included projections of the future rather than historical statistical analysis and contained two primary components: (1) projections of royalty-paying and royalty-free production from DWRRA and subsequent programs under several policy scenarios, and (2) hypothetical projections that enable the policy analyst to assess the “tradeoff” of production and revenue for alternative deepwater royalty relief policies in general.

barrel. To perform this analysis we compare the amount of reserves discovered in each policy alternative that provides royalty relief versus the No Relief scenario.

Table 1-21. Foregone Royalties per Incremental BOE Discovered for Each Alternative Compared with No Relief Scenario, 2003-2042 Projection.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Reserves Discovered (mmBOE)	Present Value Royalty Revenue (mm)	Present Value of Lease Bonus and Rental Revenue (mm)	Total Present Value of Fiscal Variables (mm)	Dollar per BOE
DWRR - Field	All	30	4.54	49,005	\$54,901	\$5,300	\$60,201	
			Diifference	1,006			-\$1,989	-\$1.98
DWRR - Lease	All	30	4.54	49,772	\$52,148	\$6,099	\$58,247	
			Diifference	1,773			-\$3,942	-\$2.22
Current	All	30	4.54	48,692	\$56,291	\$4,290	\$60,581	
			Diifference	693			-\$1,608	-\$2.32
No Relief	All	30	4.54	47,999	\$58,367	\$3,823	\$62,190	

Note: Values in \$2003. Present value at 12%. Reserves are ultimate (grown) amounts.

Table 1-21 indicates a clear trade-off between the increase in reserves discovered and a decrease in royalty revenue collection. On one hand, for this \$30/bbl scenario, all forms of royalty relief lead to an increase in the amount of reserves discovered versus the No Relief scenario. In assessing the results of Table 1-21, it is important to note we are using a simulation of the future to demonstrate the trade-off between incremental discovery effects and revenue collection. The No Relief scenario does not back-cast what *would* have happened between 1996 and 2002 without deepwater royalty relief.

Analysis of projected production data indicates that simulations using royalty relief alternatives increase production from future discoveries. In addition, we realize that along with this increase in production comes a decrease in the amount of royalty revenue collected due to a greater portion of the production enjoying relief from royalties as a result of each policy alternative. While the ultimate cumulative projected production from forecasted discoveries extends far beyond the 2042 forecast cut-off, the amount of reserves discovered allows an investigation into the impacts of each alternative.

One might expect that as royalty relief increases, the amount of foregone royalties would increase per incremental barrel of reserves discovered. Yet, when we consider the present value of additional lease bonus and rental revenue, we actually observe a greater trade-off in terms of reserves discovery and total revenue collection for the Current Program (on a per barrel basis) versus the highest relief scenario, DWRR – Lease. For every additional barrel discovered under the current royalty alternative, \$2.32 is “lost” in royalty revenue. The larger per barrel amount of foregone royalties for the current alternative is largely driven by a minimal change in lease and bonus royalty revenue compared with the No Relief scenario. However, while the current royalty alternative does not appear to generate much excitement at the leasing level, those who find and develop reserves under this program are taking advantage of the royalty incentives – to

the point it is “costing” the government more per barrel in lost revenue than the larger royalty relief alternatives.

Chapter 2

Literature Review

In this chapter we discuss our review of the theoretical and empirical literature on lease bidding, especially as it relates to the Gulf of Mexico. We undertook this review of the literature for two purposes: first, to understand particular theories and approaches to modeling leasing and bidding behavior to assist in our development of such models; and second, to review prior studies that have examined the effects of governmental policy on leasing and bidding behavior. Appendix A to this volume includes a bibliography of all of the sources we reviewed that were found to be particularly relevant. In this chapter we focus on those articles that influenced the development of our approach to analyzing deepwater leasing and bidding or our alternative programmatic analysis contained in Task 2. We have divided the literature into several different categories including literature on lease bidding and auction theory, statistical policy analysis of leasing, and analysis of DWRRA.

Lease Bidding Literature

To a large extent the lease bidding literature begins with the early work performed by Capen et al. (1971) on competitive bidding and application of decision theory to the analysis of bidding.⁹ We discuss the Capen et al. model in greater detail in Chapter 5 as we rely on this model as an approach to explain bidding for deepwater tracts and the role MMS plays to influence such bidding behavior. The Capen et al. model takes an omniscient point of view of a single bidder competing for a tract of uncertain value against uncertain competition. The point of view is omniscient in that it knows the true value to the bidder of what is being sold. In the model, the bidder gets a random estimate of the value of the tract with a known, log-normally distributed error distribution. The model is strictly proportional. In particular, the bidder's strategy is characterized as a fraction (not a general function) of its estimate. The model assumes that the bidder makes an estimate of its competition. The bidder may model specific competitors or generic ones. For each competitor, it assigns a probability to its bidding, a probability distribution of its random, log-normally distributed value estimate, and a deterministic or random distribution of its proportional bidding strategy. The model uses a Monte Carlo simulation of the auction, and calculates the bidder's expected gain or loss for a wide range of bidding fractions. From this, it is easy to select the "bid fraction" that produces the highest expected return.

The Capen et al. model allows for the "winner's curse" phenomenon caused by competition for a tract of uncertain value.¹⁰ The winning bidder is normally the bidder who has overestimated the value of the tract the most. Stated differently, the winner's curse is "the punishment visited upon competitors who do not react in their own best interests to increasing competition by restraining their own."¹¹ Bidders therefore must correct sufficiently for this or

⁹ Earlier academic work on bidding models (e.g., Rothkopf, 1969) had developed similar expected value models, but this was the first to apply it directly to bidding and leasing of oil and gas tracts.

¹⁰ The authors wrote, "In competitive bidding, the winner tends to be the player who most overestimates true tract value. And yet another: He who bids on a parcel what he thinks it is worth will, in the long run, be taken for a cleaning." (p. 643)

¹¹ Lohrenz (1987), p. 1105.

suffer the “winner’s curse.” The Capen et al. article was the first work to identify the winner’s curse and to suggest that bidders alter their behavior to take it into consideration.

Considerable subsequent research was spawned by Capen et al. including several articles by E. L. Dougherty, John Lohrenz and various co-authors. Dougherty and Nozaki (1975) used the Capen et al. bidding model to study the optimal bid fraction under differing assumptions regarding: (1) uncertainty of the estimates of tract value (competitors’ and bidders); (2) number of competitors; and (3) competitors’ bid fraction. The authors found that the optimal bid fraction was determined by the number of bidders, how aggressively they bid, and the relative accuracy of estimating a tract’s true value versus the competition. A major contribution was to posit different levels of competitive activity, ranging from the so-called “bumbling sheep” – competitors who are poorly informed and not aggressive – to competitors who are tough and informed, and the corresponding bid fraction the bidder should bid depending on the form that the competition would take.

Dougherty and Lohrenz (1976) analyzed empirical data on bidding behavior on OCS leases from 1954-1974 to test some of the assumptions of these bid models. First, they found that bids tend to be log-normally distributed, although in some cases there are abnormally low bids (a fact which we continue to see in today’s OCS sales). They found that the ratio of the high bid to the mean of all bids tends to increase with the number of bids per lease and the average amount “left on the table”¹² decreases as the number of bids per lease increases. Also, they found that joint bidders tend to bid on leases receiving more bids, and joint bidders bid higher bonuses all other things being equal. Finally, they found that there was no apparent time trend in the variances observed in bidding, i.e., there appeared to be little or no “learning” about bidding behavior over time. Interestingly, our analyses confirm that many of these trends still exist today.

Dougherty and Lohrenz (1980) explored differences between so-called royalty and bonus bidding. They perform a statistical study of royalty bidding and found that royalty bids tend to be normally distributed in contrast to bonus bids which are log-normally distributed. They also found that royalty bids tend to be lower than bonus bids. Finally, they concluded that increasing royalty rates tends to decrease ultimate recovery of production as royalties represent a cost of production. This has important implications for our Task 2 analysis of the impact of royalty relief on ultimate resource development and production.

Dougherty, Johnson, Bruckner and Lohrenz (1981) analyzed why certain bidders paid higher than average bonuses for certain tracts and examined whether these higher bidders obtained more profitable tracts, i.e., was there a correlation between higher bids and more profitable tracts? Using federal OCS lease data from 1954 through 1977, the authors found that by purchasing more expensive tracts, bidders did increase their chances of finding producing leases. However, they also found that for any lease that produced revenue, all bidders dealt with the same level of uncertainty that was not correlated to whether a bidder paid more or less to acquire the tract, i.e., they were not necessarily more profitable relative to other producing leases.

¹² “Money left on the table” is defined as the difference between the amount bid by the high bidder and the amount bid by the next highest bidder.

In a study of “money left on the table” on OCS sales, Megill and Wightman (1984) found that the amount “overbid” has averaged 45 percent of the winning bid and that it has been consistent across time.¹³ They claimed this is due in part to the sealed bid nature of OCS lease auction sales. The authors confirmed that bids are log-normally distributed due to uncertainties and differing views regarding the value of a particular tract. They also showed that as the number of bidders for a tract increases, the percentage amount overbid declines. Our research and analysis as discussed in Chapter 5 is consistent with these findings.

Englebrecht-Wiggans, Dougherty and Lohrenz (1986) used a competitive bidding model to explain differences in the distribution of the number of bids received on different tracts. They note that there is uncertainty regarding the number of bids an individual tract will receive and posit a model of three different types of leases to explain the differences in bidding activity. They suggest that there are three types of leases – those with no competition, those with a low level of competition, and those with a high level of competition.¹⁴ The authors tested their model against actual OCS sales data and found that it performs quite well. The implication is that bidders should consider their view of the lease type in estimating the number of competing bids a lease will receive. We apply this approach in analyzing bidding activity.

Lohrenz (1987) explored the optimum bonus bid on OCS leases by examining models of different competing bidders. He also considered two different objective functions on the part of the bidder: (1) maximizing reserves and (2) maximizing the present value derived from additional production. Lohrenz applied a Poisson distribution to estimate the number of bids received per lease and assumed based on historical data that bids for oil and gas leases are log-normally distributed (an assumption we employ). He found that solo bidding results in higher bid values and more leases won than joint bidding with the same budget and he provided a quantitative analysis of the winner’s curse. As discussed in Chapter 5, we employ a Poisson distribution in our bidding model to assess the likelihood of competitive bids.

Hendricks and Porter (1988) also apply bidding and auction theory to OCS leasing. They built on the theoretical work of Wilson, Milgrom and others and apply their analysis to sales of drainage tracts between 1959 and 1969. Drainage tracts are defined as tracts that are adjacent to tracts on which resources have been discovered. The reason to focus on drainage tracts (as opposed to wildcat tracts) is that there is asymmetric information about drainage tracts – firms which own neighboring tracts have better information than non-neighbors. They state that this fits with the theoretical auction models developed by others. The data and analyses demonstrate that neighboring firms do possess informational advantages, and generally bid lower fractions of value than non-neighbors. They found that this leads to a realization of higher profits and general avoidance of the winner’s curse. The authors also concluded that the pattern of neighbor bids indicates a lack of competitive behavior for drainage tracts either through the use of joint bids or some other form of transfer payment.

Hendricks, Pinske and Porter (1999) analyzed OCS wildcat lease sales from 1959 to 1970 to determine whether a common value model was most appropriate. They computed bid

¹³ In our analysis of GoM lease sales from 1983 to 2003, we found that the amount overbid averaged 44 percent of the winning bid, again an indication that overbidding is ever present.

¹⁴ This approach is similar to that of Dougherty and Nozaki (1975).

markups and rents under alternative hypotheses of private and common values. A common value model assumes that bidders are uncertain about common characteristics related to the value of a lease such as the size of any potential reserves, future oil and gas prices and the costs of exploration and development. The assumption of a common value model has important implications for bidding behavior; in a common value situation, aggressive bidding is tempered by winner's curse considerations. The authors concluded that both common value and private value components appear to exist in the lease data, but bidding behavior appears to be most consistent with a common value model. They also concluded that the bidding data demonstrates the existence of the winner's curse and that bidders do adjust their bidding behavior accordingly. Our approach to modeling and analyzed bidding behavior is consistent with a common value model.

Statistical and Policy Analysis of OCS Leasing

In addition to bidding models and auction theory, a number of authors have performed considerable statistical analyses of bidding in OCS leases. Several of these studies have served as a starting point for some of the statistical work we perform in this study. Mead (1969) presented an early analysis of OCS leasing in which he found that the high bid for a lease was driven largely by the number of bidders and not necessarily whether it was a profitable lease (ex post), or whether a major firm was bidding. Mead's regression model posited that the high bid was a function of the number of bidders, whether it was a solo or a joint bid, the average water depth of the lease (a proxy for the cost of the lease), the value of the lease, lease acreage, and whether a major oil company participated as the winning bidder.

Mead's work was criticized by Berger and Lohrenz (1978) citing other work by Mead as well as their own as the basis for their criticisms. They pointed to prior studies indicating that majors did tend to bid higher bonus and that there was a non-linear (log-normal) relationship between high bids and number of bidders.¹⁵ Also they found that the error term in Mead's regression was correlated with the number of bids per lease and possibly other independent variables and thus they had no confidence in Mead's results.

Mead and Sorensen (1980) performed a detailed analysis of lease sales in the GoM over the period 1954-1975 and developed various regression-based models of bidding and leasing behavior. The authors' primary focus was on the competitive nature of OCS lease bidding and the after-tax rate of return earned by successful bidders on OCS leases. Of greater interest to us is the regression model employed by Mead and Sorensen. They utilized an ordinary least squares log linear approach specifying the high bid (log) as a function of several explanatory variables including the following:

- Number of bidders (log)
- Present value of production (log)
- Number of acres in a tract (log)
- Water depth (log)
- Number of wells drilled in first 24 months of lease (log)

¹⁵ Thus in our high bid regressions we posit a log-linear function.

Existence of joint bidders as winning bidders
Large firms as the winning bidder
Drainage vs. wildcat lease
Geographical area of lease
Inflation adjustment

This model was clearly an improvement over Mead's prior work. They also performed detailed research comparing pre and post-1970 time periods and found an observable difference in bidding behavior between the two time periods. The authors cite both economic and political changes which caused this fundamental shift in behavior. The number of bidders had a lower impact on the high bid in the later time period as was the case for the effect of joint bidders. Majors, however, had a more significant impact. From our standpoint this basic regression model explains a high degree of the observed variation in high bids (R^2 ranging from .54 to .67 in different formulations), and intuitively, the independent variables provide a reasonable basis for explaining the variation in high bids. As discussed in Chapter 5, we utilize a slightly refined version of this model in performing some of our statistical analyses, and therefore this work is an important foundation for some of our modeling work. A later article by Mead, Moesidjord and Sorensen (1986) extended their econometric analysis of OCS leasing and evaluated the effectiveness of the OCS bonus bidding system. They analyzed how the level of the winning bonus bid (the dependent variable) is affected by other variables. Three sets of variables are employed to measure the following characteristics of the lease auction:¹⁶

1. Quality of the tract
2. The competitive structure of the lease market
3. Amount and distribution of information available to bidders

The authors use a similar data series on lease bids to measure these elements as was utilized in their earlier regression analyses including the present value of production, the number of wells drilled within 24 months following lease sale, number of acres in a tract, water depth, number of bids, size of winning bidder, solo or joint bid as winner, and wildcat vs. drainage tract. They also apply a time element to the regression model. Their conclusions are consistent with earlier studies, finding that: leases with better prospects command higher bids; drainage leases receive higher bids than wildcat leases; there is no appreciable difference in the level of bids between large and small firms for drainage leases, but large firms did bid more for wildcat leases. Joint bidding had no impact on the level of high bids, but it does permit entry into the bidding market for small firms and the size of the high bid increases as the number of bidders increased. As discussed in Chapter 5, we utilize the basic Mead model as one of our primary regression models applied to the 1983-2003 time period.

Lease Program Studies

¹⁶ These three features form the basis for most regression models of bidding behavior in the literature, although different variables are used by different authors as measures of these features. It is important to note that these features are based in large part on the literature discussed in the prior section.

A series of studies were performed in the early to mid 1980s that evaluated the effect of various elements of the government's OCS leasing program. Several of these studies were performed by various government agencies as well by outside economists and policy analysts. The FTC (see Mulholland 1984) performed a study on the effect of a ban on intra-major joint bidding. This ban on majors' joint bidding was instituted in 1975 and arose from concern that joint bids among major oil companies were reducing the revenue received by the federal government in lease sales and the ban was reducing competition. The FTC examined OCS bids between 1973 and 1979 and found no convincing evidence for the imposition of the ban, yet the effect of the ban had been relatively minor.

The author of the report developed two regression models. The first model examined the number of bids per lease tract as a function of a measure of the quality of the tract and characteristics related to the lease sale itself, as well as a dummy variable for the joint bidding ban. Quality was measured by using the pre-sale value of the tract as computed by the government; other variables specified in the model included the type of royalty regime employed, the type of tract (drainage, wildcat), the number of tracts available during the sale, the water depth of the tract, and the distance of the tract from shore. The results of the regression model indicate no significant impact of the ban on the overall level of bidding activity.

The second model examined the impact of the joint bidding ban on the level of high bids received. High bids were modeled to be a function of the presale value of the tract, the type of tract, water depth, distance from shore, type of bidder (major, non-major, joint). This model found that joint bidding by majors did not reduce the level of bids, but the ban on joint bidding had not reduced significantly the level of bids. Along with Mead's work this paper provides a useful starting point for understanding prior attempts to model the OCS leasing process, although under the earlier tract-nomination form of leasing. Indeed this work represents the first attempt to model both the level of bids and the number of bids per tract, although no attempt is made to link or join the two models.

The MMS (U.S. Department of the Interior 1985) prepared a report which evaluated the effectiveness of various types of "bidding systems" for OCS leases. Specifically, the study examines the use of different royalty regimes employed in lease sales between 1979 and 1984 and also provided an initial look at possible differences between tract-nomination leasing and area-wide leasing.¹⁷ Although the study examined impacts on the number of bidders and the relative level of lease bids, no econometric analysis was employed. The report found that the move to area-wide leasing had increased the total number of tracts receiving bids, although the number of tracts receiving five or more bids per tract declined (p. 17). The report noted that when tracts receive only one or two bids, some have argued that the government does not receive fair market value; however, the report indicated that the decline in average high bid per lease appeared to be due to lower oil and gas prices (and expected future prices) as opposed to the institution of area-wide leasing.

¹⁷ Tract nomination sales allowed a limited number of tracts to be offered in a given sale based on industry interest, and estimates of potential value generated by the government. Area-wide leasing was instituted in 1983 and greatly increased the number of tracts available by making all unleased tracts in a given planning area available for sale.

The GAO (1985) performed an econometric study of the level of bonus bids under the tract-nomination leasing system compared with area-wide leasing. GAO reviewed the first ten area-wide sales and estimated the effects of the area-wide program on exploration activity, competition, and bid revenues. GAO found that it could not assess statistically the impact on production, although it appeared that exploration activity had increased under area-wide leasing.¹⁸ However, based on a series of regression analyses, the study found that area-wide leasing had reduced the number of bids per lease (but not the level of participation in a lease sale), and the level of lease bids. These findings were based on a relatively simple econometric model of lease bidding and the number of bids.

GAO posited that the number of bids and the level of bids were influenced by a similar set of explanatory variables. These included: the value of the tract, the bidding system employed, the type of tract, location of the tract, the price of crude oil, interest rates, the proportion of joint bids received and the year in which the lease sale occurred. These variables were selected to control for differences in the value and quality of the tracts as well as general market factors, and GAO employed dummy variables to account for the switch to area-wide leasing. The number of bidders per tract was also employed as an explanatory variable in the high bid equation. GAO utilized both an ordinary least squares (OLS) procedure as well as a two-stage least square model (TSLS); the two-stage model explicitly accounts for the fact that there may be interaction between the high bid and the number of bidders.

The results of GAO's regression models do not explain a large proportion of the variability on the dependent variables (R^2 of .3), and the coefficient on the area-wide dummy does not yield consistent or stable results across various formulations of the models. In other words, in some models the coefficient on the dummy variable is significant, and in other cases it is not, and the sign on the coefficient switches from negative to positive depending on the model formulation. This casts doubt on the reliability of the results. As discussed below, other economists have described other issues related to GAO's work which leaves one with little confidence in the results.

Farrow (1987) performed a similar study on the impact of the change from tract nomination to area wide leasing. He criticizes the GAO study and presents his own econometric study which shows that the GAO study was flawed, and there is no evidence to indicate that the decline in high bids was due to the switch to area wide leasing. Farrow utilizes a simplified two equation model that explains the number of bids and the high bid per lease. Explanatory variables include: the estimated value of the tract, the number of bids per tract, oil prices, interest rates, the presence of joint bidders, a dummy variable for location, three dummies for different lease terms, a dummy for the switch to area-wide leasing and dummy variables for time. Changes in oil prices have a large impact – Farrow finds that lower oil prices caused a decline of over \$1.4 million in the high bid per tract.¹⁹ Further he found that the variable for area-wide

¹⁸ GAO had the same problems as we do in this study of examining actual exploration and production impacts. Insufficient time has elapsed since the programmatic change to provide realistic time-series data on exploration or production trends for leases sold under the "new" programs. This is due to the inherent large lag (up to 10 years or more) between lease sales and the initiation of exploratory activity.

¹⁹ As with the GAO study, Farrow's regressions yielded relatively low R^2 values in the range of .35. As he notes this leaves a substantial amount of variation in the level of high bids unexplained.

leasing is not significant and thus concludes that one cannot reject the hypothesis that this change in leasing structure had no impact on the level of high bids.

Moody and Kruvant (1990) performed a more detailed analysis of the change to area-wide leasing and employed a more detailed and rigorous econometric model to explain the observed changes in high bids that occurred with the advent of area-wide leasing. The authors employ a two stage model that describes the number of bidders and the high bid as a function of estimated tract value, the cost to develop the tract, the type of tract, and various characteristics of the bidders. Oil prices and location are also included as explanatory variables in the model. An important distinction in the Moody and Kruvant model is that before estimating the two stage model, they estimate a probit model on a dummy variable indicating whether a tract actually received a bid or not. This is important because under tract nomination sales, only a certain number of tracts were offered for sale whereas under area-wide leasing all tracts in a given area were available. This step eliminates the sample selection problem of a failure to observe tracts that do not receive a bid, a problem that existed in both the GAO study and Farrow's study.

The authors then estimate a two-stage least squares model on those tracts that did receive bids (and for which an estimated value was computed). The results of their model indicate that the policy shift variable was significant. Further they find that the shift to area-wide leasing caused the number of bids per tract to decline and the average bid per tract to decline as well. Further, they found that the value of the tracts being offered for sale had also declined due to the decline in oil prices thus confirming in part Farrow's findings and contradicting them in part. The estimates of lower revenue offered by Moody and Kruvant are considerably lower than those provided by GAO. The Moody and Kruvant model provides an excellent and tested approach for developing a regression model of OCS bidding to apply to our analysis of the change in royalty regime of DWRRA. We apply a two-stage model in Chapter 5 to explain the level of high bids which is similar in nature to Moody and Kruvant.

Other papers have evaluated other policy aspects of the OCS leasing structure and are mentioned here briefly, although they do not involve the level of econometric modeling discussed above. Lohrenz (1988) estimated the profitability of OCS leasing over time as well as projections of future profitability. Of the 1,220 leases he evaluated, 63 percent earned nothing, i.e., never produced, and another 14 percent lost money. The average rate of return (pre-tax) for all leases was 9.5 percent. Lohrenz concluded that the market for GoM leases was highly competitive, the rates of return were relatively low, and rates of return on hotly contested leases (i.e., leases with more than five bidders) were even less profitable, a sign, he states, of the winner's curse.

Hendricks, Porter and Tan (1992) explored the question of whether the government received a fair return on the sales of its leases from 1954 to 1973. They analyzed different types of leases and found that the government did capture all economic rents on wildcat leases but not on drainage or development leases. They claim this is due to asymmetries in information for drainage leases. They then develop a model which shows that if the neighbor firms can be excluded from the bidding process, the government can capture all of the rents in a first price, sealed bid auction. They recognize that this is not a practical alternative.

A recent monograph by J. C. Boué (2002) examined various factors influencing OCS leasing. This work reviewed the trends in leasing and exploration in the GoM including trends following the passage of DWRRA. Although no econometric work is performed, the author provides considerable analysis of data on leasing and bonus bids. Boué finds that technology and oil prices explain as much of the variation in the number and level of bids received for OCS tracts, including since 1995. The author also concludes that area-wide leasing did not have the beneficial effects the government believed that it would.

Finally a recent paper by Iledare et al. (2004) provides quantitative evidence regarding the determinants of high bonus bids in GoM lease sales. The authors provide data on a number of characteristics of OCS leasing such as number of bids per tract, number of bidders per sale, number of single bid tracts, the value of leases bids, and the like. They then develop a model of high bids where the high bid is a function of four factors: lease value, degree of competition, type of bidding (joint, solo), and other factors such as time, policy variables including DWRRA. The model the authors specify takes the form of the log of the high bid as a function of number of bids per lease, crude oil prices, various dummy variables (joint or solo bid, water depth, tract type, time trend).

The regression model utilizes data on lease sales covering the 1983-1999 period. No explicit variable is employed to account for policy changes such as the passage of DWRRA which makes the results of the analysis less helpful. The results do indicate that the number of bidders has a positive impact on the high bid as does the presence of joint bidders. Oil prices have some positive effect on high bids as prices go up and the average high bid for deepwater leases is higher than for shallow water leases (but the authors do not say whether this is largely attributable to DWRRA).²⁰

Options Models

Since the late 1980s, economists and theorists have applied financial options theory to OCS leasing. Specifically, the theory is applied to valuing offshore leases with much of the focus of this literature is on a comparative analysis of the efficiency of using option theory as opposed to traditional discounted cash flow (DFC) analysis in estimating the value of a lease. Although not directly related to bidding, this literature provides an alternative approach to understanding the value inherent in OCS leases and what may drive decision makers to submit bids for these leases. Indeed options theory is an interesting approach to evaluating the bidding process, and we build on this theory in some of our analyses of leases sold as discussed in Chapter 3.

Paddock et al. (1988) were the first to apply financial options theory to offshore petroleum leasing. They look at the holder of a lease as passing through three distinct stages prior to actual production: exploration, development and extraction (production). The exploration and development stages represent options of the leaseholder, sequential stages in which the leaseholder may continue or abandon the project. The authors model the value of the lease as a “compound option” where the unexplored lease is an option on the development

²⁰ Note that a major shortcoming of this approach is the failure to account for the interaction between the high bid and number of bidders variables which the two-stage models specifically incorporate.

option. Valuing the undeveloped reserve becomes a function of the discounted value of the developed reserve, the variance in the rate of change in the value of that reserve, the per unit development cost, the lease term, the riskless rate of interest, and the net production revenue less depletion. The value of the option is highly dependent on expected/actual changes in oil prices. The authors argue that the option approach and the data required to value a lease under such an approach is much simpler and easier to develop than a DCF approach, and does not require the subjective use of risk-adjusted discount rates. The authors applied the option value model to actual lease sales, comparing actual bid prices and government estimated values with values derived from the option model. They find that the options values tend to be well within the range of industry bids and government estimates which they conclude substantiates their approach.

Various articles authored by oil company officials and others discuss the use of options theory to value specific oil field investments as opposed to lease sales. Lehman (1989) of ARCO points out that DCF analysis fails to properly deal with future oil price uncertainty and application of options theory is an improvement in that regard. He notes that frequently oil companies will use some form of dynamic programming technique to model changing oil prices and competitive behavior, but the success of such approaches is often mixed. He applies option theory to show the value of the option to delay an investment in developing an oil field.

Bjeksund and Ekern (1990) and Bjeksund (1991) value the investment in an oil field using option theory. They argue that this type of capital budgeting problem that includes price uncertainty and flexibility to make a go/no-go decision later in time is an excellent application of option theory. They compare results of an investment in an oil field project under a traditional DCF approach and with option theory. They show that the DCF model tends to understate the true value of the investment opportunity especially where the developer may defer the development decision, i.e., wait for the option to be “in the money.”

Dickens and Lohrenz (1996) question the utility and validity of options theory for valuing oil and gas investments. They find that option pricing methods are most useful for oil and gas projects that are already developed and in decline as opposed to in pre-development stages. Option theory, they conclude does little better in dealing with all of the uncertainties involved in oil and gas projects, and as opposed to DCF analysis, options methods may overvalue such investments because option value reflects limited downside risk while allowing upside gain.

Pickles and Smith (1993) extended the earlier work of Paddock et al. (1988) in valuing offshore leases using options theory. Pickles and Smith explore the value of an option to delay the development decision (as well as the exploration decision) which earlier work did not address. The option value again depends on movements in oil prices. The authors determine the maximum amount that should be bid on offshore leases using option theory and assess the application of this theory to U.K. and U.S. leasing auctions. They find that application of option theory can present different results than traditional discounted cash flow analyses.

Smith and McCardle (1997) note that much of the prior work applying options theory to exploration and development decisions oversimplifies the types of projects encountered and fails

to provide comparisons to decision analytic approaches. They conclude that both option theory and decision analysis approaches can model flexibility in decision making. Further they believe that both approaches can be used as compliments in evaluating oil and gas investment projects.

Bradley (1998) demonstrates that valuation of an oil field investment under different tax and royalty regimes can vary significantly depending on the approach used to estimate the investment's value. Tax and royalty regimes affect the risk associated with the returns from a project, and thus options theory is a useful tool to assess such investments. He shows that nonlinear fiscal regimes yield different values depending on the approach used because of a combination of direct risk effects due to price uncertainty as well as changes in the implied discount rate due to operating and fiscal leverage.

Finally Davis and Schantz (2000) present an options approach to modeling and valuing OCS leases from the government's perspective. They apply a compound option model similar to Pickles and Smith and Paddock et al. and apply it from the perspective of the lessor, i.e., the government, rather than the lessee as much of the rest of the literature does.²¹ They estimate oil price thresholds indicating when it is the optimal time to put the lease out for sale. The authors evaluate the effect of lease term, royalty rates, and rental payments on the timing and efficiency of developing a lease. The authors find that the majority of leases tend to be developed near the end of the lease term, an indication that the leases are developed if they are in the money at or near expiration. The authors estimate relatively small losses due to imposing a finite term to leases. Rental payments also cause a reduction in the resource rent due to earlier exercise of the option to develop. Royalties in an options context tend to delay exercise by increasing the oil price at which exercise is warranted and by a greater amount than the opposing impact of rental payments and finite lease terms. Royalties also reduce bonus payments. The authors conclude that the impact of finite lease terms, royalties and rental payments have "a remarkably minor impact on the efficiency of resource development in the Gulf of Mexico."

DWRRRA

A few papers have commented on the impact of DWRRRA on leasing and exploration activity. Derman and Johnston (2000) claim that royalty relief provided by DWRRRA provided the incentive to lease and develop large number of tracts in deep water areas that might otherwise never have been developed. They point to the increase in number of leases sold in deep water and claim that this will lead to an increase in exploration activity. Furthermore, they state that the program should lead to an increase not only in lease bonus revenue, but also an increase in oil and gas production, and royalty and tax payments. We address these issues in our Task 2 modeling effort, but it is interesting to note that the authors do not provide any quantitative estimate of the likely increase in revenues. The authors do make the point that royalty relief tends to lower the breakeven threshold for fields of moderate size in the deepwater Gulf and DWRRRA has probably made certain fields of moderate size economic that otherwise would not have been economic to produce.

²¹ The authors use this approach to respond to some of the proposals made by Mead and others for changes in the government's leasing program.

MMS has issued a number of reports on exploration and development in the deepwater GoM and also point to DWRRA as a stimulus for leasing activity. In its 2002 report, MMS (2002) stated that DWRRA spurred a number of different activities in the Gulf of Mexico including seismic surveys, leasing, and exploration activity. They noted that in the first few years of the DWRRA there was a significant upswing in leasing activity, but it was still relatively early to determine the impact on discoveries or production. In the 2004 report, MMS (2004) indicated that there had been a big expansion in deepwater activity due in part to DWRRA. The report pointed to the upswing in leasing activity which it claims was due to several factors including DWRRA, new technology, expanded seismic surveys, new discoveries in deepwater and observed higher production rates in deepwater. This report pointed to the fact that 5 percent of deepwater (>200m) oil production was now attributable to DWRRA and later leases and 14 percent of deepwater (>200m) gas production was attributable to DWRRA and later leases.

Finally Godec, Kuuskra and Kuck (2002) published a series of articles discussing the future of GoM exploration and production and the role of the federal government. The authors stated that DWRRA had had a significant impact on leasing and if continued would cause a significant increase in ultimate recoverable reserves. Their justification for this impact is that they believe that a much larger proportion of the remaining fields to be discovered in the GoM will be moderate to small size fields, whereas others including MMS believe that much of the remaining resource potential is in larger fields. The economics of these smaller fields, the authors contend are more likely to be influenced by royalty relief. They compare future production over the next 20 years assuming no royalty relief vs. continuing relief as applied under DWRRA and conclude that incremental cumulative production would increase by 3 billion barrels of oil and 12 trillion cu. ft of natural gas with royalty relief.

Chapter 3 Leases Sold and Sale Participation

Introduction

The study addressed the effect of the DWRRA and the post-DWRRA program, contrasted with no royalty relief, on the following aspects of lease sales:

- Number of tracts bid on and leases sold
- Number of lease sale participants
- Major versus non-major company participation

Effects are given for three water depth classes:

- *0-200 meters – shallow water:* Deepwater royalty relief does not apply directly but might have indirect effects.
- *200-800 meters – deepwater:* Although policies give different amounts of relief to 200-400 meters and 400-800 meters, subclasses are combined in order to provide enough data for statistics.
- *800-plus meters – deepwater:* Policies give larger amount of relief.

This chapter presents data on leases bought, leases held, and sale participation, as well as numerous possible explanatory variables. The effects of policies are estimated in two ways:

1. Simple statistics that do not involve regression analysis;
2. Regression models that include policy dummies.

The findings are summarized in the conclusion of the chapter.

Leases Sold, Participation, and Related Variables

Leases Sold

We categorize the number of leases sold by water depth for purposes of this report. Water depth provides a convenient approximation of lease royalty term categories, as explained in the next section. Tracts bid on are closely related to leases issued or sold. The main difference is that some high bids – typically 2 to 5 percent – are rejected in the course of bid

adequacy review. Figure 3-1 shows the number of leases sold between 1983 and 2003 in shallow and deepwater, that is, 200 meters and over, for all of the Gulf of Mexico. Features of this graph include:

- Both deepwater and shallow water leases sold show similar cyclical patterns. The cycles begin with peaks in 1983 or 1984, when the study data began.
- Cycle peaks appear to relate to policy shifts, shown as “areawide” (the start of areawide leasing), “MinBid” (a reduction of the minimum bid amount), “DWRRA,” and “post-RR” (start of post-DWRRA program).
- Peaks last for about three years.
- Cycles cover five to seven year periods.
- Shallow water leases sold show a fairly stable variance, whereas the 800-plus meter pattern has a large spike from 1995 to 1998.

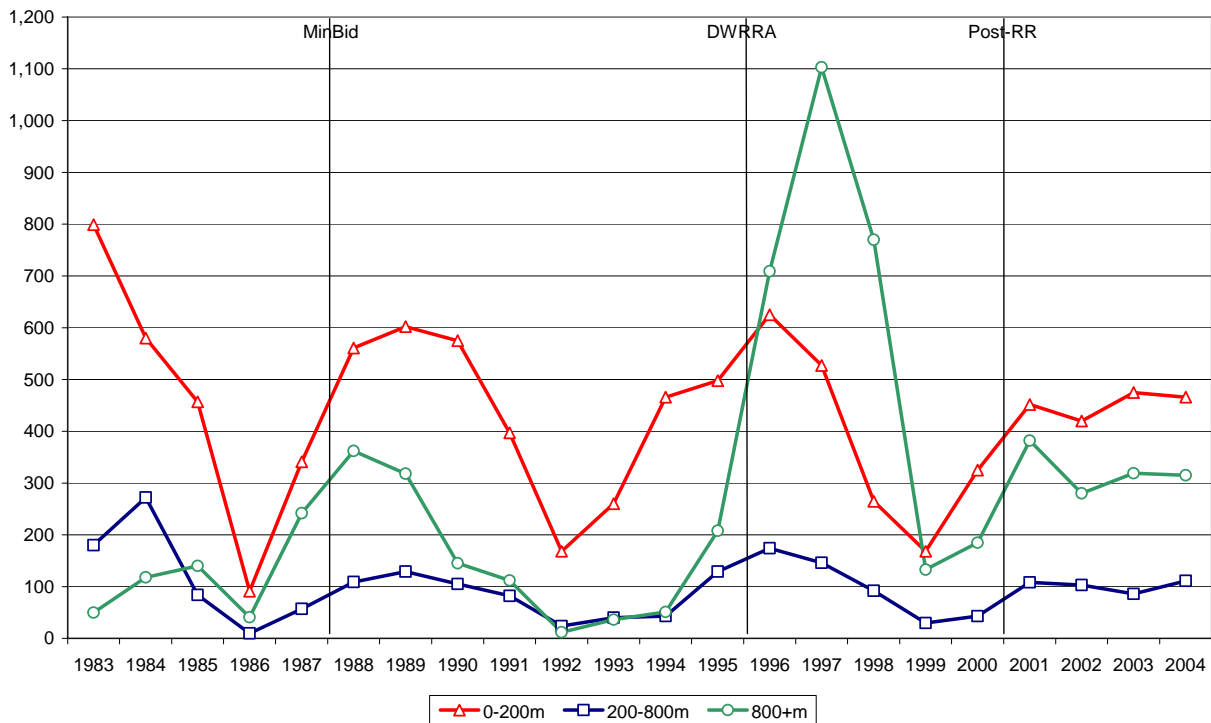


Figure 3-1. Leases Sold, By Depth.

The leasing patterns shown have a degree of similarity for both deep and shallow water, and notably, both patterns show peaks that occur around the principal policy changes. In most instances, there is actually an upward change immediately *before* the year the policy takes effect.

Areawide and minimum bid policies applied to all water depths, but deepwater royalty relief applied only to deepwater. The effect of deepwater royalty relief on shallow water leasing may be explained by complementarity. That is, when the price of deepwater resource options was reduced by royalty relief, the demand for both deep and shallow water leases increased. This idea is examined further in regression analysis below.

Leases Held By Industry, Stock Replacement, and Stock Adjustment

Leases sold and issued are a main factor in the creation of private stocks of leases held. As an accounting identity, the stock of leases changes from one sale to the next as:

$$\begin{aligned} \text{Stock in } t &= \text{Stock in } t-1 \\ &+ \text{Leases sold and issued between } t-1 \text{ and } t \\ &- \text{Leases terminated between } t-1 \text{ and } t \end{aligned}$$

The time series of leases held (just prior to lease sale at the date indicated) is illustrated below in Figure 3-2. Both the deepwater and shallow water series show cyclical patterns where a rise in stock corresponds to a peak in leases sold and issued.

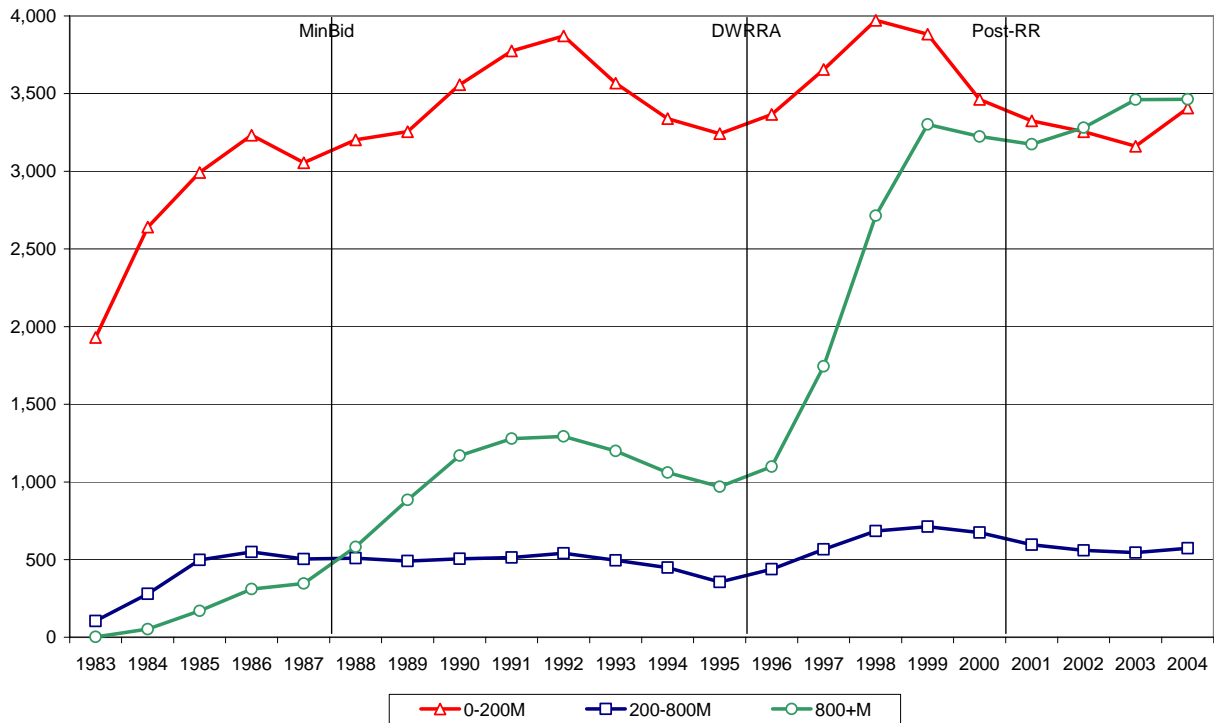


Figure 3-2. Leases Held, By Depth.

Since the cycle of leases sold is five to seven years, it appears that the cycle of leases sold and issued reflects stock replacement by firms. In support of this line of thought, note that lease terms are:

- 0-400 meters ... 5 years
- 400-800 meters ... 5 years for exploration
- 800-plus meters... 10 years

The idea is that, given the initial build-up of stock at the start of areawide leasing in 1983-1984, the industry would be more or less satisfied with the stock in hand, and uninterested in buying more leases until five or six years later. At that time, many of the leases would expire; and a large number of lease additions would be needed to replace stock.²² The next surge of replacement buying would occur five or six years after that. To test for this effect statistically, it is not enough to simply include a five-year lagged term for leases sold, as the term might pick up other effects as well; it seems necessary to examine a data series of lease terminations and its possible relationship with lease buying. In the course of the study, the dynamics of the lease stock were examined in more detail. The stock held was broken out as leases producing, leases drilled and not producing, and leases not yet drilled. Although they were interesting in themselves, these details were not significant for the regression analysis reported later in this chapter.

We assume that the industry active in the Gulf over the study period maintained a continuing level of interest in the area that was stable to a meaningful degree, such that it makes sense to think of replacement buying. Furthermore, the same inventory concept allows that policy can have the effect of shifting the level of desired stock. When the desired level of stock shifted up (due to policy), leases sold would surge for a limited adjustment period. And after new inventory targets are reached, leases sold would drop, even if the policy remains in effect. The data as shown in Figure 3-1 confirm this theory. Hypotheses about leases sold in relation to leases held can be developed formally by means of a lease inventory model. This model is presented at the end of this chapter. We use this theory to specify variables, in particular the policy variables, in the regression models.

Participants, Leases per Participant

We define a participant as a company or person bidding. In particular, a joint bidding combination does not count as a participant. Instead, the persons who join together are each participants. Leases sold can be viewed as a product of two factors, participants and the average leases sold per participant:

$$(\text{Number of participants in sale}) \times (\text{Leases sold per participant})$$

²² On one hand, strikingly many leases are held to term without being acted on, a fact explained by the model of lease inventory presented below. On the other hand, the number of leases relinquished early, without activity, is not trivial.

These two terms are related to each other as number of buyers and purchases per buyer. The number of buyers increases as demand factors cause potential buyers to demand at least one lease at the expected price. Demand factors may include a need for inventory additions and higher profit expectations (for example, due to policy). One way to view this is:

- People who are ongoing participants in these lease sales increase the number of leases they buy thanks to higher profit expectations, etc.
- People who used to buy, so to speak, less than one lease then increase the number of leases they buy to at least one.

In consumer theory, an often-used simplification is that buyers enter a market with a predetermined budget, and they buy more or fewer items according to the price. By this approach, the price of the good does not affect the number of buyers, but does affect items purchased per buyer. For this report, price is examined in another chapter, and provisionally, any feedback from the high bid model to the leases per participant model is ignored.

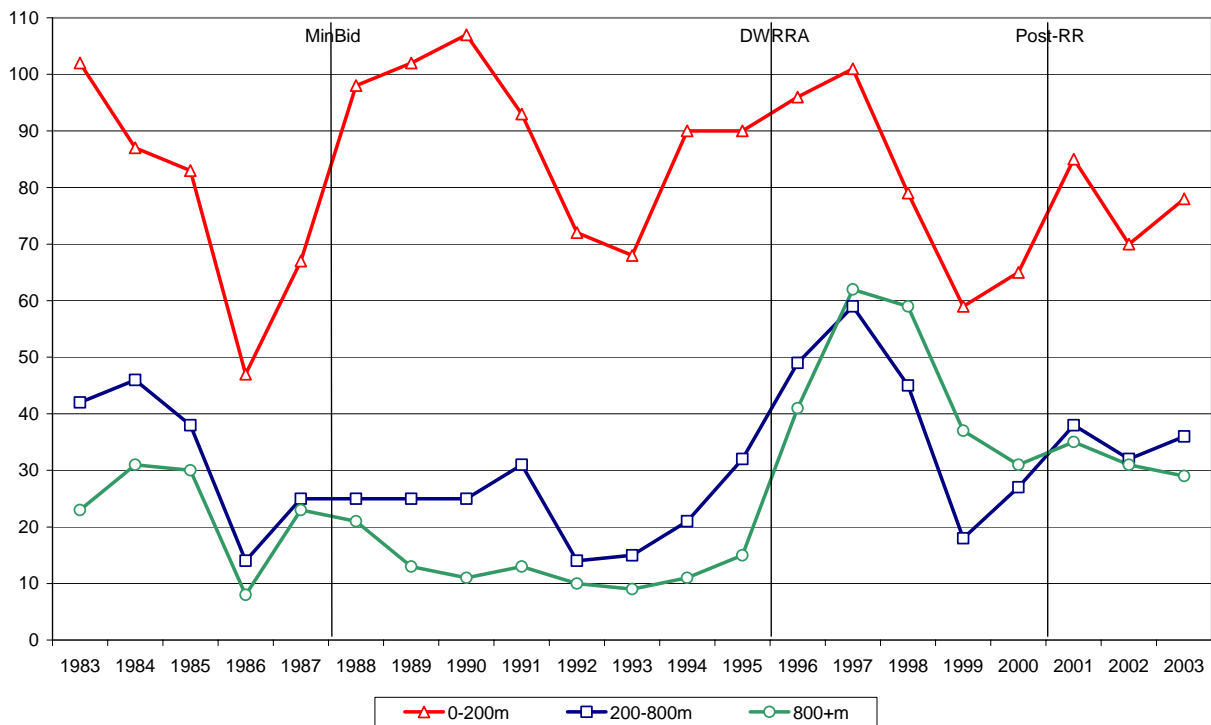


Figure 3-3. Participants, By Depth.

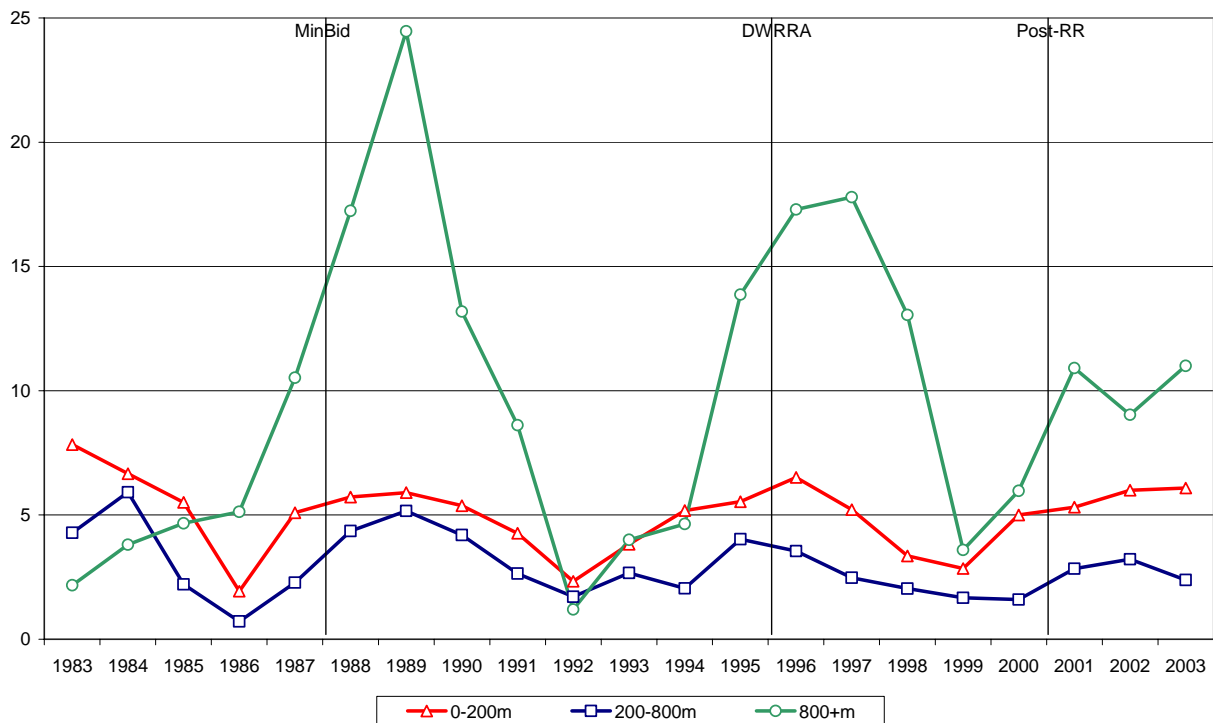


Figure 3-4. Leases Sold per Participant, By Depth.

Figures 3-3 and 3-4 show the number of participants by water depth as well as the number of leases sold per participant. The number of participants in shallow water follows a pattern similar to that seen for leases sold. The same can be said to a lesser degree for deepwater; the number of participants in deepwater around 1988-1989 is a possible exception as it does not peak strongly the way leases sold does. As for the ratio of leases sold per participant, it too shows a cyclical pattern, for both deep and shallow water, similar to the pattern for leases sold. The strong peak in leases per participant in deepwater in 1988-1989 is the reason for high numbers of leases sold at that time. For some periods and depths, leases per participant lead the participants by a year or more, as in the case of the deepwater classes in 1995. It is interesting when this happens at the beginning of an upswing as it typically indicates that the major companies (and generally the majors already active in the area) increase their buying first, and then other, smaller players enter the market.

Variables Considered in the Study

Leases Sold and Their Royalty Terms

The number of leases sold means the number of tracts for which a lease is issued. When a valid high bid is acceptable to MMS, the lease is normally issued, except for rare instances where a lease fails to be executed for some reason at the final stage. Unfortunately, several slightly different counts of deepwater leases and leases with DWRRA royalty relief were derived over the course of this study. In different contexts, the count of leases sold is given as 3,385,

3,391, or 3,401. First, for purposes of this study, it is convenient to categorize leases sold by water depth. Two different counts of deepwater leases sold, 1996-2000, appeared in the course of the study, 3385 and 3391 as shown in Table 3-1.

- There are 3,385 deepwater leases sold under DWRRA according to the “LeaseHist” data file derived from MMS database. This is the file that the regression analysis of leases sold used.
- There are 3,391 deepwater leases sold under the DWRRA according to the “LeaseDetails” data file derived from MMS database.

The reason for the discrepancy of six leases is unknown.

Table 3-1. Deepwater Leases Sold, 1996-2000, Two Different Data Files.

Sale	200-800			800+		
	LeaseHist	LeaseDetails	Diff	LeaseHist	LeaseDetails	Diff
157	64	64	0	392	392	0
161	110	110	0	317	317	0
166	74	74	0	521	522	1
168	72	72	0	582	583	1
169	53	53	0	507	508	1
171	39	39	0	263	264	1
172	12	12	0	74	75	1
174	18	18	0	59	60	1
175	26	26	0	108	108	0
177	17	17	0	77	77	0
Total	485	485	0	2900	2906	6

Second, it is noted that the set of deepwater leases, sold 1996-2000, approximates the set of leases with DWRRA royalty suspension terms; but there are slight differences. The differences are summarized in Tables 3-2 and 3-3.

- Of the 3,391 deepwater leases sold, 1996-2000, three did not receive royalty suspensions.
- Of 3,401 leases sold under DWRRA with royalty suspensions, 13 were shallow water (less than 200 meter).

In this study, we assume that the set of DWRRA deepwater leases is an acceptable approximation of the set of leases with royalty suspensions. There is no similar discrepancy between the royalty terms and water depths for the leases sold in the post-DWRRA period, 2000-2003 in this study.

Table 3-2. DWRRA Leases Classed By Depth.

Count Of Leases That Are Deepwater, Based On LeaseDetails Database					
SALE_NUMBER	BID_SYSTEM_CODE				Grand Total
	R 1/6	RS A	RS B	RS C	
157		26	38	392	456
161	1	34	72	320	427
166		27	48	521	596
168		15	51	589	655
169	1	22	29	509	561
171		12	29	262	303
172		7	5	75	87
174		6	12	60	78
175		8	18	108	134
177	1	5	10	78	94
Grand Total	3	162	312	2914	3391

Note: R 1/6 has no royalty suspension. The other codes have DWRRA royalty suspensions associated with 200-400 meter, 400-800 meter, and 800-plus m.

Table 3-3. DWRRA Leases Classes by Royalty Terms.

Count Of Leases That Have Royalty Suspension				
SALE_NUMBER	WD_Class			Grand Total
	0_200	200_800	800plus	
157	2	64	392	458
161	4	109	317	430
166	1	74	522	597
168	1	72	583	656
169		52	508	560
171	1	39	264	304
172		12	75	87
174	3	18	60	81
175		26	108	134
177	1	16	77	94
Grand Total	13	482	2906	3401

We used the following variables as possible explanatory variables for the number of leases sold:

Oil & gas prices – Current and expected future oil and gas prices may influence the number of leases sold, as they would affect the expected profitability of various tracts, as well as generate greater cash that the industry can use to buy leases with. This study used the six-month average of Platt’s WTI Cushing spot price prior to the year of the sale.

Recent reserve changes – As improved information about deepwater resources became available, more leasing activity in deepwater may have occurred. Therefore, it is expected that there is a positive relationship between the number of leases sold in deepwater and the record over the previous two to three years of deepwater discoveries. The variable “Reserves” is the

total reserves added in the previous year. (Reserves data were not available for 2003 when the analysis was done. In order to preserve the 2003 observation for regressions, a value for change in reserves in 2003 was extrapolated from the preceding years.)

3-D Seismic coverage – Increased seismic coverage in a given area or water depth might increase the number of leases sold. This is another possible measure of the impact of information on the number of leases sold. We measure the 3-D seismic coverage both in terms of square miles covered and blocks covered. The series for 3-D seismic starts in 1992. Prior to that year, there were 2-D seismic data, but the hypothesis here is that 3-D seismic surveys provided new information, particularly pertinent to expansion in deepwater.

Share of 3-D seismic – An alternative indicator of information by water depth class is its share of total Gulf 3-D seismic coverage. The share in a year t is the ratio:

$$\text{Share of seismic (t)} = \text{seismic coverage in class (t)} / \text{total Gulf seismic coverage (t)}$$

Theoretically the relative increase of seismic coverage in deepwater, more specifically the 800-plus meter class, is a good indicator of the value of the information to support new opportunities for leasing in frontier areas. In multiple-equation regression analysis, this variable embodies a subtle cross-equation relationship, since the denominator of the ratio is the total, that is, the sum of seismic areas in all depth classes.

Leases held – Leases held by firms just prior to the sale can have an effect in two ways. First, the larger the stock held, the more likely it is that firms have reached their derived inventory size, according to the lease inventory model. A large stock then implies lower demand for additional leases. Second, there are a limited number of tracts that may ultimately have recoverable resources, and those that are thought to have the highest probability of possessing resources tend to be leased first. Thus, as the inventory of leases held in a given area and water depth increases, the additional leases available in that area will be viewed as less likely to be developed, and these leases are less likely to be bid on.

Leases held is the result of prior leases sold offset by prior leases terminated. As such, a time series of leases held incorporates a lagged effect of leases sold. In a regression with leases sold on the LHS and leases held on the RHS, leases held is likely to work, to some degree, as lagged leases sold. That might be a desirable part of the model (see time-series analysis elsewhere in this chapter). We additionally observe that simulation of leases sold using a counterfactual input set must be done statically if leases held are not also adjusted in the simulation.

Improvements in technology (infrastructure, drilling, etc.) – It is expected that as technology advances, especially as it relates to deepwater drilling and production systems, this would lead to an increase in the number of leases sold. This increase would be due in large part to the fact that technology opens up areas that otherwise could not be explored or developed economically. We used historical trends in drilling depths as a proxy for technological advances – specifically, the fifth-deepest drilling depth for the year, lagged one year.

Bid Rejection Rate – If the MMS increased its bid rejection rate for a given lease sale relative to previous lease sales, it would necessarily tend to reduce the number of leases sold (versus bid on) in the sale. Also, it might have a negative influence on the number of leases sold in the future. This variable is not lagged in data, but it can be lagged one year in the regression model.

Majors bidding – Large firms may be more likely to bid on more leases for a given lease sale than small firms due to financial constraints facing small firms, or other reasons. For this study, firms were divided into majors and non-majors following definitions used in the past by MMS (U.S. DOI 2002, 2004) to determine whether more large firm involvement has led to more leasing activity. The variable is defined as the percent of high bids made by majors.²³ As an alternative to the variable used, percent of bids by majors, one can consider the percent of high bids by majors. In most of the sales, the majors have a larger share of high bids than they have of all bids made, as shown below. The tendency shown can be due to two factors. In some sales, the majors place many bids in unexplored areas where their bids are uncontested. It is also possible that majors tend to place higher bids (see next chapter).

Joint bidding – The existence of joint bids might be expected to have a positive influence on the number of leases sold as it may allow more small firms to enter the lease sale market than otherwise would be able. This study used the percent of bids that were made by joint bidders. An alternative variable we considered is the percent of high bids by joint bidders. In most of the sales, the joint bidders have a very slightly smaller share of high bids than they have of all bids made, as shown below.

Gross Domestic Product (GDP) – The U.S. GDP for the year might be a relevant indicator of overall industrial expansion or contraction. This variable can be transformed into change in GDP, to avoid econometric problems.

Sale date – Sale date is a time-trend variable. When an analysis addresses Central, Western, or Eastern sales specifically, we use the sale date, and when an analysis addresses the whole of the Gulf of Mexico, we use an average of the year's sale dates.

Competition – Competition in lease sale is addressed in the next chapter. Competition ought not to be used on the RHS of a single regression equation explaining participants, since it is itself likely to be explained by the number of participants.

Tracts Offered – The number of tracts offered in each sale is large but limited. This variable is examined in detail in Chapter 4.

Participants – The number of participants in a sale is highly correlated with leases sold as shown above. It is likely to be influenced by policy and perhaps ought to be regarded as endogenous in a policy simulation model.

²³ This variable ought not to be used on the RHS of regressions when the DWRRA is being investigated. Plausibly, the influx of non-majors in 1996-1998 lease sales was partly due to the policy itself.

Leases sold per participant – Leases per participant is the ratio of leases sold and participants.

Other variables that were considered but not used in leasing and participation regressions included:

Undrilled stock – As mentioned earlier, the study investigated ways to break down the stock of leases held, specifically, in terms of leases producing, drilled but not producing, or undrilled. Most leases in the total stock are undrilled, and except for a trend over time for a larger share of leases in stock to be undrilled, the undrilled stock behaves the same as the leases held variable.

Type of tracts made available – To the extent a larger percentage of tracts offered for sale are drainage tracts, or are located next to proven or developed tracts, it is expected that a larger number of leases will be sold, again due to the information effect. However, drainage tracts were rare in deepwater over the period of our study.

Summary Statistics

Tables 3-4 through 3-6 provide the means and the standard errors of the means for the non-policy variables, grouped in several ways by water depth and policy period. The standard error (which is the standard deviation divided by the square root of the number of observations) can be added or subtracted to the means to give a sense of whether two means are significantly different or not.

Table 3-4. Means of Study Variables, 0-200 meter.

0-200m	Pre-Policy Mean			DWRRA Mean			Post_DW Mean			All Periods Mean		
	C	W	Avg	C	W	Avg	C	W	Avg	C	W	Avg
Number of Leases Sold	273.92	155.77	214.85	269.20	112.80	191.00	325.67	123.33	224.50	280.19	140.90	210.55
Participants	73.85	53.62	63.73	71.60	44.80	58.20	68.00	39.00	53.50	72.48	49.43	60.95
Leases Sold Per Participant	3.54	2.75	3.15	3.58	2.48	3.03	4.80	3.35	4.08	3.73	2.77	3.25
Competitive Bids, Share	0.27	0.28	0.28	0.30	0.17	0.24	0.28	0.13	0.20	0.28	0.23	0.26
Deepest Drilled	22,130.62	22,130.62	22,130.62	23,183.40	23,183.40	23,183.40	23,191.00	23,191.00	23,191.00	22,532.76	22,532.76	22,532.76
GDP (\$)	6,823.34	6,823.34	6,823.34	9,077.32	9,077.32	9,077.32	10,093.40	10,093.40	10,093.40	7,827.15	7,827.15	7,827.15
Change in GDP	218.65	218.65	218.65	357.06	357.06	357.06	171.20	171.20	171.20	244.82	244.82	244.82
Bids by Joint Bidders	0.35	0.31	0.33	0.22	0.16	0.19	0.26	0.16	0.21	0.31	0.25	0.28
High Bids By Joint, Share	0.34	0.29	0.32	0.23	0.14	0.18	0.25	0.16	0.21	0.30	0.23	0.27
Leases Held	2,632.62	1,109.00	1,870.81	3,414.60	1,179.60	2,297.10	3,173.67	1,109.67	2,141.67	2,896.10	1,125.90	2,011.00
Change in Leases Held	167.46	72.35	119.90	83.80	-13.40	35.20	-75.33	6.00	-34.67	112.86	42.45	77.65
Bids by Major, Share	0.35	0.33	0.34	0.16	0.17	0.17	0.12	0.09	0.10	0.27	0.26	0.26
High Bid by Major, Share	0.37	0.36	0.36	0.18	0.18	0.18	0.14	0.10	0.12	0.29	0.28	0.28
Oil Price	22.01	20.99	21.50	20.12	20.56	20.34	27.73	28.02	27.88	22.38	21.89	22.14
High Bids Rejected, Share	0.06	0.05	0.05	0.01	0.05	0.03	0.02	0.02	0.02	0.04	0.04	0.04
Rental Rate	3.31	3.31	3.31	5.00	5.00	5.00	5.00	5.00	5.00	3.95	3.95	3.95
Reserve Change	609.01	200.11	404.56	489.83	155.51	322.67	421.65	24.05	222.85	553.87	164.34	359.10
3-D Seismic (Mil Sq Miles)	5.71	1.58	3.65	52.25	15.36	33.80	67.71	21.49	44.60	25.65	7.71	16.68
3-D Seismic (Blocks)	865.31	287.77	576.54	7,607.60	2,795.40	5,201.50	9,485.67	3,929.00	6,707.33	3,702.10	1,405.00	2,553.55
Undrilled Leases Held	754.23	457.31	605.77	1,205.40	476.60	841.00	1,001.67	452.00	726.83	897.00	461.14	679.07

Table 3-5. Statistics of Study Variables, 200-800 meter.

200-800	Pre-Policy Mean			DWRRA Mean			Post_DW Mean			All Periods Mean		
	C	W	Avg	C	W	Avg	C	W	Avg	C	W	Avg
Number of Leases Sold	48.31	42.46	45.38	45.80	51.20	48.50	48.00	51.00	49.50	47.67	45.76	46.71
Participants	21.23	18.31	19.77	27.80	27.20	27.50	26.33	21.00	23.67	23.52	20.81	22.17
Leases Sold Per Participant	2.11	2.30	2.20	1.55	1.72	1.63	1.84	2.42	2.13	1.94	2.18	2.06
Competitive Bids, Share	0.25	0.18	0.21	0.22	0.22	0.22	0.19	0.33	0.26	0.23	0.21	0.22
Deepest Drilled	17,181.31	17,181.31	17,181.31	20,766.40	20,766.40	20,766.40	23,083.33	23,083.33	23,083.33	18,878.05	18,878.05	18,878.05
GDP (\$)	6,823.34	6,823.34	6,823.34	9,077.32	9,077.32	9,077.32	10,093.40	10,093.40	10,093.40	7,827.15	7,827.15	7,827.15
Change in GDP	218.65	218.65	218.65	357.06	357.06	357.06	171.20	171.20	171.20	244.82	244.82	244.82
Bids by Joint Bidders	0.38	0.27	0.33	0.36	0.30	0.33	0.22	0.30	0.26	0.36	0.28	0.32
High Bids By Joint, Share	0.37	0.26	0.32	0.35	0.29	0.32	0.21	0.29	0.25	0.35	0.27	0.31
Leases Held	300.08	180.23	240.15	382.40	281.60	332.00	377.00	242.67	309.83	330.67	213.29	271.98
Change in Leases Held	17.96	9.08	13.52	27.00	37.40	32.20	-12.33	-30.33	-21.33	15.79	10.19	12.99
Bids by Major, Share	0.65	0.71	0.68	0.26	0.21	0.24	0.24	0.08	0.16	0.50	0.50	0.50
High Bid by Major, Share	0.65	0.74	0.69	0.26	0.22	0.24	0.24	0.10	0.17	0.50	0.52	0.51
Oil Price	22.01	20.99	21.50	20.12	20.56	20.34	27.73	28.02	27.88	22.38	21.89	22.14
High Bids Rejected, Share	0.04	0.02	0.03	0.03	0.03	0.03	0.07	0.02	0.04	0.04	0.02	0.03
Rental Rate	3.31	3.31	3.31	7.50	7.50	7.50	7.50	7.50	7.50	4.90	4.90	4.90
Reserve Change	78.07	16.36	47.22	138.80	44.58	91.69	70.07	39.49	54.78	91.39	26.38	58.88
3-D Seismic (Mil Sq Miles)	0.72	0.53	0.63	6.10	5.81	5.96	10.47	11.19	10.83	3.39	3.31	3.35
3-D Seismic (Blocks)	130.46	95.69	113.08	1,102.80	1,040.60	1,071.70	1,881.67	1,989.33	1,935.50	612.14	591.19	601.67
Undrilled Leases Held	160.85	142.00	151.42	202.60	226.40	214.50	185.33	188.33	186.83	174.29	168.71	171.50

Table 3-6. Statistics of Study Variables, 800-plus meter.

800+m	Pre-Policy Mean			DWRRA Mean			Post_DW Mean			All Periods Mean		
	C	W	Avg	C	W	Avg	C	W	Avg	C	W	Avg
Number of Leases Sold	90.62	46.31	68.46	320.40	259.60	290.00	148.67	146.67	147.67	153.62	111.43	132.52
Participants	14.38	8.31	11.35	35.60	32.00	33.80	27.67	19.00	23.33	21.33	15.48	18.40
Leases Sold Per Participant	6.38	6.23	6.31	8.45	7.18	7.82	5.39	7.70	6.54	6.73	6.67	6.70
Competitive Bids, Share	0.16	0.07	0.12	0.26	0.18	0.22	0.29	0.11	0.20	0.20	0.10	0.15
Deepest Drilled	14,561.69	14,561.69	14,561.69	23,255.40	23,255.40	23,255.40	27,320.67	27,320.67	27,320.67	18,454.33	18,454.33	18,454.33
GDP (\$)	6,823.34	6,823.34	6,823.34	9,077.32	9,077.32	9,077.32	10,093.40	10,093.40	10,093.40	7,827.15	7,827.15	7,827.15
Change in GDP	218.65	218.65	218.65	357.06	357.06	357.06	171.20	171.20	171.20	244.82	244.82	244.82
Bids by Joint Bidders	0.29	0.16	0.22	0.31	0.33	0.32	0.29	0.25	0.27	0.29	0.21	0.25
High Bids By Joint, Share	0.27	0.15	0.21	0.32	0.32	0.32	0.29	0.27	0.28	0.29	0.21	0.25
Leases Held	486.54	230.69	358.62	1,455.00	961.20	1,208.10	1,921.33	1,383.67	1,652.50	922.10	569.33	745.71
Change in Leases Held	51.19	23.31	37.25	243.20	207.60	225.40	39.67	39.33	39.50	95.26	69.48	82.37
Bids by Major, Share	0.81	0.88	0.84	0.55	0.42	0.49	0.31	0.31	0.31	0.67	0.69	0.68
High Bid by Major, Share	0.81	0.89	0.85	0.56	0.42	0.49	0.31	0.29	0.30	0.68	0.69	0.68
Oil Price	22.01	20.99	21.50	20.12	20.56	20.34	27.73	28.02	27.88	22.38	21.89	22.14
High Bids Rejected, Share	0.00	0.00	0.00	0.05	0.03	0.04	0.01	0.01	0.01	0.02	0.01	0.01
Rental Rate	3.31	3.31	3.31	7.50	7.50	7.50	7.50	7.50	7.50	4.90	4.90	4.90
Reserve Change	33.61	14.57	24.09	294.12	79.27	186.70	190.48	177.67	184.07	118.05	53.27	85.66
3-D Seismic (Mil Sq Miles)	1.06	0.52	0.79	31.83	19.56	25.70	59.37	39.98	49.68	16.72	10.69	13.71
3-D Seismic (Blocks)	184.92	91.08	138.00	5,552.00	3,404.60	4,478.30	10,352.33	6,962.33	8,657.33	2,915.29	1,861.62	2,388.45
Undrilled Leases Held	458.00	222.38	340.19	1,368.40	932.40	1,150.40	1,748.67	1,353.00	1,550.83	859.14	552.95	706.05

Tests of Royalty Relief Based On Means

Pre-1996 versus Royalty Relief Period

A simple but robust method for estimating the effects of royalty relief is to contrast the average participants and leases sold in the periods before and during the policy periods using actual historical data.²⁴ There are different ways to frame this test. The simplest is to contrast the averages before the royalty relief periods (both DWRRA and post-DWRRA) and during the

²⁴ Leases sold data are from the LeaseHist database.

periods. The results by that method are shown below in Table 3-7. Number of participants refers to participants shown separately for the Central and Western Gulf areas.²⁵

Table 3-7. Change in Means from 1983-1995 to 1996-2003 Periods.

