OTC 8710

Design and Rationale of the Final Rule on the Deep Water Royalty Relief Act

M.B. Rose, T.W. Farndon, and S.J. Fraser, Minerals Management Service

Abstract

Following passage of the Deep Water Royalty Relief Act in November 1995, the Minerals Management Service (MMS) implemented its deep water royalty relief program for existing leases (any in most areas of the Gulf of Mexico that were issued before the act and are located in water deeper than 200 meters) with publication of an interim rule in May 1996. Comments subsequently received from the oil and gas industry focused on six core issues: categorical qualification, application timing, certification, complexity, treatment of historic costs, and criteria for material changes and redeterminations. The first half of this paper reviews the basic relief qualification process and summarizes the changes MMS made in the program in response to industry comments as well as the reasons for making these changes. The final rule was published in January 1998.

Inquiries and initial applications submitted under the Act identified some oversights and omissions in the evaluation and implementation procedures. These included possible changes to the field composition after an application, poor representation of the geologic data, the effect of ownership changes on sunk cost, justifying the development option chosen over alternatives, unanticipated cost arrangements and structures, wide and skewed cost distributions, contingency and excessive overhead cost factors, and evaluating fields that mix pre- and post-Act leases. These issues prompted MMS to reexamine policy on field assessment, certain costing issues, potential alternative development systems, and field configurations. The second half of this paper reviews the lessons learned so far from experience with eight implementation issues.

This paper should afford those who seek deep water royalty relief in the future a better understanding of the process. The Act directs that MMS grant royalty relief only where it is economically necessary. However, forecasting the economics of a deep water oil and gas project is complex and subject to substantial uncertainty. Among other things, current economic assessments can be overtaken by rapid technological advances, by dramatic price or cost changes, or by increased experience and understanding of deep water oil and gas development. The MMS will balance this uncertainty with industry needs because royalty relief may well be a necessary condition for development of some significantly sized deep water fields.

Introduction

In the 10 years preceding passage of the Outer Continental Shelf Deep Water Royalty Relief Act (DWRRA) in 1995, production of oil from the Gulf of Mexico Outer Continental Shelf (OCS) was remarkably steady. For the years 1985 through 1994, annual oil production in the Gulf of Mexico Federal OCS (as measured by published crude oil and condensate sales volume) varied from a low of 272 to a high of 312 million barrels. The stability of these results was somewhat surprising, given the small proportion of production that emerged from newly discovered fields in this period.

Over 90 percent of the total production for the period was from shallow water leases (i.e., those in less than 200 meters of water). Thus, based on trends existing in the early to mid-1990's, a decline in Gulf of Mexico Federal OCS oil production by the turn of the century appeared inevitable. Under these circumstances, the Minerals Management Service (MMS) backed policies designed to encourage development of frontier areas of the OCS.

Nevertheless, MMS initially expressed several concerns upon reviewing early bills relating to royalty relief on deep water leases. These forerunner bills emphasized across-the-board royalty relief for existing leases based on capital recovery cost concepts. Both congressional funding rules for new programs (i.e., “Pay-as-you-go” provisions) and MMS responsibilities to ensure receipt of fair market value, mitigated against broad scale royalty relief unrelated to need. Further, because of experience with profit share leases, MMS was apprehensive about another capital recovery system that required extensive and continuing administrative and accounting burdens.

The final version of the deep water bill addressed these concerns. It authorized MMS to provide relief for existing leases only if royalties would make a difference with regards to developing or not developing a field. Also, the form of relief would involve only a simple suspension of royalty payments for a predetermined amount of production. With these modifications in place, the royalty incentives language was added to the Senate's Alaskan Power Administration bill. Now supported by both MMS and the Department of Energy, the bill passed both houses of Congress by about a two to one margin, and was signed as Public Law 104-58 by President Clinton on November 28, 1995.

This paper focuses on those elements of the DWRRA that relate to existing deepwater leases. Note, however, that the Act added several new responsibilities and requirements for other categories of leases as well. For example, the Secretary of the Interior's authority to reduce or eliminate royalties was explicitly extended to nonproducing lease in most areas of the Gulf of Mexico, regardless of water depth.

Also, all new deep water fields leased in the Gulf of Mexico region through the year 2000 have automatic royalty volume suspensions similar to the large minimums (from 17.5 to 87.5 million barrels of oil equivalent, depending on water depth) specified for qualified existing deep water leases. It is instructive to observe that in the 2 calender years preceding passage of the DWRRA, bidding for newly issued leases in deep water was modest at best: 78 tracts in 1993, and 71 tracts in 1994. Subsequently, bidding on deep water tracts exploded: 334 in 1995, 877 in 1996, and 1,280 in 1997. Clearly, the mandated royalty suspensions available to new fields, regardless of economic need, played an important role in this outcome.

In implementing the DWRRA, the MMS issued an interim rule in May 1996 and a final rule in January 1998. Along the way MMS conducted a 2-day public workshop attended by over 200 participants, held an industry session at offices of the American Petroleum Institute and reviewed numerous comments submitted in response to the proposed rules. In the end, the final rule consisted of the following major elements for deep water royalty relief for existing fields, some of which will be discussed later in the paper.

- Stipulated minimum royalty suspensions volumes are related to the fields upon which the leases reside, not to each individual lease on the field.
- To receive approval of relief, the MMS must be convinced by a documented, quantitative analysis both that the field is unprofitable without relief and that it can be made profitable with relief.
- Companies may avail themselves of a two-stage application process, but MMS is not bound by its findings in the first stage.
- Royalty relief, if approved, is conditional on the fulfillment of several performance conditions associated with the actual timing, cost, and type of development system, in comparison to equivalent elements presented in the application for relief.
- Royalty relief, if rejected, may be reapplied for under certain conditions involving designated changes in geologic information, resource prices, or cost.
- Special rules have been designed to handle particularly complex issues associated with evaluating applications (e.g., allocation of royalty relief among leases in a field, eligibility of cost elements, treatment of input uncertainty, quantification of financing terms, and provisions for selecting the appropriate development systems, costs, and timing scenarios).

In all of these cases, the goal was to balance the intent of the Act, fairness to individual applicants, and MMS's programmatic responsibility to serve and protect the public interest. This paper describes how MMS chose to achieve this balance. The first section reviews the basic relief determination process. The following section summarizes how MMS responded to six major issues raised in comments on the interim rule. Then a section discusses implementation problems encountered during 18 months of operation under the interim rule, and the concluding section offers some general observations on the process and MMS's experience.

Deep Water Royalty Relief Process

Leases in existence before November 1995 whose lessees desire royalty relief for a deep water Gulf of Mexico field must apply to the MMS regional office. Applicants need to demonstrate that the field actually can be produced economically with relief from Federal royalties. MMS then determines whether the field could be produced economically without relief from Federal royalties. This section reviews the key elements in this process and highlights the changes from the interim rule to the final rule.

