Appendix C

Economic Analysis of a Representative Deep-Water Gas Production Project

This appendix provides an analysis of the economic merit of a representative deep-water gas prospect. The two defining characteristics of deep-water operations are the extremely high costs and the high degree of uncertainty surrounding many physical and economic parameters that affect project returns. The economic merit of large-scale project investments in deep-water regions is evaluated using a discounted cash flow (DCF) model to determine the expected returns associated with a representative project. Expected returns are dependent on the assumptions regarding selling prices; the costs of drilling, operation, and all equipment; and the production performance of the wells.

The DCF model, which is based on expected values of key variables, is a common approach that provides measures of profitability conditioned on the values of the input data. This method can be employed to evaluate the project under different scenarios, in which the expected returns are determined as values of selected variables are altered. The measures from such analysis methods are useful, but limited because they provide an incomplete range of possible outcomes.

Project risk is caused by uncertainty from unforeseen or unknowable conditions or events that affect costs or performance. Adverse conditions may be present in the formation or at the seabed, affecting either the installation of subsea equipment or its operation. Events, such as mudslides in the subsurface, can increase costs or cause operations to cease altogether. Market events, such as lower prices than anticipated, are quite familiar to most operators, both onshore and offshore. In fact, the net price received for production is subject to variation not only because of market events, but also because of deviations in transportation costs from expected levels. When transportation costs are higher than expected, the net unit revenue remaining for the production operations is correspondingly lower. This uncertainty confronts producers whether they also own the transportation facilities or not.

The appendix describes the representative deep-water project that is used in the DCF model to calculate the return on investment based on a given set of input values. It then presents the results of a comparative analysis of economic returns using a sensitivity approach that alters the values for a variable or set of variables in a particular way.

The project evaluation is then extended to recognize explicitly the impact of uncertainty. The uncertainty analysis is conducted using the DCF model within an iterative sampling procedure. The results of multiple trials are compiled to produce a frequency distribution that describes the set of possible outcomes along with estimated probabilities of occurrence. The results of this analysis provide a richness of detail in characterizing the possible outcomes that substantially enhances subsequent decisionmaking whether from the point of view of the investment project manager or a policymaker considering programs to impose incentives or penalties on gas and oil activities. In addition to the more complete information regarding the project, the results show that the calculated returns based on the expected values of input variables do not necessarily equal the expected value of the returns based on the distribution of expected returns.

Characteristics of the Representative Deep-Water Project

The present examination uses a hypothetical deep-water project as the basis of its analysis. This project has significant characteristics that are consistent with those of known projects, either active or in development. It does not describe a particular project, but it serves as an illustrative model that reflects the relevant economics of deep-water investment. The characterization of the representative project is based primarily on information from three sources: the Minerals Management Service (MMS), background information used in the Energy Information Administration's (EIA) National Energy Modeling System (NEMS), and company information as reported in the professional literature.

The expected profitability of a project depends on the output price and a comprehensive set of costs, physical performance characteristics, and institutional parameters, such as tax rates (values for major input variables in the DCF analysis appear in Table C1). The proposed project produces natural gas as its primary product with petroleum liquids as a secondary output. The project produces from one discovery well and from 12 wells drilled during a 2-year development period. The success rate for developmental wells drilled is 75 percent. Wells produce at the initial flow rate for 18 months, then yearly flow declines geometrically at a constant rate. Project costs are consistent with those for a field in 2,000 feet of water. The project is evaluated on a standalone basis for tax purposes. All applicable Federal tax provisions apply, but the project is assumed to be outside State waters and thus not liable for State taxes. As a deep-water project, initial production is exempt from royalty payment obligations. The net price received for produced gas is $1.50 per thousand cubic feet and the discount rate is assumed to be 10 percent.

Project Evaluation with Certain Data

The initial project evaluation is based on the common approach in which expected values for all relevant variables are adopted as input variables, and measures of expected returns conditional on the set of input values are calculated. Under this approach, the expected returns, such as net profitability or rate of return, represent an average or "likely" outcome. The expected value measures then are compared with threshold values for acceptability or with similar valuations of other projects for ranking. This simple approach has the advantage of expediency and the results generally are considered to be well understood.