	Participants	Leases Sold
<i>0-200 m</i>		
Central	-4	16
Western	-11	-39
<i>200-800 m</i>		
Central	6	-2
Western	7	9
<i>800+ m</i>		
Central	18	165
Western	19	171

The *t*-test assumes that the two groups being contrasted have equal variances. This is true enough for the 0-200 meter class, marginal for 200-800 meter and the aggregated, and false for the 800-plus meter class. The tables below provide an alternative to the simple *t*-test that allows for unequal variances. To summarize the results of contrasting averages 1983-1995 and 1996-2003:

0-200 meters – The 1996-2003 period average participants and leases sold were mostly lower after 1995, with the exception of leases sold in the Western area, but the differences in means are not significant.

200-800 meters – Period average participants and leases sold were mostly higher after 1995, with the exception of leases sold in the Central area; but again the differences are not significant.

800-plus meters – Period average participants and leases sold were both higher after 1995, and the differences in means are significant.

Combining the results in the following tables, the magnitude of the effect of royalty relief is indicated.

Table 3-8. Means of Pre-royalty Relief and Royalty Relief Periods, Central 0-200 meter.

Variable	Test	N	Mean
Participants	Pre-RR	13	73.846
Participants	RR	8	70.250
Participants	Diff		3.596
Leases Sold	Pre-RR	13	273.923
Leases Sold	RR	8	290.375
Leases Sold	Diff		-16.452

²⁵ Note that participants in aggregate do not equal sum of participants in separate areas or depth classes.

Table 3-9. t-tests of Pre-royalty Relief and Royalty Relief Periods, Central 0-200 meter.

T-Tests					
Variable	Method	Variances	DF	t Value	Pr > t
PCPTS	Pooled	Equal	19	0.51	0.6132
PCPTS	Satterthwaite	Unequal	16	0.53	0.6063
LEASES_SOLD	Pooled	Equal	19	-0.30	0.7680
LEASES_SOLD	Satterthwaite	Unequal	15.6	-0.30	0.7656

Table 3-10. Means of Pre-royalty Relief and Royalty Relief Periods, Western 0-200 meter.

Variable	Test	N	Mean
Participants	AM Only	13	53.615
Participants	RR	8	42.625
Participants	Diff		10.990
Leases Sold	AM Only	13	155.769
Leases Sold	RR	8	116.750
Leases Sold	Diff		39.019

Table 3-11. t-tests of Pre-royalty Relief and Royalty Relief Periods, Western 0-200 meter.

T-Tests					
Variable	Method	Variances	DF	t Value	Pr > t
PCPTS	Pooled	Equal	19	1.61	0.1237
PCPTS	Satterthwaite	Unequal	18	1.73	0.1015
LEASES_SOLD	Pooled	Equal	19	1.32	0.2033
LEASES_SOLD	Satterthwaite	Unequal	18.1	1.55	0.1387

Table 3-12. Means of Pre-royalty Relief and Royalty Relief Periods, Central 200-800 meter.

Variable	Test	N	Mean
Participants	AM Only	13	21.231
Participants	RR	8	27.250
Participants	Diff		-6.019
Leases Sold	AM Only	13	48.308
Leases Sold	RR	8	46.625
Leases Sold	Diff		1.683

Table 3-13. t-tests of Pre-royalty Relief and Royalty Relief Periods, Central 200-800 meter.

T-Tests					
Variable	Method	Variances	DF	t Value	Pr > t
PCPTS	Pooled	Equal	19	-1.48	0.1552
PCPTS	Satterthwaite	Unequal	14.2	-1.46	0.1665
LEASES_SOLD	Pooled	Equal	19	0.13	0.8970
LEASES_SOLD	Satterthwaite	Unequal	19	0.15	0.8848

Table 3-14. Means of Pre-royalty Relief and Royalty Relief Periods, Western 200-800 meter.

Variable	Test	N	Mean
Participants	AM Only	13	18.308
Participants	RR	8	24.875
Participants	Diff		-6.567
Leases Sold	AM Only	13	42.462
Leases Sold	RR	8	51.125
Leases Sold	Diff		-8.663

Table 3-15. t-tests of Pre-royalty Relief and Royalty Relief Periods, Western 200-800 meter.

T-Tests					
Variable	Method	Variances	DF	t Value	Pr > t
PCPTS	Pooled	Equal	19	-1.26	0.2243
PCPTS	Satterthwaite	Unequal	15.1	-1.26	0.2263
LEASES_SOLD	Pooled	Equal	19	-0.62	0.5405
LEASES_SOLD	Satterthwaite	Unequal	15.4	-0.63	0.5388

Table 3-16. Means of Pre-royalty Relief and Royalty Relief Periods, Central 800-plus meter.

Variable	Test	N	Mean
Participants	AM Only	13	14.385
Participants	RR	8	32.625
Participants	Diff		-18.240
Leases Sold	AM Only	13	90.615
Leases Sold	RR	8	256.000
Leases Sold	Diff		-165.385

Table 3-17. t-tests of Pre-royalty Relief and Royalty Relief Periods, Central 800-plus meter.

T-Tests					
Variable	Method	Variances	DF	t Value	Pr > t
PCPTS	Pooled	Equal	19	-4.78	0.0001
PCPTS	Satterthwaite	Unequal	11.1	-4.36	0.0011
LEASES_SOLD	Pooled	Equal	19	-2.93	0.0085
LEASES_SOLD	Satterthwaite	Unequal	8.21	-2.42	0.0413

Table 3-18. Means of Pre-royalty Relief and Royalty Relief Periods, Western 800-plus meter.

Variable	Test	N	Mean
Participants	AM Only	13	8.308
Participants	RR	8	27.125
Participants	Diff		-18.817
Leases Sold	AM Only	13	46.308
Leases Sold	RR	8	217.250
Leases Sold	Diff		-170.942

Table 3-19. t-tests of Pre-royalty Relief and Royalty Relief Periods, Western 800-plus meter.

T-Tests					
Variable	Method	Variances	DF	t Value	Pr > t
PCPTS	Pooled	Equal	19	-5.27	<.0001
PCPTS	Satterthwaite	Unequal	9.89	-4.64	0.0009
LEASES_SOLD	Pooled	Equal	19	-3.37	0.0032
LEASES_SOLD	Satterthwaite	Unequal	7.87	-2.73	0.0261

DWRRA vs. Post-DWRRA

Viewed another way, how did the DWRRA period contrast with the post-DWRRA period? Table 3-20 shows that the means of the participants between DWRRA to post-DWRRA declined. Period average leases sold dropped in 800-plus meters, whereas in 0-200 meters it rose and in 200-800 meters it remained approximately unchanged. Changes in means from one policy period to the other were not generally significant by the t-test, but the tests suffer from a small number of data points.

Table 3-20. Change in Means From 1996-2000 To 2001-2003 Periods.

	Participants	Leases Sold
<i>0-200</i>		
Central	-4	56
Western	-6	11
<i>200-800</i>		
Central	-1	2
Western	-6	0
<i>800+</i>		
Central	-8	-172
Western	-13	-113

Table 3-21. Means of DWRRA and Post-DWRRA Periods, Central 0-200 meter.

Variable	Test	N	Mean
Participants	RR	5	71.600
Participants	Post-RR	3	68.000
Participants	Diff		3.600
Leases Sold	RR	5	269.200
Leases Sold	Post-RR	3	325.667
Leases Sold	Diff		-56.467

Table 3-22. t-tests of DWRRA and Post-DWRRA Periods, Central 0-200 meter.

T-Tests					
Variable	Method	Variances	DF	t Value	Pr > t
PCPTS	Pooled	Equal	6	0.31	0.7645
PCPTS	Satterthwaite	Unequal	5.56	0.39	0.7128
LEASES_SOLD	Pooled	Equal	6	-0.63	0.5547
LEASES_SOLD	Satterthwaite	Unequal	5.02	-0.80	0.4617

Table 3-23. Means of DWRRA and Post-DWRRA Periods, Western 0-200 meter.

Variable	Test	N	Mean
Participants	RR	5	44.800
Participants	Post-RR	3	39.000
Participants	Diff		5.800
Leases Sold	RR	5	112.800
Leases Sold	Post-RR	3	123.333
Leases Sold	Diff		-10.533

Table 3-24. t-tests of DWRRA and Post-DWRRA Periods, Western 0-200 meter.

T-Tests					
Variable	Method	Variances	DF	t Value	Pr > t
PCPTS	Pooled	Equal	6	0.61	0.5660
PCPTS	Satterthwaite	Unequal	5.72	0.67	0.5264
LEASES_SOLD	Pooled	Equal	6	-0.37	0.7226
LEASES_SOLD	Satterthwaite	Unequal	5.33	-0.47	0.6593

Table 3-25. Means of DWRRA and Post-DWRRA Periods, Central 200-800 meter.

Variable	Test	N	Mean
Participants	RR	5	27.800
Participants	Post-RR	3	26.333
Participants	Diff		1.467
Leases Sold	RR	5	45.800
Leases Sold	Post-RR	3	48.000
Leases Sold	Diff		-2.200

Table 3-26. t-tests of DWRRA and Post-DWRRA Periods, Central 200-800 meter.

T-Tests					
Variable	Method	Variances	DF	t Value	Pr > t
PCPTS	Pooled	Equal	6	0.20	0.8491
PCPTS	Satterthwaite	Unequal	4.45	0.26	0.8067
LEASES_SOLD	Pooled	Equal	6	-0.14	0.8936
LEASES_SOLD	Satterthwaite	Unequal	4.78	-0.18	0.8648

Table 3-27. Means of DWRRA and Post-DWRRA Periods, Western 200-800 meter.

Variable	Test	N	Mean
Participants	RR	5	27.200
Participants	Post-RR	3	21.000
Participants	Diff		6.200
Leases Sold	RR	5	51.200
Leases Sold	Post-RR	3	51.000
Leases Sold	Diff		0.200

Table 3-28. t-tests of DWRRA and Post-DWRRA Periods, Western 200-800 meter.

T-Tests					
Variable	Method	Variances	DF	t Value	Pr > t
PCPTS	Pooled	Equal	6	0.71	0.5041
PCPTS	Satterthwaite	Unequal	4.19	0.94	0.3984
LEASES_SOLD	Pooled	Equal	6	0.01	0.9936
LEASES_SOLD	Satterthwaite	Unequal	4.42	0.01	0.9917

Table 3-29. Means of DWRRA and Post-DWRRA Periods, Central 800-plus meter.

Variable	Test	N	Mean
Participants	RR	5	35.600
Participants	Post-RR	3	27.667
Participants	Diff		7.933
Leases Sold	RR	5	320.400
Leases Sold	Post-RR	3	148.667
Leases Sold	Diff		171.733

Table 3-30. t-tests of DWRRA and Post-DWRRA Periods, Central 800-plus meter.

T-Tests					
Variable	Method	Variances	DF	t Value	Pr > t
PCPTS	Pooled	Equal	6	1.05	0.3333
PCPTS	Satterthwaite	Unequal	4.52	1.37	0.2345
LEASES_SOLD	Pooled	Equal	6	1.34	0.2303
LEASES_SOLD	Satterthwaite	Unequal	4.02	1.78	0.1496

Table 3-31. Means of DWRRA and Post-DWRRA Periods, Western 800-plus meter.

Variable	Test	N	Mean
Participants	RR	5	32.000
Participants	Post-RR	3	19.000
Participants	Diff		13.000
Leases Sold	RR	5	259.600
Leases Sold	Post-RR	3	146.667
Leases Sold	Diff		112.933

Table 3-32. t-tests of DWRRA and Post-DWRRA Periods, Western 800-plus meter.

T-Tests					
Variable	Method	Variances	DF	t Value	Pr > t
PCPTS	Pooled	Equal	6	2.06	0.0850
PCPTS	Satterthwaite	Unequal	4.35	2.70	0.0492
LEASES_SOLD	Pooled	Equal	6	0.89	0.4094
LEASES_SOLD	Satterthwaite	Unequal	4.25	1.17	0.3037

Issues for the Regression Analysis

Equations

The fact that participants and leases sold (and leases per participant as well) cycle in similar patterns is striking and implies that both series might be determined by some of the same factors. Most importantly, it may be possible that both series are functions of the policy variables. Thus policies may have two effects:

- Policies like royalty relief tend to attract more participants to the sale; more “customers enter the store,” as it were, due to the policies.
- Policies also tend to increase the number of leases bought by participants.

The implication is that a simultaneous equation model is appropriate in which participants and leases sold are both endogenous.

We examined possible transformations (log, etc.) for the participants and leases sold variables. A transformation is indicated for the 800-plus meter series, but not the other depths. Therefore, to be consistent among the various regression equations, the study did not perform transformations. Cross-equation parameter constraints were examined, as mentioned below, but ultimately not used. Participation in a sale might be viewed as a matter for probit or similar modeling, however, we did not have independent variables appropriate for that approach.²⁶

Periodicity and Autocorrelation

Autocorrelation analysis of participants and leases sold addresses two issues:

- Is there a need for an autoregressive term in the model?

²⁶ We did use probit and similar models in modeling competition, see Chapter 4.

- As discussed above, routine lease stock replacement might explain the peaks and valleys observed in participants and leases sold. Is the periodicity as simple as a five-year replacement cycle?

Tables 3-33 through 3-44 give the autocorrelation (ACF) and partial autocorrelation functions (PACF) for each water depth class for number of participants and leases sold. The dot indicates two standard deviations.²⁷ For this analysis, data for areas were combined and Eastern sale data included, resulting in a single, annual observation series for each depth class. Note that having six lags is more than 25 percent of the number of observations (21); hence inferences from these statistics must be made with caution. Although stationary transformations would perhaps be considered for some of the series examined, none were made for the sake of simplicity and clarity, with the partial exception of a time trend for the 800-plus meter class, as mentioned below.

0-200 meters

The ACF of participants shows a pattern consistent with a six-year autoregressive cycle. Only the first and third ACF lags are significant, but considering the small sample, the ACF does support the general idea of a six-year cycle. The same comments can be made of the ACF and PACF of leases sold in 0-200 meters. A six-year cycle does not exactly match with the five-year primary term, but it is not inconsistent with it either. Some leases are given an extension if work is taking place, and it is possible that firms do some of their inventory replacement buying with a slight delay. (Additional comments are made below.)

Table 3-33. ACF of Participants, 0-200 meter.

Autocorrelations																								
Lag	Covariance	Correlation	-1	9	8	7	6	5	4	3	2	1	0	1	2	3	4	5	6	7	8	9	1	Std Error
0	249.583	1.00000												*****										0
1	103.454	0.41451						.						*****.										0.218218
2	-50.227945	-.20125						.			****						.							0.252948
3	-123.010	-.49286								*****							.							0.260461
4	-100.331	-.40200						.		*****							.							0.301619
5	-10.541518	-.04224						.			*						.							0.326136
6	89.023648	0.35669						.						*****			.							0.326397

²⁷ Leases sold data are from LeaseHist database.

Table 3-34. PACF of Participants, 0-200 meter.

Partial Autocorrelations		-1	9	8	7	6	5	4	3	2	1	0	1	2	3	4	5	6	7	8	9	1
Lag	Correlation																					
1	0.41451							.					*****	.								
2	-0.45046												*****				.					
3	-0.28047								.				*****				.					
4	-0.17824							.					****				.					
5	-0.00106							.									.					
6	0.18514							.					****				.					

Table 3-35 ACF of Leases Sold, 0-200 meter.

Autocorrelations																								
Lag	Covariance	Correlation	-1	9	8	7	6	5	4	3	2	1	0	1	2	3	4	5	6	7	8	9	1	Std Error
0	29117.569	1.00000												*****	*****	*****	*****	*****	*****	*****	*****	*****	*****	0
1	11680.932	0.40116							.					*****	.									0.218218
2	-8232.232	-.28272						.					*****				.							0.250890
3	-19354.316	-.66470											*****	*****	*****	*****	*****	*****	*****	*****	*****	*****		0.265629
4	-11191.851	-.38437						.					*****				.							0.335614
5	3887.396	0.13351						.					***				.							0.355959
6	15114.076	0.51907						.					*****	*****	*****	*****	*****	*****	*****	*****	*****	*****		0.358336

Table 3-36. PACF of Leases Sold, 0-200 meter.

Partial Autocorrelations		-1	9	8	7	6	5	4	3	2	1	0	1	2	3	4	5	6	7	8	9	1
Lag	Correlation																					
1	0.40116							.					*****	.								
2	-0.52875												*****				.					
3	-0.46187												*****				.					
4	-0.04873							.			*						.					
5	-0.02185							.									.					
6	0.14467							.					***				.					

200-800 meter

The patterns for this class are similar, but weaker, than the patterns for shallow water. Again, the ACF pattern is suggestive of a six-year cycle for both variables.

Table 3-37. ACF of Participants, 200-800 meter.

Autocorrelations																									
Lag	Covariance	Correlation	-1	9	8	7	6	5	4	3	2	1	0	1	2	3	4	5	6	7	8	9	1	Std Error	
0	144.585	1.00000													*****										0
1	73.989310	0.51174						.							*****										0.218218
2	-7.749271	-.05360					.				*						.							0.269368	
3	-39.229349	-.27132					.				****						.							0.269876	
4	-31.757046	-.21964					.				****						.							0.282567	
5	-14.114674	-.09762					.				**						.							0.290583	
6	16.752187	0.11586					.						**				.							0.292141	

Table 3-38. PACF of Participants, 200-800 meter.

Partial Autocorrelations	
Lag	Correlation
1	0.51174
2	-0.42739
3	-0.02231
4	-0.05747
5	-0.04505
6	0.18699

Table 3-39. ACF of Leases Sold, 200-800 meter.

Autocorrelations																								
Lag	Covariance	Correlation	-1	9	8	7	6	5	4	3	2	1	0	1	2	3	4	5	6	7	8	9	1	Std Error
0	3660.054	1.00000													*****									0
1	1565.944	0.42785							.						*****									0.218218
2	-1103.276	-.30144							.		*****							.						0.255054
3	-1749.468	-.47799							.		*****							.						0.271489
4	-881.021	-.24071							.		*****							.						0.308976
5	342.691	0.09363							.				**					.						0.317780
6	976.825	0.26689							.				****					.						0.319091

Table 3-40. PACF of Leases Sold, 200-800 meter.

Partial Autocorrelations	
Lag	Correlation
1	0.42785
2	-0.59305
3	-0.03550
4	-0.15365
5	0.04504
6	0.03379

800-plus meter

The patterns for this class are slightly different. For both participants and leases sold, ACF are indicative of a basic AR(2) process, and there is little suggestion of a six-year cycle. This is not surprising for two reasons:

- Leases in the 800-plus meter class have a 10-year primary term (instead of five years).
- There was no initial boom in lease buying in 1983 for this depth class, hence no wave of replacement buying in 1993 would be expected. The class is “frontier” within the period covered by this study.

Lest the pattern difference be due to a time trend in the data for this class, the variable *saledate* was tentatively included. Although the regressions on *saledate* yielded a significant coefficient

for that variable, the autocorrelation analysis of the residuals showed patterns similar to the patterns for the raw data. Therefore, the raw data autocorrelation analysis is presented below.

Table 3-41. ACF of Participants, 800-plus meter.

Autocorrelations																								
Lag	Covariance	Correlation	-1	9	8	7	6	5	4	3	2	1	0	1	2	3	4	5	6	7	8	9	1	Std Error
0	225.361	1.00000													*****									0
1	163.931	0.72742						.							*****									0.218218
2	82.433431	0.36578					.								*****		.							0.313070
3	35.582119	0.15789					.								***		.							0.332800
4	1.764820	0.00783					.										.							0.336348
5	-24.957240	-0.11074					.					**					.							0.336356
6	-44.624879	-0.19802					.					****					.							0.338088

Table 3-42. PACF of Participants, 800-plus meter.

Partial Autocorrelations	
Lag	Correlation
1	0.72742
2	-0.34692
3	0.12520
4	-0.17912
5	-0.03560
6	-0.11790

Table 3-43. ACF of Leases Sold, 800-plus meter.

Autocorrelations																								
Lag	Covariance	Correlation	-1	9	8	7	6	5	4	3	2	1	0	1	2	3	4	5	6	7	8	9	1	Std Error
0	73507.583	1.00000													*****									0
1	45745.518	0.62232						.							*****									0.218218
2	3303.525	0.04494					.								*		.							0.290695
3	-14731.629	-.20041					.			****						.								0.291026
4	-15965.086	-.21719					.			****						.								0.297525
5	-13241.621	-.18014					.			****						.								0.304981
6	-7412.861	-.10084					.			**						.								0.310006

Table 3-44. PACF of Leases Sold, 800-plus meter.

Partial Autocorrelations	
Lag	Correlation
1	0.62232
2	-0.55874
3	0.24609
4	-0.28425
5	0.06057
6	-0.03395

The autocorrelation analysis leads to two conclusions.

1. For the two depth classes with a five-year primary or five-year exploration lease term, there is evidence of a six-year cycle, for both participants and leases sold. Although a six-year cycle is fairly consistent with the idea of inventory replacement buying, in these classes it is not an exact match.²⁸ Thus, some other cause of cyclicity might be present. An alternative (or complementary) explanation for the cycle is provided by the policies of minimum bid and royalty relief, which are indicated in the graphs presented in this chapter. The policies

²⁸ In the course of the study, the stock of leases was divided into parts: producing leases, drilled but not producing, and undrilled leases. An accounting framework was set up that showed how many leases terminated early, at term, or continued past term. This accounting was helpful in developing the inventory model of leasing (cf. Appendix B). Unfortunately, the accounting framework did not yield any better regression models than those presented in this chapter.

happen to occur at approximately five to seven year intervals. Thus, we cannot find a way to distinguish statistically between the two explanations for the cycles.

2. Both participants and leases sold have an autoregressive element. Regressions might well include AR(1) terms.²⁹

Issues for Regression Analysis Using Policy Variables

Options for Specifying Policy Dummy Variables

We defined the policy variables as dummy variables. There are questions of model specification that must be resolved as regards these policy dummy variables. We considered three alternative specifications to consider.

Option 1: Continuing Dummy

The first possible approach is to define the dummy as zero when the policy is in effect and 1 otherwise. By this approach, area-wide leasing would always be in effect over the 1983-2003 period covered by the analysis; DWRRA would be 1 in the years 1996-2000, and zero otherwise, etc. The problem with this specification is obvious from an examination of the data on leases sold shown above. A five-year dummy for DWRRA would cover both a peak in leases sold 1996-1998 and a trough in leases sold 1999-2000. The dummy defined that way would capture a rise or fall in the *average* leases sold *over the five year* period, and it would fail to make use of the information available about the peak-and-decline pattern. Notwithstanding, this type of dummy variable can help address the question, how many more (or less) leases were sold due to DWRRA? It gives a simple answer in terms of the average leases sold over the period.

Option 2: Impulse Dummy

The second way is to define the dummy as an “impulse” variable. By this approach, a policy dummy is 1 in the year the policy starts, and zero otherwise; thus, for example, DWRRA would be 1 in 1996 and zero otherwise. The impulse specification is an explicit representation of the prediction of the lease inventory model. When royalty relief drops the price of reserves, there is an immediate adjustment in the level of stocks desired, and there is a surge in the addition of leases to stocks. Insofar as a short-term surge of leases bought is able to bring inventories up to desired levels, the demand for more leases is promptly reduced. Although this approach avoids the problem of a continuing dummy of covering too many years, a single-year impulse runs into the opposite problem of covering too short a period. We see in Figures 3-1 and 3-2, for example, that the peaks tend to last for about three years. Also, the year in which the policy starts is not necessarily the year in which it has its full or greatest impact; its impact might instead be delayed or spread out over several years. That consideration leads to the third option.

²⁹ In regression models, a variable for the stock of leases held or the change in stock might, among other things, bring an autoregressive effect into the models.

Option 3: Impulse With Distributed Effect

The third way is to specify a distributed effect. The policy is assumed to have part of its effect when it first takes effect and part of its effect over a short period, perhaps two or three years in our context. However, it does not necessarily have an effect over the entire policy period, e.g., five years for DWRRA. Or, considering the “cosine” pattern in the data, it might have a positive effect for a couple of years and then no effect or a negative effect in the next couple of years. This specification is also consistent with the lease inventory model. It accounts for the possibility that the adjustment, after the policy begins, in lease stock is not completed in the first sale. Some buyers return for a second or third year, and there are late entrants as well. There might be budgetary constraints, or perhaps new information is developed after the first year of the policy period. It is also possible that after the lease buying surge of the first couple of years, leasing is unusually depressed, creating a boom-bust pattern. Perhaps budgets are depleted; or perhaps lease stock additions actually overshoot the desired stock level, implying that there is no stock-replacement leasing for a couple of years. It is also possible that buyer expectations or other conditions happen to shift in a direction that depresses lease demand.

Econometrically, the policy dummy itself is the single-year impulse form, and it enters the regression model by way of a transfer function that distributes the impact over the specified number of years. There are some problems. First, each lag on policy variables cuts one year of observation from the front of the data. For instance, if the model (where B is the lag operator) is:

$$\begin{aligned} \text{Leases sold} &= \text{non-policy variables} \\ &+ (1 - B - B\text{-squared}) * b * MB \\ &+ (1 - B - B\text{-squared}) * b * DWRRA \\ &+ (1 - B - B\text{-squared}) * b * \text{Post_DWRRA} \end{aligned}$$

Instead of 21 observations for the 1983-2003 period, there are 18 observations, 1985-2003, and even fewer degrees of freedom. Note that the observations lost are those covering the initial impact of area-wide leasing. There are two unfortunate implications. One is that all parameter estimates might be biased. The other is that the strategy of adding one lag at a time, to determine the best number of lags, is hindered by instability of parameter estimates.

Another issue is that the technique of distributed lag function is intended for a case where the input variable happens more than once. For instance, one might be studying the impact of Federal Reserve actions on financial markets, and in that case there are a number of times when the Fed changes policy. In that case, a regression model of distributed lag makes sense. In contrast, this study focuses on only two royalty relief policy “events.” The technique of distributed lag seems more appropriate for a more general theory of fiscal policy impacts. For instance, one might consider examining all three major fiscal policy changes by a single input, namely, an input series that is 1 in 1988, 1996, and 2001, and a distributed lag function. The idea would be that all three fiscal policy changes have a similar distributed impact on lease buying, perhaps according to the lease stock model.

Recognizing the small sample problem, the study proceeded to add continuing-effect dummies for DWRRRA and post-DWRRRA to the no-policy model, to review the regression results for significance, and to compare with results of tests of means. Distributed lag dummies were left for future work.

The policy variables potentially included are:

- **DWRRRA5, Post_DWRRRA3** – These are the continuing-effect dummies for DWRRRA and the post-DWRRRA periods. Regarding water depth:
 - DWRRRA applied to 200-800 meter and 800-plus meter depths. More precisely, it gave smaller relief amounts to 200-400 meter than to 400-800 meter within the 200-800 meter class.
 - The post-DWRRRA policy was slightly complicated as regards water depth. In 2001, it applied only to 800-plus meter; in 2002 and 2003, it applied also, with smaller relief amounts, to 400-800 meters (but never to 200-400 meters).
- **DWRRRA96, DWRRRA97, etc.** – 1 in 1996 and zero otherwise, etc.
- **Post-DWRRRA01, etc.** – 1 in 2001 and zero otherwise, etc.

Rental rate is a policy variable that was considered but ultimately omitted. The pre-production rental rate was increased starting in 1994 and, in deepwater, again starting 1996. It is doubtful that this cost increase was significant enough to have an effect on numbers of participants or leases sold.

Areawide and minimum bid policies are of less interest for purposes of this chapter than are the royalty relief policies, and they are not included in most regressions. Area-wide leasing commenced in 1983. The minimum bid for leases was reduced substantially, from \$150/acre to \$25 or \$37.50, for all water depths starting in 1988. Minimum bid is an important variable for our analysis performed in Chapter 5, which examines high bid amounts.

Instability of Regression Estimates

It is to be expected that re-estimating of the model with dummies added leads to changes in coefficients estimated previously for models containing only non-policy variables. Ideally, the changes are small, that is, coefficients are “stable” in that sense. Unfortunately, in our case, re-estimation of the model with dummies can cause large changes in the coefficients. This occurs because the no-policy models are usually weak to begin with. The no-policy models do not explain much, and when the dummies are added, the dummies have relatively strong explanatory power. The implication is that the coefficients of the dummies tend to overstate the effect of the policy.

To deal with the problem, one might try to develop additional non-policy data and improve the no-policy models. Insofar as we have considered the principal non-policy variables already, there appears to be no statistical solution to this problem. Thus, in this report, the results of the policy model regressions were qualified, and they are presented alongside other information to guide policy analysis.

Constraints on Parameters

The number of leases sold for all depths aggregated is, in reality, equal to the sum of leases sold in the water depth classes. For the number of participants, the relationship is not easy to summarize or predict. Imagine that there are, on average, 15 participants in 0-200 meters, 20 in 200-800 meters, and 25 in 800-plus meters. Some of these participants are unique to their class, but others can be active in two or three classes. Certainly the number of participants in all depths aggregated is larger than the maximum class number – in this illustration, it must be larger than 25. And it must be no more than the sum of the class numbers – in the illustration, no more than (15 + 20 + 25 =) 60.

Thus, in reality:

$$\text{Leases (all depths)} = \text{leases (0-200)} + \text{leases (200-800)} + \text{leases (800-plus)}$$

$$\text{Pcpts (all depths)} \geq \max(\text{pcpts (0-200)}, \text{pcpts (200-800)}, \text{pcpts (800-plus)})$$

$$\text{And } \leq \text{pcpts (0-200)} + \text{pcpts (200-800)} + \text{pcpts (800-plus)}$$

Consider next the coefficients of the policy dummy variables. For participants, there is no lower bound constraint, while the upper bound constraint still pertains. The absence of a lower bound constraint can be illustrated as follows. Suppose the following firms are active in a pre-policy sale:

<u>0-200 m</u>	<u>200-800 m</u>	<u>800 plus m</u>	<u>All</u>
A	D	E	A
B			B
C			C
			D
			E

Then suppose that a policy sale has the following participants:

<u>0-200 m</u>	<u>200-800 m</u>	<u>800 plus m</u>	<u>All</u>
A	D	E	A
B	A	A	B
C	B	B	C
		C	D
			E

In this example, firms active in some classes become active in other classes, but no new participants that were never active before in the Gulf have been added. The coefficient of the policy dummy ought to show positive effects on participation in 200-800 meters and 800-plus meters, but not on the aggregate. For leases sold, the coefficient of the aggregate policy dummy ought to equal the sum of the coefficients of the depth class dummies.

One wants to see these same relationships in the predictions of regression models. However, when each water depth is associated with its distinct regression equation and each is estimated independently, the relationships are not guaranteed. To guarantee that desired relationships are present in predictions of regression models, one must impose constraints on the parameter estimates. Imposing a constraint on parameters implies that the equations for depth classes are no longer independent; instead, they comprise a system of equations.

Participants for Both Areas versus Separate Areas

In a related issue, confusion can arise about the relation of participants in both areas, Central and Western, combined as distinct from the two separate areas. Consider, for instance, the depth class 0-200 meters in the pre-policy (1983-1995) period as shown in Table 3-45. The average number of participants for both areas combined is 85. But the average number of participants for the Western area is 54, and the average for the Central area is 74. Plainly the two separate area numbers cannot be averaged to equate to the number for both areas. Indeed, the average for both areas (85) is greater than the larger of the separate area numbers (74).³⁰

Table 3-45. Participants by Sale Area Versus Both Combined, 0-200 meter.

0-200 m		Participants
<i>Period</i>	WGM	Mean
Pre-Policy	0	73.85
	1	53.62
DWRRA	0	71.60
	1	44.80
Post-RR	0	68.00
	1	39.00
0-200 m		Participants
<i>Period</i>		Mean
Pre-Policy	Both	85.08
DWRRA	Both	80.00
Post-RR	Both	77.67

³⁰ For reference, the following tables give the mean number of participants both ways. In the tables, WGM equals 0 for Central area, and it equals 1 of the Western area.

Table 3-46. Participants by Sale Area Versus Both Combined, 200-800 meter.

200-800 m		Participants
<i>Period</i>	WGM	Mean
Pre-Policy	0	21.23
	1	18.31
DWRRA	0	27.80
	1	27.20
Post-RR	0	26.33
	1	21.00
200-800 m		Participants
<i>Period</i>		Mean
Pre-Policy	Both	27.15
DWRRA	Both	39.60
Post-RR	Both	35.33

Table 3-47. Participants by Sale Area Versus Both Combined, 800-plus meter.

800+ m		Participants
<i>Period</i>	WGM	Mean
Pre-Policy	0	14.38
	1	8.31
DWRRA	0	35.60
	1	32.00
Post-RR	0	27.67
	1	19.00
800+ m		Participants
<i>Period</i>		Mean
Pre-Policy	Both	16.77
DWRRA	Both	46.00
Post-RR	Both	31.67

Results of Regression Analysis of DWRRA And Post-DWRRA

Estimation by Two-Stage Least Squares (2SLS)

For the final regressions in this chapter, the two equations, participants and leases sold, were joined in a simultaneous system, allowing for an effect of participants on leases sold and vice versa. The simultaneous model was estimated by two-stage least squares (2SLS). We separately estimated the model system for each water depth class. Data for the regressions covered 21 years, 1983-2003, and two separate areas, Central and Western. Thus, the data included 42 observations in all (but the observation for 1983 was lost when variables were transformed by differencing). The 42 observations were pooled as a single data set, and the variable *WGM* was defined to indicate which area a particular sale related to. *WGM* is 0 for the Central area and 1 for the Western area. Since data relate to particular sales, the *participants* variable was defined on a sale basis, a detail that is explained above.³¹

³¹ Leases sold data are from LeaseHist database.

We selected regressors for two equation models in final form by informal backwards selection.

- Each equation included the other endogenous variable on the right-hand side (RHS).
- Usually, leases held was included, and it was entered as a difference, $ls_chg = leases_held[t] - leases_held[t-1]$.
- Usually, reserves added in the prior year were included.

For each water depth, the results given below include estimates of parameters, simulations of combined impacts from policies, and graphs of the simulation results.

Simulation of Policy Impacts

For purposes of policy analysis, individual estimated parameters are of minor interest; instead, the impacts are mainly computed by simulation runs that use the combined equations in the model system.

Consider the simple two-equation model:

$$S = a1 * D + a2 * DWRRA$$

$$D = b1 * S + b2 * DWRRA$$

where DWRRA is a policy period dummy, and S and D are endogenous variables. (Other exogenous variables are omitted for simplicity.) If the question is, how did DWRRA affect S, the answer is computed from the differentiated equation:

$$dS/d(DWRRA) = a1 * dD/d(DWRRA) + a2$$

The parameter $a2$ is the “direct” effect, and the other term is the effect via the other equation in the system. There is no presumption which effect is larger; that is, it can easily happen that the term, $a1 * dD/d(DWRRA)$, is the principal factor, while $a2$ is near zero or statistically insignificant with the “wrong” sign. The effects of dD on dS and dS on dD repeat in a sort of multiplier effect, and when the model system is used to create simulations, the multiplier effect is accounted for.

Parameter Estimates

0-200 meters

Regression and simulation results are presented for 0-200 meter for the sake of completeness. In the policy simulation, the impact of no royalty relief (“without” policy) is to reduce participants and increase leases sold by relatively small amounts.

Table 3-48. 2SLS Parameters, Participants 0-200 meter.

Root MSE	8.4600	R-Square	0.8449
Dependent Mean	60.9524	Adj R-Sq	0.8073
Variable	Parameter Estimate	t Value	Pr > t
Intercept	42.5293	3.3498	0.0013
Leases Sold	0.1263	1.6953	0.0947
Joint Bidders	19.0034	0.7716	0.4430
Major Bidders	-34.5213	-1.7380	0.0868
Change in Leases Held	0.0085	0.7514	0.4550
Reserve Estimates	0.0009	0.2043	0.8388
WGM	-3.7822	-0.3636	0.7173
DWRRA	-5.0040	-0.9797	0.3308
Post-DWRRA	-15.8523	-2.0803	0.0413
Instruments:	Joint Bidders, Major Bidders, Change in Leases Held, Reserve Estimates, WGM, DWRRA, Post-DWRRA, Seismic Coverage, and GDP Change		

Table 3-49. 2SLS Parameters, Leases Sold 0-200 meter.

Root MSE	64.7824	R-Square	0.7538
Dependent Mean	210.5476	Adj R-Sq	0.7031
Variable	Parameter Estimate	t Value	Pr > t
Intercept	4.2038	0.0188	0.9851
Participants	3.1514	0.8345	0.4070
Change in Leases Held	0.0639	0.8028	0.4249
Reserve Estimates	-0.0130	-0.4131	0.6808
WGM	-60.8839	-0.7352	0.4648
Joint Bidders	114.6802	0.5133	0.6095
DWRRA	13.9060	0.4862	0.6284
Post-DWRRA	63.1358	1.8147	0.0740
Instruments:	Joint Bidders, Major Bidders, Change in Leases Held, Reserve Estimates, WGM, DWRRA, Post-DWRRA, Seismic Coverage, and GDP Change		

Table 3-50. Policy Simulation, Participants And Leases Sold, 0-200 meter.

Period	Actual Participants	Participants Added By Policy	Actual Leases Sold	Leases Sold Added by Policy
	Sale Mean	Sale Mean	Sale Mean	Sale Mean
Pre-Policy	63.73	0.00	214.85	0.00
DWRRA	58.20	-5.39	191.00	-3.10
Post-DWRRA	53.50	-13.09	224.50	21.89

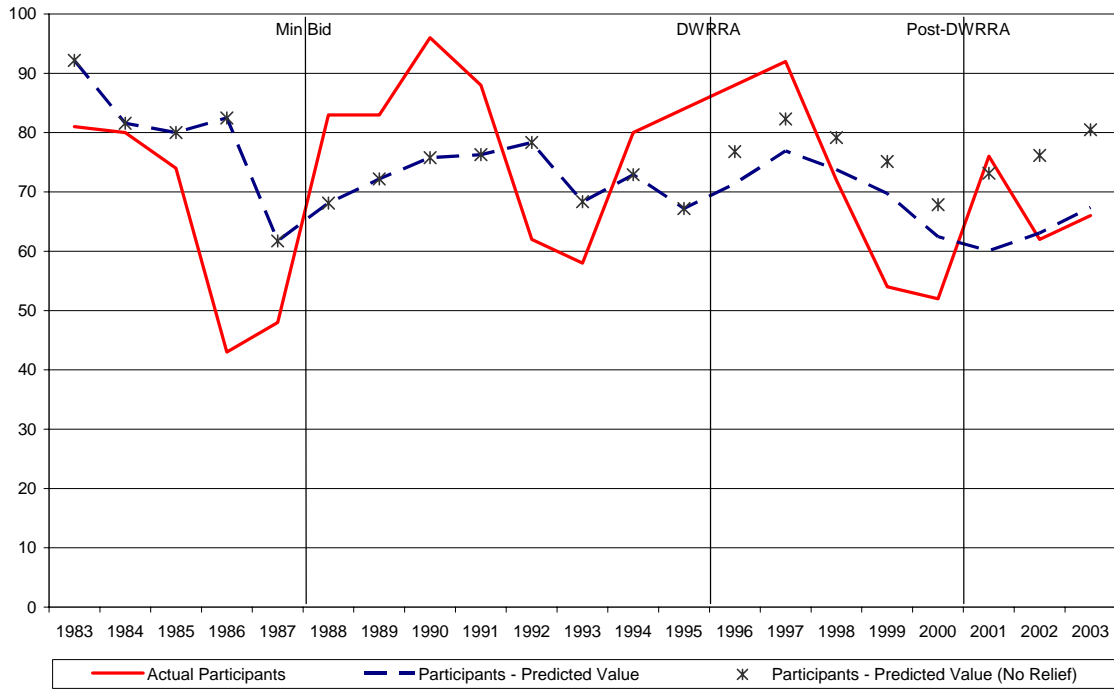


Figure 3-5. Actual and Predicted Participants, Central 0-200 meter.

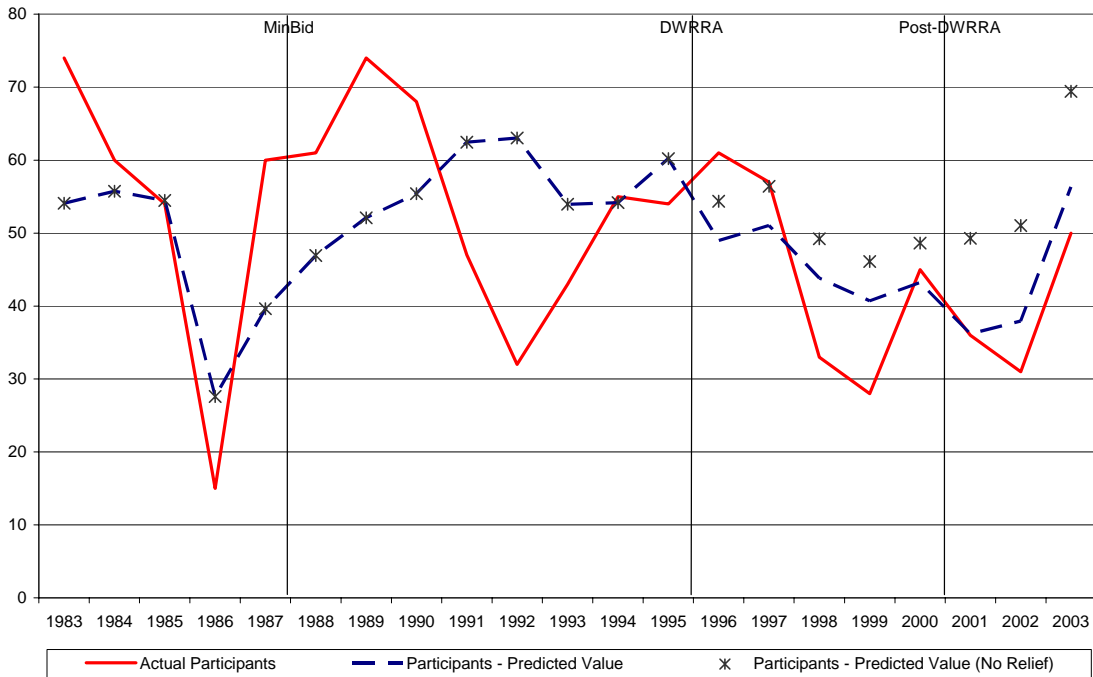


Figure 3-6. Actual and Predicted Participants, Western 0-200 meter.

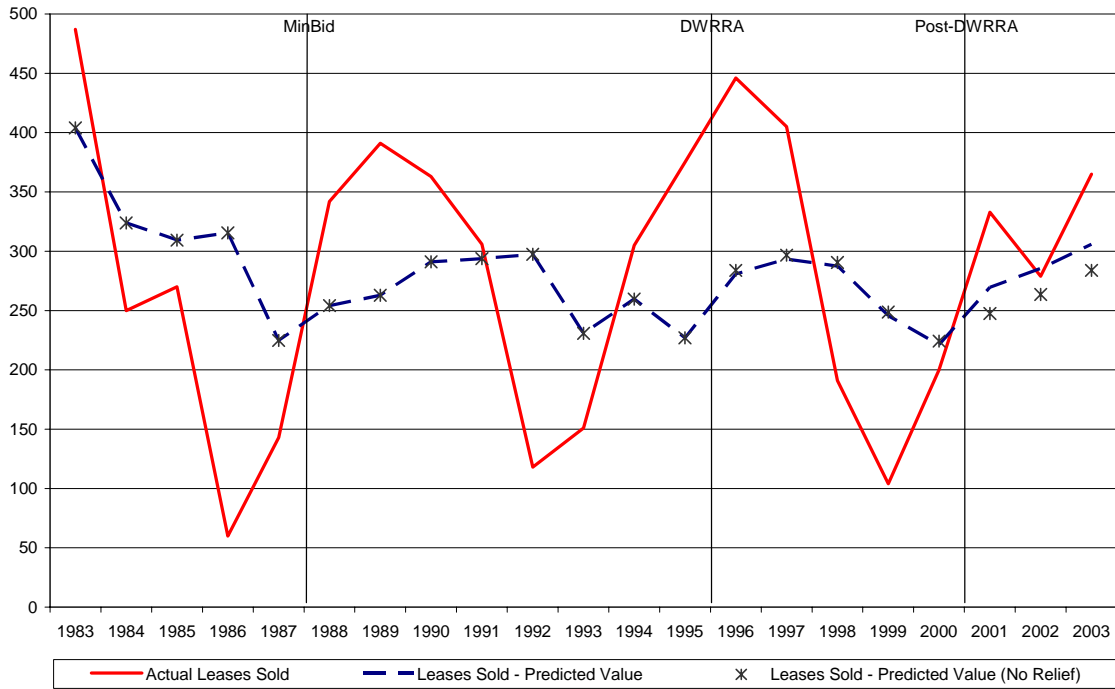


Figure 3-7. Actual and Predicted Leases Sold, Central 0-200 meter.

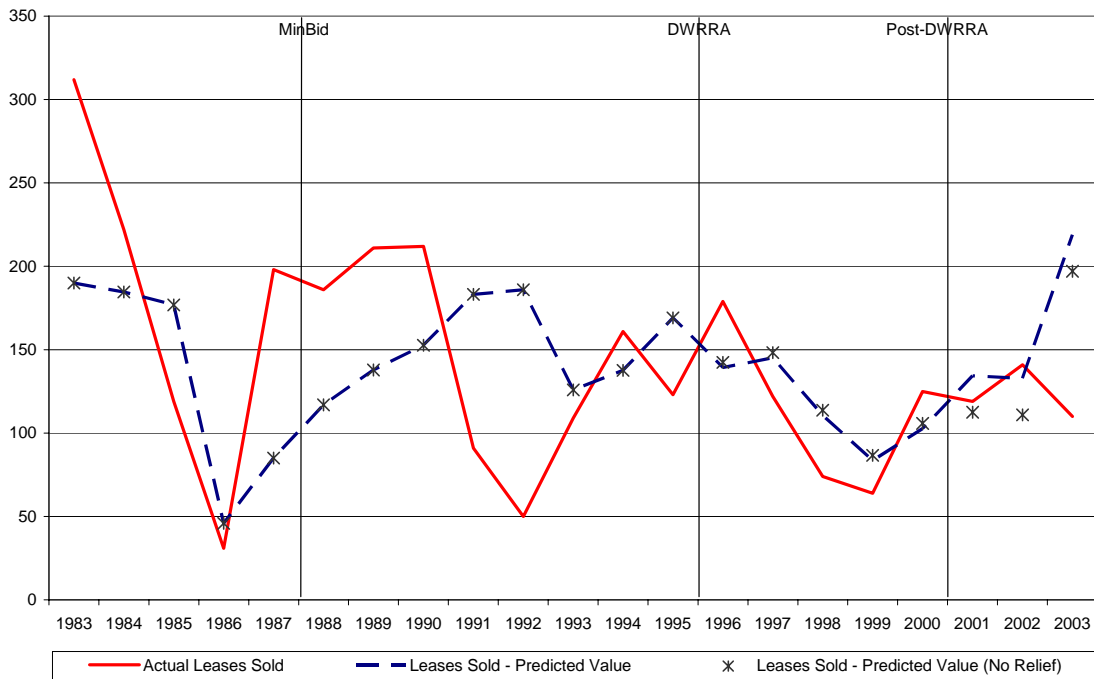


Figure 3-8. Actual and Predicted Leases Sold, Western 0-200 meter.

200-800 meters

In 200-800 meters, the estimated coefficients for period dummies are positive for participants and negative for leases sold. The “wrong” sign for the period dummies in the case of leases sold is overpowered by the positive impact of participants on leases sold. The several effects are combined in the policy simulation, and it turns out that the no-royalty relief case (“without” policy) would have 16 fewer participants and 22 fewer leases sold than occurred in the DWRRA period. These impacts are averages of the policy period (five years for DWRRA).

Table 3-51. 2SLS Parameters, Participants 200-800 meter.

Dependent Variable	Participants		
Root MSE	15.9579	R-Square	-0.7724
Dependent Mean	22.1667	Adj R-Sq	-1.2708
Variable	Parameter Estimate	t Value	Pr > t
Intercept	-49.9411	-0.4937	0.6231
Leases Sold	-0.3435	-0.2656	0.7914
Joint Bidders	9.0251	0.4301	0.6685
Major Bidders	37.7477	0.4870	0.6279
Change in Leases Held	0.0753	0.7954	0.4292
Reserve Estimates	0.0582	0.6646	0.5086
WGM	2.4861	0.3173	0.7520
Oil Price	2.4394	0.5393	0.5915
DWRRA	23.5209	0.6204	0.5372
Post-DWRRA	12.2121	0.5895	0.5576
Instruments:	Joint Bidders, Major Bidders, Change in Leases Held, Reserve Estimates, WGM, DWRRA, Post-DWRRA, Seismic Coverage, Oil Price and GDP Change		

Table 3-52. 2SLS Parameters, Leases Sold 200-800 meter.

Root MSE	15.3256	R-Square	0.7656
Dependent Mean	46.7143	Adj R-Sq	0.7174
Variable	Parameter Estimate	t Value	Pr > t
Intercept	-7.4787	-0.6302	0.5307
Participants	2.4312	5.5447	0.0000
Change in Leases Held	-0.1129	-1.2931	0.2005
Reserve Estimates	-0.0423	-1.4260	0.1586
WGM	1.3098	0.2551	0.7994
GDP Change	0.0352	1.0866	0.2812
DWRRA	-16.5884	-2.1746	0.0332
Post-DWRRA	-11.1765	-1.2440	0.2179
Instruments:	Joint Bidders, Major Bidders, Change in Leases Held, Reserve Estimates, WGM, DWRRA, Post-DWRRA, Seismic Coverage, Oil Price and GDP Change		

Table 3-53. Policy Simulation, Participants and Leases Sold, 200-800 meter.

Period	Actual Participants	Participants Added By Policy	Actual Leases Sold	Leases Sold Added by Policy
	Sale Mean	Sale Mean	Sale Mean	Sale Mean
Pre-Policy	19.77	0.00	45.38	0.00
DWRRA	27.50	15.92	48.50	22.12
Post-DWRRA	23.67	8.75	49.50	10.09

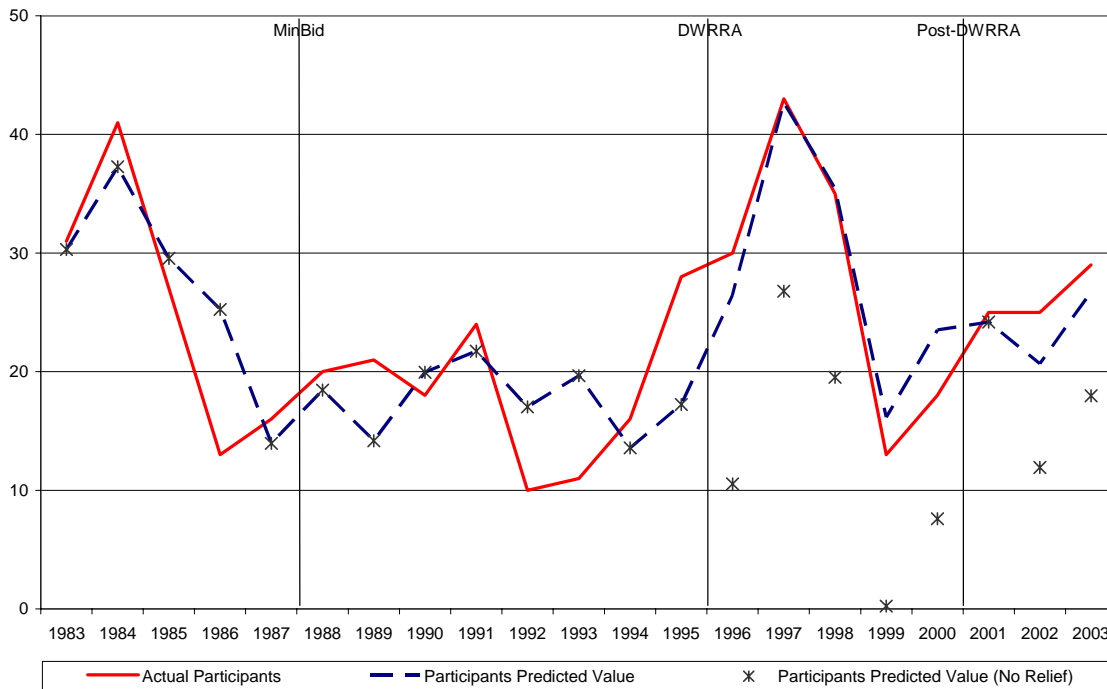


Figure 3-9. Actual and Predicted Participants, Central 200-800 meter.

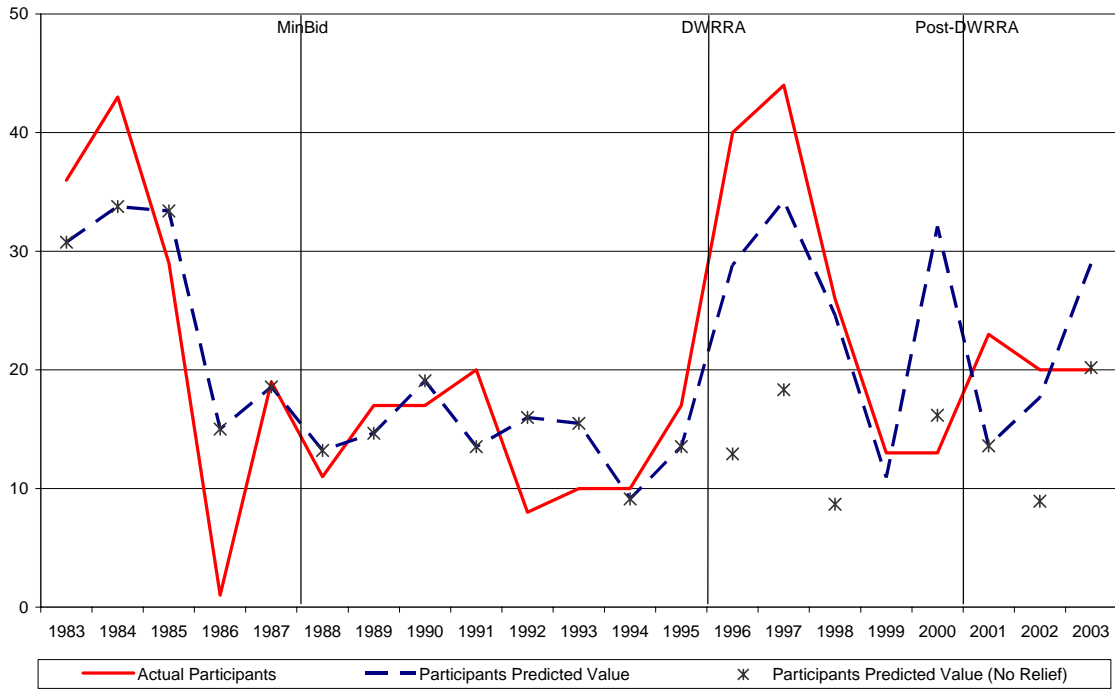


Figure 3-10. Actual and Predicted Participants, Western 200-800 meter.

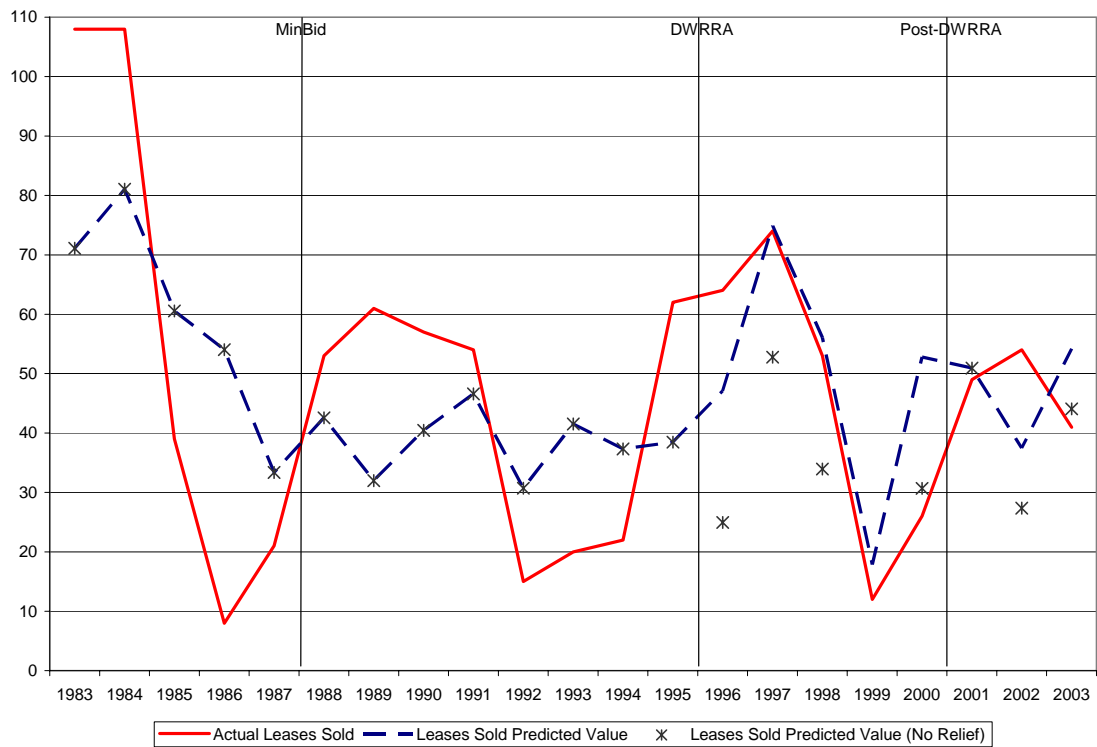


Figure 3-11. Actual and Predicted Leases Sold, Central 200-800 meter.

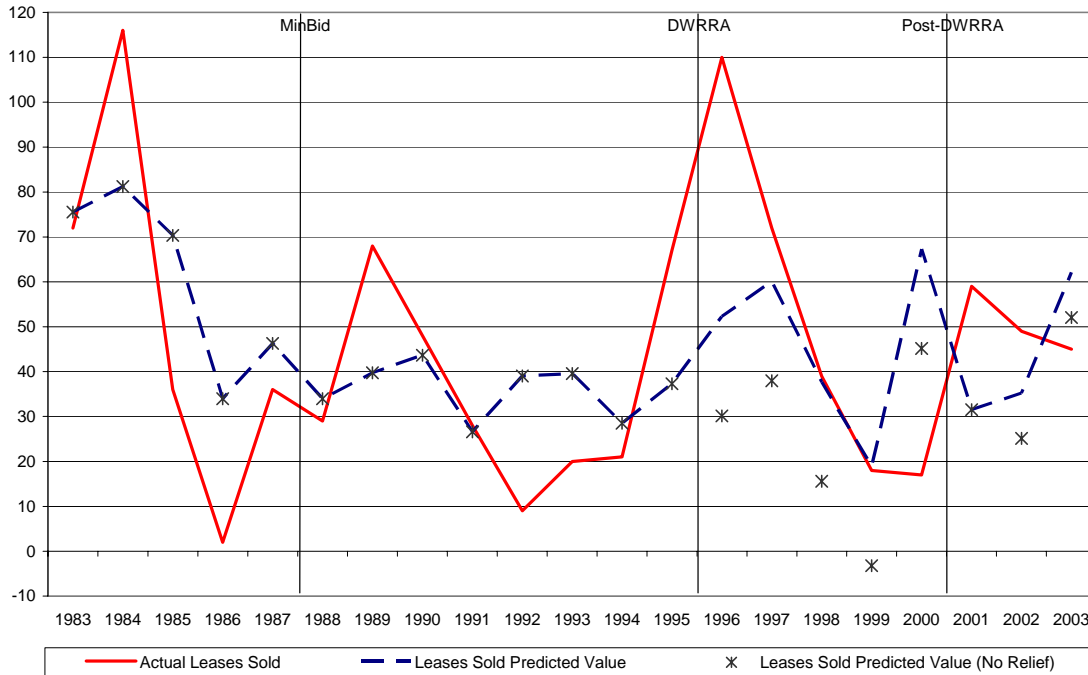


Figure 3-12. Actual and Predicted Leases Sold, Western 200-800 meter.

800-plus meters

In 800-plus meters, the estimated coefficients for period dummies are positive for participants and mixed for leases sold. Again, the “wrong” sign for the post-DWRRA period dummy in the case of leases sold is overpowered by the positive impact of participants on leases sold. The several effects are combined in the policy simulation, and it turns out that the no-royalty relief case (“without” policy) would have 12 fewer participants and 106 fewer leases sold than occurred in the DWRRA period. These impacts are averages of the policy period (five years for DWRRA).

Table 3-54. 2SLS Parameters, Participants 800-plus meter.

Dependent Variable	Participants		
Root MSE	4.2627	R-Square	0.9024
Dependent Mean	18.4048	Adj R-Sq	0.8823
Variable	Parameter Estimate	t Value	Pr > t
Intercept	4.7577	2.8391	0.0059
Leases Sold	0.0288	3.0616	0.0031
Joint Bidders	21.1964	5.8554	0.0000
Change in Leases Held	0.0209	3.2248	0.0019
Reserve Estimates	0.0058	0.9179	0.3619
WGM	-2.0780	-1.4450	0.1530
DWRRA	9.1272	3.5719	0.0007
Post-DWRRA	7.7572	3.4732	0.0009
Instruments:	Joint Bidders, Major Bidders, Change in Leases Held, Reserve Estimates, WGM, DWRRA, Post-DWRRA, Seismic Coverage, Oil Price and GDP Change		

Table 3-55. 2SLS Parameters, Leases Sold 800-plus meter.

Dependent Variable	Leases Sold		
Root MSE	88.1406	R-Square	0.6761
Dependent Mean	132.5238	Adj R-Sq	0.6206
Variable	Parameter Estimate	t Value	Pr > t
Intercept	-20.8621	-0.4503	0.6539
Participants	6.7705	2.1494	0.0351
Change in Leases Held	0.1327	0.9302	0.3555
Reserve Estimates	0.1261	0.9860	0.3276
WGM	9.0520	0.2814	0.7793
DWRRA	24.0557	0.3529	0.7253
Post-DWRRA	-22.4216	-0.3991	0.6910
Instruments:	Joint Bidders, Major Bidders, Change in Leases Held, Reserve Estimates, WGM, DWRRA, Post-DWRRA, Seismic Coverage, Oil Price and GDP Change		

Table 3-56. Policy Simulation, Participants and Leases Sold, 800-plus meter.

Period	Actual Participants	Participants Added By Policy	Actual Leases Sold	Leases Sold Added by Policy
	Sale Mean	Sale Mean	Sale Mean	Sale Mean
Pre-Policy	11.35	0.00	68.46	0.00
DWRRA	33.80	12.19	290.00	106.61
Post-DWRRA	23.33	8.83	147.67	37.38

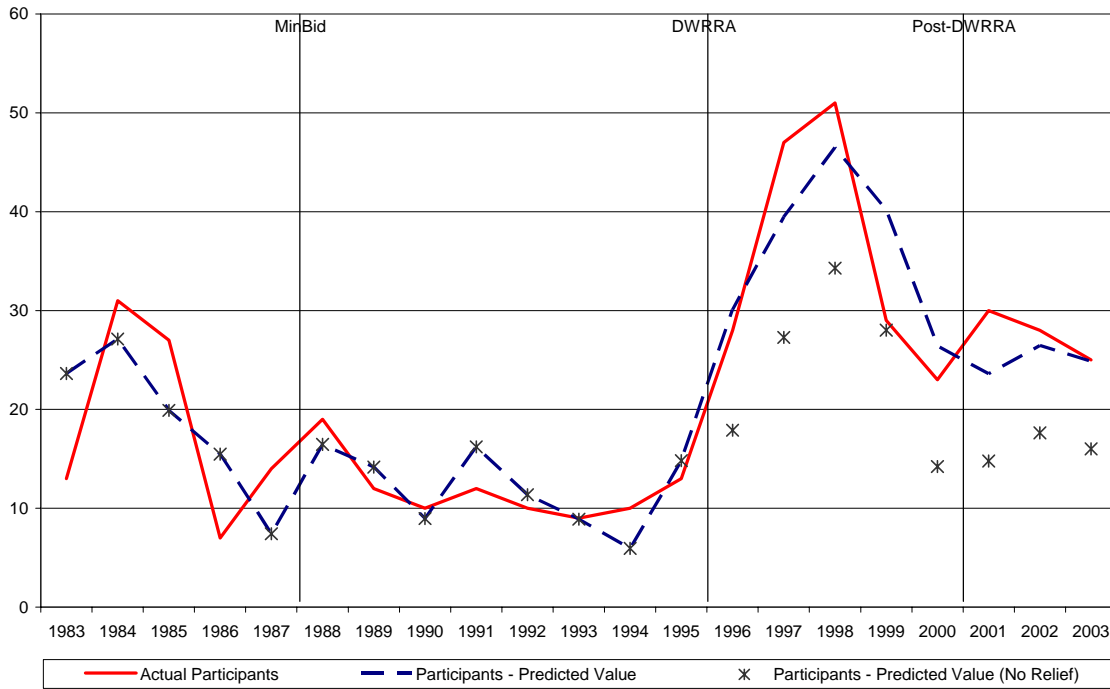


Figure 3-13. Actual and Predicted Participants, Central 800-plus meter.

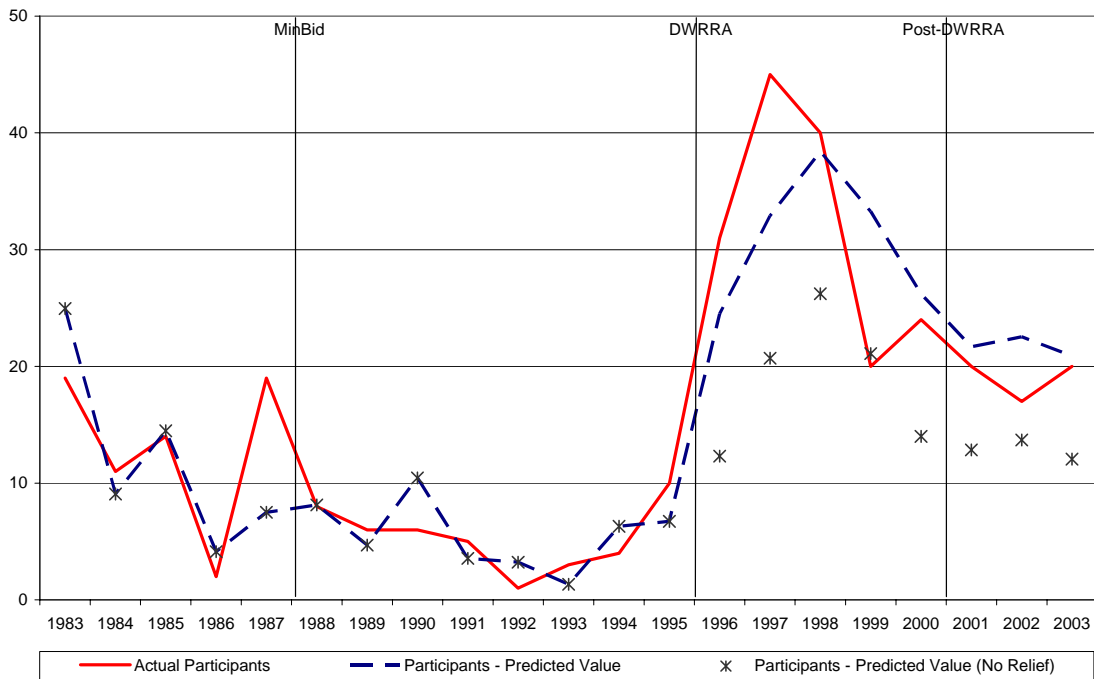


Figure 3-14. Actual and Predicted Participants, Western 800-plus meter.