Application. The requirements of the application are enumerated in the final rule while specific instructions for how to comply with the application requirements are contained in the deep water royalty relief guidelines. Basically, an applicant must prepare an economic analysis using the MMS software, RSVP. RSVP is an acronym for *Royalty Suspension Viability Program*. The final rule adds an option for applicants to request a preliminary, nonbinding evaluation before submitting the formal application for the field.

Reports. Applications consist of a series of six reports that present and defend all the basic data needed to perform an economic analysis of the field.

- The Administrative Information Report contains material concerning ownership of each lease in the field, identifying data about each existing and proposed well in the field, a description of the field history, any royalty obligations other than to the Federal Government, what category of relief is being applied for, and a narrative description of the planned field development.
- The Deep Water Economic Viability and Relief Justification Report contains the economic analysis that justifies relief for the field, including analysis using RSVP.
- The Geological and Geophysical Report contains raw and interpreted data intended to support the inputs to the resource estimation module of the RSVP.

- The Engineering Report justifies the method of development proposed for the field.
- The Production Report identifies the timing, rate, duration, and expected production profile from the development of the field as well as evidence of the expected product quality.
- The Cost Report identifies and provides supporting evidence of the spending profiles for delineation, development, and production activities for each potential scenario.

New to the final rule, approved applicants must submit a Fabricator's Confirmation Report and a Post-Production Report instead of the interim rule's Preproduction Report requirement. These reports verify compliance with the performance conditions which must be met to activate relief.

- The Fabricator's Confirmation Report is filed when fabrication begins on the production facility. It officially notifies MMS of what type of development system is being constructed and when fabrication actually started.
- The Post-Production Report is filed within 60 days after first production from the field. It documents all expenditures before first production.

Software. The MMS computer program RSVP is central to the economic analysis required to justify a request for royalty relief. In conjunction with the publication of the final rule for deep water royalty relief, MMS released RSVP version 2.0. All applications submitted under the final rule must use the program RSVP 2.0, until further notice.

The RSVP is a spreadsheet program. Originally, the RSVP was programmed and ran on *DOS* versions of *LOTUS 1-2-3* and *@Risk*. The RSVP 2.0 is a reprogrammed version that uses Microsoft's *Excel* and Decisioneering's *Crystal Ball*. The current program is fully functional in either the *Windows* 3.x or *Windows 95* environment.

The conversion of the program to this new software affords the user convenience in acquiring the necessary software, user friendliness in working in a Windows environment with direct linking between the spreadsheet and risk analysis software, and increased flexibility. Users can choose from 17 types of input distributions compared to the limited choices of only triangular or lognormal distributions in the original version of RSVP.

Validation. MMS uses the information contained in the royalty relief application to decide whether the field merits royalty relief. The first step in this process is the completeness review. MMS does a completeness review during the first 20 working days following the submission of a royalty relief application to confirm that all the necessary elements of the application are present. The completeness review is not an evaluation of the data for reasonableness, nor does it absolve the applicant from being asked to supply additional data if found necessary.

Following the completeness review , the evaluation begins. Specialists in each discipline review the data contained in the application to determine if each item is reasonable and represents the best possible interpretation or method of doing things. Geologists and geophysicists review all of the data contained in the Geological and Geophysical Report as well as all other relevant data in the possession of or obtainable by MMS. Often this review will involve an independent interpretation of the field's reservoirs for comparison with the applicant's interpretation. Engineers review the Engineering and Production Reports to determine if the planned development scheme and expected production profiles are reasonable. Economists and engineers review the Cost Report to see that all costs are fairly represented and conform to requirements concerning overhead and other allowable cost issues. The MMS uses all available material to make these determinations, including its existing Gulf of Mexico database and expert systems software for estimating costs.

The entire MMS evaluation team of experts becomes involved in reviewing the RSVP inputs for reasonableness and correct usage. Special attention is paid to the characterization of uncertainty in the model inputs and whether the distributions and applied risk factors are reasonable.

Several important checks have been added to the evaluation of model inputs beginning with use of the new RSVP version 2.0. First is a check to see if sunk costs provide the margin of acceptance for deep water relief. If so, this is a signal for a possible audit of sunk costs. Next is a check to see that at least 90 percent of the RSVP iterations are used in the calculations of net present value (NPV). If more than 10 percent of iterations invoke the loss limiting rule, this indicates that the data are too uncertain. Finally, there are two checks on the symmetry and scatter of the application data. One is to see that the mean value of capital costs over all trials does not exceed the applicant's point estimate of capital costs for the most likely scenario by more than a reasonable percentage (currently 7.5 percent). Two is to insist that the most likely scenario cover at least 1/3 of all trials. Together, these refinements insure that the best estimate for the most likely scenario is representative of the uncertainty the applicant faces while allowing applicants to use multiple scenarios to incorporate modest costs for expected and unexpected problems. We chose the 7.5 percent parameter value as the midpoint between a 20 percent cost increase and a 5 percent cost decrease. If costs are more than 20 percent above the most likely estimate, then some trials are inconsistent because the conditions they portray would authorize a redetermination. A 5 percent cost decrease represents a conservative estimate of cost saving that the applicant may be able to achieve.

Evaluation. The economic viability analysis is the key element in the application. Once satisfied that all the necessary data are reasonable and complete, the MMS evaluation team examines the applicant's economic analysis of the field without royalties and conducts another with royalties.

Dual Criteria. The RSVP is used to perform two economic tests in the deep water royalty relief economic evaluation process. First, applicants use it to calculate the prospective net present value (PNPV) of the field. That is, prospectively speaking (ignoring sunk costs), could the field ever become economic even if it never has to pay Federal royalties? Applicants may choose the discount rate for this evaluation from a range prescribed by MMS (currently 10 to 15 percent). This choice recognizes diversity among applicant's costs of capital and risk preferences.

The PNPV must be positively valued for the field to qualify for relief. A negatively valued PNPV indicates that it is not economic to develop the field in the prescribed manner because, even while never paying Federal royalties, it will not even recover the planned future investments, much less past ones.

Second, MMS uses an augmented version of RSVP to calculate the field's full net present value (FNPV) at the same discount rate the applicant used to calculate PNPV. The FNPV is the test of whether the field could become economic while considering post-discovery historic (sunk) costs and while paying full Federal royalties. The FNPV must be negative for the field to qualify for relief. A positively valued FNPV indicates that the field can be economically produced even considering sunk costs and the obligation to pay Federal royalties at the full lease rate.