The DCF model with reference case values for the input estimates yields present value profit (PVP) and internal rate of return (IROR) for the representative gas project of $14.8 million and 11.1 percent, respectively. These results indicate that this project should be undertaken since it will be profitable at the assumed discount rate of 10 percent and price of $1.50 per thousand cubic feet. This evaluation was conducted on a standalone project basis, which affects the present value of tax deductions. The expensed items and amortized capital expenditures are used only to offset tax liabilities generated by revenues from this project. The pattern of sizeable expenditures early in project development followed by years of revenues ensures that the present value of the associated tax writeoffs is reduced. If the project is evaluated from the perspective of an ongoing firm that can use the deductions as incurred to offset tax liabilities generated elsewhere in the firm, the PVP and IROR rise to $32.5 million and 13.0 percent, respectively. The effectiveness of the firm's tax planning will determine how successfully the project might approach such returns. This case indicates that this project may return even higher value than reflected in the initial estimation.

Table C1. Values for Selected Variables of the Representative Deep-Water Natural Gas Project Under Three Scenarios

	Scenarios		
Variables	Pessimistic	Reference	Optimistic
Input			
Drilling costs (million dollars per well)	12.5	10.0	7.5
Operating costs (dollars per thousand cubic feet)	0.30	0.25	0.20
Upfront capital expenditure (million dollars)	387.5	350.0	312.5
Output Price (dollars per thousand cubic feet)	1.25	1.50	1.75
Initial well flow rate (million cubic feet per year)	4,000	5,000	6,000
Decline rate for well production (percent)	6.0	5.0	4.0
Water saturation point, measured as production relative to initial rate (percent)	78.75	75.0	71.2
Output			
Present Value Profit (million dollars)	-272.4	14.8	323.5
Internal Rate of Return (percent)	-14.1	11.1	33.4

Note: Output results from use of a simple discounted cash flow model. Dollar values are discounted to 1997 dollars.
Source: Energy Information Administration, Office of Oil and Gas.

These results, which favor the decision to pursue this project, are conditional on the specific values of the input data. The pervasive uncertainty associated with each of these variables suggests that the eventual project return is likely to vary from any particular estimate. The interest in characterizing the range of outcomes for a proposed project often is addressed by employing a scenario approach to assess the sensitivity of calculated profitability under alternative conditions. The resulting set of outcomes comprise a range of measures that are then used to evaluate the investment decision.

Many key variable values simply cannot be known in advance. Output prices, especially as markets have become more competitive, have become subject to dramatic shifts, which can be factored into the evaluation even if the occurrence is expected to be a low probability. Sensitivity analysis was conducted with output prices at $1.25 and $1.75 per thousand cubic feet, a 16.7-percent variation from the assumed value of $1.50. This limited fluctuation in price is well within observable market patterns. At the lower output price, the expected returns fall, becoming a loss of $58.4 million (discounted at 10 percent) and the IROR is 5.5 percent. The higher price results in a PVP of $86.4 million and an IROR of 16.6 percent.

There are numerous other changes that may greatly alter the expected return. Examples of positive events include higher output prices, lower costs, or substantially greater well performance than originally anticipated. The possibility of other outcomes as a result of changes in a set of variables can also be analyzed. Pessimistic and optimistic scenarios were established for the representative project by systematically varying selected variables, using shifts from 9 to 25 percent (Table C1).[1] The optimistic assumptions describe a project that yields more than $323.5 million, with an associated IROR of more than 33 percent. On the other hand, the conditions of the pessimistic scenario produce losses of more than $272 million and an IROR of -14.1 percent.[2]

The potential investor at this point has a set of possible outcomes, ranging from a "home run" to utterly disastrous without additional information or a clear framework within which the outcomes can be assessed. For example, the preceding results suggest that, on average, the project should provide a profitable return. However, the decision should account for the possibility of other outcomes. These shortcomings of the standard DCF approach can be alleviated to some degree with an explicit treatment of project risk.