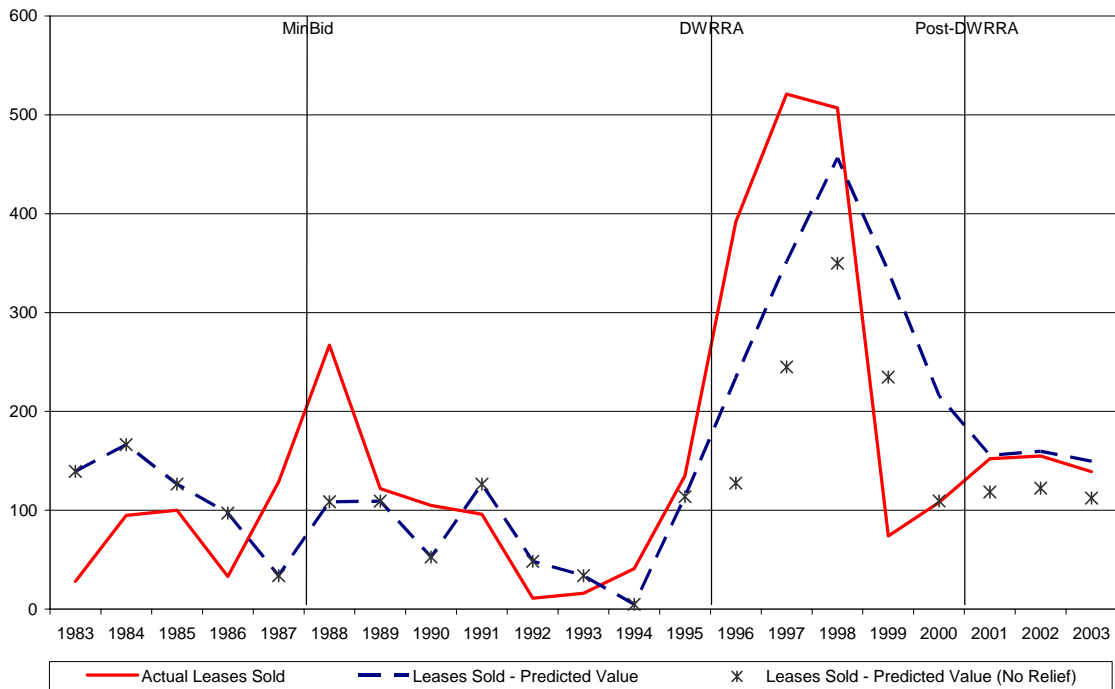


Figure 3-15. Actual and Predicted Leases Sold, Central 800-plus meter.

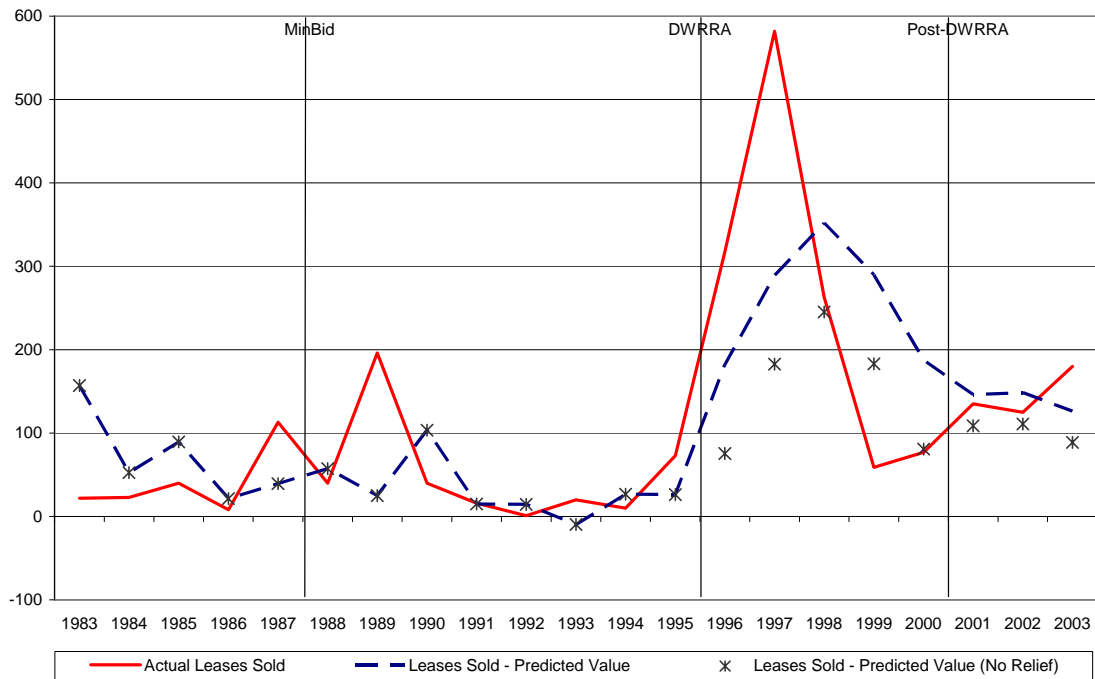


Figure 3-16. Actual and Predicted Leases Sold, Western 800-plus meter.

Chapter 4

Lease Sale Competition

Introduction

In this chapter we discuss our research and analysis of the effect of the DWRRA and the post-DWRRA program, contrasted with no relief, on the *number of bids per tract*.³² First, we review historical data on competition and number of bids and then we discuss our investigation of various econometric topics related to competition as well as to some extent on high bids. An important research question is how incentives such as royalty relief influence competition and the level of high bids. Since competition influences high bids, there is overlap between Chapter 4 and Chapter 5 because bids per tract and high bid amounts are determined together in our econometric model.

The analysis covers three water depth classes:

- *0-200 meters – shallow water:* Deepwater royalty relief does not apply directly but might have indirect effects.
- *200-800 meters – deepwater:* Although policies give different amounts of relief to 200-400 meters and 400-800 meters, data are combined to provide enough observations.
- *800-plus meters – deepwater:* Policies give larger amount of relief.

Data cover lease sales from 1983 to 2003 for the Western and Central Gulf of Mexico. The Eastern Gulf of Mexico data are omitted because they often are outliers, reflecting several differences between the limited and occasional Eastern offering and the area-wide, annual offering of the Western and Central areas.

Bids per Tract and Related Variables

Trends in Bids per tract

Tracts Offered and Probability of Bid

Most tracts offered in a lease sale are not bid on. Although Chapter 3 examined the aggregate level and change in tracts bid on or leased, this chapter focuses on characteristics of tracts (including royalty relief) that make them attractive to bidders. Various characteristics of an individual tract offered and the sale it is offered in affect the probability that it will be bid on.

³² To be clear, a “tract” means an offshore block when it is offered for lease, and a “lease” means the contract giving rights to the block. Thus, a block is given a new tract number each time it is offered. A lease number is assigned when it receives a bid in the lease sale.

Naturally, the perceived oil or gas potential at the block is relevant, but unfortunately, it cannot be observed by the econometrician. Other factors are considered in connection with regression analysis, below.

Many tracts offered are associated with little or no public information that might help one estimate the probability of any bids. There are two classes of potential information about a tract which is summarized in Figure 4-1:

- (a) The tract was previously leased (and then terminated in any of various ways) or previously bid on (and not awarded), or both. Such tracts are associated with lease-specific information, often public.
- (b) The tract was covered by 3-D seismic or other investigations that are not tract-specific but allow an analyst to make inferences about the individual tract. However, this tract-specific information is not generally in a form useful for econometric analysis. A partial exception is that, in bid adequacy review, MMS examines this information to determine tract viability (that is, indication of profitable resources), and tract viability determination is useful and important information. Unfortunately, viability is only determined for tracts that receive a bid.

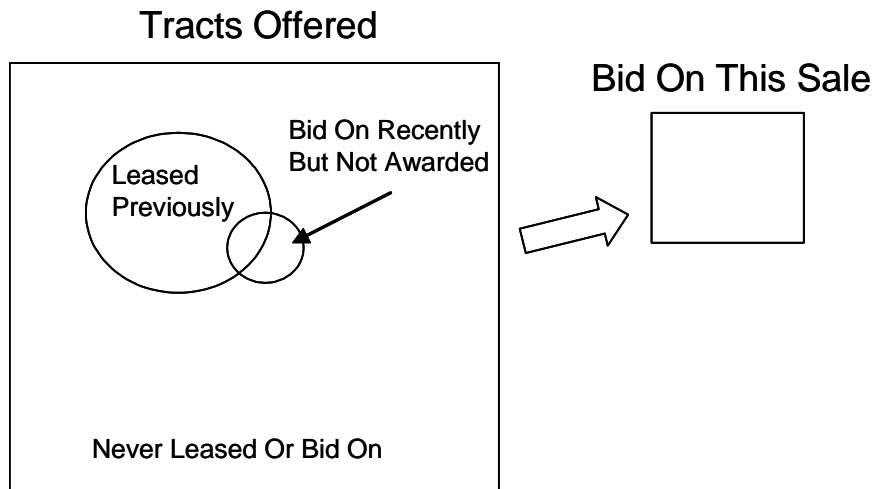


Figure 4-1. Tract Characteristics.

Some tracts that were bid on in a given sale were never leased or bid on previously, and deepwater royalty relief had major effects on bidding for this class of tracts. Also a main effect of deepwater royalty relief was to increase (temporarily) the probability that a deepwater tract, never bid on before, would receive a bid. Also, characteristics of tracts that make them attractive for a bid might be associated with a tendency (however slight) for multiple bids, and a royalty relief lease term might be such a characteristic.

As we saw in Chapter 3, tracts offered for sale follow a roughly cyclical pattern over time. As Tables 4-1 through 4-3 show, tracts offered, averaged by policy period, tended to decline over the policy periods, except for a recent, slight rise in shallow water. Meanwhile, tracts bid on in sales, again averaged by policy period, rose – in deepwater – in the DWRRA period and then returned to a lower level in the post-DWRRA period. In shallow water, tracts bid on, averaged by period, showed only small variation. The implication is that the ratio of tracts bid-to-offered rose for the DWRRA period and then returned to lower levels, in all depths. The change is greatest for 800-plus meters.

Table 4-1. Tracts Offered In Sale, Average of Policy Period, By Depth.

Water Depth	Pre-Policy 1983-1995	DWRRA 1996-2000	Post_DW 2001-2003	All
	Mean	Mean	Mean	Mean
0-200 m	1781.43	1367.50	1562.10	1661.64
200-800 m	507.75	406.36	395.43	465.00
800-plus m	3586.03	2912.24	2214.08	3012.83

Table 4-2. Tracts Bid On In Sale, Average of Policy Period, By Depth.

Water Depth	Pre-Policy 1983-1995	DWRRA 1996-2000	Post_DW 2001-2003	All
	Mean	Mean	Mean	Mean
0-200 m	295.23	278.94	279.81	289.51
200-800 m	67.45	71.28	53.17	66.21
800-plus m	127.86	431.40	151.49	292.28

Table 4-3. Ratio of Tracts Bid On To Tracts Offered In Sale, Average Of Policy Period, By Depth.

Water Depth	Pre-Policy 1983-1995	DWRRA 1996-2000	Post_DW 2001-2003	All
	Mean	Mean	Mean	Mean
0-200 m	0.17	0.21	0.19	0.18
200-800 m	0.16	0.20	0.17	0.17
800-plus m	0.04	0.15	0.07	0.10
Grand Total	0.14	0.18	0.15	0.16

Table 4-4 shows simple correlation statistics for the ratio of bid-to-offer and the number of bids per lease. The data are sale averages, for instance, sale 72 in 0-200 meter has a ratio of tracts bid-to-offer of 0.228 and bids per lease averaging 1.54. The correlation is significantly positive in all water depths. That is, tract characteristics or sale characteristics, such as oil price, that increase the probability of tracts being bid on also increase the chance of multiple bids at tracts. The aspects of a tract and its sale that attract a bidder in the first place also tend to attract a second or third bidder, to a degree.

Table 4-4. Correlation of Bid-To-Offer and Bids Per Lease, Sale Average.

	<i>Pearson Correlation</i>	<i>Significance Probability</i>
0-200 m	0.64710	<.0001
200-800 m	0.40885	0.0072
800-plus m	0.50098	0.0007

Trend Toward Reoffering

Another trend in tracts offered is that, increasingly, they have been previously leased, or at least bid on. By the same token, tracts bid on over time are increasingly likely to have been leased or bid on previously. Table 4-5 shows this trend, and gives the number of tracts bid on that were leased previously as opposed to those that were not previously leased. In shallow water and 200-800 meters, re-leasing has become prevalent. In deepwater, the former availability of never-leased tracts is currently giving way to offering and bidding on tracts that have been leased previously.

Table 4-5. Tracts Bid on That Had Been Leased Previously, By Depth and Period.

0-200 m				
	Period			
<i>Frequency</i>	1983-1995	1996-2000	2001-2003	1983-2003
Never Before Leased	3,836	399	194	4,429
Leased 1 or more times before	2,157	1,575	1,185	4,917
Total	5,993	1,974	1,379	9,346
200-800 m				
	Period			
<i>Frequency</i>	1983-1995	1996-2000	2001-2003	1983-2003
Never Before Leased	835	104	32	971
Leased 1 or more times before	381	409	283	1,073
Total	1,216	513	315	2,044
800-plus m				
	Period			
<i>Frequency</i>	1983-1995	1996-2000	2001-2003	1983-2003
Never Before Leased	1,629	2,255	480	4,364
Leased 1 or more times before	149	754	417	1,320
Total	1,778	3,009	897	5,684

Trends in Bids per Lease

Trends in bids per lease (in other words, bids at the tracts that receive bids),³³ grouping the data in various ways, are shown in Tables 4-6 and 4-7 and Figures 4-2 through 4-7. Although there has been substantial year-by-year variation in bids per lease in 0-200 meters and 200-800 meters, when the variable is averaged over policy periods, the average has not changed greatly.

- About 70 percent of the leases in 0-200 meters and 200-800 meters received a single bid.
- Bids per lease in both 0-200 meters and 200-800 meters averaged about 1.4 bids.

³³ MMS publishes tracts offered, bid on, and sold. Tracts bid on can be classed by water depth readily since the data files for lease history include the estimated water depth of each lease, whether it is ultimately awarded or not (due to bid rejection, etc.). Gathering data for tracts offered but not bid on is more difficult, and generally less (or zero) information is available. This study collected comprehensive data for tracts bid on but not for those that did not receive bids.

In 800-plus meters, a change in bids per lease occurred about the time the DWRRA took effect. Prior to that time, bids per lease in 800-plus meters tended to be significantly less than other depth classes. The DWRRA period brought competition in 800-plus meters closer to the average level of competition of the other depth classes.

Table 4-6. Bids per Lease, Mean and Variance 1983-2003.

	0-200 m		200-800 m		800-plus m	
	Mean	Var	Mean	Var	Mean	Var
Bids Per Lease	1.49	1.06	1.42	0.73	1.35	0.76

Table 4-7. Bids per Lease By Depth and Period, Frequency and Percentage.

Count of Leases					Percent of Column				
0-200 m	Period				0-200 m	Period			
BIDS	Pre-Policy	DWRRA	Post-DW	All	BIDS	Pre-Policy	DWRRA	Post-DW	All
1	4,197	1,399	1,054	6,650	1	70.0%	70.9%	76.4%	71.2%
2	1,142	344	214	1,700	2	19.1%	17.4%	15.5%	18.2%
3	350	128	74	552	3	5.8%	6.5%	5.4%	5.9%
4	173	43	25	241	4	2.9%	2.2%	1.8%	2.6%
5	60	30	7	97	5	1.0%	1.5%	0.5%	1.0%
6	29	14	1	44	6	0.5%	0.7%	0.1%	0.5%
7	23	6	1	30	7	0.4%	0.3%	0.1%	0.3%
8	8	7	1	16	8	0.1%	0.4%	0.1%	0.2%
9	4	2	0	6	9	0.1%	0.1%	0.0%	0.1%
10	3	1	1	5	10	0.1%	0.1%	0.1%	0.1%
11	1	0	0	1	11	0.0%	0.0%	0.0%	0.0%
13	1	0	1	2	13	0.0%	0.0%	0.1%	0.0%
15	2	0	0	2	15	0.0%	0.0%	0.0%	0.0%
All	5,993	1,974	1,379	9,346	All	100.0%	100.0%	100.0%	100.0%

Count of Leases					Percent of Column				
200-800 m	Period				200-800 m	Period			
BIDS	Pre-Policy	DWRRA	Post-DW	All	BIDS	Pre-Policy	DWRRA	Post-DW	All
1	893	362	233	1,488	1	73.4%	70.6%	74.0%	72.8%
2	220	97	57	374	2	18.1%	18.9%	18.1%	18.3%
3	61	31	17	109	3	5.0%	6.0%	5.4%	5.3%
4	24	9	6	39	4	2.0%	1.8%	1.9%	1.9%
5	13	11	0	24	5	1.1%	2.1%	0.0%	1.2%
6	1	2	2	5	6	0.1%	0.4%	0.6%	0.2%
7	4	1	0	5	7	0.3%	0.2%	0.0%	0.2%
All	1,216	513	315	2,044	All	100.0%	100.0%	100.0%	100.0%

Count of Leases					Percent of Column				
800+ m	Period				800+ m	Period			
BIDS	Pre-Policy	DWRRA	Post-DW	All	BIDS	Pre-Policy	DWRRA	Post-DW	All
1	1,528	2,228	719	4,475	1	85.9%	74.0%	80.2%	78.7%
2	192	449	133	774	2	10.8%	14.9%	14.8%	13.6%
3	27	193	33	253	3	1.5%	6.4%	3.7%	4.5%
4	22	79	9	110	4	1.2%	2.6%	1.0%	1.9%
5	7	28	2	37	5	0.4%	0.9%	0.2%	0.7%
6	2	11	1	14	6	0.1%	0.4%	0.1%	0.2%
7	0	7	0	7	7	0.0%	0.2%	0.0%	0.1%
8	0	5	0	5	8	0.0%	0.2%	0.0%	0.1%
9	0	4	0	4	9	0.0%	0.1%	0.0%	0.1%
10	0	1	0	1	10	0.0%	0.0%	0.0%	0.0%
11	0	3	0	3	11	0.0%	0.1%	0.0%	0.1%
13	0	1	0	1	13	0.0%	0.0%	0.0%	0.0%
All	1,778	3,009	897	5,684	All	100.0%	100.0%	100.0%	100.0%

Count of Leases					Percent of Column				
All WD	Period				All WD	Period			
BIDS	Pre-Policy	DWRRA	Post-DW	All	BIDS	Pre-Policy	DWRRA	Post-DW	All
1	6,618	3,989	2,006	12,613	1	110.4%	202.1%	145.5%	135.0%
2	1,554	890	404	2,848	2	25.9%	45.1%	29.3%	30.5%
3	438	352	124	914	3	7.3%	17.8%	9.0%	9.8%
4	219	131	40	390	4	3.7%	6.6%	2.9%	4.2%
5	80	69	9	158	5	1.3%	3.5%	0.7%	1.7%
6	32	27	4	63	6	0.5%	1.4%	0.3%	0.7%
7	27	14	1	42	7	0.5%	0.7%	0.1%	0.4%
8	8	12	1	21	8	0.1%	0.6%	0.1%	0.2%
9	4	6	0	10	9	0.1%	0.3%	0.0%	0.1%
10	3	2	1	6	10	0.1%	0.1%	0.1%	0.1%
11	1	3	0	4	11	0.0%	0.2%	0.0%	0.0%
13	1	1	1	3	13	0.0%	0.1%	0.1%	0.0%
15	2	0	0	2	15	0.0%	0.0%	0.0%	0.0%
All	8,987	5,496	2,591	17,074	All	150.0%	278.4%	187.9%	182.7%

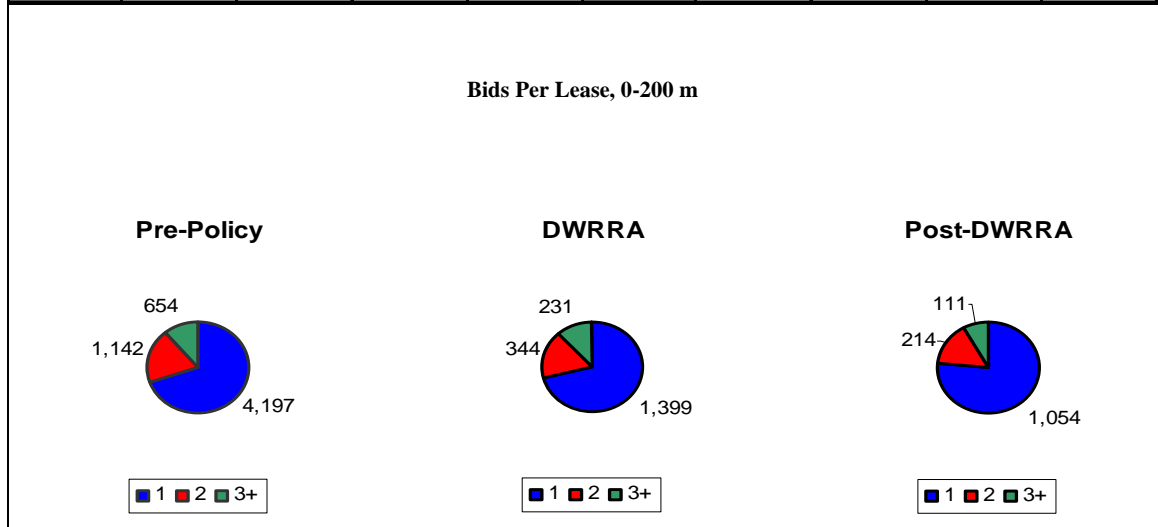


Figure 4-2. Frequency of Bids per Lease, By Period 0-200 meter.

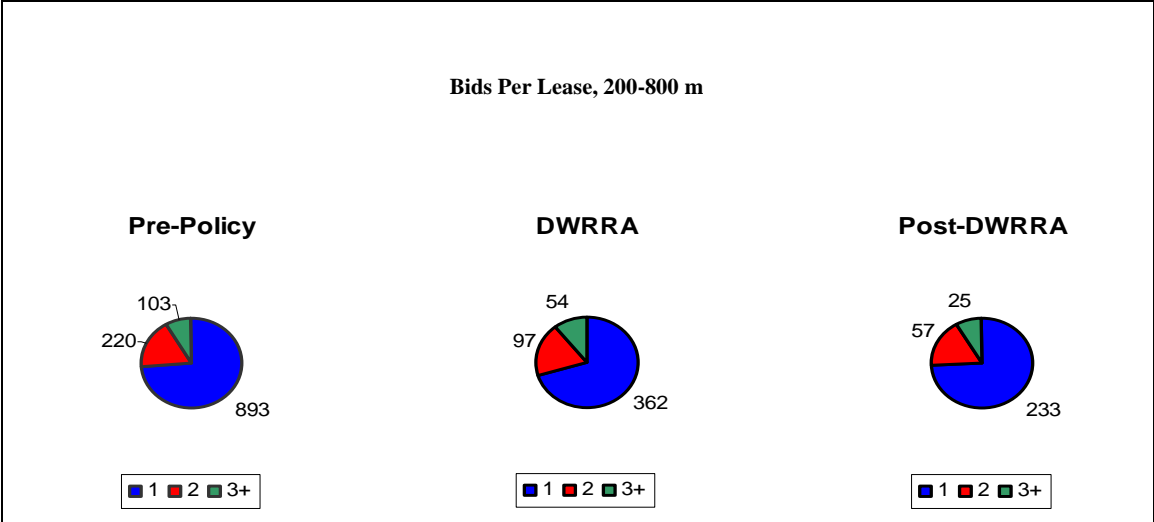


Figure 4-3. Frequency of Bids per Lease, By Period 200-800 meter.

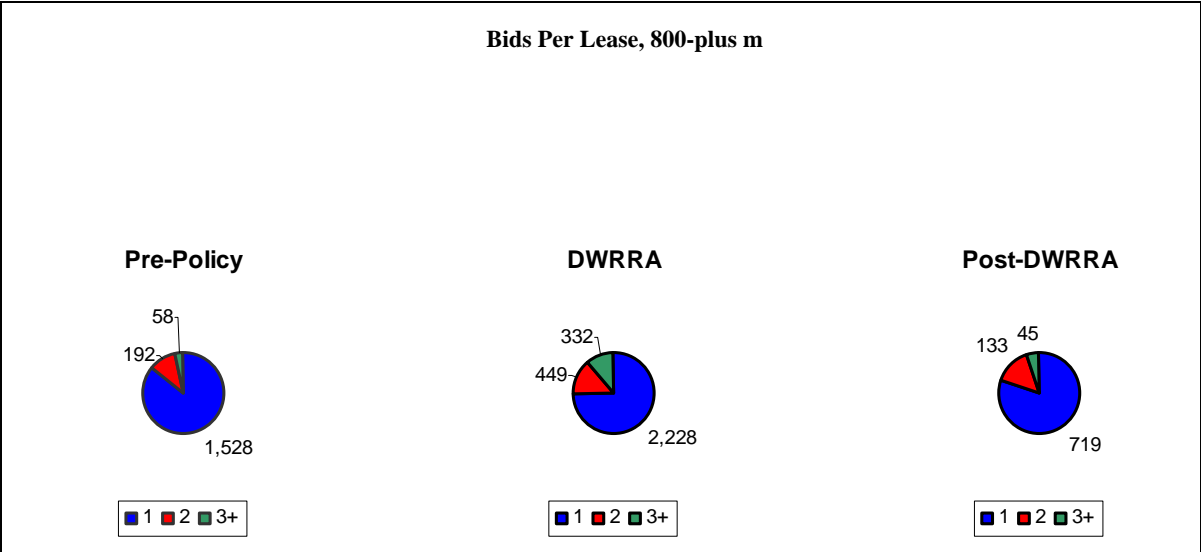


Figure 4-4. Frequency of Bids per Lease, By Period 800-plus meter.

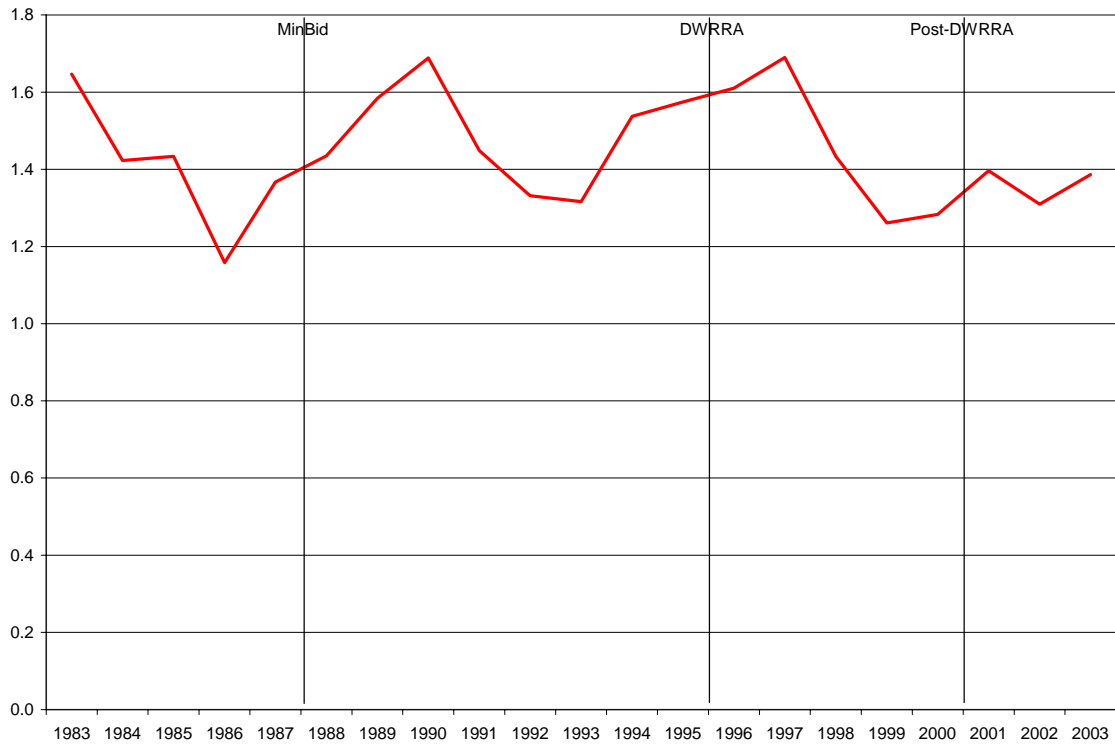


Figure 4-5. Average Bids per Lease 1983-2003, 0-200 meter.

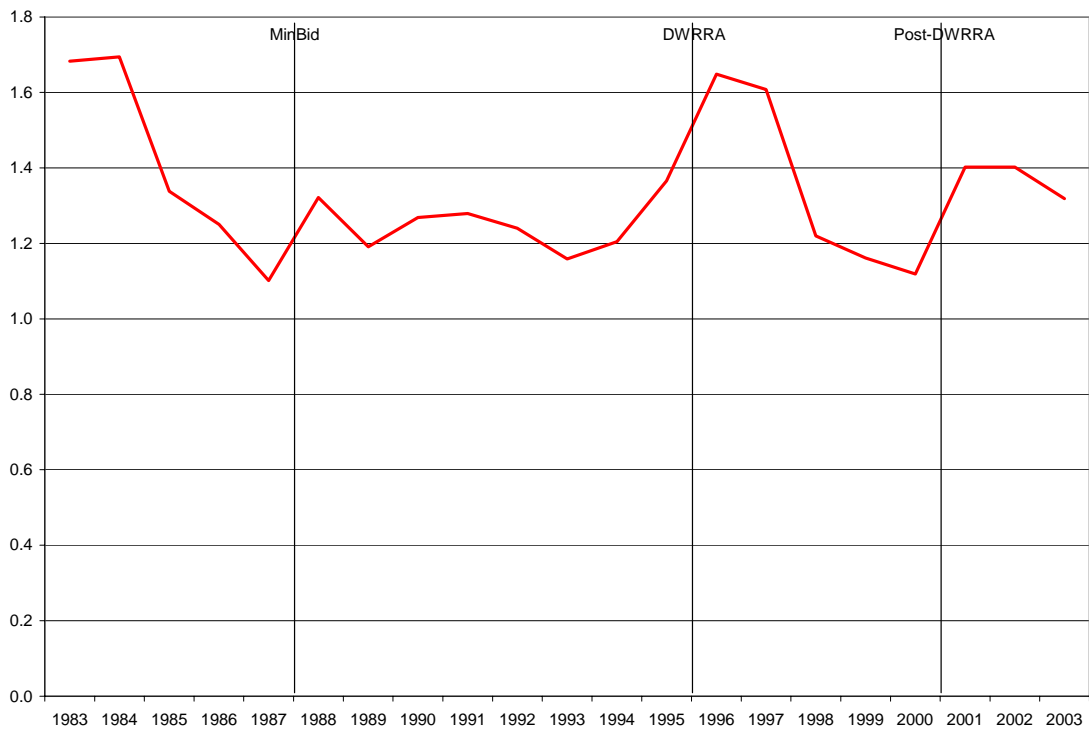


Figure 4-6. Average Bids per Lease 1983-2003, 200-800 meter.

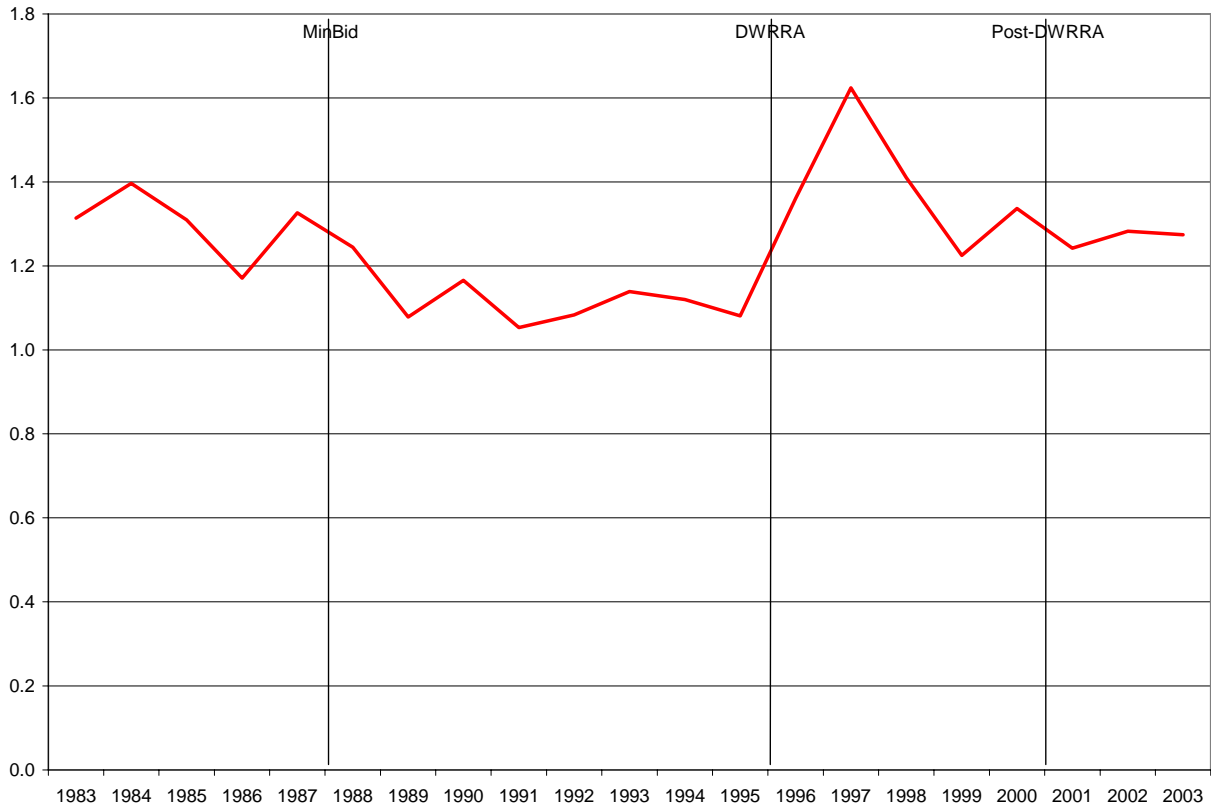


Figure 4-7. Average Bids per Lease 1983-2003, 800-plus meter.

Effects of Royalty Relief Based on Means

This section provides an indication of the effects of royalty relief based simply on contrasting means using historical data and without relying upon regression analysis. The t-test of whether the means of two groups are the same or not rests on an assumption that the variable is distributed normally. That is certainly not the case for bids per tract. Notwithstanding, the distribution of sale-by-sale average bids per tract might be assumed to be distributed in a more normal pattern. In Chapter 5, it is shown that average high bid, per sale which is related to some extent with competition, has a roughly lognormal distribution.

Heteroskedasticity must also be examined, that is, the case that when means are different, it is likely that variances are different too. Therefore, standard deviation is illustrated in the following table of means and variances for policy periods. In view of these problems, t-test results are not provided for these means.

Table 4-8. Statistics of Bids per Lease, By Period and Depth.

	Pre-Policy	DWRRA	Post-DW
0-200			
N	5993	1974	1379
Mean	1.5088	1.5213	1.3655
St.Dev.	1.0485	1.0808	0.8509
Skewness	3.6779	3.1208	4.6102
200-800			
N	1216	513	315
Mean	1.4071	1.4795	1.3778
St.Dev.	0.8391	0.9334	0.7656
Skewness	2.8607	2.5556	2.7101
800+			
N	1778	3009	897
Mean	1.1969	1.4649	1.2664
St.Dev.	0.5768	1.0446	0.6154
Skewness	3.9272	3.8356	2.9028
All			
N	8987	5496	2591
Mean	1.4333	1.4865	1.3327
St.Dev.	0.9534	1.0482	0.7679
Skewness	3.8230	3.4760	4.2227

As summarized below in Tables 4-9 through 4-11, it is evident that the mean of the bids per lease has increased in deepwater since 1995 in association with royalty relief. In shallow water, the change in mean was reduced overall. Contrasting the pre-royalty relief period with the first, DWRRA, relief period, the mean of bids per tract increased in all depths and more so in deepwater. Contrasting the DWRRA with the post-DWRRA relief periods, the mean of bids per tract fell in all depths.

Table 4-9. Change in Mean of Bids per Lease from 1983-1995 to 1996-2003 Periods.

Water Depth	Bids Per Lease
0-200m	-0.052
200-800m	0.034
800+m	0.223
All Depths	0.004

Table 4-10. Change in Mean of Bids per Lease from 1996-2000 to 2001-2003 Periods.

Water Depth	Bids Per Lease
0-200m	-0.156
200-800m	-0.102
800+m	-0.198
All Depths	-0.154

Table 4-11. Change in Mean of Bids per Lease from 1983-1995 to 1996-2000 Periods.

Water Depth	Bids Per Lease
0-200m	0.013
200-800m	0.072
800+m	0.268
All Depths	0.053

Theoretical Model and Econometric Issues

In this section we present the simplified model of bidding, including the simultaneous determination of the amounts bid. Before doing so, however, several interesting characteristics of the number of bids per tract may be observed over the entire period of study, 1983-2003. It is important to keep these characteristics in mind as we describe the exposition of the model.

- Most of the tracts offered in a given sale received no bids at all. One primary reason for this was many of them had no reasonable potential for oil or gas at the time.³⁴
- If any bids were placed for a tract, usually only one bid was placed. Typically there was no actual competition, that is, only a single bidder, although in a single-round, sealed-bid auction, a bidder must take account of at least potential competition as well as the possibility that MMS may reject the bid. *Prima facie*, this is a striking and perhaps odd pattern. If one assumes for the sake of argument that tracts that are bid on have some value, then when there are, on average, 80 participants in shallow water lease sales (less in deeper water), why would most prospective tracts be uncontested?
- Occasionally, substantial competition (such as three or more bids) occurred at a tract. It is an open question as to what circumstances promoted significantly greater competition for these tracts. A plausible theory is that some of the same factors that attract a bid for a tract never bid on previously also promote multiple bids. Also, there might be a statistical similarity of this case and other cases of the “power law,” that is, a principle that, for a given good for sale, there will be a few varieties of superior quality that attract most of the potential buyers.³⁵

Common Value Model and Modifications

The theoretical model of bidding can be explained in steps. It begins with the common-value model under uncertainty, one of the paradigms in auction theory. Common-value means that if people were certain about the quality of an item being offered at auction, they would value

³⁴ New technology and new information may obviously change this fact over time.

³⁵ The power distribution is discussed in Chapter 5.

it the same. Thus the value of a known amount of oil and gas is approximately the same to any businessman. Under uncertainty, however, people arrive at different estimates of the value of the item, e.g., if the potential amount of oil or gas is uncertain, people arrive at different estimates of the amount.

In the literature on lease bidding, it is assumed that when a number of persons make separate estimates of the expected tract value, based partly on public information, then their estimates have a shifted lognormal distribution (e.g., Capen et al., 1971). Figure 4-8 represents this probability density distribution of value estimates for a single tract and many evaluators. The mean and variance are purely hypothetical. In this particular illustration, the mean of the evaluators' estimates is about \$56,000 expected NPV. The mode is less (and happens to be -\$300,000). So it is most likely that an evaluator chosen at random would estimate that the tract has a negative expected NPV; however, if there are many evaluators, a number of them would probably arrive at positive value estimates.

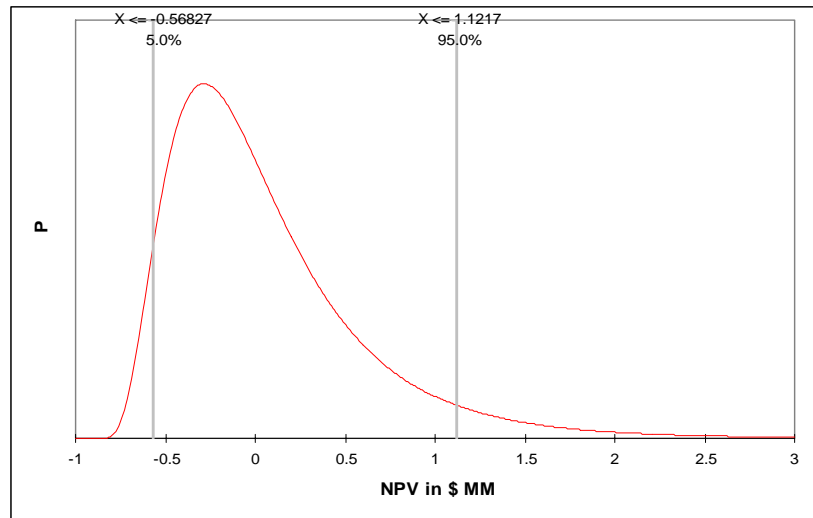


Figure 4-8. Hypothetical Distribution of Tract Valuations.

Option value might be added to the estimated NPV, especially when the estimated NPV is close to zero or is negative. Thus even if a tract is expected to be unprofitable with little oil at the time of the sale, after the lease is bought, the lessee can wait (at only minimal holding cost – the rental fee) for new information which might raise that valuation later. This is described in more detail in the Appendix B (technical appendix to Chapter 3) where we discuss the inventory model. In that way, any negative probability of the tract value is moved to zero or slightly positive range, and the lognormal distribution might be modified thereby. The distribution of bids can be inferred from the value distribution by means of the bid function. Bid function is explained in the next chapter. In brief, the bidding model accounts for the fact that the winner might have valued the tract too high. Thus, in arriving at an optimal bid amount, the estimated value is discounted. The extent of the discount depends on, among other things, the bidder's estimate of the evaluation distribution and the bidder's expectation of the number and level of competing bids. Although the logic of the bid function might be assumed to hold for all potential bidders, their estimates of competition and evaluation would naturally vary.

Another factor relating to the bid level is the minimum bid of the auction. Offshore lease sales currently require a minimum bid that amounts to approximately \$145,000 for a typical lease (more in deepwater). If a bidder initially desires to bid less than that, in theory at least, he would not bid.³⁶ After taking into account this option value and the discounting of the bid, the distribution of bid amounts might now look something like what is shown in Figure 4-9. In this hypothetical case, the potential bids less than the 0.145 level (if that is the minimum bid) would probably be classified as non-bids.

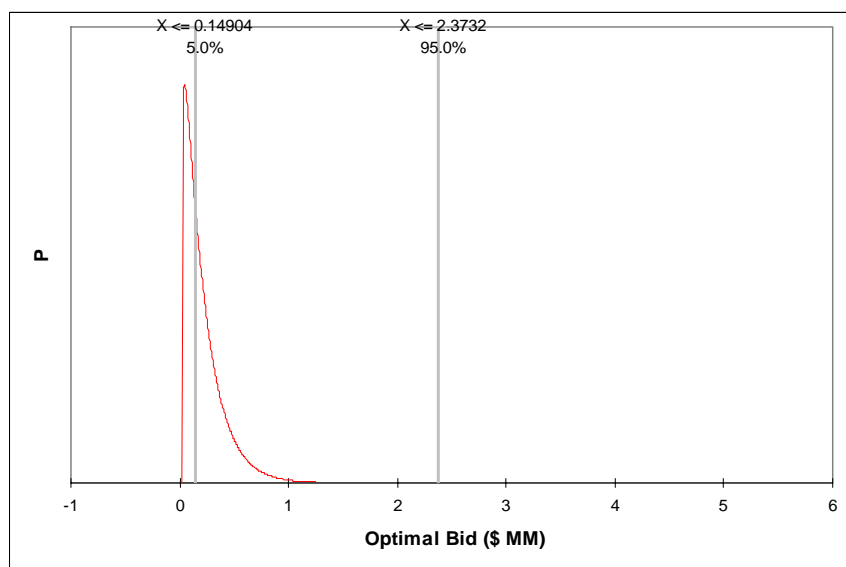


Figure 4-9. Hypothetical Distribution of Bid Amounts.

At this stage, the model can explain, to a degree, a large proportion of non-bids. What remains to be explained is the reason why most tracts that are bid on receive only one bid. If there are a large number of potential bidders, then a tract that is even only marginally attractive ought, nonetheless, to receive a number of bids. There is a special case that the model, at this stage, can shed light on, and it is a case relevant to deepwater. Suppose that a tract block has no known potential but has a small amount of option value. Given a limited number of potential bidders, it might happen that only one bidder is far out along the right-hand tail of the bid distribution in this case. If so, possibly only that single bid would be in excess of the minimum bid. It is possible that this case might have occurred frequently in the deepwater frontier area.

As a final modification to the common value model, the number of potential bidders is another variable. The number of participants averaged about 80 over 1983-2003, but about three-quarters of the tracts that received any bids received only single bids. One explanation might be that participants may have *specialization*, that is, they tend to look seriously at only certain classes of tracts. Some participants are spatially specialized, meaning they have expertise

³⁶ Starting in 1987, the minimum bid was lowered substantially. As shown in Chapter 3, the change raised competition in shallow water, but even in shallow water, the increase appears to have been temporary. Another factor that can be mentioned in this connection is the pre-production rental. This rent is due at leases that are not paying royalty. Rent is a holding cost, and its expected present value at the time of sale might be added to minimum bid. Other holding costs can be considered as well, e.g., any cost to the lessee of simply keeping the lease.

in only certain areas of the Gulf or own infrastructure (e.g., pipelines) that lend itself to bidding in only certain areas. Or, perhaps some participants (such as the majors) specialize in more costly frontier areas, whereas smaller firms tend to look at the less costly, better known shallow water areas. Also firms with a demand for only a small number of leases to add to their inventory, as reflected in small bidding budgets, would not incur the cost of examining a relatively large number of tracts to bid on. Firms falling into that group would, instead, use broad criteria to reduce the scope of examination to a few tracts, and they might well be regarded as potential bidders for only that small set of tracts. If specialization causes the potential bidders for a tract to number only a few, that fact would increase the likelihood that only a single bid would be in excess of minimum bid. (If so, specialization would also further depress any expectation of competition.)

Econometric Issues

The econometrics of count data is a large subject area, and for this study, the scope of models and statistics must be strongly restricted. The research included only relatively simple models and methods such as parametric models. At a number of places, the study mentions econometric problems that can be addressed in future work. The analysis reported here begins with univariate statistics and then proceeds to regression analysis. Univariate statistics of bids per tract begin by demonstrating how the data are not normally distributed. One model appropriate for count data is the Poisson model, and properties of the fit of that model to the data such as dispersion are examined.

Initially, the data for regression analysis are pooled by water depth class, meaning all tracts in a water depth class are covered at once, without regard for the sale date. Notwithstanding, the data are actually longitudinal, and the implicit time dimension gives rise to some econometric problems mentioned later. Regression analysis examines whether various factors influence the expected mean and other dimensions of the count, which are constant over the data set in the univariate statistics. The regression analysis begins with the Poisson model, and the count is viewed provisionally as a true event count, where the bid is the event. Nevertheless, it is possible to interpret bids as a transformation of a latent continuous variable, namely, the tract evaluation and bid optimization, which motivates a probit model.

The preponderance of zeroes is not uncommon for a count event, but in this study, the data set omits the zero bid tracts. The reason is that (in the area-wide leasing setting) there is usually no information available (e.g., no evaluation, no viability determination, no bidder characteristics) about tracts that receive no bids.³⁷ The zero-truncation creates econometric problems.

³⁷ A few helpful explanatory factors can be found for leases that are not bid on. An example is seismic coverage; whether there is 3-D seismic coverage of any block at a point in time is available. Not currently available yet feasible to construct is the amount of infrastructure (such as pipelines) that is a certain distance from the lease block; other spatial factors such as distance to other active leases or leases with drilling or discovery is also feasible. Another approach is to analyze the set of leases offered that have ever been bid on previously; at least some leases of that set are not bid on for at least one successive sale.

Poisson Regression Model

The effect of regressors in the Poisson regression model is typically to generate residuals that are less like count data. The residuals are not integers, and they might have a frequency distribution resembling the lognormal. Despite the theoretical deficiencies of ordinary least squares (OLS) regression, based on the assumption of normality of residuals, if there sample is large, straightforward OLS or OLS of a log-linear transformation might perform fairly well compared with the Poisson or other count model and will be examined. The predicted mean bids per tract according to the Poisson model is:

$$\text{Mu}[i] = \exp(x[1] B[1]) * \exp(x[2] B[2]) * \dots$$

where i is an observation (i.e., a tract) and $x[i]$ and $B[i]$ are the values of the regressors and their coefficients, respectively, for that observation. This is the multiplicative form. It is also possible to specify an additive form, where $\exp(.)$ terms are added instead of multiplied, but a drawback is that the predicted mean for some observations might be negative. In this model, the expected or mean number of bids is different for each tract (when some of the regressors have different values).

The variance of the Poisson model happens to be the same as the mean. This fact implies heterogeneity, in contrast with normality assumed by OLS. It also implies a simple test for goodness-of-fit, namely, that the estimated mean and variance ought to be about equal, called equi-dispersion. For testing of statistical significance of the Poisson model, equi-dispersion is needed. If equi-dispersion fails, alternatives to simple Poisson are available.

The interpretation of coefficients estimated for the Poisson with the multiplicative mean formulation can be more complex than for OLS. A coefficient, $B[i]$, means the proportionate change (i.e., percentage change) in the mean for a one-unit change in the regressor. Differentiating with respect to a regressor, $x[m]$,

$$D \mu \text{ hat}[m]/d x[m] = B[m] * \mu \text{ hat}[m]$$

where the μ hat varies by observation..³⁸

The data set in this study is *truncated* by omission of zero bids. In general, for the Poisson model, the mean of the truncated distribution is greater than that of the full distribution, of course, and the variance is less. The relationship of the truncated distribution mean, θ , and the full distribution mean, μ , is:

$$\text{Theta}[i] = \mu[i] + \text{delta}[i].$$

where delta depends on parameters and a so-called λ term,

$$\lambda(r - 1, \mu[i])$$

³⁸ Cameron and Trevidi (1998) p 80.

where r is the cutoff, in this study equal to 1. The adjustment is analogous to Mill's ratio in continuous models and included in the work of Moody and Krueger, discussed below.

When zero values are omitted for the Poisson model, the conditional distribution – that is, conditional on the bids per tract being greater than 0 – has mean:

$$E(y[i] | y[i] > 0) = \mu[i] / (1 - \exp(-\mu[i]))$$

Re-arranging, the mean of the full distribution might be inferred from the mean of the conditional distribution by numerical method. For instance, if the conditional distribution mean is assumed to be 1.49, the full distribution mean is 0.86. Another formula relating the conditional mean and the full mean is: full mean equals conditional mean times probability of bids per tract greater than zero. For instance, if the conditional mean is 1.49, then the theoretical probability of bids greater than zero is roughly 60 percent, again implying a full distribution mean of roughly 0.8 or 0.9. The variance of the truncated distribution is also different from that of the parent Poisson distribution. There are two major implications:

- Equi-dispersion is not a property of the zero-truncated Poisson distribution. That is, the test of mean equals variance is not exactly valid.
- In general, if the truncated Poisson model is estimated and tested under the misspecification of a full Poisson distribution, estimates will be inconsistent and tests not exactly valid.

Ordered Probit Regression Model

The ordered probit model is appropriate inasmuch as the data cover a number of integer values (not just 0 and 1, as would be fitting for binary probit models) and the values are in order (not unordered classes). If there are only a few observations for a high value, aggregation of the high-end is needed. (If high bid counts are combined in a “X+” grouping, the result is a right-censored data set with its own econometric issues.) Like binary probit, ordered probit assumes an unobserved continuous variable that maps into the count variable according to whether the former exceeds a criterion value. The residual is assumed to be normally distributed.

OLS and Other Regression Models

OLS might give results that are fairly similar to the Poisson regression model, and so it is worth considering. However, OLS assumes homoskedastic variance of bids per tract which we have seen is not that case. Another problem is that the OLS predicted values might be negative for some observations. A log transformation of bids per tract might be used (and since the data start at one, there is no problem of what to do with zeroes in the data).

Zero Truncation

Data and Simulation of Truncated Distribution

As explained in Chapter 3, in area-wide leasing, all blocks not under active lease are offered for sale. If the active lease inventory of industry increases, the number of leases offered afterwards must decrease. Thus the simple accounting of how many leases were sold and terminated in the preceding year determines the number of tracts offered in the subsequent sale. As Figure 4-10 shows, in recent years the number of tracts offered series has tended to decline for both planning areas and all depths. Lately the offerings have numbered about 4,000 tracts in each area.

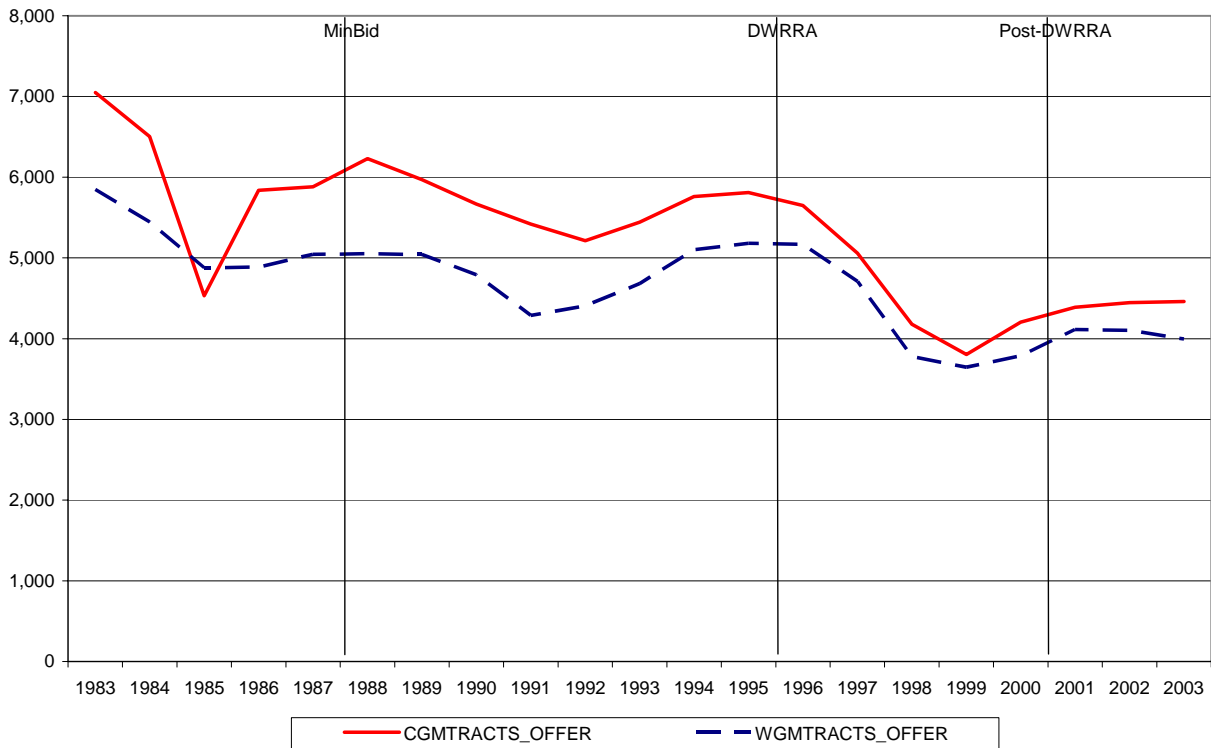


Figure 4-10. Tracts Offered, Central and Western Gulf.

Figure 4-11 shows the ratio of tracts bid on in a sale to the number of tracts offered in the same sale. This ratio has varied from as low as 2 percent to as high as 20 percent. The DWRRA early years, 1996-1998, cover the historically high bid-to-offer ratios of 15 percent to 20 percent.

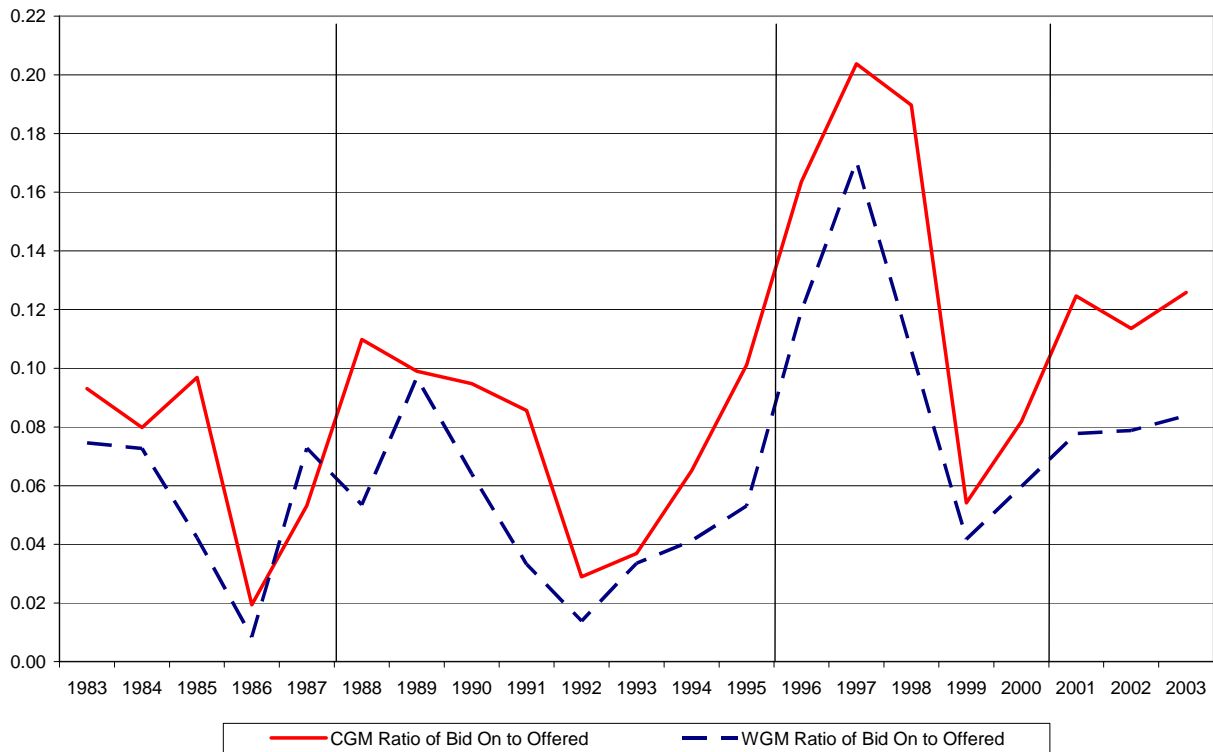


Figure 4-11. Ratio Tracts Bid On to Tracts Offered, Central and Western Gulf.

The probability of at least one bid on a tract being offered, based on the bid-to-offered ratio has averaged 16 percent, with some variation by area and period as indicated in Table 4-12. Interestingly the probability was some what higher in the DWRRA period, especially in ultra-deepwater (800+ meters) as compared with the other periods.

Table 4-12. Probability of a Tract Receiving Any Bids, by Area and Policy Period.

Water Depth	Pre-Policy 1983-1995	DWRRA 1996-2000	Post_DW 2001-2003	All
	Mean	Mean	Mean	Mean
0-200 m	0.17	0.21	0.19	0.18
200-800 m	0.16	0.20	0.17	0.17
800-plus m	0.04	0.15	0.07	0.10
Grand Total	0.14	0.18	0.15	0.16

The theoretical Poisson distribution predicts various proportions of no-bid tracts, depending on the parameter. We computed the theoretical distributions in three cases: mean is 0.5, 1.0, and 1.5.

- If the mean is 0.5, then the Poisson distribution predicts about 58 percent no-bid tracts, 31 percent single bid, etc.
- If the mean is 1.0, the Poisson predicts about 36 percent no-bid tracts.

- If the mean is 1.5, the Poisson predicts about 22 percent no-bid tracts,

Since the data show that typically about 84 percent of tracts offered receive no bids at all, the implication of this statistic by itself is that the mean (of the distribution with zeroes) is roughly 0.2. At the extreme, simulation shows that a mean of 0.1 implies:

- 90 percent of the tracts receive no bids, and
- 9 percent of the tracts receive 1 bid.

Using this assumption about the mean, all of the remaining cases of number of bids are crowded into less than 1 percent of the total.

On the other hand, if the data are truncated at zero, one observes only the frequency of bid counts greater than zero. The theoretical distribution of the Poisson in that case is:

- If the mean (of the true distribution, which includes zeroes) is 0.5, then the Poisson distribution predicts about 75 percent of the tracts that receive any bids, receive a single bid.
- If the mean of the true distribution is 1.0, the Poisson predicts about 60 percent of the observations receive a single bid.
- If the mean of the true distribution is 1.5, the Poisson predicts about 43 percent of the observations receive a single bid.

Since the historical data show that typically 70-80 percent of the observations receive a single bid, the implication is that the true mean is about 0.5 (a bit smaller for deepwater). Thus, it is plain from these simulations that, assuming a Poisson model, the true mean of bids per tract must lie in the general range of 0.2 to 0.5. It is further evident that the Poisson model is unlikely to give a very good fit to the entire distribution of tract outcomes because if it gets the 0-bid frequency right, then it under-predicts the 1-bid (plus) count, and if it gets the 1-bid count right, then it under-predicts the 0-bid count. We term this the “excess zeroes” problem.

Is The Problem Important?

Obviously a regression run on only the set of non-zero bids per tract is going to match the sample mean of the non-zero set, not the full set. For instance, for 0-200 meters:

- (a) The mean of tracts bid on (1983-2003) is 1.49. That is the mean of the non-zero observations.
- (b) Suppose there are, on a rough average, 1,500 tracts offered per sale in 0-200 meters, implying $(1,500 * 21 =)$ 31,500 tracts offered in a hypothetical data set for that depth. Of that, 5,000 or so observations are the non-zero bids set, leaving 26,500 with zero bids.

- (c) The mean of the with-zeroes data set must be roughly $(1.49 * 5000/31500 + 0 =) 0.24$.

However, as explained, a simple Poisson model with mean of 0.2 would under-predict the non-zero bid counts. Thus should we be concerned about the zero-bid tracts for purposes of the policy analysis of this study? On one hand, if the zero-bid tracts are without interest at any price, e.g., utterly non-prospective, then they presumably matter little for this study, as royalty relief would not tend to generate bids for them. On the other hand, if a large number of zero-bid tracts have a small pre-relief value, but the optimal bids happen to fall below minimum bid, then increasing their underlying value by reducing royalties might generate bids for them. Thus, an increase in demand for leases might *both* increase the bidding on small value, single-bid tracts *and* increase bids per tract where there is competition. The implication is that the zero-bid tracts can be relevant for the subject of this study.

Variables Considered For Regression Analysis on Number of Bids

Basic Statistics of Data

The variables considered for inclusion in regression analysis are listed in Table 4-13.

Table 4-13. Statistics of Variables for Regression Analysis, by Period 0-200 meter.

0-200M	Pre-Policy 1983-1995		DWRRA 1996-2000		Post_DW 2001-2003		1983-2003	
	Mean	StDev	Mean	StDev	Mean	StDev	Mean	StDev
Bids	1.51	1.05	1.52	1.08	1.37	0.85	1.49	1.03
Multiple Bids	0.30	0.46	0.29	0.45	0.24	0.42	0.29	0.45
Participants	91.10	13.06	86.47	15.51	77.83	6.04	94.09	12.78
Re-Leased	0.05	0.21	0.03	0.17	0.01	0.11	0.04	0.19
High Bid By Major	0.39	0.49	0.20	0.40	0.13	0.33	0.31	0.46
High Bid By Joint	0.34	0.47	0.22	0.42	0.23	0.42	0.30	0.46
High Bid Per Acre (Current\$)	326.28	943.14	126.88	190.92	96.47	184.55	250.26	770.38
High Bid Per Acre (Constant\$)	309.91	930.25	88.58	134.35	58.89	111.51	226.13	757.06
Drainage/Development	0.09	0.28	0.01	0.12	0.00	0.05	0.06	0.23
Area Block Sequence	1.44	0.67	2.26	0.91	2.71	1.05	1.80	0.93
Repeat Block	0.36	0.48	0.80	0.40	0.86	0.35	0.53	0.50
Minimum Bid Per Acre (Current\$)	69.22	59.77	25.00	0.00	25.00	0.00	53.35	52.35
Minimum Bid Per Acre (Constant\$)	65.69	60.71	17.36	0.61	15.29	0.45	48.04	54.04
MMS Value (Current\$)	170.46	923.11	48.82	100.24	49.89	85.81	131.98	766.76
MMS Value (Constant\$)	162.97	906.26	34.06	70.50	30.43	52.45	121.73	752.19
Viable	0.49	0.50	0.22	0.41	0.42	0.49	0.42	0.49
Rental Rate	3.38	0.78	5.02	0.21	5.01	0.12	3.96	1.01
Seismic Coverage	0.24	0.43	1.00	0.00	1.00	0.00	0.52	0.50
Thousand Tracts Offered	1.78	0.67	1.37	0.27	1.56	0.18		

Table 4-14. Statistics of Variables for Regression Analysis, by Period,-200-800 meter.

200-800M	Pre-Policy 1983-1995		DWRRA 1996-2000		Post_DW 2001-2003		1983-2003	
	Mean	StDev	Mean	StDev	Mean	StDev	Mean	StDev
Bids	1.41	0.84	1.48	0.93	1.38	0.77	1.42	0.85
Multiple Bids	0.27	0.44	0.29	0.46	0.26	0.44	0.27	0.45
Participants	32.69	9.70	47.63	11.40	35.29	2.57	95.35	12.11
Re-Leased	0.02	0.14	0.04	0.19	0.03	0.17	0.03	0.16
High Bid By Major	0.69	0.46	0.31	0.46	0.17	0.38	0.52	0.50
High Bid By Joint	0.37	0.48	0.32	0.47	0.25	0.43	0.34	0.47
High Bid Per Acre (Current\$)	378.23	985.81	169.62	252.78	154.50	300.15	291.39	786.71
High Bid Per Acre (Constant\$)	364.93	983.80	119.20	178.24	94.92	184.94	261.64	777.53
Drainage/Development	0.03	0.18	0.02	0.13	0.00	0.00	0.02	0.15
Area Block Sequence	1.35	0.55	2.13	0.79	2.71	0.88	1.76	0.86
Repeat Block	0.31	0.46	0.80	0.40	0.90	0.30	0.52	0.50
Minimum Bid Per Acre (Current\$)	76.71	61.59	25.00	0.00	25.00	0.00	55.76	53.85
Minimum Bid Per Acre (Constant\$)	73.35	62.59	17.52	0.46	15.35	0.43	50.40	55.71
MMS Value (Current\$)	110.93	235.24	66.99	135.12	75.01	120.90	94.93	202.13
MMS Value (Constant\$)	104.96	224.42	47.05	95.26	45.99	74.09	82.35	186.19
Viable	0.36	0.48	0.26	0.44	0.65	0.48	0.38	0.49
Rental Rate	3.33	0.74	7.49	0.16	7.49	0.14	5.01	2.12
Seismic Coverage	0.20	0.40	1.00	0.00	1.00	0.00	0.53	0.50
Thousand Tracts Offered	0.51	0.32	0.41	0.18	0.40	0.18		

Table 4-15. Statistics of Variables for Regression Analysis, by Period 800-plus meter.

800+M	Pre-Policy 1983-1995		DWRRA 1996-2000		Post_DW 2001-2003		1983-2003	
	Mean	StDev	Mean	StDev	Mean	StDev	Mean	StDev
Bids	1.20	0.58	1.46	1.04	1.27	0.62	1.35	0.87
Multiple Bids	0.14	0.35	0.26	0.44	0.20	0.40	0.21	0.41
Participants	18.33	6.69	52.91	10.90	31.59	2.51	98.38	13.76
Re-Leased	0.00	0.04	0.02	0.13	0.02	0.15	0.01	0.12
High Bid By Major	0.86	0.35	0.61	0.49	0.30	0.46	0.64	0.48
High Bid By Joint	0.21	0.41	0.30	0.46	0.27	0.45	0.27	0.44
High Bid Per Acre (Current\$)	114.61	186.41	160.56	382.35	146.73	351.91	144.00	328.91
High Bid Per Acre (Constant\$)	106.54	180.20	112.47	268.73	90.37	218.07	107.13	236.51
Drainage/Development	0.00	0.05	0.00	0.06	0.00	0.06	0.00	0.06
Area Block Sequence	1.09	0.29	1.27	0.48	1.54	0.64	1.25	0.48
Repeat Block	0.08	0.28	0.25	0.43	0.46	0.50	0.23	0.42
Minimum Bid Per Acre (Current\$)	49.40	49.55	26.44	3.99	37.50	0.00	35.37	29.68
Minimum Bid Per Acre (Constant\$)	46.11	49.66	18.51	2.32	22.93	0.67	27.84	30.47
MMS Value (Current\$)	51.45	59.71	65.49	159.68	63.87	171.97	60.76	138.04
MMS Value (Constant\$)	47.92	57.37	45.78	111.30	38.98	103.02	45.53	96.06
Viable	0.12	0.33	0.16	0.37	0.55	0.50	0.21	0.41
Rental Rate	3.31	0.73	7.50	0.00	7.50	0.00	6.19	1.98
Seismic Coverage	0.17	0.38	1.00	0.00	1.00	0.00	0.74	0.44
Thousand Tracts Offered	3.59	0.63	2.91	0.69	2.21	0.56		

Frequency Analysis of Multiple Bids and Study Variables

The principal purpose of analysis reported in this section is to identify factors that might be associated with multiple (two or more) bids. This examination is a preliminary step toward the regression analysis. Table 4-16 reports historical data on number of tracts where there was a single bid versus those with multiple bids (i.e., more than one bid). While this section does not attempt to analyze cause and effect, our perspective is that competition occurs, not by design, but as a chance result that is favored by certain conditions, and the favoring conditions can be identified. The analysis generally is based on pooled data, that is, data that are aggregated without regard for the sale date.

Table 4-16. Policy Period Single Bid Versus Multibid by Water Depth.

0-200 m	Bids		
	1	2+	Total
Pre-Policy 1983-1995	4197 70.0%	1796 30.0%	5993
DWRRA 1996-2000	1399 70.9%	575 29.1%	1974
Post_DW 2001-2003	1054 76.4%	325 23.6%	1379
0-200 m Total	6650	2696	9346
200-800 m	Bids		
	1	2+	Total
Pre-Policy 1983-1995	893 73.4%	323 26.6%	1216
DWRRA 1996-2000	362 70.6%	151 29.4%	513
Post_DW 2001-2003	233 74.0%	82 26.0%	315
200-800 m Total	1488	556	2044
800-plus m	Bids		
	1	2+	Total
Pre-Policy 1983-1995	1528 85.9%	250 14.1%	1778
DWRRA 1996-2000	2228 74.0%	781 26.0%	3009
Post_DW 2001-2003	719 80.2%	178 19.8%	897
800-plus m Total	4475	1209	5684

Participants

The following tables classify participants in each depth class into two groups. If the number of participants in a sale is less than all-time average for that depth, it is classed as “LT_AVG”; otherwise, it is “MT_AVG.”³⁹ For instance, in 0-200 meters, sales with less-than-average participation are associated with 24 percent of the tracts receiving multiple bids. Whereas, more-than-average participation is associated with 33 percent of the tracts receiving multiple bids. A tendency for larger participation to promote competition is seen in all depth classes

³⁹ The all-time average is a simple average over all leases, not an average of sale averages.