Fields that achieve a positive PNPV and a negative FNPV will be awarded at least the minimum suspension volume prescribed by the DWRRA. Minimum suspension volumes vary according to the water depth of the leases that comprise the field. The DWRRA directs MMS to determine the appropriate royalty suspension volume should the minimum not prove to be enough. The RSVP is also used for this volume determination. In the PNPV mode, royalties are entered into the calculation following the minimum suspension volume. A positive value indicates the minimum suspension volume is adequate. A negative value indicates a larger suspension volume is needed. In these cases, a tailored suspension volume is calculated using the RSVP by trial and error.

Another new feature that has been added to the RSVP in version 2.0 is loss limiting. On each iteration, the loss limiting feature estimates the field's NPV without considering royalties or sunk costs using a low discount rate (currently 5 percent). The purpose of loss limiting is to identify illogical results. For instance, when RSVP draws random samples it is possible that very small reserves could get drawn together with very high costs, resulting in large, readily foreseen losses. Such extreme outcomes would not happen in the real world so they are eliminated from the theoretical world. Note that substantial losses calculated at the applicant's chosen discount rate are not identified as illogical. The loss limiting feature replaces the huge losses indicated by the PNPV and FNPV calculations from iterations that fail to achieve a positive NPV at the loss limiting discount rate. For these iterations, a negative NPV of the first year's proposed development cost is assigned for PNPV evaluations and a negative NPV equal to that amount plus sunk costs is assigned for FNPV evaluations.

Simulation Model. The RSVP is a development and production simulation and discounted cash flow model that estimates resources from all reservoirs, the cost of production facilities, numbers and costs of development wells, the ultimate recovery, and the NPV of the field. The program relies on statistical distributions of input variables, provided by applicants and verified by MMS, to employ stochastic sampling as it performs repeated calculations over many iterations. The results of each calculation are saved, and collectively the results of all trials produce distributions of possible results.

The RSVP performs two distinct functions. It calculates field resources in the Resource Module and then calculates field economics using the Viability Module. Both modules work in concert, however, since the field resources calculated in the Resource Module are needed to calculate field economics in the Viability Module.

On each simulation iteration, the Resource Module does several things. It predicts whether each reservoir will produce by sampling from the binomial input distribution of the *Probability the Reservoir Will Produce*. Further, it predicts whether each reservoir will be an oil reservoir or gas reservoir or both by sampling a custom input distribution of the *Probability of an Oil Reservoir, a Gas Reservoir, or an Oil and Gas Reservoir*. Also, it samples from input probability distributions of *Gas-Oil Ratio, Condensate Yield, Acres, Average Net Pay, Oil Recovery,* and *Gas Recovery* for each reservoir and then computes the gross reservoir volume and the oil, associated gas, gas, and condensate resources for each reservoir. Finally, the Resource Module calculates the field results of the above items by summing the results across all reservoirs.

The objective calculations of the Resource Module (which become key inputs to the Viability Module) are total field resources expressed in barrels of oil equivalent (BOE) and the fraction of this figure that is liquid hydrocarbons (composed of oil or condensate). Another Resource Module result that is important to the Viability Module is the identification of dry exploration reservoirs. For each reservoir, applicants indicate in the resource module whether the reservoir has been previously penetrated by a well. For purposes of evaluation reservoirs that have not been penetrated are deemed exploration reservoirs. The Viability Module does not count drilling and completion costs for exploration reservoirs that are sampled as being dry during an iteration. The model presumes that the applicant would not drill the reservoir on those trials. This is a new feature of the RSVP and is exclusive to RSVP version 2.0.

The Viability Module employs a two-stage sampling of resources and reserves that simulates a sequential decision-making process. In the first stage, the Resource Module calculates the field's ***resources***. Field resources represent the volume of recoverable hydrocarbons thought to exist at the time of the application. The Viability Module uses field ***resources*** to simulate the decision concerning which development platform scenario and related infrastructure to construct and to predict if oil or gas will be the dominant product from the field.

In the second stage the Viability Module calculates the field's ***reserves***. The Viability Module samples reserves from a truncated normal input distribution of resources that is unique for each iteration. The mean value used to establish each iteration's unique distribution is the resource estimate from the iteration (calculated in the Resource Module). Each iteration's unique distribution is further characterized by using the minimum and maximum value and half the standard deviation of the entire output distribution of field resources (determined through a separate earlier simulation of the RSVP's Resource Module). The Viability Module samples oil fraction for the field's reserves in an identical manner by using the Resource Module results for the oil fraction of the field's resources. This "second sampling" of field reserves produces a random reserves estimate that is related to the original resource estimate and simulates the sequential knowledge gained about a field's resources and reserves during its development. The Viability Module uses field ***reserves*** to simulate decisions concerning how many and when wells will be drilled and completed. The reserves estimate is also the determining factor on which production profile will emerge and what the ultimate recovery will be for the field.

The Viability Module samples on each iteration from distributions of average well drilling costs, average well completion costs, oil and gas transportation costs, oil and gas prices, and price growth vectors. This sampling is independent of resources, reserves, and any related variables. All of this sampled data from an iteration is then used to perform a discounted cash flow evaluation of the field. The objective of the discounted cash flow evaluation is the NPV of the field. Depending on the mode of the RSVP simulation, the mean of the distribution of NPV from every iteration is the PNPV or the FNPV.

Look-back Features. The royalty relief qualification determination is a forecast that largely depends on assumptions and information provided by applicants. Applicants have an inevitable incentive to interpret the subjective information they provide to improve chances for qualifying because even if they barely qualify, they get very large suspension volumes. To offset this tendency, MMS relies on a few performance conditions and redetermination requirements as well as the RSVP analysis and the review process described above.

To guard against premature applications, applicants must adhere to certain key assumptions, the violation of which invalidates the evaluation. These include a stipulation that any relief granted is only valid for the type of development system proposed in the application. Also, any relief granted is valid only if fabrication on this system starts within 1 year of relief approval. Finally, actual preproduction costs must be at least 80 percent of those estimated in the application to keep all the royalty suspension volume. Applicants who notify MMS that actual costs ended up lower than 80 percent by the time production begins keep one-half the royalty relief suspension volume. Otherwise, as with the other two performance conditions, the regulations revoke all relief. The structure of this arrangement mitigates incentives to unnecessarily incur large amounts of costs to retain relief or for applicants to forecast develop they don't really intend to spend.

To guard against speculative applications, the regulations restrict the right applicants have to a reapply for royalty relief on a field to the occurrence of specific conditions that clearly invalidate an earlier evaluation. New well or seismic data obtained after the first application entitles an applicant to apply for a redetermination. Otherwise, MMS will revisit its determination on a field only if prices drop by at least 25 percent or costs estimates rise by at least 20 percent before production begins.