Project Evaluation Under Uncertainty

The representative project is analyzed using the simple DCF model within an iterative sampling technique that randomly draws values for selected input variables from the specified distribution for each. The set of randomly sampled input values, along with the given values for all other variables, is used to determine the values for PVP and IROR. The results from each trial are compiled to form a frequency distribution of possible outcomes. The distribution shows the range of possible outcomes along with their frequency, which indicates the relative probability of occurrence. The probability weighted average of all occurrences is the mean of the distribution, or the expected outcome. The distribution has a number of attributes that provide useful insights into the economic merit of the investment.

As an illustrative exercise, selected input variables that describe the representative project are respecified as stochastic variables. The selected stochastic variables are the output price, drilling costs, operating costs, upfront capital expenditures, the initial flow rate per well, the decline rate for production (after the first 18 months), and the water saturation level at which gas production ceases. These variables were selected as major factors affecting profitability, and they have shown themselves in the available data to be subject to wide variation, because of either market fluctuations or unanticipated physical characteristics of the geologic structure or its contents. The variables are assumed to conform to a symmetric triangular distribution with expected values equal to the input data of the Reference Case (Table C2).[3] All other data and the basic DCF model itself are unchanged.

Allowing the selected seven input variables to be randomly perturbed yields a wide range of outcomes with a mean, or expected value, PVP of $1.4 million. The PVP ranges from a low of $158 in losses to a profit of $179 million

[1]The pessimistic and optimistic values are the mid-point values between the most likely and minimum or maximum values used in the stochastic analysis in the following sections.

[2]In practice, the massive losses in the pessimistic outcome may be contained somewhat if early actions such as well flow testing provide the firm with sufficient information to terminate the project without incurring the full project losses. However, this strategy is incapable of avoiding sizeable losses if the project is a failure.

[3]Testing with skewed distributions for the input variables was conducted and the results indicate that this was not a dominant influence.

Table C2. Representative Gas Project: Stochastic Values for Selected Input Variables and Output Values

Variables	Stochastic Variables		
	Minimum	Most Likely	Maximum
Input			
Drilling costs (million dollars per well)	5.0	10.0	15.0
Operating costs (dollars per thousand cubic feet)	0.20	0.25	0.30
Upfront capital expenditure (million dollars)	275.0	350.0	425.0
Output Price (dollars per thousand cubic feet)	1.00	1.50	2.00
Initial well flow rate (million cubic feet per year)	3,000	5,000	7,000
Decline rate for well production (percent)	3.0	5.0	7.0
Water saturation point, measured as production relative to initial rate (percent)	67.5	75.0	82.5
Output	95th Percentile	Mean Value	5th Percentile
Present Value Profit (million dollars)	-158	1.4	179
Internal Rate of Return (percent)	-3.3	9.8	23.4

Note: Stochastic variables are assumed to conform to a triangular distribution. All other variables are set at expected values.
Source: Energy Information Administration, Office of Oil and Gas.

(Figure C1).[4] Similarly, the expected value IROR is 9.8 percent, from a low of -3.3 percent to a high of 23.4 percent. The foremost difference between the simple DCF analysis and the explicit treatment of uncertainty is that the comparable measures of profitability differ. The calculated profitability from the assumed input values was a PVP of $14.8 million with an associated IROR of 11.1 percent. The profitability values based on the assumed distributions for the input variables are returns of $1.4 million and 9.8 percent.