Table 4-17. Participants Single Bid Versus Multibid, by Water Depth.

0-200 m	Bids		
	1	2+	Total
LT_AVG	3148 77.0%	939 23.0%	4087
MT_AVG	3502 66.6%	1757 33.4%	5259
0-200 Total	6650	2696	9346
200-800 m	Bids		
	1	2+	Total
LT_AVG	878 80.8%	209 19.2%	1087
MT_AVG	610 63.7%	347 36.3%	957
200-800 Total	1488	556	2044
800-plus m	Bids		
	1	2+	Total
LT_AVG	2653 83.7%	518 16.3%	3171
MT_AVG	1822 72.5%	691 27.5%	2513
800+ Total	4475	1209	5684

Tracts Bid On

Again, the variable, in this case tracts bid on in a sale, is grouped in each depth class into two groups. If the number of tracts bid on in a sale is less than all-time average for that depth, it is classed as “LT_AVG”; otherwise, it is “MT_AVG” and is shown in Table 4-18. The patterns are very similar to those for participants, and that is expected since participants and tracts bid on are highly correlated. For 800-plus meters, in fact, the frequency comparison is identical. All sales with less-than-average participation had less-than-average tracts bid on, and likewise for those sales with greater-than-average participation.

Table 4-18. Tracts Bid On Single Bid Versus Multibids by Water Depth.

0-200 m	Bids		
	1	2+	Total
LT_AVG	3153 76.2%	984 23.8%	4137
MT_AVG	3497 67.1%	1712 32.9%	5209
0-200 Total	6650	2696	9346
200-800 m	Bids		
	1	2+	Total
LT_AVG	910 78.8%	245 21.2%	1155
MT_AVG	578 65.0%	311 35.0%	889
200-800 Total	1488	556	2044
800-plus m	Bids		
	1	2+	Total
LT_AVG	2770 83.9%	530 16.1%	3300
MT_AVG	1705 71.5%	679 28.5%	2384
800+ Total	4475	1209	5684

Tracts Offered and Ratio of Bid-On To Offered

The number of tracts offered is useful in addressing the problem of zero truncation of the data set. These variables are examined in earlier sections, above. The ratio of tracts bid on to tracts offered promotes the same purpose, and it explicitly introduces the probability of the tract's receiving any bids at all in the sale. Only one or the other of these related variables ought to be included in the regression model. Table 4-19 shows the frequency of multiple bids broken out by planning area. For example, in 800-plus meters, Western had a lower frequency of multiple bids.

Table 4-19. Tracts Bid on Single Bid Versus Multibids by Water Depth and Planning Area.

0-200 m	Bids		
	1	2+	Total
Central	4305 69.6%	1879 30.4%	6184
Western	2345 74.2%	817 25.8%	3162
0-200 m Total	6650	2696	9346
200-800 m	Bids		
	1	2+	Total
Central	770 73.3%	281 26.7%	1051
Western	718 72.3%	275 27.7%	993
200-800 m Total	1488	556	2044
800-plus m	Bids		
	1	2+	Total
Central	2507 75.8%	800 24.2%	3307
Western	1968 82.8%	409 17.2%	2377
800-plus m Total	4475	1209	5684

Re-offerings

When a block is re-offered for lease after bid rejection, the subsequent bidding is strongly associated with multiple bids as shown in Table 4-20. However, one must not assume that the bidders of the earlier sale return and bid again for the re-offering. Overall, there is roughly a 50 percent chance of competition for a re-offering, and that observation is approximately true in all water depths.

Table 4-20. Tract Is Re-Offering Versus Multiple Bids.

0-200 m	Bids		
	1	2+	Total
N	6481 72.2%	2498 27.8%	8979
Y	169 46.0%	198 54.0%	367
0-200 m Total	6650	2696	9346
200-800 m	Bids		
	1	2+	Total
N	1456 73.2%	534 26.8%	1990
Y	32 59.3%	22 40.7%	54
200-800 m Total	1488	556	2044
800-plus m	Bids		
	1	2+	Total
N	4435 79.1%	1171 20.9%	5606
Y	40 51.3%	38 48.7%	78
800-plus m Total	4475	1209	5684

High Bid By Major

Only in 800-plus meters has the fact that the high bid was made by a major been associated with a large difference in multiple bids as shown in Table 4-21. In that water depth, as expected, when the high bid by majors was more frequent, there were relatively fewer multiple bid tracts. Note that prior to the DWRRA, majors tended to predominate in many sales in 800-plus meters.

Table 4-21. High Bid by Majors Single Bid Versus Multibid.

0-200 m	Bids		
	1	2+	Total
N	4517 70.1%	1929 29.9%	6446
Y	2133 73.6%	767 26.4%	2900
0-200 m Total	6650	2696	9346
200-800 m	Bids		
	1	2+	Total
N	706 71.6%	280 28.4%	986
Y	782 73.9%	276 26.1%	1058
200-800 m Total	1488	556	2044
800-plus m	Bids		
	1	2+	Total
N	1526 74.4%	525 25.6%	2051
Y	2949 81.2%	684 18.8%	3633
800-plus m Total	4475	1209	5684

High Bid by Joint Bidders

High bid by joint bidders has been associated with relatively more multiple bids in all water depths.

Table 4-22. High Bid by Joint Bidders Single Bid Versus Multibids.

0-200 m	Bids		
	1	2+	Total
N	4853 74.2%	1690 25.8%	6543
Y	1797 64.1%	1006 35.9%	2803
0-200 m Total	6650	2696	9346
200-800 m	Bids		
	1	2+	Total
N	1047 77.7%	301 22.3%	1348
Y	441 63.4%	255 36.6%	696
200-800 m Total	1488	556	2044
800-plus m	Bids		
	1	2+	Total
N	3364 81.2%	781 18.8%	4145
Y	1111 72.2%	428 27.8%	1539
800-plus m Total	4475	1209	5684

Drainage and Development (DD)

Some prior studies of leasing behavior have emphasized whether a tract is classified as drainage or development (DD), since when a tract is drainage and development, more information tends to be available (although some of that information is perhaps proprietary). The finding in the present study is that *DD* is a weakly explanatory factor, being strongest in 800-plus meters. That finding is apparent in Table 4-23 below and also in subsequent regression analysis.

Table 4-23. Drainage and Development Single Bid Versus Multibid.

0-200 m	Bids		
	1	2+	Total
N	6298 71.5%	2505 28.5%	8803
Y	352 64.8%	191 35.2%	543
0-200 m Total	6650	2696	9346
200-800 m	Bids		
	1	2+	Total
N	1454 72.9%	541 27.1%	1995
Y	34 69.4%	15 30.6%	49
200-800 m Total	1488	556	2044
800-plus m	Bids		
	1	2+	Total
N	4462 78.8%	1203 21.2%	5665
Y	13 68.4%	6 31.6%	19
800-plus m Total	4475	1209	5684

Having Been Leased Previously (Repeat_Blk)

The variable *Repeat_Blk* has the value 0 when a tract block was never previously leased, and 1 otherwise. In other words, when the variable *Sequence* has value 1 or more, *Repeat_Blk* is 1. A history of previous leasing can work in two directions. On one hand, it might imply that more information is available for the block. On the other hand, it might imply that results of exploration thus far were unsatisfactory, since a block that goes into production is not available for re-leasing. Table 4-24 shows that being previously leased is associated with increased multiple bids, in all depths.

Table 4-24. Repeat Block Single Bid Versus Multibid.

0-200 m	Bids		
	1	2+	Total
N	3327 75.1%	1102 24.9%	4429
Y	3323 67.6%	1594 32.4%	4917
0-200 m Total	6650	2696	9346
200-800 m	Bids		
	1	2+	Total
N	725 74.7%	246 25.3%	971
Y	763 71.1%	310 28.9%	1073
200-800 m Total	1488	556	2044
800-plus m	Bids		
	1	2+	Total
N	3614 82.8%	750 17.2%	4364
Y	861 65.2%	459 34.8%	1320
800-plus m Total	4475	1209	5684

High Bid

While recognizing that the high bid level is co-determined with number of bids, Table 4-25 shows higher-than-average bids are strongly associated with multiple bids, i.e., competition tends to raise the bid level.

Table 4-25. High Bid Single Bid Versus Multibid.

0-200 m	Bids		
	1	2+	Total
LT_AVG	5640 77.7%	1617 22.3%	7257
MT_AVG	1010 48.3%	1079 51.7%	2089
0-200 m Total	6650	2696	9346
200-800 m	Bids		
	1	2+	Total
LT_AVG	1304 81.0%	305 19.0%	1609
MT_AVG	184 42.3%	251 57.7%	435
200-800 m Total	1488	556	2044
800-plus m	Bids		
	1	2+	Total
LT_AVG	3799 85.3%	654 14.7%	4453
MT_AVG	676 54.9%	555 45.1%	1231
800-plus m Total	4475	1209	5684

Minimum Bid

As mentioned previously, the minimum bid was lowered from \$150 per acre to \$25 per acre in 1987, and later raised slightly for deepwater. To a degree, grouping observations by minimum bid level is akin to grouping them by time periods. This fact explains the finding that for 200-800 meters the higher minimum bid is associated with greater multiple bids: there were relatively more multiple bids in the 1983-1986 period as shown in Table 4-26.

Table 4-26. Minimum Bid Single Bid Versus Multibid.

0-200 m	Bids		
	1	2+	Total
25	5136 71.1%	2090 28.9%	7226
150	1514 71.4%	606 28.6%	2120
0-200 m Total	6650	2696	9346
200-800 m	Bids		
	1	2+	Total
25	1173 76.1%	368 23.9%	1541
150	315 62.6%	188 37.4%	503
200-800 m Total	1488	556	2044
800-plus m	Bids		
	1	2+	Total
25	3198 78.1%	895 21.9%	4093
37.5	1003 80.6%	241 19.4%	1244
150	274 79.0%	73 21.0%	347
800-plus m Total	4475	1209	5684

Viability

Viability is an important indicator of a block's prospectiveness, quality, or underlying value. As an indicator of value, it has both advantages and disadvantages relative to using the MMS value as a measure of a tract's value. Viability is determined by MMS for every lease, although the precise method of determining viability can vary according to complex bid adequacy procedures, whereas MMS dollar value is evaluated only for a subset of leases. However, viability determination does not usually include estimating a dollar value (other than minimum bid). Table 4-27 shows that viability is strongly associated with multiple bids.

Table 4-27. Viability Single Bid Versus Multibids.

0-200 m	Bids		
	1	2+	Total
N	4270 79.2%	1121 20.8%	5391
Y	2380 60.2%	1575 39.8%	3955
0-200 m Total	6650	2696	9346
200-800 m	Bids		
	1	2+	Total
N	1022 80.7%	245 19.3%	1267
Y	466 60.0%	311 40.0%	777
200-800 m Total	1488	556	2044
800-plus m	Bids		
	1	2+	Total
N	3702 82.5%	784 17.5%	4486
Y	773 64.5%	425 35.5%	1198
800-plus m Total	4475	1209	5684

MMS Value

The MMS value is determined mainly in two ways:

- (a) Lease bids accepted under phase 1 rules are generally assigned the minimum bid value by default. This is true whether they are determined to be viable or not.
- (b) Lease bids falling under phase 2 rules are usually evaluated, and the finding is the MMS value.

Class (a) contains the majority of leases, but the minimum values under (a) do not distinguish between viable, nonviable, or most 3-bid-plus leases. Class (b) evaluations correlate positively with high bid (Chapter 5) and apparently also with eventual production. Table 4-28 shows the association between whether a high bid is above average and multiple bids. Especially in deep water, the association is strong.

Table 4-28. MMS Value Single Bid Versus Multibid.

0-200 m	Bids		
	1	2+	Total
LT_AVG	4923 72.5%	1870 27.5%	6793
MT_AVG	1727 48.3%	826 51.7%	2553
0-200 m Total	6650	2696	9346
200-800 m	Bids		
	1	2+	Total
LT_AVG	1088 81.0%	299 19.0%	1387
MT_AVG	400 42.3%	257 57.7%	657
200-800 m Total	1488	556	2044
800-plus m	Bids		
	1	2+	Total
LT_AVG	4027 85.3%	961 14.7%	4988
MT_AVG	448 54.9%	248 45.1%	696
800-plus m Total	4475	1209	5684

Related Literature: Moody and Kruvant

As discussed in Chapter 2 of Volume II, Moody and Kruvant (1990) examined the effect of the change to area-wide leasing (beginning in 1983) on competition and high bids. Bids per tract were a key variable in their analysis. Moody and Kruvant specified an OLS regression for bids per tract in the context of a triangular system. Their system includes three equations: (a) a probit equation used to predict whether a tract will receive any bid at all; (b) an OLS equation to predict the number of bids for a tract; and (c) an OLS equation to predict the high bids for leases. Moody and Kruvant included an equation regarding whether a tract received any bids at all. In contrast, in the present study, the possibility that a tract offered is not bid on at all is not treated with regression analysis. Moody and Kruvant covered pre-1983 tract selection sales and a small number of post-area-wide sales. The range of their data is 1979-1984. With area-wide sales, data are no longer available to assign an appropriate valuation to most tracts that are offered but receive no bids. In this situation, Moody and Kruvant’s probit equation cannot be given an adequate implementation.

Moody and Kruvant described their system also as a two-stage probit system known as Heckman’s two-step method for estimating models with sample selection bias. Its form is:

$$\begin{aligned}
 N &= b_1 * X_1 + u_1 \quad \dots \quad \text{if } N > 0 \\
 B &= b_2 * X_2 + b_n * N + u_2 \quad \dots \quad \text{if } N > 0
 \end{aligned}$$

and

$$N = B = 0 \quad \dots \quad \text{otherwise}$$

where X1 and X2 are exogenous variables. The error terms u1 and u2 are assumed to follow a joint normal distribution. The estimation method begins with estimation of Equation (a), a probit equation with a dummy variable on the LHS indicating whether any bid was received for the tract. The resulting estimate generates a statistic called Mills ratio, which combines marginal and cumulative probability of receiving a bid. This ratio is included in estimation by OLS of Equation (b). When the ratio (lambda) has a negative coefficient, as in their results, it implies that the probability of receiving any bids at all is positively related to the number of bids received. Then the predicted bids per tract from (b) is input to estimation of Equation (c), in the manner of a one-way system, thus number of bids functions as an instrumental variable in the high bid model.

Moody and Kruvant specified the number of bids per tract equation as a function of MMS value, the number of tracts offered in the sale, some regional dummies, the percent of bids for the tract that are joint, development dummies, and the aforementioned lambda. Table 4-29 below maps their variables into variable of this study:

Table 4-29. Contrast of Moody and Kruvant and IIC Bidding Variables.

Moody and Kruvant (MK) Variables	IIC Variables	Comment
Value	MMS Value (Real \$)	MK used value based on full MMS evaluation only; IIC uses those values or, if none available, the minimum bid at viable leases or nonviable leases.
Ntracts	Tracts bid on	Whereas MK covered tract selection sales where number of tracts offered varied greatly, IIC covers only area-wide sales where tracts offered are a large number and the annual variation is relatively less.
Pctjoint	High bid joint	A minor difference in variable: IIC only noted when the high bid was joint, not when losing bids were joint.
AK, ATL, CA	Water depth class Western Gulf	Inapplicable since IIC covers only Gulf of Mexico. IIC estimates separate equations by depth class.
Proven, Develop, Drainage	DD	Current data aggregate development and drainage tracts.
Mills ratio	Frequency of no bid	IIC does not provide an equation to predict whether a tract receives a bid. Only the sale-specific frequency of no bid is available to IIC.

Another question is whether OLS regression, with assumptions about normality, is an appropriate method. To begin with, bids per tract are obviously not drawn from a normal distribution. The overall appearance of this distribution is that of the geometric or like distribution (exponential, Pareto, Poisson, etc.) Moody and Kruvant assumed that the residuals

of the bids per tract regression followed a joint normal distribution with the residuals of the high bid regression. However, the results of the regression analysis done for this study cast doubt on that assumption. The QQ-plot is suggestive of a lognormal or like distribution for the residuals.

Regression Analysis

Single-Equation Regression As Preliminary to the System Model

The regression analysis given in this section covers only single-equation models. In contrast, Chapter 5 includes competition as a variable in a multiple-equation simultaneous system, along with high bid. It is explained in Chapter 5 that the simultaneous system is the preferred model. In that sense, the models of bids per lease – the Poisson model and alternatives – presented in this section are preliminary to the system results of Chapter 5. The single-equation approach provides opportunities to consider issues that are intractable in the system model. For instance, the Poisson regression model is not easy to apply in the system model, and the E-Views and SAS software does not offer a system regression with a Poisson assumption. Thus, we can examine the Poisson model in a single equation model. The model parameters and policy effects presented in this chapter are slightly different than those in Chapter 5 owing to the difference in model structures.

The ordered probit model does not enter any system model presented in Chapter 5. In theory it might enter a system model, in the sense that the level of high bid might be determined simultaneously with the probability of receiving a given number of bids, however a mixed model of that type is an advanced topic, left to future work. In this study, the probit model is estimated only as a single equation.

Number of Participants and Competition

The regression models in this section generally included number of participants as a regressor. That is, it was assumed that competition generally is not a factor determining number of participants, so that the latter is exogenous in a model of the former. It is possible that a potential participant gives consideration to the likely level of competition in the upcoming sale, however: (a) even the relatively higher levels of competition that have been observed are not greatly higher than average and seem unlikely to deter entry, and (b) to the contrary, there might be a bandwagon effect that encourages participation at times when there are likely to be more participants and hence more competition. The years of DWRRA perhaps witnessed a land rush of that sort.

Poisson Model

Univariate analysis of bids per tract using the Poisson model was presented above. In this section, we apply multivariate regression analysis. In regression analysis, explanatory terms can be added to the right hand side (RHS) of the equation. Since this model is log-linked, the coefficients on the RHS variables have their direct effects on the log of bids per tract, instead of bids per tract. The RHS variables were arrived at by a process of backward selection.

To partially address the problem of truncation, the sale-specific variables, tracts offered and share of tracts receiving any bid were included. Neither of these variables provides tract-specific covariates. Since the data in this data set are pooled, these variables provide a limited degree of difference among tracts, i.e., was the lease sold in a sale with a certain offering size or a certain sale-wide probability of the tract being bid on. In the following pages we present various tables of estimates which include the mean values of the regressors and chi-square statistics as background information.

Without Policy Dummies

The effects estimated for 0-200 meter in Table 4-30 show:

- Viability has the greatest effect on bids per tract.
- Being a “re-lease” after bid rejection has a strong positive effect, as expected. Being covered by 3-D seismic also is a strong positive.
- WGM has an unexpected positive effect. Recall that the average number of bids in WGM has been lower than in the CGM.
- Minimum bid and rental have negative effects, as expected, although they are small effects.

Table 4-30. Results of Poisson Regression Without Dummies, 0-200 meter.

	Estimate	Chi-Square	Pr > ChiSq	MeanVal	Effect
Intercept	-0.685	55.171	0.000	1.000	-0.685
Area Block Sequence	0.054	21.585	0.000	1.802	0.098
MinBid Per Acre	-0.001	4.819	0.028	53.354	-0.029
Participants (WD)	0.011	160.646	0.000	70.114	0.757
Re-Leased	0.186	21.374	0.000	0.039	0.007
Rental Rate	-0.049	3.935	0.047	3.963	-0.193
Seismic Coverage	0.197	13.364	0.000	0.515	0.101
Tracts Offered (1000)	0.060	9.375	0.002	1.662	0.100
Viable	0.384	434.288	0.000	0.423	0.163
WGM	0.159	27.765	0.000	0.338	0.054

Figures 4-12 through 4-14 give histograms of the predicted bids per lease and the raw residuals. The prediction changes for each tract according to the effects of the RHS variables. In other words, assuming that bids per tract are Poisson, the mean (and variance) parameter of the Poisson distribution is different for each tract. Contrasted with the actual distribution of bids per lease, the predicted bids per lease under-predict single bids and also under-predict the rare, 3-plus bids per lease; by the same token, the model over-predicts 2 bids per lease. The predicted distribution approaches closer to lognormal than to Poisson, due to the effect of including regressors. The raw residuals resemble a lognormal distribution (if they were shifted to the positive side of the axis).

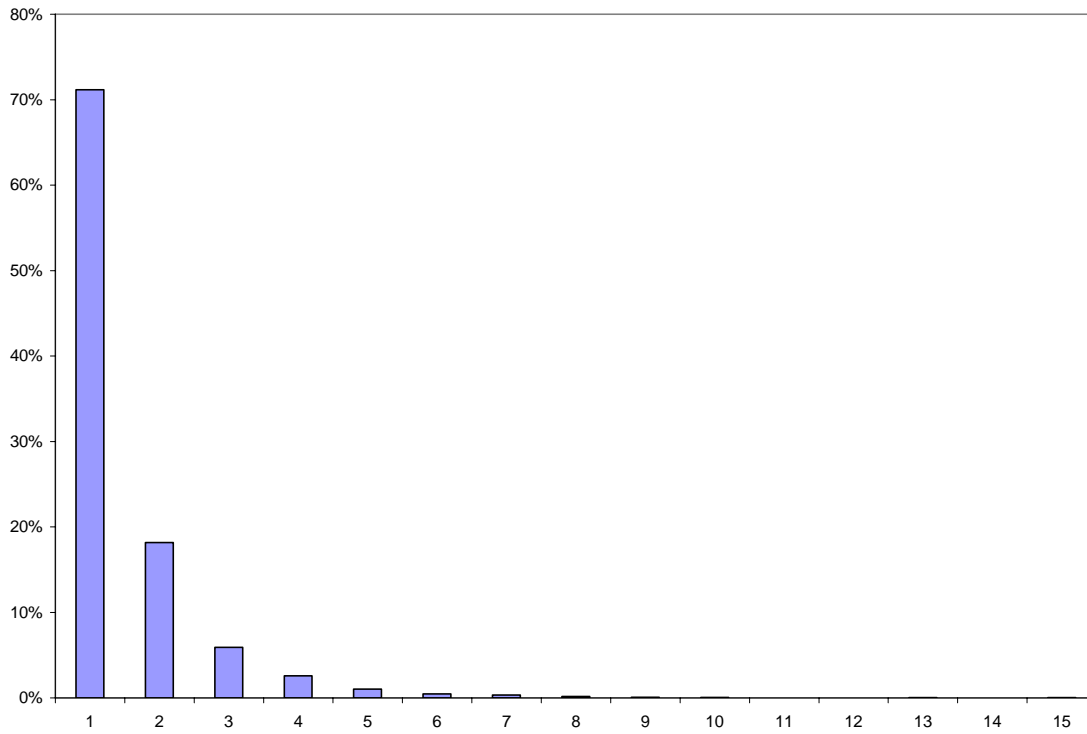


Figure 4-12. Actual Frequencies of Bids per Lease, 0-200 meter.

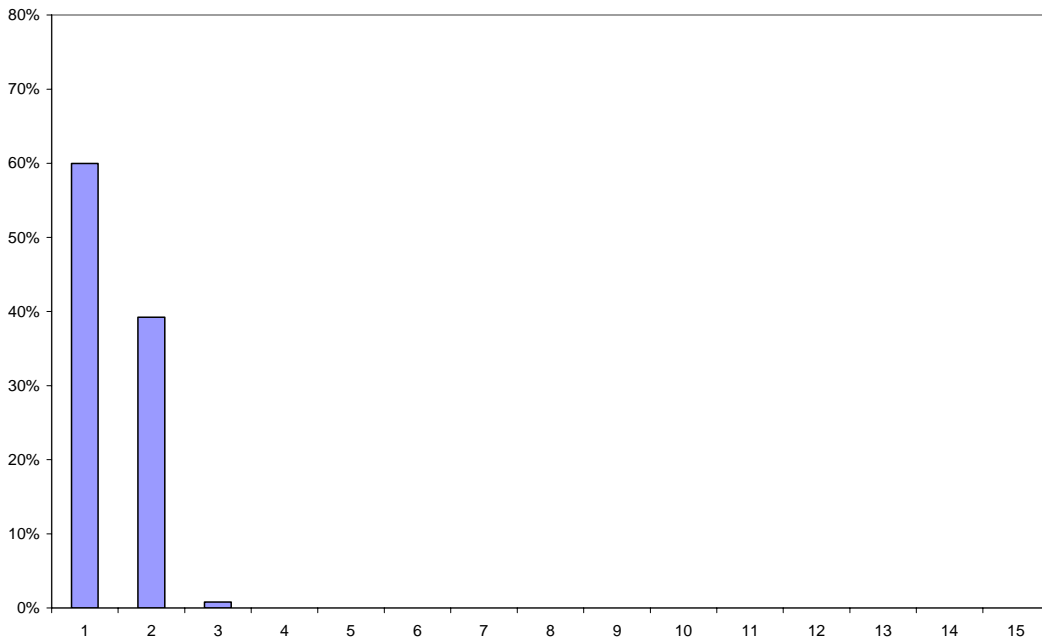


Figure 4-13. Predicted Frequencies of Bids per Lease by Poisson Regression, 0-200 meter.

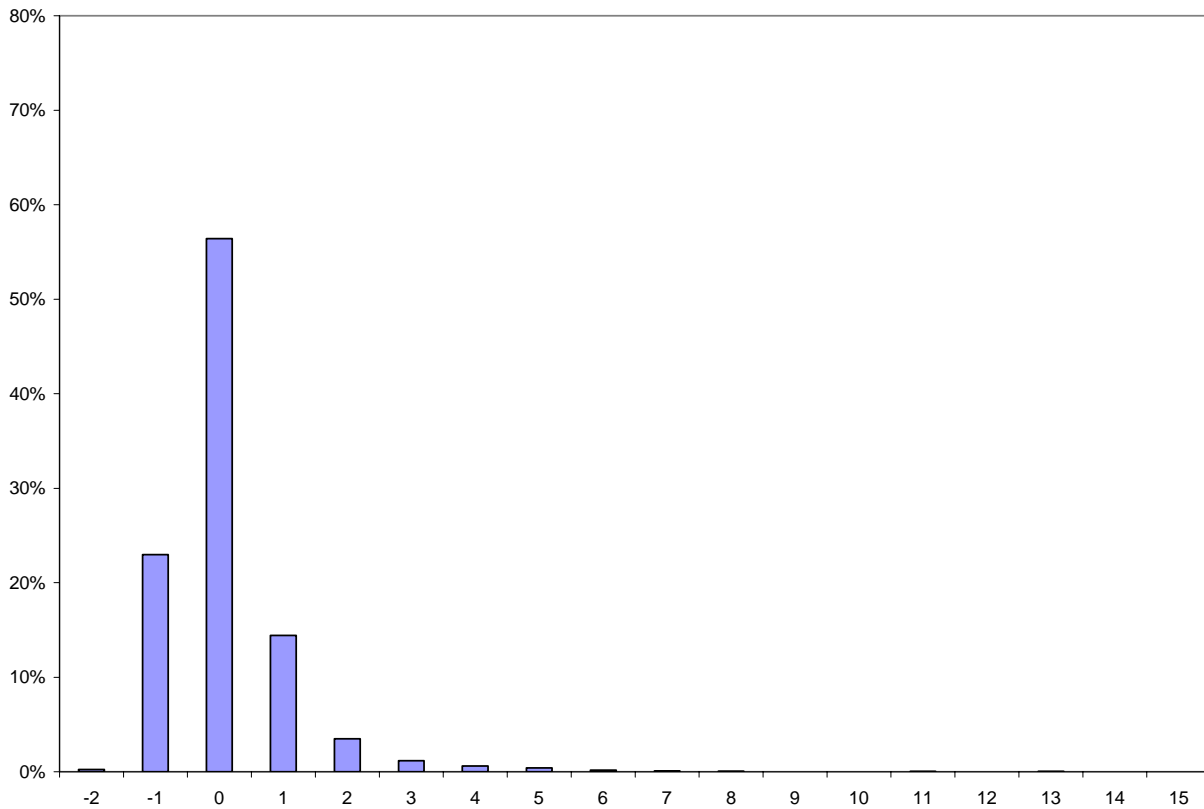


Figure 4-14. Raw Residuals for Poisson Regression, 0-200 meter.

The results of the Poisson regression models for the other depth classes are given below in Tables 4-31 and 4-32. Note the list of regressors is slightly different in each case.

Table 4-31. Results of Poisson Regression Without Dummies, 200-800 meter.

	Estimate	Chi-Square	Pr > ChiSq	MeanVal	Effect
Intercept	-0.191	5.724	0.017	1.000	-0.191
Area Block Sequence	0.090	9.292	0.002	1.755	0.157
Participants (WD)	0.012	38.678	0.000	27.444	0.333
Rental Rate	-0.026	4.548	0.033	5.014	-0.130
Tracts Offered (1000)	0.132	3.957	0.047	0.465	0.061
Viable	0.263	47.059	0.000	0.380	0.100

Table 4-32. Results of Poisson Regression Without Dummies, 800-plus meter.

	Estimate	Chi-Square	Pr > ChiSq	Mean	Effect
Intercept	-1.215	107.022	0.000	1.000	-1.215
Area Block Sequence	0.230	103.030	0.000	1.254	0.288
Participants (WD)	0.011	159.190	0.000	29.227	0.317
Tracts Offered (1000)	0.235	80.724	0.000	3.013	0.708
Viable	0.367	171.068	0.000	0.211	0.077
WGM	0.233	33.656	0.000	0.418	0.098

Poisson Model with Policy Dummies

Initially, the Poisson regression models are expanded by the two multi-year dummies, DWRRA and post-DWRRA. For example, DWRRA is 1 for 1996-2000 and zero otherwise. Adding these dummies does not usually create a problem of prior regressors losing significance with a couple of exceptions. These multi-year dummies are insignificant by the chi-squared statistic. Furthermore, sometimes the parameter of the dummy is negative, contrary to our expectation. These results are shown in Tables 4-33 through 4-35

Table 4-33. Results of Poisson Regression With Policy Period Dummies, 0-200 meter.

	Estimate	ChiSquare	Pr > ChiSq	MeanVal	Effect
Intercept	-0.641	44.646	0.000	1.000	-0.641
Area Block Sequence	0.063	27.244	0.000	1.802	0.113
DWRRA	0.031	0.994	0.319	0.211	0.006
MinBid Per Acre	-0.001	8.751	0.003	53.354	-0.040
Participants (WD)	0.009	104.385	0.000	70.114	0.657
Post-DWRRA	-0.098	7.251	0.007	0.148	-0.014
Released	0.167	16.822	0.000	0.039	0.007
Rental Rate	-0.035	1.737	0.188	3.963	-0.139
Seismic Coverage	0.161	8.787	0.003	0.515	0.083
Tracts Offered (1000)	0.082	16.062	0.000	1.662	0.136
Viable	0.392	445.616	0.000	0.423	0.166
WGM	0.115	12.687	0.000	0.338	0.039

Table 4-34. Results of Poisson Regression With Policy Period Dummies, 200-800 meter.

	Estimate	Chi-Square	Pr > ChiSq	MeanVal	Effect
Intercept	-0.161	2.641	0.104	1.000	-0.161
Area Block Sequence	0.096	10.450	0.001	1.755	0.169
DWRRA	0.057	0.450	0.502	0.251	0.014
Participants (WD)	0.011	27.345	0.000	27.444	0.306
Post-DWRRA	-0.046	0.253	0.615	0.154	-0.007
Rental Rate	-0.032	2.829	0.093	5.014	-0.162
Tracts Offered (1000)	0.140	4.410	0.036	0.465	0.065
VIABLE	0.274	48.401	0.000	0.380	0.104

Table 4-35. Results of Poisson Regression With Policy Period Dummies, 800-plus meter.

	Estimate	Chi-Square	Pr > ChiSq	MeanVal	Effect
Intercept	-1.035	47.672	0.000	1.000	-1.035
Area Block Sequence	0.236	101.798	0.000	1.254	0.296
DWRRA	-0.024	0.218	0.640	0.529	-0.012
Participants (WD)	0.011	50.849	0.000	29.227	0.307
Post-DWRRA	-0.101	3.063	0.080	0.158	-0.016
Tracts Offered (1000)	0.191	29.970	0.000	3.013	0.577
Viable	0.373	170.542	0.000	0.211	0.079
WGM	0.185	15.417	0.000	0.418	0.078

Panel Regression of Poisson Model

The motivation for limited panel regression is to obtain a better understanding of the non-intuitive negative parameters estimated for the policy dummies in most of the equations shown above. For that purpose, the focus is on 800-plus meters. Recall that, overall, the proportion of bids per lease greater than 1 increased in the DWRRA period on average, and dropped back part way in the post-DWRRA period while remaining higher than the pre-1996 average. These results are shown in Tables 4-36 through 4-38. First it is evident that most regressors included work best, by the chi-squared test, for the DWRRA period. In the other periods, some or most of them lose significance. Viability remains the strongest explanatory variable in all periods. The intercept is -0.11 with low significance in the pre-royalty relief period, and is -1.61 in the DWRRA period. This supports the negative coefficient estimated for DWRRA in the non-panel regression, earlier. However, the results for the Post-DWRRA period are the opposite; the intercept is positive. Instead, for the Post-DWRRA period, it is the region variable, *WGM*, that becomes negative. The results imply instability in the regression.

Table 4-36. Results of Poisson Regression for 1983-1995 (Pre-Policy) Period, 800-plus meter.

Parameter	Estimate	Chi-Square	Pr > ChiSq
Intercept	-0.112	0.103	0.749
Participants (WD)	0.009	7.006	0.008
WGM	-0.002	0.000	0.982
Area Block Sequence	0.025	0.098	0.755
Viable	0.434	56.049	0.000
Tracts Offered (1000)	0.000	0.052	0.820

Table 4-37. Results of Poisson Regression for 1996-2000 (DWRRA) Period, 800-plus meter.

Parameter	Estimate	Chi-Square	Pr > ChiSq
Intercept	-1.611	85.687	0.000
Participants (WD)	0.012	54.782	0.000
WGM	0.282	26.905	0.000
Area Block Sequence	0.343	140.069	0.000
Viable	0.447	133.137	0.000
Tracts Offered (1000)	0.000	49.618	0.000

Table 4-38. Results of Poisson Regression for 2001-2003 (Post) Period, 800-plus meter.

Parameter	Estimate	Chi-Square	Pr > ChiSq
Intercept	5.374	8.059	0.005
Participants (WD)	0.006	0.103	0.748
WGM	-2.325	8.733	0.003
Area Block Sequence	0.056	1.295	0.255
Viable	0.261	10.524	0.001
Tracts Offered (1000)	-0.002	6.857	0.009

DWRRA, Participants, and Competition

In the face of negative coefficients estimated above for the DWRRA dummy, the hypothesis arises that *participants*, a significant regressor that is affected by royalty relief, are a source of some of the policy effects relating to competition. In other words, it is possible that there was an important indirect impact of DWRRA on competition by way of the number of participants. This hypothesis is supported both by empirical analysis of participation in the previous chapter and by the role of potential participants in the basic model of bidding presented in this chapter. Table 4-39 is repeated from Chapter 3. It reports that, in a linear regression of policy dummies and other regressors on participants per sale and depth, the DWRRA has significant effects.

Table 4-39. Summary of Chapter 3 Simulation Results, Participants.

Period	Actual Participants	Participants Added By Policy
	Mean	Mean
Pre-Policy	63.73	0.00
DWRRA	58.20	-5.39
Post-DWRRA	53.50	-13.09
Period	Actual Participants	Participants Added By Policy
	Mean	Mean
Pre-Policy	19.77	0.00
DWRRA	27.50	15.92
Post-DWRRA	23.67	8.75
Period	Actual Participants	Participants Added By Policy
	Mean	Mean
Pre-Policy	11.35	0.00
DWRRA	33.80	12.19
Post-DWRRA	23.33	8.83

Combining the estimates of the Poisson regression model and the policy impact on the number of participants, the combined effects of DWRRA on competition were computed. The results are presented in Tables 4-40 through 4-42.⁴⁰ The base values of the variables are the averages, 1996-2000, which is the DWRRA period. For the sake of completeness, impacts on 0-200 meters are given as well as deepwater.⁴¹

⁴⁰ As noted earlier, the Poisson model is a single-equation model, and the DWRRA effects given below are not identical to the effects computed for the system model in Chapter 5.

⁴¹ Similar computations were performed for the period 2001-2003 and the post-DWRRA policy. Given the exploratory nature of the single-equation model of competition, it is not presented here. The post-DWRRA policy is covered in Chapter 5.

Table 4-40. Poisson Model: Effect of DWRRA on Average Bids Per Tract, 0-200 meter.

	Parameter	Base Values (1996-2000 Mean)	Effects	Hypothetical Values (Bold)	Effects If No DWRRA
Area Block Sequence	0.063	2.256	0.141	2.256	0.141
DWRRA	0.031	1.000	0.031	0.000	0.000
MinBid Per Acre	-0.001	25.000	-0.019	25.000	-0.019
Participants (WD)	0.009	86.465	0.811	91.860	0.861
Post-DWRRA	-0.098	0.000	0.000	0.000	0.000
Re-Leased	0.167	0.031	0.005	0.031	0.005
Rental Rate	-0.035	5.018	-0.176	5.018	-0.176
Seismic Coverage	0.161	1.000	0.161	1.000	0.161
Tracts Offered (1000)	0.082	1.368	0.112	1.368	0.112
Viable	0.392	0.215	0.084	0.215	0.084
WGM	0.115	0.302	0.035	0.302	0.035
Intercept	-0.641	1.000	-0.641	1.000	-0.641
Sum			0.544		0.564
Exp(Sum)			1.723		1.758

Table 4-41. Poisson Model: Effect of DWRRA on Average Bids Per Tract, 200-800 meter.

	Parameter	Base Values (1996-2000 Mean)	Effects	Hypothetical Values (Bold)	Effects If No DWRRA
Area Block Sequence	0.096	2.135	0.206	2.135	0.206
DWRRA	0.057	1.000	0.057	0.000	0.000
Participants (WD)	0.011	47.626	0.532	31.703	0.354
Post-DWRRA	-0.046	0.000	0.000	0.000	0.000
Rental Rate	-0.032	7.490	-0.242	7.490	-0.242
Tracts Offered (1000)	0.140	0.406	0.057	0.406	0.057
Viable	0.274	0.261	0.072	0.261	0.072
Intercept	-0.161	1.000	-0.161	1.000	-0.161
Sum			0.520		0.285
Exp(Sum)			1.682		1.329

Table 4-42. Poisson Model: Effect of DWRRA on Average Bids Per Tract, 800-plus meter.

	Parameter	Base Values (1996-2000 Mean)	Effects	Hypothetical Values (Bold)	Effects If No DWRRA
Area Block Sequence	0.236	1.268	0.299	1.268	0.299
DWRRA	-0.024	1.000	-0.024	0.000	0.000
Participants (WD)	0.011	52.911	0.556	40.718	0.428
Post-DWRRA	-0.101	0.000	0.000	0.000	0.000
Tracts Offered (1000)	0.191	2.912	0.558	2.912	0.558
Viable	0.373	0.162	0.060	0.162	0.060
WGM	0.185	0.443	0.082	0.443	0.082
Intercept	-1.035	1.000	-1.035	1.000	-1.035
Sum			0.496		0.392
Exp(Sum)			1.643		1.480

Ordered Probit Model And Multiple Bids Per Lease

The probit model is appropriate where the data generating process of the count data is continuous. This seems to be partly true for the present case. The process is one where varying

points (one per evaluator) are selected from a continuous evaluation curve and transformed by a bid function into optimal bid amounts. For each selected point, a bid is placed if the bid amount is greater than minimum bid. While the number of evaluators is discrete, the bid generating process per evaluator is continuous. Inasmuch as the probit model is different from the Poisson or other models considered above, the question of regressors can be re-opened. The model was estimated with all possible regressors (except high bid per acre, which is too similar to the viability variable). The chi-squared statistic was used as a rough but adequate guide to significance, and variables where the probability was worse than 0.1 were generally dropped. The DWRRRA and post-DWRRRA dummies were retained being of special interest.

The dependent variable was the probability of *bidsensor* which takes on the values 1 to 3-plus. The reason for censoring was policy relevance. The main issues about competition have to do with whether one, two, or three bids exist for a lease; competition exceeding three bids is desirable but rare and assumed here to be of lesser interest. Censoring affects estimates and significance statistics, notwithstanding, for this report, only the simple chi-squared statistics were used. Refinements were left for future research.

Regression Results

The following tables and figures provide, for each depth class:

- Frequency of bids, grouped by *bidsensor*, in the data.
- Illustration of the sale-by-sale fit of the model predictions; bars show the sale average probability of only 1 bid, and lines show the sale average predicted probability of same per the probit regression model
- Probit regression results; included are mean values of the RHS variables and the products of the estimated parameters and the mean values, which can be used to simulate effects of variables.

Table 4-43. Frequency of Bidsensor, 0-200 meter.

BidsCensor	Total Frequency
1	6650
2	1700
3+	996

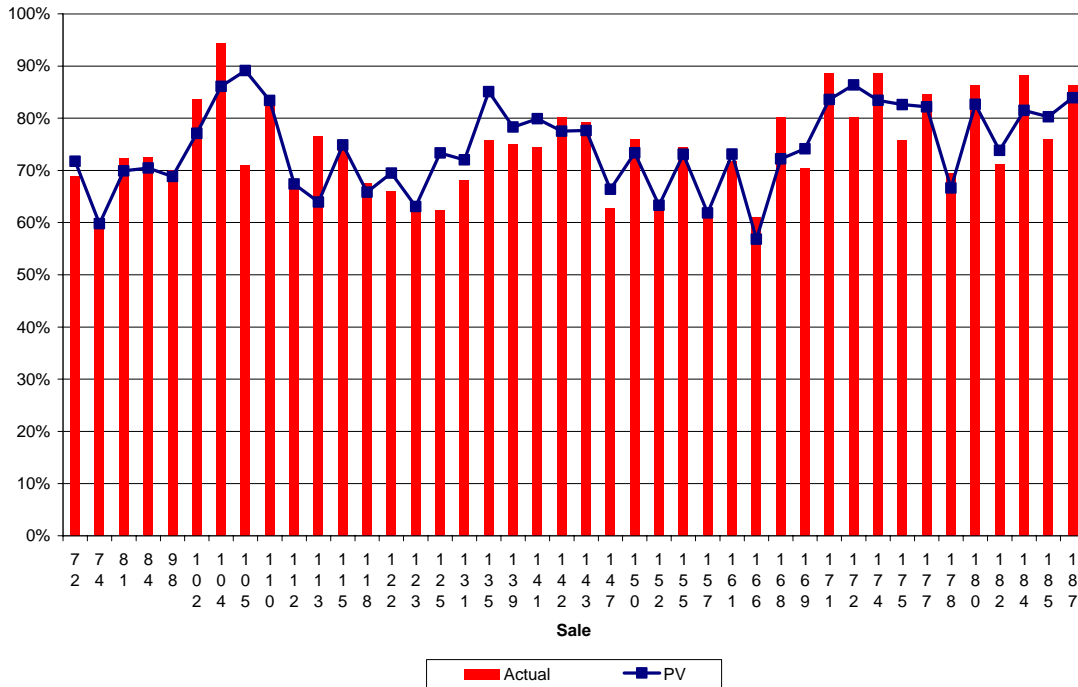


Figure 4-15. Actual Versus Predicted Probability of Single Bid, 0-200 meter.

Table 4-44. Probit Parameter Estimates, 0-200 meter.

	Estimate	Chi-Square	Pr > ChiSq	MeanVal	Product
Area Block Sequence	-0.164	70.234	0.000	1.802	-0.295
DWRRRA	0.060	1.308	0.253	0.211	0.013
HB by Joint Bidder	-0.204	45.652	0.000	0.300	-0.061
HB by Major Bidder	0.077	5.924	0.015	0.310	0.024
MinBid Per Acre	0.002	20.429	0.000	53.354	0.102
Participants (WD)	-0.011	17.198	0.000	70.114	-0.764
Post-DWRRRA	0.358	30.642	0.000	0.148	0.053
Bid Probability	-2.111	14.341	0.000	0.183	-0.387
Re-Released	-0.280	16.947	0.000	0.039	-0.011
Rental Rate	0.087	3.937	0.047	3.963	0.346
Seismic Coverage	-0.323	13.112	0.000	0.515	-0.166
Tracts Offered (1000)	-0.237	38.146	0.000	1.662	-0.394
Viable	-0.767	642.614	0.000	0.423	-0.325
WGM	-0.245	20.090	0.000	0.338	-0.083
Intercept 1	2.558	243.262	0.000	1.000	2.558
Intercept 2	3.335	407.045	0.000	1.000	3.335

Table 4-45. Frequency of Bidsensor, 200-800 meter.

Bidsensor	Total Frequency
1	1488
2	374
3+	182

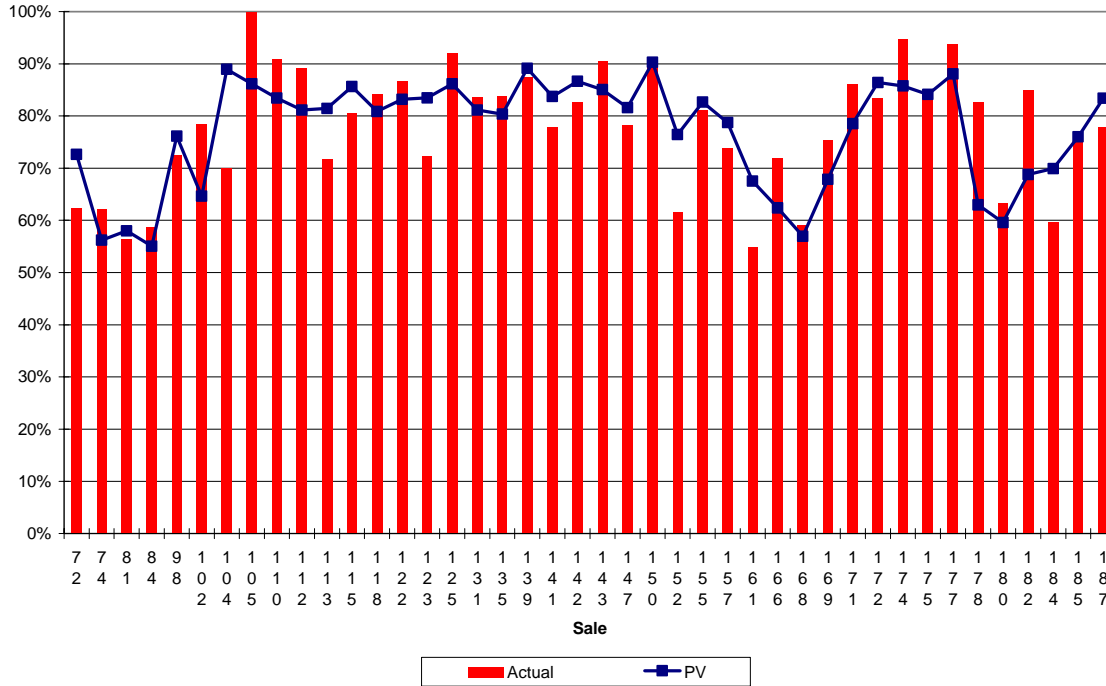


Figure 4-16. Actual Versus Predicted Probability of Single Bid, 200-800 meter.

Table 4-46. Probit Parameter Estimates, 200-800 meter.

	Estimate	Chi-Square	Pr > ChiSq	MeanVal	Product
Area Block Sequence	-0.195	20.794	0.000	1.755	-0.343
DWRRA	0.173	3.848	0.050	0.251	0.043
Participants (WD)	-0.029	68.588	0.000	27.444	-0.790
Post-DWRRA	0.296	6.388	0.012	0.154	0.046
Tracts Offered (1000)	-0.280	6.902	0.009	0.465	-0.130
Viable	-0.630	102.285	0.000	0.380	-0.239
Intercept 1	2.094	234.566	0.000	1.000	2.094
Intercept 2	2.922	415.818	0.000	1.000	2.922

Table 4-47. Frequency of Bidsensor, 800-plus meter.

Bidsensor	Total Frequency
1	4475
2	774
3+	435

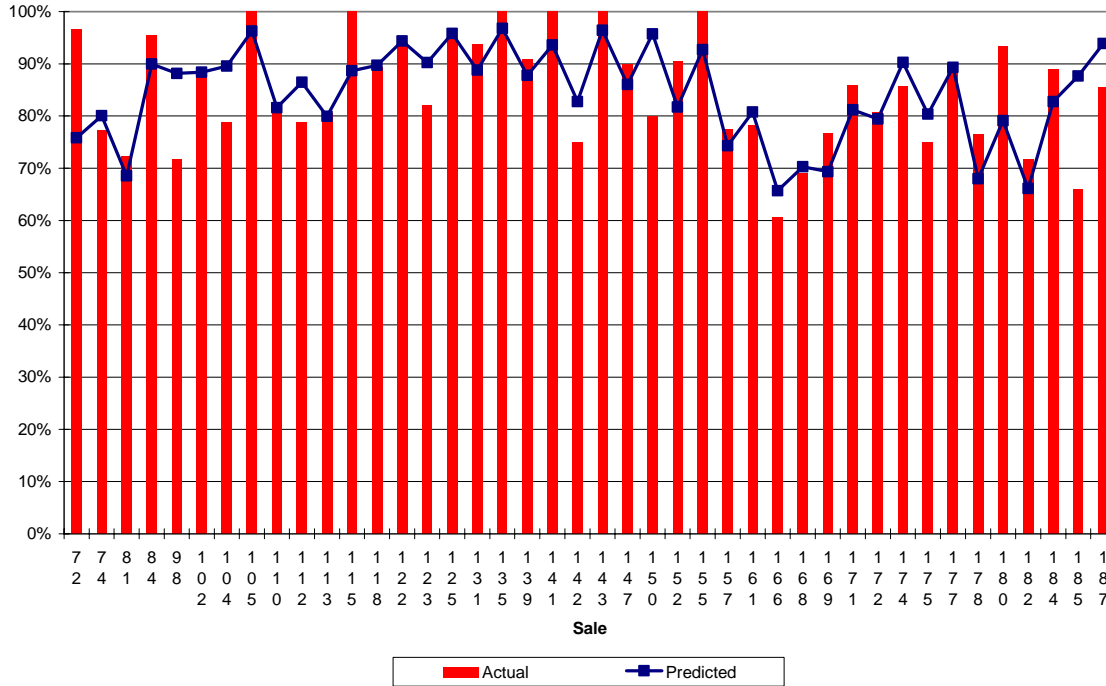


Figure 4-17. Actual Versus Predicted Probability of Single Bid, 800-plus meter.

Table 4-48. Probit Parameter Estimates, 800-plus meter.

	Estimate	Chi-Square	Pr > ChiSq	MeanVal	Product
Area Block Sequence	-0.450	125.963	0.000	1.254	-0.565
DWRRA	0.001	0.000	0.987	0.529	0.001
HB by Joint Bidder	-0.176	17.581	0.000	0.271	-0.048
HB by Major Bidder	0.092	4.643	0.031	0.639	0.059
Participants (WD)	-0.018	18.579	0.000	29.227	-0.512
Post-DWRRA	-0.017	0.031	0.860	0.158	-0.003
Bid Probability	-1.574	4.421	0.036	0.102	-0.161
Tracts Offered (1000)	-0.493	61.269	0.000	3.013	-1.487
Viable	-0.742	236.785	0.000	0.211	-0.156
WGM	-0.332	10.651	0.001	0.418	-0.139
Intercept 1	3.892	188.568	0.000	1.000	3.892
Intercept 2	4.626	262.220	0.000	1.000	4.626

Impacts of Royalty Relief

As with the Poisson model, the period dummies in the probit model do not represent generally the main effects of royalty relief on competition. The probit regression resulted in estimates for dummies that were statistically insignificant in 800-plus meters. In other depths, the coefficient estimates had greater significance, at least as indicated approximately by the chi-squared probability. However, even in those instances, the product of the coefficients and the mean values (1983-2003) implied small effects.

As for the Poisson model, *participants*, is a significant regressor that is affected by royalty relief and thus embodies some of the policy effects. The estimated change in participants due to royalty relief is incorporated in an impact simulation. To do this, the estimated change is subtracted from the actual mean participants to infer a no-relief base level of participants.

Table 4-49. Probit Model: Impacts of DWRRA, 0-200 meter.

0-200 m	With Policy			Change Due to Policy	Without Policy	
	Estimate	MeanVal	Product		MeanVal	Product
Area Block Sequence	-0.164	2.256	-0.369	0.000	2.256	-0.369
DWRRA	0.060	1.000	0.060	1.000	0.000	0.000
HB by Joint Bidder	-0.204	0.223	-0.046	0.000	0.223	-0.046
HB by Major Bidder	0.077	0.200	0.015	0.000	0.200	0.015
MinBid Per Acre	0.002	25.000	0.048	0.000	25.000	0.048
Participants (WD)	-0.011	69.933	-0.762	-5.395	75.328	-0.821
Post-DWRRA	0.358	0.000	0.000	0.000	0.000	0.000
Bid Probability	-2.111	0.213	-0.450	0.000	0.213	-0.450
Re-Leased	-0.280	0.031	-0.009	0.000	0.031	-0.009
Rental Rate	0.087	5.018	0.438	0.000	5.018	0.438
Seismic Coverage	-0.323	1.000	-0.323	0.000	1.000	-0.323
Tracts Offered (1000)	-0.237	1.368	-0.324	0.000	1.368	-0.324
Viable	-0.767	0.215	-0.165	0.000	0.215	-0.165
WGM	-0.245	0.302	-0.074	0.000	0.302	-0.074
Intercept 1	2.558	1.000	2.558	0.000	1.000	2.558
Intercept 2	3.335	0.000	0.000	0.000	0.000	0.000
Sum			0.598			0.479
Probability of Single Bid			72.51%			68.40%
Probability of Multiple Bids			27.49%			31.60%

Table 4-50. Probit Model: Impacts of DWRRA, 200-800 meter.

200-800 m	With Policy			Change Due to Policy	Without Policy	
	Estimate	MeanVal	Product		MeanVal	Product
Area Block Sequence	-0.195	2.135	-0.416	0.000	2.135	-0.416
DWRRA	0.173	1.000	0.173	1.000	0.000	0.000
Participants (WD)	-0.029	34.409	-0.990	15.922	18.487	-0.532
Post-DWRRA	0.296	0.000	0.000	0.000	0.000	0.000
Tracts Offered (1000)	-0.280	0.406	-0.114	0.000	0.406	-0.114
Viable	-0.630	0.261	-0.165	0.000	0.261	-0.165
Intercept 1	2.094	1.000	2.094	0.000	1.000	2.094
Intercept 2	2.922	0.000	0.000	0.000	0.000	0.000
Sum			0.581			0.867
Probability of Single Bid			71.95%			80.69%
Probability of Multiple Bids			28.05%			19.31%

Table 4-51. Probit Model: Impacts of DWRRA, 800-plus meter.

800-plus m	With Policy			Change Due to Policy	Without Policy	
	Estimate	MeanVal	Product		MeanVal	Product
Area Block Sequence	-0.450	1.268	-0.571	0.000	1.268	-0.571
DWRRA	0.001	1.000	0.001	1.000	0.000	0.000
HB by Joint Bidder	-0.176	0.304	-0.054	0.000	0.304	-0.054
HB by Major Bidder	0.092	0.610	0.056	0.000	0.610	0.056
Participants (WD)	-0.018	39.830	-0.698	12.193	27.637	-0.484
Post-DWRRA	-0.017	0.000	0.000	0.000	0.000	0.000
Bid Probability	-1.574	0.150	-0.237	0.000	0.150	-0.237
Tracts Offered (1000)	-0.493	2.912	-1.437	0.000	2.912	-1.437
Viable	-0.742	0.162	-0.120	0.000	0.162	-0.120
WGM	-0.332	0.443	-0.147	0.000	0.443	-0.147
Intercept 1	3.892	1.000	3.892	0.000	1.000	3.892
Intercept 2	4.626	0.000	0.000	0.000	0.000	0.000
Sum			0.686			0.898
Probability of Single Bid			75.37%			81.55%
Probability of Multiple Bids			24.63%			18.45%

Table 4-52. Probit Model: Impacts of Post-DWRRA, 0-200 meter.

0-200 m	With Policy			Change Due to Policy	Without Policy	
	Estimate	MeanVal	Product		MeanVal	Product
Area Block Sequence	-0.164	2.713	-0.444	0.000	2.713	-0.444
DWRRA	0.060	0.000	0.000	0.000	0.000	0.000
HB by Joint Bidder	-0.204	0.228	-0.047	0.000	0.228	-0.047
HB by Major Bidder	0.077	0.126	0.010	0.000	0.126	0.010
MinBid Per Acre	0.002	25.000	0.048	0.000	25.000	0.048
Participants (WD)	-0.011	59.984	-0.654	-13.087	73.071	-0.797
Post-DWRRA	0.358	1.000	0.358	1.000	0.000	0.000
Bid Probability	-2.111	0.187	-0.394	0.000	0.187	-0.394
Re-Leased	-0.280	0.012	-0.003	0.000	0.012	-0.003
Rental Rate	0.087	5.005	0.437	0.000	5.005	0.437
Seismic Coverage	-0.323	1.000	-0.323	0.000	1.000	-0.323
Tracts Offered (1000)	-0.237	1.562	-0.370	0.000	1.562	-0.370
Viable	-0.767	0.418	-0.320	0.000	0.418	-0.320
WGM	-0.245	0.274	-0.067	0.000	0.274	-0.067
Intercept 1	2.558	1.000	2.558	0.000	1.000	2.558
Intercept 2	3.335	0.000	0.000	0.000	0.000	0.000
Sum			0.789			0.288
Probability of Single Bid			78.49%			61.33%
Probability of Multiple Bids			21.51%			38.67%

Table 4-53. Probit Model: Impacts of Post-DWRRA, 200-800 meter.

200-800 m	With Policy			Change Due to Policy	Without Policy	
	Estimate	MeanVal	Product		MeanVal	Product
Area Block Sequence	-0.195	2.711	-0.529	0.000	2.711	-0.529
DWRRA	0.173	0.000	0.000	0.000	0.000	0.000
Participants (WD)	-0.029	23.663	-0.681	8.747	14.917	-0.429
Post-DWRRA	0.296	1.000	0.296	1.000	0.000	0.000
Tracts Offered (1000)	-0.280	0.395	-0.111	0.000	0.395	-0.111
Viable	-0.630	0.648	-0.408	0.000	0.648	-0.408
Intercept 1	2.094	1.000	2.094	0.000	1.000	2.094
Intercept 2	2.922	0.000	0.000	0.000	0.000	0.000
Sum			0.660			0.617
Probability of Single Bid			74.55%			73.12%
Probability of Multiple Bids			25.45%			26.88%

Table 4-54. Probit Model: Impacts of Post-DWRRA, 800-plus meter.

800-plus m	With Policy			Change Due to Policy	Without Policy	
	Estimate	MeanVal	Product		MeanVal	Product
Area Block Sequence	-0.450	1.538	-0.693	0.000	1.538	-0.693
DWRRA	0.001	0.000	0.000	0.000	0.000	0.000
HB by Joint Bidder	-0.176	0.273	-0.048	0.000	0.273	-0.048
HB by Major Bidder	0.092	0.302	0.028	0.000	0.302	0.028
Participants (WD)	-0.018	23.503	-0.412	8.832	14.671	-0.257
Post-DWRRA	-0.017	1.000	-0.017	1.000	0.000	0.000
Bid Probability	-1.574	0.073	-0.115	0.000	0.073	-0.115
Tracts Offered (1000)	-0.493	2.214	-1.093	0.000	2.214	-1.093
Viable	-0.742	0.554	-0.411	0.000	0.554	-0.411
WGM	-0.332	0.494	-0.164	0.000	0.494	-0.164
Intercept 1	3.892	1.000	3.892	0.000	1.000	3.892
Intercept 2	4.626	0.000	0.000	0.000	0.000	0.000
Sum			0.967			1.139
Probability of Single Bid			83.32%			87.27%
Probability of Multiple Bids			16.68%			12.73%

We next summarize the impact estimates presented above. According to the estimates based on the probit model, in deepwater, the DWRRA raised the probability of multiple bids per tract, and the post-DWRRA period had variable results, slightly lower in 200-800 meters but higher in 800-plus meters.

Table 4-55. Summary of Policy Impacts Per Probit Model.

Probability of Multiple Bids		
DWRRA		
	Probability Without Policy	Probability With Policy
0-200 m	31.60%	27.49%
200-800 m	19.31%	28.05%
800-plus m	18.45%	24.63%
Post-DWRRA		
	Probability Without Policy	Probability With Policy
0-200 m	38.67%	21.51%
200-800 m	26.88%	25.45%
800-plus m	12.73%	16.68%

Conclusion

This chapter addressed the effect of the DWRRA and the post-DWRRA program, contrasted with no relief, on the *number of bids per tract* which is our measure of competition. Effects are given for three water depth classes: 0-200 meters, 200-800 meters, and 800-plus meters. Data cover lease sales from 1983 to 2003 for the Western and Central Gulf of Mexico. The Eastern Gulf of Mexico data are omitted because they often are outliers, reflecting several differences between the limited and occasional Eastern offering and the area-wide, annual offering of the Western and Central areas.

Probability of a Tract Receiving Any Bid

The chapter began with examination of the number of tracts offered in each sale and the probability of a tract receiving one or more bids. Tracts offered in a sale follow a roughly cyclical pattern over time, related to leasing patterns examined in Chapter 3. As shown the tracts offered, averaged by policy period, tended to decline over the periods, except for a recent rise in shallow water. Most tracts offered in a lease sale are not bid on. The ratio of tracts bid on to tracts offered, a measure of the probability of a tract receiving one or more bids in a sale, was consistently higher in 0-200 meters and 200-800 meters than it was in 800-plus meters, averaging 18 percent and 17 percent versus 10 percent, respectively. We showed that the probability of a tract receiving one or more bids rose in the DWRRA period in all water depths and then partly reverted to earlier average levels in the post-DWRRA period.

It is likely that factors that attract a bid to a tract also promote, to a lesser degree, multiple bids at a tract. The correlation for the ratio of bid-to-offer and the number of bids per lease is significantly positive in all water depths. That is, tract characteristics, such as viability, or sale characteristics, such as oil price, that increase the probability of tracts being bid on also seem to increase the chance of multiple bids at tracts. Unfortunately, in this study, lack of data prevented investigation of specific tract characteristics in this connection.

An important trend relating to quality and information of tracts offered is that, increasingly, they have been previously leased, or at least bid on. By the same token, tracts bid

on are increasingly likely to have been leased or bid on previously. In shallow water and 200-800 meters, re-leasing has become prevalent. In deepwater, the former availability of never-leased tracts is currently giving way to offering and bidding on tracts that have been leased previously.

Mean Bids Per Lease

Turning to analysis of the number of bids received at tracts that were bid on, there has been noticeable year-by-year variation in bids per lease in 0-200 meters and 200-800 meters, but when the variable is averaged over policy periods, the average has not changed greatly.

- About 70 percent of the leases in 0-200 meters and 200-800 meters received a single bid.
- Bids per lease in both 0-200 meters and 200-800 meters averaged about 1.4.

In 800-plus meters, a change in bids per lease occurred about the time the DWRRA took effect. Prior to that time, bids per lease in 800-plus meters tended to be significantly less than other depth classes. The DWRRA period brought competition in 800-plus meters closer to the average level of competition of the other depth classes. Contrasting the pre-royalty relief period with the DWRRA period, mean bids per tract increased in all depths, more so in deepwater. Contrasting the DWRRA with the post-DWRRA relief periods, mean bids per tract fell in all depths.

Poisson Regression Model

Regression analysis of determinants of bids per lease was based on a simple theoretical model of bidding. The analysis took account, further, of the fact that bids per lease are count data, calling for certain econometric methods. The Poisson regression model was considered, as well as the lognormal and probit models. The data set included only tracts that received any bids, meaning that it is zero-truncated, creating certain econometric problems. Prior to applying the Poisson regression model, the univariate distribution of bids per lease was examined and contrasted with the theoretical Poisson distribution. Comparative graphs showed that the Poisson distribution under-predicts the single bid frequency and over-predicts the frequency of higher (two or three) bids per tract. There might also be a tendency for the Poisson to under-predict the very (say, five or more) high bids per tract, although counts over five are very rare in any case. Regression analysis is used to take account of factors other than policies that might also cause effects displayed by lease sale variables. To some extent, regression analysis attempts to isolate causality, at least as far as statistics can do so. While the variables included in final models differed somewhat by water depth, overall it was evident that:

- Viability has the greatest effect on bids per tract. This variable is the indicator of tract prospectiveness that performed best in regressions. An alternative variable that has the same meaning is the dollar value that MMS assigned to the tract, however, MMS value performed poorer in regressions as far as competition is concerned.

- Being previously leased or being a “re-lease” after bid rejection has a strong positive effect, as expected. These variables indicate both that information is available about the tract and that the information is favorable.
- The number of participants and the number of leases offered are significant. The ratio of tracts bid on to tracts offered (that is, the probability that an offered tract was bid on) was of lower significance and was dropped from the models.
- When they are significant, minimum bid and rental have negative effects, as expected, although their effects are small.

To estimate effects not otherwise accounted for by variables in the model of royalty relief policies, continuing effect dummies were defined. For DWRRA, its dummy variable has the value 1 in years 1996-2000 and is zero otherwise. The dummy variable for post-DWRRA is 1 in years 2001-2003 and is zero otherwise. The coefficient of the dummy variable represents the average annual effect over the period. It is noted that some of the other model variables, such as number of participants, also transmitted impacts from policy indirectly.

The policy period dummy variables were mostly of low significance, except for the post-DWRRA dummy in some depth classes. Also, their signs were sometimes positive and sometimes negative, not always as expected. In general, assessing the significance of a parameter estimate, as well as overall goodness of fit, is more complicated for the Poisson model with zero-truncation than it is for OLS models, and this study did not attempt to develop precise fit statistics for the model. Significance of parameter estimates was approximately inferred from chi-squared statistics.

The explanatory variable most likely to transmit impacts of royalty relief policies indirectly is the number of participants (which is examined in Chapter 3). It can be noted that viability (or alternatively, MMS value) might also transmit impacts indirectly because at the margin some tracts that would be non-viable without royalty relief are, instead, viable due to the policy. Unfortunately, there are no data available to pursue that idea.

The Poisson regression models in this chapter are single-equation models. In Chapter 5 it is explained that the preferred model is a system model in which competition and high bid are determined simultaneously. In that regard, the regression analysis of this chapter is a preliminary one that focuses on issues unique to count data analysis and other topics about competition specifically. Subject to that qualification, this chapter combines the analysis of participants from Chapter 3 and the current model of competition in order to estimate effects of royalty relief on competition. The effects estimated combine the indirect effects via participants and the direct effects via the dummy variables in the competition model. The results show that DWRRA increased bids per tract over what might have been the level in absence of the policy.

Probit Regression Model

The variable explained by the probit model is the probability of a tract receiving up to a specific number of bids (up to 1, up to 2, etc.). Inasmuch as the probit is different from the

Poisson or other models considered above, different explanatory variables were included in the models. The study defined the probability of *bidsensor* which takes on the values 1, 2, or 3-plus. The actual frequency of bids per tract, organized by the *bidsensor* scheme for the entire 1983-2003 data set, is given in the next table. Goodness-of-fit for a probit regression model means how closely its predicted cumulative probabilities match these actual data. Finally, turning to estimation of the probit regression model, as for the Poisson model, so also for the probit model, the period dummies generally do not capture the main effects of royalty relief on competition. Also, as for the Poisson model, *participants* is a significant regressor that is affected by royalty relief and thus transmits some of the policy effects indirectly. To examine the effects of royalty relief by way of participants, the study focused on the probability of a tract receiving only a single bid versus receiving multiple bids.

Chapter 5

Lease Sale Bids

Introduction

In this chapter we analyze historical data and perform statistical analysis regarding the effect of the DWRRA and the post-DWRRA program as contrasted with no royalty relief on the *magnitude of the high bids*. We rely on the literature discussed in chapter 2 as a starting basis for the theoretical model as well as our observations of the historical data. The analysis covers three water depth classes:

- *0-200 meter – shallow water*: Deepwater royalty relief does not apply directly but might have indirect effects.
- *200-800 meter – deepwater*: Although policies give different amounts of relief to 200-400 meter and 400-800 meter, data are combined to provide enough observations
- *800-plus meter – deepwater*: Policies give larger amount of relief

Data cover lease sales from 1983 to 2003 for the Western and Central Gulf of Mexico. The Eastern Gulf of Mexico data are omitted from most of this chapter's analysis because they often are outliers, reflecting several differences between the limited and occasional Eastern offering and the area-wide, annual offering of the Western and Central areas.

The effects of policies are shown in two ways:

1. Simple statistics that do not involve regression analysis
2. Regression model that includes policy dummies

The chapter also includes the explanation of our bidding model. The bidding model forms the theoretical basis of the analysis. The model shows how a bidder's uncertainty about true tract value and his expectation of competition for the lease influence the level of his bid offer. While the model is not new, an innovation in this study is including a role for bid rejection. The key implication of the model is that policies, like royalty relief, that tend to increase tracts' expected net value cause a lesser rise of high bids. In other words, it is expected that a rise in bonus bid for a tract would fall short of the risked present value of royalty suspension.