MMS Response to Comments on the Interim Rule

This section reviews how MMS responded to major issues raised in public comments on the interim rule for deep water royalty relief. Overall, comments identified some 50 separate issues. Most could be dealt with as a simple yes or no decision or as a clarification of original intent. Six issues — categorical qualification, application timing, certification, complexity, treatment of historic costs, and criteria for material changes and redeterminations — sparked in-depth reassessment and, in some cases, changes to the interim rule structure. This section summarizes for each of these six issues the interim rule provision, its purpose, the complaint raised about it, and why and how the final rule responds.

Categorical Qualification. The interim rule specifies a process whereby MMS evaluates a data intensive application from each individual field that requests relief. This case by case process is justified under the mandate to give relief only where it is needed to make development economic and where the huge ($200 million range) royalty sums are at stake.

Comments suggested establishing minimum economic field size (MEFS) screens by water depth and development concept as an alternative means to automatically qualify smaller fields as uneconomic and in need of relief. Even if MEFS are only used as guides, comments argued that this would give potential applicants some insight before they started on the full scale application process.

MMS declined to adopt an MEFS qualification system because it is more difficult and less defensible than field-specific analysis. Rapid changes in technology and price expectations quickly outdate specific MEFS. Even as guides, they are more likely to mislead than help. To give them some durability, MEFS would have to be set so low that few if any potentially viable fields would pass them. Instead, MMS adapted a two-stage approval process suggested in comments to offer some of the benefits attributed to an MEFS process. MMS offers an explicitly nonbinding assessment to those who request it before the initial application on a field. Through it, potential applicants can get an opinion on whether their field seems likely to qualify without being bound to commitments in a formal application or risking a formal rejection which limits their chance to try again.

Application Timing. The interim rule set an approved Development and Operations Coordination Document (DOCD) as a prerequisite for a royalty relief application. This looked like a convenient milestone for assuring that enough planning and appraisal had been done to support a decision on whether relief would make a difference in the development decision.

Comments argued that this connection is inappropriate for several reasons. It delays the application until too late in the field assessment process to effectively change a nondevelopment decision. The DOCD may offer the appearance that the applicant intends to develop regardless of relief. Because of expense, DOCD's are not usually produced until after a decision to develop the project is made. Also, the DOCD approval process can encounter delays that hold up the application for reasons (e.g., environmental concerns) unrelated to viability.

The MMS response dropped the requirement for an approved DOCD because it is a weak indicator of appraisal progress. The application itself actually requires more appraisal information than the DOCD. Instead, the regulation includes another way to assure that a development decision is ripe. Fabrication on the platform must start within 1 year (as opposed to 2 years in the interim rule) of relief approval and new geologic information qualifies the field for only one (the first) redetermination. The MMS didn't see these modifications as onerous in the context of the typical deep water project timeline provided by industry.

Certification. The interim rule required several certifications in a relief application. Applicants had to certify that they would not develop the field without relief. Also, they had to certify that the information, including all the future cost estimates, in the application is accurate and complete. Further, they had to secure and submit an "unqualified" opinion from a certified public accountant (CPA) on the accuracy of the historical financial information in the application. These provisions are designed to deter applications for fields that are likely to be economic without relief and to assure as much accuracy as possible in the applications received.

Comments pointed out several problems these certifications create. Price, cost, or resource conditions, especially in the rapidly changing deep water arena, could improve enough to outdate nondevelopment pledges. Some believed such pledges would require that a project be rejected by their board of directors before it could apply for royalty relief. Also, some thought that a DOCD or possibly a request for a suspension of production would contradict this statement. Independent CPA certifications add extra cost to marginal fields, especially if applications don't happen to coincide with normal accounting cycles.

The MMS response dropped the nondevelopment pledge and relaxed the CPA requirement. Doing so recognized that requiring applicants to pledge they will not develop without relief is inconsistent with the qualification test. A field can be sufficiently profitable to justify continued development and production, but show a negative present value when sunk costs are considered (as MMS is obliged to under the DWRRA). The final rule relaxes the standard for, and hopefully reduces the cost of, the CPA opinion by dropping the requirement that it be unqualified. The independent certification is still vital as it makes an audit less necessary and expedites any that may be needed.

Application and Evaluation Complexity. The interim rule prescribed submission of probability distributions for key geologic and cost data and three scenarios for spending schedules and production profiles. These inputs are used in a Monte Carlo-based analysis of field value. This is viewed as a generally accepted analytical technique appropriate to the data uncertainty prevailing at a predevelopment stage for a project. Note, the DWRRA directs MMS to pay special attention to the "increased technological and financial risk of deep water development." The rule also uses a two-part test to confirm that fields found not to be economic paying full royalties would be economic with relief.

Comments argued that this process is too complex and intrusive. Instead of probability techniques, companies at the development stage rely on analysis of risk-adjusted reserve estimates and typical costs represented in a few discrete scenarios. Also, some felt MMS had no business rejecting an application for a field that would not show a profit without royalties if the applicant still wished to develop it.

While the final rule and guidelines do clarify that the model allows use of fewer scenarios (where more planning or appraisal makes that appropriate), it retains the basic methodology. The data detail offers MMS a way to validate resource and cost assessment and thus gain confidence in the applicant-supplied information. The two-part test further assures that MMS has a valid application that captures all the important factors in the development decision.

Treatment of Historic Cost. The interim rule established certain principles for sunk cost. To be candidates for inclusion in sunk costs, the activities funded must be unambiguously related to the field in the application. Accordingly, sunk costs exclude expenses incurred prior to the field being discovered. They also exclude all payments made to the Federal Government, most prominently lease acquisition costs, or payments made to other owners or parties in a profit-sharing or royalty arrangement (transfer payments). This follows from earlier net profit share rules. Also left out, to avoid moral hazard problems, are payments for damages, losses, fines, and penalties. Expenses for abandonment of wells and platforms in existence prior to the time royalty relief is granted are excluded since they represent preexisting obligations that are not directly related to the financial aspects of the development decision. Furthermore, under certain situations no sunk costs are counted in the evaluations. This occurs in the case of an application for a field already in production or for a capital expansion project. This treatment is consistent with earlier decisions by the applicants to develop and produce under existing lease terms. Also, sunk costs are not counted when the applicant is demonstrating the economic viability of the project without royalties, and when MMS calculates the size of the volume suspension when relief is approved. In the former case, MMS wants to measure the underlying prospective field value excluding transfer payments. In the latter case, MMS does not want to provide excessive amounts of relief.

Comments objected to a number of the sunk cost provisions. Some wanted any postlease acquisition costs incurred by or on behalf of the lessee counted. Others wanted them treated just like forecast costs (i.e., escalated to current period dollars and counted at before-tax amounts) to preserve their relative importance, especially in a redetermination. Still others objected to their inclusion in only some of the economic tests.