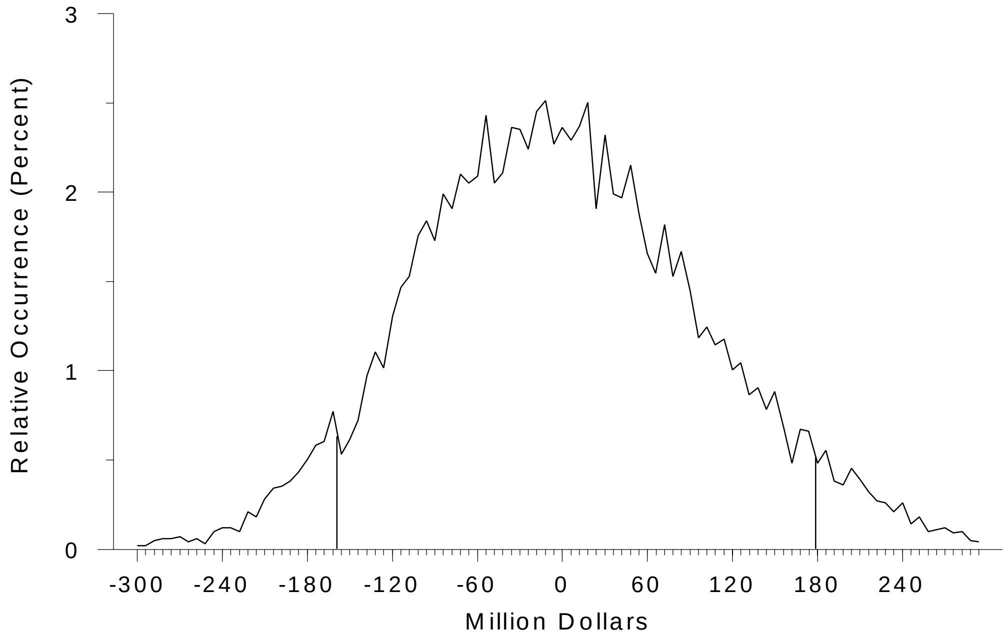
The frequency results showing the relative probability of occurrence can be transformed into a cumulative frequency distribution (CFD) that shows the probability that the results will be at least as great as the corresponding values for the PVP. Despite the positive expected value PVP, the median of -$4.4 million indicates that the odds of a positive PVP are less than 50 percent. The IROR shows a close to adequate return at the mean level, with a value of 9.8 percent, and the median at 9.6 percent, both below the acceptable threshold (Figure C2). The representative project that seemed economically viable based on the simple DCF now shows expected returns that are closer to a marginal decision level.

The CFD provides insight into the results of the scenario analysis. For example, the hypothesized shift in any one input variable for the pessimistic and optimistic scenarios is not extreme and well within the range of the observed data. This might lead to the conclusion that the combined shifts in all seven variables might be anticipated as at least somewhat likely, thus having a significant probability of occurrence. This conclusion is not validated by the uncertainty analysis results. Estimates of expected probability from a comparison of the scenario results with the distribution show that the pessimistic and optimistic scenario results are in fact so extreme that they are well outside the range given by the 95th and 5th percentiles of the distributions. In fact, these outcomes have less than a 0.5 percent chance of occurrence. Reliance on analysts' judgment to estimate the likelihood without benefit of a formal analysis is a dubious practice given the complexity inherent in the determination of joint probabilities.

The results of the uncertainty analysis show that even though the change to each variable is slight, the likelihood that all variables would shift in such a systematic fashion is remote. Since the variables are determined independently, it is more likely that variables will shift to varying degrees and often in opposing directions. The countervailing influence of these changes tends to produce results with higher probabilities around the mean. A scenario that may seem comparable to the Reference case, might be interesting but highly unlikely to occur, especially if the the shifts in the variables are all in the same direction.

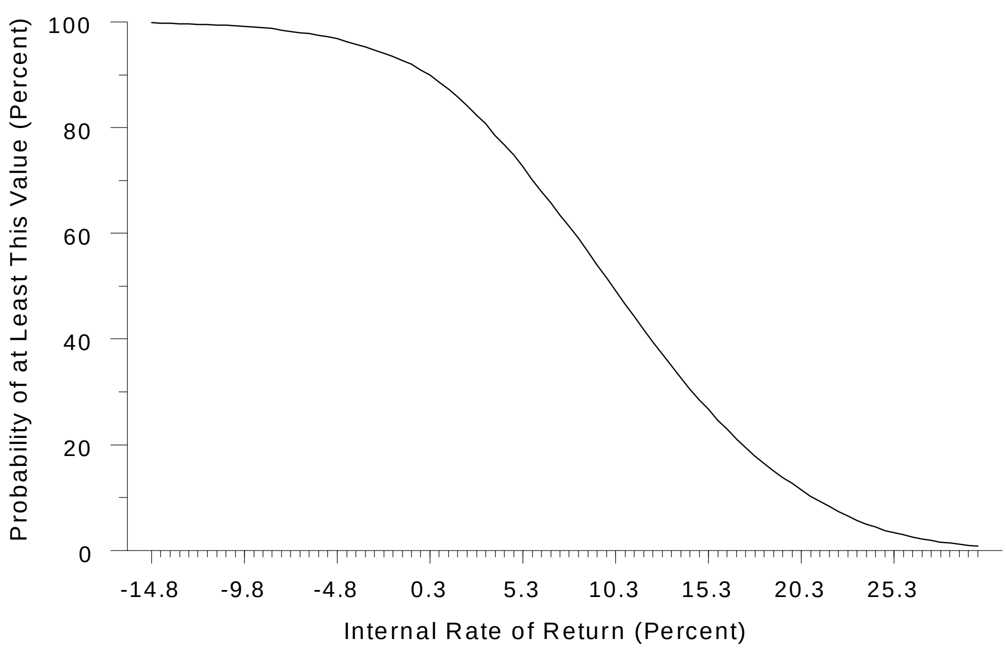
[4]The low and high values are presented at the 95th and 5th percentiles because the reported extreme low and high values from the simulation, while available in the run results, tend to be outliers that are not necessarily reliable measures of expected returns.