MMS reviews all high bids received to help ensure that they represent fair market value for the leases. The bid adequacy program *per se* is not a topic for this study; notwithstanding, it is possible that bidders take account of the bid review and potential bid rejection when they prepare their bids. Furthermore, one effect from rejection of a high bid is to encourage higher

bids for that block lease in the next sale (recalling that each area is offered for lease annually). Therefore, this study examines bid adequacy review as a possible influence on high bids.

Among the limitations of this study is the omission of a variable that is a direct indicator of perceived geologic potential or quality of a block. However, there must have been trends in block quality over the period studied. Even though new technology can effectively improve quality in the sense of making previously unprofitable or unknown resources newly available, there is presumably a tendency also for the perceived best potential to be leased first. Declining quality is expected to imply lower bid levels, other things being equal. A major issue for econometrics is that the omission of the quality indicator implies that declining quality pulls down the estimated coefficient of the policy period dummy variables. That tendency is mixed with the positive effect that royalty relief has on expected profit and on bid levels. As a result, the sign of the policy dummy in the high bid model is indeterminate, that is, it can be positive or negative.

High Bids and Related Variables

High Bids

Historical Average High Bids

First we provide an overview of historical high bids, classed by sale and water depth class. These graphs include both central and western area sales. Figure 5-1 indicates the averages of the high bids themselves (not per acre and in nominal dollars). One may observe that:

- In 0-200 meter and 200-800 meter, the average high bid of the sale was historically highest in the years following the start of area-wide leasing. It declined and never returned to those levels.
- In 800-plus meter, average high bid of the sale was high in the first area-wide leasing boom, but less markedly. Also, in this depth, the DWRRA years witnessed a greater rise than occurred at other depths.
- Smaller up-and-down patterns in the graph covering all areas are caused by the alternation of central and western area sales; western sales tend to have slightly lower bid amounts.

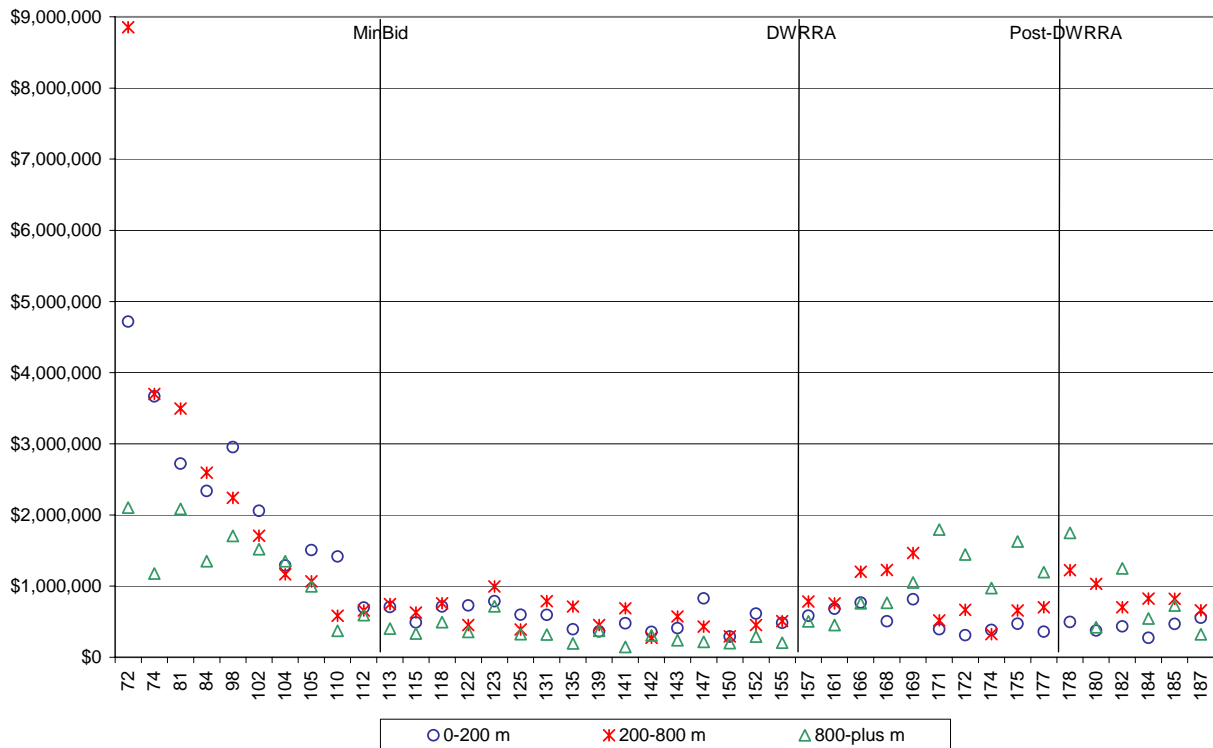


Figure 5-1. Average High Bid, Sale-By-Sale For All Areas, By Depth.

Figure 5-2 shows the average high bids placed on a per-acre basis. This conversion is useful because small tracts naturally tend to receive lower bids. The patterns are similar to those shown in Figure 5-1.

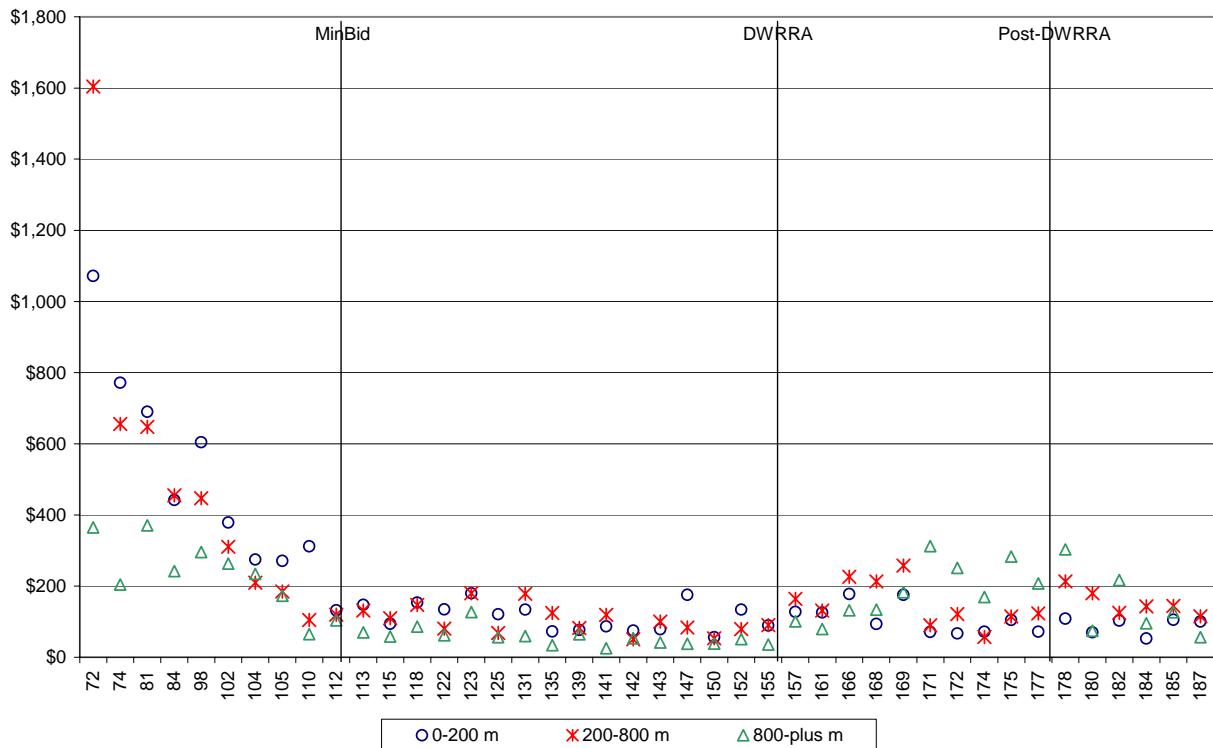


Figure 5-2. Average High Bid Per Acre, By Depth.

Figure 5-3 shows the average high bid per acre in real dollars. The producer price index is used with 1983 value equal to 1. to convert nominal dollars to real dollars. While the patterns are similar to those of the preceding figures, the values in later years are relatively lower. This conversion exacerbates the contrast between the high values of the early area-wide sales and the lower values afterwards.

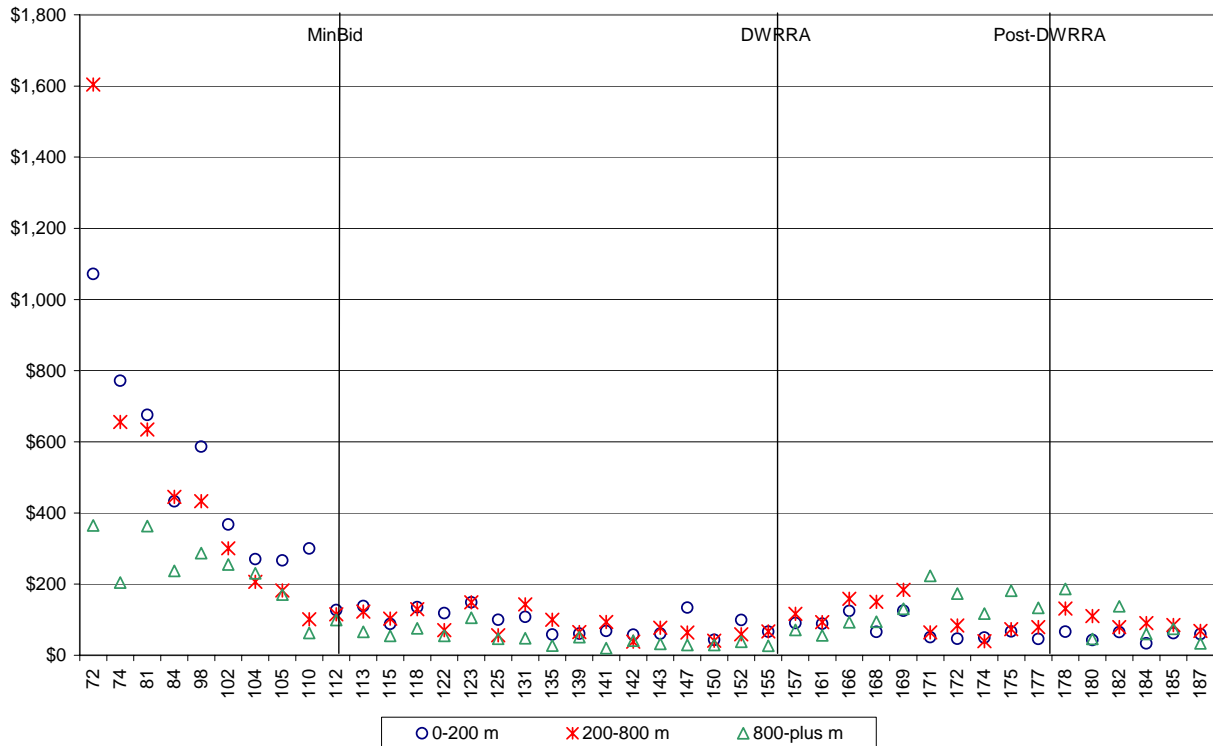


Figure 5-3. Average High Bid Per Acre In Constant Dollars, By Depth.

Distribution of High Bids

In this section we examine the univariate distribution of the high bids. The main issue addressed is that, whereas econometric modeling and estimation often assumes a normal distribution, the high bids themselves are not distributed normally. Considering the entire 1983-2003 period, the high bids and high bids per acre are both extremely skewed. Figure 5-4 illustrates the 1983-2003 distribution of high bids per acre for shallow water. The distribution is skewed even more than that for competition.

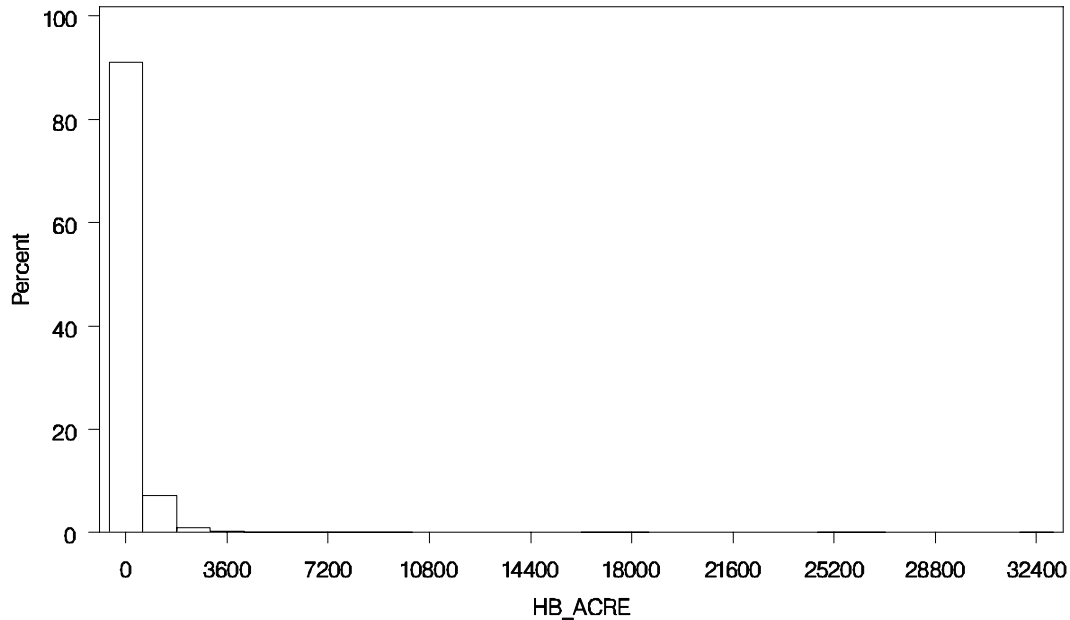


Figure 5-4. Frequency of High Bid Per Acre, 0-200 meter.

The log high bid per acre is also quite skewed, though not to such an extreme as shown in Figure 5-5. The log high bid is of interest because (a) regression models presented below make use of it, and (b) the change in graphical scale brings an interesting anomaly to light. The distribution of the log high bid per acre shows an interesting anomaly: it is bimodal. The explanation is that the lower mode, around 3.2, corresponds to the post-1988 minimum bid of \$25/acre, whereas the second mode about 5.2 corresponds to the earlier minimum bid of \$150/acre. The bimodality is evident in the data for 0-200 meters and 200-800 meters. It is not evident in 800-plus meter, for the reason that relatively few leases were sold in that depth class prior to 1988. The bimodality of the log high bid distributions poses an immediate problem for univariate analysis, which generally assumes a single-mode distribution.

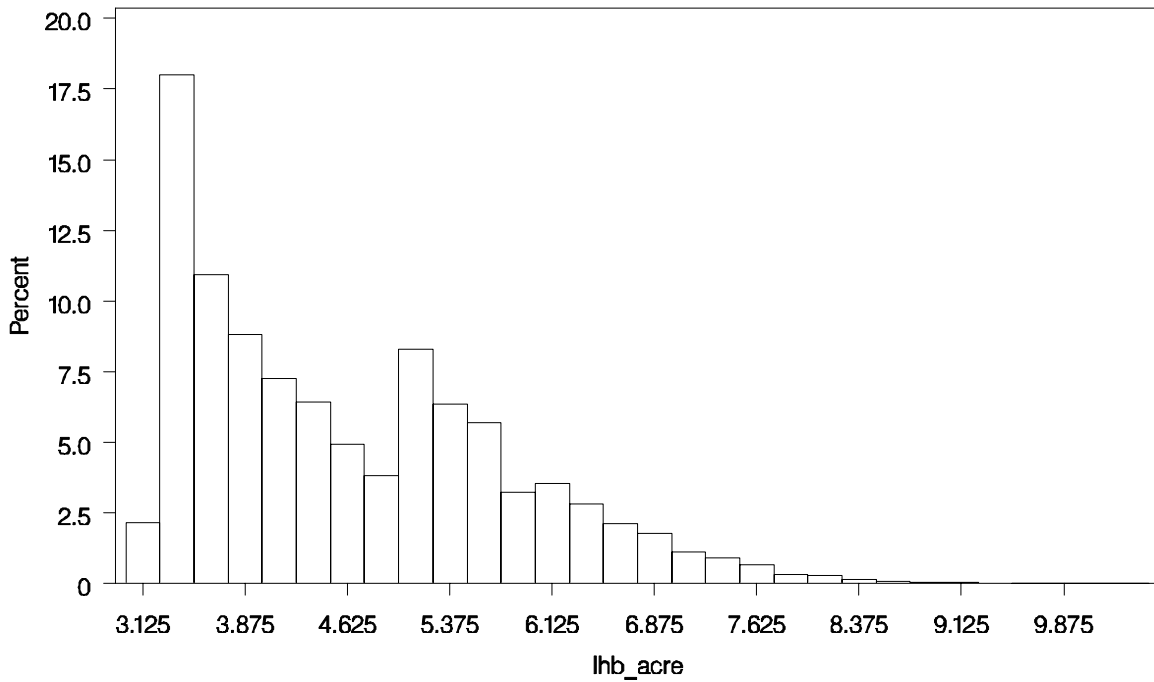


Figure 5-5. Frequency of Log High Bid Per Acre, 0-200 meter.

Considering only the frequency for 800-plus meter, which is roughly unimodal, the Pareto distribution fits well for both high bids per acre and log high bids per acre. The Gamma distribution fits fairly well for log high bids per acre, in that it has an initial rise that can reflect the short, far-left bar for 0-200 meters and 200-800 meters. The Pareto distribution is used to model phenomena where a small event is very common, a very large event occurs occasionally, and the middle range is thinly populated. This is the pattern of the high bid per acre.⁴²

⁴² The Pareto distribution is an instance of an inverse function. The probability of an event larger than X is proportional to the inverse of X.

Table 5-1. Simulated Pareto Distribution.

Event	Inverse	Event	Inverse
2	0.500	20	0.050
3	0.333	21	0.048
4	0.250	22	0.045
5	0.200	23	0.043
6	0.167	24	0.042
7	0.143	25	0.040
8	0.125	26	0.038
9	0.111	27	0.037
10	0.100	28	0.036
11	0.091	29	0.034
12	0.083	30	0.033
13	0.077	31	0.032
14	0.071	32	0.031
15	0.067	33	0.030
16	0.063	34	0.029
17	0.059	35	0.029
18	0.056	36	0.028
19	0.053	37	0.027

Comments

This preliminary univariate analysis of high bids suggest the following observations:

- High bids per acre, the preferred form of this variable, appear to be distributed by the Pareto distribution or something similar. They are not well represented by a lognormal distribution, which is the first candidate that comes to mind when a skewed, continuous distribution is needed. Nevertheless, a lognormal transformation might be used for practical reasons, as explained below.
- While this study does not try to estimate underlying resource values, it seems to be widely believed that field or block values are lognormally distributed. The implication is that the high bid distribution is not the same as the underlying resource value distribution.
- In theory, it is believed that there is some connection between the high bid and the underlying resource value. Therefore, some factors must be present that transform the underlying value distribution into the high bid distribution. Likely factors are:
 - Optimal bid formulation in the sealed-bid auction involves bidding lower than the expected underlying value.
 - The possible bids are bounded at the minimum bid.

- Frequency graphs of the longitudinal data for high bid per acre, 1983-2003, have a bimodal distribution, created by change of the minimum bid. Thus:
 - Minimum bid has a strong effect on the mass of low-level bids. However, it is an open question whether minimum bid has any effect on the less frequent high-level bids.
 - It is also an open question whether minimum bid has significant effect on sale-wide average high bid, since the average high bid reflects largely the money bid at the less frequent high-amount tracts.

Tests of Royalty Relief Based On Means of Historical Data

Method

This section provides a preliminary indication of the effects of royalty relief based on contrasting the means of the data for different periods, without using regression analysis. The mean for each period is computed from pooled high bids per acre. The t-test of whether means of two groups are the same or not rests on an assumption that the variable is distributed normally. That is not the case for high bids per tract. It is also the case that when means are different, it is likely that variances are different too. This fact is illustrated in Table 5-2, which shows the means and variances for the policy periods. In view of the facts, t-test results are not provided for these means. More sophisticated tests can be devised that account for non-normality, but that is left for future research.

Table 5-2. Statistics of High Bid Per Acre, by Period and Depth.

Both Areas	Pre-Policy 1983-1995	DWRRA 1996-2000	Post-DWRRA 2001-2003
0-200			
N	5993	1974	1379
Mean	326.283	126.883	96.471
StdDev	943.137	190.918	184.555
Skewness	17.690	3.822	9.972
200-800			
N	1216	513	315
Mean	378.231	169.620	154.497
StdDev	985.813	252.782	300.149
Skewness	7.756	4.038	5.957
800+			
N	1778	3009	897
Mean	114.609	160.556	146.733
StdDev	186.405	382.347	351.906
Skewness	5.578	8.050	6.416
All Depths			
N	8987	5496	2591
Mean	291.434	149.308	120.926
StdDev	859.898	315.206	269.390
Skewness	17.295	8.431	7.797

Change in the Mean

Using high bid data that are pooled by policy period, Tables 5-3 through 5-14 summarize the period statistics by panning areas and water depth.

Table 5-3. Change in Mean High Bid Per Acre and Bids Per Tract, Central, 0-200 meter.

CGM 0-200	Pre-Policy 1983-1995	DWRRRA 1996-2000	Post_DW 2001-2003	PP to DWRRRA	DWRRRA to Post	Pre-Policy 1983-1995	RR	PP to RR
N	3806	1377	1001	-2429	-376	3806	2378	-1428
High Bid	361.747	141.484	105.595	-220.263	-35.889	361.747	126.377	-235.370
Bids	1.504	1.592	1.437	0.088	-0.155	1.504	1.526	0.022

Table 5-4. Change in Mean High Bid Per Acre and Bids Per Tract, Western, 0-200 meter.

WGM 0-200	Pre-Policy 1983-1995	DWRRRA 1996-2000	Post_DW 2001-2003	PP to DWRRRA	DWRRRA to Post	Pre-Policy 1983-1995	RR	PP to RR
N	2187	597	378	-1590	-219	2187	975	-1212
High Bid	264.566	93.207	72.310	-171.359	-20.898	264.566	85.105	-179.460
Bids	1.517	1.358	1.177	-0.158	-0.181	1.517	1.288	-0.228

Table 5-5. Change in Mean High Bid Per Acre and Bids Per Tract, Central, 200-800 meter.

CGM 200-800	Pre-Policy 1983-1995	DWRRRA 1996-2000	Post_DW 2001-2003	PP to DWRRRA	DWRRRA to Post	Pre-Policy 1983-1995	RR	PP to RR
N	647	246	158	-401	-88	647	404	-243
High Bid	485.913	199.204	159.851	-286.709	-39.353	485.913	183.813	-302.099
Bids	1.445	1.386	1.253	-0.059	-0.133	1.445	1.334	-0.111

Table 5-6. Change in Mean High Bid Per Acre and Bids Per Tract, Western, 200-800 meter.

WGM 200-800	Pre-Policy 1983-1995	DWRRRA 1996-2000	Post_DW 2001-2003	PP to DWRRRA	DWRRRA to Post	Pre-Policy 1983-1995	RR	PP to RR
N	569	267	157	-302	-110	569	424	-145
High Bid	255.787	142.363	149.110	-113.424	6.747	255.787	144.861	-110.926
Bids	1.364	1.566	1.503	0.202	-0.062	1.364	1.542	0.179

Table 5-7. Change in Mean High Bid Per Acre and Bids Per Tract, Central, 800-plus meter.

CGM 800+	Pre-Policy 1983-1995	DWRRRA 1996-2000	Post_DW 2001-2003	PP to DWRRRA	DWRRRA to Post	Pre-Policy 1983-1995	RR	PP to RR
N	1178	1675	454	497	-1221	1178	2129	951
High Bid	126.730	157.694	218.719	30.964	61.025	126.730	170.708	43.978
Bids	1.232	1.528	1.394	0.297	-0.134	1.232	1.500	0.268

Table 5-8. Change in Mean High Bid Per Acre and Bids Per Tract, Western, 800-plus meter.

WGM 800+	Pre-Policy 1983-1995	DWRRRA 1996-2000	Post_DW 2001-2003	PP to DWRRRA	DWRRRA to Post	Pre-Policy 1983-1995	RR	PP to RR
N	600	1334	443	734	-891	600	1777	1177
High Bid	90.811	164.149	72.959	73.338	-91.191	90.811	141.416	50.605
Bids	1.128	1.385	1.135	0.257	-0.250	1.128	1.323	0.195

Table 5-9. Change in Mean High Bid Per Acre and Bids Per Tract, Central, All Depths.

CGM All	Pre-Policy 1983-1995	DWRRRA 1996-2000	Post_DW 2001-2003	PP to DWRRRA	DWRRRA to Post	Pre-Policy 1983-1995	RR	PP to RR
N	5631	3298	1613	-2333	-1685	5631	4911	-720
High Bid	326.848	154.022	142.750	-172.826	-11.272	326.848	150.320	-176.528
Bids	1.440	1.544	1.407	0.104	-0.138	1.440	1.499	0.059

Table 5-10. Change in Mean High Bid Per Acre and Bids Per Tract, Western, All Depths

WGM All	Pre-Policy 1983-1995	DWRRRA 1996-2000	Post_DW 2001-2003	PP to DWRRRA	DWRRRA to Post	Pre-Policy 1983-1995	RR	PP to RR
N	3356	2198	978	-1158	-1220	3356	3176	-180
High Bid	232.013	142.234	84.932	-89.779	-57.302	232.013	124.589	-107.424
Bids	1.421	1.400	1.211	-0.021	-0.189	1.421	1.342	-0.080

Table 5-11. Change in Mean High Bid Per Acre and Bids Per Tract, Both Areas, 0-200 meter.

Both 0-200	Pre-Policy 1983-1995	DWRRRA 1996-2000	Post_DW 2001-2003	PP to DWRRRA	DWRRRA to Post	Pre-Policy 1983-1995	RR	PP to RR
N	5993	1974	1379	-4019	-595	5993	3353	-2640
High Bid	326.283	126.883	96.471	-199.400	-30.412	326.283	114.376	-211.907
Bids	1.509	1.521	1.365	0.013	-0.156	1.509	1.457	-0.052

Table 5-12. Change in Mean High Bid Per Acre and Bids Per Tract, Both Areas, 200-800 meter.

Both 200-800	Pre-Policy 1983-1995	DWRRRA 1996-2000	Post_DW 2001-2003	PP to DWRRRA	DWRRRA to Post	Pre-Policy 1983-1995	RR	PP to RR
N	1216	513	315	-703	-198	1216	828	-388
High Bid	378.231	169.620	154.497	-208.610	-15.123	378.231	163.867	-214.364
Bids	1.407	1.480	1.378	0.072	-0.102	1.407	1.441	0.034

Table 5-13. Change in Mean High Bid Per Acre and Bids Per Tract, Both Areas, 800-plus meter.

Both 800+	Pre-Policy 1983-1995	DWRRRA 1996-2000	Post_DW 2001-2003	PP to DWRRRA	DWRRRA to Post	Pre-Policy 1983-1995	RR	PP to RR
N	1778	3009	897	1231	-2112	1778	3906	2128
High Bid	114.609	160.556	146.733	45.947	-13.823	114.609	157.381	42.773
Bids	1.197	1.465	1.266	0.268	-0.198	1.197	1.419	0.223

Table 5-14. Change in Mean High Bid Per Acre and Bids Per Tract, Both Areas, All Depths.

Both; All D	Pre-Policy 1983-1995	DWRRRA 1996-2000	Post_DW 2001-2003	PP to DWRRRA	DWRRRA to Post	Pre-Policy 1983-1995	RR	PP to RR
N	8987	5496	2591	-3491	-2905	8987	8087	-900
High Bid	291.434	149.308	120.926	-142.126	-28.382	291.434	140.215	-151.219
Bids	1.433	1.487	1.333	0.053	-0.154	1.433	1.437	0.004

We make the following observations on the contrasts for the aggregate of both areas:

- Contrasting pre-royalty relief and the combined royalty relief periods (1996-2003), the average high bid per acre fell in 0-200 meters and 200-800 meters, plainly affected by the high level of bid amounts in the early area-wide sales.

High bid per acre rose in 800-plus meters, where there was little activity in those early years.

- Contrasting DWRRA and post-DWRRA (2001-2003) periods, the average high bid per acre fell in every depth class.
- Contrasting the pre-royalty relief period and DWRRA (1996-2000), again the average high bid fell in 0-200 meters and 200-800 meters, and it rose in 800-plus meters.

Variables Considered For Regression Analysis

Prior to presenting our analysis of determinants of the high bid, the simple correlation of the series of high bid and other, possibly related, variables is presented in this section.⁴³ The variables considered for inclusion in regression analysis are listed below in Tables 5-15 through 5-17.

Table 5-15. Statistics of Variables for Regression Analysis, By Period, 0-200 meter.

0-200	AM_Only 1983-1995		DWRRA 1996-2000		Post_DW 2001-2003	
	Mean	StDev	Mean	StDev	Mean	StDev
High Bid (Current\$)	1,511,196	3,224,115	594,105	902,562	445,866	883,161
High Bid Per Acre (Current\$/a)	326.28	943.14	126.88	190.92	96.47	184.55
High Bid Per Acre (Constant\$/a)	309.91	930.25	88.58	134.35	58.89	111.51
Bid Probability	0.17	0.07	0.21	0.11	0.19	0.07
Bids Per Lease	1.51	1.05	1.52	1.08	1.37	0.85
Multiple Bids (0,1)	0.30	0.46	0.29	0.45	0.24	0.42
Re-Leased	0.05	0.21	0.03	0.17	0.01	0.11
HB by Major Bidder (0,1)	0.39	0.49	0.20	0.40	0.13	0.33
HB by Joint Bidder (0,1)	0.34	0.47	0.22	0.42	0.23	0.42
Drainage/Development Lease	0.09	0.28	0.01	0.12	0.00	0.05
Area Block Sequence	1.44	0.67	2.26	0.91	2.71	1.05
Repeat Block	0.36	0.48	0.80	0.40	0.86	0.35
MinBid Per Acre (Current\$/a)	69.22	59.77	25.00	0.00	25.00	0.00
MinBid Per Acre (Constant\$/a)	65.69	60.71	17.36	0.61	15.29	0.45
MMS Value (Current\$)	170.46	923.11	48.82	100.24	49.89	85.81
MMS Value (Constant\$)	162.97	906.26	34.06	70.50	30.43	52.45
Viable	0.49	0.50	0.22	0.41	0.42	0.49
Rental Rate	3.38	0.78	5.02	0.21	5.01	0.12
Tracts Offered (1000)	1.78	0.67	1.37	0.27	1.56	0.18
Tracts Bid On	0.30	0.12	0.28	0.14	0.28	0.10
Seismic Coverage	0.24	0.43	1.00	0.00	1.00	0.00
Participants (WD)	91.10	13.06	86.47	15.51	77.83	6.04

⁴³ In this section, the form of high bid analyzed is high bid per acre

Table 5-16. Statistics of Variables For Regression Analysis, By Period, 200-800 meter.

200-800	AM_Only 1983-1995		DWRRA 1996-2000		Post_DW 2001-2003	
	Mean	StDev	Mean	StDev	Mean	StDev
High Bid (Current\$)	2,079,647	5,412,717	935,447	1,387,387	882,879	1,728,601
High Bid Per Acre (Current\$/a)	378.23	985.81	169.62	252.78	154.50	300.15
High Bid Per Acre (Constant\$/a)	364.93	983.80	119.20	178.24	94.92	184.94
Bid Probability	0.16	0.09	0.20	0.09	0.17	0.08
Bids Per Lease	1.41	0.84	1.48	0.93	1.38	0.77
Multiple Bids (0,1)	0.27	0.44	0.29	0.46	0.26	0.44
Re-Leased	0.02	0.14	0.04	0.19	0.03	0.17
HB by Major Bidder (0,1)	0.69	0.46	0.31	0.46	0.17	0.38
HB by Joint Bidder (0,1)	0.37	0.48	0.32	0.47	0.25	0.43
Drainage/Development Lease	0.03	0.18	0.02	0.13	0.00	0.00
Area Block Sequence	1.35	0.55	2.13	0.79	2.71	0.88
Repeat Block	0.31	0.46	0.80	0.40	0.90	0.30
MinBid Per Acre (Current\$/a)	76.71	61.59	25.00	0.00	25.00	0.00
MinBid Per Acre (Constant\$/a)	73.35	62.59	17.52	0.46	15.35	0.43
MMS Value (Current\$)	110.93	235.24	66.99	135.12	75.01	120.90
MMS Value (Constant\$)	104.96	224.42	47.05	95.26	45.99	74.09
Viable	0.36	0.48	0.26	0.44	0.65	0.48
Rental Rate	3.33	0.74	7.49	0.16	7.49	0.14
Tracts Offered (1000)	0.51	0.32	0.41	0.18	0.40	0.18
Tracts Bid On	0.07	0.03	0.07	0.03	0.05	0.01
Seismic Coverage	0.20	0.40	1.00	0.00	1.00	0.00
Participants (WD)	32.69	9.70	47.63	11.40	35.29	2.57

Table 5-17. Statistics of Variables For Regression Analysis, By Period, 800-plus meter.

800+	AM_Only 1983-1995		DWRRA 1996-2000		Post_DW 2001-2003	
	Mean	StDev	Mean	StDev	Mean	StDev
High Bid (Current\$)	653,565	1,060,018	911,677	2,145,670	843,423	2,027,480
High Bid Per Acre (Current\$/a)	114.61	186.41	160.56	382.35	146.73	351.91
High Bid Per Acre (Constant\$/a)	106.54	180.20	112.47	268.73	90.37	218.07
Bid Probability	0.04	0.02	0.15	0.06	0.07	0.02
Bids Per Lease	1.20	0.58	1.46	1.04	1.27	0.62
Multiple Bids (0,1)	0.14	0.35	0.26	0.44	0.20	0.40
Re-Leased	0.00	0.04	0.02	0.13	0.02	0.15
HB by Major Bidder (0,1)	0.86	0.35	0.61	0.49	0.30	0.46
HB by Joint Bidder (0,1)	0.21	0.41	0.30	0.46	0.27	0.45
Drainage/Development Lease	0.00	0.05	0.00	0.06	0.00	0.06
Area Block Sequence	1.09	0.29	1.27	0.48	1.54	0.64
Repeat Block	0.08	0.28	0.25	0.43	0.46	0.50
MinBid Per Acre (Current\$/a)	49.40	49.55	26.44	3.99	37.50	0.00
MinBid Per Acre (Constant\$/a)	46.11	49.66	18.51	2.32	22.93	0.67
MMS Value (Current\$)	51.45	59.71	65.49	159.68	63.87	171.97
MMS Value (Constant\$)	47.92	57.37	45.78	111.30	38.98	103.02
Viable	0.12	0.33	0.16	0.37	0.55	0.50
Rental Rate	3.31	0.73	7.50	0.00	7.50	0.00
Tracts Offered (1000)	3.59	0.63	2.91	0.69	2.21	0.56
Tracts Bid On	0.13	0.08	0.43	0.16	0.15	0.02
Seismic Coverage	0.17	0.38	1.00	0.00	1.00	0.00
Participants (WD)	18.33	6.69	52.91	10.90	31.59	2.51

Correlation Analysis of High Bid Per Acre And Study Variables

The purpose of analysis reported in this section is to identify variables that might be correlated with high bid per acre.

Re-offered After Bid Rejection

The variable *released* is 1 when the block was re-offered for lease after its high bid was rejected in the preceding sale and 0 otherwise. It has a modest yet significant positive correlation with high bid per acre in 0-200 meters and 800-plus meters.

Table 5-18. Correlation of High Bid and Re-offered After Rejection.

Pearson Correlation Coefficients, N = 9346 Prob > r under H0: Rho=0		
0-200 m	HB_ACRE	RELEASED
HB_ACRE	1.00000	0.08896 <.0001
RELEASED	0.08896 <.0001	1.00000
Pearson Correlation Coefficients, N = 2044 Prob > r under H0: Rho=0		
200-800 m	HB_ACRE	RELEASED
HB_ACRE	1.00000	0.02944 0.1833
RELEASED	0.02944 0.1833	1.00000
Pearson Correlation Coefficients, N = 5684 Prob > r under H0: Rho=0		
800-plus m	HB_ACRE	RELEASED
HB_ACRE	1.00000	0.16955 <.0001
RELEASED	0.16955 <.0001	1.00000

Bids Per Tract

The number of bids per tract has a significant positive correlation with high bid per acre in all depth classes, especially in deepwater.

Table 5-19. Correlation of High Bid Per Acre and Bids Per Tract.

Pearson Correlation Coefficients, N = 9346 Prob > r under H0: Rho=0		
0-200 m	HB_ACRE	BIDS
HB_ACRE	1.00000	0.20645 <.0001
BIDS	0.20645 <.0001	1.00000
Pearson Correlation Coefficients, N = 2044 Prob > r under H0: Rho=0		
200-800 m	HB_ACRE	BIDS
HB_ACRE	1.00000	0.32145 <.0001
BIDS	0.32145 <.0001	1.00000
Pearson Correlation Coefficients, N = 5684 Prob > r under H0: Rho=0		
800-plus m	HB_ACRE	BIDS
HB_ACRE	1.00000	0.45173 <.0001
BIDS	0.45173 <.0001	1.00000

High Bid By Major

The correlation of high bid per acre and high bid by major (equals 1 if high bid was made by major, 0 otherwise) is significantly positive in 0-200 meters and 200-800 meters, and significantly negative in 800-plus meters. In theory, negative correlation can occur when major companies bid for tracts in unexplored areas where risk is high and little competition is expected, circumstances that promote bidding at nearly minimum bid level.

Table 5-20. Correlation of High Bid Per Acre and Bids Per Tract.

Pearson Correlation Coefficients, N = 9346 Prob > r under H0: Rho=0		
0-200 m	HB_ACRE	HBMAJOR
HB_ACRE	1.00000	0.11475 <.0001
HBMAJOR	0.11475 <.0001	1.00000
Pearson Correlation Coefficients, N = 2044 Prob > r under H0: Rho=0		
200-800 m	HB_ACRE	HBMAJOR
HB_ACRE	1.00000	0.08797 <.0001
HBMAJOR	0.08797 <.0001	1.00000
Pearson Correlation Coefficients, N = 5684 Prob > r under H0: Rho=0		
800-plus m	HB_ACRE	HBMAJOR
HB_ACRE	1.00000	-0.10395 <.0001
HBMAJOR	-0.10395 <.0001	1.00000

High Bid By Joint Bidders

The correlation of high bid by joint bidders (equals 1 if high bid was made by joint bidders, 0 otherwise) and high bid per acre is significantly positive in all depths.

Table 5-21. Correlation of High Bid and High Bid By Joint Bidders.

Pearson Correlation Coefficients, N = 9346 Prob > r under H0: Rho=0		
0-200 m	HB_ACRE	HBJOINT
HB_ACRE	1.00000	0.12502 <.0001
HBJOINT	0.12502 <.0001	1.00000
Pearson Correlation Coefficients, N = 2044 Prob > r under H0: Rho=0		
300-800 m	HB_ACRE	HBJOINT
HB_ACRE	1.00000	0.15661 <.0001
HBJOINT	0.15661 <.0001	1.00000
Pearson Correlation Coefficients, N = 5684 Prob > r under H0: Rho=0		
800-plus m	HB_ACRE	HBJOINT
HB_ACRE	1.00000	0.12297 <.0001
HBJOINT	0.12297 <.0001	1.00000

Water Depth

Aggregating data for all water depth classes, there is a significant negative correlation between high bid per acre and water depth.

Table 5-22. Correlation of High Bid and Water Depth.

Pearson Correlation Coefficients, N = 17074 Prob > r under H0: Rho=0		
All Depths	HB_ACRE	WATER_DEPTH
HB_ACRE	1.00000	-0.07378 <.0001
WATER_DEPTH	-0.07378 <.0001	1.00000

Drainage and Development (DD)

The correlation of drainage and development status of a tract (equals 1 if it is DD, 0 otherwise) and high bid per acre is significantly positive in 0-200 meters and 800-plus meters.

Table 5-23. Correlation of High Bid and Drainage and Development.

Pearson Correlation Coefficients, N = 9346 Prob > r under H0: Rho=0		
0-200 m	HB_ACRE	DD
HB_ACRE	1.00000	0.11485 <.0001
DD	0.11485 <.0001	1.00000
Pearson Correlation Coefficients, N = 2044 Prob > r under H0: Rho=0		
200-800 m	HB_ACRE	DD
HB_ACRE	1.00000	0.00416 0.8510
DD	0.00416 0.8510	1.00000
Pearson Correlation Coefficients, N = 5684 Prob > r under H0: Rho=0		
800-plus m	HB_ACRE	DD
HB_ACRE	1.00000	0.04366 0.0010
DD	0.04366 0.0010	1.00000

Number of Times Leased (Area_blk_seq)

Area_blk_seq equals the number of times (1 or more including the current offering) a block has been leased. Its correlation with high bid is significantly negative in 0-200 meters and 200-800 meters, and it is significantly positive in 800-plus meters. A factor that promotes a negative relation is that most previously leased tracts in shallow water become available because the earlier information discouraged drilling or development at that time. A factor that promotes a positive relation in deepwater frontier areas is that large inventories were purchased, and a number of leases expired without drilling because the lessee simply could not work at so many locations at once.

Table 5-24. Correlation of High Bid and Number of Times Leased.

Pearson Correlation Coefficients, N = 9346		
Prob > r under H0: Rho=0		
0-200 m	HB_ACRE	AREA_BLK_SEQ
HB_ACRE	1.00000	-0.10604 <.0001
AREA_BLK_SEQ	-0.10604 <.0001	1.00000
Pearson Correlation Coefficients, N = 2044		
Prob > r under H0: Rho=0		
200-800 m	HB_ACRE	AREA_BLK_SEQ
HB_ACRE	1.00000	-0.12902 <.0001
AREA_BLK_SEQ	-0.12902 <.0001	1.00000
Pearson Correlation Coefficients, N = 5684		
Prob > r under H0: Rho=0		
800-plus m	HB_ACRE	AREA_BLK_SEQ
HB_ACRE	1.00000	0.19543 <.0001
AREA_BLK_SEQ	0.19543 <.0001	1.00000

Viability and MMS Value

Viability equals 1 if a tract is deemed viable by MMS, 0 otherwise. Viability is an indicator of underlying value or prospectiveness. It is expected that viability is correlated with high bid because:

- If a tract was nonviable, usually the bid is near minimum level.
- If it was viable, the bid is more likely to range above minimum level
- Regarding the mass of bids near minimum level, it is possible that the low bids at viable tracts tend to be somewhat higher than low bids at nonviable tracts, although one has less confidence in this expectation.

Thus, viability to some degree expresses underlying tendency to receive bids substantially above minimum. This is a useful property that slightly corrects for the problem that the high bid data are truncated. The MMS value is a different type of indicator of underlying

value than viability. MMS value is equated to minimum bid when the tract is deemed nonviable, when it is deemed viable in phase 1, and when it is viable and accepted under the 3-bid rule in phase 1. Only the minority of tracts deemed viable by a phase 2 evaluation might be given a value other than minimum bid. An advantage of MMS value over viability as an indicator of underlying tract value is that MMS values cover a range of money values whereas viability is (0,1). One disadvantage of MMS value is that, given that a tract has MMS value equal to minimum bid, one cannot infer whether it is viable or not; instead, MMS value data are truncated and censored, even more than the high bid data.

However, serious and fatal problems prevent using these variables in the regression model for high bid:

- The ultimate purpose of the regression model is to show how the policy affected high bids. Although it is not a direct subject for this study, it can be presumed that the policy also was reflected MMS value. Phase 2 evaluation, especially, was done with tract-specific economic analysis that increased predicted profitability of blocks due to royalty relief. Obviously, if MMS value is a regressor alongside the dummy, then MMS value is picking up much of the effect of the policy, and the dummy is representing only a remaining set of policy effects.
- Viability might be viewed as a better choice insofar as the viability determination would, mostly, not have been directly influenced by the policy – the exception being a minor set of blocks that are marginal prospects and change from nonviable to viable due to the policy. Anticipating material given later in this chapter, viability performed poorly in the regression model. In all water depths, its estimated coefficient had a negative sign in trial 2SLS regressions. The negative sign is contradicted by the positive correlation shown below. Therefore viability was dropped from the high bid model.

Turning to the correlations, viability has a significant positive correlation with high bid in all water depth classes. MMS value, too, has a significant positive correlation with high bid in all water depth. Its correlation is greater than that of viability, as would be expected: viability is a (0,1) variable whereas MMS value is in money units. In the table for MMS value, note that the number of observations is slightly reduced due to missing values.

Table 5-25. Correlation of High Bid and Viability.

Pearson Correlation Coefficients, N = 9346 Prob > r under H0: Rho=0		
0-200 m	HB_ACRE	VIABLE
HB_ACRE	1.00000	0.11068 <.0001
VIABLE	0.11068 <.0001	1.00000
Pearson Correlation Coefficients, N = 2044 Prob > r under H0: Rho=0		
200-800 m	HB_ACRE	VIABLE
HB_ACRE	1.00000	0.12704 <.0001
VIABLE	0.12704 <.0001	1.00000
Pearson Correlation Coefficients, N = 5684 Prob > r under H0: Rho=0		
800-plus m	HB_ACRE	VIABLE
HB_ACRE	1.00000	0.27315 <.0001
VIABLE	0.27315 <.0001	1.00000

Table 5-26. Correlation of High Bid and MMS Value.

Pearson Correlation Coefficients Prob > r under H0: Rho=0 Number of Observations		
0-200 m	HB_ACRE	MMS_VAL
HB_ACRE	1.00000 9346	0.54150 <.0001 8777
MMS_VAL	0.54150 <.0001 8777	1.00000 8777
Pearson Correlation Coefficients Prob > r under H0: Rho=0 Number of Observations		
200-800 m	HB_ACRE	MMS_VAL
HB_ACRE	1.00000 2044	0.16834 <.0001 1987
MMS_VAL	0.16834 <.0001 1987	1.00000 1987
Pearson Correlation Coefficients Prob > r under H0: Rho=0 Number of Observations		
800-plus m	HB_ACRE	MMS_VAL
HB_ACRE	1.00000 5684	0.49557 <.0001 5540
MMS_VAL	0.49557 <.0001 5540	1.00000 5540

Minimum Bid

Minimum bid per acre is expected to have a large positive effect because, as a generality, a large proportion of high bids lies near the minimum level. The minimum bid levels for sales covered by the data for this study were:

- 1983-1987 \$150/acre
- 1988-1999 \$25/acre
- 2000-2003 Same in less than 800 meters, \$37.50/acre in 800-plus meters

The correlation was significantly positive in all water depths. Note that high correlation might be due to a drop in minimum bid in 1988 that was contemporaneous with a decline of high bid due to other factors starting in 1983.

Table 5-27. Correlation of High Bid and Minimum Bid.

Pearson Correlation Coefficients, N = 9346 Prob > r under H0: Rho=0		
0-200 m	HB_ACRE	MINBID_ACRE
HB_ACRE	1.00000	0.30695 <.0001
MINBID_ACRE	0.30695 <.0001	1.00000
Pearson Correlation Coefficients, N = 2044 Prob > r under H0: Rho=0		
200-800 m	HB_ACRE	MINBID_ACRE
HB_ACRE	1.00000	0.33867 <.0001
MINBID_ACRE	0.33867 <.0001	1.00000
Pearson Correlation Coefficients, N = 5684 Prob > r under H0: Rho=0		
800-plus m	HB_ACRE	MINBID_ACRE
HB_ACRE	1.00000	0.13007 <.0001
MINBID_ACRE	0.13007 <.0001	1.00000

Rental Rate

The pre-production rental rate during the study period was:

0-200 m

1983-August 1993 \$3/acre
September 1993-2003 \$5/acre

200-800 meter and 800-plus m

1983-August 1993 \$3/acre
September 1993-1995 \$5/acre
1996-2003 \$7.50/acre

Since the rental rate is a cost, one expects higher rental to be negatively related to high bid. The correlations display negative correlation for 0-200 meters and 200-800 meters, but not 800-plus meters.

Table 5-28. Correlation of High Bid and Rental Rate.

Pearson Correlation Coefficients, N = 9346		
Prob > r under H0: Rho=0		
0-200 m	HB_ACRE	RENTAL_RATE
HB_ACRE	1.00000	-0.16568 <.0001
RENTAL_RATE	-0.16568 <.0001	1.00000
Pearson Correlation Coefficients, N = 2044		
Prob > r under H0: Rho=0		
200-800 m	HB_ACRE	RENTAL_RATE
HB_ACRE	1.00000	-0.16287 <.0001
RENTAL_RATE	-0.16287 <.0001	1.00000
Pearson Correlation Coefficients, N = 5684		
Prob > r under H0: Rho=0		
800-plus m	HB_ACRE	RENTAL_RATE
HB_ACRE	1.00000	0.04837 0.0003
RENTAL_RATE	0.04837 0.0003	1.00000

3-D Seismic

3-D seismic coverage aggregated by water depth might be expected to increase bid levels by reducing risk and helping to locate prospects. (A tract-specific variable for 3-D coverage is not available.) However, the correlations do not capture that particular effect. Instead, for 0-200 meters and 200-800 meters, the rise in seismic coverage is cotemporaneous with an overall fall in high bid levels. To some extent, in regression models, seismic coverage functions as a time trend variable.

Table 5-29. Correlation of High Bid and 3-D Seismic.

Pearson Correlation Coefficients, N = 9346 Prob > r under H0: Rho=0		
0-200 m	HB_ACRE	SEISMIC
HB_ACRE	1.00000	-0.18291 <.0001
SEISMIC	-0.18291 <.0001	1.00000
Pearson Correlation Coefficients, N = 2044 Prob > r under H0: Rho=0		
200-800 m	HB_ACRE	SEISMIC
HB_ACRE	1.00000	-0.19618 <.0001
SEISMIC	-0.19618 <.0001	1.00000
Pearson Correlation Coefficients, N = 5684 Prob > r under H0: Rho=0		
800-plus m	HB_ACRE	SEISMIC
HB_ACRE	1.00000	0.02674 0.0438
SEISMIC	0.02674 0.0438	1.00000

Sale Date

A time trend variable indicates that average high bid per acre fell overall, 1983-2003, in 0-200 meters and 200-800 meters and rose slightly overall in 800-plus meters.

Tracts Offered and Tracts Bid On

Since there was an overall decline over time in the number of tracts offered in 0-200 meters and 200-800 meters, the correlation is positive in those cases. For 800-plus meters, the correlation is negative, partly due to the precise timing of peaks and declines for the variables in the DWRRA period. That is, the rise in high bid occurred just after the peak in lease buying that reduced subsequent tract offering. Correlations of high bid per acre and tracts bid on by depth class display similar results, for the same reasons.

Table 5-30. Correlation of High Bid and Tracts Offered.

Pearson Correlation Coefficients, N = 9346		
Prob > r under H0: Rho=0		
0-200 m	HB_ACRE	TRACTS_OFFER
HB_ACRE	1.00000	0.20488 <.0001
TRACTS_OFFER	0.20488 <.0001	1.00000
Pearson Correlation Coefficients, N = 2044		
Prob > r under H0: Rho=0		
200-800 m	HB_ACRE	TRACTS_OFFER
HB_ACRE	1.00000	0.06283 0.0045
TRACTS_OFFER	0.06283 0.0045	1.00000
Pearson Correlation Coefficients, N = 5684		
Prob > r under H0: Rho=0		
800-plus m	HB_ACRE	TRACTS_OFFER
HB_ACRE	1.00000	-0.04481 0.0007
TRACTS_OFFER	-0.04481 0.0007	1.00000

Probability of a Bid

The (sale-by-sale) probability of a tract in a given depth class receiving any bids is computed as the ratio of tracts bid on to tracts offered, sale by sale. (For emphasis, note that this is not a tract-specific probability.) Only for 200-800 meters is the correlation with high bid per acre significant, and in that instance, it is positive.

Table 5-31. Correlation of High Bid and Probability of a Bid.

Pearson Correlation Coefficients, N = 9346 Prob > r under H0: Rho=0		
0-200 m	HB_ACRE	ProbBid
HB_ACRE	1.00000	0.01375 0.1837
ProbBid	0.01375 0.1837	1.00000
Pearson Correlation Coefficients, N = 2044 Prob > r under H0: Rho=0		
200-800 m	HB_ACRE	ProbBid
HB_ACRE	1.00000	0.14796 <.0001
ProbBid	0.14796 <.0001	1.00000
Pearson Correlation Coefficients, N = 5684 Prob > r under H0: Rho=0		
800-plus m	HB_ACRE	ProbBid
HB_ACRE	1.00000	0.01203 0.3643
ProbBid	0.01203 0.3643	1.00000

Oil Price

Oil price has a significant positive correlation with high bid per acre.

Table 5-32. Correlation of High Bid and Oil Price.

Pearson Correlation Coefficients, N = 9346 Prob > r under H0: Rho=0		
0-200 m	HB_ACRE	OIL_PRICE
HB_ACRE	1.00000	0.17814 <.0001
OIL_PRICE	0.17814 <.0001	1.00000
Pearson Correlation Coefficients, N = 2044 Prob > r under H0: Rho=0		
200-800 m	HB_ACRE	OIL_PRICE
HB_ACRE	1.00000	0.23743 <.0001
OIL_PRICE	0.23743 <.0001	1.00000
Pearson Correlation Coefficients, N = 5684 Prob > r under H0: Rho=0		
800-plus m	HB_ACRE	OIL_PRICE
HB_ACRE	1.00000	0.06077 <.0001
OIL_PRICE	0.06077 <.0001	1.00000

Participants

The number of participants by sale and water depth class is significantly correlated with high bid. Participants in this table relate to both areas combined (instead of each area separately). Anticipating later sections of this chapter, participants were not included in regression models because it is, itself, directly affected by the policy.

Table 5-33. Correlation of High Bid and Participants (Both Areas).

Pearson Correlation Coefficients, N = 9346 Prob > r under H0: Rho=0		
0-200 m	HB_ACRE	PARTICIPANTS
HB_ACRE	1.00000	0.08189 <.0001
PARTICIPANTS	0.08189 <.0001	1.00000
Pearson Correlation Coefficients, N = 2044 Prob > r under H0: Rho=0		
200-800 m	HB_ACRE	PARTICIPANTS
HB_ACRE	1.00000	0.16436 <.0001
PARTICIPANTS	0.16436 <.0001	1.00000
Pearson Correlation Coefficients, N = 5684 Prob > r under H0: Rho=0		
800-plus m	HB_ACRE	PARTICIPANTS
HB_ACRE	1.00000	0.09228 <.0001
PARTICIPANTS	0.09228 <.0001	1.00000

Theoretical Model of High Bid Determination

According to the common-value bidding model under uncertainty, if bidders were certain about the quality of an item being offered at auction, they would value it the same. Thus, the value of a known amount of oil and gas is approximately the same to any businessman. Under uncertainty, however, people arrive at different estimates of the value of the item, e.g., if the potential amount of oil or gas is uncertain, people arrive at different estimates of the amount. In the oil literature, specifically, it is assumed that, when a number of persons make separate estimates, based partly on public information, of the expected tract value, then their estimates have a shifted lognormal distribution. Option value might be added to estimated NPV, especially when the estimated NPV is close to zero or is negative. In that way, any negative probability mass of the tract value is moved to zero or to the positive range; and the transformed distribution might be a different lognormal function or some other function.

.According to the bidding model, bidders are conscious of the uncertainty of value estimates and try to take this feature into account in order to envisage what other bids would be made for the lease and, further, to reduce the risk of having over-valued it themselves. In arriving at an optimal bid amount, the estimated value is discounted. The extent of discount

depends on, among other things, the bidder's estimate of the evaluation distribution and the bidder's expectation of the number and level of competing bids. Another factor is the minimum bid of the auction. If a bidder initially desires to bid less than that, in theory at least, he would not bid. Viewed from the perspective of analyzing the bids received for a given lease, the high bid for a tract and the number of bids received are co-determined.

We now proceed to explain and apply the theoretical bidding model to cases that are based on observed facts but without using econometric methods. After that, the chapter returns to econometric issues.

Bidding Model with Bid Rejection

The bidding model implies that bidders, even in the presence of competition, will rationally tend to bid less than the true value they believe the tract to have. Thus any increment to true value due to royalty relief will be discounted, perhaps heavily. In view of the importance of this implication, this study examined the bidding model extensively. Also, the possible influence on optimal bidding of the MMS bid adequacy process was carefully examined.

Capen et al. Model

The bidding model is based on the decision-theoretic simulation model first described by Capen et al. (1971). The Capen et al. model takes an omniscient point of view of a single bidder competing for a tract of uncertain value against uncertain competition. The point of view is omniscient in that the model "knows" the true value to the bidder of what is being sold.⁴⁴ According to the model of common-value with uncertainty, the bidder's value estimate of the tract is randomly drawn from a known, unbiased, log-normally distributed error distribution.

The bidder's strategy is characterized as simply a fraction of her estimate. The model assumes that the bidder makes an estimate of the potential competition. For each competitor, she assigns a probability to its bidding, a probability distribution of its value estimate drawn from the same log-normally distributed value distribution, and a deterministic or random distribution of its proportional bidding strategy. The model includes a Monte Carlo simulation of the auction and calculates the bidder's expected gain or loss for a wide range of bidding fractions. From the simulation results, the fraction that produces the highest expected return is identified. The model allows for the "winner's curse" phenomenon caused by competition for a tract of uncertain value.

A simple illustration follows: suppose a bidder estimates the expected underlying value of a block to have a net present value of \$10 million. By the basic theory of rent and auctions, the bidder is willing to bid up to that amount to win the lease. However, if the lease can be won at a lower bid, say \$1 million, then the bidder would retain the difference as profit (in this instance, \$9 million). However, if the bid is too low and another firm wins the lease with a higher bid, then there is a loss of \$10 million (ignoring the possibility of substituting another block of equal net value). The bid fraction is the fraction of underlying value that is bid; in this

⁴⁴ Usually, that value is normalized to one. Thus, gains and losses are expressed as fractions of this true but unknown value.

example, \$1 million/\$10 million equals 0.10 bid fraction. In the common-value model with uncertainty, the underlying value estimate is uncertain and, importantly, correlated with competitor's estimates. The person who produces the highest estimate of the block value has, with a certain probability, estimated higher than the true value. That is the "winner's curse." The rational way to handle this risk is to reduce the bid fraction. Therefore, the optimal bid fraction is arrived at by combining and weighing several considerations: uncertainty about underlying value, chance of competition, and how competitors might bid.

MMS Policies Examined

We examine three kinds of MMS policies in this model. First of all, deepwater royalty relief is reflected in the true value distribution of the tract. Thus, if royalty relief adds 10 percent to the expected value of a tract, that 10 percent is reflected in the value estimated by each potential bidder for the tract.⁴⁵

The second MMS policy included in the model (apparently this is novel) is the MMS's bid adequacy process. MMS is modeled as another bidder, except that it is a bidder whose likelihood of participation evidently is correlated with the number and levels of other bids received for a given tract. The MMS is modeled as applying its own bid fraction, and this fraction can be made to depend upon the other bids.

The third MMS policy is the minimum bid. This policy is the most difficult to include in the model. The reason for the difficulty is that the entire model structure assumes proportionality and, thus, scale independence. However, the minimum bid per acre is fixed in dollar terms, and, thus, scale-dependent. When the tract value is substantially higher than the minimum bid per acre, this minimum will clearly be of little consequence. However, many high bids lie near the minimum bid.

The MMS bid adequacy process involves a number of steps and criteria. The performance of the process, in terms of the principle rules applied, in recent sales is presented in the next table. The rules that are referred to in this table are:

Phase 1 Nonviable: High bid is accepted if the tract is nonviable according to MMS examination mainly of geologic potential.

Phase 1 3-Bid: High bid is accepted if there are 3 or more bids for the tract, subject to a certain condition about the dispersion of the bids.

Refer to Phase 2: If not accepted in phase 1, the high bid is passed to phase 2. Also, all drainage and development tracts are passed to phase 2.

Phase 2 Nonviable: High bid is accepted if MMS economic evaluation indicates the block would be unprofitable.

⁴⁵ The model is still usually normalized by the true value, while keeping track of the fact that a fraction of that true value is due to royalty relief.

Phase 2 ADV: High bid is accepted if it exceeds the MMS estimated value of the block.

Phase 2 RAM: High bid is accepted if it falls below the MMS estimated value of the block but exceeds a certain average of the MMS estimated value and the bids received.

As the data in Table 5-34 show, about 87 percent of the high bids in this period were accepted because MMS deemed the tracts nonviable (24 percent in phase 1 and 63 percent in phase 2). About 10 percent were accepted by the economic evaluation in phase 2. Other rules accepted a small number of high bids, and about 2 percent were rejected.

Table 5-34. Bid Adequacy Results, 2002-2003.

				Phase 1	%	Phase 1	%
Year	Sale	Area	Tracts Bid On	Accept Non-viable	Non-viable	Accept 3-Bid	3-Bid
2002	182	CGOM	506	182	36.0%	2	0.4%
2002	184	WGOM	323	72	22.3%	0	0.0%
2003	185	CGOM	561	123	21.9%	10	1.8%
2003	187	WGOM	335	40	11.9%	1	0.3%
		Total	1725	417	24.2%	13	0.8%

				Phase 2	%	Phase 2	%
Year	Sale	Area		Accept Non-viable	Non-viable	Accept HB > ADV	HB > ADV
2002	182	CGOM		261	51.6%	41	8.1%
2002	184	WGOM		203	62.9%	40	12.4%
2003	185	CGOM		362	64.5%	50	8.9%
2003	187	WGOM		254	75.8%	35	10.5%
		Total		1080	62.6%	166	9.6%

				Phase 2	%		%
Year	Sale	Area		Accept HB > RAM	HB > RAM	Reject	Reject
2002	182	CGOM		5	1.0%	15	3.0%
2002	184	WGOM		1	0.3%	7	2.2%
2003	185	CGOM		0	0.0%	16	2.9%
2003	187	WGOM		0	0.0%	5	1.5%
		Total		6	0.4%	43	2.5%

Simulations Using Bidding Model

First we construct the bidding model to be consistent with the Capen et al. model. Implementing the same methodology and using the Capen et al. assumptions, we duplicated their

results. These results are shown in the next figure and table. An iterative calculation yielded the optimal bid fraction, the expected present worth, and the average winning tract value at each of bid level. In the example, the optimum bid fraction is approximately 0.3.

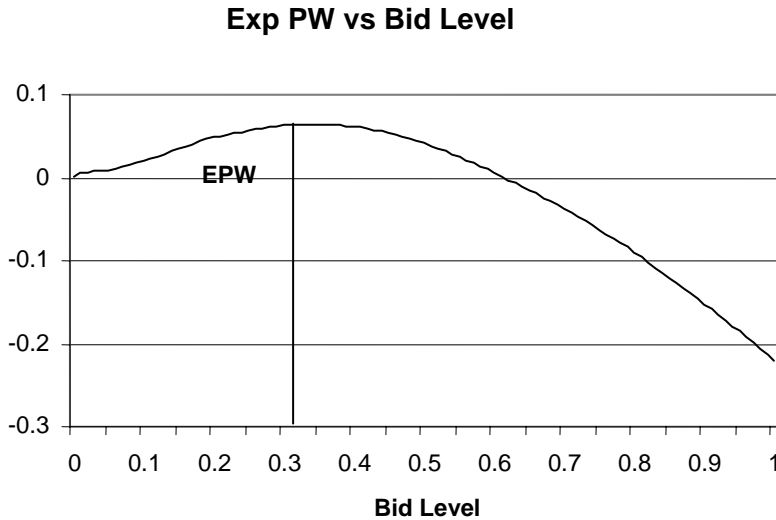


Figure 5-6. Net Worth From Bid at Various Bid Fractions, Capen Case.

Table 5-35. Net Worth From Bid At Various Bid Fractions, Capen Case.

Bidding Level	Probability of Winning	Expected PW	Avg Winning Tract Value to True Value
0.0	0.00	0.000	0.000
0.1	0.00	0.020	2.860
0.2	0.01	0.049	2.357
0.3	0.02	0.063	2.070
0.4	0.02	0.062	1.858
0.5	0.03	0.041	1.731
0.6	0.04	0.006	1.639
0.7	0.04	-0.037	1.555
0.8	0.05	-0.090	1.490
0.9	0.05	-0.152	1.440
1.0	0.06	-0.220	1.399
1.1	0.06	-0.293	1.361
1.2	0.06	-0.369	1.331
1.3	0.06	-0.449	1.302
1.4	0.07	-0.533	1.280
1.5	0.07	-0.617	1.256

The next step was to include the MMS policies described above. First, royalty relief was modeled by adjusting the tract value. To view the effects of royalty relief on bidding behavior, the bidding model was run with and without royalty relief. The first step in developing the model was to assume potential competition. Competition by a Poisson distribution with mean equal to 2 represented tracts that are expected to have competition (recognizing that most tracts actually have only one bid). The model was run repeated to find a bid fraction and bid variance shared by competitors, establishing a uniform set of expectations. This established the non-royalty relief equilibrium. Next, to include royalty relief, the simulation raised the mean of the normal distribution of the natural log of the bid, to simulate the expected increase in tract value due to royalty relief. That is, the policy changed the tract evaluation distribution. Raising the mean of the normal distribution from 0 to 0.05 simulated a 5.5 percent increase in perceived tract value.

The bidding model results are displayed below in Table 5-36. The inclusion of royalty relief had no effect on the optimal bid fraction, although it will tend to change optimal expected value and average tract value to true value at the optimal bid fraction. Intuitively, it is expected that the optimal expected value would rise, since tract value increased with royalty relief. What is more interesting, and relevant, is that the optimal bid fraction did not change. Instead, bidders are discounting the value of royalty relief consistent with the optimal bid fraction. The optimal bid fraction remained 0.28 with royalty relief, same as without it. If the tract value is increased by X percent, then bidders should only increase the value of the bid by 0.28 of X percent, thereby not increasing the bid dollar for dollar with royalty relief.

Table 5-36. Results of Bidding Model With Royalty Relief.

<u>Variable</u>	<u>Without Relief</u>	<u>With Relief</u>
Our Bid Variance	0.75	0.75
Opponent Bid Variance	0.75	0.75
Opponent Bid Fraction	0.28	0.28
Optimal Bid Fraction	0.28	0.28
Optimal Expected Value	0.236	0.25
Average Tract Value to True Value at Optimum	1.53	1.62

Number of Opponents Defined by Poisson Distribution of Mean 2.0

In reality, the implementation of the DWRRA had significant effects on the average high bid. We attempted to contrast the differences between observed bidding behavior with what one would expect from the bidding model. This was extremely difficult to do, simply because it required an estimate of the true value of the tract. Furthermore, even if one assumed a true tract value, it was difficult to establish the competitors' bid fractions, because it required some knowledge of their tract value estimate. What this means is that it was infeasible within the scope of this study to attempt a large-scale validation of the bidding model with actual sale data. Also in marginal cases, royalty relief can turn a block with little or no value into a profitable one, attracting bids where none would be made otherwise.

The second policy consideration was bid rejection, specifically the way that bid rejection can make the MMS act as a potential competitor in typically high-value tracts. Initially, the focus is on high-value, single-bid tracts. An analysis of single-bid leases for sales 113-185 shows that there is roughly a 5-8 percent chance of MMS performing an evaluation that leads to determining a value higher than the minimum bid.⁴⁶ Tables 5-37 and 5-38 present the results of the analysis of bidding and evaluation for sales 113-185 that lead to this finding.

Table 5-37. Percent of Bids Evaluated With MMS Value Above Minimum.

Water Depth	Total Bids	Evaluations	%Evaluated
<200m	4457	317	7.11%
200-800m	1068	87	8.15%
>800m	3806	192	5.04%
Total	9331	596	6.39%

Analysis of Sales 113-185

Table 5-38. Percent Evaluated Versus Level of High Bid.

Minimum	Maximum	Count	Evaluated	Won	Percent Evaluated	Percent Won	Rejection Rate
1	1.99	5444	192	22	3.53%	11.46%	3.12%
2	2.99	1560	80	24	5.13%	30.00%	3.59%
3	3.99	713	42	18	5.89%	42.86%	3.37%
4	4.99	395	39	18	9.87%	46.15%	5.32%
5	Higher	1219	243	200	19.93%	82.30%	3.53%
2 and Higher		3887	404	260	10.39%	64.36%	3.70%

Analysis of Sales 113-185

For the single-bid, high-value tract, the probability that the MMS will have a significant evaluation was estimated. As shown above, the chance of evaluation becomes slightly higher, the greater the single bid is above the minimum bid. To start, the chance of evaluation from the MMS is assumed to be 10 percent. It is assumed that the MMS evaluation implicitly reflects a bid fraction that is relative to true value plus or minus an error term. This treatment allows the model to be flexible about where MMS's evaluation will typically result. It would be implausible to assume that the MMS evaluation equates to the true underlying value, since that would lead to high rejection rates, close to 100 percent, and not the low rejection rates revealed by the data.

⁴⁶ It is important to note that this 5-8 percent figure does not represent the overall probability of an MMS evaluation, rather MMS evaluations that lie above the minimum bid per acre. In the single-bid, high value scenario, the minimum bid is of little consequence, and we focus primarily on the chance of a significant evaluation.

Setting the MMS evaluation probability, value and error term, the model can compute how the bidder's optimal strategy changes due to changes in the MMS variables. Table 5-39 presents a sensitivity analysis in the single-bid, high tract value bidding model that includes MMS participation. To explain the table, in scenario 1, there is a 10 percent chance of evaluation. When an evaluation is performed, it yields a value equal to 0.1 of true theoretical tract value plus or minus 40 percent. In this scenario, it turned out that the bidder's optimal bid fraction is 0.01, that is, the model is instructing him to bid the minimal amount and cede the approximately 10 percent of evaluated tracts (numbering 9,857 of total 100,000 tracts in the Monte Carlo simulation) to the MMS.