The MMS response clarified but did not change the treatment of sunk cost. The DWRRA requires, among other things, that MMS determine whether new production from the leases in an application for deep water royalty relief would be economic under the existing royalty arrangement. The term "economic" means that the project is sufficiently profitable to justify continued development and production. In making this financial determination, the DWRRA also states that MMS will "consider" all exploration, development, and production costs.

For the purpose of measuring financial performance, it is appropriate to include all past, current, and future project expenses. This treatment provides a means for ranking the overall profitability of various investment projects. This same treatment, however, does not provide guidance on which current projects to pursue. This is the case because the decision to proceed with development is not influenced by certain types of costs (e.g., those that have already been incurred or will have to be incurred anyway).

The MMS interpreted these directions to mean that it should include some but not all historic costs in the economic determination. Accordingly, evaluations include only historic costs which can be shown to relate to the field in the application, and then only in an amount that has not yet been recovered through other means. The MMS deems historic costs that meet this test eligible "sunk costs."

Material Change and Redetermination Criteria. The interim rule specified three material changes, any of which would cause MMS to withdraw or reduce relief, and three redetermination conditions, one of which must be met before MMS will reconsider an earlier determination. The material change conditions serve as explicit but modest look-back procedures to discourage premature applications. Applicants should have done enough delineation and planning to be willing to be bound to a particular approach, schedule, and cost estimate. The redetermination conditions support the same purpose by restricting chances for revising and resubmitting an application.

Comments noted an inconsistency between the interim rule and guidelines, which suggested the specific conditions mentioned were illustrative but not exhaustive. Some went on to argue that smaller price or cost changes, especially in combination, should be considered because they could be enough to reverse earlier determinations.

In response, the final rule and guidelines confirm that only the specific conditions listed would cause a withdrawal or qualify a redetermination. Obvious and fixed conditions avoid confusion and contention about when a determination may later be changed. Aside from tightening a couple of the listed conditions to compensate for allowing earlier applications, MMS stuck with the original criteria. Each of the specified changes are, individually, enough to invalidate an earlier determination. Further, they are sufficient to protect the public interest in not giving unnecessary relief without introducing the ambiguity and potential for frequent reevaluations inherent in smaller or combinations of changes in these factors.

The final regulation incorporates the changes discussed above as well as other less involved ones raised in the comments. The next section covers some issues encountered through efforts to implement the interim rule.

Issues in Early Applications

This section discusses eight issues raised in early applications or in questions from companies considering applications. They are certainly not all the implementation issues MMS will face, but they reveal how the MMS evaluation team (we, for the rest of this section) dealt with several unforseen complications and offer insight into how we might deal with similar issues in the future. For each issue, this section summarizes the relevant part of the rule, sketches the situation, describes our concern, and explains what and why we did or advised in each case.

Changes to Field Composition.

Background. The MMS field names committee assigns leases to a field when a well on the lease qualifies as capable of producing in paying quantities, goes into production, or is allocated production under an approved unit agreement. The MMS field names committee regularly publishes a list of leases on each identified field. Also, it update field definitions for new leases, data, or qualifying wells, any of which may be raised to MMS attention by a relief application. We take up to 1 month (20 working days) to determine whether a deep water royalty relief application is complete enough to evaluate. Once we accept an application as complete, we are obligated to make determination on it within 180 calendar days.

Situation. Field A, which is in close proximity to field B, applies for royalty relief. Each of the two fields is only tentatively identified since each has only one lease formally assigned to it. The same company holds the leases assigned to both fields. The application indicates that field A extends under two adjacent, but undrilled leases. In our review of the submission for completeness, it appeared that fields A and B may be the same field.

Concern. If we accept the application as complete and the MMS field names committee later confirms that A and B are the same field, we will have to evaluate a field that differs from the one described in the application. In effect, the application would be missing important data on the B part of the field. On the other hand, if we decide the application is incomplete, we penalize an application for conforming to MMS's last field list and for contributing data to update it. Also, if the MMS field names committee later concludes that A and B are different fields, then the application that we called incomplete would have turned out to be complete after all.

Response. In this situation, we decided not to delay relief evaluation for field A. Since its application was otherwise complete, we certified it as such. But, in the same letter we notified the applicant that the field we intend to evaluate may differ from the one described in the application. Also, since the applicant owned leases in field B, we alerted him that we may need more information from him to evaluate his application. On further review, the MMS field names committee decided A and B were separate fields, so it was fortunate that we did not interrupt our evaluation.

If, on the other hand, we had combined A and B into the same field, we planned to ask the applicant to agree to toll the clock (i.e., extend the statutory evaluation period) and modify the application to be consistent with the new field. The applicant could continue to contest this new field definition under our field appeal process, but would need to provide the extra data requested. We would resume our evaluation when he provides that extra data.

We doubt an applicant would decline to modify his application in this situation. But if the applicant should, we are inclined to reject the request for royalty relief due to a lack of the required data on the actual field. In other inadequate data situations (e.g., fields that appear to extend into unleased blocks, missing or implausible costs that the applicant can't supply or justify), we would proceed to evaluate with our best estimate for the missing input data. The field modification situation where the applicant owns other leases added to the field is different. As opposed to the unleased block situation, the applicant does have additional geologic data on leases that MMS now concludes are part of the same field. As for costs, necessary items can be better approximated from other sources than can the site-specific geologic data needed to proceed with a reasonable field evaluation.

Summary Insight.

- We don't delay evaluation of an otherwise complete royalty relief application while the MMS field names committee wrestles with modifying the definition of its field.
- Once an application is complete, we would suspend evaluation and request data on leases added to a field when MMS formally modifies the field definition.
- Only in the unique circumstances created when a subsequent field modification renders the application data incomplete do we consider aborting an evaluation and rejecting an application. But, we would be unlikely to do so unless we reserved that right in the completeness notification and the applicant failed upon our request to provide necessary information which he should possess.

Dealing with Poorly Represented Geologic Data.

Background. We rely on applicants to submit detailed information for fields seeking deep water royalty relief. Included in this information are certain raw and interpreted geological and geophysical data that is crucial to the calculation of recoverable resources for the proper economic analysis of the field.

In our role as the steward of the Nation's offshore resources, we have access to any geological and geophysical data collected on the Federal OCS. Therefore, we may posses other raw data on the field than that used by an applicant. This could be in the form of additional seismic surveys or simply data from neighboring or analogous leases that may not have been available to the applicant. We independently review the information submitted by applicants and may compare data and interpretations with other available material.

Situation. An application contains 3-dimensional (3D) seismic data on part of its prospect field and 2D seismic over the rest. In addition to the resulting incompatibility, the 3D data had scaling problems that distorted image interpretation. Also, we found substantial differences in net pay counts between those given in the application and those produced by generally used software for interpreting well logs. No explanation was offered to account for this. Finally, we were unable to decipher how the applicant determined minimum and most likely values for areal extent of individual reservoirs.