Figure C1. Frequency Distribution of Present Value Profit for the Representative Gas Project



Note: The areas in either 'tail' of the distribution represent the 5th and 95th percentiles, which outcomes are low probability events.
Source: Energy Information Administration, Office of Oil and Gas.

Figure C2. Internal Rate of Return - Representative Gas Project (Cumulative Frequency Distribution)



Source: Energy Information Administration, Office of Oil and Gas.

Key Project Variables

Analysis based on the explicit treatment of uncertainty also provides an opportunity to assess the influence of the different variables on the estimated returns. Any change that increases revenues or productivity, or reduces costs or taxes will enhance the project returns. Operators have a keen interest in identifying those factors with the largest impact in order to focus their efforts most productively. The multiple outcomes inherent in the uncertainty analysis allows for the computation of rank correlations between the output and input variables on a pairwise basis. The correlation coefficients are a measure of the degree to which any stochastic input variable and the output variable change together, which is presumed to measure the relative influence of the input variable to the output value. The correlation factor is a guideline for further analysis, but conclusions may be conditional, as can be seen in the following examples.

The major influences on the PVP estimate for the representative project are the initial flow rate and the output price (Figure C3). The initial flow rate dominates due to its pivotal role in the project characterization as a major determinant of total field recovery and the positive relation between its value and the present value of project cost recovery for tax purposes. The price variable determines the total revenue for any given production schedule for the field, which has a direct impact on profitability. The decline rate is a key influence on the length of the productive life of the well, as well as the ultimate recovery per well. Drilling cost per well and the upfront capital costs correlate with PVP, but they seem to have less influence on the PVP based on the rank correlation. This additional information regarding project profitability can be quite useful to the operator.

Given that drilling costs are a lesser influence on profitability, while the initial flow and well decline rate are strong factors, it is a prudent strategy for the operator to address well drilling and completion technology even when this raises costs. As long as the cost increments are managed properly, the productivity gains may be well justified. For example, the representative project would be at a break-even level with initial well flows of 4,797 million cubic feet per year, given drilling costs of $10 million per well. Application of enhanced drilling and completion technology that might raise the flow to 5,700 million cubic feet, less than 19 percent, is worthwhile as long as the cost per well was no greater than $15 million (assuming all other well productive parameters remain unchanged.) Conversely, actions that could lower drilling costs by as much as 50 percent are uneconomic if they reduce initial flow by as little as 19 percent. Changes in the upfront capital costs require a larger offset in initial flow rate than is the case for drilling costs, despite the lower rank correlation coefficient. A rise or fall in upfront capital costs of 50 percent would require a corresponding 33-percent shift in initial flow rate, which is consistent with the relatively large capital expenditure (Table C3).

The explicit treatment of uncertainty in project analysis provides a richness of information that has a number of strong advantages in considering issues related to investment decisionmaking by offshore investors and operators. The significant and pervasive uncertainty surrounding many of the key attributes of any potential deep-water operation has considerable impact on the economic merit of projects proposed in this frontier. Applications of this approach are not limited to investment decisions. Explicit treatment of uncertainty can be quite useful to policymakers in evaluating the merits of possible changes in legislation or regulation. The consideration of the impact of the royalty relief program for deep-water projects is a good example of policy analysis applications.