In scenario 2, the probability of evaluation is 30 percent. The bidding model now dictates an optimal bid fraction of 0.13, suggesting it is more beneficial to compete with the MMS and not simply cede the (30,000 of 100,000) tracts the MMS evaluates. However, this is a phenomenon with a limited threshold, only observed at low bid fractions. Even with these assumptions, the difference in expected value at bid fractions of 0.01 and 0.13 is only 0.022, and it appears that MMS participation is not a major driving force behind bidding levels.

Table 5-39. Bidder's Optimal Strategy Versus MMS Bid Adequacy Scenarios, Single-Bid Case.

	Scenario			
	1	2	3	4
Bid Variance	0.75	0.75	0.75	0.75
MMS Evaluation Probability	10%	30%	10%	30%
MMS Evaluation Value	0.10	0.10	0.30	0.30
MMS Evaluation Error Term	40%	40%	40%	40%
MMS Evaluations	9,869	30,008	9,943	29,957
MMS "Wins" at Optimum	9,857	16,510	9,943	29,957
Optimal Bid Fraction	0.01	0.13	0.01	0.01
Optimal Expected Value	0.89	0.71	0.89	0.69
Average Tract Value to True Value at Optimum	1.00	1.12	1.00	1.00

In scenario 3, the MMS evaluation probability reverts to 10 percent, while the evaluation value is 0.3 times the true tract value. The bidder's optimal bid fraction is similar to that for scenario 1. The best course of action is to bid the minimum bid, and not compete with the MMS for the (roughly 10,000 of 100,000) evaluated tracts.

Finally, in scenario 4, the MMS evaluation probability is raised again to 30 percent while keeping the evaluation value at 0.3. Counterintuitively, the threshold for the observed phenomenon in scenario 2 is here an important element. Instead of increasing, the bidding model dictates an optimum bid level of 0.01. There is a decrease in the expected value compared with scenario 3, as the bidder is ceding more tracts to the MMS.

Thus within the range of scenarios considered, MMS is not generally a strong source of competition. One implication is that the reason for the high bid in this case must be, in many

instances, because of potential competition from other firms; without potential bids from other firm, the optimal bid often ought not to be at a high level at all but instead the minimum.

The single-bid, high-value tract analysis can be extended to consider a hypothetical case. While the historical data has shown that the probability of a significant evaluation is seemingly small, the bid model can be used to address the question: what would happen to the optimal bid fraction if the MMS performed evaluations 100 percent of the time? The results are presented in Table 5-40, where scenario 5 represents the inclusion of a significant MMS evaluation for each tract. For reference, we include scenario 4. Now, the assurance of the MMS as a competitor leads the firm away from a 0.01 optimal bid fraction, increasing it to 0.42. We observe a corresponding decrease in the optimal economics, and an increase in the average winning tract value to true value ratio. The increase in the optimal bid fraction is consistent with what one would expect to observe in a sale with increased competition. We now turn our attention to bidding model results associated with higher levels of competition.

Table 5-40. Bidder’s Optimal Strategy When MMS Evaluates Every Tract, Single Bid Case.

Bidding Model Results for Single-Bid, High-Value Tracts with Complete MMS Participation	Scenario	
	4	5
Bid Variance	0.75	0.75
MMS Evaluation Probability	30%	100%
MMS Evaluation Value	0.30	0.30
MMS Evaluation Error Term	40%	40%
MMS Evaluations	29,957	100,000
MMS "Wins" at Optimum	29,957	51,631
Optimal Bid Fraction	0.01	0.42
Optimal Expected Value	0.69	0.15
Average Tract Value to True Value at Optimum	1.00	1.65

Next, we examined multiple bid tracts where there is substantial competition from other bidders. Although the MMS does not appear to be the primary source of competition on high-value tracts, for completeness the analysis looks at any effect MMS participation would have on bidding behavior in multiple bid tracts. Again, the focus is on high-value tracts, steering clear of the minimum bid per acre to maintain the scale independence of the bidding model. In multiple bid scenarios, the simulation attempted to include representation of the bid adequacy rules to address the probability and evaluation value of the MMS participation. Thus, a Monte Carlo iteration with three or more bidders would not receive an evaluation, leaving it to the 3-bid rule, and any iteration with one bidder would follow the same logic as the single-bid, high-value scenarios. In the case of two bidders, the effect of bid adequacy rules was approximated by averaging the simulated MMS value and the maximum competitive bid. We tested the sensitivity of the bidding model to changes in the level of MMS participation in high-value, two-bid tracts with assured competition as shown in Table 5-41.

Table 5-41. Bidder's Optimal Strategy Versus MMS Bid Adequacy Scenarios, Two Bid Case.

	Bidding Model Results for Two-Bid (Assured Competition), High-Value Tracts				
	Scenario				
	1	2	3	4	5
Bid Variance	0.75	0.75	0.75	0.75	0.75
Opponent Bid Variance	0.75	0.75	0.75	0.75	0.75
Opponent Bid Fraction	0.33	0.33	0.33	0.33	0.33
MMS Evaluation Probability	n/a	20%	20%	50%	50%
MMS Evaluation Value	n/a	0.25	0.50	0.25	0.50
MMS Evaluation Error Term	n/a	40%	40%	40%	40%
MMS Evaluations	n/a	20,101	20,005	49,934	49,972
MMS "Wins" at Optimum	n/a	4,553	11,215	10,876	26,870
Optimal Bid Fraction	0.33	0.33	0.33	0.35	0.35
Optimal Expected Value	0.26	0.25	0.22	0.23	0.17
Average Tract Value to True Value at Optimum	1.46	1.50	1.54	1.52	1.66

For reference only, a scenario with no MMS presence was included as scenario 1. Without MMS presence, the optimal bid fraction is 0.33, and the optimal expected value is 0.26. This optimal bid fraction represents equilibrium with the one opponent, who is also bidding with a fraction of 0.33. In the other scenarios, the MMS plays a role as a potential competitor, with various probabilities. Despite seemingly large variation of MMS valuation assumptions, the differences among scenarios 2 to 5 in the bidder's optimal bid fraction are relatively minor. Instead, it is the presence of an assured competing firm that raises the optimal bid fraction from the minimal level of most single-bid tract scenarios.

Thus far, the cases have been deterministic in the sense they specify the number of competitors (0 or 1). The model can randomize competition, defined by a Poisson distribution of mean 1.0. As the model iterates, the number of competitors is selected from the Poisson distribution, capping the number of competitors at 14 (or some other number). When implementing competition defined by a Poisson mean, a low mean is specified, consistent with findings given in Chapter 4. For this analysis, the bidding model does not include MMS bid rejection. The results are presented in Table 5-41. As can be seen whether MMS serves as a potential "bidder" makes almost no difference in the bidder's optimal bid fraction, and relatively minor differences in the optimal expected value and average tract value to true value at the optimal bid fraction. In contrast, uncertain competition appears to be important in raising the level of high bids.

Table 5-42. Optimal Bidding With Random Competition.

Bidding Model Results, Exclusion/Inclusion of MMS As a Bidder

<u>Variable</u>	<u>Without MMS</u>	<u>With MMS</u>
Our Bid Variance	0.75	0.75
Opponent Bid Variance	0.75	0.75
Opponent Bid Fraction	0.21	0.21
Optimal Bid Fraction	0.21	0.22
Optimal Expected Value	0.47	0.45
Average Tract Value to True Value at Optimum	1.24	1.27

Number of Opponents Defined by Poisson Distribution of Mean 1.0

Econometric Issues

Having established the theoretical underpinnings to the analysis of high bids per acre we now turn to the econometric analysis.

Minimum Bid Truncation

In Chapter 4, the problem of truncation was examined in detail. The problem as posed in Chapter 4 is that there are likely to be persons who would place a bid between zero and the minimum bid if that were allowed, but they choose not to bid at all given the minimum bid requirement. Viewed from the perspective of the level of high bids, the optimal bidding strategy can lead to optimal bid amounts that are less than the minimum bid for some or all bidders. Truncation of the number of bidders per lease implies that the bidders for low-value leases are inclined to reduce their bid factor for two complementary reasons:

- The expected competition is reduced to the extent that most potential competition is expected to fall below minimum bid and drop out.
- Remaining in the set of bidders for the lease implies that the lease value might be overestimated (the winner's curse).

Thus truncation affects the empirical distribution of high bids just as it affects the distribution of number of bidders. The distribution of high bids between zero and minimum bid cannot be observed. As a result, parameters estimated by 2SLS, even with the log-transformation of the dependent variables, might be biased, and simple significant tests (such as chi-squared) need to be refined. Corrective techniques similar to the methods examined in Chapter 4 can be applied. That research is left for future work.

Simultaneity of Competition and High Bid Equations

As mentioned above, the model applied in this chapter assumes that high bid and competition are co-determined. The theoretical model of bid determination and the common-value bidding model combine to show how people's perceptions of underlying value of a block both influence whether they will bid anything above minimum bid at a block and, if so, how much. Typically, two-stage least squares (2SLS) is employed for estimating parameters of simultaneous equations. The problem immediately arises that 2SLS often assumes the residuals of the two equations follow a joint normal distribution. Is this appropriate where the univariate analysis has revealed that high bid, by itself, follows a Pareto or similar distribution, and (as reported in Chapter 4) competition is a count variable following a Poisson or other discrete distribution? As noted in Chapter 4, when regressors are added to the competition equation, the residual of the model tends to approach the normal shape. The same tendency can be expected for the high bid equation. For this reason, it can be expected that a multivariate regression model with competition and high bid both log-transformed might provide an adequate approximation of a model with more precise distributional assumptions.

Inconsistency of Count and Continuous Variables

Unfortunately, there is an additional complication. Bids per lease is a count variable, as discussed at length in Chapter 4. To explore the problems that can arise when the simultaneous equation model mixes continuous and count variables, a preliminary 2SLS estimate was made, focusing on data for 0-200 m. Most available regressors were included at this stage, given the purpose of the exercise. The regression results for 0-200 meter are shown in Tables 5-43 and 5-44.

Table 5-43. 2SLS Preliminary Estimates, 0-200 meter, Log High Bid Parameters.

Root MSE	0.7615	R-Square	0.5827
Dependent Mean	4.6828	Adj R-Sq	0.5821
Variable	Parameter	t Value	Pr > t
Intercept	2.6614	37.7120	0.0000
Bids	0.4043	50.3932	0.0000
Re-Leased	0.2769	6.2830	0.0000
HB By Major	0.0101	0.5486	0.5833
HB By Joint	0.2079	11.3241	0.0000
Drainage/Development	0.1300	3.6840	0.0002
Area Block Sequence	0.0908	7.8029	0.0000
MinBid Per Acre	0.0129	61.7944	0.0000
MMS Value	0.0001	11.5390	0.0000
Rental Rate	0.0078	0.3626	0.7169
Seismic Coverage	-0.1342	-3.0082	0.0026
Tracts Offered (1000)	0.1019	5.8970	0.0000
Bid Probability	1.6417	14.7189	0.0000

Table 5-44. 2SLS Preliminary Estimates, 0-200 meter, Log Bids Per Lease Parameters.

Root MSE	0.4208	R-Square	0.1528
Dependent Mean	0.2657	Adj R-Sq	0.1516
Variable	Parameter	t Value	Pr > t
Intercept	-0.0498	-1.2198	0.2226
HB Per Acre	0.0001	18.8258	0.0000
Re-Leased	0.1422	5.8722	0.0000
HB by Major	-0.0240	-2.3919	0.0168
HB by Joint	0.0658	6.6286	0.0000
Drainage/Development	-0.0589	-3.0193	0.0025
Area Block Sequence	0.0364	5.9287	0.0000
Viable	0.2597	26.5193	0.0000
MinBid Per Acre	-0.0014	-10.0292	0.0000
Rental Rate	-0.0315	-2.6597	0.0078
Seismic Coverage	0.0488	1.9684	0.0491
Oil Price	-0.0032	-3.3307	0.0009
Tracts Offered (1000)	0.1082	11.2902	0.0000
Bid Probability	0.8865	14.5880	0.0000

While the residuals for the log high bid equation are skewed, they are much less skewed than the univariate analysis revealed; as expected, including regressors had the effect that the residuals approach a normal distribution. The residuals for log bids per lease have a bimodal or multimodal pattern. The cause of the multimodality can be discovered by analyzing subsets of predicted and actual bids per lease. Whereas the actual log bids per lease is a highly-skewed, count variable and bounded by $\log(1)$, the predicted log bids per lease obtained by 2SLS is a less-skewed, continuous variable and not bounded. The mode of actual *lbids* is 0, while the mode of predicted bids is 0.22, so it is not surprising that the higher of the peaks of residuals (equals actual minus predicted) is about -0.22.

For each discrete level of bids per lease, the corresponding predictions of log bids per lease are roughly normally distributed and conditionally biased to one side or the other. The problem here is an instance of a general type of problem where the number of events and the size of events are co-determined. There are many examples in consumer markets, where number of shopping trips and amount spent per trip are assumed to be co-determined. In theory, one approach to this type of problem might be to assume that both events and sizes are dependent on the same set of instruments. If their dependency is entirely a matter of being generated from the same instruments, then the problem is simplified. Attractively, by this approach, each of the two variables can be analyzed with models of appropriate forms, e.g., Poisson, truncated, etc.

However, that possible approach seems unsatisfactory for the case in hand. On one hand, it is true that underlying block value is an important, unobserved common factor driving both the number of bids and the amounts of bids. That fact in itself would encourage the simplification. On the other hand, the upshot of the optimal bidding model described above is that a person's bidding strategy for a particular lease is a complex combination of expected competition and estimated underlying block value. Given that the inter-dependency of the high bid and competition cannot be captured in some simplified model, it would seem necessary to specify a joint probability distribution, which appears difficult. Therefore, the inconsistency in

conventional 2SLS of type between actual bids per lease and predicted bids per lease is a problem which is left to future work to investigate.

Role of Participants Variable

As shown in Chapter 4, the number of participants in a sale is a positive influence on bids per lease in a sale. In some instances, it is also positively related to high bids, and in any case, if it enters either equation in a simultaneous equation model, it affects estimates of both equations. The question arises how best to handle this third variable; e.g., should an equation for participants be included as a third equation in the model system? A relevant difference between the participants variable and the variables that are the focus here is that the number of participants is a sale class variable, and in contrast, high bid and bids per lease are tract variables. This property is not unique to participants; there are several sale class variables on the RHS of the high bid and the competition equations (e.g., tracts offered, oil price, share of bids by joint bidders, and more).

Even so, it is intuitively evident that a problem can be created if one tries to use number of participants on the LHS, as would be done in a three-equation 2SLS model. While participants is a class variable that varies only by sale and water depth class, most of the potential regressors are tract specific. What, then, if participants were allowed to appear only on the RHS in a two-equation system? In addition to the estimation problem, a difficulty would arise for estimating and simulating policy impacts. Suppose an equation has two policy-related variables on the RHS, participants and a period dummy. Then to simulate a policy scenario, both terms must be specified: the dummy is given a counterfactual value and the participants variable is set at the level it would have in that scenario. But what is that level? There are two options. One, the results of the simulation in Chapter 3 can be used to set the scenario for participants exogenously. Two, the participants variable can be omitted, and the period dummy contains the influence of that omitted variable. Assuming that 2SLS performs well with the participants variable omitted, that is the preferred option. Note that, even following that approach, participants are not out of the picture. They remain an explicit factor in determining leases sold. Bear in mind, too, that, over-all, royalty revenues are the product of leases sold and high bid per lease, and in that way, participants have an explicit effect on royalty revenues.

Role of Quality Variable

Similar considerations relate to value variables that might proxy for the geologic quality of blocks. Data for MMS value and MMS-determined viability might seem suitable as proxies for the unavailable data that would directly indicate the perceived geologic potential of blocks. However, as explained earlier, neither variable is an appropriate regressor, in fact, in the high bids model. Notwithstanding, viability is a useful regressor in the competition model, considering the conclusions reached in Chapter 4. Therefore, viability can play a role in a simultaneous equation system that includes the two models.

Since both quality and participants are omitted from the high bid model, the effects of these variables must be reflected in included variables. Most of all, it is expected, they are reflected in the policy period dummy variables. To the extent that block quality, in particular,

has tended to decline over time, the quality effect on the policy dummy contradicts the positive influence of royalty relief on profitability and high bid level. As a result, the expected sign of the estimated coefficient of the policy dummy is indeterminate.

Results of Regression Analysis With Policy Variables

Variables Included

While E-Views does not provide a stepwise selection option for 2SLS, the approach followed for this study uses backwards selection informally. The models without policy period dummies are estimated at first with a full set of regressors. Then variables are eliminated from the model set one by one, in accordance with simple significance statistics. Afterwards, the policy period dummies are added to the models.

As explained above:

- *Mms_val* was omitted from both models.
- *Viable* was used in the competition model only.

Similarly, only one of the two related variables, *area_blk_seq* and *repeat_blk* can be used in an equation. The *area_blk_seq*, that is, the number of times the block has been offered for leasing (1 or more) was selected. Of the three sale-specific variables, *tracts_offer*, *tracts bid on*, and *prob bid*, only two of the three can be included in a given equation since the probability of receiving a bid is simply the ratio of the other two.

Regression Estimates

Parameter Estimates By 2SLS With Policy Dummies

For each of the equations, several possible regressors were dropped as being of low significance (that is, probability greater than t over 20 percent) by the t-test. The retained regressors, including policy period dummies, are shown in the Tables 5-45 through 5-47. Results for 0-200 meters are provided for completeness. While most parameters have the expected signs, the competition model results include a counter-intuitive negative sign on the log high bids variable.

Table 5-45. 2SLS Estimates, 0-200 meter, Log High Bids.

Dependent Variable	LN(High Bid Per Acre)		
Root MSE	0.7939	R-Square	0.5400
Dependent Mean	4.6293	Adj R-Sq	0.5394
Variable	Parameter Estimate	t Value	Pr > t
Intercept	3.1715	54.4269	0.0000
LN(Bids)	1.5653	24.2627	0.0000
WGM	-0.1059	-3.5000	0.0005
Released	0.1527	3.1889	0.0014
Drainage/Development	0.1911	5.2507	0.0000
Area Block Sequence	0.0365	2.9081	0.0036
MinBid Per Acre	0.0134	59.2986	0.0000
Water Depth	0.0018	9.1431	0.0000
Seismic Coverage	-0.1579	-5.6017	0.0000
Tracts Offered (1000)	0.0762	3.9387	0.0001
Bid Probability	0.6251	3.3071	0.0009
DWRRA	0.1163	3.9556	0.0001
Post-DWRRA	0.0252	0.7703	0.4411
Instruments:	WGM, Released, Drainage/Development, Area Block Sequence, MinBid Per Acre, Water Depth, Seismic Coverage, Bid Probability, DWRRA, Post-DWRRA, HB by Joint, Viable, Oil Price, Tracts Offered		

Table 5-46. 2SLS Estimates, 0-200 meter, Log Bids Per Lease.

Dependent Variable	LN(Bids)		
Root MSE	0.4412	R-Square	0.0685
Dependent Mean	0.2657	Adj R-Sq	0.0675
Variable	Parameter Estimate	t Value	Pr > t
Intercept	0.1693	4.4386	0.0000
LN(High Bid Per Acre)	-0.0179	-2.2495	0.0245
WGM	-0.0528	-5.3528	0.0000
Released	0.1232	4.8185	0.0000
HB by Joint	0.0881	8.0805	0.0000
Drainage/Development	-0.0529	-2.5851	0.0097
Area Block Sequence	0.0562	9.1690	0.0000
Viable	0.2499	22.3921	0.0000
Water Depth	-0.0005	-4.0501	0.0001
DWRRA	0.0190	1.4638	0.1433
Post-DWRRA	-0.1327	-8.2984	0.0000
Instruments:	WGM, Released, Drainage/Development, Area Block Sequence, MinBid Per Acre, Water Depth, Seismic Coverage, Bid Probability, DWRRA, Post-DWRRA, HB by Joint, Viable, Oil Price, Tracts Offered		

Table 5-47 through 5-50 present the results for the other water depth categories.

Table 5-47. 2SLS Estimates, 200-800 meter, Log High Bids.

Dependent Variable	LN(High Bid Per Acre)		
Root MSE	0.9203	R-Square	0.4265
Dependent Mean	4.7288	Adj R-Sq	0.4231
Variable	Parameter Estimate	t Value	Pr > t
Intercept	3.5108	24.5971	0.0000
LN(Bids)	1.9657	9.2925	0.0000
WGM	-0.1710	-2.0891	0.0368
Released	0.3507	2.5860	0.0097
Drainage/Development	0.0644	0.4750	0.6348
Area Block Sequence	0.0954	2.4838	0.0130
MinBid Per Acre	0.0113	18.3250	0.0000
Water Depth	0.0000	-0.3935	0.6940
Seismic Coverage	-0.2196	-3.1501	0.0016
Tracts Offered (1000)	0.0503	0.3707	0.7109
Bid Probability	0.4371	0.9939	0.3203
DWRRA	0.2172	3.1424	0.0017
Post-DWRRA	0.0644	0.7461	0.4556
Instruments:	WGM, Released, Drainage/Development, Area Block Sequence, MinBid Per Acre, Water Depth, Seismic Coverage, Bid Probability, DWRRA, Post-DWRRA, HB by Joint, Viable, Oil Price, Tracts Offered		

Table 5-48. 2SLS Estimates, 200-800 meter, Log Bids Per Lease.

Dependent Variable	LN(Bids)		
Root MSE	0.3832	R-Square	0.1850
Dependent Mean	0.2399	Adj R-Sq	0.1798
Variable	Parameter Estimate	t Value	Pr > t
Intercept	-0.3634	-4.5851	0.0000
LN(High Bid Per Acre)	0.0466	1.9984	0.0457
WGM	0.0486	1.4187	0.1561
Released	0.0137	0.2365	0.8130
HB by Joint	0.0535	2.5232	0.0117
Drainage/Development	-0.0724	-1.2760	0.2020
Area Block Sequence	0.0507	3.9501	0.0001
Viable	0.1847	8.6115	0.0000
Water Depth	0.0000	0.1280	0.8982
Oil Price	-0.0012	-0.5175	0.6048
Tracts Offered (1000)	0.1967	3.3879	0.0007
Bid Probability	0.6724	3.7302	0.0002
DWRRA	0.0291	1.1713	0.2416
Post-DWRRA	-0.0712	-2.0211	0.0433
Instruments:	WGM, Released, Drainage/Development, Area Block Sequence, MinBid Per Acre, Water Depth, Seismic Coverage, Bid Probability, DWRRA, Post-DWRRA, HB by Joint, Viable, Oil Price, Tracts Offered		

Table 5-49. 2SLS Estimates, 800-plus meter, Log High Bids.

Dependent Variable	LN(High Bid Per Acre)		
Root MSE	0.9166	R-Square	0.0797
Dependent Mean	4.2928	Adj R-Sq	0.0779
Variable	Parameter Estimate	t Value	Pr > t
Intercept	3.6493	51.7226	0.0000
LN(Bids)	2.3707	19.1581	0.0000
WGM	0.0896	3.1478	0.0016
Released	0.5786	5.1997	0.0000
Drainage/Development	0.2053	0.9695	0.3323
Area Block Sequence	-0.0256	-0.6676	0.5044
MinBid Per Acre	0.0109	23.2395	0.0000
Water Depth	-0.0001	-6.0457	0.0000
Seismic Coverage	-0.1861	-3.0169	0.0026
Bid Probability	-1.6653	-5.0803	0.0000
DWRRA	0.5151	7.7791	0.0000
Post-DWRRA	0.3623	5.7331	0.0000
Instruments:	WGM, Released, Drainage/Development, Area Block Sequence, MinBid Per Acre, Water Depth, Seismic Coverage, Bid Probability, DWRRA, Post-DWRRA		

Table 5-50. 2SLS Estimates, 800-plus meter, Log Bids Per Lease.

Dependent Variable	LN(Bids)		
Root MSE	0.3614	R-Square	0.1903
Dependent Mean	0.1929	Adj R-Sq	0.1885
Variable	Parameter Estimate	t Value	Pr > t
Intercept	-0.7729	-7.4731	0.0000
LN(High Bid Per Acre)	0.0280	1.5183	0.1290
WGM	0.0369	1.6607	0.0968
Released	0.0322	0.7144	0.4750
HB by Joint Bidder	0.0458	3.5957	0.0003
Drainage/Development	-0.0778	-0.9291	0.3529
Area Block Sequence	0.1564	12.3785	0.0000
Viable	0.2337	12.5017	0.0000
Water Depth	0.0000	3.4205	0.0006
Oil Price	0.0057	3.8056	0.0001
Tracts Offered (1000s)	0.0984	6.2055	0.0000
Bid Probability	1.0097	8.6656	0.0000
DWRRA	0.0130	0.6440	0.5196
Post-DWRRA	-0.0872	-2.7034	0.0069
Instruments:	WGM, Released, Drainage/Development, Area Block Sequence, Viable, MinBid Per Acre, Water Depth, Seismic Coverage, Oil Price, Tracts Offered, Bid Probability, DWRRA, Post-DWRRA		

The regression analysis revealed that:

- Bids per acre have a positive effect on high bids in all depths, and vice versa, high bids have (with one exception) a positive effect on bids per acre in most depths. This is consistent with theory and with the reasoning that led to the simultaneous model structure.
- Minimum bid per acre has a significant positive effect on high bids in all depths.
- Viability, an indicator of block quality, has a significantly positive effect on competition.
- Other regressors mostly have expected effects. Seismic coverage has counter-intuitively negative effects on high bid, and the reason is probably that it increased over time while average high bids and competition tended down.
- The predictive ability of the model is relatively weak as shown by the low R-squared statistics.

Regarding the policy period dummies:

- Both of the dummies, the DWRRA period and the post-DWRRA have a positive effect on high bids in all depths.
- As for competition, the DWRRA dummies are positive and the Post-DWRRA dummies are negative in all depths.

Table 5-51. Summary of Policy Period Dummies, 2SLS Log High Bid Regression.

	DWRRA	Post-DWRRA
0-200	0.116	0.025
200-800	0.217	0.064
800+	0.515	0.362

Bold Means Significant to better than 5% by T-Test

Table 5-52. Summary of Policy Period Dummies, 2SLS Log Bids Per Lease Regression.

	DWRRA	Post-DWRRA
0-200	0.019	-0.133
200-800	0.029	-0.071
800+	0.013	-0.087

Bold Means Significant to better than 5% by T-Test

Impacts of Royalty Relief

As both of the equations in the system are log-linked, the estimated parameters cannot be interpreted directly. As for the models of Chapter 4, the effect of a unit change in a regressor

must be calculated. In this case, the calculations are performed by simulation of the 2-equation system.

Simulation Method

The estimates of effects of the DWRRA are derived by simulation of the simultaneous equation model. There are two types of effects that transmit impacts of policy in such a simulation:

- Each of the two equations includes policy period dummies.
- The two endogenous variables affect each other, by a sort of multiplier. Intuitively, greater competition implies higher bid level, which in turn implies greater competition, etc.

After parameters were estimated from data covering 1983-2003 for the two-equation system, the log high bid and the log bids per lease were predicted for two sets of exogenous values:

1. One based on actual DWRRA period averages. These are the predictions that are plotted in the preceding section.
2. The other based on counterfactual DWRRA periods where the period dummies are set to zero.

Correction to Predicted Values of Log Model

The log-linear model has transformed error terms. In such a model, the predicted values that are generated by the model, while unbiased as regards the log form, are biased as regards the level form. That is, a given predicted value in log form, $\log_{\hat{}}(x)$, is unbiased, however when the transformation is reversed, $\exp(\log_{\hat{}}(x))$, is biased. In such a case, the bias reflects the factor, $(\sigma^2)/2$. Here, σ is the standard error of the regression. The approximate correction is to reverse the transformation by means of the computation:

$$\text{Predicted } x_{\hat{}} = \exp(\log_{\hat{}}(x) + \sigma^2/2)$$

The impact tables show that this correction, while it is a good approximation for the overall 1983-2003 regression, is sometimes less successful as a correction for specific periods. The reason is that there is a mismatch of the σ , estimated from the full time set, and the smaller time sets covered by policy periods. The mismatch can be corrected by panel regression, but that is left for future work. The present purpose is not to obtain accurate predictions of high bid or competition but, instead, to obtain the difference between predictions with dummies set at actual values and dummies set at counterfactual values, as representing the effects of the policies.

In the following tables:

L HB ... log high bid per acre.
 HB... high bid per acre
 L Bids... log bids per tract
 Bids... bids per tract
 AM only... 1983-1995
 DWRRA... 1996-2000
 Post_DW... 2001-2003

0-200 meters

For the sake of completeness, regression simulation results are given for shallow water.

Table 5-53. Impacts of Policies on High Bid Per Acre, Both Areas, 0-200 meter.

0-200	Actual LN HB	Predicted LN HB With Policy	Actual HB	Predicted HB With Policy	Predicted LN HB No Policy	Predicted HB No Policy	HB Added By Policy (With Minus Without)
AM Only	4.87	4.87	326.28	275.81	4.87	275.81	0.00
DWRRA	4.29	4.29	126.88	103.89	4.14	90.13	13.76
Post-DWRRA	4.09	4.09	96.47	85.04	4.26	101.56	-16.52

Table 5-54. Impacts of Policies on Bids Per Tract, Both Areas, 0-200 meter.

0-200	Actual LN Bids	Predicted LN Bids With Policy	Actual Bids	Predicted Bids With Policy	Predicted LN Bids No Policy	Predicted Bids No Policy	Bids Added By Policy (With Minus Without)
AM Only	0.28	0.28	1.51	1.47	0.28	1.47	0.00
DWRRA	0.28	0.28	1.52	1.47	0.26	1.44	0.02
Post-DWRRA	0.21	0.21	1.37	1.37	0.34	1.56	-0.19

200-800 m

Regression and simulation results for 200-800 meter are shown in Tables 5-55 and 5-56. We see that:

- Log bids per tract and log high bids per acre affect each other positively, as expected.
- Predicted participants enter both equations positively, as expected.
- In the earlier regression results, it can be seen that both period dummies have positive effects for the high bids equation, as expected, even though average high bids had fallen from earlier levels. Thus, the policy period dummies indicate the policies were directly counter-acting and overcoming historical down-trends in high bids. However, the estimate for the post-DWRRA period is insignificant.
- The regression results also show that both period dummies have negative effects on bids per tract, contrary to theoretical expectation. This result implies that the

positive tendency of royalty relief was weak regarding competition, easily overwhelmed by down-trends due to other, omitted factors.

- Combining effects in a simulation of the two-equation model, it turns out that the policy increased high bid per acre in DWRRA but reduced it in the post-DWRRA period. The reduction in the post-DWRRA period is mainly the result of combining the insignificant and small parameter in the high bid equation and the significantly negative parameter in the competition equation.

Table 5-55. Impacts of Policies on High Bid Per Acre, Both Areas, 200-800 meter.

200-800	Actual LN HB	Predicted LN HB With Policy	Actual HB	Predicted HB With Policy	Predicted LN HB No Policy	Predicted HB No Policy	HB Added By Policy (With Minus Without)
AM Only	4.90	4.91	378.23	322.44	4.91	322.44	0.00
DWRRA	4.53	4.53	169.62	152.26	4.23	112.58	39.69
Post-DWRRA	4.38	4.36	154.50	127.85	4.42	134.87	-7.02

Table 5-56. Impacts of Policies on Bids Per Tract, Both Areas, 200-800 meter.

200-800	Actual LN Bids	Predicted LN Bids With Policy	Actual Bids	Predicted Bids With Policy	Predicted LN Bids No Policy	Predicted Bids No Policy	Bids Added By Policy (With Minus Without)
AM Only	0.23	0.23	1.41	1.36	0.23	1.36	0.00
DWRRA	0.27	0.27	1.48	1.42	0.22	1.36	0.06
Post-DWRRA	0.22	0.25	1.38	1.40	0.30	1.46	-0.07

The policy simulations indicate what would have happened without the policy, based on the policy period dummies and interaction effects among the two equations. The “without policy” case leaves all other variables – i.e., other than dummies, high bids, and competition – at the levels they were historically. The simulations for 200-800 meter indicated, regarding the DWRRA:

- Policy and associated, unidentified factors increased high bid per acre by \$40 for the combined Central and Western areas, averaging over the DWRRA years, contrasted with the no-policy period.
- Policy and associated, unidentified factors left bids per tract almost the same as the pre-policy period, averaging over the five years.

Regarding the post-DWRRA program:

- Policy and associated, unidentified factors decreased high bid per acre by -\$7, averaging over the 3 policy years, contrasted with the no-policy period.
- Policy and associated, unidentified factors lowered bids per tract by a negligible amount.

800-plus meter

The simulation results for 800-plus meter are given in Tables 5-57 and 5-58.

Table 5-57. Impacts of Policies on High Bid Per Acre, Both Areas, 800-plus meter.

800+	Actual LN HB	Predicted LN HB With Policy	Actual HB	Predicted HB With Policy	Predicted LN HB No Policy	Predicted HB No Policy	HB Added By Policy (With Minus Without)
AM Only	4.17	4.17	114.61	139.62	4.17	139.62	0.00
DWRRRA	4.36	4.36	160.56	130.64	3.78	72.79	57.85
Post-DWRRRA	4.30	4.30	146.73	125.44	4.13	106.18	19.26

Table 5-58. Impacts of Policies on Bids Per Tract, Both Areas, 800-plus meter.

800+	Actual LN Bids	Predicted LN Bids With Policy	Actual Bids	Predicted Bids With Policy	Predicted LN Bids No Policy	Predicted Bids No Policy	Bids Added By Policy (With Minus Without)
AM Only	0.12	0.12	1.20	1.21	0.12	1.21	0.00
DWRRRA	0.25	0.25	1.46	1.38	0.22	1.34	0.04
Post-DWRRRA	0.16	0.16	1.27	1.28	0.25	1.39	-0.11

The simulations for 800-plus meter indicated with respect to the DWRRRA:

- Policy and associated, unidentified factors increased high bid per acre by \$58 for the combined Central and Western areas, averaging over the DWRRRA years.
- Policy and associated, unidentified factors raised bids per tract by 0.04 for the combined areas, averaging over the five years.

Regarding the Post-DWRRRA program:

- Policy and associated, unidentified factors raised high bid per acre by \$19, averaging over the policy years, contrasted with the no-policy period.
- Policy and associated, unidentified factors lowered bids per tract by -0.11, averaging over the policy years.

Conclusions

In this chapter, we addressed the effect of the DWRRRA and the post-DWDRRA program, contrasted with no royalty relief, on the *magnitude of the high bids*. The analysis covers three water depth classes:

- *0-200 meter – shallow water*: Deepwater royalty relief does not apply directly but might have indirect effects

- *200-800 meter – deepwater*: Although policies give different amounts of relief to 200-400 meter and 400-800 meter, data are combined to provide enough observations.
- *800-plus meter – deepwater*: Policies give larger amount of relief.

Data cover lease sales from 1983 to 2003 for the Western and Central Gulf of Mexico. The Eastern Gulf of Mexico data are omitted from most of this chapter’s analysis because they often are outliers, reflecting several differences between the limited and occasional Eastern offering and the area-wide, annual offering of the Western and Central areas. The historical data analysis showed that:

- Contrasting pre-royalty relief and the combined royalty relief periods (1996-2003), the average high bid per acre fell in 0-200 meter and 200-800 meter, plainly affected by the high level of bid amounts in the early area-wide sales. High bid per acre rose in 800-plus meter, where there was little activity in those early years.
- Contrasting DWRRA and post-DWRRA (2001-2003) periods, the average high bid per acre fell in every depth class.
- Contrasting the pre-royalty relief period and DWRRA (1996-2000), again the average high bid fell in 0-200 meter and 200-800 meter, and it rose in 800-plus m.

As part of the theoretical basis of the study, a bidding model was examined and applied. The model implies that bidders, even in the presence of competition, will rationally tend to bid less than the true value they believe the tract to have. Thus, any increment to true value due to royalty relief will be discounted, perhaps heavily. Also, the possible influence on optimal bidding of the MMS bid adequacy process was examined.

The regression model applied in this study assumes that high bid and competition are co-determined. The theoretical model of bid determination and the common-value bidding model combine to show how people’s perceptions of underlying value of a block both influence whether they will bid anything above minimum bid at a block and, if so, how much. 2SLS was employed for estimating parameters of simultaneous equations. It was assumed that a multivariate regression model with competition and high bid both log-transformed can provide an adequate approximation of a model with more precise distributional assumptions. As an additional complication, bids per lease is a count variable, and high bid is a continuous variable; and the econometric problem arising for a simultaneous equation model that mixes continuous and count variables was examined.

The regression estimation revealed that:

- Bids per acre had a positive effect on high bids in all depths, and vice versa, high bids in most depths had a positive effect on bids per acre. This is consistent with theory and with the reasoning that led to the simultaneous model structure.

- Minimum bid per acre had a significant positive effect on high bids in all depths.
- For competition, viability had a significantly positive effect, as well.

The estimates of effects of the policies were derived by simulation of the simultaneous equation model. There are two types of effects that transmit impacts of policy in such a simulation:

- Each of the two equations includes policy period dummies. The dummies represent the combination of effects from royalty relief and associated variables not otherwise identified in the model, notably geologic properties of blocks.
- The two endogenous variables to affect each other, by a sort of multiplier. Intuitively, greater competition implies higher bid level, which in turn implies greater competition, etc.

After parameters were estimated from data covering 1983-2003 for the two-equation system, the log high bid and the log bids per lease were predicted for two sets of exogenous values:

1. One based on actual policy period averages. These are the predictions that are plotted in the preceding section.
2. The other based on counterfactual policy periods where the period dummies are set to zero.

The results indicate that in the deepwater areas the DWRRA policy had a positive impact on high bids, and a positive but much smaller impact on the number of bids. In the post-DWRRA period, the policy had a negative, but statistically insignificant impact on the level of high bids and a very minor negative impact on bids.

Chapter 6

Impact of Royalty Relief on Exploration Activity

Introduction

In this chapter we discuss the impacts of royalty relief on exploration, discovery and production related to leases sold during the DWRRA period. We hypothesize that royalty relief may influence activity related to exploration, development, and production of oil and gas resources in the following ways:

- By creating incentives to drill sooner in certain areas or to explore deepwater areas more intensively.
- Greater emphasis on exploration may lead to accelerated rates of discoveries and subsequent production.

Unfortunately, limited data exist on the effects of royalty relief on exploration and discovery for leases that were sold during the DWRRA period. Data contained in this chapter are current through August 2004. Leases sold in water depths greater than 800 meters have a ten year lease term, and therefore, even leases sold in the first year of the DWRRA (1996) have not yet expired and thus limited information exists about impacts for leases sold in these water depths. Leases sold in the 200-400 meter range have five year terms and therefore some exploration and discovery information is known about these leases at least for the 1996-1998 period. Finally, leases in the 400-800 meter range have eight year terms and thus only a limited amount of information is known about these leases that were sold during DWRRA.

This lack of complete information regarding exploration and discovery (let alone production) on leases issued during the DWRRA period constrains our ability to perform much detailed statistical analysis. We have performed data analyses where possible, and we have attempted some statistical analysis related to exploration activity. Where possible we have examined historical trends in exploratory drilling and discoveries and made comparisons between pre-DWRRA leases and those issued during DWRRA. In addition, we have analyzed whether any relationships exist between lease sale variables such as number of leases sold, bid levels, and competition and subsequent exploratory activity.

In this chapter, we focus on the following aspects of exploration activity:

- Number of exploration wells drilled;
- Number of exploration plans filed;
- Number of leases drilled;
- Number of leases filing exploration plans;

- Number of new fields discovered.⁴⁷

Data Analysis

Exploration activity may be measured by the number of exploration (wildcat and other) wells drilled, the size and number of new discoveries and the number of development/exploration plans filed with MMS. We do not expect that the size and number of new discoveries or the advent of actual production will be terribly helpful given the lag between lease sales and ultimate discoveries and first production dates (up to 15 years, especially in deepwater). For example in water depths greater than 200 meters for leases that have been sold since 1995, only 67 out of 4,366 leases (1.53 percent) have production on them. This is not an indication of the ultimate production we might see from these cohorts of lease sales, but rather an indication of the lag between lease sales and the date of first production. We also investigate trends in exploratory drilling, the discovery rate, and the size of discovered resources on leases issued before and during the DWRRA. With regard to exploration activity, we hypothesize that drilling activity in a given water depth may be a function of the following:

- **Oil/gas prices (price cycles)** – We expect a positive, but lagged, relationship between increases in prices and increases in drilling activity. In our prior work we have investigated this relationship to some extent and we believe there is a positive but lagged relationship. A recent article (Petroleum Economist 2004) suggests, however, that there has been a “decoupling” of commodity prices and capital investment decisions in oil and gas exploration.
- **Technology** – Improvements in technology allow more drilling in deeper depths and at lower costs and thus would be expected to have a positive impact on exploration activity in deepwater. In terms of measures of technological advances, we use historical trends in drilling depths.
- **Rig availability** – The availability of drilling rigs suitable for deepwater activity is expected to have an impact on the number of wells drilled. MMS notes in its Deepwater Reports (2002 and 2004) the likelihood that the lack of drilling rigs for deepwater may constrain deepwater drilling activity. In recent years, improvements in drilling technology have contributed to faster drilling rates which may ease this constraint somewhat.
- **State of resource/seismic information** – We hypothesize that with increased seismic coverage in a given area or water depth, drilling activity would likely increase.
- **Infrastructure availability** – We expect that the current availability of pipelines, platform structures, and subsea tie-ins would all be expected to have a positive influence on drilling activity in an area where such infrastructure may already exist as compared to areas not served by such infrastructure.

⁴⁷ We were unable to estimate statistically the effects of royalty relief on new field discoveries due to lack of data.

- **Age of the lease/time to expiration** – For each lease sale cohort, we expect more drilling activity to occur near or about the time that the term of the lease expires.
- **Tract Value** – There are three measures used as a proxy for the tract’s value. We expect that there is a positive relationship between a tract deemed “viable” by the MMS, and its potential to drill. A similar measure is whether the tract is classified as a Drainage/Development Tract by the MMS. Each of these represents information about a particular lease that makes them better candidates to eventually be drilled. A third measure of the tract’s value is the MMS Value, which is determined as part of the MMS Bid Adequacy procedure. We expect a positive correlation between the MMS Value and the lease’s potential to drill.
- **High bids** – Leases that attracted the largest bonus bids may be expected to be the ones that are drilled first. This would be true if the firm submitting the high bid has better information about the tract’s potential or believes there is a strong likelihood of finding resource on that tract. We also investigate whether the type of bidder plays a role in determining the likelihood of a lease to drill. This is measured by dummy variables indicating if the lease was won by a major bidder, or a joint venture bidder.
- **Number of Bids** – Leases that attracted the most bidders may be expected to be the ones that are drilled first. This would be true if a greater number of bidders is an indication that there is a lot of information known about the tract’s potential or likelihood of finding resource on that tract.
- **Water Depth** – Although we have accounted for differences in drilling by breaking out our analyses into three water depth categories (0-200 meter, 200-800 meter and 800-plus m), we would expect that within these three categories, the deeper the water depth, the less likely the lease will drill due to the increased costs of deeper drilling.
- **Sequence of Lease on Block** – This is measured in two ways: the sequence of the lease on the block, equal to one plus the number of leases previously leased on a block, or a dummy variable indicating whether or not there was previous leasing activity on that particular block. We anticipate a positive relationship with exploration activity. This would be true if more information is known, or drilling and exploration has occurred on blocks that have had previous leases.
- **WGM** – Historical data indicates that leases sold in Central Gulf sales are more likely to drill than those sold in Western Gulf sales. We therefore expect a negative relationship between WGM and a lease’s probability of drilling.
- **Rental Rate** – We expect a positive correlation between the rental rate and the likelihood of exploration activity on a lease. Once a lease begins production, it is no longer responsible for paying rental fees, creating an incentive to begin drilling on a lease.

- **DWRRA** – We expect that royalty relief may have accelerated drilling activity by reducing the total cost of developing a lease or field.

As a first pass at testing some of these hypotheses, we examined historical data on exploration activity and some of these other variables. We utilize two important measures of exploration activity: drilling activity and filing of exploration plans with MMS. Most prior studies have focused on drilling activity, but we believe that exploration plans might provide an “earlier” view of a company’s intent to develop a lease, and therefore be helpful for purposes of this study.

Table 6-1 shows three measures of exploration activity broken out by time period and water depth: the average number of leases drilled, the average number of leases filing exploration plans, and the average number of leases either having drilled and/or filed an exploration plan. As expected, in the more recent time periods, and in deeper water, there is less overall exploration activity, particularly in 800-plus meter, where only 10 percent of DWRRA leases and 4 percent of post-DWRRA leases have either drilled or filed an exploration plan with the MMS. This is predominantly attributable to the lag between the purchase of a lease and the commencement of exploration activity on the lease.

Table 6-1. Mean Number of Leases Drilled and/or Filing Exploration Plans, By Period and Depth.

	Mean Leases Sold	Mean Leases Drilled	Percent of Leases Drilled	Mean Leases Filing E-Plans	Percent of Leases Filing E-Plans	Mean Leases Drilled OR Filed E-Plan	Percent of Leases Drilled OR Filed E-Plan
0-200 m							
Pre-Policy 1983-1995	430	181	42%	170	40%	227	53%
DWRRA 1996-2000	382	109	28%	113	31%	144	38%
Post-RR 2001-2003	449	75	17%	56	14%	97	22%
200-800 m							
Pre-Policy 1983-1995	91	25	27%	19	22%	31	34%
DWRRA 1996-2000	97	16	17%	22	24%	25	26%
Post-RR 2001-2003	99	9	9%	6	6%	11	11%
800-plus m							
Pre-Policy 1983-1995	137	19	14%	22	17%	27	20%
DWRRA 1996-2000	580	32	5%	45	8%	58	10%
Post-RR 2001-2003	295	10	3%	7	3%	13	4%

Data on Leases Drilled is Current as of August 2004

Figures 6-1 and 6-2 show the inventory of drilled and un-drilled leases by lease sale year cohort and by water depth (0-200 meter and 200-plus meter). Each lease is classified into four categories: 1) lease drilled but has since been relinquished or expired; 2) lease never drilled and was relinquished or expired; 3) lease has not yet drilled (as of August 2004) but is still in inventory; and 4) lease has drilled and remains in inventory. These figures demonstrate the contrasting patterns of drilling activity in shallow and deep water areas. Two important differences are emphasized in comparing these figures: 1) a consistently greater number of leases drilling in shallow water, and 2) the lag between the lease sale and drilling activity, particularly in deep water. This is highlighted by the larger number of leases still being held (but not yet drilled) as far back as 1995 in 200-plus meters. However, Figure 6-2 indicated an increase in drilling activity in the 200-plus meter leases for leases sold in the year before and directly after

the implementation of royalty relief. The decline in the years thereafter is not surprising, again, given the delays between lease sale and initial exploratory effort.

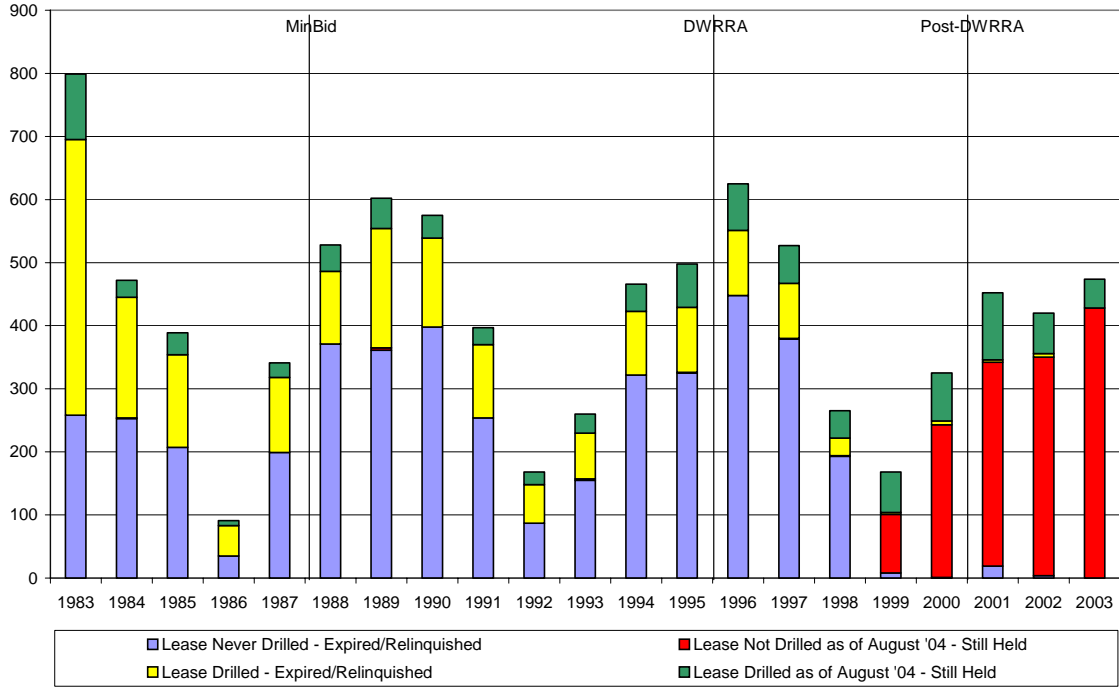


Figure 6-1. Inventory of Drilled and Un-Drilled Leases, 0-200 meter.

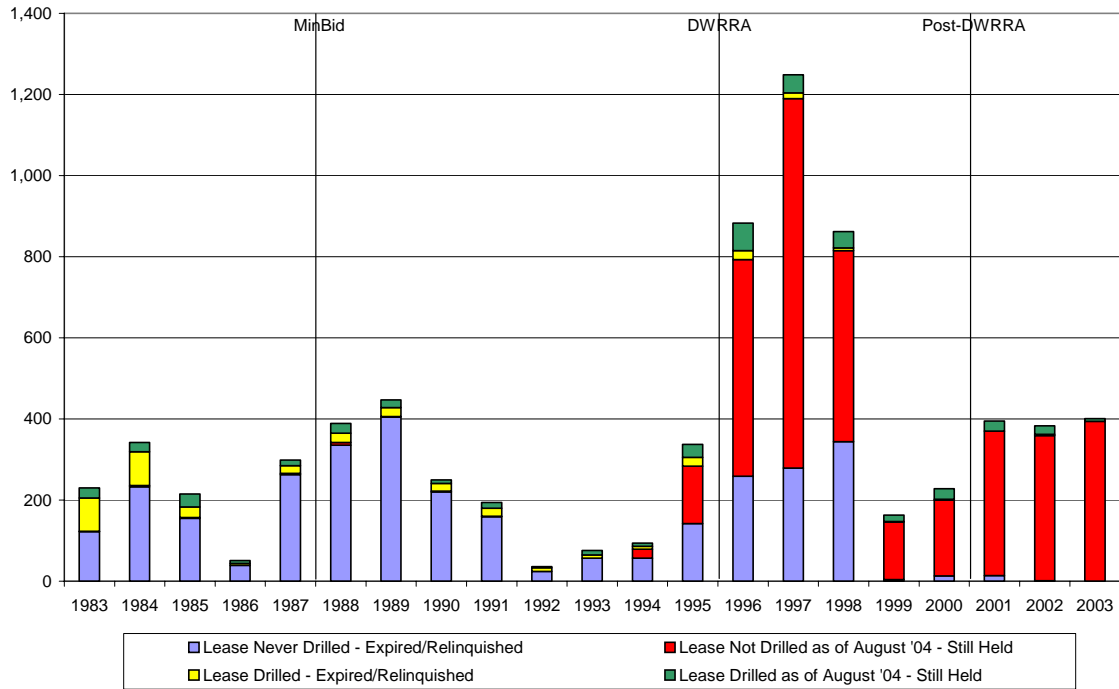


Figure 6-2. Inventory of Drilled and Un-Drilled Leases, 200-plus meter.

As Chapter 4 demonstrated there was a significant increase in the number of leases sold in deepwater during the DWRRRA policy period. Thus some of the increase in drilling in deep water shown in Figure 6-2 is likely the result of an increase in number of leases available for drilling. In an attempt to normalize for the increase in the number of leases sold, Figure 6-3 shows the percentage of leases sold for a given lease sale that have been drilled as another measure of exploration activity. This figure indicates an increase to about 25 percent of all leases sold in that year being drilled for the 200-800 meter water depth area in the initial year of royalty relief and then a subsequent decline. In the ultra-deepwater area the increase appears to come for leases issued later in the DWRRRA period which given the relative young age of these leases is another indication of an increase in overall exploration activity.

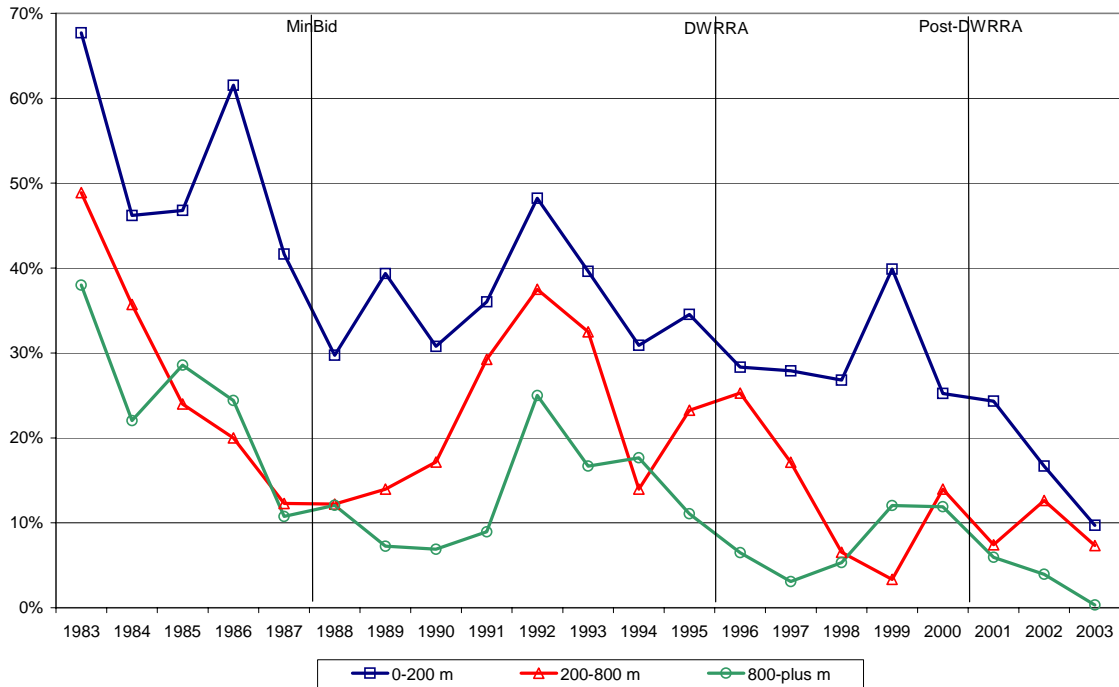


Figure 6-3. Percent of Leases Drilled by Lease Year Cohort and Water Depth.

To illustrate the lag between when a lease is sold and when exploration activity is typically initiated, Figure 6-4 shows for different water depths the lag between when a lease is sold and when the first exploratory well (E-well) is drilled on that lease. As can be seen in shallow water, almost 50 percent of the leases are drilled within the first two years after the lease sale. In the 200-800 meter the trend is similar, however in ultra-deepwater (800 plus meters), the lag grows significantly such that it takes five years before 50 percent of the leases have the first e-well drilled. Furthermore, 20 percent of the leases that drill do not drill their first e-well until the last year of the lease term or even later.⁴⁸ This figure confirms the lag between lease sale and initial exploration effort which makes the analysis of the effect of DWRRRA on exploration effort all the more difficult.

⁴⁸ A lessee can apply for an extension of lease term if it has an intention to conduct exploratory activity which is why a significant percentage (10 percent) of deepwater leases do not drill until *after* 10 years. Note that even five and eight year term leases exhibit initial drilling activity past the expected lease term expiration due to this phenomenon.

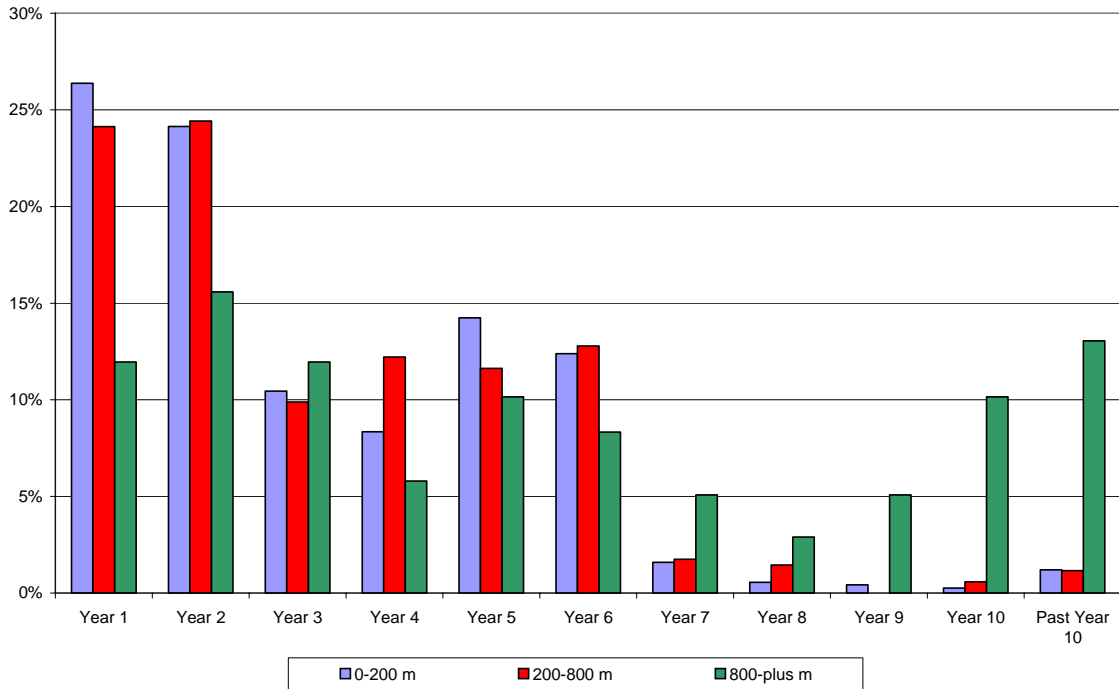


Figure 6-4. Distribution by Year After Lease Awarded of First E-Well Drilled, 1983-2002.

Figure 6-5 shows the pattern of exploration well drilling by sale year and by water depth.⁴⁹ It shows the increase in e-well drilling for lease sales directly after the start of the DWRRA, and continued activity on leases sold during that period. The 1998 lease sales cohort indicates a significant increase in drilling activity in deepwater. Interestingly these sales had some of the largest bonus bids and such drilling activity may be related to the magnitude of the bids.

⁴⁹ Exploration wells are defined as those wells drilled between the effective date of a lease and the initiation of any production.

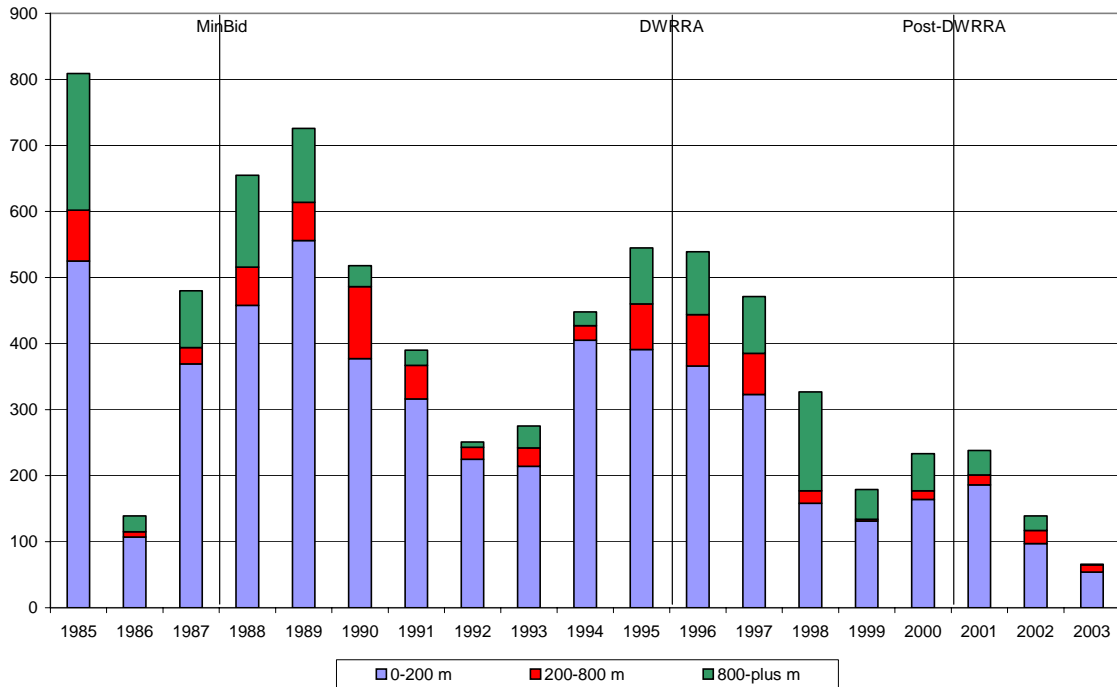


Figure 6-5. Exploratory Wells Drilled by Lease Year Cohort and Water Depth, 1985-2003.

The other measure of exploratory activity, the number of exploration plans filed, is shown in Figure 6-6. As one might expect, the pattern shown in this figure is quite similar to that in Figure 6-5, however, the number of exploration plans filed is much lower than the number of wells drilled due to the fact that several wells may be drilled as a result of filing *one* exploration plan. Nevertheless, this figure confirms the data in Figures 6-1, 6-2 and 6-3 which show a modest increase in exploration activity for leases sold directly after the implementation of royalty relief.

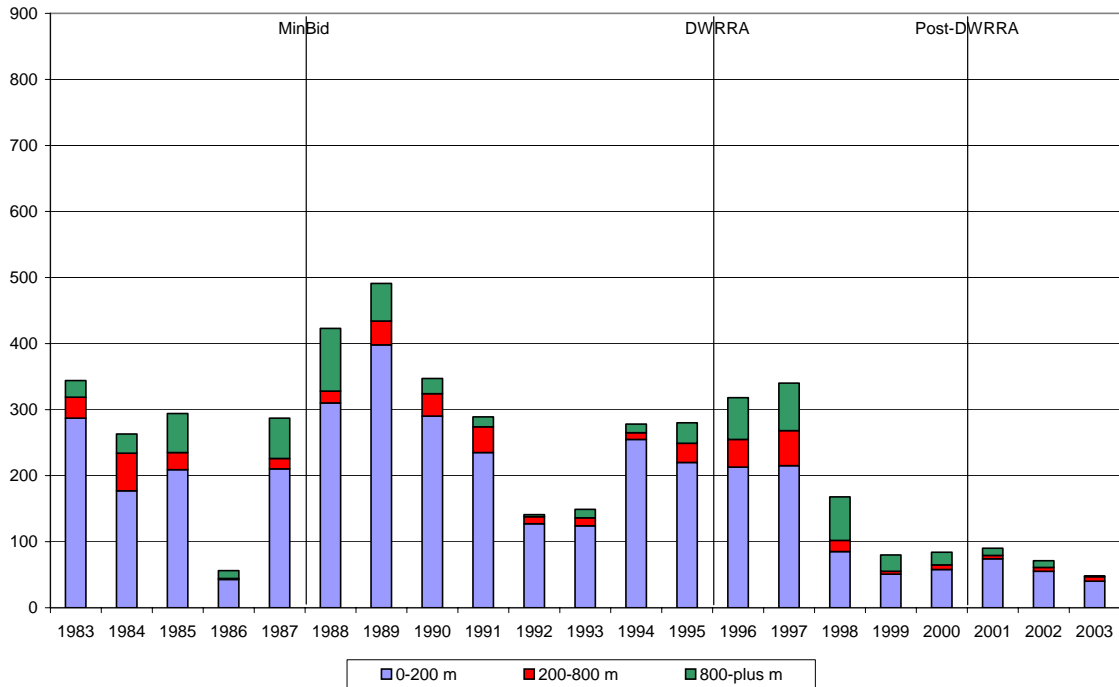


Figure 6-6. Total Number of Exploration Plans Filed by Lease Sale Year and Water Depth, 1983-2003.

We now turn to whether lease sales variables have any effect on exploration activity. We suggested that leases and lease sales that attracted higher bids might attract more intensive exploratory activity, perhaps due to the expected higher value of those leases. Figure 6-7 compares the total amount of winning bids with the percentage of leases sold that were drilled to see if high money lease sales prompted more exploration activity. This trend is apparent in the early years (1983-1990), but after 1990 there is almost an inverse relationship between the amount spent and the relative intensity of drilling activity.⁵⁰

⁵⁰ We divided these data by water depth category and could find no discernable or different trends. Again for the deep water areas it is really too soon to tell whether the higher bids made in the lease sales in 1996-1998 have led to more drilling activity.

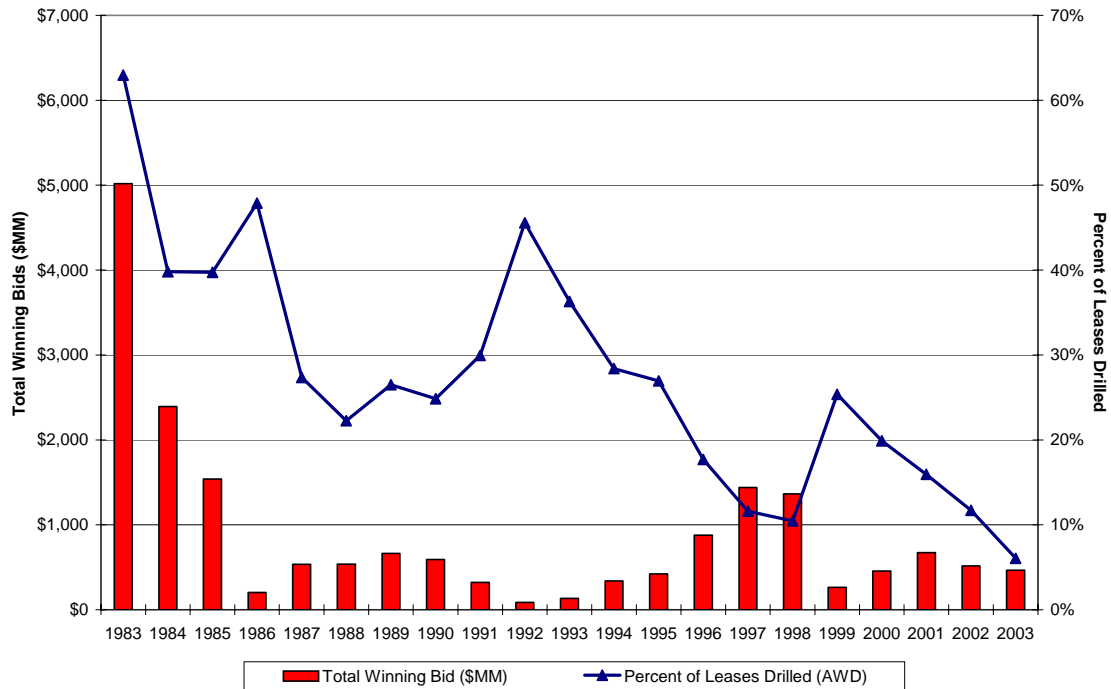


Figure 6-7. Total Winning Bid Amount (\$MM) versus Percent of Leases Drilled, 1983-2003.

In addition we examined whether there was any correlation between the size of a lease sale and the intensity of drilling activity. The thought here was that a large lease sale creates a cohort of leases that receives more attention in terms of exploratory effort. However, we found no significant correlation between the size of the lease sale (at any water depth)⁵¹ and the amount of drilling activity and that exploration activity in general did not seem highly correlated with lease variables.

On the other hand, there does appear to be a significant correlation between the total size of a lease sale (total amount spent) and the ultimate production that has come from those leases. Figure 6-8 presents a scatter-gram showing the correlation between the amount spent in a lease sale and the ultimate production from those leases. As can be seen there is a high correlation ($R^2 = .78$) between these variables which indicates that bidders do have some rational expectations that as they bid higher amounts they will find reserves.

⁵¹ Correlation coefficients ranged from .10 to .15 at different water depths regarding the relationship between the number of leases sold and the number of leases drilled.