Concern. In order to make a defensible royalty relief decision, we must be able to understand and explain precisely how the data elements for the Resource Module of the RSVP were determined. Much of the interpretation of geologic data should be objective in nature. Once well tests and logs are available and maps are generated, the calculation of reservoir acreage, thickness, etc. is fairly straight forward. However, the manner in which uncertainty is expressed for these RSVP Resource Module data elements is more subjective in nature. The estimation of the probabilities that each reservoir will produce; the probabilities that each reservoir is an oil, gas, or an oil and gas reservoir; and the type and character of each of the input distributions for each reservoir's acreage, thickness, gas-oil ratio, and recovery are of paramount importance to the calculation of the field's economics. We may have data outside the application which we judge better represents some of these characteristics of the field.

Response. In this situation, we decided we had enough other data on the area to conduct a sound geological evaluation. We used our own alternative 3D data set on the whole area supplemented by the seismic data in the application to construct a consistent and reproducible depiction of the area. We then combined this revised interpretation with well log data from the application, some standard planimetering techniques, and information on plays and average recoveries available from our *Gulf of Mexico Atlas* project. This process allowed us to derive logical minimum and most likely values for net pay, reservoir area, and oil recoveries. We accepted the maximum values for these inputs offered in the application as reasonable. When we discovered that our revisions to the geological evaluation were not enough to disqualify the field for relief, we did not toll the clock to seek comment from the applicant.

Summary Insight

- We use application plus any other data we have on the field.
- We evaluate with the RSVP only inputs that we can independently confirm.
- We are more inclined to toll the evaluation clock and seek clarifications or additional data from the applicant when our proposed revisions to the application would cause it to be rejected.

Sunk Cost and Changes in Ownership.

Background. Among the principles we established for counting sunk cost is that they had to unambiguously contribute to the exploration, development, and production of the field in the application and that only those amounts that have not been recovered already are relevant.

Situation. Company M approached us about its plans to buy into a prospective project and then apply for royalty relief for the field it is on. Companies J, K, and L now own the leases in the field and have spent over $50 million on discovery and delineation wells. Company M's question was whether it could still count these sunk costs if they acquired the shares now held by Companies J and K. It argued that if it acquired ownership after a relief decision, those sunk costs would have been counted, so why not if it acquired ownership before the decision. A related question was that, if not, could the application still count those costs if Companies J and K retained nominal shares (1 percent) in the project.

Concern. A particularly troubling situation arises when parties who are not the potential recipients of royalty relief have incurred some sunk costs. For one thing, they may have little incentive to provide suitable documentation of their expenses. For another, they have been fully compensated for their activities by subsequent owners and no longer have liability for lease activities. In general, former owners enjoy neither the benefits nor the responsibilities of applicants.

A related problem, suggested by this situation, occurs when there is a break in ownership that is followed by reacquisition of an ownership share by the same company. If we allowed this reacquisition to modify the treatment of sunk costs in comparison to a case with a simple break in ownership, then there would be an incentive to form partnerships prior to applying for royalty relief solely for the purpose of increasing the chances for approval.

Further complications could arise if applicants can sell all of their interests in a lease while we are evaluating the application without affecting eligibility rules on historical costs. In these cases, similar verification and compensation issues discussed previously could arise.

Response. To avoid problems with the large variety of possible ownership arrangements, we intend to follow a few simple rules that are consistent with our general treatment of the sunk cost dilemma. Eligible sunk costs are counted only for current owners and their full shares only back through their most recent break in ownership. The rules for counting sunk costs continue until we make a final determination on an application. As such, a break in ownership during our determination could affect the amount of sunk costs that we count. However, the magnitude of the sunk costs that we include will not change if owners at time of application simply rearrange shares among themselves or retain some ownership while adding an additional owner.

Examples of ownership changes are discussed in the guidelines. The rules on ownership shares are applied separately to each lease on the field in the application. Accordingly, historic ownership shares held by company, lease, and time period must be carefully documented in the application.

Summary Insight.

- Rearrangement of ownership shares that includes all shareholders at time of discovery does not affect our treatment of sunk costs for a field.
- Breaks in ownership reduce allowable sunk costs in proportion to former owners shares.

Justifying Chosen Development System.

Background. The interim and final rules stipulate that we will withdraw approved royalty relief for a change in development system from the one proposed in the application. Therefore, applicants must decide on the single most economical development system for the field and proceed with that choice throughout development in order to remain eligible for deep water royalty relief. It is important that submission of the application be timed following this decision by applicants, since there is no changing systems following application for relief without losing the benefits of the relief. It is also important that applicants explicitly justify their decision in the application.

Situation. An applicant proposed to use a Spar Buoy Platform to develop its field. Our independent analysis indicated that in similar circumstances, other types of development systems (converted semisubmersible or mini-tension leg platform) have been preferred. Specifically, if subsea well heads were used, a converted semisubmersible platform appeared to promise better economics. Also, the greater expense of the proposed predrilled wells seemed a redundant expense with a drilling-capable Spar platform.

Concern. We are obliged to evaluate the most economical system for the development of a field. For many deep water development projects there may not be a clear and obvious choice as to which would be the most economical development system for the production of the field's reserves. Hence, we believe a necessary part of a complete application is a detailed explanation with supporting data of why the proposed system was chosen over other potential systems.

We realize that in making this decision applicants consider many factors including water depth; seafloor conditions; proximity of the field to other structures, existing infrastructure, or other potential future developments; the field geography and orientation of reservoirs; the preference for subsea wells or surface wellheads; and if the system will serve as a possible host for other developments. However, to be credible, the application must summarize these considerations.

Response. For this and other concerns, we tolled the clock and asked for additional explanation. The applicant's response indicated his choice of systems was justified by his circumstances. Specifically, the large number of recompletions and the cost of the necessary well maintenance anticipated made surface wellheads mandatory, eliminating the choice of a converted semisubmersible. As the mini-tension leg platform was yet unproven in the Gulf of Mexico, we agreed it was not appropriate for a marginal field. Based on subsequent analysis, we stipulated in the approval letter that relief was conditional on predrilled wells and on installation of a Spar Buoy Platform with surface wellheads and that could only accommodate a workover rig. Installation of a Spar with a drilling rig or capable of holding one would lose relief.

Summary Insight.

- We require a full explanation of why one development system is chosen as superior to alternatives.
- We carefully specify the development approach that must be used to keep relief we grant.

Facility Financing Terms.