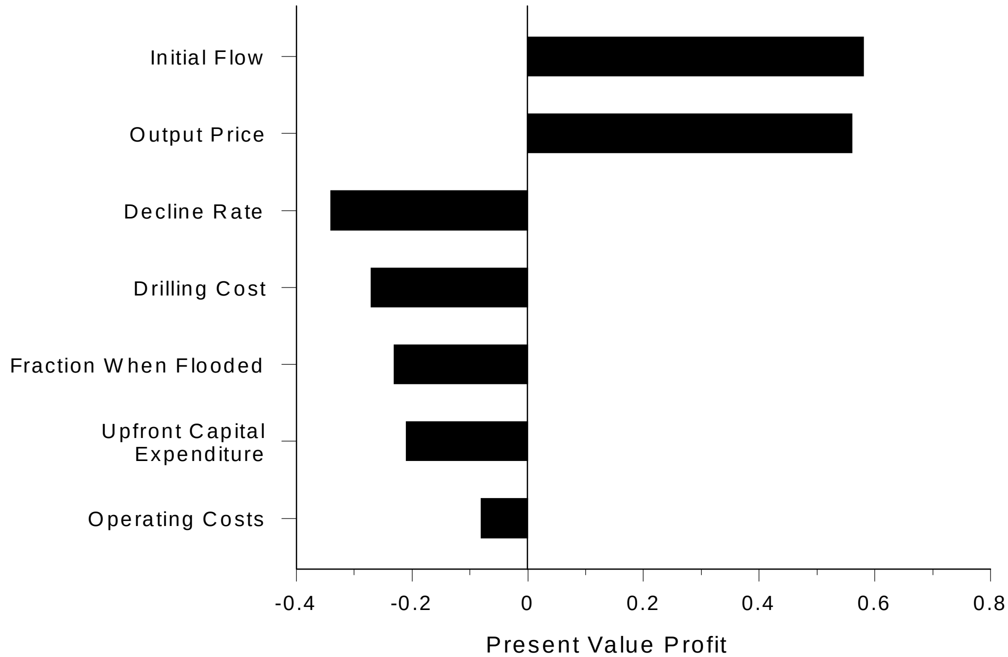
Analysis of Investment Incentives Under Royalty Relief

The Outer Continental Shelf Deep Water Royalty Relief Act (DWRRA) was passed in 1995 and mandates royalty relief for certain oil and gas leases in at least 200 meters of water in the Gulf of Mexico.[5] This legislation has been one of the most controversial national policies affecting gas and oil activities in the deep water. Opponents have charged that the program is an unnecessary financial reward. Proponents have claimed that the combination of royalty relief and recent technological advancements in the deep water are the prime reasons for record lease sales by the Minerals Management Service (MMS) in 1997. The implications of the DWRRA are assessed by use of the DCF model. Results of the economic evaluation under conditions of uncertainty show that the major stimulus of the DWRRA may be more from its impact on the relative chance of success and failure, than from the simple gains in expected returns.

The DWRRA defines the deep-water area as that in water depths greater than 200 meters (656 feet). The deep-water

[5]Title III of S.395, *The Alaska Power Administration Sale Act*, signed into law by President Clinton on November 28, 1995.

Figure C3. Rank Correlations for Present Value Profit and Input Variables



Source: Energy Information Administration, Office of Oil and Gas.

Table C3. Required Initial Production Rates Based on Alternative Cost Assumptions

Test A. Drilling Costs per Well			
Drilling costs (million dollars)	5	10	15
Required initial production rate (million cubic feet per year)	3,905	4,797	5,700
Test B. Upfront Capital Costs			
Capital costs (million dollars)	275	350	425
Required initial production rate (million cubic feet per year)	3,231	4,797	6,382

Note: The *required initial production rate* is that rate at which present value profit is zero.
Source: Energy Information Administration, Office of Oil and Gas.

zone is further divided into three parts for different levels of royalty relief. The zones are 200-to-400 meters (656-1,312 feet), 400-to-800 meters (1,312-2,625 feet), and greater than 800 meters (2,526 feet). The DWRRA provides for volumes of new production that will not be subject to royalty payments. Production in excess of the stated levels is subject to standard royalty charges (Table C4). An eligible lease is one that results from a sale held after November 28, 1995, 200 meters or deeper, lying wholly west of 87 degrees 30 minutes west Longitude.