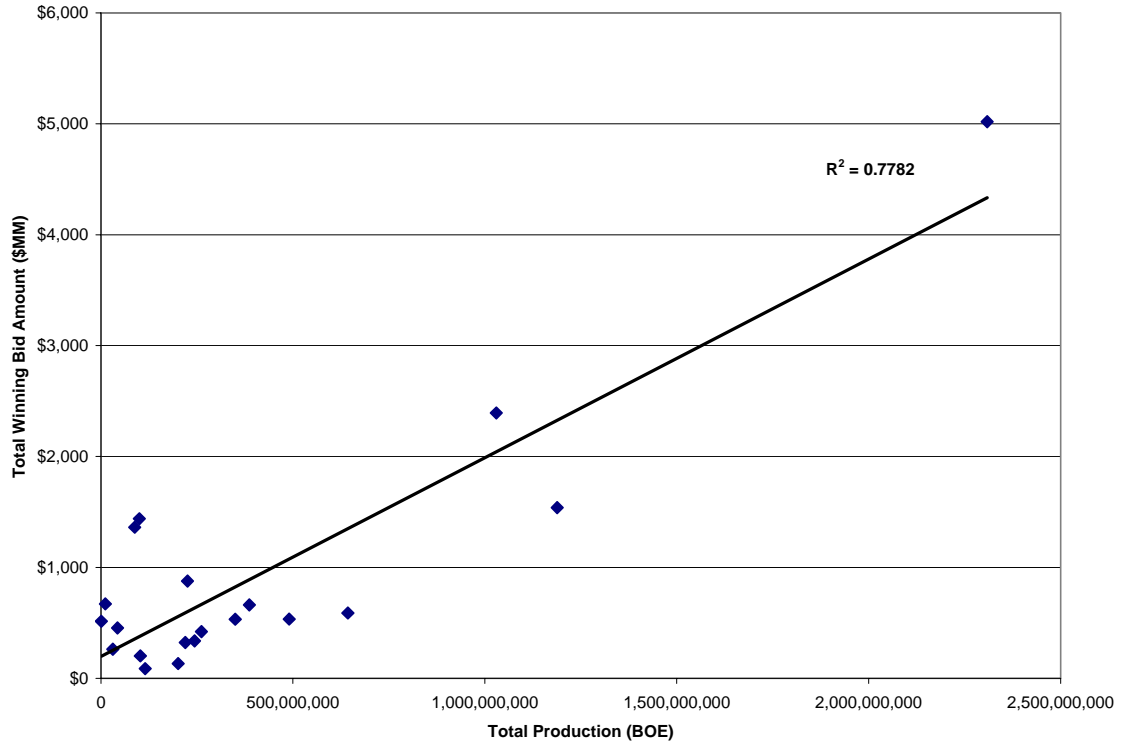


Figure 6-8. Total Winning Bid Amount (\$MM) versus Total Production by Lease Year, 1983-2003.

Next we turn to the output of exploration activity, namely resource discovery and production. Figure 6-9 shows the increase in deepwater reserves over time, including the significant increase in reserves in the 800+ meter depth. Much of this is attributable to pre-DWRRA leases, but in the last few years the amount of reserves added by DWRRA leases has begun to increase substantially.

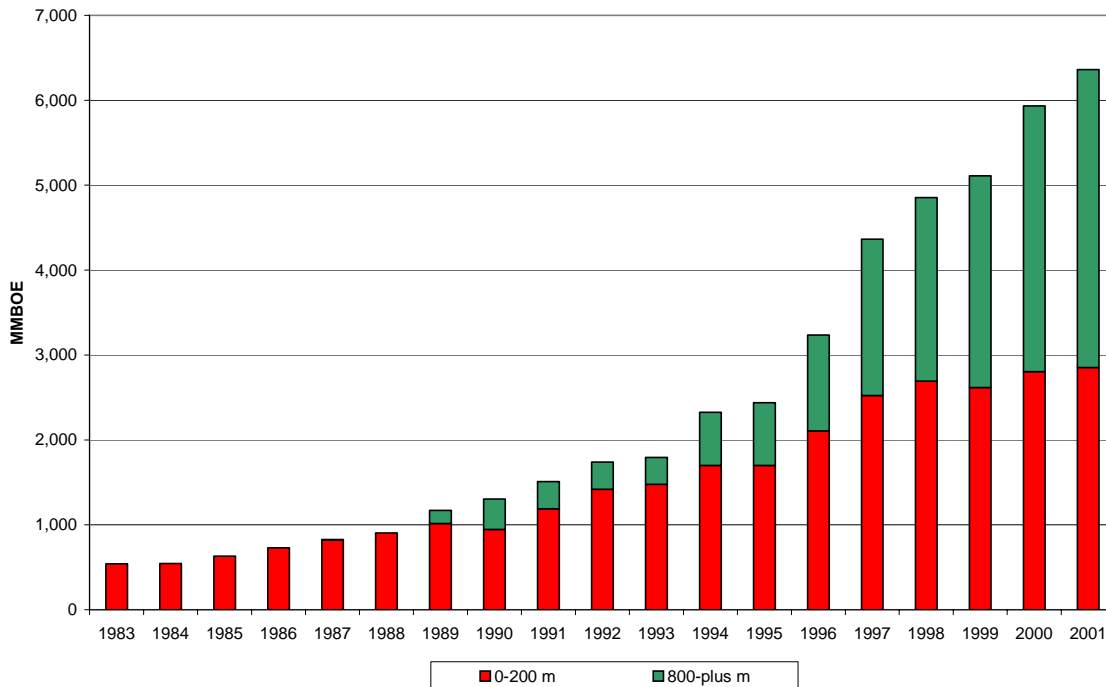


Figure 6-9. Deepwater Reserve Estimates.

Recent indications (*Petroleum Economist* 2004) suggest that there has been a significant slow-down in exploration activity in the Gulf, including in deepwater:

Over the last two years, the number of rigs operating in water depths of 1,000-4,999 feet⁵² has slipped steadily. At the peak of activity, in 2001, the rig count in that water-depth range averaged 41 and about 2,000 wells were drilled. Since 2002, the average number of rigs operating in the sector has declined by 29% and the number of wells drilled is down by 37%, the MMS reports.

Despite this decline in drilling, there have been several new major discoveries in deepwater. By the end of 2003, there were 86 deepwater projects that had begun production, a five-fold increase over the number on stream in 1997 (*Petroleum Economist* 2004). Figure 6-10 shows the percentage of field discoveries by field size category for leases sold before DWRRA compared with during and after DWRRA. As can be seen there are more fields discovered in the size 8-10 range as well as the very large 13-17 field size range during DWRRA, although this is partially a function of the few total number of fields discovered for leases sold in the 1996-2001 time period. The greater percentage of fields found in the size 8-10 range supports the idea discussed above that royalty relief tends to make “marginal” fields more profitable. Table 6-2 presents data on the fields discovered in deepwater areas that are attributable to leases sold during the DWRRA period.

⁵² This range of water depths is approximately equal to 300-1,525 meters.

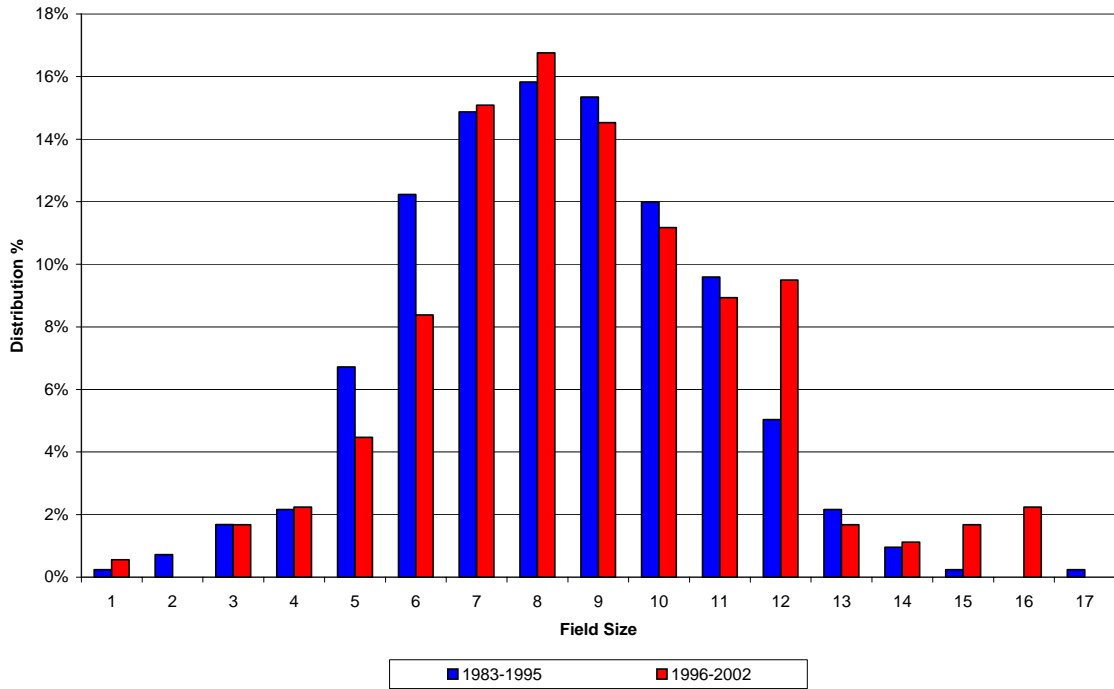


Figure 6-10. Percentage of Field Discoveries by Field Size Before and During Deepwater Royalty Relief.

Table 6-2. Fields Discovered in Deepwater (200-plus meter) Attributable to DWRRA Leases.

Field	Water Depth	Sale Year	Discovery Year*	Field Size**
AT037	2458	2000	2001	11
EB158	251	1996	2001*	NA
EB168	296	1996	1997	9
EB205	415	1996	2001	10
EB421	853	1996	2001	10
EB430	836	1997	2000	8
EB579	1046	1997	2002	13
EB597	1035	2000	2001	10
EB668	1174	2001	2003*	NA
EB759	1279	1998	2003	11
EW878	564	1997	2000	11
GB179	259	1996	1997	9
GB197	262	1997	2003*	NA
GB205	510	2001	2002*	NA
GB367	339	1996	1999*	NA
GB668	977	1996	2000	13
GB700	1319	1997	2004*	NA
GB877	1639	1999	2001	7
GC114	853	1998	1999	9
GC177	573	1996	1999	9
GC178	566	2003	2004*	NA
GC243	960	1998	2001	13
GC282	879	1996	2001	12
GC339	1079	2000	2001	15
GC379	1195	2001	2001	14
GC507	1323	2001	2002*	NA
GC608	1350	1997	2000	12
GC646	1355	1998	2004*	NA
MC066	403	2002	2002	14
MC252	1614	1997	1999	11
MC299	1904	2000	2001	12
MC305	2249	1998	1999	12
MC348	2295	1998	1999	12
MC509	1367	2000	2001	11
MC555	1516	2000	2001	9
MC582	698	1996	1998	14
MC728	1685	1996	2002	12
MC751	501	2001	2002	12
MC773	1738	1998	1999	12
MC849	1180	1999	2002	13

* For these particular fields, the "Discovery Year" is actually the year in which the discovering lease was assigned to the field.

**Data not available ("NA") to determine field size.

Figure 6-11 shows the percentage of leases that have become productive by lease sale year. Again for deepwater areas greater than 200 meters the data are not terribly useful during the DWRRRA period due to the extreme lag between lease sale and first production. This figure does indicate that shallow water leases produce at a relative constant rate of leases sold whereas in deepwater the rate is much more variable.

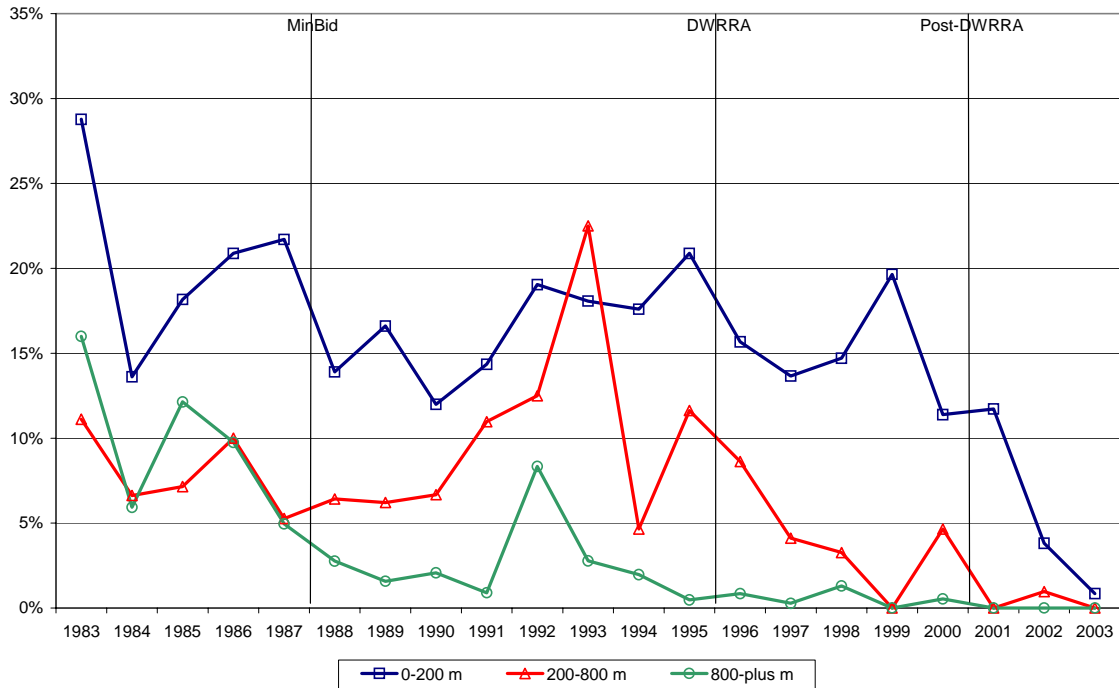


Figure 6-11. Percent of Leases With Production by Lease Cohort Year, 1983-2003.

Figure 6-12 shows the contribution to Gulf production of leases sold before, during and after DWRRRA. Interestingly the increase in production from leases sold during DWRRRA has increased rather significantly in the last few years, although the number of leases contributing to that increase remains relatively small as Figure 6-11 shows. Nevertheless since 2000, there has been a sizeable increase and by 2003 one observes some production from leases sold in the post-DWRRRA period.

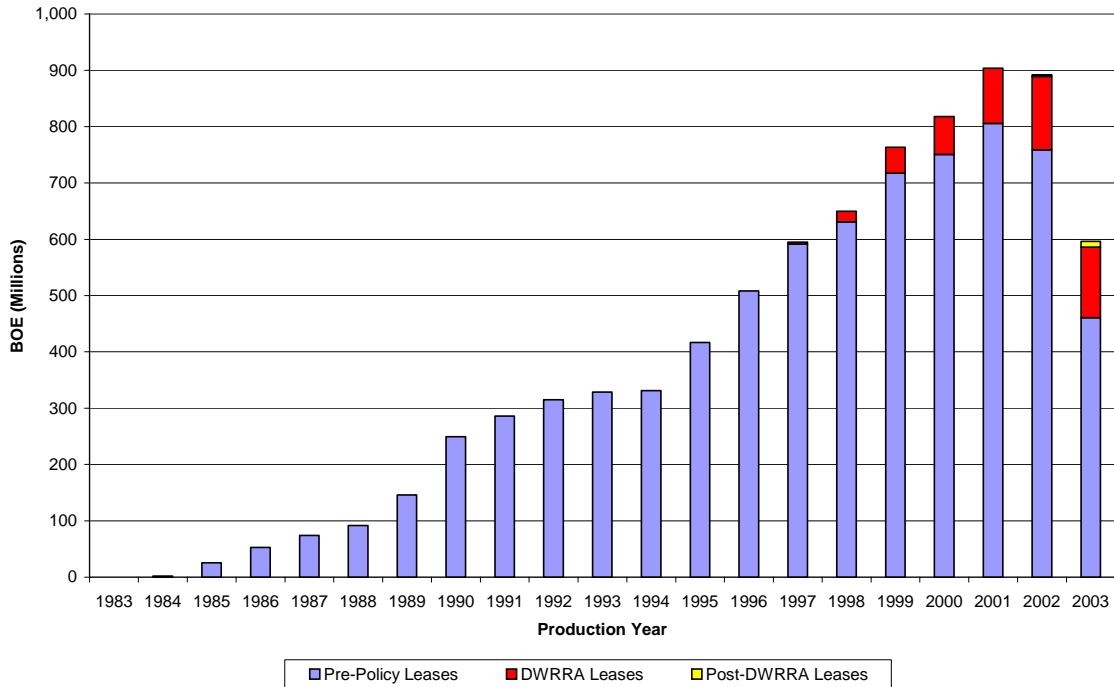


Figure 6-12. Total Production Per Year from Area-Wide (1983-2003) Leases, All Water Depths.

Figure 6-13 shows production by water depth attributable to each lease sale year cohort. As can be seen relatively small volumes of production can be attributed to lease sales during and after DWRRRA although production in over 800 meters has been forthcoming already from leases sold in the 1996-1998 period, and significant amounts of production in the 200-800 meter range are also being produced from leases sold during the DWRRRA period.⁵³ Figure 6-14 compares the contribution of deepwater production produced from DWRRRA leases versus prior period leases, indicating a significant increase in recent years even as production from pre-DWRRRA leases begins to decline. Again due to the lags between lease sales and exploration and development activity, it is impossible to conclude what the impact that royalty relief has been on discoveries and new production based on this limited amount of historical data.

⁵³ Most of the new production from leases awarded during the DWRRRA years has actually come from shallow water leases as opposed to deepwater leases.

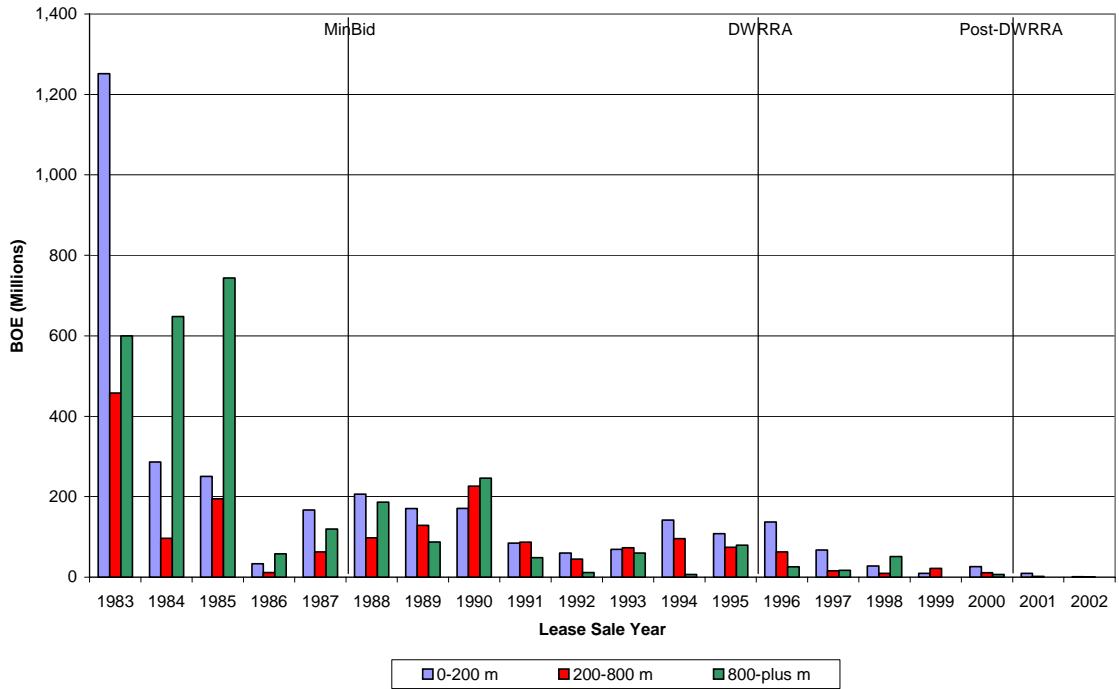


Figure 6-13. Total Production Per Lease Year Cohort by Water Depth.

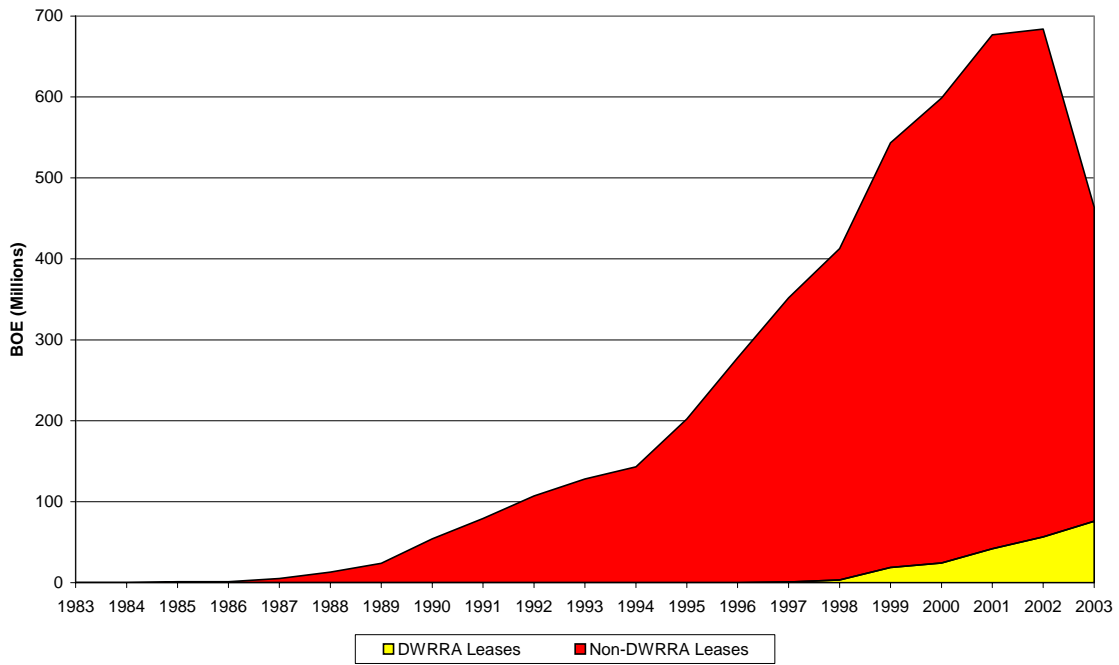


Figure 6-14. Contribution of DWRRRA Lease Production to Total Annual Deepwater Lease Production, 200-plus meter (Area-Wide Leases Only).

Next we turn to the hypothesized relationships between exploration activity and other possible variables. The literature has indicated that drilling is related to oil and gas prices and future expectations of such prices.⁵⁴ We have analyzed this relationship and found that drilling tends to respond to expected profitability which in turn is related indirectly to oil and gas prices. Figure 6-15 displays the relationship between exploration activity as measured by wells drilled and oil price. This figure indicates that there is some relationship but there appears to be a lag in the drilling response to movements in price. More importantly there appears to be cycles of price movements followed by cyclical drilling responses. The arrows on Figure 6-15 attempt to illustrate these price cycles; a downward trend from 1983 to 1988, followed by a two year increase, then followed by a four year decline between 1990 and 1994, a two year upswing, followed again by a two-year downswing, and finally an increase in 1999-2000.

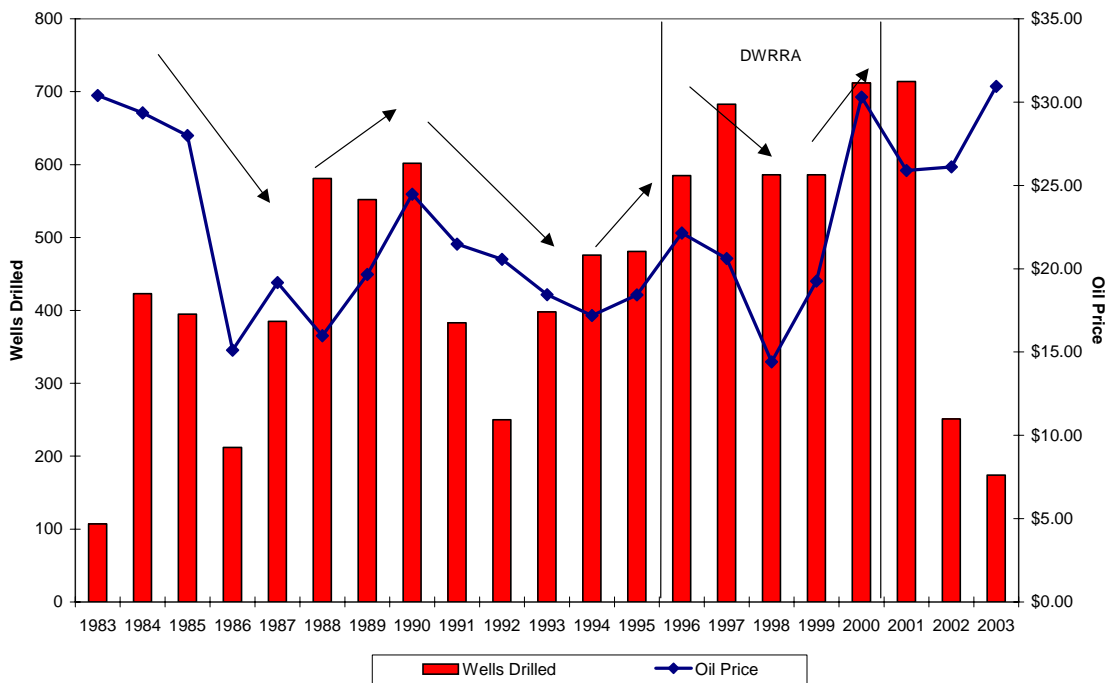


Figure 6-15. Total Wells Drilled versus Oil Price.

We also examined the trend in drilling depths as a possible determinant of the increase in deepwater exploration activity where the increase in drilling depth is a proxy variable for technological progress. Figure 6-17 shows two measures of the increase in drilling depth, water depth and wellbore true vertical depth (TVD). Water depth measures the water depth in which the drilling has occurred whereas TVD measures the total drilling depth actually achieved. Each displays a remarkable trend of increasing depth and severity of operations, with increasing water

⁵⁴ Recent articles suggest, however, that this historical relationship may be changing (Petroleum Economist 2004).

depth showing the most significant change in recent years. There seems little doubt that technology has played a role in companies' ability to explore in deeper water depths.⁵⁵

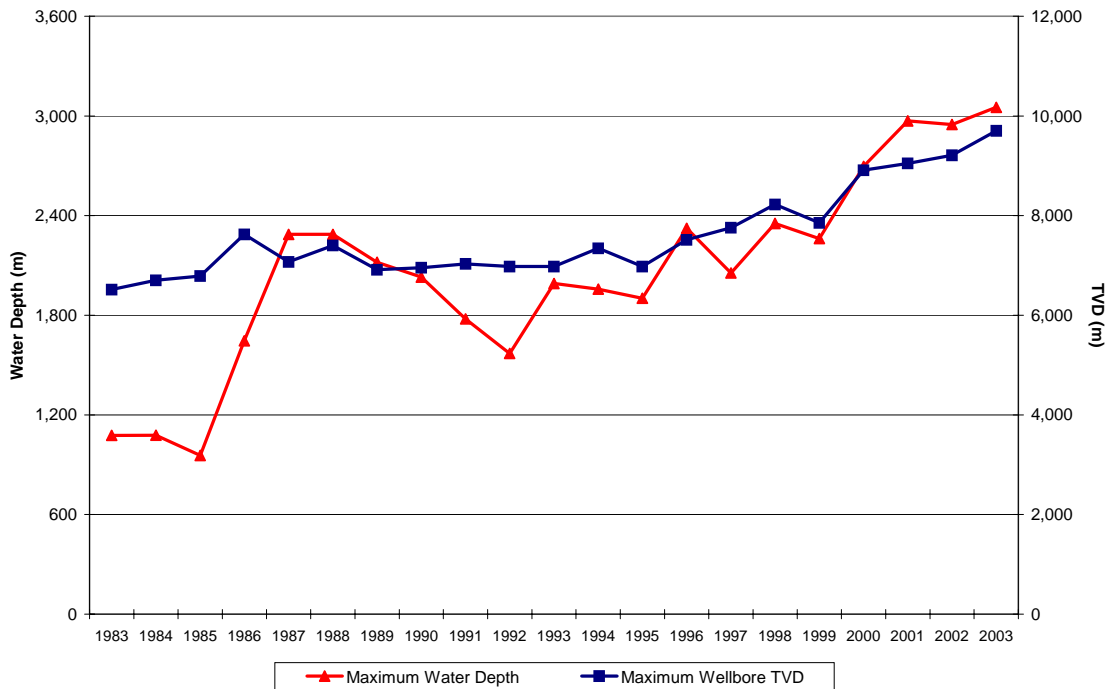


Figure 6-16. Trends in Drilling Depths.

The data analysis suggests that technology and oil prices play an important role in determining exploration activity, especially in deepwater areas. Lease variables seem to have little impact, at least in terms of exploratory activity. Given the lags between lease sales and exploration activity, it is difficult to model the impact of DWRRA on exploration activity and certainly impossible to model its impact on production.

Finally, Figure 6-17 indicates drill rig utilization rates in the Gulf of Mexico for the period 1990-2004. These rates are reflective of deepwater drilling, as Semi-Sub and Submersible Rigs are the two most commonly used rigs for deepwater drilling. These data indicate relatively low rates of utilization for much of the time frame, suggesting that rig availability may not have been a constraint on exploration activity. The only period of high utilization was in 1997-1998 and this period did not last for an especially long period of time.⁵⁶

⁵⁵ This is confirmed by a recent study by Iledare (2000) which found that changes in technology have had a significant effect on drilling and the productivity of drilling.

⁵⁶ Data on ultra-deepwater drillships is more limited, but also suggests limited periods of constrained capacity and indeed currently a “surplus” in such capacity.

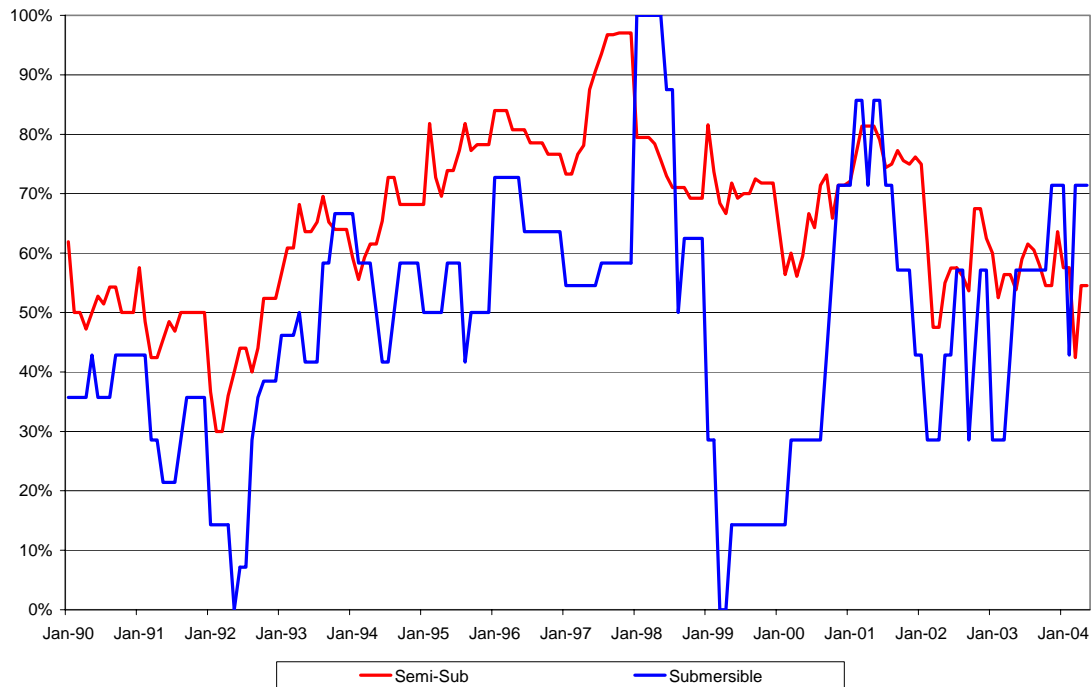


Figure 6-17. Rig Utilization Rates by Rig Type, 1990-2004.

Statistical Analysis

To analyze statistically the relationship between royalty relief and exploration activity, we tested several models of drilling activity. None of our initial models performed particularly well or were able to explain much of the variation in the number of wells drilled or the number of exploration plans filed with MMS, our two dependent variables. These models were measured using both time-series and longitudinal data. In the time-series model the dependent variables were measured as the number of wells drilled or exploration per lease year cohort in order to incorporate lease-specific variables. The longitudinal data set included the number of wells drilled and the number of exploration plans filed *per lease*.

The best approach, given limited time-series data to assess DWRRA impacts, was a model in which the decision by a lease to drill was modeled as a two-part decision. The first part was to model which particular leases are drilled over the lifetime of the lease term, and the second part was to model the factors that affect those leases that are actually drilled and which ones produce discoveries and whether royalty relief played a role in either of those events. To model the first part, we employed a probit regression model that attached a probability to whether a lease would be drilled or not with the probability being a function of a number of different variables, each of which are discussed at the beginning of this chapter. The impact of

royalty relief was measured by including a dummy variable for DWRRA leases.⁵⁷ The dependent variable was whether or a lease was drilled and alternatively whether an exploration plan had been filed for that lease.

Tables 6-3, 6-4 and 6-5 present mean values for variables tested in our probit regression models broken out by water depth and time period.

Table 6-3. Mean Values for Exploration Activity Variables, 0-200 meter.

Variable	0-200			
	Pre-Policy	DWRRA	Post-DWRRA	All
Drilled	0.421	0.285	0.168	0.353
Filed E-Plan	0.396	0.295	0.126	0.333
Drilled OR Filed E-Plan	0.529	0.377	0.215	0.449
Days to Expected Lease Expiration	0.000	62.748	1,072.693	176.848
DWRRA	0.000	1.000	0.000	0.216
WGM	0.363	0.295	0.274	0.335
Sale Date	32,531.627	35,744.935	37,384.900	33,964.552
Water Depth	51.286	50.602	44.071	50.040
Rental Rate	3.384	5.017	5.004	3.983
Area Block Sequence	1.442	2.242	2.699	1.806
Repeat Block	0.362	0.796	0.857	0.531
High Bid on Lease	1,522,295.160	604,388.953	447,613.221	1,160,417.446
Bids on Lease	1.529	1.532	1.365	1.505
High Bid by Major Bidder	0.391	0.204	0.127	0.310
High Bid by Joint Bidder	0.340	0.226	0.225	0.298
MMS Value	479,570.804	208,678.307	203,058.749	390,748.510
Drainage/Development Tract	0.073	0.010	0.003	0.049
Viable	0.455	0.191	0.404	0.390
Oil Price	20.925	23.201	30.918	22.168
Pipelines	0.146	0.126	0.017	0.122
Platforms	0.225	0.103	0.007	0.165

⁵⁷ Due to the lag between a lease sale and drilling activity, we did not attempt to measure the impact of the Post-DWRRA period on exploration activity. Based on the analysis presented in Figure 6-4, we estimated a potential drilling date for each lease that was still in inventory that had not been drilled as of August 2004. Based on this potential drilling date (month and year), we included the average Oil Price for the 7-month period (3 months prior, including that month, and 3 months after) for the hypothetical drilling date as an explanatory variable. Therefore, any lease who's hypothetical drilling date fell after the date for which actual Oil Price data was available (at the time of the analysis) was excluded from the analysis.

Table 6-4. Mean Values for Exploration Activity Variables, 200-800 meter.

Variable	200-800 m			
	Pre-Policy	DWRRA	Post-DWRRA	All
Drilled	0.274	0.169	0.092	0.221
Filed E-Plan	0.214	0.227	0.061	0.195
Drilled OR Filed E-Plan	0.339	0.256	0.116	0.285
Days to Expected Lease Expiration	0.000	349.922	1,864.119	365.628
DWRRA	0.000	1.000	0.000	0.248
WGM	0.468	0.528	0.509	0.489
Sale Date	32,291.082	35,682.295	37,382.184	33,892.937
Water Depth	481.075	506.318	529.239	494.535
Rental Rate	3.325	7.485	7.491	4.979
Area Block Sequence	1.339	2.105	2.672	1.728
Repeat Block	0.306	0.788	0.891	0.513
High Bid on Lease	2,123,967.081	957,793.530	912,250.143	1,653,779.525
Bids on Lease	1.409	1.497	1.375	1.426
High Bid by Major Bidder	0.697	0.324	0.157	0.523
High Bid by Joint Bidder	0.373	0.315	0.249	0.340
MMS Value	518,921.848	312,749.752	328,591.282	442,709.435
Drainage/Development Tract	0.025	0.016	0.000	0.019
Viable	0.346	0.214	0.625	0.355
Oil Price	20.055	24.690	34.338	22.322
Pipelines	0.123	0.041	0.010	0.086
Platforms	0.026	0.000	0.000	0.016

Table 6-5. Mean Values for Exploration Activity Variables, 800-plus meter.

Variable	800-plus m			
	Pre-Policy	DWRRA	Post-DWRRA	All
Drilled	0.136	0.055	0.033	0.077
Filed E-Plan	0.163	0.078	0.025	0.096
Drilled OR Filed E-Plan	0.196	0.100	0.043	0.121
Days to Expected Lease Expiration	36.247	1,214.104	2,952.667	1,114.172
DWRRA	0.000	1.000	0.000	0.521
WGM	0.338	0.448	0.497	0.420
Sale Date	32,591.141	35,696.177	37,425.826	34,978.517
Water Depth	1,461.388	1,834.606	1,549.497	1,669.867
Rental Rate	3.313	7.500	7.500	6.161
Area Block Sequence	1.085	1.263	1.532	1.249
Repeat Block	0.083	0.248	0.460	0.229
High Bid on Lease	654,290.023	915,643.013	835,872.868	819,364.775
Bids on Lease	1.198	1.460	1.265	1.345
High Bid by Major Bidder	0.858	0.612	0.298	0.641
High Bid by Joint Bidder	0.212	0.307	0.278	0.272
MMS Value	288,740.649	284,362.252	305,432.390	288,721.951
Drainage/Development Tract	0.002	0.003	0.003	0.003
Viable	0.117	0.130	0.547	0.193
Oil Price	20.986	28.208	29.284	25.352
Pipelines	0.076	0.010	0.000	0.030
Platforms	0.011	0.000	0.000	0.004

The model results indicate that tract type (Drainage/Development Tract) has the strongest influence on the likelihood that a lease would be drilled.⁵⁸ Other variables were positive and significant including competition, high bid, oil price (except in deepwater) and whether the lease was on a block in which other leases had been in prior lease sales. Water depth, sale date, high bids by majors and the dummy variable for Western Gulf leases were all significant and had negative coefficients, indicating that these factors made it less likely a lease would drill. Other variables such as rig availability and infrastructure were not significant. Tables 6-4, 6-5 and 6-6 present the probit model results for 0-200 meters, 200-800 meters and 800-plus meters water depths respectively. It should be noted that the predictive ability of these models is relatively low as given by the low R^2 , although the coefficients of independent variables are all significant.

Tables 6-6, 6-7 and 6-8 also present results for the probit regression analysis with the dependent variable representing whether or not the lease had filed an exploration plan. The results are very similar, in terms of the value and sign of the coefficients, to the results of the drilling regressions with a few exceptions. These exceptions include a positive sign on the sale date variable in 0-200 meters, and a negative sign on the oil price variable in all three water depths. Although the sale date variable is not significant in the 0-200 meter exploration plans regression, the positive sign on the coefficient indicates that leases from more recent sales actually have a higher probability of having filed an exploration plan.

Table 6-6. Probit Parameter Results for Exploration Activity, 0-200 meter.

⁵⁸ The Drainage/Development dummy variable is not included in the ultra-deepwater regression. It was omitted from the regression because it was statistically insignificant, which is most likely due to the very small percentage (about 0.3 percent) of leases in deepwater that have actually been classified as Drainage/Development tracts. However, when added to the model, it was shown to have a high value on the coefficient with a positive sign.

Dependent Variable:	Drilled			Filed Exploration Plan		
McFadden R-squared	0.1260			0.0815		
Mean dependent var	0.3873			0.3605		
S.E. of regression	0.4453			0.4549		
Variable	Parameter Estimate	Chi-Square	Pr > ChiSq	Parameter Estimate	Chi-Square	Pr > ChiSq
Intercept	1.1328	8.4646	0.0036	-0.0682	0.0327	0.8565
Bids	0.2203	161.3294	0.0000	0.2442	244.0397	0.0000
Drainage/Development	0.2498	13.6557	0.0002	0.3081	22.0790	0.0000
DWRRRA	-0.2097	22.6515	0.0000	-0.3618	69.3665	0.0000
High Bid by Major	-0.3492	103.3949	0.0000	-0.4319	162.8824	0.0000
High Bid	0.0000	283.2152	0.0000	0.0000	2.7626	0.0965
Oil Price	0.0101	10.9092	0.0010	-0.0357	140.1065	0.0000
Sale Date	-0.0001	21.6815	0.0000	0.0000	0.7775	0.3779
Water Depth	-0.0020	27.7549	0.0000	-0.0017	21.8159	0.0000
WGM	-0.2178	45.7249	0.0000	-0.1634	26.4197	0.0000
Repeat Block	0.0787	4.2511	0.0392	0.1825	23.7489	0.0000
Obs with Dep=0	4,941			5,157		
Obs with Dep=1	3,123			2,907		
Total obs	8,064			8,064		

Table 6-7. Probit Parameter Results for Exploration Activity, 200-800 meter.

Dependent Variable:	Drilled			Filed Exploration Plan		
McFadden R-squared	0.1931			0.0871		
Mean dependent var	0.2411			0.2093		
S.E. of regression	0.3771			0.3878		
Variable	Parameter Estimate	Chi-Square	Pr > ChiSq	Parameter Estimate	Chi-Square	Pr > ChiSq
Intercept	-1.2346	48.3867	0.0000	-0.3146	3.1223	0.0772
Bids	0.3094	51.7507	0.0000	0.2109	29.5530	0.0000
Drainage/Development	0.7372	11.6797	0.0006	0.4480	4.3009	0.0381
DWRRRA	-0.3955	18.6594	0.0000	-0.0352	0.1629	0.6865
High Bid	0.0000	81.5495	0.0000	0.0000	4.9525	0.0261
Oil Price	0.0162	7.0225	0.0080	-0.0297	21.6772	0.0000
Water Depth	-0.0008	15.8679	0.0001	-0.0006	10.8092	0.0010
WGM	-0.4327	35.2818	0.0000	-0.3575	25.2740	0.0000
Repeat Block	0.2109	6.8984	0.0086	0.5381	47.2522	0.0000
Obs with Dep=0	1,360			1,417		
Obs with Dep=1	432			375		
Total obs	1,792			1,792		

Table 6-8. Probit Parameter Results for Exploration Activity, 800-plus meter.

Dependent Variable:	Drilled			Filed Exploration Plan		
McFadden R-squared	0.2072			0.1004		
Mean dependent var	0.0957			0.1151		
S.E. of regression	0.2668			0.3065		
Variable	Parameter Estimate	Chi-Square	Pr > ChiSq	Parameter Estimate	Chi-Square	Pr > ChiSq
Intercept	0.0128	0.0055	0.9407	-0.1146	0.5361	0.4641
DWRRRA	-0.5946	56.6366	0.0000	-0.3516	25.6064	0.0000
High Bid by Major	-0.3399	25.2570	0.0000	-0.1728	8.0446	0.0046
High Bid	0.0000	149.8046	0.0000	0.0000	76.0535	0.0000
Oil Price	-0.0226	11.7325	0.0006	-0.0251	17.2700	0.0000
Repeat Block	0.5995	65.7068	0.0000	0.4046	35.6570	0.0000
Water Depth	-0.0003	26.7248	0.0000	-0.0001	8.9893	0.0027
WGM	-0.3530	29.5221	0.0000	-0.3173	31.2361	0.0000
Obs with Dep=0	4,061			3,974		
Obs with Dep=1	430			517		
Total obs	4,491			4,491		

A noteworthy observation of the regression results is the consistent negative sign on the DWRRRA coefficient, which indicates that a lease was less likely to drill or file an exploration plan if it was leased during the DWRRRA period. One possible explanation for the negative coefficient on the DWRRRA dummy is that the lease sales during the DWRRRA period produced many more leases in deepwater areas, and thus a relatively low percentage of total deepwater leases have actually initiated any exploration activity at this point in time compared with deepwater leases sold in the pre-DWRRRA period. The lack of sufficient time series data on exploration activity on leases sold in deepwater areas during the royalty relief period means that any interpretation of these results is fraught with difficulty.

This idea is substantiated when looking at simulation results of the hypothetical situation had no policy existed. These results are presented in Tables 6-9 and 6-10. In all cases, the models, which are based on the regression results presented in Tables 6-6, 6-7 and 6-8, estimate that the probability of a lease drilling or filing an exploration plan would actually improve had the policy not existed. For example, in 800-plus meters, the model predicts that 13 percent of leases would have drilled had no policy existed, compared to the actual probability of only 5 percent. Likewise, the probability of a lease in 800-plus meter filing an exploration plan is estimated to be 13 percent had the policy not existed, compared to only 8 percent with the policy in effect.

Table 6-9. Simulation Results of Probability of Lease Drilling Without Policy.

0-200	Annual Actual Probability of Lease Drilling	Annual Probability of Lease Drilling Attributed to Policy Variable	Annual Hypothetical Probability of Lease Drilling (No Policy)
Pre-Policy	42%	0%	42%
DWRRRA	28%	-7%	35%
200-800	Annual Actual Probability of Lease Drilling	Annual Probability of Lease Drilling Attributed to Policy Variable	Annual Hypothetical Probability of Lease Drilling (No Policy)
Pre-Policy	27%	0%	27%
DWRRRA	17%	-10%	27%
800+	Annual Actual Probability of Lease Drilling	Annual Probability of Lease Drilling Attributed to Policy Variable	Annual Hypothetical Probability of Lease Drilling (No Policy)
Pre-Policy	14%	0%	14%
DWRRRA	5%	-8%	13%

Table 6-10. Simulation Results of Probability of Filing an Exploration Plan Without Policy.

0-200	Annual Actual Probability of Lease Filing E-Plan	Annual Probability of Lease Filing E-Plan Attributed to Policy Variable	Annual Hypothetical Probability of Lease Filing E-Plan (No Policy)
Pre-Policy	40%	0%	40%
DWRRRA	29%	-12%	42%
200-800	Annual Actual Probability of Lease Filing E-Plan	Annual Probability of Lease Filing E-Plan Attributed to Policy Variable	Annual Hypothetical Probability of Lease Filing E-Plan (No Policy)
Pre-Policy	21%	0%	21%
DWRRRA	23%	-1%	24%
800+	Annual Actual Probability of Lease Filing E-Plan	Annual Probability of Lease Filing E-Plan Attributed to Policy Variable	Annual Hypothetical Probability of Lease Filing E-Plan (No Policy)
Pre-Policy	16%	0%	16%
DWRRRA	8%	-6%	13%

The second stage of the model provided even less meaningful results. We modeled discoveries as a probability distribution over the leases for which drilling had taken place, i.e., the subset of drilled leases). In all cases the royalty relief dummy variable was not significant, and the explanatory power of the regression was relatively low. Given the strong likelihood that we would be unable to produce a model in which the royalty relief variable would attain any significance, we did not attempt to develop this model any further.

Conclusion

The time frame for analyzing the impact of royalty relief on exploration and development is too limited to be able to generate any meaningful conclusions that stand up to statistical scrutiny. The data suggest some increase in drilling activity on leases sold during the first few years of the DWRRRA, but the data are limited at this point in time to be able to generalize about

impact. The first few years of the DWRRA program was also accompanied by an increase in oil prices which also may have stimulated drilling activity. Further, the dramatic technological progress achieved in drilling depths and operating in deeper and deeper water depths clearly stimulated exploration activity in deepwater. Therefore, it is difficult to isolate the impact of royalty relief on exploration activity even for leases whose terms have expired.

Chapter 7

Projection of Fiscal Effects of Alternative Program Designs

Introduction

In this chapter, we present projections of possible future economic effects from several alternative royalty relief programs. These alternative programs were provided to us by the MMS and include the following:

1. A deepwater royalty relief program that resumes (in the first forecast year) the original provisions of the DWRRA, implemented with a field-based definition of suspension volume and new production requirement. (*DWRR – Field*);
2. A deepwater royalty relief program that resumes the provisions of the DWRRA, but is implemented with a lease-based definition of suspension volume and dropping the new production requirement. (*DWRR – Lease*);
3. A deepwater royalty relief program that continues the program like the current administrative program, with a lease-based definition of suspension volume specified for year 2003 sales. (*Current*);
4. No future royalty relief for deepwater leases beginning in the first model forecast year. (*No Relief*).

The study investigated the fiscal effect of the alternative deepwater royalty programs by projecting, for each alternative scenario, the following activities over a forty-year period commencing with 2003:

- a. Number of exploratory wells drilled;
- b. Fields discovered;
- c. Reserves discovered;
- d. Total oil and gas production;
- e. Oil and gas production from fields discovered after 2002;
- f. Royalty-free oil and gas production; and
- g. Bonus, rental and royalty revenue;

We used the IIC, Inc. EDP model⁵⁹ developed for the MMS to determine all impacts with the exception of rental and bonus revenue. The EDP model is a comprehensive forecasting program that employs a variety of inputs including the existing resource base, the undiscovered resource base, resource prices, cost parameters, and federal regulatory constraints and policy programs. We constructed an exogenous model to determine rental and bonus revenue. We relied on the results of our historical lease sales and bidding analyses to estimate the future number of leases sold and bonus bids that then allows the estimation of future rental payments and bonus revenue.

This chapter discusses each alternative royalty relief program, the models employed to determine future effects, assumptions underlying the projections, and the overall results. We focus on the relative differences between each comparable projection, and address whether programs that include more generous royalty incentives tend to accelerate exploration activity. It is important to note that under each royalty program and price assumption, the projections are always forward-looking. The results of our analysis do not address the question of what *would have happened* in the past under the different royalty scenarios. Furthermore, the projections do not include reclassification of any existing discoveries or modification of existing field-specific inputs under the different royalty programs.

Royalty Relief Programs

The MMS provided us with information concerning the four alternative royalty relief programs. Each program was implemented at the beginning of the projection period. For fields discovered on leases sold prior to the projection period, we employed the actual historical royalty program in place at the time of the lease sale. If a field was discovered from a lease awarded between 1996 and 2000, the original DWRRA suspension volumes were used, while fields discovered on leases sold after the DWRRA relied upon the current program.⁶⁰ Fields discovered on leases let during the projection period rely on the particular alternative program under investigation.

Table 7-1 shows the royalty suspension volumes for each of the four royalty relief programs. The first program extends royalty relief for future lease sales according to the provisions outlined in the original DWRRA. These provisions specify certain royalty relief volumes on a field-level basis according to specific water depths. The second and third alternative royalty relief programs involve computing suspension volumes on a lease basis, as opposed to a field basis. The second program, listed in Table 7-1, applies the original DWRRA program but on a lease basis. Under the third alternative program, fields are assigned suspension volumes in a manner consistent with the second program alternative, but on a significantly reduced scale, according to the current royalty relief program. The fourth program eliminates all future royalty relief. Under this scenario, any and all fields discovered from lease sales

⁵⁹ This model was developed for MMS in a prior study. See IIC, Inc. (2004).

⁶⁰ Remaining royalty suspension volumes for existing fields were provided by the MMS. For this study, we have not adjusted these remaining suspension volumes despite the recent Kerr-McGee and Santa Fe court rulings. Remaining suspension volumes for existing fields remained consistent throughout each royalty alternative forecast. In addition, we have not considered the impact of production requirements for lease-based relief attributed to future field discoveries.

occurring in the future would not be eligible for royalty relief. Each alternative royalty relief program was assumed to last the duration of the projection period.

Table 7-1. Royalty Suspension Volumes under the Four Programs.

Program	Field or Lease Basis	Suspension Volume (mmBOE) by Water Depth (meters)				
		0-200	200-400	400-800	800-1600	1600+
DWRR - Field	Field	0	17.5	52.5	87.5	87.5
DWRR - Lease	Lease	0	17.5	52.5	87.5	87.5
Current	Lease	0	0	5	9	12
No Relief	Not Applicable	0	0	0	0	0

One major difference between the DWRRRA and the current program is that the former used a “field” definition of the relief volume suspension whereas the latter used a “lease” definition. The DWRR-Lease and Current alternative royalty relief programs involve computing suspension volumes on a lease basis, as opposed to a field basis. The DWRR-Lease program applies the original DWRRRA suspension volumes but on a lease basis. Thus, under the DWRR-Lease program alternative, fields discovered in 600 meters of water would be entitled to suspension volumes equal to the number of leases per field multiplied by the suspension volume.

As part of the DWRR-Lease royalty relief program, it was necessary to address the pre-production requirements of the DWRRRA. Based on our review of available field data and the structure of the IIC, Inc. EDP model, we elected not to change the historical, existing field data. We recognize that dropping the new production requirement would conceivably open the door for relief on existing fields, but it would be highly speculative on our part to attempt to forecast any time series of relief, and attempt to modify the EDP model to handle that relief. Furthermore, the MMS, during a mid-project meeting, indicated that eight applications, with a ninth pending, had been filed, seeking relief on leases sold prior to 1996. We do not believe the outcome of these applications, including granting of possible relief, would change our results or conclusions in a material manner, and thus elected to assume no additional relief.

Model Discussion

We employed two different models to determine the projected economic effects required by the MMS. The first, the EDP model, was previously developed for the MMS to forecast exploration, development, and production activity in the Gulf of Mexico (IIC 2004). A complete description of the model is contained in three volumes, available from the MMS. The second model was an exogenously developed program to project rental and lease bonus revenue for the projection period under the four alternative programs. The combination of results from the two models provides a complete picture of the fiscal and resource effects under each program.

The IIC EDP Model

In a previous engagement, the MMS required a fast-running expected value simulation of future exploration, development and production in the Gulf of Mexico. We developed a model that interfaced with underlying data contained in an Access database, and presented results in a Microsoft Excel workbook. Each model run encompasses a forty-year projection period. A key

factor in determining the projection period is the availability of current, up-to-date actual data to serve as a historical foundation for the forecasting algorithms. We elected to use 2003 as the beginning of the projection period, based on the accuracy of the available resource, discovery, and production data as of that date.⁶¹

Primary outputs are wells drilled of various types, fields discovered, production of oil and gas, infrastructure additions and removals, and royalty revenue. The IIC EDP Model also makes available a myriad of secondary parameters that the user can extract from the status variables generated by the model. The detailed output required by some applications of the model suggested that an aggregate perspective (e.g., GoM wide or play-level) would either be inadequate, or require excessive aggregation of widely disparate variables. Therefore, we elected to include a substantial amount of field-level modeling, while retaining the capability to aggregate where appropriate.

The four alternative royalty relief programs were incorporated under different price assumptions, but rely upon the same historical data that underlies each EDP model run. Although the model is constructed to compute data on a field-level basis, we aggregate the data across planning area and water depth category, as well as for the total Gulf of Mexico. This geographical diversity in reporting results allows us to isolate specific trends or anomalies in different regions.

A central feature of the IIC EDP Model is its economic submodel that computes revenue from production and estimates costs. Each model year, a net present value (NPV) for each area and size of field is computed. User inputs include a commodity price path, cost escalators that apply to internal capital and operating costs, and royalty rules and incentive structures. The NPVs are used as primary components of the model's simulation of a producer/explorer's decision process. Rising (falling) NPVs stimulate (reduce) exploratory drilling and make smaller fields more (less) attractive to develop and produce.

The principal components of the NPV determination are expected revenues, exploration and drilling costs, development costs, operating costs, depreciation and user-defined inputs such as the tax rate, royalty rate, possible suspension volume, and discount rate. The NPV calculation begins with the determination of a typical unconstrained field production profile, and then computes the annual costs of exploration, development, and production of the field. Revenues are based on the production profile, the current model year price, and the decision-maker's estimation of where the price will head in the future via a price escalator (which can be positive, zero or negative). In addition, revenues are adjusted for taxes and royalties. Once the cost and net revenue streams are determined, the discounted cash flow over a forty-year cycle is summed to arrive at the NPV for a particular area and size of field. These values are stored in an array, where they are retrieved as needed to determine the economic viability of a field.

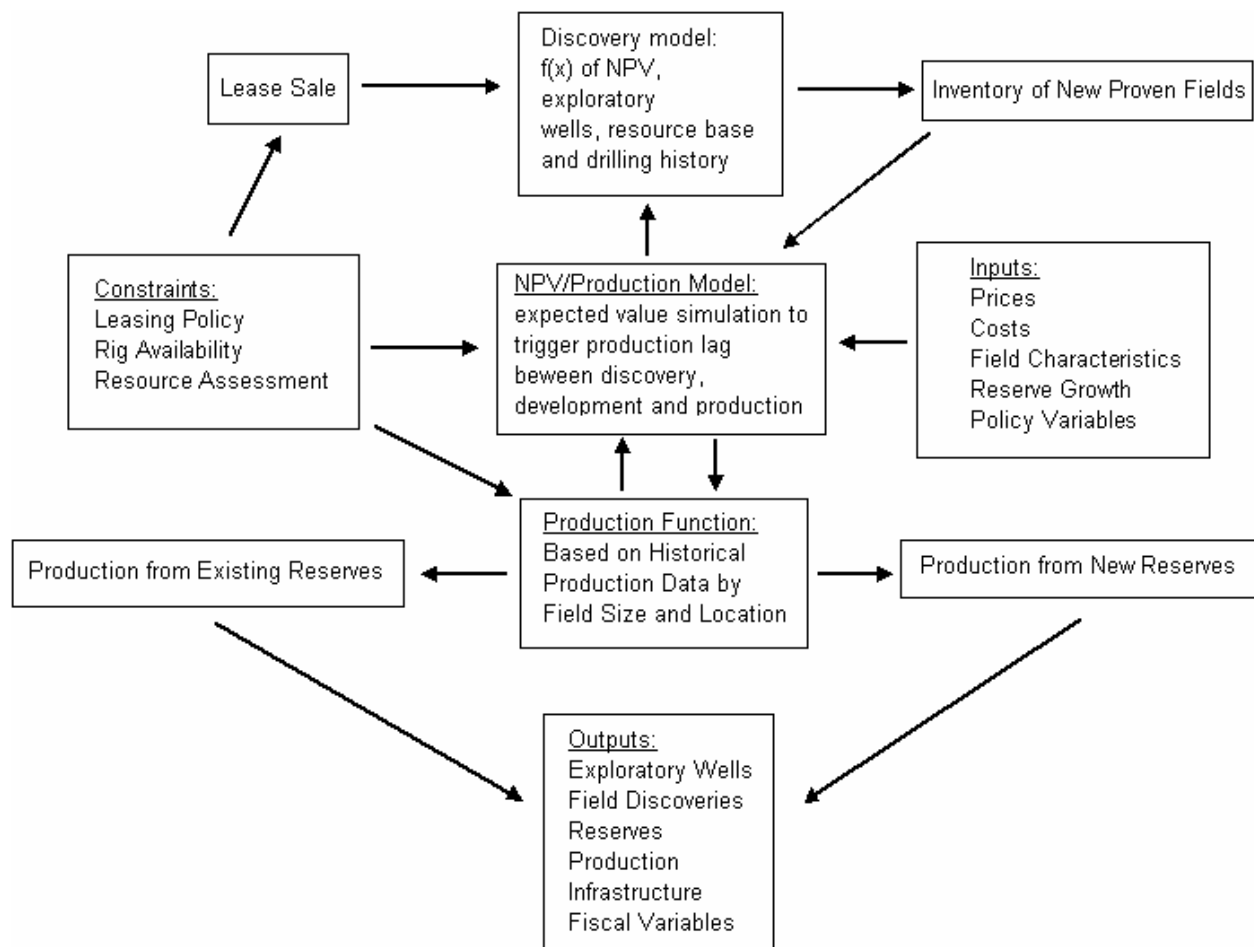
The ability to incorporate the alternative royalty relief programs in the NPV calculation allows the user to examine the impact these programs will have on future exploration activity.

⁶¹ Typically, there are several lags involved in the accuracy of the data provided by the MMS. As more recent data are acquired and verified, the EDP model is designed to allow for inclusion of additional "historical" years beyond the current end date of 2002, allowing the projection period to begin later, and extend further into the future.

Once exploration has discovered new fields, the relative differences in the royalty relief programs will also be realized in the variations in royalty revenue received from the future production associated with model discoveries.

Figure 7-1 presents a stylized overview of the IIC EDP model. The model itself is composed of several components or submodels including one which models the process of discovering new fields, another which generates economic parameters by which exploration/producers are simulated to make decisions affecting both the discovery process and the development/production process, and finally a component that estimates field production and reserves appreciation. As noted above, the model generates a series of output tables indicating number and type of wells drilled, fields discovered, production of oil and gas, infrastructure additions and remaining resources.

Figure 7-1: Schematic of IIC EDP Model.



The simulation is easiest to describe in terms of the normal flow of the exploration and development process as follows:

- Profitability, both due to recent and prospective discoveries, stimulates exploratory “wildcat” well drilling. Factors that influence profitability include oil

and gas prices, costs of development and production, taxes, royalties, size of field, potential fields left to be discovered, and many other factors, both input and internally generated.

- Exploratory wells find new fields. The number of fields found in an area in a particular year depends on the total field estimate input for that area and what has been found in previous years.
- If newly discovered fields are economic to produce, i.e., the economic submodule generated a positive net present value (NPV), they enter a queue and move toward production in a subsequent year if resources (principally in-field well drilling) are available for development.
- After discovery, a field's reserves appreciate according to a user input schedule (simulating the continual in-field exploration and delineation process). Production is a function of reserve levels for fields as they mature.
- At some point, a field's reserves are essentially exhausted, so its infrastructure assets are retired, and it ceases production.

Output variables such as reserves added, production, revenue flows, wells drilled, platforms installed and removed, and pipeline miles installed, are tabulated and made available to the analyst.

The EDP model makes a comprehensive forecast of Gulf of Mexico offshore oil and gas activities starting with the year 2003. The projections of each royalty alternative commence with 2003 and activities that occurred prior to the first projection year have not been altered. For example, when projecting offshore oil and gas activities associated with the alternative that provides no relief, this only applies to lease sales commencing in 2003. We have not retroactively changed the leasing policy associated with deepwater royalty relief prior to 2003 to model what would have happened had royalty relief programs never been instituted.

Each EDP model forecast provides results containing the same set of outputs, regardless of changes in the input assumptions, and employs a consistent set of terminology. For this study:

- *Exploratory wells drilled* refer to the number of exploratory wells drilled to find previously undiscovered fields. Exploratory wells in the EDP model can be viewed as “wildcats” in the purest sense, as they discover only new fields, not new reservoirs in existing fields.
- *Fields discovered* represent the expected number of previously undiscovered fields discovered as a result of exploratory well drilling.
- *Grown reserves discovered* are the total amount of reserves found with each new field discovery. Data provided by the MMS Resource and Evaluation Department indicate that fields typically “grow” over time from their initial resource estimate,

through in-field reservoir discovery and reserves appreciation. Grown reserves represent the ultimate resource estimate, including the amount of reserves discovered over time, in addition to the original reserve estimate.

- *New fields* are fields projected to be discovered in the forecast period (2003-2042). These discoveries are forecasted by the model and are also labeled as *model discoveries*
- *New production* represents production from fields that are discovered between 2003 and 2042. These include model discoveries on leases let prior to 2003..
- *Existing fields* are field discoveries that occurred prior to the first projection year (2003). Existing fields retain any royalty relief given by the DWRRA or Post-Act programs, unchanged by the royalty relief scenario under investigation. Discoveries associated with years 2003-2005 are “future” for purposes of this study, and the forecast of these years does not necessarily match the historical record for these years.
- Financial variables are computed in constant dollars, and *present value* variables are computed using a discount rate of 12 percent.
- *Price thresholds* represent price levels which royalty relief is foregone, regardless of remaining suspension volumes, when the annual resource price exceeds the threshold level.

EDP Model Modifications

The EDP model was originally developed as a field-level forecasting model, designed to project exploration, development and production variables in the Gulf of Mexico. Attempting to model these parameters under the four alternative royalty relief programs required us to make several modifications. Although many modifications were minor and enhanced the functionality of the model, there were some significant changes to handle the lease-level royalty suspension volumes dictated by two of the alternative programs.

The original EDP model mandated the user to define a unique gas to oil price ratio. The model user would enter in a projected oil price path (\$/boe) and establish the gas price (\$/mcf) as a fixed ratio of the oil price. The latest version of the EDP model allows the user to establish projected oil and gas price paths independent of each other over the forty-year projection period. In addition, the user is now allowed to enter similar projected oil and gas price paths to establish price thresholds.⁶² Thus, if the user wants to exceed the oil price threshold for a specified period, he can enter in an oil price threshold path that is lower than the projected actual oil price path during the desired time period.

⁶² In periods of high oil and/or gas prices, price thresholds, defined by the MMS, serve to cancel royalty relief on production of oil and gas.

The most significant issue we faced in modifying the EDP model was attempting to incorporate lease-specific behavior into a model designed to handle field-specific input parameters. There are two primary changes: first, inclusion of a lease to discovery lag, and second, definition of royalty suspension volumes on a lease basis. With regard to both issues, it was necessary to make some simplifications and assumptions that allowed rapid model modification to arrive at timely results. The MMS provided us guidance and agreed the simplifications and assumptions were reasonable for projecting the future fiscal and resource impacts associated with the four alternative royalty relief programs.

We established a lease to discovery lag, shown in Table 7-2, for each water depth category, which served as a basis for determining which lease “rules” to employ for new discoveries. Assuming that the lease to exploration lag is uniform for all leases across a particular water depth is a simplification of what is actually observed. Typically, initial drilling on a lease occurs at various times between the commencement of the lease term and the final year before lease expiration. The values shown in Table 7-2 are a simplification, aimed at capturing the mean of this drilling distribution for each water depth.

Table 7-2. Lag Between Lease Commencement and Exploratory Drilling.

Water Depth	Lag (Years)
0-60	2
60-200	2
200-400	3
400-800	4
800-1600	5
1600-2400	5
2400+	6

Originally, the EDP model only allowed the user to enter a royalty suspension volume on a field basis for a particular water depth category, independent of field size. Although this methodology is suitable for modeling the original DWRRA volumes, it failed to adequately allow the user to model the current DWRRA volumes, and any program that applies suspension volumes on a lease-level basis. We changed the model to allow the user the choice to either apply volumes on a field- or lease-level basis. For lease-level volumes, it was necessary to estimate the number of producing leases per field over the life of the field. Using historical data, we examined each Gulf of Mexico field and determined the total number of distinct leases that had produced over its life. We then averaged the number of leases per field age, specific to field size, across water depth and subsequently plotted the data.⁶³ We determined the approximate number of producing leases we can expect over the life of the field by examining the trend when the field age equals 50 years, and scaling this number back to help compensate for future expectations, and to avoid overcompensating royalty relief for all leases at the beginning. The

⁶³ We elected to average the fields within each water depth category, 0-200, 200-800 and 800+ meters, and then “average the averages” for our final analysis. We did this to avoid unfairly biasing the results towards shallower water depths, where there was considerably more data. This assumption was based on the possibility that deeper water fields may ultimately have a lower number of producing leases per field compared with similar fields in shallow water. Ideally, we would perform the analysis for each water depth, but because deeper water fields are relatively immature, there is not a sufficient time horizon to draw conclusions accurately.

results for each field class size are summarized in Table 7-3. This allowed us to determine the appropriate royalty suspension volume for the field based on the lease-level suspension volume multiplied by the number of expected producing leases.

Table 7-3. Producing Leases per Field Size

USGS Field Size	Producing Leases
<8	1
8	1.5
9	1.5
10	2.5
11	2.75
12	3.75
13	4
>13	5

Inherent in this change are two approximations of what is actually observed. First, we are “front-loading” the royalty relief, even though we recognize that different producing leases are not all sold in the initial lease sale associated with the field discovery. This approximation will tend to overestimate the level of royalty relief in the initial years, and possibly underestimate the level of royalty relief in the later years. Second we are assuming that there is a set number of producing leases based on field size, even though historically this number has been a distribution over fields of the same size. Similar to the lease to exploration lag, the values shown in Table 7-3 are a simplification, aimed at capturing the mean of producing leases per field distribution for each field size.

The Lease Bonus-Rental Model

The lease bonus-rental model determines the present value of future cash flows for rental and lease bonus revenue earned by OCS lease sales in the forty-year projection period for the four royalty relief program scenarios discussed above.⁶⁴ The model relies on an estimation of the number of leases sold in each year, as this value directly affects bonus revenue, and the inventory of leases held, upon which rental revenue is computed. The manner in which these values were determined required some generalization and estimates based on historical lease data provided by the MMS as well as our statistical analyses described in Chapters 3 and 5.

Determination of Leases Sold in the Future

The primary input into the front-end model is the estimate of the number of leases sold in each of the 40 years of the projection period. Values for the number of leases sold are determined based upon historical averages of leases sold, implications from the regression results discussed in Chapter 3 and our judgment regarding the duration of the programmatic impacts on lease sales. Initial year values (2003) for each of the four scenarios, as shown in Table 7-4 below, are determined as follows:

⁶⁴ Results include only the Central (CGM) and Western (WGM) Gulf of Mexico Regions. The Eastern Gulf of Mexico Region (EGM) was omitted due to the expectation of few if any future EGM sales.

- **DWRR – Field** – Initial year value takes the no relief value and adds the average number of leases added per year by the Deepwater Royalty Relief Policy (1996-2000), as determined by regression results.
- **DWRR – Lease** – Initial year value takes the half of the difference between the DWRR-Field and Current scenario initial year values, and adds that difference to the larger of the two values.⁶⁵
- **Current** – Initial year value takes the no relief value and adds the average number of leases added per year by the Post-Deepwater Policy Period (2001-2003), as determined by regression results.
- **No Relief** – Initial year value is based on the mean value of leases sold per year in Central and Western Gulf sales between 1983 and 1995.

Table 7-4. Estimation of Leases Sold in Year One Under Four Relief Programs.

Program	0-200 m	200-800 m	800-plus m
No Relief	430	91	137
DWRR-Field	424	135	350
DWRR-Lease	498	147	419
Current	473	111	212

These results are utilized as the basis upon which we determined the number of leases sold for the remainder of the time period. In each subsequent year, the new estimate of leases sold is based on the total number of tracts offered in the sale, a value determined from the number of leases sold in the prior year, as well as newly expired and producing leases. After year one, the number of leases sold each year was based on year one’s ratio of leases sold to tracts offered (“L/T”).⁶⁶ The ratio for each year (for each program and water depth) is multiplied by the total number of tracts offered in that year’s sales to determine the number of leases sold in that year. In the 0-200 meter and 200-800 meter water depth categories, the L/T ratios for the Current, DWRR-Field and DWRR-Lease Programs remain constant for projection years two through five, utilizing year one’s L/T ratio. Beginning in year six, the ratio used for these programs is that of the No Relief scenario. In the 800+ meter water depth category, year one’s L/T ratio is used for the Current, DWRR-Field and DWRR-Lease Programs in year two, and then ratio gradually decreases, until it reaches the L/T ratio used for No Relief in year six and beyond.⁶⁷ The ratios for the No Relief Scenario remain constant for all forty years.