Background. For the interim rule we designed a format for the economic analysis which envisioned that major facility acquisitions would occur as purchases from owner's capital -- or capital expenditures. The traditional discounted cash flow measure of the net worth of a project implicitly relies on this sort of purchasing terms. Further, both the interim and final rules are clear about the exclusion of interest as an eligible cost of development since these costs are explicitly "built in" to a traditional discounted cash flow analysis. Finally, to realize royalty relief the applicant must provide verification that he has met certain prescribed performance conditions on starting construction and on spending before production begins.

Situation. An application proposed the leasing, rather than purchasing of the platform facilities.

Concern. There is no limit to the creative arrangements that can arise when there is a need. The consideration of facility leasing raised a variety of pertinent issues related to facilities acquisition and capital expenditures.

- Included in private rental payments is a return on investment to the owner of the property. This is a cost to the lessee of the property that would not exist if it was purchased in cash. Moreover, this extra cost is akin to interest on a loan used to purchase the property.
- Lease payments continue after the cost of the property, with returns to the owner, has been fully paid. These payments have the combined effect of raising the cost of the property to the lessee above its value and forcing earlier abandonment. Monthly lease payments throughout the life of a project reduce the operating margin such that costs eclipse revenues sooner than in traditional purchase arrangements, thus, forcing premature abandonment.
- Leasing arrangements for production facilities raise real problems for enforcing the performance conditions. Applicants can claim they have no control over actual owner's construction schedules, and, with monthly rental payments in lieu of a purchase, there would is no capital expenditure to verify the 80-percent performance condition.
- Since the lessee of property does not own it, the property has no residual value (salvage value) to the lessee at the end of the project. If the property were truly owned by the applicant, it could either be reused or sold, assuming some useful life remained.

Response. We explored the appropriate treatment of alternative financing arrangements for typical capital investment expenditures at length. In the end, we decided that similar expenditures across all relief applications should be considered equally and optimally regardless of specific actions, needs, or creative financing arrangements by applicants. Therefore, to insure fair and consistent treatment, capital investments are to be considered in the conventional manner as lump-sum purchases made prior to installation and offset by salvage value at abandonment.

Where necessary, when applicants propose unusual financing arrangements, we will use applicant data to construct an imputed figure of development costs. We will use this estimate for the economic analysis and for the preproduction development cost target of the 80-percent performance condition. If the ownership of the property does not reside with the applicant, we will construct an imputed salvage value of the property to be used in the economic analysis.

If the applicant is not the actual owner of the property, the applicant shall be responsible for having the property owner notify MMS when construction has begun. The applicant is further responsible for providing documentation of actual preproduction costs (whether they are property owners or not) at the time of first production.

Summary Insight.

- We strive to preserve the integrity of the evaluation and confirmation process across a variety of applicant circum--stances.
- As necessary, we will standardize facility financing arrangements and impute potential salvage value to platforms, etc.

Degree of Uncertainty in Cost Scenarios.

Background. Applicants characterize uncertainty in three ways: with from one to three scenarios to represent possible development scales and production profiles, with ranges for capital cost estimates for each scenario, and with probability distributions to represent possible values for major geologic and cost variables. We use the expected value from a large number of trials (currently 1,000) drawn at random from these scenarios, ranges, and distributions to distinguish fields likely to be profitable from those not likely to be profitable. To encourage candid input assumptions, we reserve the right to withdraw or reduce relief for certain deviations from plans and conditions portrayed in the application. Such deviations, called material changes, invalidate our forecast of the field's value. One such material change occurs when actual preproduction spending turns out to be less than 80 percent of the application's best estimate of those costs. Conversely, when the estimate for development costs rise by more than 20 percent, a redetermination is in order.

Situation. An application estimates development drilling and capital costs as $300 million with a possible range of from -30 percent to +60 percent of that ($210 million to $480 million). The applicant argues that the wide range is needed to reflect the risk of shortages and escalating prices for key inputs like day rates for drill ships. Also, the $300 million point estimate combines a number of elements, some of which include a contingency factor of 15 percent to account for the possibility that one or more significant components may have been omitted.

Concern. We cannot reliably forecast whether royalty relief makes a difference between profit or loss because the application is too vague. Actual development costs could be half or as much as double the estimated value. Indeed, some portion of the evaluation trials use costs that signify a material change (they are less than 80 percent of the applicant's best estimate of preproduction costs). These trials are inconsistent with an assumption of either zero or full royalties because they would cause a mandatory reduction in relief. Another, larger portion of the trials use costs so high as to indicate that so much changed that the applicant is entitled to a redetermination. In general, proposals that allow costs to vary by this much imply that the application is premature because applicants are not yet confident enough in their cost estimates to be willing to be held to them as a condition of keeping relief for which they may qualify.

The unsymmetric cost range and the contingency factors serve to deflate the expected value estimate for the field. Cost samples above the mean dominate those below the mean, indicating that the $300 million is below the mean value of the preproduction costs. Also, the 80-percent material change threshold specified by the regulation ($240 million in this case) is really more than 20 percent below what the whole application indicates is the expected preproduction cost. Uncertainties expressed through contingency factors shift the mean values of cost distributions above the most likely value as presented and supported by backup reports. Yet that is the estimate we verify in our evaluation. Contingencies offer more evidence that the proposal is premature and serves to double count uncertainty in the evaluation structure.

Response. We ask the applicant to revise his cost estimates in two ways. One, eliminate a separate contingency factor and include any residual risk associated with incomplete design either in the separate development scenarios or in the range around the expected cost estimate. Two, confine the range around the expected value to no more than plus or minus 20 percent. Either the applicant or we must narrow such estimates to be consistent with the standardized evaluation structure prescribed in the regulations and to insure fair treatment of all fields that apply for a volume suspension.

For the final rule, we seek to preclude premature applications like this one with four technical changes to how we implement the relief evaluation. One, we revised the standard model to calculate the sampled distribution of capital costs, preproduction costs, and of all costs, both for all trials and for just those using the applicant's most likely scenario. Two, we stipulate that the all-trial mean of capital costs cannot exceed the mean of the most likely scenario by more than 7.5 percent and that the confidence interval on capital costs in the most likely scenario be symmetric around the input amount. Three, we also stipulate that the minimum value of preproduction costs not be less than 80 percent of the mean of the most likely scenario. Four, we make clear in the guidelines that we consider contingencies or multipliers in cost estimates ineligible because they double count uncertainty.

Summary Insight.

- We will not allow applicants to use uncertainty specifications to bias cost estimates or to invalidate performance conditions.
- We have and may again enhance the RSVP model to highlight for us and for applicants input configurations that appear to do this.

Treatment of Overhead Costs.