A sensitivity analysis was conducted to show the impact of the DWRRA on a new field project evaluation. The previous analysis of the representative project was based on the assumption that the project qualified for royalty relief under the DWRRA. Removal of the royalty relief benefits from the project assessment shows a clear shift in the investment incentives for this project. Substantial profits remain a distinct possibility, with a 25-percent chance of profits of $38.3 million at the 10-percent discount rate, compared with a 35-percent chance in the base case results.

Table C4. Offshore Oil and Gas Volumes Exempt from Royalty Charges Under the *Outer Continental Shelf Deep Water Royalty Relief Act*

	Minimum Volumes	
Depth	**Barrel of Oil Equivalent** (million barrels)	**Equivalent Gas Volume** (billion cubic feet)
200-400 meters (656-1,312 feet)	17.5	98.5
400 to 800 meters (1,312-2,625 feet)	52.5	295.6
>800 meters (2,526 feet)	87.5	492.6

Note: The barrel of oil equivalent volumes were converted into billion cubic feet based on assumed heat content of 5.8 million Btu per barrel of oil and 1,030 Btu per cubic foot of gas.

Source: Energy Information Administration, Office of Oil and Gas.

However, the expected return from the PVP distribution PVP distribution shows an economic loss of $14.6 million, compared to the previous expected value of $1.4 million. The chance of at least breaking even decreased from 49 percent to 37 percent. Further, the IROR shifted downwards to 7.5 percent, a significant reduction from the earlier 9.8-percent return. The chance of achieving a 10-percent or greater return on this project is 37 percent without the royalty relief program (Figure C4). In fact, the program may be strongest in reducing the likelihood of losses as an important element in promoting additional investment in deep-water projects.

The royalty relief program increases the expected value return from the deep-water offshore projects. However, it also enhances the perceived returns in a fundamental way that is more readily apparent when such a project is assessed under conditions of uncertainty. In light of the substantial investment volumes involved, corporate managers would have to be risk neutral in order to be unaffected by the shift in the relative occurrence of success and failure. Risk aversion on the part of the firms active in this region likely would result in avoiding such marginal investments without the additional relief.

Evidence supporting this assessment of the impact of the DWRRA can be found in the lease sales conducted since the effective period for royalty relief began. Federal lease sales during 1991-92 resulted in the MMS accepting only 878 bids from companies. The 1993-94 Outer Continental Shelf sales resulted in only 943 accepted bids. In 1995-96, the number of accepted bids increased to 2,204. In the last four sales during 1996-97, each sale broke the previous record for submitted bids. The stimulus from the royalty relief provisions seems readily apparent when the bids are broken down by water depth levels. The fraction of blocks in water deeper than 200 meters (656 feet) receiving bids in 1994 was less than 10 percent of all bids for blocks in the Western and Central Gulf of Mexico. By 1997, blocks in water deeper than 800 meters (2,526 feet) received more than half the bids (Figure C5). This is particularly impressive given that the water depth record for production was less than 1,800 feet a mere 10 years earlier. In 1995 there were only 5,000 active leases in the Gulf of Mexico region. By January 1997, this had reached 6,177 leases. Estimates from the MMS indicate that by 1998 there should be more than 8,300 leases.

The explicit treatment of risk and uncertainty is a useful tool for consideration of the royalty relief provisions as a stimulus for deep-water development. The analysis shows that the program strengthens the positive incentives to invest, while lessening the negative aspects of deep-water opportunities. It does not directly address the effectiveness of the policy in achieving the goal of motivating the intended behavior. Nor does this analysis show whether the royalty relief program is the best alternative to promote such behavior.