⁶⁵ There is no historical data from which to measure such a policy, however we estimate this policy to have the largest effect of the three, thus modifying the value of leases sold to exceed that of the other two policies.

⁶⁶ The value used for the number of tracts offered in year one, 8,455, was the actual number of tracts offered in the 2003 OCS sales. The L/T Ratio was calculated by taking the number of leases sold at each water depth and in each program and dividing by 8,455. Source: MMS Table 2. *Gulf of Mexico Oil & Gas Lease Offerings*.

⁶⁷ For Programs 1, 2 & 3 in the 800+ meter Water Depth Category, year two’s ratio is the L/T ratio determined from year one’s leases sold. Ratios for Years 3-5 are determined by taking the sum of the ratio for Program 4 with Programs 1, 2 & 3 respectively, and multiplying by .75 for year 3, .5 for year 4, and .25 for year 5. Based on the

The number of tracts offered each year starts with the number of tracts offered in year one, which we estimated to be 8,455 based on actual data. The number of tracts offered in each subsequent year is then calculated by taking the starting value from the previous year, subtracting the total number of leases sold in that year, and adding back in any leases that expired in the year. This is based on an assumption that all leases, unless they go into production, will ultimately be re-offered in a later sale.

Lease expiration is another key consideration in this calculation. Lease expiration is based on analysis of historical lease data with the sample including all area-wide leases which had expired as of the end of 2001. Although each lease is associated with a specified lease term, based on water depth, it is rare that the lease life extends for the exact contractual lease term. Therefore, we have divided expiring leases into three categories: 1) regular leases, which expire within 180 days of the expected expiration of the lease,⁶⁸ 2) extended leases, which expire beyond 180 days after the contractual expiration date, and 3) leases that go into production. In examining the data, we determined the percentage of all expiring leases that fall into each of these three categories, and the average length of time between the effective date of the lease and its expiration (or its commencement of production), shown in Table 7-5.

Table 7-5. Timeframe of Expiring Leases.

Water Depth	Percent of Leases			Average Life of Lease in Years		
	Extended	Producing	Regular	Extended	Producing	Regular
0-200 m	8.4%	10.0%	81.6%	7.2	4.2	4.6
200-800 m	11.0%	8.2%	80.8%	8.0	6.6	4.7
800-plus m	5.8%	9.2%	85.0%	10.6	11.2	6.5

Due to the fact that these values are based on historical data, the leases in production reflect the high activity in shallow water and the low activity in deepwater in the period between 1983 and 2001. Due to the forward-looking nature of the model, we made the assumption that the number of producing leases in the shallow water would decline, while leases in production in deepwater would increase. We therefore modified the values of the percent of leases that will go into production from 18.52 to 10.00 percent in 0-200 meters and from 3.52 to 9.18 percent in 800-plus meters.⁶⁹

Besides the approximation of when the estimated number of leases sold will expire is the estimation of when pre-2003 leases will expire. As of the end of 2002, there were 4,684 leases in inventory.⁷⁰ We used the values in Table 7-5 to determine when these leases would expire or begin producing in the future, and incorporated their expiration into the total number of tracts offered as well as into the inventory of leases held. The remaining active leases, that

data and the regression results, we saw a significant decline in the effect of the program variable on the number of leases sold after a few years.

⁶⁸ The “expected” expiration date is determined by taking the effective date of the lease using the 1900 date system, and adding 365 days multiplied by the length of the lease term. Source: Lease Details Table provided by the MMS.

⁶⁹ The difference in the percentage of leases going into production was allocated to the percentage of leases with regular expiration, changing the values of regular expiration for 0-200 meter from 73.04 percent to 81.56 percent and for 800+ meter from 90.66 percent to 85.00 percent.

⁷⁰ The 4,684 leases include 1,311 in 0-200 meter, 341 in 200-800 meter and 3,032 in 800+ meter.

hypothetically should have expired prior to the end of 2001, remained in our 2002 beginning inventory as a proxy measure for anomalous leases that have extensive lease lives.⁷¹

Rental Revenue

The calculation of rental revenue is based on the total number of leases in inventory in each water depth category at a given point in time. Similar to the calculation of the number of tracts offered, the inventory calculation is based principally on the number of leases sold and the number of leases expiring or going into production each year. The year-end inventory is calculated by taking the previous year's ending inventory, adding in any new leases sold, and subtracting out the number of leases expiring, as well as the number of leases that go into production, as these leases are no longer responsible for paying rental fees. Once the inventory for each water depth was established, the appropriate rental payments of \$5.00 per acre for 0-200 meters and \$7.50 per acre for 200+ meters were applied to each lease in inventory in order to determine the total annual rental revenue on a dollar per acre basis. This value was then multiplied by the median values of 5,000 acres for 0-200 meter leases and 5,760 acres for both 200-800 meter and 800+ meter leases to get the annual dollar value for rental revenue.⁷²

Bonus Revenue

The lease bonus revenue for each of the forty projected years is determined by multiplying the number of leases sold by the average high bonus bid in each year. The average high bid is determined using both historical data as well as the regression results discussed in Chapter 5. Actual data were used to calculate the average high bid for the No Relief scenario. The sample used included lease sales from 1986 through 1995 in which no royalty relief program existed, with the result being \$139.63 per acre in 0-200 meter, \$112.58 in 200-800 meter and \$73.82 in 800-plus meters.⁷³

The average high bids for the remaining three programs are shown in Table 7-6. These values were determined by taking the average high bid for the No Relief scenario, and applying the impact of the regression results, as well as making other generalizations where the regression implications were not available, or not statistically significant. The impact on the high bid for the DWRR-Field and Current relief programs are directly related to the regression results presented in Chapter 5. For example, based on the regression results for 800-plus meter, the average high bid per acre was \$57.85 higher during the Deepwater Royalty Relief Period, our proxy for the DWRR-Field program. Therefore, the average high bid per acre increased from \$73.82 for the No Relief Program, to \$131.67 for the DWRR-Field program. Similar adjustments were made for the 0-200 meter and 200-800 meter water depths. However, the Post-Royalty Relief dummy variable, our proxy for the Current program, was statistically insignificant in the regression results for the 0-200 meter and 200-800 meter water depths. The average high bid for the 0-200 meter and 200-800 meter water depths for the Current program was

⁷¹ These extended term leases remaining in inventory includes 61 leases in 0-200 meter, 52 leases in 200-800 meter and 139 leases in 800+ meter (252 total leases).

⁷² Source: Lease Details Table Provided by MMS.

⁷³ Although there were area-wide lease sales from 1983-1985, these sales included many anomalous bids, thus we excluded these sales from our high bid estimate.

subsequently modified to reflect the high bid utilized for the No Relief scenario. Therefore, only the 800-plus meter average high bid reflects the implications of the regression results for the Current program. Finally, the average high bid for the DWRR-Lease program had to be estimated using the values of the other two relief (DWRR-Field and Current) programs due to the fact that no historical data exists for a DWRR-Lease type program. Because of the nature of this type of program, providing the most incentive for potential lessees, the average high bid for this program was estimated to reflect the most successful of the relief programs. The high bid for the DWRR-Lease program was estimated by taking half of the difference between the average high bid for the DWRR-Field and Current relief programs and adding this difference to the larger of the two values, which, in each case, is the DWRR-Field value.

Table 7-6. Estimation of High Bid Per Acre Under Four Relief Programs.

Program	0-200 m	200-800 m	800-plus m
No Relief	\$139.63	\$112.58	\$73.82
DWRR-Field	\$153.39	\$152.26	\$131.67
DWRR-Lease	\$160.27	\$172.11	\$150.96
Current	\$139.63	\$112.58	\$93.09

These values for the high bid for each program are then multiplied by the estimated number of leases sold each year for the four programs. This gives us our estimate of the bonus revenue earned by the MMS in each of the forty years of the projection period.⁷⁴

Present Value Estimate of Revenue

The present value estimate of revenue is used to determine the prospective economic income stream for the MMS from rental and bonus revenues over the forty-year period from 2003 to 2042. The present value estimate for each year is calculated using rental and bonus revenues and the present value interest factor (“PVIF”), which is calculated as:

$$PVIF = \frac{1}{(1+r)^t}$$

where r is the discount rate and t is the year for which the PVIF is being calculated.⁷⁵ Once the PVIF is calculated for each year, it is then multiplied by the sum of that year’s rental and lease bonus revenues, giving an estimate of present value income stream for each of the 40 years. These values are then summed to give a forty-year estimate of the present value of future cash flow for each of the four royalty relief programs as shown in Table 7-7. As discussed below these estimates are integrated with the other fiscal impacts that flow directly out of the EDP model to provide a comprehensive fiscal impact analysis of each of the program alternatives.

Table 7-7. Present Value Estimate of Rental and Bonus Revenue Under Four Relief Programs.

⁷⁴ We also developed separate estimates by water depth based on regressions performed specific to each water depth category and normalized these to be consistent with the total area-wide estimates.

⁷⁵ We applied the mid-year discounting convention for t assuming all cash flows are remitted and received at the mid-point in the year. In addition we applied a 12 percent discount rate in this model to be consistent with the discount rate used in the EDP model.

Program	0-200 m	200-800 m	800-plus m	Total
No Relief	\$2,562,670,445	\$524,624,353	\$735,689,534	\$3,822,984,332
DWRR-Field	\$2,629,823,924	\$744,877,891	\$1,925,126,474	\$5,299,828,289
DWRR-Lease	\$2,865,935,915	\$844,688,528	\$2,388,502,301	\$6,099,126,744
Current	\$2,598,739,120	\$583,328,127	\$1,108,062,073	\$4,290,129,320

Model Inputs

The forty year projections for each alternative royalty relief program are dependent on various inputs and assumptions into the EDP⁷⁶ and the Lease Bonus-Rental models. The notable inputs include:

- Undiscovered resource base and discovered fields that exist as of year-end 2001 (EDP)
- Discount rate (EDP and Lease Bonus-Rental)
- Oil and Gas Price Projections (EDP)
- Price Threshold Assumptions (EDP)
- Royalty Relief Program (EDP)

The EDP model is easily configured to handle a variety of resource distributions. For the current study, the discovered and undiscovered resource estimates are based on the MMS National Assessment and supplemental data provided by the MMS Gulf of Mexico Resource and Evaluation Department. The resource distributions were provided at a level of detail sufficient to categorize individual fields by planning area and water depth category.⁷⁷ The MMS provided us with an initial undiscovered resource base and list of existing fields. The data include the volume of undiscovered resources in various regions of the Gulf of Mexico and serve as the foundation for projected discoveries, and subsequently, development and production. In addition, we were provided information concerning the number and size of existing fields in the Gulf of Mexico. For each existing field, the MMS had data on the cumulative oil and gas production through the end of 2001, the ultimate grown field size, oil to gas ratio and the existing level of infrastructure. Any modifications to this data set were either provided by or agreed to by the MMS. We did not adjust these data sets based on differences in price or policy assumptions. Each forty-year projection draws upon the same set of discovered fields and undiscovered resources to determine the future exploration, development, production and fiscal effects.

In addition, we relied upon MMS guidance for the appropriate selection of certain model parameters, including discount rate, resource price scenarios, reserve growth parameters, federal

⁷⁶ The inputs and assumptions that underlie the EDP model are discussed at length in IIC (2004) and will not be covered here.

⁷⁷ We employ three planning areas (Central, Western and Eastern) and seven water depth categories (0-60, 60-200, 200-400, 400-800, 800-1600, 1600-2400, and 2400+ meters).

leasing policy, and production calibration factors. We used a 12 percent discount rate, based upon discussions with the MMS. This discount rate is employed uniformly over the forty-year projection period, independent of the price or policy assumptions. The discount rate is primarily used in computing the net present value of cash flows related to different fields in each model year, as described in the EDP model overview. The discount rate is also used to compute the present value of the projected annual royalty, rental and lease bonus revenue.

The initial base projection was performed using a real oil price of \$30 per barrel and a gas price of \$4.54 per mcf, under the DWRR-Lease program provisions. The results of the initial base run were consistent with MMS expectations and served as a calibration of the model. The remainder of the model runs performed under Task 2 of this project involved one of two price series, specifically provided by the MMS. The two price series are displayed in Table 7-8, and represent real prices.⁷⁸

Table 7-8. Price Inputs Provided by the MMS.

Scenario	Oil Price (\$/bbl)	Gas Price (\$/mcf)
1	\$30.00	\$4.54
2	\$46.00	\$6.96

One other issue concerning prices relates to the price thresholds. When royalty relief price thresholds are exceeded, fields with suspension volumes do not receive relief on oil and/or gas produced, thus foregoing the relief.⁷⁹ In order to test the sensitivity of the results to price thresholds, we ran the EDP model using each price scenario and relief program but included periods where the price thresholds were exceeded. The decision to test specific sensitivity periods was based on discussion with the MMS regarding expectations of when price thresholds would be exceeded. The price paths in the EDP model are defined explicitly by the user. In that sense, the user is establishing simple mean expectations of the future under a stochastic price model. The MMS periodically reviews the price thresholds and it is reasonable, given the uniformity of the user-defined price path, to assume periods where the price threshold might be exceeded.⁸⁰

Results

The first step was to ensure that the projected results were not unreasonable given actual historical data and reasonable expectations of the future. As shown in Figure 5-2, the future expected production trend indicates a rise in the overall level of production, followed by a steady decline after the volume peaks in 2017. The primary reason for the observed increase is a series of large fields that are known, but not currently producing, as of the first model year. As these large fields begin production, they build up to a peak before declining. Another factor leading to

⁷⁸ For a full discussion of how the price series is treated in the EDP model, please refer to OCS Study MMS 2004-018.

⁷⁹ Litigation aimed at overturning the DWRR price threshold as implemented by the MMS is possible in the future.

⁸⁰ Also as a result of discussions with the MMS, we investigated the possibility that price thresholds were not applicable for certain leases granted in 1998 and 1999. We tested the significance of this issue by comparing the maximum relief, high price, threshold exceeded case with one in which fields attributed to leases let in 1998 and 1999 were not subject to those price thresholds. The difference was minimal based on our analysis and we did not pursue the issue for all different price and royalty program combinations.

the rise in production is a corresponding increase in exploratory drilling during the late 1990s and the initial model years, shown in Figure 7-3.

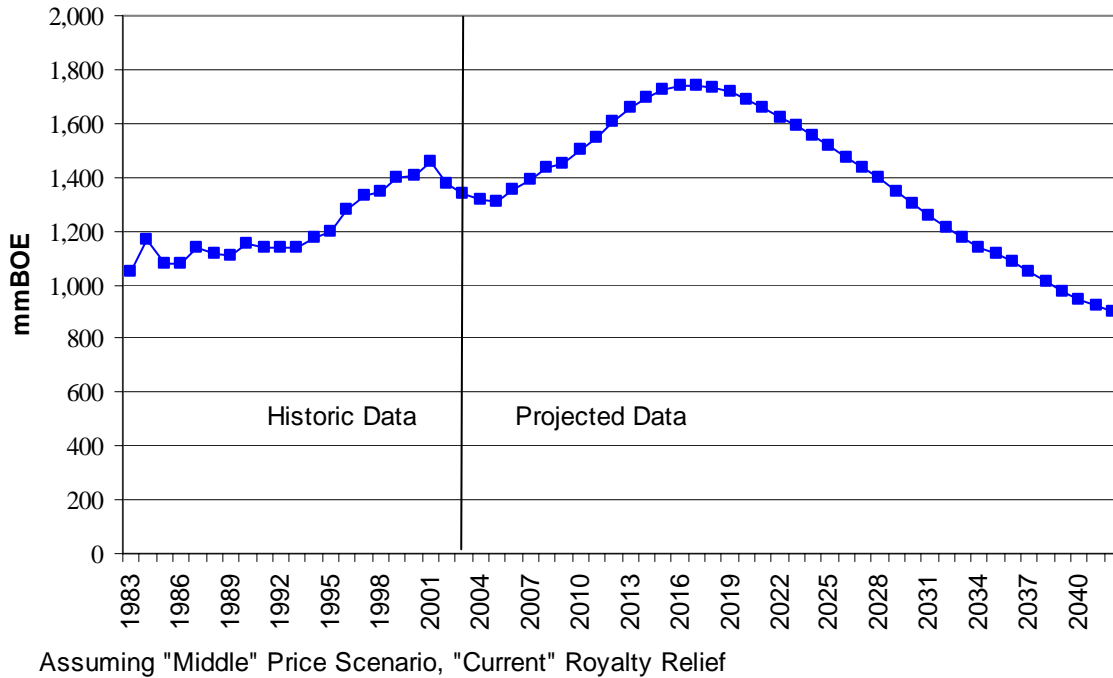


Figure 7-2. All Gulf of Mexico Production.

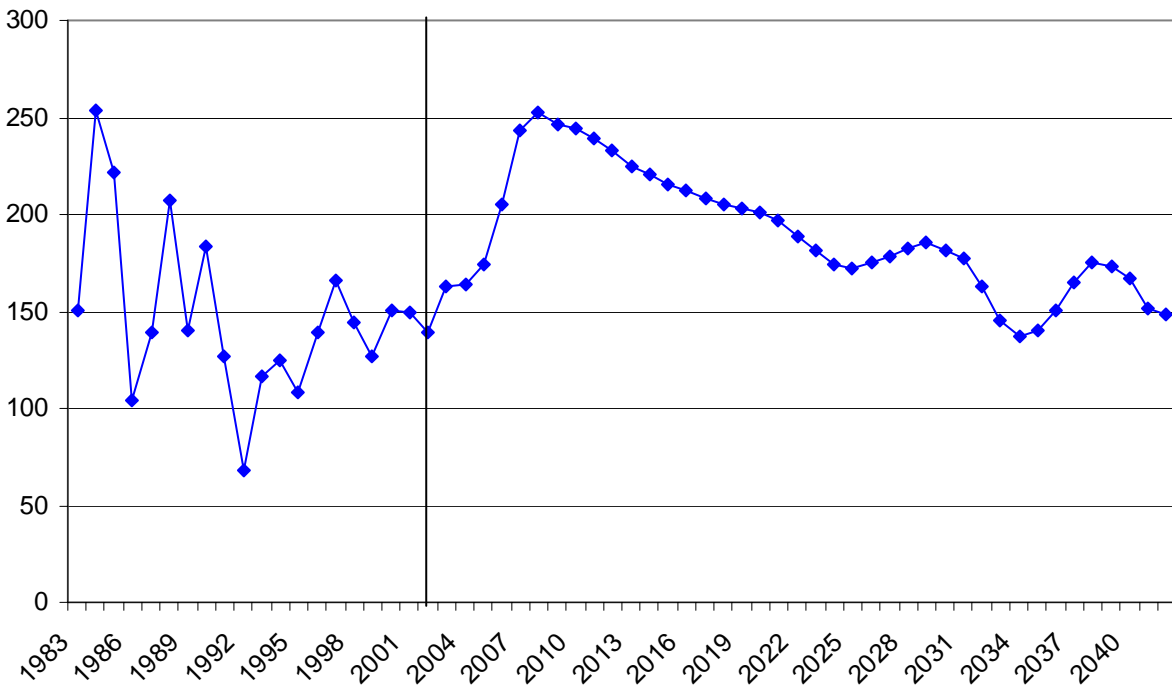


Figure 7-3. Exploratory Well Drilling, All Gulf of Mexico.

The drilling results indicate that the overall upward trend observed in the late 1990s is forecasted to continue, peaking in 2008, before entering a declining trend over the majority of the remaining forty-year projection period. This is consistent with the production data, as increased drilling leads to a larger number of fields found. As more fields are discovered, we expect to see an increase in the production associated with these fields, once development is completed. Once we completed the base run, and validated the reasonableness of the forecast, we began our analysis of the four alternative royalty relief programs under different price assumptions.

We started by performing model runs using the current royalty relief program under the two different price assumptions provided by the MMS. Table 7-9 lists forty-year EDP model results for the price scenarios, where price thresholds are never exceeded. The results only include the sum of values over the forty-year projection period, and do not include historical results prior to the first model year. We see that a significant portion of future production and royalty collection is attributable to fields that have yet to be discovered. Although the percent of undiscounted total royalty revenue is substantial, the present value of the royalty revenue from new fields represents a much smaller percentage due to the fact new field production is not expected until a few years into the future.

Table 7-9. Effects of Price on Activities at All Fields under the DWRR-Lease Royalty Alternative.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Discovered Fields	Exploratory Wells Drilled	Reserves Discovered (mmBOE)
DWRR - Lease	All	30	4.54	678	7,675	49,772
DWRR - Lease	All	46	6.96	796	9,921	57,281
			Difference	119	2,246	7,510

Table 7-9 (continued)

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Total Gas Production (Bcf)	Total Oil Production (mmBbl)	New Gas Production (Bcf)	New Oil Production (mmBbl)
DWRR - Lease	All	30	4.54	152,869	29,204	97,800	16,689
DWRR - Lease	All	46	6.96	172,734	32,992	117,665	20,477
			Difference	19,866	3,788	19,866	3,788

Table 7-9 (continued)

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Present Value Royalty Revenue (mm)	Present Value of New Field Total Royalty Revenue (mm)	Percent of Production from New Fields	Percent of Present Value Royalty Revenue from New Fields
DWRR - Lease	All	30	4.54	52,148	17,504	60%	34%
DWRR - Lease	All	46	6.96	92,864	33,390	65%	36%
			Difference	40,715	15,886		

Note: Values in \$2003. Present value at 12%. Reserves are ultimate (grown) amounts.

The results are consistent with common sense, considering the EDP model is largely dependent on the oil and gas price to stimulate exploration activity. We include the incremental difference due to price in the results of Table 7-9. At higher prices, there is a rise in the net present value of expected field discoveries, which leads to an increase in exploration activity relative to lower price scenarios. This increase leads to a domino effect, as an increase in exploratory well drilling will lead to an increase in discoveries, and subsequently production, infrastructure, and collection of royalties.

Figures 7-4 and 7-5 illustrate the relative differences in oil and gas production between the two price scenarios. As the price increases, the peak of production is shifted farther into the future. In addition, we notice that the relative difference in production between the \$30 and \$46 case narrows as we approach the end of the projection period. Both of these points are directly related to the level of discoveries that occur in the projection period. As depicted in Figure 7-6, projected field discoveries in the \$46 case are accelerated in the initial years of the forecast period. These discoveries stretch out the production curve and extend the peak slightly into the future after their build-up period. Production from new field discoveries is the driving force behind the shift in the production peak. Furthermore, by accelerating the rate of discovery in the \$46 case, we end up with less to discover in the later time period relative to the \$30 case. We observe this trend in Figure 7-6, where a slightly larger number of discoveries in the \$30 case after 2025.

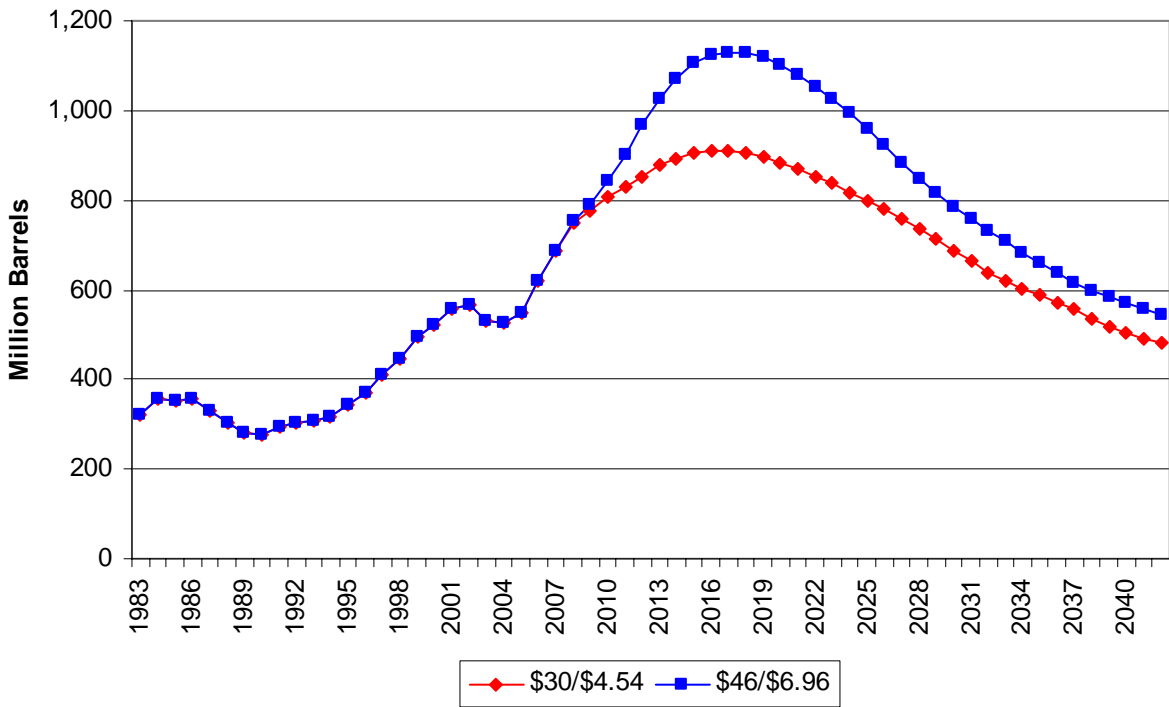


Figure 7-4. Effects of Price on Oil Production at All Fields Under Current Royalty Alternative.

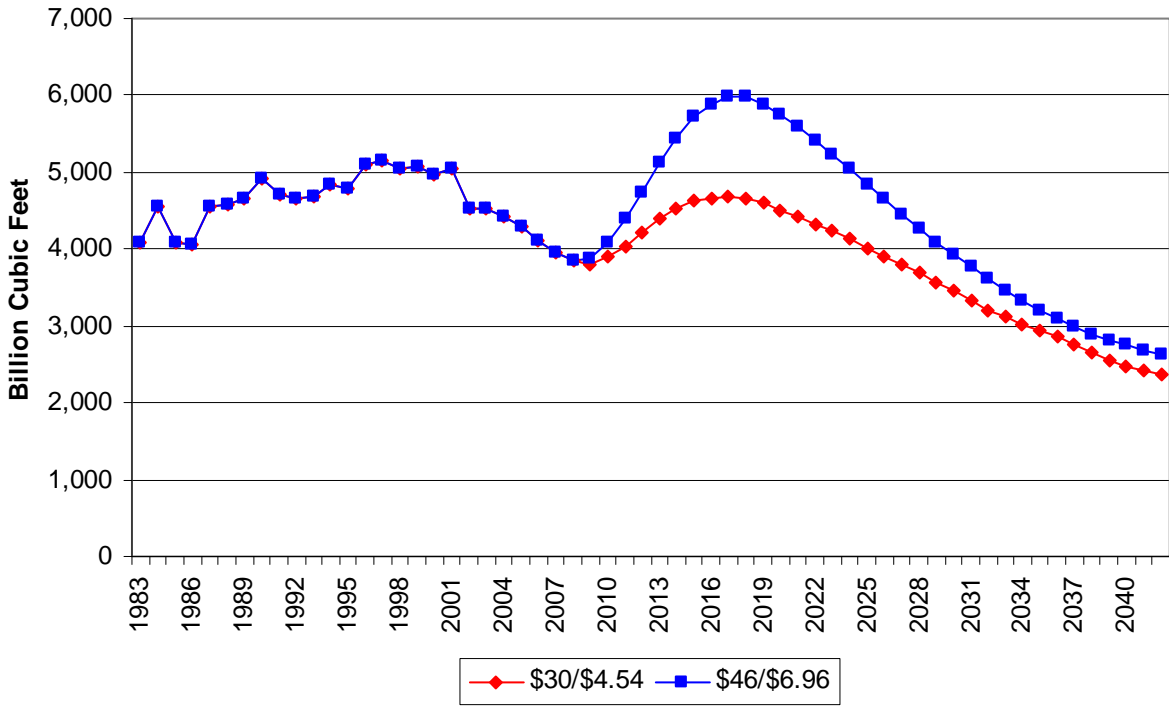


Figure 7-5. Effects of Price on Gas Production at All Fields Under Current Royalty Alternative.

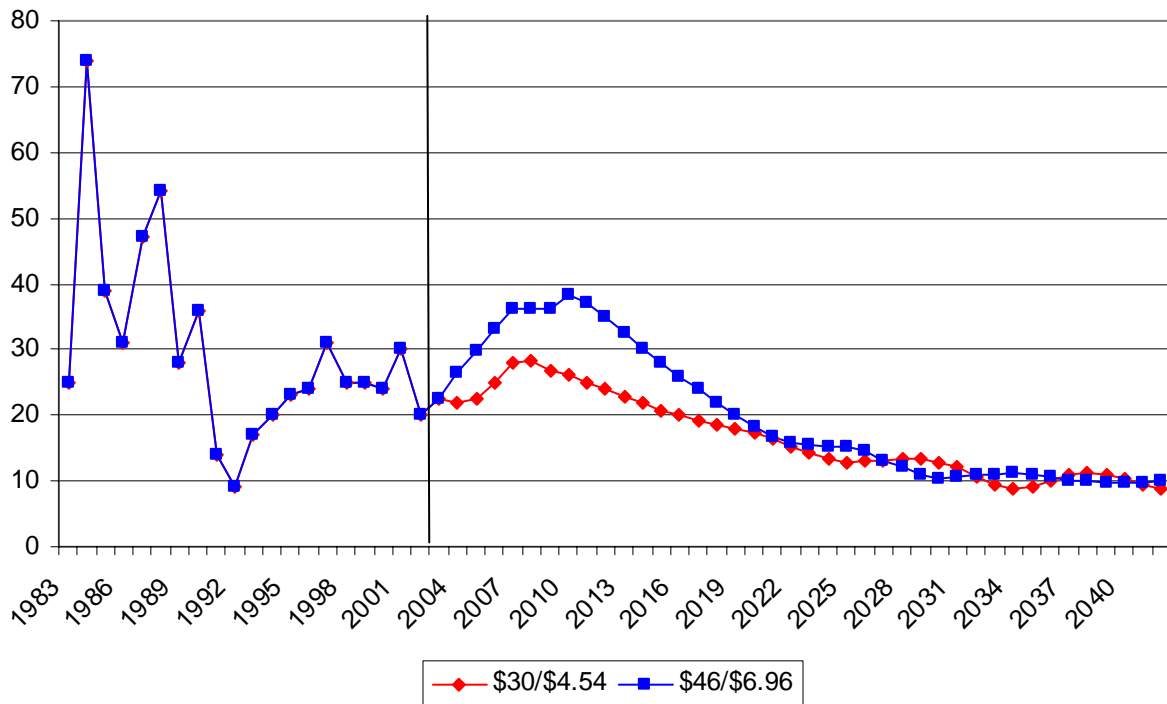


Figure 7-6. Effects of Price on Field Discoveries at All Fields Under Current Royalty Alternative.

The most significant, and obvious, difference between the different price scenarios involves the expected royalty revenue, shown in Figure 7-7. Under the current program, or any of the four programs, there will be large variation in expected royalty revenue because it is a direct multiplicative function of oil and gas prices. The relationship among the two price cases is also exaggerated by the difference in future discoveries. In the higher price case, we expect more discovery, and subsequently higher production and royalty revenue. Referring to Table 7-9, we would expect to collect an additional \$40 billion in present value royalty revenue based on the higher oil and gas price. Although this number may seem astonishing at first, it is quite consistent with our expectations considering the \$16 per barrel and \$2.44 per mcf differentials between the two price scenarios.

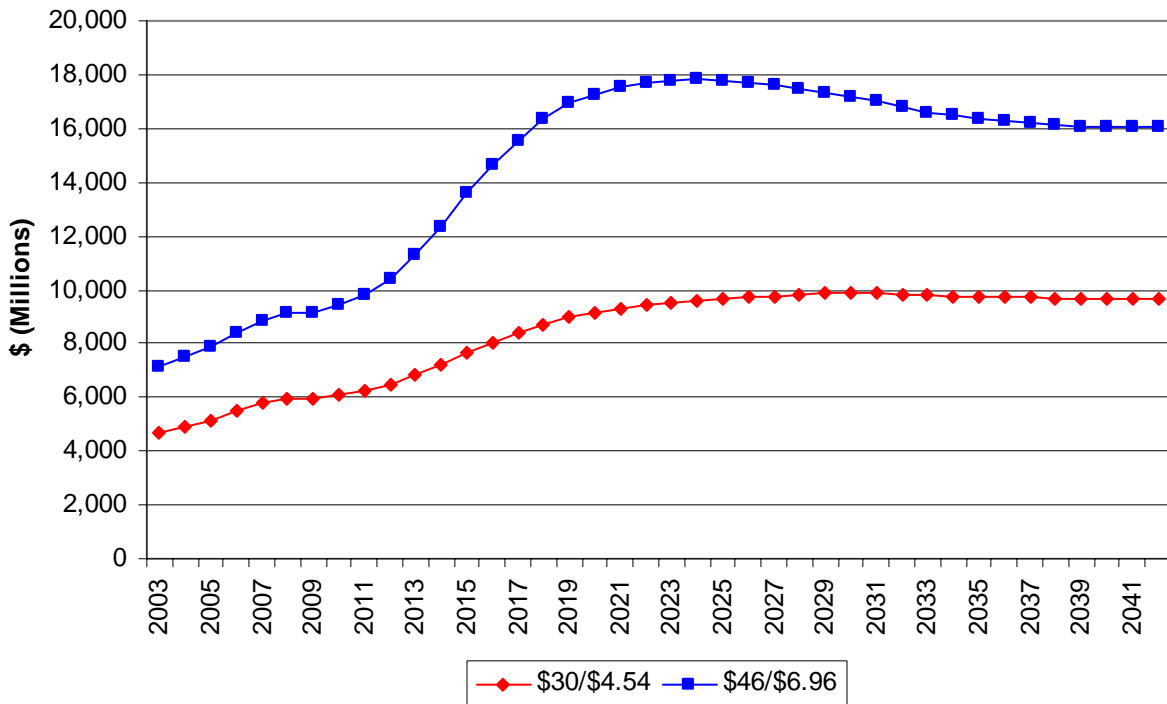


Figure 7-7. Effects of Price on Royalty Revenue (Not Discounted) Under Current Royalty Alternative, All Fields.

It is clear that price is the driving factor leading to variation in results under the same royalty relief program. What is more interesting, and more relevant, is examining the differences observed under the alternative royalty relief programs. Table 7-10 shows the results for the offshore oil and gas activity under each royalty alternative⁸¹ for the \$30 per barrel and \$4.54 per mcf price case. Similar results for the higher price scenario are presented in Table 7-11. These results are independent of price thresholds, i.e., we have assumed that the price threshold would never be exceeded.

⁸¹ All results include only the sum of values over the 40-year projection period (2003-2042), and do not include historical results prior to the first model year.

Table 7-10. Effects of Royalty Scenario on Activities at All Fields, \$30 Oil Price.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Discovered Fields	Exploratory Wells Drilled	Reserves Discovered (mmBOE)
DWRR - Field	All	30	4.54	672	7,607	49,005
DWRR - Lease	All	30	4.54	678	7,675	49,772
Current	All	30	4.54	669	7,568	48,692
No Relief	All	30	4.54	664	7,509	47,999

Table 7-10 (continued)

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Total Gas Production (Bcf)	Total Oil Production (mmBbl)	Royalty-Free	
						Gas Production (Bcf)	Royalty-Free Oil Production (mmBbl)
DWRR - Field	All	30	4.54	151,590	28,871	23,918	5,577
DWRR - Lease	All	30	4.54	152,869	29,204	39,937	9,669
Current	All	30	4.54	151,009	28,725	16,628	3,766
No Relief	All	30	4.54	149,715	28,379	9,163	1,789

Table 7-10 (continued)

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Royalty-Paying Gas Production (Bcf)	Royalty-Paying Oil Production (mmBbl)	Total	
						Royalty Revenue (mm)	Present Value Royalty Revenue (mm)
DWRR - Field	All	30	4.54	127,672	23,293	\$314,661	\$54,901
DWRR - Lease	All	30	4.54	112,932	19,535	\$265,258	\$52,148
Current	All	30	4.54	134,380	24,959	\$334,762	\$56,291
No Relief	All	30	4.54	140,552	26,590	\$357,946	\$58,367

Note: Values in \$2003. Present value at 12%. Reserves are ultimate (grown) amounts.

Table 7-11. Effects of Royalty Scenario on Activities at All Fields, \$46 Oil Price.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Discovered Fields	Exploratory Wells Drilled	Reserves Discovered (mmBOE)
DWRR - Field	All	46	6.96	799	9,970	57,510
DWRR - Lease	All	46	6.96	804	10,047	58,062
Current	All	46	6.96	796	9,921	57,281
No Relief	All	46	6.96	791	9,839	56,644

Table 7-11 (continued)

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Total Gas Production (Bcf)	Total Oil Production (mmBbl)	Royalty-Free	
						Gas Production (Bcf)	Royalty-Free Oil Production (mmBbl)
DWRR - Field	All	46	6.96	173,134	33,092	25,565	6,624
DWRR - Lease	All	46	6.96	174,240	33,382	43,709	11,258
Current	All	46	6.96	172,734	32,992	16,998	4,499
No Relief	All	46	6.96	171,638	32,699	7,206	1,908

Table 7-11 (continued)

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Royalty-Paying	Royalty-Paying	Total	Present Value
				Gas Production (Bcf)	Oil Production (mmBbl)	Royalty Revenue (mm)	Royalty Revenue (mm)
DWRR - Field	All	46	6.96	147,569	26,468	\$540,789	\$90,172
DWRR - Lease	All	46	6.96	130,532	22,125	\$454,533	\$85,112
Current	All	46	6.96	155,737	28,492	\$577,720	\$92,864
No Relief	All	46	6.96	164,432	30,791	\$625,735	\$97,367

Note: Values in \$2003. Present value at 12%. Reserves are ultimate (grown) amounts.

There are several notable differences among the four royalty alternatives. As the amount of relief increases, we observe a corresponding increase in the overall amount of exploratory well drilling, field and reserve discovery, total oil and gas production, as well as the amount of production exempt from royalties. The highest relief scenario, DWRR – Lease, enjoys a significant amount of royalty-free production compared with the overall production (Table 7-12). In both the \$30 and \$46 oil price scenarios, close to 30 percent of forecasted production is not subject to royalties. This is contrasted by the \$30 and \$46 No Relief scenarios, where only 6.2 percent and 5.0 percent, respectively, of forecasted production were not subject to royalties. Not surprisingly, the total royalty revenue collected under the DWRR – Lease program is significantly lower than the No Relief scenario.

Table 7-12. Comparison of Royalty-Free Production for All Fields, Offshore Gulf of Mexico.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Total Production (mmBOE)	Total Royalty-Free Production (mmBOE)	Percent of Total Production that is Royalty-Free
DWRR - Field	All	30	4.54	55,844	9,833	17.6%
DWRR - Lease	All	30	4.54	56,405	16,775	29.7%
Current	All	30	4.54	55,594	6,725	12.1%
No Relief	All	30	4.54	55,019	3,420	6.2%
DWRR - Field	All	46	6.96	63,899	11,173	17.5%
DWRR - Lease	All	46	6.96	64,386	19,035	29.6%
Current	All	46	6.96	63,727	7,524	11.8%
No Relief	All	46	6.96	63,239	3,190	5.0%

A differential analysis shows that although the amount of royalty-free production increases as royalty relief volumes rise, the *present value* of royalty payments does not experience the same magnitude of change. As depicted in the \$30 oil price scenario in Table 7-13, the amount of foregone royalty revenue by instituting the maximum relief scenario, DWRR – Lease, represents a 10.7 percent reduction compared with the No Relief scenario, despite an almost four-fold increase in the amount of royalty-free production. This trend is magnified in the \$46 oil price case, where a 12.6 percent reduction in the present value of royalty collection versus royalty-free production increases of almost 500 percent.

Table 7-13. Comparison of Effects of Royalty Alternatives with No Relief Scenario.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Percent Change in Total Production	Percent Change in Royalty-Free Production	Percent Change in Total Royalty Revenue Collection	Percent Change in Present Value of Royalty Revenue Collection
DWRR - Field	All	30	4.54	1.5%	187.5%	-12.1%	-5.9%
DWRR - Lease	All	30	4.54	2.5%	390.5%	-25.9%	-10.7%
Current	All	30	4.54	1.0%	96.6%	-6.5%	-3.6%
DWRR - Field	All	46	6.96	1.0%	250.2%	-13.6%	-7.4%
DWRR - Lease	All	46	6.96	1.8%	496.7%	-27.4%	-12.6%
Current	All	46	6.96	0.8%	135.9%	-7.7%	-4.6%

Note: Values in \$2003. Present value at 12%

The magnitude of changes between the different royalty relief alternatives is somewhat obscured in the previous tables by examining results concerning all fields. Examining production from fields that are discovered under the different proposed royalty alternatives is far more relevant in assessing the value of each potential program. Table 7-14 presents similar forecast results limited only to fields discovered by the model. A small portion of these fields are discovered from lease sales prior to 2003 which are limited to the existing royalty programs

in place.⁸² The remaining fields are discovered on lease sales beginning in 2003 and are subject to the different royalty alternatives. Removing results attributable to the fields that existed prior to 2003, the first projection year, allows a comparison of how each royalty alternative influences expected activity in the forecast period.

Table 7-14. Effects of Alternative Royalty Scenario on Activities for New Fields Only.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	New Gas	New Oil	Royalty-Free	Royalty-Free
				Production (Bcf)	Production (mmBbl)	New Gas Production (Bcf)	New Oil Production (mmBbl)
DWRR - Field	All	30	4.54	96,521	16,356	19,682	5,088
DWRR - Lease	All	30	4.54	97,800	16,689	35,701	9,180
Current	All	30	4.54	95,940	16,210	12,393	3,277
No Relief	All	30	4.54	94,646	15,865	4,927	1,300
DWRR - Field	All	46	6.96	118,065	20,577	25,565	6,624
DWRR - Lease	All	46	6.96	119,171	20,868	43,709	11,258
Current	All	46	6.96	117,665	20,477	16,998	4,499
No Relief	All	46	6.96	116,569	20,184	7,206	1,908

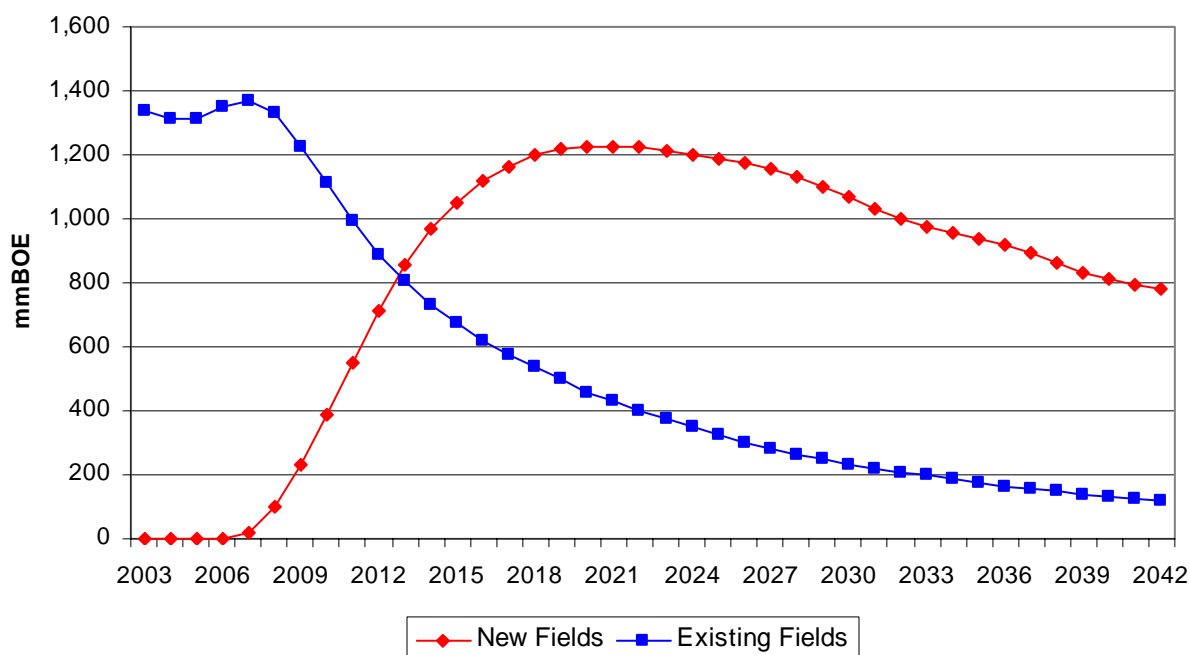
Table 7-14 (continued)

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Royalty-Paying	Royalty-Paying	New Field	Present Value of
				New Gas Production (Bcf)	New Oil Production (mmBbl)	Total Royalty Revenue (mm)	New Field Total Royalty Revenue (mm)
DWRR - Field	All	30	4.54	76,839	11,268	\$194,445	\$16,114
DWRR - Lease	All	30	4.54	62,099	7,509	\$145,042	\$13,361
Current	All	30	4.54	83,547	12,933	\$214,546	\$17,504
No Relief	All	30	4.54	89,719	14,565	\$237,730	\$19,580
DWRR - Field	All	46	6.96	92,500	13,953	\$356,458	\$30,699
DWRR - Lease	All	46	6.96	75,463	9,610	\$270,202	\$25,639
Current	All	46	6.96	100,668	15,978	\$393,389	\$33,390
No Relief	All	46	6.96	109,363	18,276	\$441,404	\$37,893

Note: Values in \$2003. Present value at 12%.

A significant portion of future production and royalty collection is attributable to fields that have yet to be discovered. Although the amount of undiscounted total royalty revenue attributable to future discoveries is substantial, the present value of the royalty revenue from new fields represents a much smaller percentage due to the fact new field production is not expected for several years into the future. Figure 7-8 illustrates the production effect, by comparing the time-series of existing field production, with the production expected from model discoveries. Initial new field production does not begin until 2007, corresponding with field discoveries projected to occur in 2003. Figure 7-8 is representative of the \$30/bbl scenario and the current royalty relief alternative, but a similar pattern holds true across each different royalty alternative and resource price scenario.

⁸² It is important to recall that we did not attempt to change history by addressing what would have happened if previous deepwater royalty relief programs had been modified.



Assuming \$30/bbl Price Scenario, "Current" Royalty Relief Alternative

Figure 7-8. All Gulf of Mexico Production, Separated by Field Discovery.

Any assessment of the fiscal impact of each different royalty alternative is incomplete without inclusion of bonus and rental income associated with future lease sales under each alternative. Table 7-15 presents the combined fiscal effects for each alternative royalty scenario. We immediately note the results of the lease bonus rental model are the same across both price assumptions. The regression analyses of lease sales and bonus bids found that oil price was not a significant explanatory variable, and as such, the lease bonus rental model should not be expected to be sensitive to different price scenarios.

Table 7-15. Total Fiscal Effects of Alternate Royalty Scenario on Activities for All Fields.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Present Value	Present Value	Present Value
				Royalty Revenue (mm)	of Lease Bonus and Rental Revenue (mm)	Total Present Value of Fiscal Variables (mm)
DWRR - Field	All	30	4.54	\$54,901	\$5,300	\$60,201
DWRR - Lease	All	30	4.54	\$52,148	\$6,099	\$58,247
Current	All	30	4.54	\$56,291	\$4,290	\$60,581
No Relief	All	30	4.54	\$58,367	\$3,823	\$62,190
DWRR - Field	All	46	6.96	\$90,172	\$5,300	\$95,472
DWRR - Lease	All	46	6.96	\$85,112	\$6,099	\$91,212
Current	All	46	6.96	\$92,864	\$4,290	\$97,154
No Relief	All	46	6.96	\$97,367	\$3,823	\$101,190

Note: Values in \$2003. Present value at 12%.

As we increase the amount of royalty relief, we observe a corresponding decrease in the present value of total royalty revenue collected. Part of this decline is offset by an increase in the additional bonus and rental revenue derived from increased activity in lease sales. However, the foregone royalty collection is never fully recovered by the increase in the lease and rental revenue, when compared to the No Relief scenario. Table 7-16 illustrates the net impact of the three alternatives that include royalty relief compared with the one program that does not allow any future royalty relief.

Table 7-16. Comparison of Fiscal Effects of Royalty Alternatives with No Relief Scenario.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	"Loss" in	"Gain" in	Net Impact (mm)	Percent of Total Revenue Foregone for Royalty Relief
				Present Value Royalty Revenue (mm)	Present Value Lease and Bonus Revenue (mm)		
DWRR - Field	All	30	4.54	(\$3,465)	\$1,477	(\$1,989)	-3.2%
DWRR - Lease	All	30	4.54	(\$6,218)	\$2,276	(\$3,942)	-6.3%
Current	All	30	4.54	(\$2,075)	\$467	(\$1,608)	-2.6%
DWRR - Field	All	46	6.96	(\$7,194)	\$1,477	(\$5,718)	-9.2%
DWRR - Lease	All	46	6.96	(\$12,254)	\$2,276	(\$9,978)	-16.0%
Current	All	46	6.96	(\$4,503)	\$467	(\$4,036)	-6.5%

Note: Values in \$2003. Present value at 12%.

Comparing the two price scenarios, we observe a large variation in future royalty revenue because it is a direct multiplicative function of oil and gas prices. The relationship among the two cases is also exaggerated somewhat by the difference in future discoveries and reserves discovered. In the higher price case, we expect more exploratory well drilling, a greater number of fields discovered leading to a higher amount of reserves discovered, and subsequently higher production and royalty revenue. These results are independent of price thresholds, i.e., we have assumed that the price threshold would never be exceeded.

In assessing differences among the royalty relief alternatives, the greatest difference lies between the DWRRA suspension volumes applied on a lease basis (DWRRA-Lease) and eliminating future royalty relief altogether (No Relief). Inclusion of fields discovered prior to the model projection period obscures to a large extent the differences between implementing each alternative royalty relief program in the future. We expect the existing fields to continue development and production regardless of policy initiatives directed at stimulating exploration in the future. Therefore, it is important to investigate the change in production and royalty revenue attributable to model discovered fields only, which is shown in Table 7-17.

Table 7-17. Comparison of Effects Between Maximum Relief Scenario (DWRR – Lease) and No Relief for New Fields.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Royalty-Free			Present Value of New Field Royalty Revenue (mm)
				New Production (mmBOE)	New Production (mmBOE)	Royalty-Paying New Production (mmBOE)	
DWRR - Lease	All	30	4.54	34,091	15,532	18,559	\$13,361
No Relief	All	30	4.54	32,706	2,177	30,529	\$19,580
Difference				1,385	13,355	-11,970	(\$6,218)
Percent Change				4.2%			-31.8%
DWRR - Lease	All	46	6.96	42,072	19,035	23,038	\$25,639
No Relief	All	46	6.96	40,926	3,190	37,736	\$37,893
Difference				1,146	15,845	-14,698	(\$12,254)
Percent Change				2.8%			-32.3%

Note: Values in \$2003. Present value at 12%.

The difference between the no-relief and maximum relief scenarios is striking, not only in the production difference, but in the present value of future royalty relief. In the \$30/bbl price scenario, we observe an increase in production of only 4.2 percent, associated with a decrease in the present value of new field royalty revenue of approximately 32 percent. At the higher price, production from model discoveries increases by 2.8 percent, while the present value of royalty collection declines by 32 percent.

Table 7-18 summarizes the net fiscal effects per barrel of oil equivalent discovered that one can expect from implementing each of the four plans. In particular, we focus on the amount of foregone royalties necessary to discover each incremental barrel. In this case, we assume that the No Relief scenario represents the minimum baseline to calculate these effects.

Table 7-18. Foregone Royalties per Incremental BOE Discovered for Each Alternative Compared with No Relief Scenario.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Reserves Discovered (mmBOE)	Present Value Royalty Revenue (mm)	Present Value of Lease Bonus and Rental Revenue (mm)	Total Present Value of Fiscal Variables (mm)	Dollar per BOE
DWRR - Field	All	30	4.54	49,005	\$54,901	\$5,300	\$60,201	
				Diiference				-1,989
				1,006				-\$1.98
DWRR - Lease	All	30	4.54	49,772	\$52,148	\$6,099	\$58,247	
				Diiference				-\$3,942
				1,773				-\$2.22
Current	All	30	4.54	48,692	\$56,291	\$4,290	\$60,581	
				Diiference				-\$1,608
				693				-\$2.32
No Relief	All	30	4.54	47,999	\$58,367	\$3,823	\$62,190	

Table 7-18 (continued)

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Reserves Discovered (mmBOE)	Present Value Royalty Revenue (mm)	Present Value of Lease Bonus and Rental Revenue (mm)	Total Present Value of Fiscal Variables (mm)	Dollar per BOE
DWRR - Field	All	46	6.96	57,510	\$90,172	\$5,300	\$95,472	
				867				-\$5,718
								-\$6.60
DWRR - Lease	All	46	6.96	58,062	\$85,112	\$6,099	\$91,212	
				1,418				-\$9,978
								-\$7.04
Current	All	46	6.96	57,281	\$92,864	\$4,290	\$97,154	
				638				-\$4,036
								-\$6.33
No Relief	All	46	6.96	56,644	\$97,367	\$3,823	\$101,190	

Note: Values in \$2003. Present value at 12%. Reserves are ultimate (grown) amounts.

The results portrayed in Table 7-18 raise several interesting points. We observe a clear trade-off between the increase in discovery of reserves and a decrease in royalty revenue collection. On one hand, for the \$30/bbl price scenario, all forms of royalty relief lead to an increase in the amount of reserves discovered versus a No Relief scenario. However, as the amount of royalty relief increases, the present value of royalty revenue collected decreases, despite the additional reserves discovered, and potential additional production.

One might expect that as royalty relief increases, the amount of foregone royalties would increase per incremental barrel of reserves discovered. Yet, when we consider the present value of additional lease bonus and rental revenue, we actually observe a greater trade-off in terms of reserves discovery and total revenue collection for the current program on a per barrel basis. For every additional barrel discovered under the current royalty alternative, \$2.32 is “lost” in royalty revenue. The larger per barrel amount of foregone royalties for the current alternative is largely driven by a minimal change in lease and bonus revenue compared with the No Relief scenario. In other words, the current alternative is estimated to generate less bonus revenue to offset the loss in royalty revenue. The current royalty alternative does not appear to generate much excitement at the leasing level, and those who find and develop reserves under this program are

taking advantage of the royalty incentives – to the point it is “costing” the government more per barrel in lost revenue than the larger royalty relief alternatives.

The higher price scenario also yields interesting results that slightly contrast what was observed at the lower price. In this instance, we observe that as royalty relief increases, the amount of foregone royalties would increase per incremental barrel of reserves discovered.. Thus, the greatest trade-off is not with the Current royalty alternative, but rather with the maximum relief scenario, DWRR – Lease. This apparent shift is largely driven by the price impact in stimulating exploration activity, regardless of royalty alternatives. As Table 7-18 depicts, higher resource prices lead to increases in the amount of reserves discovered. However, the difference in the amount of reserves discovered between those programs with relief and the No Relief scenario is *lower* in the \$46 per barrel case, compared with the \$30 per barrel case. Intuitively, the higher resource price has a greater financial impact on field economics than the incremental impact of royalty suspension volumes.

We also examined the data specific to water depth categories. This is particularly relevant given that there are variations in the royalty relief programs across water depths. Table 7-19 and 7-20 presents forecast results for each royalty alternative separated by water depth. There are relatively few differences in the results for the shelf region for each royalty alternative. This is not surprising, as prior deepwater royalty initiatives and the alternatives considered here do not involve suspension volumes for shallow regions.⁸³

Table 7-19. Effects of Alternative Royalty Scenario on Activities at Different Water Depth Categories, All Fields, \$30 per Barrel Oil Price.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Reserves Discovered (mmBOE)	Total Production (mmBOE)	Total Royalty-Free Production (mmBOE)	Present Value Royalty Revenue (mm)
DWRR - Field	Shelf	30	4.54	10,382	15,573	226	\$25,480
DWRR - Lease	Shelf	30	4.54	10,377	15,573	226	\$25,480
Current	Shelf	30	4.54	10,385	15,573	226	\$25,480
No Relief	Shelf	30	4.54	10,385	15,573	226	\$25,480
DWRR - Field	Slope	30	4.54	4,507	5,884	1,025	\$6,191
DWRR - Lease	Slope	30	4.54	4,536	5,912	1,772	\$5,657
Current	Slope	30	4.54	4,479	5,861	570	\$6,598
No Relief	Slope	30	4.54	4,464	5,848	383	\$6,787
DWRR - Field	Deepwater	30	4.54	34,115	34,386	8,582	\$23,230
DWRR - Lease	Deepwater	30	4.54	34,859	34,919	14,777	\$21,011
Current	Deepwater	30	4.54	33,828	34,160	5,928	\$24,213
No Relief	Deepwater	30	4.54	33,149	33,598	2,810	\$26,099

Note: Values in \$2003. Present value at 12%. Reserves are ultimate (grown) amounts.

⁸³ For this study we have not considered the future impact of deep gas initiatives instituted by the MMS. However, several existing fields have deep gas suspension volumes and we account for these volumes in our existing resource distribution. As a result, certain royalty-free volumes appear in the Shelf region. We recognize that we are understating the ultimate amount of royalty-free production in the Shelf region, considering future discoveries in this region may be able to take advantage of the deep gas initiatives.

Table 7-20. Effects of Alternative Royalty Scenario on Activities at Different Water Depth Categories, All Fields, \$46 per Barrel Oil Price.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Reserves Discovered (mmBOE)	Total Production (mmBOE)	Total Royalty-Free Production (mmBOE)	Present Value Royalty Revenue (mm)
DWRR - Field	Shelf	46	6.96	11,735	16,916	226	\$41,134
DWRR - Lease	Shelf	46	6.96	11,737	16,916	226	\$41,134
Current	Shelf	46	6.96	11,735	16,916	226	\$41,134
No Relief	Shelf	46	6.96	11,736	16,917	226	\$41,135
DWRR - Field	Slope	46	6.96	4,785	6,227	1,155	\$9,791
DWRR - Lease	Slope	46	6.96	4,800	6,241	1,968	\$8,849
Current	Slope	46	6.96	4,764	6,207	616	\$10,568
No Relief	Slope	46	6.96	4,750	6,194	396	\$10,927
DWRR - Field	Deepwater	46	6.96	40,990	40,756	11,035	\$39,247
DWRR - Lease	Deepwater	46	6.96	41,525	41,229	18,084	\$35,129
Current	Deepwater	46	6.96	40,783	40,603	7,925	\$41,161
No Relief	Deepwater	46	6.96	40,158	40,128	3,811	\$45,305

Note: Values in \$2003. Present value at 12%. Reserves are ultimate (grown) amounts.

We observe the majority of the differences are driven by changes in the deepwater environment particular to each royalty alternative. However, it is interesting to note that even in the slope region, implementation of a royalty relief program will stimulate additional reserve discovery and field production. The differences observed in Table 7-20 are the result of increased exploration activity that occurs with royalty relief. This is evident from Figure 7-9, which compares exploratory well drilling in the slope and deepwater regions for the DWRR – Lease and No Relief programs. The implementation of relief leads to higher levels of exploratory well drilling, which subsequently results in increased development and production activity.

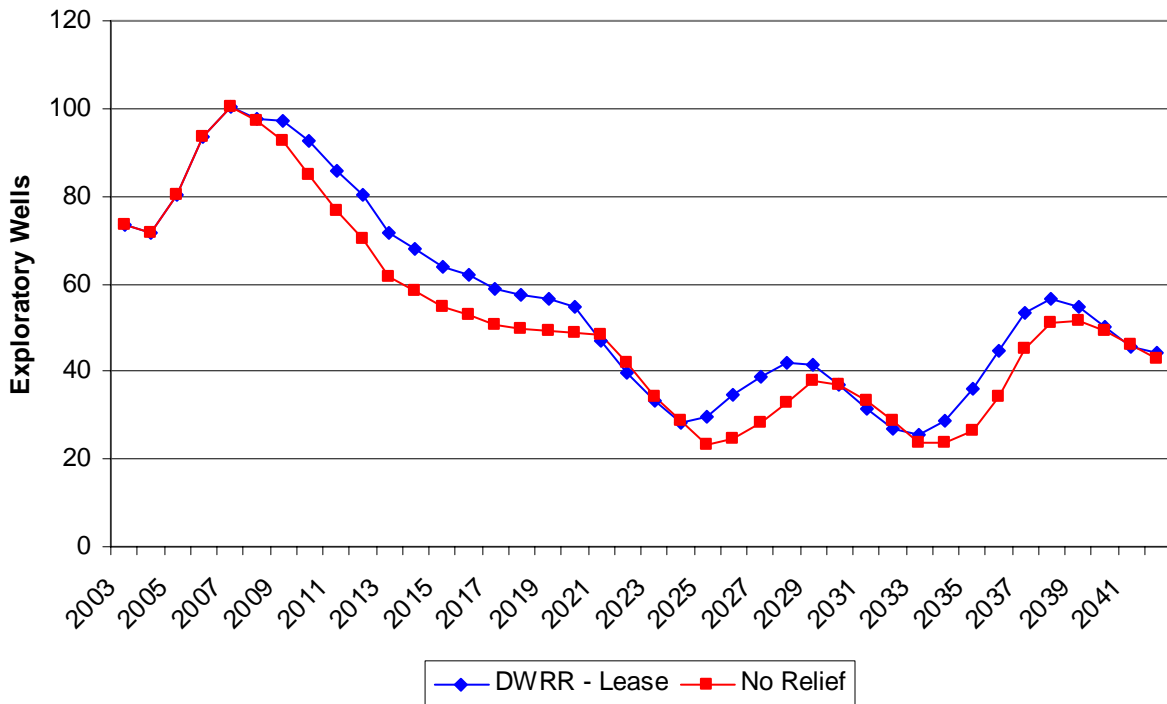


Figure 7-9. Exploratory Well Drilling, Combined Slope and Deepwater Regions, Gulf of Mexico.

It is important to remember that viewing results from all fields, including both existing and new fields, masks the nature of program differences. A large, significant portion of the production difference between the programs is derived from future discoveries of deepwater fields. Table 7-21 analyzes the forecast results limited to new field discoveries between 2003 and 2042.

Table 7-21. Effects of Alternative Royalty Scenario on Slope and Deepwater Activities, New Fields.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	New Production (mmBOE)	Royalty-Free New Production (mmBOE)	Royalty-Paying New Production (mmBOE)	Present Value of New Field Royalty Revenue (mm)
DWRR - Field	Slope	30	4.54	3,690	783	2,907	\$2,394
DWRR - Lease	Slope	30	4.54	3,718	1,530	2,188	\$1,859
Current	Slope	30	4.54	3,667	327	3,339	\$2,801
No Relief	Slope	30	4.54	3,654	141	3,513	\$2,990
DWRR - Field	Deepwater	30	4.54	21,872	7,808	14,064	\$6,994
DWRR - Lease	Deepwater	30	4.54	22,405	14,003	8,402	\$4,775
Current	Deepwater	30	4.54	21,646	5,155	16,491	\$7,977
No Relief	Deepwater	30	4.54	21,084	2,037	19,047	\$9,863
DWRR - Field	Slope	46	6.96	4,033	912	3,121	\$3,968
DWRR - Lease	Slope	46	6.96	4,047	1,725	2,322	\$3,027
Current	Slope	46	6.96	4,013	373	3,640	\$4,745
No Relief	Slope	46	6.96	4,000	153	3,847	\$5,104
DWRR - Field	Deepwater	46	6.96	28,241	10,261	17,980	\$14,352
DWRR - Lease	Deepwater	46	6.96	28,714	17,310	11,405	\$10,234
Current	Deepwater	46	6.96	28,089	7,151	20,938	\$16,266
No Relief	Deepwater	46	6.96	27,613	3,037	24,576	\$20,410

Note: Values in \$2003. Present value at 12%. Reserves are ultimate (grown) amounts.

Once again we note as the amount of relief volume increases, so does the amount of new production and naturally, the level of royalty-free production. Perhaps most striking is the difference between royalty-free production and royalty-paying production when considering the maximum relief scenario, DWRR – Lease. At \$30 per barrel, the amount of royalty-free production in the DWRR – Lease scenario is nearly double the royalty-free production in the DWRR – Field scenario, and is almost seven times the amount in the No Relief scenario.

Price Thresholds

Thus far, the results presented in this chapter have not included consideration of the effect of hitting the price thresholds inherent in the royalty relief programs. In periods of high oil and gas prices, price thresholds serve to rescind the royalty relief available to leases and/or fields. In addition, the oil and gas production during these periods cannot be “banked” for future relief. Volumes produced are deducted from the lease or field remaining royalty suspension volume. It is very difficult to accurately predict when price thresholds would be exceeded, particularly when examining three succinct price series, as we are currently using. In order to show the impacts of price thresholds, we elected to perform sensitivity analyses under each price scenario and royalty program assumption.

For each price scenario, we assumed there would be a specified amount of time at the beginning of the model run when actual prices would exceed the price thresholds. This assumption was based on discussions with the MMS, in which they indicated that the level of the price thresholds would often be reconsidered after a period of time, e.g., five years. Furthermore, we assumed that in \$30/bbl price scenario the period of time where price thresholds were exceeded would be less than that for the high price scenario. To test the sensitivity of our

results to price thresholds, we ran our model assuming that price thresholds would be exceeded for five and eight years for the \$30/bbl and \$46/bbl price scenarios respectively. Table 5-14 presents the results of our sensitivity analyses for price thresholds.

Table 7-22. Comparative Effects When Price Thresholds are Exceeded in Each Royalty Alternative, All Fields.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Present Value Total	Present Value Total	Difference (mm)	Percent Reduction
				Royalty Revenue when Price Thresholds Exceeded (mm)	Royalty Revenue when Price Thresholds Not Exceeded (mm)		
DWRR - Field	All	30	4.54	\$57,222	\$54,901	\$2,321	4.06%
DWRR - Lease	All	30	4.54	\$54,469	\$52,148	\$2,321	4.26%
Current	All	30	4.54	\$58,612	\$56,291	\$2,321	3.96%
No Relief	All	30	4.54	\$60,688	\$58,367	\$2,321	3.82%
DWRR - Field	All	46	6.96	\$95,499	\$90,172	\$5,327	5.58%
DWRR - Lease	All	46	6.96	\$90,395	\$85,112	\$5,283	5.84%
Current	All	46	6.96	\$98,208	\$92,864	\$5,345	5.44%
No Relief	All	46	6.96	\$102,860	\$97,367	\$5,493	5.34%

Note: Values in \$2003. Present value at 12%.

At first glance, it seems striking that the net difference for the four alternative programs is the same for the \$30/bbl price scenario but not for the \$46/bbl price scenario. This is a direct result of the inherent lags in lease to drilling, and drilling to production. Even with a five-year period of price thresholds being exceeded, model discoveries have still not begun production. In addition, there is a slight difference in how the net present values are calculated for the high price scenario. In the \$30/bbl lower price scenario, it was assumed that the price thresholds would never be met, from an operator’s point of view.⁸⁴ However, based on discussions with the MMS, we decided to alter this assumption in the \$46/bbl price scenario. When calculating net present values for discoveries in years where the price thresholds were exceeded, the operator would assume that he or she would never receive royalty relief, leading to lower net present values of field discoveries. The impact is seen in the difference in expected royalty revenue between alternative royalty relief programs. For example, under the maximum royalty relief scenario, the eight-year price threshold period would lead to an additional \$5.28 billion in revenue collections, as opposed to an additional \$5.49 in the No Relief scenario.

Conclusion

The purpose of Task 2 of this project was to investigate relative differences between alternative deepwater royalty relief programs in the Gulf of Mexico. We performed numerous simulations that projected future exploration, development and production over a 40-year period

⁸⁴ This assumption is also used by the MMS, as outlined in the Appendices to Benefit/Cost Analysis For Final Deep Gas Rule (available at http://www.mms.gov/econ/PDFs/AppendicesToFinalDG_B-CAnalysis.pdf):

In the economic analysis of the production and fiscal effects of the deep gas rule we assumed the price threshold had no influence on drilling intensity and discoveries, in effect the price threshold would never be breached. The rationale for this assumption is that discontinuation of royalty suspension coincides with a period of significant premium relative to the price for which OCS operators plan. By definition, that premium is large enough to cover full royalty and leave as much profit, i.e., incentive to drill, as royalty relief would have at the planned for price.

for each alternative royalty program. The results show that royalty relief accelerates projected exploration and production activity and the more generous the royalty relief program, the greater our expectation of accelerated exploration, development, and production activity. We also note that the projections were very sensitive to price, and price assumptions, not royalty relief, had the largest impact on the relative levels of exploration and discovery activity. Alternatively, leasing and bidding behavior appear to be relatively insensitive to price.

We also made an economic assessment of the financial impact of implementing a royalty relief program. Our findings show that although royalty relief stimulates exploration, development, and production, there is a corresponding loss, sometimes significant, in the amount of royalty revenue collected. This loss is offset to some extent by an increase in lease bonus and rental revenue collected by the government in future lease sales. We observed that the larger the relief, the greater loss in foregone royalty per BOE discovered and BOE produced. Third, the issue is complicated by the inclusion of price thresholds. In periods where price thresholds are exceeded, we observe a decrease in the royalty revenue collected, although in the lower price scenarios we generally do not observe variation in our expected exploration activity. We did not attempt to predict when price thresholds were exceeded, but rather tested the sensitivity of the results to periods of lower price thresholds.



The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.



The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Minerals Revenue Management** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.