Background. Deep water royalty relief guidelines substantially adopt the cost accounting structure prescribed in regulations for Net Profit Share Leases. This structure describes what we consider allowable charges in a variety of cost categories (e.g., labor, materials, contract services) because they reasonably benefit development and operation of a field. This structure permits inclusion of shares of indirect or joint costs (i.e., costs of activities that benefit more than one development), which can and should rightfully be allocated to the field. It acknowledges that some joint costs may be difficult to explicitly allocate by also allowing a modest overhead amount (4 percent when large capital costs are being recovered and 10 percent thereafter) for certain cost categories.

Situation. We received an application that included a 20-percent overhead in cost estimates, but did not try to allocate joint costs to the field. The applicant cited convenience and tax reasons for avoiding project accounting on vital support and safety activities and noted that this overhead rate is typical among comparable companies. Further, the applicant argued that building a tracking system to identify and allocate appropriate shares of corporate wide costs is too costly an activity to impose on a marginal project just to meet the verification report due when production starts. The applicant views joint cost allocations as feasible only where project accounting structures are established.

Concern. We have no expertise at determining appropriate overhead charges, yet those proposed in this case exceed the value of royalty relief for marginal fields. Marginal projects, which are the target for royalty relief, should have cost streams close to revenue streams. In that situation, it is likely that the value of a 12.5-percent royalty is less than a 20-percent overhead amount. Why should the external landowner forego a share when the indirect internal corporate support collects its customary share from marginal projects? We do not allow royalty overrides, which in many ways are similar to overhead. In general, marginal prospects, as opposed to clearly profitable prospects, should pay marginal cost not the average cost for common or joint activities in a company.

As for determining an appropriate overhead rate, applicants provide the estimates for future costs. Our ability to verify those are based on comparison with other projects or available costing systems. These sources either don't break out overhead or use much more modest percentages. Typically, these independent costing sources do not offer guidance on what general and administrative activities should cost, perhaps because they vary so much by company. Also, defining legitimate overhead rates requires at least some rough accounting system to identify joint activities and determine a share that is appropriate for the field that is the subject of the application. In that case, applicants should be able to attribute an appropriate share to the field as allocable joint costs.

Response. We continue to prescribe a standard 5-percent overhead rate, much as we prescribe a standard price forecast. We set it at a modest amount so it is unlikely to alone be the deciding factor in whether the field qualifies for relief. The approach puts all applicants on a common footing and avoids complexities of dealing with corporate accounting that divert attention from estimating whether the particular field is worth developing. By the same logic, we decided to base decisions on before tax cash flow so as to avoid the issue of what the appropriate tax rate is for an individual applicant. In general, profitability forecasts at a predevelopment stage are simply not precise enough to capture all possible variables.

Summary Insight.

- Overhead is reserved for those rare common costs that cannot be reasonably allocated.
- Candidate fields for royalty relief should pay a smaller share of common costs than more profitable developments.

Mixing Pre- and Post-Act Leases on a Field.

Background. Leases acquired in a sale held within 5 years after the DWRRA are called Eligible leases. Eligible lease automatically qualify a nonproducing field to which we assign them for the minimum suspension volumes specified in the DWRRA. Leases acquired before the DWRRA must apply and pass an economic-need test to qualify their nonproducing field for relief. Typically, multiple leases overlie a field, and unless there is an approved unitization agreement, relief is allocated based on actual production. We do not require that fields be unitized to get relief. But relief applications must include all leases on the field, unless we grant an exception. Successful applicants must meet performance conditions to keep relief.

Situation. Lease X, a pre-Act lease, and lease Y, an Eligible lease, propose to jointly apply for royalty suspension on a nonproducing field that is in 900 meters of water. The applicants argue that lease Y can only produce 25 million barrels of oil equivalent (BOE) from its part of the field.

Concern. In evaluating the application for economic-need, we need to account for the fact that the field already qualifies for as much as 87.5 million BOE of royalty free production. If there is no approved unitization agreement, however, we cannot be assured how much production lease Y will actually achieve. Reserve estimates tend to grow in time. Also, if we approve the application for lease X to share relief or for additional relief for the field, we cannot hold lease Y to the performance conditions on which we depend for assurance that the application represents the field's true prospects.

Response. To be fair to lease X, we do not arbitrarily assume that lease Y will ultimately find a way to produce all the royalty free volume to which it is already entitled. Instead we evaluate the application in the absence of relief using our best judgement about how much lease Y will ultimately produce royalty free. To account for lease Y's freedom from performance conditions, we typically construct and sample from a distribution of possible production levels for lease Y. If we then foresee a profit for the field, lease X does not qualify to produce royalty free. Lease Y retains all royalty free production that was part of its lease terms. If the field appears to lose money despite the relief lease Y can use, lease X qualifies to share relief and even to increase the field's relief if that is warranted.

As for performance conditions, lease Y keeps its automatic relief regardless of what transpires. Lease X keeps relief it qualified for if development matches the proposed system, construction starts within 1 year, and its owner certifies that at least 80 percent of the preproduction cost estimate was spent. If all predevelopment costs are certified but are less than 80 percent of the application's estimate, lease X retains access to half of the field's relief. If the owner of lease X can only certify part of the preproduction costs spent on the field (e.g., lease Y declines to certify expenditures), lease X may lose all relief. This would occur if the applicant is unable to certify spending at least 80 percent of the preproduction cost estimate in the application. The logic here is that incomplete certification is akin to providing intentionally inaccurate information, which is grounds to withdraw approval of relief.

Summary Insights.

- We evaluate the economics of a field counting whatever royalty relief it already has and is likely to use.
- We recognize and attempt to compensate for the fact that Eligible leases on a field cannot be held to performance conditions.

Conclusions

The final rule on deep water royalty relief for existing leases defines the system we have devised to implement the mandate in the enabling legislation to suspend royalties only where it is economically necessary. The rule is complicated because evaluating the prospective economics of an oil and gas fields is complex, especially when new leases and some historical cost must be considered, and subject to substantial uncertainty. We have decided to deal with that situation by relying on a detailed presentation of intentions in a complete application, a stochastic evaluation process buttressed by modest look-back conditions that preclude violation of certain key assumptions. Nonetheless we recognize that current economic assessments can be over-taken by rapid technological advances, by dramatic price or cost changes, or by cumulative additions to our experience and understanding of deep water oil and gas development. As our evaluation capability evolves, we will continue to balance public and industry interests because we believe royalty relief is a necessary condition for development of some significantly sized deep water fields.

Acknowledgments

The authors thank Mike Melancon, Kevin Karl, and Al Durr of the MMS Gulf of Mexico regional office for always providing a practical counterpart to our theoretical perspective. Also, we appreciate the contributions of a number of individuals in industry that have stepped forward with real applications or thoughtful questions on the interim rule. Finally, we thank Brenda Dickerson and others in the MMS rules processing team for their tenacity in getting the complex rule through the approval process so we could release this paper.