Figure C4. Cumulative Frequency Distributions for Internal Rate of Return for the Representative Gas Project With and Without Royalty Relief

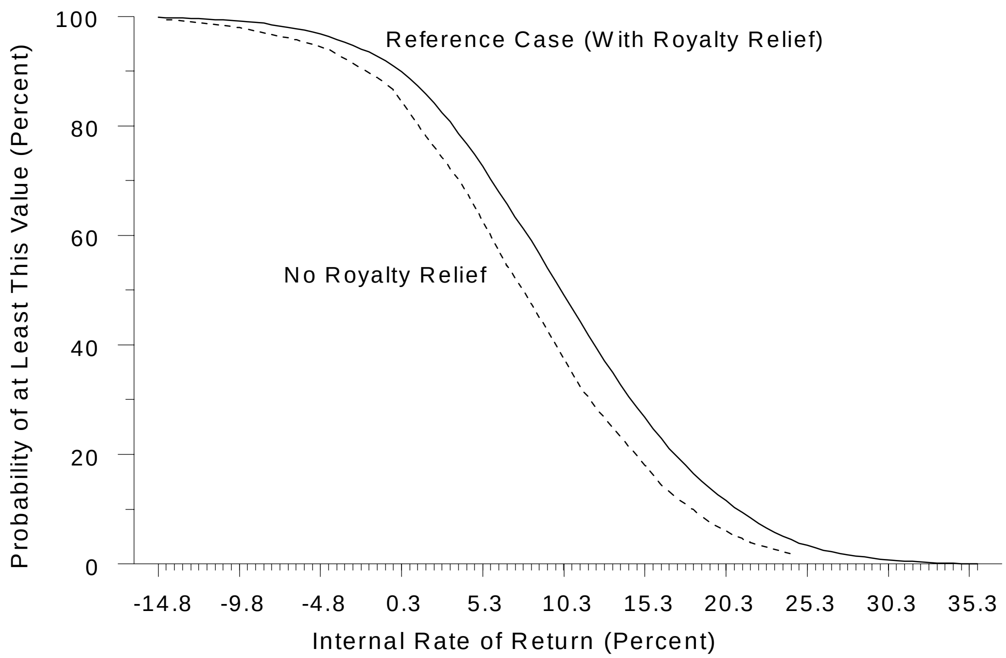
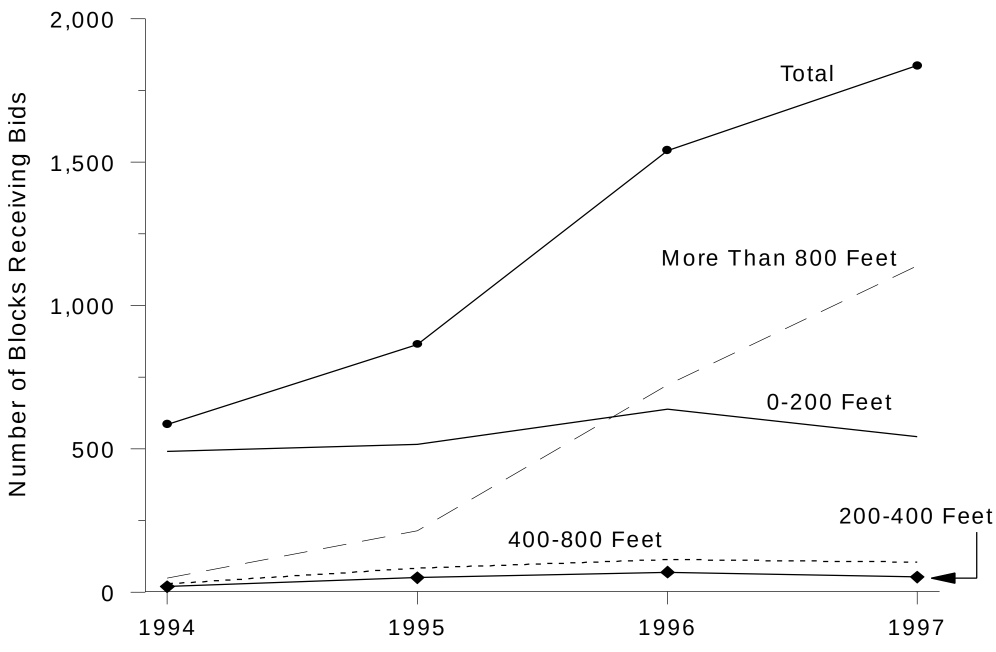


Figure C5. Gulf of Mexico Blocks Receiving Bids by Depth Class, 1994-1997



Source: Energy Information Administration, Office of Oil and Gas.